ORDER NO. 89072

IN THE MATTER OF THE APPLICATION OF THE POTOMAC EDISON COMPANY FOR ADJUSTMENTS TO ITS RETAIL RATES FOR THE DISTRIBUTION OF ELECTRIC ENERGY	* * * * * * *	BEFORE THE PUBLIC SERVICE COMMISSION OF MARYLAND CASE NO. 9490

Before: Mindy L. Herman, Commissioner (Chair)[1]
Michael T. Richard, Commissioner
Anthony J. O'Donnell, Commissioner

Issued: March 22, 2019

[1] *See* Designation of Panel dated January 9, 2019, ML#223597, Case No. 9490 Docket (Dkt) Item No. 30.

APPEARANCES

Jeffrey P. Trout, Teresa K. Harrold, J. Joseph Curran, III, Christopher S. Gunderson, Susan R. Schipper, and Meredith K. Boram for The Potomac Edison Company.

Paula M. Carmody, William F. Fields, Joseph G. Cleaver, and Patrick E. O'Laughlin for the Maryland Office of People's Counsel.

Lloyd J. Spivak and Michael A. Dean for the Maryland Public Service Commission Staff.

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I. INTRODUCTION AND EXECUTIVE SUMMARY

On August 24, 2018, The Potomac Edison Company ("Potomac Edison" or "the Company") filed with the Maryland Public Service Commission ('the Commission") a request to increase its rates for electricity in the amount of $19,180,923 ("Application").[2] The revenue requirement was updated in the Company's supplemental direct filing to $19,690,789.[3] According to Potomac Edison, the impact of this proposed rate increase on the typical residential customer would be $5.77 per month, representing an increase of 6% in the customer's total bill and an increase of 26% in the distribution portion of the customer's bill.[4] Potomac Edison last requested a rate increase from the Commission nearly 25 years ago, in Case No. 8652 filed on April 15, 1994.[5]

The Company stated that the filing of its base rate case was driven by (i) investments in the electric distribution system to improve service and reliability for its customers; (ii) the desire to pass on to ratepayers the savings from the Tax Cut and Jobs Act of 2017 ("TCJA") in a manner that is based on up-to-date, fully-vetted revenue needs and class cost allocations; and (iii) revisions to Company Tariffs necessitated by the Company's divestiture of generation assets and the implementation of electric restructuring policies.[6] Additionally, Potomac Edison requested Commission authorization to implement a reliability surcharge, the Electric Distribution Investment Surcharge ("EDIS"), in order to fund four incremental reliability programs. This surcharge, if fully

[2] Potomac Edison August 24, 2018 Application at 5.
[3] PE Exhibit (Ex) 24, Supplemental Direct Testimony of Raymond E. Valdes ("Valdes Supplemental") at 2.
[4] Valdes Supplemental at 2-3. Mr. Valdes testified that the "typical" residential customer consumes approximately 1,000 kWh per month.
[5] PE Ex 4, Direct Testimony of James A. Sears ("Sears Direct") at 6.
[6] Application at 4-6. The Company stated that as a result of the TCJA, the total rate increase being sought was reduced by $7.2 million.

authorized, would raise the typical residential customer bill by an additional $0.73 per month.[7]

Finally, the Company requested in its Application an authorized return on equity of 10.80% that, when added to the Company's long-term debt, would result in overall rate of return of 7.75%.[8] The Commission carefully considered this request together with the evidence presented by the other parties. Based on the record in this case, we find that a reduced return on equity of 9.65% provides for a fair and appropriate return and will allow Potomac Edison to obtain any necessary capital investment at reasonable interest rates. The Commission also approves the Company's requested reliability surcharge, with modifications and subject to conditions, as explained below.

The Commission has thoroughly reviewed Potomac Edison's Application and the evidence presented by all of the parties to the case, as well as the public's comments. After careful consideration, we authorize Potomac Edison to increase its electric rates by **$6,199,378**, which will result in an increase to the average monthly Standard Offer Service residential bill of **$2.13** (including the EDIS).[9] That amount represents an increase of 2.12% in the customer's total electric bill, or an increase of 9.72% in the distribution-only portion of the customer's bill. As in prior rate cases, we have strived to limit rate impacts while allowing the Company to invest in safety and reliability and continue to modernize its distribution system for the benefit of its customers. Additionally, given that several studies provided by Potomac Edison were outdated, including its depreciation study (approximately 25 years old) and certain cost of service studies (also approximately

[7] Sears Direct at 8.
[8] PE Ex 9, Direct Testimony of Dylan W. D'Ascendis ("D'Ascendis Direct") at 2-3.
[9] The average Standard Offer Service residential customer consumes approximately 1,000 kWh per month. Of the $2.13 increase, approximately $0.12 per month is attributable to the EDIS.

25 years old), the Commission is requiring the Company to file updates to these studies. Specifically, Potomac Edison is directed to file a new depreciation study within 18 months of the date of this Order in a Phase II proceeding. Additionally, the Company shall file updated studies utilized in its jurisdictional cost of service study and cost of service study, such that all updated studies are current to within one year of the test year in the Company's next base rate case.

II. BACKGROUND

On August 24, 2018, pursuant to §§ 4-203 and 4-204 of the Public Utilities Article ("PUA"), *Annotated Code of Maryland*, Potomac Edison filed an Application to increase its retail rates for the distribution of electric energy in Maryland. By Order No. 88812 issued August 29, 2018, the Commission suspended the proposed rates for an initial period of 150 days from September 24, 2018. On October 1, 2018, the Commission issued Order No. 88851, which extended the initial suspension period by 30 days, to March 23, 2019.[10]

In the Application, Potomac Edison asked the Commission for authority to increase its rates for providing electric distribution services to its customers in Maryland by $19,180,923 million. Potomac Edison's request was based on a 12-month test year ending June 30, 2018, which at the time of filing included 8 months of actual data and 4 months of forecasted data.[11]

The Company filed direct testimony in support of its request at the time of the Application and supplemental direct testimony on October 22, 2018. The Commission's Technical Staff ("Staff") and the Office of People's Counsel ("OPC") filed direct testimony

[10] Order No. 88851 at 5.
[11] Potomac Edison Application at 5.

on November 20, 2018 and November 27, 2018. All parties filed rebuttal testimony on December 20, 2018, and surrebuttal testimony on January 17, 2019. A public hearing was held on January 15, 2019, in Cumberland, Maryland. Evidentiary hearings were held at the Commission's offices in Baltimore on January 22 through 28, 2019, to admit the pre-filed testimony and for cross examination. Parties filed post-hearing briefs on February 13, 2019 and reply briefs on February 27, 2019.

III. DISCUSSION AND FINDINGS

A. EDIS

Potomac Edison proposed an Electric Distribution Investment Surcharge to recover, through a tracker mechanism, incremental costs associated with four reliability improvement programs: (i) changing the Company's vegetation management ("VM") program from a five-year cycle to a four-year cycle, (ii) additional distribution automation ("DA"), (iii) accelerated underground cable replacement, and (iv) additional recloser installation.[12]

OPC

OPC witness Lanzalotta testified that there is little justification for the additional reliability spending under EDIS after considering (i) the Company's current reliability performance, (ii) that the Company's 2017 performance already meets or exceeds reliability standards currently proposed through 2023, and (iii) that the Company's reliability performance through 2017 does not yet reflect all of the reliability-related work that has been done.[13]

[12] Each of the programs is described in detail in the Direct Testimony of Donald McGettigan ("PE Ex 11) ("McGettigan Direct") starting at 8.
[13] OPC Ex 26, Direct Testimony of Peter J. Lanzalotta ("Lanzalotta Direct") at 10.

In addition, OPC witness Pavlovic testified that Potomac Edison's EDIS proposal is largely devoid of the items necessary to satisfy programmatic requirements such as a list of program projects, project-specific performance objectives, project-specific timeline milestones, and stipulation of rate base review of projects. On the basis of these deficiencies, Mr. Pavlovic recommended that Commission reject Potomac Edison's EDIS proposal.[14]

Staff

Staff witness Lo reviewed each of the proposed EDIS programs and concluded that each would provide benefits and was cost effective.[15]

According to Mr. Lo, the Company's proposed vegetation management program would encompass accelerating from a five-year cycle to a four-year cycle in order to further reduce tree-caused outages and improve reliability performance.[16] A mid-cycle hazard tree patrol would be implemented to identify and mitigate problem areas.[17] Mr. Lo testified that the proposed accelerated VM program would address the primary cause of outages on Potomac Edison's overhead distribution system which is tree damage. If Potomac Edison were to transition to a four-year trimming cycle, at an incremental increase in spending of $4.1 million per year, the Company projected an annual incremental system average interruption frequency index ("SAIFI") improvement of 0.027 from 2019 through 2022.[18]

According to Mr. Lo, the proposed additional DA schemes over the ten-year period will further enhance Potomac Edison's system reliability and customer reliability by

[14] In comments filed on January 29, 2019, Montgomery County agreed with OPC's recommendation to reject the proposed EDIS. ML# 223748, Dkt Item No. 46.
[15] Staff Initial Brief at 40.
[16] Staff Ex 24, Direct Testimony and Exhibits of Christopher Lo ("Lo Direct") at 8.
[17] Lo Direct at 8.
[18] Lo Direct at 8-9.

isolating faulted line sections and restoring a circuit in an event of a circuit lockout, thereby reducing the overall impact of an outage.[19] He testified that Potomac Edison expects to see an incremental reliability improvement from the additional DA schemes with an estimated spend of $26 million in order to fully implement the program.[20]

With respect to the underground cable replacement program, Mr. Lo testified that Potomac Edison expects to see an annual incremental SAIFI improvement with an estimated spend of $12.5 million per year to replace all of the unjacketed bare concentric neutral cables over a 23-year period.[21]

Mr. Lo testified that with full implementation of the recloser program, consisting of replacing 270 reclosers over a five-year period, Potomac Edison expects to see an annual incremental SAIFI improvement with an estimated spend of $1.2 million per year beginning in 2020.[22]

Mr. Lo recommended several conditions be placed on the approval of Potomac Edison's EDIS proposal. Mr. Lo recommended that the Company be required to file for a new EDIS surcharge to be in effect at the beginning of each calendar year, to include a reconciliation of costs, as well as a mechanism for milestone and metrics review, similar to the reporting employed with Potomac Electric Power Company's ("Pepco") Grid Resiliency Charge ("GRC") and Baltimore Gas and Electric Company's ("BGE") Electric Reliability Investment ("ERI") surcharge.[23] Mr. Lo indicated that the actual investments should also be reviewed by the Commission in subsequent rate case filing(s), and if

[19] Lo Direct at 10.
[20] Lo Direct at 10.
[21] Lo Direct at 11.
[22] Lo Direct at 12.
[23] The GRC is a reliability investment surcharge that the Commission approved for Pepco in Case No. 9311. Similarly, the ERI is a reliability investment surcharge that the Commission approved for BGE in Case No. 9326. Lo Direct at 16-17.

approved, accepted into base rates at that time, and reduced from the surcharge accordingly.[24] Mr. Lo also stated that Potomac Edison's usage of the EDIS surcharge should also have a "sunset provision" as discussed in Staff witness Valcarenghi's Direct Testimony.[25]

Lastly, Mr. Lo recommended that the Commission clarify that approval of an EDIS surcharge by the Commission is not a prudency determination, but only reflects the Commission's concurrence that it appears prudent at this time to move forward with accelerating reliability improvements through its EDIS proposed programs.[26]

Party Responses

Potomac Edison witnesses Valdes and McGettigan responded to Staff's recommended conditions. Mr. Valdes testified that the Company agreed that an annual EDIS filing should be made at the Commission, to include a reconciliation of past costs and revenues.[27] However, with regard to Staff's recommendation for a sunset provision and the filing of a base rate case to determine prudency, Mr. Valdes stated that the EDIS programs encompass a period longer than the initial four years for which Potomac Edison has submitted data.[28] Mr. Valdes pointed out that the substation recloser program is proposed for a five-year period, the distribution automation program is proposed for a ten-year period, and the underground cable replacement program is proposed for a 23-year period. Potomac Edison envisions that these programs will continue to be authorized for their respective lengths through the annual surcharge filing process.[29] Mr. Valdes testified

[24] Lo Direct at 18.
[25] Lo Direct at18.
[26] Lo Direct at18.
[27] PE Ex 25, Rebuttal Testimony of Raymond E. Valdes ("Valdes Rebuttal") at 41.
[28] Valdes Rebuttal at 44.
[29] Valdes Rebuttal at 44.

that filing a base rate case is unnecessary, and that if, after a period of time, the Commission determines that certain aspects of the EDIS have leveled off, the EDIS rate increment can simply be added to base rates, or Potomac Edison could certify the investments by establishing that the investments and related recoveries were prudent at that time.[30]

Mr. McGettigan testified that with respect to the other procedural mechanics of program administration, the Company had expected those sorts of details to be finalized after the hearings, once the Commission had ruled on the substance of the programs.[31] He described Staff witness Lo's recommendations as "reasonable starting points for working towards the final details."[32]

In its Initial Brief, Potomac Edison acknowledged that the Commission retains the discretion to determine if and for how long the programs should be in place.[33]

Commission Decision

As Staff points out in its Initial Brief, an increase in number and severity of weather events such as the 2010 Snowmaggedon, 2011 Hurricane Irene, June 2012 Derecho, and October 2012 Superstorm Sandy led the Commission to focus on the reliability and resiliency of the Maryland electric distribution system.[34] In 2012, the Governor's Grid Resiliency Task Force recommended reliability improvements to the distribution systems of the electric companies through the use of reliability spending surcharges with the restriction that accelerated reliability cost recovery should be "exclusively for accelerated and incremental investments and expenses."[35] Thereafter, the Commission authorized

[30] Valdes Rebuttal at 44.
[31] PE Ex 12, Rebuttal Testimony of Donald J. McGettigan ("McGettigan Rebuttal") at 2.
[32] McGettigan Rebuttal at 2-3.
[33] Potomac Edison Initial Brief at 32-33.
[34] Staff Initial Brief at 41.
[35] *Weathering the Storm: Report of the Grid Resiliency Task Force* (2012) at 80.

accelerated electric distribution system reliability improvements with partial cost recovery through a surcharge for three investor-owned electric companies.

Most of the work Potomac Edison proposed for recovery under the EDIS would be similar in scope to the distribution system reliability improvement programs approved by the Commission for the other three electric companies. The Commission agrees with Staff that the additional Distribution Automation, accelerated underground cable replacement, and additional recloser installations are all cost-effective projects that are incremental to the Company's current planned investments. Similar to those programs approved for the other three investor-owned electric companies, these projects will be beneficial to customers by providing improved safety and more reliable service. Therefore, we approve these three initiatives for surcharge recovery, with the additional conditions Staff suggested, as outlined below.

However, when the Commission considered accelerated vegetation management programs in Case No. 9326, the Commission stated, "[i]n deciding whether surcharge recovery is appropriate, we considered how much of a program's cost is comprised of operation and maintenance ("O&M") expenses. Although enhancing reliability will require some amount of O&M expense, we find it less appropriate for initiatives that are predominantly comprised of O&M expenses to be recovered through a surcharge mechanism."[36] In this case, the Company did not provide evidence or make arguments that persuade the Commission to reconsider its position about the appropriateness of a surcharge recovery mechanism for O&M expenses, nor did the Company specifically

[36] *See* Order No. 86060, *In the Matter of the Application of Baltimore Gas and Electric Company for Adjustments to its Electric and Gas Base Rates* at 137-138.

identify vegetation management program capital expenses that might be recovered through a surcharge. [37]

Other utilities proposing similar accelerated programs have not claimed that vegetation management was comprised of any portion of capital costs. Clearing of forest is not routine vegetation management on a periodic cycle. Again, in this case the Company did not make persuasive argument that the removal of danger trees, which might be considered a capital expense, could amount to the incremental capital costs proposed by Potomac Edison, when moving from a five-year cycle to a four-year tree trimming cycle. At best, Potomac Edison's proposal to move from a five-year trimming cycle to a four-year trimming cycle is predominantly comprised of O&M expenses. Therefore, the Commission denies this portion of the EDIS. This is not to say that the Company should not move to a four-year trimming cycle if that is what is required for it to achieve compliance with COMAR 20.50.12.09.

Regarding Potomac Edison's remaining EDIS programs, the Commission finds that they will provide benefits to customers and be cost effective. Potomac Edison's existing DA programs have been shown to improve the Company's overall system reliability[38] and Staff witness Lo testified that the DA program through the EDIS will provide significant

[37] Potomac Edison witness Valdes stated that a portion of the Company's incremental estimated costs for vegetation management is capitalized. When questioned at the hearing, Mr. Valdes referenced one line of Exhibit REV-23, p. 1 of 8, and testified, "I think the capitalization of it has to do with items that are beyond the traditional maintenance, maybe clearing the forest, removal of danger trees, I think that falls under, if I recall, I think that falls under a capitalized item." Tr. at 375. No other evidence supporting capitalized VM was produced.

[38] *See* McGettigan Direct at 10: "Since the installation of the first DA scheme, PE has avoided approximately 2,500 customer interruptions and 330,000 minutes of customer interruptions that would have been experienced prior to automation."

additional reliability benefits.[39] Potomac Edison's underground cable replacement program will also provide important reliability benefits. The Company projects that it will experience an increasing number of underground cable failures as unjacketed cables reach or exceed the end of their lifespan, and its underground cable program will proactively address this problem through replacement, rather than waiting for cable failure, as its current reactive program entails.[40] Finally, Potomac Edison's recloser program will replace approximately 270 reclosers to reduce the number of circuit lockouts as well as to reduce the number of customers impacted by such lockouts. Staff witness Lo testified that this program will result in a reduction in the number of momentary outages as well as customers experiencing sustained outages.[41] Overall, Staff witness Lo concluded that the EDIS programs are cost-effective and beneficial to ratepayers and warrant a departure from traditional ratemaking principles.[42] With regard to the non-VM EDIS programs, the Commission agrees. Potomac Edison's EDIS programs pertaining to DA, accelerated underground cable replacement, and recloser installation are therefore approved.

The Commission adopts Staff's recommendations with regard to annual reporting and annual reconciliation, which the Company agreed to, and we will hold Potomac Edison to the same standards as we did Pepco and BGE with respect to their accelerated programs and associated surcharges.

The Commission notes that while the programs proposed by Potomac Edison extend beyond 2022, surcharge recovery related to monies spent after 2022 is not approved

[39] Mr. Lo testified that Potomac Edison's DA program will "further enhance PE's system reliability and customer reliability by isolating faulted line sections and restoring a circuit in an event of a circuit lockout, thereby reducing the overall impact of an outage." Lo Direct at 9-10.
[40] Case No. 9490 Evidentiary Hearing Transcript ("Tr.") at 117-18 (McGettigan).
[41] Lo Direct at 12.
[42] Staff Initial Brief at 41.

by this Order. Staff recommended that the EDIS program "sunset" after the initial period elapses.[43] The Commission agrees with Staff; there should be a sunset date for this type of accelerated initiative. Potomac Edison maintains that it should not be required to file a base rate case in order for projects, and cost recovery, to be fully reviewed for prudency. Although prudency could be determined outside of the rate case context, with the surcharge at its last reconciled amount maintained indefinitely, we think that could lead to confusion and is not appropriate. Moreover, Potomac Edison indicated that it would be filing rate cases with greater frequency than in the past.[44] As a parameter for how often Potomac Edison intends to file rate cases in Maryland going forward, Potomac Edison witness Valdes stated that Potomac Edison's sister company in West Virginia has filed three cases in the past 12 years.[45] This timeframe corresponds with the initial period proposed by Potomac Edison, and it only makes sense for Potomac Edison to align its next rate case with the end of its initial EDIS program (2022).

Accordingly, the Commission directs the Company to submit a base rate case application that aligns with the end of the initial four-year period (end of 2022 or early 2023). The projects undertaken and the EDIS revenues will be subject to full review in that base rate case, and if the net capitalized amount spent on the three programs approved in this Order is deemed reasonable and prudent, such costs will be rolled into the rate base resulting in termination of the EDIS mechanism.[46]

[43] This may have been stated as five years; we note that the time period from 2019-2022 is a four-year period.
[44] *See* Tr. at 372.
[45] Tr. at 372.
[46] Should Potomac Edison file sooner than the end of the EDIS, the Commission may review completed reliability projects and roll them into rate base.

Potomac Edison is permitted to return to the Commission before the conclusion of the EDIS sunset and make a case for extension of surcharge recovery for any of the three programs. Potomac Edison also may continue with any of these proposed enhanced reliability programs after the sunset of the EDIS for as long as it deems appropriate and recover prudent costs associated therewith in a traditional manner. However, the Commission is not making a determination as part of this Order that Potomac Edison's programs are entitled to surcharge recovery for their full duration.

B. Adjustments to Rate Base and Operating Income

Rate base represents the investment a company makes in plant and equipment to provide safe and reliable electric service to it customers. Operating income is derived from the revenues the Company receives for electric service less the prudently incurred costs of providing service to customers. Adjustments to the Company's rate base and operating income were offered, accepted, or disputed by the various parties. The Commission has reviewed the record and accepts the uncontested rate base and operating income adjustments and resolves the disputed adjustments below.

1. Adjustment 4: Storm Damages

Potomac Edison

Adjustment No. 4 increases the test-year O&M expense level for storm damage expense. The adjustment compares the five-year annual average of storm-related expenses to the test year and adjusts upwards for the difference.

Due to the volatility of storm expenses, the Company proposes to institute deferral accounting for storm expense which will compare storm O&M expense to the amount collected in rates. According to Mr. Adams, deferral accounting will be calculated on a

monthly basis, with any over-collection recorded as a regulatory liability and any under-collection recorded as a regulatory asset, to ensure that on an annual basis, customers will pay only the actual incurred level of storm expense.[47] Since deferral accounting will be set up as a tracker mechanism, distribution rates will not be adjusted until the Company's next base rate case, at which time the cumulative regulatory liability or regulatory asset would be presented to the Commission for ultimate disposition in customer rates.[48]

OPC

OPC witness Effron opined that the Commission should not approve Potomac Edison's proposal to institute deferral accounting for storm damage expense. He stated that the Company has not established that implementation of deferral accounting for storm damage expense is necessary or appropriate.[49] He believes that the use of a five-year average to determine normalized storm damage expense in the context of base rate cases allows the Company a reasonable opportunity to recover its actual storm damage expenses.[50] In his opinion, the Company has not established that its proposed deferral accounting mechanism is superior to continuing the use of a rolling five-year average of storm costs in base rate cases, from the perspective of either customers or shareholders.[51]

Staff

Staff does not agree with the Company's proposal to increase the test-year storm O&M expense based on a five-year average (2014 through 2018, each ending June 30). Staff witness Poberesky testified that although using a several consecutive years average

[47] PE Ex 16, Direct Testimony of Jeffrey L. Adams ("Adams Direct") at 7.
[48] Adams Direct at 7.
[49] OPC Ex 30, Direct Testimony of David J. Effron ("Effron Direct") at 28.
[50] Effron Direct at 28.
[51] Effron Direct at 28.

for certain volatile expenses is a normal ratemaking practice, the storm expense for the year ending June 30, 2014, was extraordinarily high, and this outlier should have not been used in the calculation of the going-level storm O&M expense.[52] However, Ms. Poberesky testified that if the abnormal year of 2014 is removed, the going-level expense falls below the test-year expense.[53] Therefore, Staff recommends that the Commission reject the Company's adjustment for an increase to going level of storm O&M expense and to use the test-year storm O&M expense as a going level of expense instead.[54] At the hearing, Ms. Poberesky elaborated on Staff's position that the extremely high 2014 costs of $9.5 million should be removed as an outlier. She calculated four-year, three-year, and two-year averages, and because they were all lower than the Company's five-year average, she found the test-year storm expense to be comparable and appropriate to use in this case.[55]

Staff does not object to Potomac Edison's proposal to institute deferral accounting and believes the proposal is reasonable with the condition that both the regulatory asset and the regulatory liability will earn a return at the Company's most recent authorized rate of return.[56]

Party Responses

Potomac Edison does not agree with Staff's recommendation to remove 2014 storm costs that the Company stated are larger than the other years in the five-year average but not an anomaly.[57] Potomac Edison witness Adams further stated that use of a tracking mechanism would eliminate the need to adjust historical amounts to determine the proper

[52] Staff Ex 13, Direct Testimony of Yulia Poberesky ("Poberesky Direct") at 10.
[53] Poberesky Direct at 10.
[54] *Id.*
[55] Tr. at 522-23.
[56] Poberesky Direct at 11.
[57] PE Ex 18, Rebuttal Testimony of Jeffrey L. Adams ("Adams Rebuttal") at 5.

level of storm damage expense.[58] Potomac Edison stated that it agreed to Staff's conditions on such a tracking mechanism.[59]

OPC argues on brief that Potomac Edison has not provided basic details surrounding its proposal to set up a storm fund, and its sponsoring witness was uncertain as to the exact mechanics of the proposal.[60] OPC contends that missing from the Company's initial storm fund proposal was an explanation of the reconciliation of storm fund accruals and actual expenses.[61] OPC strongly disagrees with the imposition of carrying costs in the event of an under-collection.[62]

OPC concluded that because Potomac Edison failed to meet its burden on the storm fund proposal, it should be rejected.[63]

Commission Decision

The Commission agrees with Staff that there is no justification to deviate from the test-year storm costs which are slightly higher than recent averages when excluding 2014 as an anomaly. Therefore, the Commission rejects the Company's adjustment to a five-year average of storm costs. The Commission is persuaded by Mr. Effron's testimony that the Company has not established that implementation of deferral accounting for storm damage expense is necessary or appropriate. Accordingly, the Commission declines to adopt Potomac Edison's proposal for a storm fund at this time. Based on the testimony in this case, the Commission believes the amount of test-year storm costs provides a reasonable level of expense in determining the revenue requirement.

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[58] *Id.*
[59] Adams Rebuttal at 5.
[60] OPC Initial Brief at 19.
[61] OPC Initial Brief at 19.
[62] OPC Initial Brief at 20.
[63] OPC Initial Brief at 20.

2. Adjustment 10: OPEB Smoothing

Potomac Edison

Potomac Edison witness Valdes testified regarding the pension and other post-employment benefits ("OPEB") expenses on the Company's test year books. Mr. Valdes testified that Adjustment No. 10 is necessary because, effective with an accounting change implemented for fiscal year ended December 31, 2011, FirstEnergy Corp. ("FirstEnergy") and its subsidiaries immediately recognize actuarial gains and losses[64] associated with pension/OPEB in earnings in the year incurred, which increases the possibility that the per-books expense can be significantly higher or lower than the expense determined under the delayed recognition of actuarial gains and losses accounting method previously utilized by the Company. Mr. Valdes explained that removal of the pension/OPEB MTM in Adjustment No. 10, and its replacement with a smoothing mechanism, eliminates the extreme volatility in any one annual period and neutralizes the impact of immediate recognition of actuarial gains and losses on the ratemaking process.[65] He stated AON-Hewitt calculated the net accumulated actuarial loss that would have existed assuming that the 2011 accounting change and the merger with FirstEnergy had not occurred. This calculation was based on the accumulated actuarial losses that existed at Potomac Edison prior to the merger and the actuarial losses that were incurred subsequent to the merger, less what would have been amortized in those years. The smoothing mechanism in Adjustment No. 10 includes the amortization of this recalculated accumulated net actuarial loss that would have been recognized during the year ended December 2017, thereby

[64] Immediate recognition of actuarial gains and losses in earnings is commonly referred to as mark-to-market ("MTM") accounting. Valdes Direct at 3-4.
[65] Valdes Direct at 5.

allowing pension and OPEB expense for the test year to reflect a smoothing of the amortization of actual net actuarial losses from prior years.[66]

OPC

Mr. Effron agreed with the Adjustment 10 in principle, however, he stated that the smoothing adjustment to test-year pension and OPEB should be eliminated unless the Company is able to provide documentation supporting the calculation of the smoothed amortization of the pension/OPEB actuarial gains and losses.[67]

Staff

Mr. Valcarenghi testified that the smoothing mechanism in Adjustment 10 might be appropriate if a pattern of volatility exists that needs to be mitigated; however, a review of Potomac Edison's data did not suggest volatility of a magnitude to warrant the adjustment advocated by the Company.[68] He stated that if a smoothing adjustment is deemed necessary, Staff disagrees with Potomac Edison's computation.[69] However, Staff's position is that since Potomac Edison has not established a case for volatility, the adjustment should be rejected.[70]

Party Responses

In rebuttal, Company witness Valdes maintained that there is significant volatility in the MTM portion of pension/OPEB, varying in just one year from a decrease of $25.6 million in 2013 to an increase of $36.5 million in 2014.[71] Mr. Valdes also maintained that

[66] Valdes Direct at 5.
[67] Effron Direct at 12.
[68] Staff Ex 11, Direct Testimony of David Valcarenghi ("Valcarenghi Direct") at 11.
[69] Valcarenghi Direct at 14.
[70] Valcarenghi Direct at 14.
[71] Valdes Rebuttal at 11.

the computation was performed accurately.[72]

OPC witness Effron indicated that Potomac Edison provided additional actuarial documentation for the smoothing adjustment in rebuttal testimony. He testified that the smoothing of the actuarial gains and losses appeared to be consistent with the general practice used by other regulated utilities to determine periodic pension and OPEB costs.[73]

Commission Decision

A smoothing adjustment is appropriate where a test-year cost can be shown to have significant variation from year to year. With demonstrated volatility, test-year costs may not be representative of the conditions the Company will experience in a future rate effective period and adjustment becomes necessary. Based on the Company's rebuttal testimony and Mr. Effron's surrebuttal testimony, the Commission is satisfied that there is demonstrated volatility in the OPEB costs and that the proposed smoothing mechanism will better align expenses and rate recovery. The Commission will accept the smoothing mechanism in Adjustment No. 10.

3. Adjustment 11: Rate Case Expenses

Potomac Edison

Mr. Adams testified that Adjustment 11 reflects an increment for rate case expenses reflective of one-third of the projected cost of the Company's current rate case.[74] These rate cases expenses include charges for items such as return on equity ("ROE") studies, legal fees, and customer notifications.[75]

[72] Valdes Rebuttal at 12.
[73] OPC Ex 31, Surrebuttal Testimony of David J. Effron ("Effron Surrebuttal") at 6.
[74] Adams Direct at 9.
[75] Adams Direct at 9.

Staff

Based on regulatory principles, Staff asserted that rates should be developed only on actual, prudent, known and measurable rate case expenses.[76] Staff believes Potomac Edison should be required to submit detailed documentation to support actual costs incurred and that the Company should only recover actual expenses incurred through the hearings in this case.[77]

Noting that Potomac Edison estimated $164,400 for external legal fees, Staff explained that the Commission has previously expressed a concern with respect to excessive hourly rates for outside legal representation.[78] Staff continues to believe that $300 per hour is a more appropriate rate for outside legal services that are charged to ratepayers.[79]

Party Responses

Potomac Edison is concerned that not all rate case expenses will be subject to recovery. Mr. Adams stated that actual billings for rate case expenses associated with the evidentiary hearings in this proceeding, scheduled to be held from January 22, 2019 through January 30, 2019, such as Rate of Return Consultant Fees, External Legal Fees, and Non-Payroll Incremental Employee Expenses, will not be available at the earliest until the close of the Company's accounting records for February of 2019.[80] He further stated that the Company anticipates incurring additional external legal expenses and consultant fees associated with the briefing stage of this proceeding that concludes February 27, 2019,

[76] Poberesky Direct at 12.
[77] Poberesky Direct at 12.
[78] Poberesky Direct at 13.
[79] Poberesky Direct at 13.
[80] Adams Rebuttal at 7.

which will not be billed and reflected on the Company's accounting records until March of 2019.[81] The Company thus believes that its estimate of total rate case expenses is appropriate for recovery.

Staff witness Poberesky indicated that Potomac Edison provided an update to a data request regarding its rate case expenses on January 14, 2019.[82] Ms. Poberesky updated her adjustment for these now known and measurable expenses. Staff still recommended that costs related to the Company's outside counsel be limited to $300 per hour. Staff further recommended that actual, reasonable level of expenses incurred should be amortized over a three-year period.[83]

On cross-examination, Ms. Poberesky testified that she has no objection to the particular counsel hired or used, but believes that recovery of outside legal fees, recovered from Maryland ratepayers, should be limited.[84] She added that although the case on which she was relying for application of a cap was decided in 2013, based on her review, "in that Columbia case, the recovery per hour, … it was very much similar to what is being charged in this case."[85]

As Staff pointed out in its Initial Brief, the $300 per hour cap "does not, and is not necessarily intended to reflect the full hourly charge billed, but a reasonable level" to be recovered from ratepayers.[86]

[81] Adams Rebuttal at 7.
[82] Staff Ex 14, Surrebuttal Testimony of Yulia Poberesky ("Poberesky Surrebuttal") at 3.
[83] Poberesky Surrebuttal at 3.
[84] Tr. at 526-527.
[85] Tr. at 527-528.
[86] Staff Initial Brief at 13.

Commission Decision

The Commission finds that the recommendation of $300 per hour operates as a cap on outside legal expenses. In other words, regardless of the actual hourly rate charged, Staff is recommending the amount passed on to ratepayers be capped at $300 per hour.

The Commission believes Staff was required to fully support why a cap is appropriate in this particular case. It is not enough to point to other cases in which such a cap was applied without articulating whether and how the instant case is analogous. Staff did not assert, for example, that presenting this case was within the core competency of in-house counsel at Potomac Edison, with assistance from FirstEnergy, particularly in light of the fact that the Company has recently filed rate case proceedings in West Virginia. Nor did Staff assert that this case was not worthy of the degree (number of hours and level of experience of counsel) of assistance provided externally. And Staff did not claim that the amount being charged was excessive.[87]

Moreover, Staff failed to articulate why ratepayers should only pay a portion of the actual external legal fees incurred. Accordingly, the Commission declines to apply the cap on outside legal fees requested by Staff. Following what the Commission has done in the past in allowing recovery of actual rate case expenses,[88] Potomac Edison's actual, known and measurable rate case expenses, including outside legal fees actually incurred during 2018, will be allowed.[89]

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[87] *See* Tr. at 530-531.

[88] *See, e.g., In the Matter of the Application of Baltimore Gas and Electric Company for Adjustments to Its Electric and Gas Base Rates*, Case No. 9326, Order No. 86060 (December 13, 2013).

[89] According to Post-Hearing Exhibit YP-7-Revised, filed on February 8, 2019, the actual expenses incurred as of 12/31/2018 were $148,162. This is the only figure in the record of actual, known and measurable rate case expenses. Had additional rate case expenses become known and measurable as of the hearings, Potomac Edison was required to introduce them into evidence; however, Potomac Edison failed to do so. Potomac Edison did not file supplemental information in response to Staff's Post-Hearing Exhibits, or otherwise, as other utilities have done post-hearing, and the record closed.

4. Adjustment 12: Holding Company Corporate Expense

Potomac Edison

Adjustment 12 is an adjustment to increase going-level expense to reflect certain corporate financial expenses. Mr. Adams testified that these corporate financial expenses include such items as audit fees of the parent company, stock administration, and investor relations.[90] Mr. Adams testified that all of these expenses are necessary in the ordinary course of business and help enable Potomac Edison to raise funds for investment in plant, property and equipment as well as operating funds.[91]

Staff

Staff recommended removing corporate financial expenses from Potomac Edison's test-year O&M expenses because the expense is investor and stockholder related and financial performance related.[92] Staff witness Poberesky elaborated that Potomac Edison explained in its response to Staff's Data Request No. 6-25 that these corporate expenses are accounted for on the books of Potomac Edison's parent, FirstEnergy, and are not billed or allocated to Potomac Edison except for ratemaking purposes.[93] She testified that the connection of these expenses to benefiting ratepayers has not been established and the costs are not part of normal allocation of costs between the parent and its affiliates.[94] Accordingly, Staff asserts these expenses should not be part of the Company's test-year O&M expenses.

[90] Adams Direct at 9.
[91] Adams Direct at 9.
[92] Poberesky Direct at 16.
[93] Poberesky Direct at 16.
[94] Poberesky Direct at 16.

Party Responses

Potomac Edison witness Adams reiterated that the Company believes expenses such as audit fees, stock administration costs, and investor relations expenses are necessary in the ordinary course of business. He testified that if the parent company did not incur these expenses on behalf of its subsidiaries, each individual subsidiary company, including Potomac Edison, would have to incur its own individual costs.[95] He added that within the administrative and general expense section of the Federal Energy Regulatory Commission ("FERC") Uniform System of Accounts, there are provisions for inclusion of stockholder meeting expenses, directors' fees and expenses, and outside auditor's fees, which he believes underscores the assumption that these types of costs are normal, expected costs for a utility, and should be included for cost recovery.[96]

Commission Decision

The Commission finds credible Mr. Adams' testimony that such expenses as audit fees, stock administration costs, and investor relations expenses would need to be paid by Potomac Edison if the parent company did not incur these expenses on behalf of its subsidiaries. Accordingly, the Commission will allow Potomac Edison's Adjustment 12 for holding company corporate expense.

[95] Adams Rebuttal at 9.
[96] Adams Rebuttal at 10.

5. Adjustment 23: Post Test Year Reliability Projects (Adjustment 14: Depreciation Expense on Post Test Year Reliability Projects; Adjustment 25: Accumulated Depreciation – Post Test Year Reliability; and Adjustment to ADIT Test Year Reliability Projects and Adjustment to ADIT Post Test Year Reliability Projects)

Potomac Edison

Adjustment 23 increases plant in service to reflect terminal treatment of capital expenditures for reliability-related projects to be placed in service between the end of the test year and the end of 2018, prior to the hearings in this case.[97] Mr. Adams testified that the construction projects included within Adjustment 23 are needed to improve reliability by upgrading and modernizing the distribution system.[98]

Adjustment 14 is to reflect the going-level increase in depreciation expense associated with the terminal treatment of capital expenditures for reliability-related projects to be placed in service between the end of the test year (June 30, 2018) and the end of the calendar year (December 31, 2018), prior to the anticipated start of hearings.[99]

Adjustment 25 is a rate base adjustment to reflect the increase in accumulated depreciation associated with the terminal treatment of capital expenditures for reliability-related projects placed in service between the end of the test year (June 30, 2018) and the end of the calendar year (December 31, 2018).[100]

OPC

Mr. Effron testified that Potomac Edison's proposal to include reliability plant additions through December 2018 in rate base goes beyond what the Commission has

[97] Adams Direct at 12.
[98] Adams Direct at 13.
[99] Adams Direct at 10.
[100] Adams Direct at 13.

allowed in the most recent gas and electric distribution rate cases.[101] Citing to Case No. 9443, Mr. Effron proposed limiting the pro forma adjustment for reliability plant to additions through August 2018, which is two months after the end of the test year.[102]

Mr. Effron explained that one of the elements of the adjustments to rate base for reliability plant additions is the adjustment to accumulated deferred income taxes ("ADIT") related to those plant additions.[103] Mr. Effron noted that in calculating the ADIT adjustments, Potomac Edison took into account a five-year modified accelerated cost recovery system tax depreciation but did not recognize any capital repair deductions, which he believes should be taken into account in the calculation of ADIT related to reliability plant additions.[104] Mr. Effron explained that the capital repairs deductions represent expenditures that are capitalized to plant accounts on the Company's books of account but are deducted as repairs expense in the determination of currently taxable income, as allowed by the Internal Revenue Service ("IRS") Code.[105] Mr. Effron testified that the capital repairs deductions should also be taken into account in the calculation of the ADIT related to reliability plant additions.[106] Mr. Effron determined in discovery that the Company did not take into account the capital repairs deductions because the information was not complete. Mr. Effron found unreasonable the Company's assumption that the capital repairs deduction will be zero, simply because it does not know exactly what the capital repairs deductions will be.[107] Mr. Effron offered that a more reasonable approach

[101] Effron Direct at 4-6.
[102] Effron Direct at 7.
[103] Effron Direct at 8.
[104] Effron Direct at 8.
[105] Effron Direct at 8.
[106] Effron Direct at 8.
[107] Effron Direct at 8-9.

would be to estimate the applicable capital repairs deductions based on actual capital repairs deductions in relation to distribution plant additions.[108]

Staff

Staff expressed concern that Adjustment 23 included estimated costs that the Company would not be able to update for actuals in time for a review by the parties prior to the start of the hearings in this case.[109] Staff recommended allowing the Company to move into rate base only projects that are used and useful and supported by actual costs.[110] Staff recommended an adjustment to remove two of the six months of post-test period reliability, and reserved its right to adjust further based on the updates provided by the Company.[111]

Staff also recommended that November and December 2018 plant investments net accumulated depreciation and accumulated deferred income taxes costs be removed until the Company provides the required information.[112]

Party Responses

In rebuttal, Potomac Edison provided updated information for November and indicated that the information for December would be available prior to the hearings. Mr. Adams testified that because the inclusion of the post-test year period of July through December 2018 will be known and measurable by the time of the hearings in this case, the Company is not estimating or projecting the additions.[113] Mr. Adams maintained that the inclusion of these additions for reliability plant will permit the Company the opportunity to

[108] Effron Direct at 9.
[109] Poberesky Direct at 7.
[110] Poberesky Direct at 7.
[111] Poberesky Direct at 7-8.
[112] Poberesky Direct at 8.
[113] Adams Rebuttal at 13.

earn the return authorized by the Commission and possibly increase the time between future Company rate filings.[114]

Mr. Adams disagreed with OPC's proposal to adjust the Company's calculation of ADIT for an estimated capital repairs deduction. While Mr. Adams agreed that some capital repairs deduction would occur, he opposed the adjustment because the data to calculate the precise amount is not yet available and the rate calculated by Mr. Effron may not be accurate.[115]

OPC witness Effron stated that if Mr. Adams believed the capital repairs deduction was overstated, he should have provided an alternative calculation of the appropriate factor, with supporting documentation, because it is not appropriate to assume that the capital repairs deductions for reliability plan additions will be zero.[116]

Staff indicated that Potomac Edison provided updated information to reflect the actual spend related to safety and reliability investments; thus, Staff concluded that the adjustment should be allowed now that they are known and measurable.[117] As Staff further explained in its Initial Brief, the adjustments corresponding to the post-test year reliability plant for depreciation expense, accumulated depreciation, and accumulated deferred income taxes follow from the amount of post-test year plant allowed in rate base.[118]

Commission Decision

Potomac Edison did not request approval of reliability spending through use of a forecasted test year or "rate year"; rather, the Company requested adjustments to its

[114] Adams Rebuttal at 13.
[115] Adams Rebuttal at 14-15.
[116] Effron Surrebuttal at 4-5.
[117] Staff Initial Brief at 9.
[118] Staff Initial Brief at 9.

historical test-year period for reliability projects undertaken up to the hearings in this case.

The Commission has permitted adjustments to the historical test-year period for recovery of reliability investments (as opposed to requiring utilities to wait until the next rate case), if such investments are known and measurable. The Commission finds that to ensure that Potomac Edison can provide safe and reliable service, recovery of known and measurable expenses for actual, prudently incurred costs for non-revenue producing safety and reliability investments through the hearing date is appropriate. In two recently decided rate cases, the Commission has approved post-test-year reliability and safety spending through the hearings,[119] and the Commission will allow the same for Potomac Edison here. Staff has verified these costs; accordingly, the Commission will accept Staff's updated Adjustments 23, 14, and 25.

With regard to the capital repairs deduction to both ADIT for test year reliability projects and post-test-year reliability projects, the Commission agrees with OPC witness Effron that Potomac Edison had a burden to do more than argue that OPC's estimate was incorrect. It is within the Commission's knowledge and experience, both in Strategic Infrastructure Development and Enhancement cases as well as rate cases, that a capital repairs deduction should be taken. The Commission finds the Company's use of zero as the amount of a capital repairs deduction unreasonable. Based on Mr. Effron's and Mr. Adam's testimonies, it is clear that some amount of capital repairs will be deducted, thereby reducing ADIT. According to the Company's testimony, the capital repairs deduction must be estimated at this time. Therefore, Potomac Edison's use of zero as the

[119] *See* Case No. 9481, *In the Matter of the Application of Washington Gas Light Company for Authority to Increase Existing Rates and Charges and to Revise its Terms and Conditions for Gas Service*, Order No. 88944 at 73-75; and Case No. 9484, *In the Matter of the Application of Baltimore Gas and Electric Company for Adjustments to its Gas Base Rates*, Order No. 88975 at 12.

value of the capital repairs deduction is itself an estimate. OPC presented testimony that zero is not a reasonable estimate and provided a fully supported estimate in the record. Despite bearing the burden, the Company did not provide a supported estimate. The Commission will accept OPC's estimate as an appropriate deduction. Accordingly, the final adjustments to ADIT for both terminal test-year reliability spend and post-test-year reliability spend incorporate OPC's capital repairs deduction.

6. Adjustment 27: Cash Working Capital

Potomac Edison

Mr. Adams testified that Adjustment 27 reflects the going-level amount of cash working capital associated with the adjustments in this case as supported by the Company's lead/lag study.[120]

Staff

Staff adjusted cash working capital ("CWC") using Potomac Edison's lead-lag study model to reflect the related change based on the O&M expenses and interest synchronization adjustments proposed by Staff. Staff recalculated the CWC based on Potomac Edison's actual data revised as of January 25, 2019, and based on the jurisdictional allocators sponsored by Staff witness Baker.

Party Responses

Mr. Adams agreed that CWC should reflect the Commission-approved level of O&M expenses and interest expense, but disagreed with the inclusion of income tax expense because in this instance, the going-level income taxes are negative and do not

[120] Adams Direct at 14.

represent a cash requirement for the Company on a going-level basis.[121] At the hearing, Mr. Adams conceded that whatever the Commission determines is the correct level or appropriate level of cash working capital is the amount that should be used.[122]

Commission Decision

The parties do not contest Potomac Edison's methodology for determining CWC. However, CWC is affected by other, contested operating income adjustments and the ultimate interest expense adjustment. Based on the Commission's determinations in the other sections of this Order, Potomac Edison's CWC requirement will be increased in the amount of $274,000.

7. Prepaid balances

OPC

Mr. Effron testified that Potomac Edison's inclusion of prepaid balances in rate base is not appropriate because, to the extent the Company pays certain costs before such costs are actually charged as an expense, this is recognized in the lead-lag study that the Company used to determine its cash working capital allowance.[123] Mr. Effron provided the example of Maryland property taxes, the largest item of other taxes, for which there is a lag of negative 54.38 days.[124] Mr. Effron stated that this negative lag implicitly recognizes the payment of this cost before it is actually charged to expense and increases the cash working capital allowance accordingly, by approximately $1.5 million in the example of Maryland property taxes.[125] He concluded that inclusion of the negative lags

[121] Adams Rebuttal at 3.
[122] Tr. at 178.
[123] Effron Direct at 10.
[124] Effron Direct at 10.
[125] Effron Direct at 10.

for expenses paid in advance in the lead-lag study and also the prepaid balances from the Company's balance sheet in rate base double counts the effect of the advance payments for these items on the Company's total working capital requirement.[126]

Party Responses

Potomac Edison witness Adams claimed that Mr. Effron was incorrect that prepaid assets are already being recovered through the CWC component of rate base.[127] Mr. Adams explained that CWC represents funds the Company is required to have available to bridge the timing difference between receipt of revenues and expenditures. He stated that the inclusion of prepayments, similar to the inclusion of materials and supplies, represents expenditures of funds which could have been invested in plant, property, and equipment and eligible to earn a return as part of rate base. He continued that while the life cycle of prepaid assets may be shorter than other assets, they still represent capital that is tied up for an extended period and not available for investment in other assets. He testified that the inclusion of the 13-month average balance of prepayments in rate base is the proper and appropriate means to ensure the Company has an opportunity to earn a return on all customer-related investments. Mr. Adams asserted that the negative payment lag for tax cited by Mr. Effron represents the number of days between the service period of the taxes and payment by the Company of those taxes but does not represent the recovery of the taxes. Prepayments are created when certain expenditures are made and expensed over a period of time, which may span more than the test year.[128]

[126] Effron Direct at 10.
[127] Adams Rebuttal at 15.
[128] Adams Rebuttal at 15.

Mr. Adams further testified that the lag for prepaid expenses is used in the determination of the amount of CWC needed by the Company on a daily basis the same way as any other expenditure recorded as an expense, but this does not mean the prepayment balances are included in the CWC and earning a return.[129] Mr. Adams maintained that the only way the capital recorded as prepayment and waiting to be expensed can earn a return is to include prepayments in rate base.[130]

Mr. Effron testified that Mr. Adams was correct that the negative lag for property taxes does not represent the lag in recovery of those taxes from ratepayers; however, the revenue lag takes into account the lag in recovery from ratepayers.[131] Mr. Effron maintained that the payment of property taxes in advance of recovery from customers is already taken into account in the lead-lag study and inclusion of the prepaid balances in rate base would double-count the payment of these items in advance of collection from customers.[132]

On cross-examination by the Commission, Mr. Effron added that he is not aware of other companies similarly double counting for such items as property or other taxes.[133]

Commission Decision

The Commission finds Mr. Effron's testimony regarding the inclusion of prepaid balances in rate base convincing and the Commission accepts Mr. Effron's adjustment related thereto. The Company did not meet its burden of persuasion that the payment of property taxes in advance of recovery from customers is not already taken into account in

[129] Adams Rebuttal at 15-16.
[130] Adams Rebuttal at 16.
[131] Effron Surrebuttal at 5.
[132] Effron Surrebuttal at 5.
[133] Tr. at 875.

the lead-lag study such that inclusion of the prepaid balances in rate base would double-count the payment of these items in advance of collection from customers. In the Commission's experience, other Maryland investor-owned utilities do not include these types of prepayments as a rate base adjustment.

8. Depreciation accrual rates

Potomac Edison's current rates for electric service include depreciation rates based on a depreciation study for plant for the period ended December 31, 1993. These rates applied to current plant balances, calculate a yearly depreciation expense of $33.9 million.

OPC

OPC witness Garren calculated a depreciation expense of $16.6 million. Given that Potomac Edison had not performed a depreciation study as part of its filing, Mr. Garren propounded numerous data requests in addition to the data requests propounded by Commission Staff related to depreciation.[134] Mr. Garren testified that OPC was provided the plant and retirement data necessary to perform an updated depreciation study.[135] Although Mr. Garren specifically stated that he did not perform a comprehensive depreciation study, utilizing this data and his own analysis, Mr. Garren proposed adjustments to the depreciation rates and accruals utilized for plant depreciation.[136] Mr. Garren applied the SFAS-143 methodology, which has been utilized by this Commission since 2007,[137] to the Company's currently approved net salvage ratios.[138]

[134] OPC Ex 16, Direct Testimony and Exhibits of James S. Garren ("Garren Direct") at 3-4.
[135] Garren Direct at 4.
[136] *See* Tr. at 661 and 711. *See also* Spanos Rebuttal at 2.
[137] Case No. 9092, Order No. 81517*, Re Potomac Electric Power Company*, 98 Md. P.S.C. 228, 251 (2007).
[138] Garren Direct at 3.

Mr. Garren testified that it is typical for utility companies to file for new depreciation studies every three to five years to ensure that the depreciation parameters are based on the most recent data and that annual depreciation accruals do not become too low or too high relative to the actual retirement experience of the Company in question.[139] Mr. Garren stated that because Potomac Edison has not filed a depreciation study in almost 25 years, a significant portion of the Company's plant in service has never been analyzed for its appropriate average service life.[140] He found the Company's average service lives to be significantly low across the board.[141]

Staff

Staff witness Valcarenghi testified that generally, depreciation rates should be reviewed every three to five years.[142] Given the large passage of time since the last depreciation study was performed, Staff recommended that Potomac Edison be directed to perform a depreciation study relative to its electric depreciable property and that the study be filed with the Commission not more than one year after an Order in this case.[143]

Party Responses

Company witness Valdes testified that Potomac Edison evaluated the reasonableness of its existing rates prior to filing this case through comparison with a depreciation study that had been performed on the Company's assets for a depreciation case filed on April 30, 2014, by Potomac Edison and its affiliate Monongahela Power Company ("Mon Power") in West Virginia related to electric utility plant as of

[139] Garren Direct at 4.
[140] Garren Direct at 4.
[141] Garren Direct at 4.
[142] Valcarenghi Direct at 14; Tr. at 506.
[143] Valcarenghi Direct at 15.

December 31, 2013.[144] Mr. Valdes stated that the equipment Potomac Edison purchases is basically the same equipment whether it is purchased and installed in Maryland or West Virginia.[145]

John J. Spanos, Senior Vice President of Gannett Fleming Valuation and Rate Consultants, LLC, responded on behalf of the Company to the depreciation proposals of OPC witness Garren stating that Mr. Garren's proposals are based on a limited analysis and not the result of a comprehensive depreciation study.[146] Mr. Spanos also testified that depreciation studies should be performed every five to six years.[147] When asked whether longer service lives result in lower depreciation expense, Mr. Spanos testified that depreciation rates are built on multiple factors that affect the rate, not just service life, but also the net salvage component, the plant to reserve ratio, and the age distribution of the assets, and it is only after you take all of these components into account that you know whether rates will go up or down.[148] He stated a full comprehensive depreciation study incorporates interviews and field work and statistical analysis and scrubbing of data.[149] However, he testified that Potomac Edison's current overall composite rates are within reason and it was not critical in his opinion that such a full comprehensive depreciation study be done in this case.[150]

On cross-examination, Mr. Spanos stated that the Mon Power depreciation studies are more representative of what is happening with PE Maryland than the 25-year-old

[144] Valdes Rebuttal at 1-2.
[145] Valdes Rebuttal at 2.
[146] PE Ex 39, Rebuttal Testimony of John J. Spanos ("Spanos Rebuttal") at 2.
[147] Tr. at 769 (Spanos).
[148] Tr. at 734-735.
[149] Tr. at 740.
[150] Tr. at 764.

study.[151] He testified that with a 25-year-old study, there will have been changes that occurred, some of which will increase depreciation expense, and some of which will decrease depreciation expense.[152] He stated that he would feel more comfortable using estimates that were similar to Mon Power because those estimate are more up to date.[153]

OPC witness Garren maintained that Potomac Edison's deprecation rates are old and must be updated.[154]

When asked by the Commission how the results of the recommended depreciation study should be incorporated into rates, Staff witness Valcarenghi testified that one option would be to have a Phase II to the present case.[155] Mr. Valcarenghi noted that, so as to not overburden customers with unjustly high rates, the Commission could make rates in this case subject to adjustment in a Phase II proceeding to the extent a large disparity due to the new depreciation rates is found in Phase II.[156]

Commission Decision

Everyone in this case seems to agree on one thing: a new depreciation study needs to be performed. Potomac Edison is directed to undergo a depreciation study immediately. Upon completion of a new depreciation study, the depreciation expense will be further adjusted in Phase II of this proceeding. The Commission will not entertain an argument on the part of Potomac Edison that the depreciation study directed today will not align with the test year. For whatever reason, Potomac Edison decided to not file a more current

[151] Tr. at 742, 764. In his testimony, Mr. Spanos referred to Mon Power as "PE West Virginia" and to the Company as "PE Maryland."
[152] Tr. at 764.
[153] Tr. at 764.
[154] OPC Ex 18, Surrebuttal Testimony of James S. Garren ("Garren Surrebuttal") at 3.
[155] Tr. at 499.
[156] Tr. at 499.

depreciation study with this rate case, arguing that a 25-year-old study is reasonable. Accordingly, any argument regarding the failure of the depreciation study to align with the test year would be disingenuous at best. Moreover, Potomac Edison witness Sears testified that in his tenure in his current position (5-1/2 years), the Company has never been denied any support from its parent company, FirstEnergy.[157] Potomac Edison witness Valdes confirmed the Company receives adequate resources from FirstEnergy to meet its regulatory requirements in Maryland, and that, depending on availability, other entities within the FirstEnergy corporate umbrella could provide assistance as well.[158] Therefore, the Commission fully expects Potomac Edison to perform this depreciation study not later than 18 months from the date of this Order.[159]

Potomac Edison does not believe its depreciation rates and current depreciation expense are unreasonable. However, the Company's own depreciation expert testified that the Mon Power depreciation studies are more representative of what is happening with the Company than the 25-year-old study, since they are more up to date, suggesting that the most recent Mon Power depreciation study should be used instead. This record evidence supports an adjustment to depreciation expense based on expert analysis of existing depreciation information as compared to the Mon Power depreciation information.[160] Depreciation rates approved by the Commission herein include employing the SFAS-143

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[157] Tr. at 37.
[158] Tr. at 380-381.
[159] Although Potomac Edison witness Valdes hazarded a guess that it might take two years to perform a depreciation study ***and*** prepare another base rate case, Tr. at 379, on cross-examination by OPC's counsel, Mr. Valdes intimated that performing a depreciation study (without layering on a full rate case) would only take six or more ***months***. Tr. at 306. Additionally, in a colloquy with the Commission, Mr. Valdes testified that Potomac Edison receives adequate resources from FirstEnergy to meet its regulatory requirements in Maryland and that if Potomac Edison were to conduct another depreciation study, the Company could be assisted by FirstEnergy. Tr. at 380-81 (Valdes). Given these representations, the Commission finds that an 18-month period to file the study is reasonable.
[160] Staff Exhibit 23.

methodology currently adopted in Maryland. Accordingly, the Company's depreciation expense will be adjusted downward by $4.2M.[161] Upon completion of a new depreciation study, the depreciation expense and rates established herein will be adjusted further in a Phase II of this proceeding.

9. Adjustment – Incentive Compensation

Potomac Edison proposed to include in its test-year O&M expenses short-term incentive, long-term incentive compensation, and potential discretionary bonuses.

OPC

Mr. Effron testified that the Commission's general approach regarding the recovery of incentive compensation from ratepayers is that companies should only be allowed to recover non-financial-related goal expenses to the extent they can demonstrate that such expenses provide benefits to ratepayers.[162] Mr. Effron testified that the portion of short-term incentive compensation ("STIP") expense that relates to financial objectives is 31%, and that the portion of the long-term incentive compensation ("LTIP") that relates to financial objectives is 67%. Accordingly, in Mr. Effron's opinion, 31% of STIP expense and 67% of LTIP expense should be eliminated from the Company's revenue requirement.[163]

Staff

Noting that the Commission has historically removed incentive compensation from the cost of service when the goals are tied primarily to achieving financial success,

[161] Along with a corresponding adjustment to accumulated depreciation.
[162] Effron Direct at 14-15.
[163] Effron Direct at 15.

Staff recommended removing the costs related to short- and long-term incentive compensation that are related to achieving Potomac Edison's financial goals.[164]

Party Responses

Potomac Edison argued on brief that its inclusion of long-term and short-term incentive compensation is both reasonable and appropriate. Potomac Edison contends that if it were to remove its incentive programs tied to financial goals, it would have to raise base salaries to attract skilled and talented employees and prevent attrition to competing employers, thus incentive pay is important because it improves performance and minimizes costs.[165]

Commission Decision

The Commission is not directing Potomac Edison to discontinue its incentive programs; the financial goals of these programs appear to benefit the Company's shareholders. However, the Commission is charged with determining which expenses should reasonably be passed on to ratepayers and the Commission will continue to disallow costs associated with financial-related goals as not benefitting ratepayers. Given that Staff's adjustment most accurately reflected Commission policy on this issue, the Commission adopts Staff's adjustment.

10. Adjustment – Supplemental Executive Retirement Plan

Supplemental Executive Retirement Plan ("SERP") is a program designed to provide enhanced retirement compensation for highly compensated individuals at levels that are above levels set forth in IRS guidelines.

[164] Poberesky Direct at 14-15.
[165] Potomac Edison Initial Brief at 21.

OPC

OPC witness Effron explained that the IRS Code limits the benefits that can be received by participants in qualifying defined benefit retirement plans.[166] Mr. Effron discussed three recent cases, Case Nos. 9418, 9424, and 9443, in which the Commission has disallowed 100% of SERP costs because there was no evidence that SERP was necessary to attract or retain highly qualified executives. Mr. Effron quoted the Commission decision in Case No. 9443, "to disallow 100 percent of SERP expenses reflects the position the Commission has taken in recent Pepco and Delmarva rate cases that ratepayers should not pay for pension benefits for company executives beyond IRS limits" and eliminated SERP from pro forma test year operating expenses.[167]

Staff

Staff recommended that all costs related to the SERP program not be included in rates because the costs are excessive based on IRS guidelines and because it is debatable whether the program is necessary to attract and retain executive talent.[168] Mr. Valcarenghi cited to Case No. 9418 in which the Commission excluded 100% of SERP costs when Pepco failed to demonstrate that the program was fundamental to attract and retain executive talent.[169] He argued that Potomac Edison should be required to clearly demonstrate the necessity of the program as a tool for the acquisition and retention of talent, as well as how the program benefits ratepayers.[170]

[166] Effron Direct at 12.
[167] Effron Direct at 13-14.
[168] Valcarenghi Direct at 16.
[169] Valcarenghi Direct at 16.
[170] *Id.*

Party Responses

Potomac Edison argued on brief that inclusion of SERP expenses in its test year operating expenses is reasonable and appropriate given the valuable nature of Potomac Edison's SERP program. Potomac Edison witness Oblack testified that Potomac Edison's peer utilities offer SERP, and that 80% of energy and utility companies worldwide have SERP programs.[171]

Commission Decision

The Commission has consistently held that ratepayers should not pay for pension benefits for company executives beyond the IRS limits. The Company has not provided any evidence that would support revising Commission precedent on this matter. Accordingly, the Commission will disallow 100% of SERP expenses in this case.

11. Adjustment – Employee Activity Costs

Employee Activity Costs are incurred for non-business activities such as employee picnics, parties, luncheons, and award dinners.

Staff

Staff recommended continuing what the Commission has done most recently, which is to split these expenses between ratepayers and shareholders because these morale-boosting costs are a benefit to both ratepayers and shareholders.[172]

Party Responses

The Company disagreed that employee activity costs should be split between customers and shareholders. Potomac Edison witness Adams testified that Potomac

[171] Potomac Edison Initial Brief at 21-22.
[172] *See* Poberesky Direct at 13-14.

Edison's test year amounts for employee activity accounts are wholly related to awards given to Operations, Lines, and Meter Reading employees under the Company's "Celebrate Success" program.[173] Mr. Adams testified that because these employees are on the "front lines" of the Company's distribution business, their performance is tied to service to Potomac Edison's customers.[174]

Commission Decision

The Commission finds, as it has in prior cases, that improved employee morale and any improvements in productivity that might result from these types of programs benefit both shareholders and ratepayers. The Commission did not distinguish between types of employees in prior cases and we do not believe there is a distinction to be made. Accordingly, the Commission accepts Staff's adjustment that would accept 50% of this adjustment.

12. Allowance for Funds Used During Construction and Interest Synchronization

While Parties did not file positions on Allowance for Funds Used During Construction ("AFUDC") and interest synchronization, adjustments are necessary to maintain consistency with the decisions made in this Order. AFUDC is a mechanism by which the utility is allowed to earn a return on funds expended to make a capital investment while the capital project is under construction. The effect of accruing that return at the authorized rate of return, as opposed to the current rate of return by the Company, is a reduction to operating income of $103,849.

[173] Adams Rebuttal at 8.
[174] Adams Rebuttal at 9.

The interest synchronization calculation is uncontested as to methodology, cost of debt, and Potomac Edison's capital structure. Therefore, utilizing the final rate base, the Commission finds that the appropriate interest synchronization results in an operating income decrease of $296,934.

Finally, based on acceptance of Staff's position with regard to the jurisdictional cost of service study, further adjustments are reflected in Appendix A.

C. Tax Cuts and Jobs Act Regulatory Liability

On February 15, 2018, in Case No. 9473, the Commission directed all Maryland utilities to track the impacts of the TCJA beginning on January 1, 2018, and apply regulatory accounting treatment to those impacts. Potomac Edison did so. Subsequently, on October 5, 2018, in Order No. 88860, the Commission directed the Company to make a one-time bill credit to customers to discharge the regulatory liability of the TCJA from January 1, 2018 through September 30, 2018. The Commission further ordered the Company to continue tracking the regulatory liability during this proceeding.

Staff

Staff reviewed Potomac Edison's compliance with Commission Order No. 88860 in Case No. 9473 for a one-time refund. Staff witness Valcarenghi found the calculation reasonable except for two necessary adjustments—one to eliminate Potomac Edison's smoothing of pension/OPEBs and the second to include compounding of interest accrued on the liability.[175] Mr. Valcarenghi calculated that the refund should have been $48,345 larger than the $4,998,464 Potomac Edison distributed.[176] With respect to the regulatory

[175] Valcarenghi Direct at 6-7.
[176] Valcarenghi Direct at 7.

liability the Company has been accruing since September 30, 2018, Staff witness Valcarenghi recommended that it should be discharged through a second refund to ratepayers when the rates from this case are put into effect.[177]

Party Responses

Potomac Edison maintains that it is entitled to retain $3.13 million in deferred adjustments to income tax, which have resulted from the TCJA. Potomac Edison argues that the TCJA regulatory liability refund ordered by the Commission for the period January 1, 2018 through September 30, 2018, was considered an "extraordinary" issue outside the context of a base rate proceeding.[178] Potomac Edison further argues that it has now proven that the Company is and has been underearning its authorized ROE by a significant margin, and the change in current taxes does not eliminate the revenue deficiency for the Company.[179] Therefore, Potomac Edison contends that it should be permitted to retain the $3.1 million regulatory liability as a temporary means of mitigating the Company's deteriorating ROE.

OPC agrees that the Commission should order Potomac Edison to refund to customers the TCJA savings from October 1, 2018, through the date that the rates go into effect in this case. OPC contends that there is no support in logic or fact for making a distinction because the issue has now arisen in a rate case.[180]

As Staff points out in its Initial Brief, in response to passage of TCJA, the Commission directed Maryland public service companies to track the impacts of the TCJA beginning January 1, 2018, and apply regulatory accounting treatment. The Commission

[177] Valcarenghi Direct at 7.
[178] Potomac Edison Initial Brief at 55.
[179] Potomac Edison Brief at 55.
[180] OPC Initial Brief at 18.

also directed Maryland utilities to make a filing explaining the expected impacts of the TCJA on their expenses and revenues, and when and how they anticipated passing on those effects to their customers. Thereafter, the Commission required Maryland public service companies to issue refunds and modify going forward rates so as to ensure that the benefits of the reduction in taxes included in the TCJA flowed through to ratepayers as fully and expeditiously as possible.

As Staff notes, in response to the Commission's directives, Potomac Edison tracked the tax reductions but argued that the TCJA tax cuts should only be flowed through to ratepayers through reduced rates set in a rate case, and offered a commitment to file the instant rate case sometime in the third quarter of 2018.

As further explained by Staff, explicitly rejecting Potomac Edison's arguments as to single-issue ratemaking, the Commission found "that the TCJA-related regulatory liability acknowledged by Potomac Edison and confirmed by Staff are extraordinary savings that warrant immediate recognition in the rates that customers pay."[181]

Commission Decision

Potomac Edison shall discharge the remaining regulatory liability through a one-time credit paid to ratepayers. This is consistent with prior orders of the Commission and returns the over-collected tax dollars to customers as soon as practicable. The Commission does not accept Potomac Edison's argument that because it was not earning its authorized rate of return, it should retain the TCJA benefit. If Potomac Edison felt it had been underearning its authorized rate of return by a significant margin over a period of

[181] Staff Initial Brief at 20, *citing In the Matter of the Impact of the Federal Tax Cuts and Jobs Act of 2017 on Maryland Utilities*, Case No. 9473, Order No. 88860, slip op at 7 (Oct. 5, 2018).

years, it could have filed a rate case some time in the intervening 25 years since its last base rate case. It did not; thus, the Commission will treat the TCJA regulatory liability as it has in prior cases by returning it to customers.

The Commission accepts Staff's position that interest on Potomac Edison's regulatory liability should be compounded,[182] and will make an adjustment to account for the fact that Potomac Edison did not compound interest on its regulatory liability through September 30, 2018, in its initial refund. Accordingly, the total amount to be discharged in the second bill credit is comprised of two amounts: (i) the amount of the regulatory liability from October 1, 2018 through March 22, 2019, adjusted to account for compounded interest;[183] and (ii) the difference between the amount Potomac Edison paid out for the liability accrued through September 30, 2018, and the amount Potomac Edison should have paid out had it correctly computed compounded interest.

D. Cost of Capital

A company's cost of capital, or overall rate of return ("ROR"), consists of its ROE and return on the cost of debt.[184] The ROR is the rate at which the Company has an opportunity to attract capital on reasonable terms and earn a return on its investment in order to attract and retain investors in a competitive market.[185] In 1923, in *Bluefield*

[182] We did not accept Staff's adjustment to the TCJA regulatory liability related to OPEB smoothing since we accepted the Company's position on the issue.
[183] The amount reflected in Appendix A, $3,142,581, is based on the monthly regulatory liability amount of $535,930.58 per ML# 222778 (Case No. 9473); this amount includes interest through March 22, 2019; the amount discharged must include additional carrying costs through the date the credit is made to the first group of customers."
[184] The cost of capital is a utility's overall rate of return, which is the sum of the weighted returns the utility must earn on its stock (equity) and bonds (debt) to attract investors in those securities. Unlike return on debt, return on equity is not directly observable and must be estimated based on market data. Case No. 9299, *In the Matter of the Application of Baltimore Gas and Electric Company for Adjustment in its Electric and Gas Base Rates*, Order No. 85374, slip op at 42 (Feb. 2013).
[185] See *Bluefield Water Works and Improvement Co. v. PSC of West Virginia,* 262 U.S. 679 (1923); *Federal Power Commission v. Hope Natural Gas Co.,* 320 U.S. 591 (1944).

Waterwork & Improvement Co. v. West Virginia Public Service Commission,[186] the Supreme Court held that "[t]he return should be reasonable, sufficient to assure confidence in the financial soundness of the utility, and should be adequate under efficient and economical management, to maintain and support its credit and enable it to raise money necessary for the proper discharge of its public duties."[187] The Supreme Court later expanded upon *Bluefield*, stating, "[f]rom the investor or company point of view it is important that there be enough revenue not only for operating expenses but also for the capital costs of the business. These include service on the debt and dividends on the stock."[188] The return to the equity owner should be "commensurate with the returns on investments in other enterprises having corresponding risks."[189]

While the cost of debt can be directly observed, the ROE is determined by comparison to other investments of comparable risk. Usually this is done by comparison to "proxy" companies based on characteristics reasonably similar to the utility in question and examining their ROEs as guidance for determining the appropriate ROE for the utility in question. The Commission looks to the analyses of the parties, which vary in methodology and approach.

Potomac Edison, Staff, and OPC all agree that the Company's proposed actual capital structure of 52.82% common equity and 47.18% long-term debt is appropriate for ratemaking purposes.[190] The parties also agree that the Company's embedded long-term

[186] 262 U.S. 679 (1923).
[187] 262 U.S. at 693.
[188] 320 U.S. at 603.
[189] 320 U.S. at 603.
[190] PE Ex 8, Supplemental Direct Testimony of Joseph Dipre ("Dipre Supplemental") at 1.

debt cost rate is 4.335%.[191] However, the parties' ROE analyses differed, which led them to recommend varying RORs, as discussed below.

Potomac Edison

Dylan D'Ascendis, Director at ScottMadden, Inc., testified for Potomac Edison regarding cost of capital. He developed his recommendation by applying several cost of common equity models including the Discounted Cash Flow ("DCF") model, the Risk Premium Model ("RPM"), and the Capital Asset Pricing Model ("CAPM") (both traditional and empirical) to a market data of a proxy group comprised of seventeen electric utility companies (the "Utility Proxy Group.") He also applied the DCF model, RPM, and CAPM to a proxy group of fifteen domestic, non-price regulated companies that he testified were comparable in risk to the Utility Proxy Group (the "Non-Price Regulated Proxy Group.")[192]

Mr. D'Ascendis selected companies for his Utility Proxy Group based on criteria that included (i) appearing in the Electric Utility Group of *Value Line's Standard Edition* ("Value Line"), (ii) having 70% or more of operating income derived from regulated electric operations during fiscal year 2017, (iii) not being involved in any major merger or acquisition at the time of preparation of testimony, (iv) not having cut or omitted common dividends during the five years ending 2017, (v) having Value Line and Bloomberg Professional Services ("Bloomberg") adjusted betas, (vi) having positive Value Line five-year dividends per share growth rate projections, and (vii) having Value Line, Reuters, Zacks, or Yahoo! Finance consensus five-year earnings per share growth rate

[191] PE Ex 7, Direct Testimony of Joseph Dipre ("Dipre Direct") at 4.
[192] D'Ascendis Direct at 4.

projections.[193] Although Mr. D'Ascendis acknowledged that Potomac Edison is a pure-play transmission and distribution ("T&D") company, he included vertically-integrated electric companies in his proxy group because there are no pure-play T&D electric companies that operate in a single jurisdiction available. Mr. D'Ascendis found that during the five-year period ending 2017, the Utility Proxy Group achieved an average earnings rate on book common equity of 8.67%.[194]

Regarding his DCF analysis, Mr. D'Ascendis applied the single-stage growth DCF model. That model is based on the theory that the present value of an expected future stream of net cash flows during the investment holding period can be determined by discounting those cash flows at the cost of capital, or the investors' capitalization rate.[195] The DCF model is based on the premise that an investor buys a stock for an expected total return rate, which includes the cash flows received from dividends as well as market price appreciation. In applying this method, Mr. D'Ascendis used analysts' five-year forecasts of the growth in each of the Utility Proxy Group companies' earnings per share. His analysis included earnings growth estimates from several sources, including Value Line, Reuters, Zacks and First Call.[196] Applying the Constant Growth DCF Model to his Utility Proxy Group, Mr. D'Ascendis calculated a mean result of 8.66% and a median of 8.92%, which he averaged to yield 8.79%, which is the final result of his DCF common equity

[193] D'Ascendis Direct at 11. Seventeen companies met Mr. D'Ascendis's criteria, including ALLETE, Inc., Alliant Energy Corporation, Ameren Corporation, American Electric Power Company, Inc., Duke Energy Corporation, Edison International, El Paso Electric Company, Entergy Corporation, IDACORP, Inc., Eversource Energy, Northwestern Corporation, OGE Energy Corp., Otter Tail Corporation, Pinnacle West Capital Corporation, PNM Resource Inc., Portland General Electric Company, and Xcel Energy Inc.
[194] D'Ascendis Direct at 12.
[195] D'Ascendis Direct at 15.
[196] D'Ascendis Direct at 4, Table 2.

analysis.[197] He used the average of the median and the mean to consider all of the proxy company results, while mitigating the high and low outliers of those results.

Mr. D'Ascendis also performed an RPM analysis, which he stated is based on the principle that investors require greater returns for bearing additional risk.[198] The model assumes that investors require higher returns for common stock than for bonds, because common equity shareholders are subordinate to debt holders in any claim on a company's assets and earnings. Mr. D'Ascendis stated that according to RPM theory, "one can estimate a common equity risk premium over bonds (either historically or prospectively) and use that premium to derive a cost rate of common equity."[199]

Mr. D'Ascendis used two risk premium methods to calculate an appropriate common equity return. First, he applied the Predictive Risk Premium Model ("PRPM"), which estimates the risk-return relationship directly, by using monthly market returns in addition to expectations of the risk-free rate of bonds. Using this method, Mr. D'Ascendis calculated a mean PRPM common equity cost rate for the Utility Proxy Group of 10.30% and a median of 10.62%. As he did for the DCF analysis, he averaged the mean and the median to arrive at 10.46%. Second, he employed the RPM using a Total Market Approach, which derives the risk premium using known metrics as a proxy for risk. More specifically, using the Total Market Approach, Mr. D'Ascendis added a prospective public utility bond yield to an average of (i) an equity risk premium derived from a beta-adjusted total market equity risk premium, (ii) an equity risk premium based on the S&P Utilities Index, and (iii) an equity risk premium based on authorized ROEs for electric utility

[197] D'Ascendis Direct at 17.
[198] D'Ascendis Direct at 17.
[199] D'Ascendis Direct at 18.

companies.[200] Using the Total Market Approach, Mr. D'Ascendis calculated a common equity cost of 10.15%. He averaged the results of the Total Market Approach with the PRPM above to reach a final RPM common equity cost rate of 10.31% for the Utility Proxy Group.[201]

Mr. D'Ascendis also performed a CAPM analysis to estimate Potomac Edison's common equity requirement. CAPM theory defines risk as the co-variability of a security's returns with the market's returns as measured by the beta coefficient.[202] The model adds a risk-free rate of return to a market risk premium, which is adjusted proportionately to reflect the systematic risk of an individual security relative to the total market, as measured by the beta coefficient.[203]

In addition to the traditional CAPM, Mr. D'Ascendis also performed the empirical CAPM ("ECAPM"). Mr. D'Ascendis stated that the ECAPM compensates for the fact that the empirical Security Market Line described by the CAPM formula is not as steeply sloped as the predicted Security Market Line. Accordingly, Mr. D'Ascendis applied both the traditional CAPM and the ECAPM to the Utility Proxy Group companies and averaged the results. He calculated a mean CAPM/ECAPM result of 9.96%, a median CAPM/ECAPM of 9.72%, and averaged the two to yield 9.84%. Mr. D'Ascendis's indicated common equity cost rate using the CAPM/ECAPM was therefore 9.84%.[204]

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[200] D'Ascendis Direct at 20.
[201] D'Ascendis Direct at 29.
[202] D'Ascendis Direct at 29.
[203] The CAPM model is expressed in the following equation: $R_s = R_f + \beta(R_m - R_f)$, where R_s is equal to the return rate on the common stock; R_f is equal to the risk-free rate of return; R_m is equal to the return rate on the market as a whole; and β is equal to the adjusted beta coefficient (representing the volatility of the security relative to the market as a whole). D'Ascendis Direct at 30.
[204] D'Ascendis Direct at 33.

In addition to applying the common equity models to the Utility Proxy Group, Mr. D'Ascendis used a comparable earnings model, by applying the DCF, RPM, and CAPM models to Non-Price Regulated Proxy Group. Mr. D'Ascendis argued that non-price regulated firms operating in the competitive marketplace provide an "excellent proxy" as long as they are comparable in total risk to the Utility Proxy Group.[205] He derived the selection criteria for this proxy group by using the beta coefficients and related statistics derived from Value Line regression analyses of weekly market prices from the most recent five years. He required that the companies (i) be covered by Value Line; (ii) be domestic, non-price regulated companies; (iii) their beta coefficients must lie within plus or minus two standard deviations of the average unadjusted beta of the Utility Proxy Group; and (iv) the residual standard errors of the Value Line regressions must lie within plus or minus two standard deviations of the average residual standard error of the Utility Proxy Group.[206] Mr. D'Ascendis's selection criteria resulted in a proxy group of fifteen domestic, non-price regulated firms. Applying the common equity models to the Non-Price Regulated Proxy Group resulted in the following: 12.20% (DCF), 11.54% (RPM), and 10.99% (CAPM). The average of the mean and median of these models is 11.56%, which Mr. D'Ascendis used as the indicated common equity cost rates for the Non-Price Regulated Proxy Group.[207]

Utilizing the multiple common equity models and multiple proxy groups, Mr. D'Ascendis calculated an indicated cost of common equity rate of 10.10%. He then applied three adjustments to reflect the relative risk differences between Potomac Edison

[205] D'Ascendis Direct at 33.
[206] D'Ascendis Direct at 34.
[207] D'Ascendis Direct at 36.

and the Utility Proxy Group. First, he applied an adjustment for business risk. Mr. D'Ascendis stated that business risk reflects the uncertainty associated with owning a company's common stock without the company's use of debt and/or preferred stock financing. Business risks faced by utilities include the regulatory environment, environmental compliance requirements, and service territory economic growth.[208] Mr. D'Ascendis testified that Potomac Edison faces increased business risk compared to the Utility Proxy Group because of its smaller relative size and its perceived regulatory risk.[209] He stated that "smaller companies are generally less able to cope with significant events that affect sales, revenues and earnings."[210] He also testified that investors generally demand higher returns from smaller firms to compensate for the diminished marketability and liquidity of their securities. Mr. D'Ascendis applied a business risk premium of 0.30% as a result.

Mr. D'Ascendis also applied a credit risk adjustment. He testified that Potomac Edison's long-term credit rating of Baa2 is two notches lower than the Utility Proxy Group's average long-term issuer rating of A3.[211] Accordingly, Mr. D'Ascendis applied a credit risk adjustment of 0.27% to reflect Potomac Edison's increased credit risk relative to the Utility Proxy Group companies. Finally, Mr. D'Ascendis made an adjustment to account for flotation costs, representing the cost of issuing new common stock, including underwriting fees and out-of-pocket expenses for printing, legal, and registration. Mr. D'Ascendis argued that flotation costs should be recovered through an adjustment to common equity cost rates even when there has not been an issuance during the test year,

[208] D'Ascendis Direct at 6.
[209] D'Ascendis Direct at 38.
[210] D'Ascendis Direct at 38.
[211] D'Ascendis Direct at 44.

because the ROE models he used do not reflect flotation costs, and the costs are permanently unavailable for investment in utility rate base. Mr. D'Ascendis therefore included an adjustment of 0.12% to reflect flotation costs.[212] Adding the three adjustments to the 10.10% unadjusted cost of common equity yields a cost of common equity rate of 10.79%, which Mr. D'Ascendis then rounded up to 10.80%, representing his final recommended ROE for Potomac Edison.[213]

The results of Mr. D'Ascendis's cost of capital analysis are presented below:

Table 1: Potomac Edison ROE Analysis

Discounted Cash Flow Model	8.79%
Risk Premium Model	10.31%
Capital Asset Pricing Model	9.84%
Comparable Earnings Model (Non-Price Regulated Proxy Group)	11.56%
Indicated Cost of Common Equity Before Adjustments	10.10%
Business Risk Adjustment	0.30%
Credit Risk Adjustment	0.27%
Flotation Cost Adjustment	0.12%
Indicated Cost of Common Equity after Adjustments	10.79%
D'Ascendis's Final Recommended Cost of Common Equity	10.80%

Company witness Dipre, Senior Advisor, Strategy-Long Term Planning & Forecasting for FirstEnergy Services Company, testified regarding Potomac Edison's capital structure. He testified that the Company proposes to utilize its actual capital structure for purposes of developing cost of capital, including the appropriate cost of

[212] D'Ascendis Direct at 47.
[213] D'Ascendis Direct at 48.

equity. He further testified that as of June 30, 2018, Potomac Edison's actual capital structure consists of 52.82% common equity and 47.18% long-term debt.[214] He stated that the Company does not have any preferred stock or short-term debt, and that the Company's embedded long-term debt is 4.335%.[215] Potomac Edison submitted that the calculation of the Company's actual capital structure was done in the same manner as the Commission approved in the last several rate cases, including the most recent decision in Case No. 9484.[216]

Using the capital structure provided by Mr. Dipre and the cost of equity proposed by Mr. D'Ascendis, the Company proposed an overall rate of return of 7.75%, as shown in the table below:

Table 2: Potomac Edison Rate of Return Analysis

Component	Capital Ratio	Cost	Weighted Cost Rate
Long-Term Debt	47.18%	4.335%	2.05%
Common Equity	52.82%	10.80%	5.70%
Rate of Return	100%		7.75%

Staff

Staff witness VanderHeyden, Director of the Commission's Electricity Division, provided testimony regarding cost of capital on behalf of Staff. He listed five criteria of a fair common equity return, including: (i) capital attraction, whereby the return is set high enough to attract the capital needed by the utility to maintain and upgrade its distribution system; (ii) management efficiency, where a higher return is awarded to utility

[214] Dipre Supplemental at 1-2.
[215] Dipre Direct at 3.
[216] Potomac Edison Initial Brief at 38.

management for efficient operation of the distribution system; (iii) rate stability, such that ROE awards make gradual movement; (iv) consumer rationing, which acknowledges that an artificially high or low ROE could interfere with the optimal consumption of electric service; and (v) fairness to investors, which, in addition to (i) above, recognizes the concerns of investors who have already made investments.[217]

In developing his proxy group, Mr. VanderHeyden looked to companies with similar risk to Potomac Edison. He noted that Potomac Edison is solely a distribution company that does not own generation assets in its Maryland rate base.[218] He acknowledged, however, that there are few, if any, companies that are organized as stand-alone electric distribution companies for the proxy group. Mr. VanderHeyden therefore used all of the companies in Value Line's Electric East, Central, and West groups. He then removed Evergy, Inc., because it was recently formed from a merger. He retained all companies that pay a dividend and for which Value Line provided a financial strength rating of at least B++. He then removed FirstEnergy, the corporate parent of Potomac Edison.

To this proxy group, Mr. VanderHeyden applied the DCF and CAPM methods and averaged the results. He also used the Internal Rate of Return ("IRR") method, which uses a series of calculations of net present value ("NPV") to determine the discount rate that would cause the NPV of a series of cash flows over a period to equal zero. Mr. VanderHeyden's use of the IRR method yielded a result of only 6.94%. Mr. VanderHeyden excluded this result from his final recommended ROE because the IRR return was close to Potomac Edison's cost of debt, which is illogical given that equity

[217] Staff Ex 26, Direct Testimony of Phillip VanderHeyden ("VanderHeyden Direct") at 4-5.
[218] VanderHeyden Direct at 9.

investors require a premium for equity risk.[219] Mr. VanderHeyden testified that the low IRR result was driven by the current elevated price of the proxy group stocks.

In his DCF analysis, Mr. VanderHeyden used the constant growth model. He used the adjusted closing stock prices from the companies in the proxy group as reported by Yahoo! Finance for the six months prior to the filing of Potomac Edison's base rate case. He then utilized the annual earnings growth as projected for each proxy group company by Value Line for the period ending in 2021-2023 as well as Yahoo! Finance's reported dividends for the 12 months ending September 30, 2018. He added the earnings growth rates for each proxy group company to each company's respective dividend yield to obtain an individual DCF return. However, Mr. VanderHeyden removed from this result the companies with stock symbols ED, ETR, and IDA because their calculations indicated a ROE of less than 7%, which he testified was unrealistically low.[220] Similarly, he removed the company with stock symbol AGR because of its unrealistically elevated level of 16.84%. Using this approach, Mr. VanderHeyden calculated a DCF return on common equity of 9.51%.[221]

In his CAPM analysis, Mr. VanderHeyden used a mix of current and projected 30-year U.S. Treasury rates to determine the risk-free rate. He used Value Line to determine the betas for the stocks of each company in his proxy group. He also used an equity risk premium derived from the historical market return as provided by Duff and Phelps. Applying the CAPM method to his proxy group, he calculated an ROE of 9.04%.[222] Mr. VanderHeyden observed that his CAPM result for Potomac Edison is lower

[219] VanderHeyden Direct at 11.
[220] VanderHeyden Direct at 16.
[221] VanderHeyden Direct at 13, 17.
[222] VanderHeyden Direct at 18.

than the CAPM result in his previous rate case, and testified that there has been a reduction in the projected long-term treasury rate and the proxy group's betas, resulting in a reduction in the CAPM ROE result when compared to the proxy group from that prior case. Mr. VanderHeyden contended that this is mainly due to a reduction in the anticipated increase in long-term interest rates when compared with the anticipated rate of increase projected last year.

Mr. VanderHeyden then averaged the CAPM ROE of 9.04% with his DCF ROE of 9.51% to reach a mean of 9.28%. He lowered the 9.28% ROE to 9.25% to account for the impact of certain mergers and corporate transactions within the proxy group. The 9.25% return on common equity is Staff's final recommendation on ROE. Accounting for Potomac Edison's cost of long-term debt, Mr. VanderHeyden recommended that the Company's rate of return be 6.93%.[223]

Mr. VanderHeyden compared his cost of capital results to Potomac Edison's and observed that his recommendation included several similarities with Mr. D'Ascendis's. For example, Mr. VanderHeyden stated that he used all of the same companies used in Mr. D'Ascendis's proxy group, with the exception of a few Mr. VanderHeyden excluded because their DCF results were too low.[224] Mr. VanderHeyden noted that he and Mr. D'Ascendis also used the constant growth model of the DCF, and used earnings growth rather than dividend, cash flow, or book value growth estimates in their respective DCF calculations.

Mr. VanderHeyden testified that he saw several deficiencies with Potomac Edison's cost of capital analysis. First, he criticized Mr. D'Ascendis's use of the ECAPM,

[223] Staff Ex 27, Surrebuttal of Phillip VanderHeyden ("VanderHeyden Surrebuttal") at 28.
[224] VanderHeyden Direct at 25.

noting its results are 86 basis points above the corresponding CAPM method and well above the range of returns ordered by the Commission in the last several years. He stated that the ECAPM is not widely accepted in the financial community and that using it to reflect returns form the entire stock market is unnecessary because regulated utilities like Potomac Edison, with monopoly service territories, are inherently more stable than unregulated companies. Second, Mr. VanderHeyden questioned Mr. D'Ascendis's use of projected Value Line and Bloomberg S&P 500 market returns of 16%, stating that those returns are well in excess of the historic mean annual return. Third, Mr. VanderHeyden faulted Mr. D'Ascendis's use of the PRPM and Total Market Approach, arguing that he did not provide a foundation for why it was needed. Mr. VanderHeyden observed that Mr. D'Ascendis did not provide the median of his Total Market Approach, which would have lowered the result by 67 basis points and is inconsistent with Mr. D'Ascendis's other cost of capital calculations.[225] Fourth, Mr. VanderHeyden objected to Mr. D'Ascendis's use of a Non-Price Regulated Proxy Group, noting that the Commission has previously found inclusion of such proxy groups inappropriate for setting the ROE of a monopoly distribution company.[226]

Finally, Mr. VanderHeyden criticized Mr. D'Ascendis's three adjustments to his recommended ROE. He noted that the Commission has rejected adjustments for flotation costs in the last several rate cases, and argued that flotation costs should be awarded only upon the submission of verifiable costs of issuing new stock.[227] Mr. VanderHeyden stated that Potomac Edison's evidence of flotation costs relates only to its issuance of stock

[225] VanderHeyden Direct at 34.
[226] VanderHeyden Direct at 38, citing Order No. 83907.
[227] VanderHeyden Direct at 23, citing Proposed Order of the Hearing Examiner, Case No. 9424 (January 4, 2017) at 155-56.

through its former parent Allegheny Power in the year 2003, well outside the test year. He therefore recommended against inclusion of flotation costs. Mr. VanderHeyden also opposed any adjustment for business risk or credit risk, arguing that Potomac Edison is a stable distribution company with in a low-risk environment. Mr. VanderHeyden concluded that if Mr. D'Ascendis's non-utility results and ECAPM results were excluded and his adjustments were denied, the average of Mr. D'Ascendis's DCF and CAPM methods would provide a ROE of 9.25%.

OPC

David C. Parcell, Principal and Senior Economist of Technical Associates, Inc., testified on behalf of OPC regarding Potomac Edison's cost of capital. He testified that the Supreme Court decisions of *Bluefield Water Works and Improvement Co. v. Public Serv. Comm'n of West Virginia*[228] and *Federal Power Comm'n v. Hope Natural Gas Co.*[229] set forth the three economic and financial parameters of comparable earnings, financial integrity, and capital attraction.[230] He further stated that those cases support the opportunity cost principle that "a utility and its investors should be afforded an opportunity (not a guarantee) to earn a return commensurate with returns they could expect to achieve on investments of similar risk."[231]

Mr. Parcell testified regarding the recent trends in economic conditions in the country as well as their impact on capital costs. He asserted that one impact of the Great Recession has been a reduction in actual and expected investment returns, as evidenced by a decline in short-term and long-term interest rates. He argued that regulatory

[228] 262 U.S. 679 (1923).
[229] 320 U.S. 591 (1942).
[230] OPC Ex 12, Direct Testimony of David C. Parcell ("Parcell Direct") at 5.
[231] Parcell Direct at 5.

agencies have recognized this decline in capital costs by authorizing lower ROEs for regulated utilities in each of the last several years.[232] Mr. Parcell acknowledged that the Federal Reserve has raised the Federal Funds rate on eight occasions between December of 2015 and September 2018, but he maintained that even with the tapering and eventual ending of the Federal Reserve's Quantitative Easing program, interest rates have remained low. He testified that even though the rates on U.S. Treasuries and public utility securities have increased since the beginning of 2018, government and utility long-term lending rates remain near historically low levels, reflecting lower capital costs.

Mr. Parcell used three common equity models to develop his recommended ROE, including the DCF, CAPM, and Comparable Earnings. He selected companies for his proxy group pursuant to the following criteria: (i) market cap of $10 billion to $25 billion or greater, (ii) common equity ratio of 40% or greater, (iii) Value Line Safety rank of 1 or 2, (iv) S&P stock ranking of A or B, (v) S&P and Moody's bond ratings of BBB or A, (vi) currently pays dividends, and (vii) not involved in mergers or acquisitions.[233] Mr. Parcell used a second proxy group that consisted of the companies chosen by Company witness D'Ascendis for his proxy group.

Like cost of capital witnesses for Potomac Edison and Staff, Mr. Parcell utilized the Constant Growth DCF model. Applying the DCF model to his proxy groups, Mr. Parcell calculated rates between 6.9% and 8.9%. He narrowed the range to 8.4% to 8.9% to represent the current DCF-derived ROE for the proxy groups.[234] Mr. Parcell also completed a CAPM analysis. Using this method, he calculated a ROE range of 6.6% to

[232] Parcell Direct at 8.
[233] Parcell Direct at 16-17.
[234] Parcell Direct at 20.

7.0% for the proxy groups.[235] Mr. Parcell observed that the CAPM results were lower than his DCF results and his Comparable Earnings method. He posited two reasons for this. First, he stated that risk premiums are currently lower than was the case in prior years. Second, he stated that the level of interest rates on U.S. Treasury bonds has been lower in recent years, which pushed the CAPM results downward.

Mr. Parcell also based his recommended ROE on the Comparable Earnings method, which is based on the prospective return available to investors from alternative investments of similar risk.[236] For this method, Mr. Parcell examined realized ROEs for the groups of proxy utilities as well as unregulated companies and evaluated investor acceptance of these returns by referencing the resulting market-to-book ratios. Mr. Parcell stated that a market-to-book ratio greater than one (i.e., greater than 100%) reflects a situation where a company is able to attract new equity capital without dilution. Mr. Parcell examined the ROEs of the proxy group of utilities as well as the S&P 500 Composite group for the sixteen-year period 2002-2017. He also examined projected ROEs for 2018, 2019, and 2021-2023. Mr. Parcell found that historic ROEs of 9.5% to 10.0% have been adequate to produce market-to-book ratios of 139% to 158% for the utilities.[237] He determined that projected ROEs for 2018, 2019, and 2021-2023 within the range of 9.5% to 10.8% achieved market-to-book ratios of 190% or greater. For the S&P 500 Composite group, he found that this group's average ROEs ranged from 12.4% to 13.4%, with average market-to-book ratios between 242% and 275%. Mr. Parcell noted, however, that the S&P 500 group is riskier than the utility proxy group. Mr. Parcell concluded his Comparable

[235] Parcell Direct at 23.
[236] Parcell Direct at 23.
[237] Parcell Direct at 25.

Earnings method analysis by stating that a range of 9.0% to 10.0% reflects the actual and prospective ROEs for the proxy groups.[238]

Analyzing the results of his three common equity methods, Mr. Parcell found an overall range of 6.6% to 10.0%, which he narrowed to 6.8% to 9.5% when using mid-point values. Mr. Parcell concluded that a ROE range of 8.9% to 9.5% with a mid-point of 9.2% would provide a fair and just return for the Company.[239] Mr. Parcell accepted Potomac Edison's actual capital structure and embedded cost of debt calculated by Company witness Dipre. Using those figures and his recommended ROE, Mr. Parcell determined that Potomac Edison's cost of capital (rate of return) is a range of 6.75% to 7.06%, with a mid-point of 6.90%.

Mr. Parcell provided a number of criticisms of Potomac Edison's cost of capital calculations. Mr. Parcell observed that his DCF conclusion is similar to Mr. D'Ascendis's 8.79% calculation. However, over all, Mr. Parcell testified that Mr. D'Ascendis's ROE recommendations were "beyond the mainstream of authorized ROE's for electric utilities throughout the U.S. in recent years."[240] Mr. Parcell challenged Mr. D'Ascendis's use of the Risk Premium Model, noting that the PRPM in particular was relatively new and untried and has not been accepted or endorsed by any regulatory agency. Mr. Parcell also questioned the Total Market Approach, arguing that Mr. D'Ascendis's use of total stock returns over the 1926-2017 period created several problems. For example, the 1926-2017

[238] Parcell Direct at 26.
[239] Although Mr. Parcell did not expressly reduce his recommended ROE as a result, he observed that if the Commission approves either Potomac Edison's proposed Storm Damage Accrual Mechanism or its EDIS, the Company will have significantly reduced its risk. He testified that the EDIS in particular would permit Potomac Edison to recover reliability costs without going through the process of filing a general rate proceeding, reduce regulatory lag, and transfer risk from the Company to customers. Parcell Direct at 28-29.
[240] Parcell Direct at 30.

period was heavily influenced by the Great Depression, World War II, and the high inflation/interest rate environment of the 1970s and 1980s, making comparisons regarding investor expectations during those periods inapplicable to the current period. Mr. Parcell also criticized Mr. D'Ascendis's CAPM analysis because it used forecasted yields on U.S. Treasury and utility bonds as the risk-free rate rather than the current yield. He noted that the 30-year Treasury bonds currently yield well below the 3.69% used by Mr. D'Ascendis in his risk-free rate. Addressing the ECAPM analysis, Mr. Parcell charged that Mr. D'Ascendis arbitrarily ignored the actual betas of the proxy utilities and improperly assigned hypothetical betas to them. Mr. Parcell questioned the use of a Non-Price Regulated Proxy Group, arguing that unregulated companies face different risks and operational characteristics than utilities.[241]

Mr. Parcell also challenged Mr. D'Ascendis's three adjustments to his ROE. First, he objected to Mr. D'Ascendis's request for flotation costs. He testified that Potomac Edison has not demonstrated that FirstEnergy has or intends to issue new common equity for the purpose of infusing equity into Potomac Edison. Additionally, Mr. Parcell opposed the adjustment for business risk, arguing that Potomac Edison failed to demonstrate that a small electric utility should receive a higher ROE than a large one.[242] In particular, Mr. Parcell noted that many of the proxy electric utilities have multiple subsidiaries that operate in different jurisdictions, but that these individual utility subsidiaries do not raise their equity capital directly from investors, but instead do so as part of a consolidated entity. In that regard, FirstEnergy operates one of the largest investor-owned electric systems in the U.S. Mr. Parcell also challenged the notion that smaller utilities are riskier than larger

[241] Parcell Direct at 35.
[242] Parcell Direct at 36.

ones, since both categories are fully regulated.[243] Finally, Mr. Parcell opposed any financial adjustment for Potomac Edison relating to the Company's lower credit rating. Mr. Parcell argued that Potomac Edison's credit rating has been negatively influenced by the ratings of its parent, FirstEnergy, relating to FirstEnergy's high-risk, unregulated operations. Mr. Parcell concluded that Potomac Edison's ratepayers should not be penalized for FirstEnergy's higher risk operations that are unrelated to Potomac Edison.

Party Responses

In his rebuttal testimony, Mr. D'Ascendis objected to much of the methodology and conclusions of the Staff and OPC witnesses. He argued that they relied too heavily on the DCF model, which understated the required return for investors.[244] In particular, he claimed that the market-to-book ratios of the proxy groups are considerably higher than their historical averages, causing a downward bias in the DCF analysis. He claimed that the 50% weight Staff and OPC witnesses attributed to the DCF skewed the result and he further argued that their failure to use other common equity methods, such as ECAPM, rendered their conclusions inaccurate. Mr. D'Ascendis criticized the proxy group selection criteria used by Staff and OPC, arguing that they improperly omitted the percentage of net operating income and assets attributable to regulated electric operations.[245]

Regarding Staff's cost of equity analysis, Mr. D'Ascendis faulted Mr. VanderHeyden for misapplication of the CAPM. Specifically, he argued that Mr. VanderHeyden erred by (i) failing to consider the ECAPM, and (ii) using historical

[243] Parcell Direct at 37. Mr. Parcell noted, for example, that water utilities, which are often the smallest of regulated utilities, tend to have the lowest authorized ROEs—a fact that contradicts Mr. D'Ascendis's theory that smaller size should result in upward adjustments to authorized returns.
[244] D'Ascendis Rebuttal at 2.
[245] D'Ascendis Rebuttal at 16.

measures for his market return rather than projected market risk premiums.[246] Mr. D'Ascendis also contended that Mr. VanderHeyden should have included other cost of equity models, such as the RPM and Comparable Earnings model. He further argued that Mr. VanderHeyden failed to reflect the greater investment risk of Potomac Edison compared to his utility proxy group. Mr. D'Ascendis further claimed that Mr. VanderHeyden should have included a flotation adjustment. Mr. D'Ascendis argued that flotation costs should be recovered on a perpetual basis because the benefits of that capital extend indefinitely, and that it is immaterial whether Potomac Edison experienced actual flotation costs during the test year.[247]

Regarding OPC's cost of equity analysis, Mr. D'Ascendis asserted that OPC's ROE recommendation, in conjunction with the agency's request for a 9% decrease in distribution rates, offended notions of gradualism.[248] He observed that the U.S. Energy Information Administration showed an increase in electricity prices of 50.8% over the period 1994-2015, which made OPC's request for a rate decrease "counterintuitive," and which, if approved, would put negative pressure on Potomac Edison's credit rating. Mr. D'Ascendis also disagreed with Mr. Parcell's heavy weighting of his DCF results as well as his application of the CAPM. Mr. D'Ascendis argued that Mr. Parcell's CAPM calculation of 6.80% demonstrated that the result was "unreasonable on its face" and that the low result stemmed from incorrect inputs in Mr. Parcell's calculations.[249] Mr. D'Ascendis criticized Mr. Parcell's Comparable Earnings analysis, claiming that

[246] D'Ascendis Rebuttal at 21-22.
[247] D'Ascendis Rebuttal at 30-31.
[248] D'Ascendis Rebuttal at 39.
[249] D'Ascendis Rebuttal at 41. In particular, Mr. D'Ascendis argued that Mr. Parcell (i) incorrectly relied on a historical risk-free rate, when both ratemaking and the cost of capital are prospective; (ii) incorrectly calculated the market risk premium; and (iii) failed to incorporate an ECAPM analysis. D'Ascendis Rebuttal at 42-43.

Mr. Parcell's supposition that a direct relationship between market-to-book ratios and the rate of earnings on book common equity is not supported.[250] Mr. D'Ascendis also faulted the proxy group selected for Mr. Parcell's Comparable Earnings method, arguing that it was not sufficiently broad-based and should have excluded utilities, to avoid circularity. Finally, Mr. D'Ascendis argued that Mr. Parcell should have adjusted his ROE upward to account for Potomac Edison's smaller size. He disputed Mr. Parcell's argument that Potomac Edison should be viewed as part of the larger FirstEnergy company, claiming that ratemaking principles dictate that Potomac Edison be evaluated as a stand-alone entity based on its operations in Maryland only.

In his surrebuttal testimony, Mr. Parcell argued that the authorized ROE for electric utilities has continued to decline over the past several years, with the most recent ROEs well below 10.0%. His calculations of mean average and median by year since 2013 are:

Table 3: Mean and Median ROEs by Year[251]

Year	Average	Median
2013	9.82%	9.82%
2014	9.76%	9.75%
2015	9.60%	9.53%
2016	9.68%	9.60%
2017	9.68%	9.60%
2018(2Q)	9.58%	9.50%

Mr. Parcell also dismissed Mr. D'Ascendis's criticism of his proxy group selection, noting that he applied all of his ROE analyses to both his proxy group as well as Mr. D'Ascendis's proxy group, so that his ROE findings and conclusions reflect the proxy groups for both

[250] D'Ascendis Rebuttal at 54.
[251] Parcell Surrebuttal at 3.

the Company and OPC. Mr. Parcell disagreed with the notion that the DCF model underestimates the investor required return, arguing that Mr. D'Ascendis's attempt to "reprice" stock values in order to develop a DCF cost rate "in line with what he thinks the results should be" was improper and contrary to the principle of efficient markets.[252] Mr. Parcel also disagreed with Mr. D'Ascendis's claim that his CAPM analysis should have used forecasted yields on Treasury bonds rather than current yields. Mr. Parcell argued that analysts should not use prospective stock prices as the basis for the dividend yield because the use of prospective stock prices is speculative. Mr. Parcell disagreed that he should have incorporated the ECAPM, which he argued overstates the cost of equity for companies with betas below that of the market.[253] Finally, Mr. Parcell disagreed that Potomac Edison's ROE should be adjusted upward to reflect its smaller size as compared to the proxy group. He contended that most of the proxy electric utilities have multiple subsidiaries in multiple jurisdictions, yet raise capital directly from investors as consolidated entities.

In his surrebuttal testimony, Mr. VanderHeyden disagreed with Mr. D'Ascendis's contention that Mr. VanderHeyden gave undue weight to the DCF analysis, noting that if he had provided greater weight to his lower CAPM result of 9.04%, his overall ROE recommendation would have been lower than the 9.25% he provided.[254] Mr. VanderHeyden also rejected the claim that the DCF method would understate investors' required return due to stock price volatility. He observed that he removed the results from companies ED, ETR, and IDA due to unrealistically low DCF results, which

[252] Parcell Surrebuttal at 4.
[253] Parcell Surrebuttal at 10.
[254] VanderHeyden Surrebuttal at 4.

helped prevent understatement of the final DCF result. Mr. VanderHeyden also argued that there was nothing improper about using a historic equity risk premium in his CAPM analysis, because historic data provides certainty as compared to prospective data.[255] In that regard, Mr. VanderHeyden referenced the IHS Markit estimate that stock returns will be less than 3% over the next three years,[256] making his historic return of 12.06% appear generous towards the Company. Additionally, Mr. VanderHeyden asserted that Mr. D'Ascendis's 16% market return lies at the "extreme end" of the historic average and market projections.[257] Regarding the ECAPM, Mr. VanderHeyden argued that the method is not widely accepted or used by the financial community, is insufficiently supported academically, and is unduly complicated and speculative.[258] In contrast, surveys of investment professionals demonstrate that the DCF and CAPM methods are the dominant methods used. Mr. VanderHeyden further stated that he used these two methods because they take different approaches and use different data points. The DCF, for example, is specific to a particular company and does not use data from the broader market. In contrast, the CAPM uses market information regarding the relative risk and price movements of the subject company and compares that to an index of companies representing the overall stock market. Mr. VanderHeyden argued that the risk premium method discussed by Mr. D'Ascendis is a simplified precursor to the CAPM. Mr. VanderHeyden stated that he did not use the risk premium method because of concern that it would overweight the relative risk approach of the CAPM as against the direct approach of the DCF.[259]

[255] VanderHeyden Surrebuttal at 10.
[256] VanderHeyden Surrebuttal at 11.
[257] VanderHeyden Surrebuttal at 12.
[258] VanderHeyden Surrebuttal at 17.
[259] VanderHeyden Surrebuttal at 19.

Mr. VanderHeyden opposed the three upward adjustments Mr. D'Ascendis applied to his final ROE. Mr. VanderHeyden observed that the District of Columbia Public Service Commission ("D.C. Commission") found that a "small size adjustment" should apply only to a company in a competitive industry and that an adjustment for a regulated utility was improper in view of the utility's monopoly as a distribution company in the utility's service territory.[260] Mr. VanderHeyden also opposed Mr. D'Ascendis's inclusion of flotation costs. Mr. VanderHeyden stated that the Commission's policy is to approve flotation costs only when the utility demonstrates that they were incurred during the test year or that the utility would incur flotation costs during the rate effective period. Because Potomac Edison did not make this demonstration, flotation costs should be denied.[261]

Commission Decision

The Supreme Court set forth the fundamental elements for determining a fair return on the investments of a regulated utility in the cases *Bluefield Waterwork* and *Hope Natural Gas*.[262] In those cases, the Court found that a return on equity should be (i) comparable to returns investors expect to earn on investments of similar risk, (ii) sufficient to ensure confidence in the company's financial integrity, and (iii) adequate to maintain and support the company's credit and to attract capital. After having reviewed and considered the witnesses' testimony in view of the *Bluefield* and *Hope* decisions, the Commission finds that an ROE of 9.65% for Potomac Edison's electric operations represents a fair and appropriate return.

[260] VanderHeyden Surrebuttal at 22.
[261] VanderHeyden Surrebuttal at 25.
[262] *Bluefield Co. v. Pub. Serv. Comm'n*, 262 U.S. 679, 693 (1923); and *Fed. Power Comm'n v. Hope Natural Gas Co.*, 320 U.S. 591, 603 (1944).

The Commission observes that the witnesses used different methodologies and assumptions to estimate Potomac Edison's cost of equity. That is not a criticism. As Staff witness VanderHeyden explained regarding the calculation of a fair return: "This information is not tabulated in a book or posted on the Internet; it is observed by analyzing the returns expected by investors based on several methods of analysis."[263] The determination of a fair ROE therefore requires a degree of discretion from the cost of capital expert. For example, he or she must choose which model or models to employ, how to assemble the most representative proxy group, and whether or how to exclude outliers from the analysis, to name just a few of the parameters.

The ROE witnesses in this proceeding used various analyses to estimate the appropriate return on equity for Potomac Edison's electric distribution operations, including the DCF model, the CAPM (including the traditional and empirical versions), risk premium methodologies, and comparable earnings models. Although the witnesses argued strongly over the correctness of their competing analyses, the Commission is not willing to rule that there can be only one correct method for calculating a ROE. Neither will the Commission eliminate any particular methodology as unworthy of basing a decision.[264] The subject is far too complex to reduce to a single mathematical formula.[265] That conclusion is made apparent, in practice, by the fact that the expert witnesses used discretion to eliminate outlier returns that they testified were too high or too low to be considered reasonable, even when using their own preferred methodologies.

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[263] VanderHeyden Direct at 6.

[264] For the reasons discussed below, the Commission places less weight on the ECAPM and the Company's comparable earnings method based on the Non-Price Regulated Proxy Group. Nevertheless, the Commission will not preclude a party from submitting such studies or declare categorically that these methodologies should receive no weight.

[265] *See* Case No. 9326, Order No. 86060 at 76. "We find all of these analytical tools helpful and will not rely on any one to the exclusion of the others in making our decision."

Utilizing the cost of capital methodologies discussed above, the parties provided a range of ROE recommendations, as shown below.

Table 4: Summary of Party ROE Calculations

Method and Adjustments	Potomac Edison	Staff	OPC
DCF	8.79%	9.51%	8.65%
CAPM	9.41%	9.04%	6.80%
ECAPM	10.27%	N/A	N/A
Risk Premium Model	10.31	N/A	N/A
Comparable Earnings Model	11.56%	N/A	9.5%
Flotation Adjustment	12 bp	N/A	N/A
Merger Adjustment	N/A	-0.03%[266]	N/A
Business Risk	0.30%	N/A	N/A
Credit Risk	0.27%	N/A	N/A
ROE Recommendation	**10.80%**	**9.25%**	**9.20%**
Rate of Return	**7.75%**	**6.93%**	**6.90%**

OPC recommended the lowest ROE of 9.20%. Nevertheless, part of OPC witness Parcell's recommendation included a CAPM result of 6.80%. The Commission views this result as abnormally low, especially compared to the results of the same CAPM methodology conducted by Potomac Edison and Staff witnesses. The Commission also observes that Mr. Parcell testified that a ROE range of 8.9% to 9.5% for Potomac Edison would provide a fair and just return for the Company, with the 9.5% acknowledging the results of his comparable earnings analysis.[267] Potomac Edison witness D'Ascendis

[266] *See* VanderHeyden Direct at 17 and 21.
[267] Parcell Direct at 28-29.

provided the highest recommended ROE of 10.80%. Nevertheless, his DCF and CAPM analyses resulted in a significantly lower 8.79% and 9.41% returns, respectively.

Considering all the cost of capital evidence presented by the parties in this proceeding, the Commission finds that a return on equity of 9.65% is just and reasonable and will be sufficient to meet Potomac Edison's capital needs. That award recognizes that Potomac Edison is a stable distribution company that does not own generation in its Maryland rate base and that operates in a low-risk environment.[268] Additionally, the Commission's award recognizes that even with the ending of the Federal Reserve's Quantitative Easing program, interest rates have remained low, with government and utility long-term lending rates remaining near historically low levels. In making this award, the Commission observes that the 9.65% return awarded today lies within the range of ROEs recommended by the parties (9.20% to 10.80%). Additionally, the 9.65% award fits within the range of mean average and median ROEs approved by public utility commissions in the last few years, as shown in Table 3 above.

In considering the array of evidence presented on cost of capital, the Commission concludes that Potomac Edison's comparable earnings method (based on its Non-Price Regulated Proxy Group) should be given little weight. The Commission has previously found that including unregulated companies in the proxy group produces results that are "significantly out of line" for a regulated distribution company and "justifies rejection of the non-utility returns."[269] Non-utility companies are significantly riskier than regulated distribution utilities and should require markedly higher returns than regulated entities. For that reason, the Commission held that "[r]eliance on a non-utility proxy group, containing

[268] VanderHeyden Direct at 9.
[269] *Balt. Gas & Elec. Co*., 102 MD PSC 75, 105 (2011).

companies fully subject to market risk, is an inappropriate basis for calculating the ROE of a regulated monopoly electric [or] gas distribution company."[270] Similarly, the Commission finds that the ECAPM result should be given little weight. As Staff witness VanderHeyden observed, the ECAPM is not widely accepted by the financial community in determining ROEs.[271] In Case No. 9424, the law judge observed that the ECAPM is "rarely, if ever … cited in professional literature" and Commission witnesses have generally not used it as a primary method.[272]

The Commission further finds that the adjustments proposed by Potomac Edison for business risk, credit risk, and flotation costs should be rejected. Regarding business risk, the Commission finds that Potomac Edison's size as a relatively small electric distribution utility does not justify an upward adjustment in ROE. The Company has submitted evidence that small, unregulated companies may face greater risk than medium to large companies. However, that elevated risk does not extend to regulated utilities, which have the benefit of a monopoly service territory and a captive customer base. As Staff witness VanderHeyden stated: "[I]f a company in a competitive industry increases its prices, the company faces the risk of losing customers to competitors. But because a utility is a monopoly as the sole distribution company in its service territory, the utility does not face the risk of losing customers if the utility increases its prices."[273]

The D.C. Commission recently addressed this issue and reached a similar result, finding: "Regulation provides a safety valve for those small regulated utilities that significantly diminishes their risk relative to larger regulated companies. That safety valve

[270] *Balt. Gas & Elec. Co*., 102 MD PSC 75, 105 (2011).
[271] VanderHeyden Surrebuttal at 12-13.
[272] Case No. 9424, Proposed Order at 152.
[273] VanderHeyden Surrebuttal at 23.

protects small companies from competition and allows small companies to increase their rates without facing competitive pressures."[274] Finally, empirical studies confirm that industrial betas tend to decrease with firm size but regulated utility betas do not.[275] Accordingly, Potomac Edison's request for an upward adjustment to reflect enhanced risk due to its relatively small size is denied.

The Commission also denies Potomac Edison's request for flotation costs. The Commission has granted flotation costs only where the utility has demonstrated that it incurred verifiable costs of issuing new stock during the test year or will incur such flotation costs during the rate effective period.[276] In Case No. 9336, BGE made a similar argument to that proposed by Potomac Edison now—namely, that flotation costs should be recovered on a perpetual basis because the benefits of that capital extend indefinitely. The Commission held: "BGE has merely presented argument that investors are entitled to an adjustment for flotation on an ongoing basis whether or not the Company actually incurs such costs. We reject that argument."[277]

Finally, the Commission finds that Potomac Edison's testimony that the Company should receive an upward adjustment to its ROE based on credit risk should be given little weight. The Commission has not generally included an upward adjustment in ROE to reflect the lower credit rating of a regulated utility from the proxy group with which it is compared. Furthermore, Staff and OPC presented evidence that Potomac Edison is a stable

[274] District of Columbia Public Service Commission, Case No. 1137, Order No. 18712 at 28 (March 3, 2017).
[275] VanderHeyden Surrebuttal at 23, citing Wong, Annie, "Utility Stocks and the Size Effect: An Empirical Analysis," Journal of the Midwest Finance Association at 95-101 (1993).
[276] *Pepco*, 107 Md. PSC 701, 755 (2017). For example, the Commission approved the recovery of flotation costs in Case Nos. 9336 (Pepco), 9311 (Pepco), and 9285 (Delmarva Power).
[277] *In the Matter of the Application of Baltimore Gas and Electric Company for Adjustments to its Electric and Gas Base Rates*, Case No. 9406, Order No. 87591 at 156 (June 3, 2016).

distribution company in a low-risk environment that should not be granted an additional upward adjustment due to financial risk.

Considering all the evidence related to cost of capital provided in this proceeding, the Commission finds that a cost of equity award of 9.65% complies with the standards established by *Hope* and *Bluefield,* is comparable to returns investors expect to earn on investments of similar risk, is sufficient to ensure confidence in Potomac Edison's financial integrity, and will enable the Company's investors to receive a fair return commensurate with risk. Additionally, the ROE is adequate to maintain and support Potomac Edison's credit and to attract needed capital.

Given that no party objected to the actual capital structure proposed by Potomac Edison witness Dipre, the Commission accepts for purposes of determining rate of return that the Company's capital structure consists of 52.82% common equity and 47.18% long-term debt. Additionally, the Company's embedded long-term debt cost rate is 4.335%. Potomac Edison's weighted average cost of capital for electricity is therefore as follows:

Table 5: Authorized Return

Type of Capital	Ratios	Cost Rate	Weighted Cost Rate
Long-Term Debt	47.18	4.335%	2.05%
Common Equity	52.82%	9.65%	5.10%
Total	100%		7.15%

E. Cost of Service

The purpose of a cost of service study ("COSS") is to determine the costs a customer class imposes upon a utility. The purpose of a jurisdictional cost of service study ("JCOSS") is to determine the costs a jurisdiction imposes upon a utility, if the utility is

serving customers in different states. Costs may be directly assigned or allocated based upon various allocation methodologies. Once costs are assigned, then class (and jurisdictional) rates of return can be developed, which are used to design customer rates. The Commission uses the results from cost of service studies as a guide in developing appropriate customer class rates. There are three components of both a JCOSS and a COSS: functionalization, classification, and allocation. Functionalization is the process of assigning utility revenue requirements to specified utility functions, such as production, transmission, distribution, customer, and general. In that process, rate base and expenses are divided into different categories based on the use of the item causing costs. Classification is the separation of the functionalized costs into operational uses, which include demand, energy, and customer costs. Finally, allocation involves the separation of the classified costs to either the appropriate jurisdiction or customer class for the JCOSS and COSS, respectively.[278]

Potomac Edison does business as an electric public utility in Maryland and West Virginia and operates transmission facilities in Virginia. Therefore, Potomac Edison first allocated the Company's rate base, revenues, and expenses in a JCOSS, which reflects the costs of providing this service to customers in each jurisdiction. Potomac Edison then used a COSS to assign and allocate its Maryland-specific distribution costs to its customer classes in Maryland, based upon the principles of cost causation and revenue responsibility. In this case, Staff and OPC developed an alternative JCOSS and COSS. Much of the testimony on this portion of the rate case centered on which studies more accurately determined costs.

[278] Staff Ex 17, Direct Testimony of Benjamin Baker ("Baker Direct") at 4-5.

Potomac Edison

Lora M. Oblack, State Regulatory Analyst for FirstEnergy in the Rates and Regulatory Affairs Department – West Virginia/Maryland, testified for the Company regarding Potomac Edison's JCOSS and COSS.[279] She testified that Potomac Edison does business as an electric public utility in Maryland and West Virginia and operates transmission facilities in Virginia.[280] The Company also has wholesale customers subject to jurisdiction of FERC. Because of its multi-state footprint, Ms. Oblack stated that it was necessary to perform a jurisdictional separation study to determine the fair share of costs and revenues attributable to Potomac Edison-Maryland ("PE-Maryland") distribution customers from the total Potomac Edison amounts.

Ms. Oblack stated that a going-forward (referred to as "going-level") JCOSS was prepared for PE-Maryland in accordance with the historical practices used by the Company and accepted by the Commission.[281] Similarly, Potomac Edison prepared a distribution going-level COSS for PE-Maryland. The JCOSS and COSS were based on a test year of nine months actual plus three months forecast for the period of July 1, 2017 through June 30, 2018. The studies upon which Potomac Edison based its JCOSS and COSS were old, including a 1986 Pole Sample Study and a 1986 Zero Intercept Study. In her Supplemental Testimony, Ms. Oblack updated the forecast period with actuals for the going-level JCOSS and COSS.[282]

[279] Potomac Edison referred to its JCOSS as a Jurisdictional Separation Study.
[280] PE Ex 20, Direct Testimony of Lora M. Oblack ("Oblack Direct") at 2-3.
[281] Potomac Edison witness Adams defined a going-level adjustment as "reflect[ing] a fully adjusted test year *prior* to the Company's proposed revenue change or change in expenses related to the proposed revenue change." Adams Direct at 4-5.
[282] PE Ex 21, Supplemental Direct Testimony of Lora M. Oblack ("Oblack Supplemental") at 2.

Regarding the JCOSS, Ms. Oblack stated that the purpose of the study was to identify rate base, revenues, and expenses that should be allocated or assigned to the Maryland jurisdictional portion of Potomac Edison's operations for the test year.[283] The study involves a functionalization step, where rate base, expenses, and revenues recorded on the books of Potomac Edison are separated on a functional basis (such as production, transmission, distribution, customer service, administrative, and general) between Maryland and the Company's other jurisdictions. In the classification step, common costs were classified into four major allocation categories (including demand, plant-related, labor-related, and customer-related) and then allocated as appropriate to the Maryland jurisdiction. After determining Maryland jurisdictional rate base, revenues, and expenses, the final step involved an additional allocation or direct assignment to establish Maryland distribution-related revenues and expenses. Potomac Edison used two primary allocations for this last step derived from Potomac Edison FERC Form 1, Distribution of Salaries and Wages, and from an internally developed separation study allocation of Maryland total plant to Maryland distribution plant.

Potomac Edison primarily used the Average Coincident Peak ("ACP") method to allocate demand-related costs, which Ms. Oblack stated is consistent with Commission precedent. Plant-related costs were assigned to Maryland distribution based upon a ratio of Maryland distribution plant to total Potomac Edison plant. PE-Maryland labor-related costs were determined by an allocator developed within the JCOSS based upon payroll taxes, functionalizing those expenses based on the Potomac Edison FERC Form 1 Distribution of Salaries and Wages, and applying appropriate allocations to each of the

[283] Oblack Direct at 4.

functionalized components. Customer-related costs were allocated based on a ratio of the number of PE-Maryland customers to total Potomac Edison customers. Costs that were not solely distribution-related were allocated to Maryland distribution based on a ratio of Maryland distribution plant to total Maryland plant.

Ms. Oblack included several adjustments in the JCOSS.[284] For example, salary and wage increases were annualized to reflect a full year of increase (Adjustment 2). She similarly included adjustments for savings plan costs, going-level medical insurance expenses, group life insurance expense, Federal Insurance Contributions Act expense, and materials and supply.

Regarding the COSS, Ms. Oblack testified that the primary purpose of the study is to assign Potomac Edison's revenue requirement to rate schedules based on principles of cost causation.[285] Ms. Oblack stated that the COSS is designed as a guide to show the pattern of costs in serving one class of customers relative to serving another class.[286] She added that a reasonable attempt should be made to bring all rates as close as possible to cost-based equality while maintaining the reasonable differences among rate schedules. The COSS analyzes, classifies, and allocates a utility's cost of providing service among the applicable rate schedules. The rates are then set to recover Potomac Edison's total revenue requirement on a basis that is commensurate with the cost of serving each rate schedule. Ms. Oblack stated that the COSS allocates costs to rate schedules by selecting allocators based on causal relationships between the customers' demands and usage characteristics, and the costs Potomac Edison incurs to furnish service to customers served

[284] Oblack Direct at 6-7.
[285] Oblack Direct at 11.
[286] Oblack Direct at 15.

under each rate schedule. Potomac Edison's JCOSS was the main data source for the COSS.

Ms. Oblack stated that the COSS involved a two-step process consisting of (i) classification and (ii) allocation of costs to assign costs to each rate schedule based on principles of cost causation. Ms. Oblack testified that because the vast majority of costs incurred in providing electric service are common costs not directly related to any one customer, group of customers, or area of service, the costs must first be classified among (a) capacity/demand-related costs, which vary with items such as the size of plant and equipment; and (b) customer costs, which vary with the number of customers served.

Once overall costs have been defined and classified, they must be allocated among the various classes of customers. Ms. Oblack stated that distribution capacity costs were first allocated to those rate schedules who receive service from the distribution-related facilities based on their demand responsibility.[287] Next, customer costs were allocated to rate schedules based on their customer responsibility.

Two methods of capacity cost allocation were used—ACP and non-coincident peak ("NCP"). The ACP method was used for subtransmission and capacitor line transformer plant. The NCP method was used for demand-related primary and secondary distribution plant. Ms. Oblack testified that it is appropriate to use the NCP method of allocation of demand costs for the primary and secondary distribution plant because engineers size primary and secondary distribution equipment to adequately serve local area loads. She also stated that the methodology is consistent with the methodology submitted by Potomac Edison in Case Nos. 8469 and 8652. Ms. Oblack Exhibit LMO-9 provides a summary of

[287] Oblack Direct at 12.

customer and demand data used to develop the principal COSS allocation factors, including the number of customers, the NCP demands reflected at the generation level, and the ACP demands reflected at the generation level.

Ms. Oblack concluded that the COSS demonstrates that Maryland's current distribution going-level rate of return is only 4.85%, which is well below Potomac Edison's requested rate of return of 7.75%.

Staff

Staff witness Baker, a Regulatory Economist in the Commission's Electricity Division, provided testimony on behalf of Staff. He stated that he did not propose any modifications to the method Potomac Edison used to separate costs between Maryland and other jurisdictions in its JCOSS. He testified that Potomac Edison's demand allocator was acceptable. However, Mr. Baker did propose several modifications to the Company's JCOSS and COSS, including revision to Potomac Edison's functionalization of Maryland distribution costs from Maryland total costs.[288] For example, Mr. Baker incorporated all of the going-level adjustments proposed by Staff witnesses Poberesky and Valcarenghi into the JCOSS. He prorated an equal proportion of the adjustment to the going level adjustments based on the separation of costs currently used to develop going-level Adjustment 23 (related to post-test period reliability projects through the test year) and Adjustment 25 (related to accumulated depreciation for post-test year reliability projects). Mr. Baker also included a modifier to the tax values in the JCOSS to ensure that the adjustments proposed by Staff witness Poberesky are reflected in the JCOSS.

[288] Staff Ex 17, Direct Testimony of Benjamin Baker ("Baker Direct") at 16.

Mr. Baker questioned Potomac Edison's use of the Salary & Wages allocator to separate distribution plant from total plant. He observed that FERC policy requires general plant to be allocated on the basis of labor, unless the utility can show that labor ratios are unreasonable under the circumstances.[289] Mr. Baker further stated that Maryland utilities allocate some or all of their general plant costs among rate classes using labor allocators.

Mr. Baker expressed several concerns with Potomac Edison's COSS. He challenged the reliability of Potomac Edison's data, given its age, noting that the Company is classifying plant between demand and customer components using studies from 1986 through 1994.[290] Specifically, the Company included a 1986 Pole Sample Study and a 1986 Zero Intercept Study.[291] The Company also used a 1993 study that separated primary and secondary costs for conduit and conductors in FERC accounts 366 and 367. Mr. Baker testified that the outdated studies could result in improper allocation among rate classes. "PE's Zero Intercept Study is 32 years old and PE's system has changed since then."[292] For example, he argued that the inputs of the studies are either booked costs or hypothetical rebuilding costs, which would have changed since 1986. He also observed that Potomac Edison used five out-of-date studies in its COSS and that these studies "do have a significant impact on revenue allocation among the classes."[293] Accordingly, Mr. Baker recommended that the Commission require that in conjunction with its next base rate case, Potomac Edison file updated studies utilized in both the JCOSS and the COSS, such that

[289] Baker Direct at 18, citing 583 FERC ¶ 61,091 (1978).
[290] Baker Direct at 20.
[291] Mr. Baker testified that a zero intercept system study attempts to classify plant for a hypothetical no-load situation. In other words, the study examines what costs would be incurred for a hypothetical distribution system with zero customer demand. The related minimum system study attempts to determine the minimum size distribution system that can be built to serve the minimum loading requirements of the customer. Baker Direct at 6.
[292] Baker Direct at 28.
[293] Baker Direct at 31.

all updated studies are current to within one year of the test year in the Company's next base rate case.

Mr. Baker raised additional questions about Potomac Edison's Zero Intercept Study, in addition to the study's age. Mr. Baker noted that the study has a large impact upon residential customers, observing that if the study is removed from the COSS, the residential class goes from being the largest under-earning class (with a Unitized Rate of Return ("UROR") of 0.68) to a UROR of about 1.[294] Mr. Baker also testified that Potomac Edison is the only investor-owned utility that uses a zero intercept study, with BGE and Delmarva Power & Light Company ("Delmarva") both recommending against it in recent rate cases.[295] Nevertheless, Mr. Baker acknowledged that Choptank Electric Cooperative, Inc. ("Choptank") and Southern Maryland Electric Cooperative, Inc; ("SMECO") both utilize some form of minimum system study. In previous cases before the Commission, those utilities argued that the study demonstrates that a minimum portion of the grid is necessary to make electric service available.

As a compromise, Mr. Baker proposed that a weight of one-third be given to Potomac Edison's COSS with distribution depreciation functionalized and inclusive of the Zero Intercept Study and that a weight of two-thirds be given to the COSS without the Zero Intercept Study.[296] He also asked that the Commission direct Potomac Edison submit a COSS with and without a zero intercept study in its next base rate case, so that the parties

[294] Baker Direct at 24. Mr. Baker acknowledged that utilizing the COSS with the Zero Intercept Study, the residential class is the largest under-earner, with a UROR of 0.65, while Schedule PP is the largest over-earner, with a UROR of 3.03. Baker Direct at 14, Table 2.
[295] Baker Direct at 25.
[296] Baker Direct at 28.

to the case and the Commission can further consider the appropriateness of using a zero intercept study to allocate costs for Potomac Edison's service territory.[297]

Mr. Baker also faulted the Company's treatment of distribution depreciation. He asserted that Potomac Edison should further functionalize distribution depreciation to provide better alignment with cost causation, arguing that it would substantially impact the final UROR. He stated that Potomac Edison is currently allocating distribution depreciation using total distribution plant, which is not as closely aligned to cost causation as it would be with greater functionalization. If the Company functionalized distribution depreciation in the same manner as it did with distribution plant, Mr. Baker found that the correction would have a substantial impact on classes PP and PH (by moving class PP from a UROR of 2.94 to one of 1.75).[298]

Mr. Baker proposed allocating services using number of customers in lieu of splitting services between demand and customer costs, as Potomac Edison did in its COSS.[299] Mr. Baker argued that Potomac Edison's decision to split services in FERC Account 369 between demand and customer costs may be inappropriate because FERC Account 369 is typically considered "100% customer." Mr. Baker claimed that the definition of service lines—that they are "low voltage conductors that extend from line transformers and secondary distribution lines and make a connection to the customer's wiring system at the service entrance point"— demonstrates that their costs are typically customer driven, not demand driven.[300]

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[297] Baker Direct at 31.
[298] Baker Direct at 21, Table 8. In contrast, this correction would move rate class PH from 0.92 to 0.84.
[299] Baker Direct at 30.
[300] Baker Direct at 30, citing Vogt, Lawrence J., Electricity Pricing Engineering Principles and Methodologies, CRC Press Taylor & Francis Group (2009) at 498.

Mr. Baker expressed concern with Potomac Edison's allocation of general and intangible plant in its COSS.[301] Mr. Baker stated that Potomac Edison functionalizes general and intangible plant utilizing a Salary & Wages allocator, but the Company allocates general and intangible plant using plant allocators. In order for the allocation of these costs to match the functionalization, Mr. Baker recommended that the Commission direct Potomac Edison to provide a COSS in its next base rate case that includes a labor allocator to better reflect the functionalization of general and intangible plant and to be more consistent with cost causation.

Mr. Baker raised the issue of whether it is appropriate for Potomac Edison to use ACP to allocate subtransmission costs and FERC Accounts 362 and 368 costs.[302] Mr. Baker acknowledged that Potomac Edison has used ACP in the past to allocate these two accounts in its COSS, but noted that this was when Potomac Edison was a vertically integrated utility. At this time, Mr. Baker suggested it may be more appropriate to allocate the costs of these accounts with an NCP allocator. Mr. Baker raised a similar issue with the lighting class, which he noted has little to no demand during the coincident peak, but does utilize the subtransmission system during periods that are not within the coincident peak period. Accordingly, Mr. Baker recommended that the Commission require that in its next base rate case, Potomac Edison submit testimony supporting or rejecting the use of the ACP methodology to allocate costs related to subtransmission and FERC Accounts 362 and 368 capacitors based on current system conditions and cost causation.

Finally, Mr. Baker observed that there is a "dip" in residential demand in the test year when compared to years 2017 and 2016 for the one NCP allocator that is used to

[301] Baker Direct at 32.
[302] Baker Direct at 32-33.

allocate secondary costs. Mr. Baker testified that if 2017 had been the test year, those differences may have led to a different UROR.[303] Mr. Baker therefore recommended that in its next base rate case, Potomac Edison provide five years of demand at transmission, subtransmission, primary, and secondary levels, as well as their resulting allocators that are used in the COSS.

OPC

OPC witness Pavlovic, Senior Consultant and Managing Director of PCMG and Associates, LLC, testified on behalf of OPC. He asserted that Potomac Edison's JCOSS incorrectly classifies and allocates General and Intangible plant costs.[304] Specifically, he argued that Potomac Edison's methodology was flawed in that it directly assigned to the Maryland jurisdictional system General and Intangible plant and then allocated those costs to the Maryland distribution system as labor related. Mr. Pavlovic contended that the NARUC Manual and the definitions for General and Intangible plant contained in the FERC Uniform System of Accounts make clear that "general and intangible plant comprise precisely those facilities and costs that are not directly assignable to any specific sub function of a utility's operation and thus are to be classified as common."[305] In order to properly allocate the costs of this common plant, Mr. Pavlovic recommended using for the JCOSS the ratio of Maryland distribution plant to total company plant. With this correction, Mr. Pavlovic concluded that the Maryland distribution rate base would be substantially decreased and operating income, earned return, and earned rate of return would substantially increase.

[303] Baker Direct at 34, Table 17.
[304] OPC Ex 8, Direct Testimony of Karl R. Pavlovic ("Pavlovic Direct") at 9.
[305] Pavlovic Direct at 10.

Mr. Pavlovic also attested to methodological errors in Potomac Edison's COSS.[306] In particular, he contended that Potomac Edison's COSS incorrectly classifies primary and secondary lines and transformer costs as both demand related and customer related, which is inconsistent with cost causation. He argued that utilities such as Potomac Edison design and construct primary and secondary lines and transformers based on the peak demand caused by customers and not on the number of customers. Correcting for that error would reduce the residential class rate base and increase the residential class's indexed rate of return up to a unity of 1.00.[307] Mr. Pavlovic also observed that Potomac Edison's Zero Intercept Study was "over 30 years old and not representative of Potomac Edison's current cost structure."[308]

Party Responses

Potomac Edison witness Oblack opposed most of the recommendations of Staff and OPC regarding the JCOSS. She argued against using a customer allocator for allocating intangible plant in the Company's JCOSS, claiming that Intangible Plant primarily consists of software purchased and used to support the business, the costs of which are not contingent on the number of customers.[309] She therefore concluded that an allocation related to plant is better suited than one based on the number of customers. She argued that OPC witness Pavlovic was incorrect that Potomac Edison's JCOSS allocates both general and intangible plant using a direct assignment to the Maryland jurisdiction. She stated that intangible plant is allocated on GP35 (Transmission and Distribution Plant) and is not directly assigned. She further clarified that FERC plant accounts 389 (Land and

[306] Pavlovic Direct at 12.
[307] Pavlovic Direct at 14.
[308] Pavlovic Direct at 12.
[309] PE Ex 22, Rebuttal Testimony of Lora M. Oblack ("Oblack Rebuttal") at 2.

Land Rights) and 390 (Structures and Improvements) should be assigned directly because service centers and land relate to a specific jurisdiction. Additionally, because they are not directly assignable to any specific sub-function, they were properly booked to General Plant.[310]

Ms. Oblack also opposed the recommendations of Staff and OPC related to the COSS. She challenged Mr. Baker's proposal to further functionalize depreciation, noting that the COSS did not further functionalize because this was not the method used and approved in the Company's last base rate case.[311] She opposed Staff and OPC recommendations related to the Zero Intercept Study because the study is consistent with what the Company has filed in previous rate cases before the Commission. She also asserted that a portion of services (related to FERC Account 369) may be demand related. Ms. Oblack opposed the additional studies recommended by Mr. Baker. She stated he "has not established why an across-the-board requirement to update every study to within one year of the test period is necessary."[312] She also stated that the costs to the Company of conducting such a study would be considerable. For the same reasons, she opposed any requirement for the Company to (i) file a COSS with and without a Zero Intercept Study, (ii) file testimony in a subsequent rate case supporting or rejecting the use of the ACP methodology, or (iii) provide five years of demand at transmission, subtransmission, primary, and secondary levels. Regarding the five years of demand, Ms. Oblack further stated that because PJM has a two-year restriction related to out-of-market resettlements, Potomac Edison does not keep five years worth of demand data.

[310] Oblack Rebuttal at 3-4.
[311] Oblack Rebuttal at 12.
[312] Oblack Rebuttal at 13.

In his rebuttal testimony, OPC witness Pavlovic disputed Staff witness Baker's proposed modification of Potomac Edison's customer-related classification of the Company's primary and secondary line and transformer costs and resulting class indexed rates of return.[313] Mr. Pavlovic testified that Potomac Edison's Planning Criteria provides no indication that "the number of customers plays any role in the design of Potomac Edison's primary and secondary lines and transformers and therefore in the incurrence of the costs of those facilities."[314] Mr. Pavlovic also argued that the Zero Intercept Study violates cost causation principles and that Staff's COSS, which incorporates the Zero Intercept Study, is flawed.[315] Accordingly, Mr. Pavlovic recommended that any revenue requirement approved by the Commission be allocated on the basis of Staff's COSS *without* the Zero Intercept Study.

In his surrebuttal testimony, Staff witness Baker stated that he supports directly allocating service center costs to jurisdictions when the service center has no operation that crosses borders.[316] However, when service centers house operations that serve both Maryland and West Virginia, he recommends separating general building and structure costs between Maryland and West Virginia using a plant allocator. Mr. Baker further testified that some service centers house operations that serve customers and plant in both Maryland and West Virginia.

Mr. Baker further addressed the issue of whether general and intangible plant should be allocated using labor or plant.[317] He reviewed Potomac Edison's general and

[313] OPC Ex 9, Rebuttal Testimony of Karl R. Pavlovic ("Pavlovic Rebuttal") at 3-4.
[314] Pavlovic Rebuttal at 5.
[315] Pavlovic Rebuttal at 8.
[316] Staff Ex 18, Surrebuttal Testimony of Benjamin Baker ("Baker Surrebuttal") at 4.
[317] Baker Surrebuttal at 6.

intangible FERC accounts by line items and determined that at least half of the general costs are driven by labor, and approximately half of the intangible costs are driven by plant.[318] According to his analysis, Mr. Baker concluded that Potomac Edison should continue to separate total general plant costs using a labor allocator. However, he found that the Company should separate total intangible plant costs using a plant allocator. Mr. Baker clarified that Company witness Oblack was incorrect that Mr. Baker argued for the separation of intangible plant between Maryland and West Virginia by customer instead of plant.[319] Instead, Mr. Baker stated that his analysis supported that this cost category is more clearly aligned with plant.

Despite OPC witness Pavlovic's opposition to the partial weighting of the Zero Intercept Study in the COSS, Mr. Baker testified that the partial weighting was appropriate.[320] He stated that issues such as customer location that are not correlated with demand may drive costs and that "[r]emoving the zero intercept method entirely from the cost of service study could partially result in unfair allocation of revenues to non-residential customers."[321] Finally, based on Ms. Oblack's rebuttal testimony, Mr. Baker adjusted his recommendation that Potomac Edison provide five years of demand at transmission, subtransmission, primary, and secondary levels to only three years of such data.[322]

In his surrebuttal testimony, OPC witness Pavlovic argued that Potomac Edison's direct assignment of General Plant Accounts 389 and 390 is not consistent with the principle of cost causation.[323] He contended that the fact that the Company uses plant ratios

[318] Baker Surrebuttal at 8.
[319] Baker Surrebuttal at 14.
[320] Baker Surrebuttal at 16.
[321] Baker Surrebuttal at 17.
[322] Baker Surrebuttal at 21.
[323] OPC Ex 10, Surrebuttal Testimony of Karl R. Pavlovic ("Pavlovic Surrebuttal") at 4.

to allocate its other general plant accounts (Accounts 391-399) undermines the Company's use of direct assignment for Accounts 389 and 390. He stated that the NARUC Manual provides that direct assignment of functionalized plant is appropriate only to customers and only when that plant is functionally independent of the integrated system and devoted to the exclusive use of the customers to which it is directly assigned. Mr. Pavlovic concluded that direct assignment to jurisdictions is not consistent with cost causation and that allocation based on plant ratios is the appropriate methodology for allocation. Mr. Pavlovic also contested Ms. Oblack's rebuttal testimony regarding the classification and allocation of primary and secondary lines and transformers in Potomac Edison's COSS.[324] Specifically, Mr. Pavlovic challenged the premise that the Commission had approved in a prior rate case the Company's use of a minimum system zero intercept classification of a portion of the cost of primary and secondary lines and transformers as customer-related. Mr. Pavlovic argued that the classification methodology was neither contested by the parties nor discussed in the Commission's order.

Commission Decision

The Commission finds that the JCOSS and COSS as revised by Staff witness Baker present the most accurate and appropriate measure of the costs PE-Maryland imposes on Potomac Edison as well as the costs the various customer classes impose on the Company. For example, Staff's JCOSS makes going-level adjustments to reflect the values contained in the testimonies of Staff witnesses Poberesky and Valcarenghi, to be consistent with the going-level adjustments that Potomac Edison made to its JCOSS.[325] Mr. Baker also

[324] Pavlovic Surrebuttal at 9.
[325] Baker Direct at 16.

presented convincing testimony regarding Potomac Edison's treatment of distribution depreciation and the Company's allocation of general and intangible plant in its COSS as well as the Company's treatment of certain FERC accounts. For example, Mr. Baker's testimony demonstrated that Potomac Edison's practice of allocating distribution depreciation using total distribution plant yields results not as closely aligned with cost causation as would have been the case had the Company used greater functionalization. Mr. Baker found fault in Potomac Edison's use of the Salary & Wages allocator in its JCOSS to separate distribution plant from total plant, arguing that FERC policy requires general plant to be allocated on the basis of labor, unless the utility can show that labor ratios are unreasonable under the circumstances.[326] Mr. Baker also provided sound recommendations that Potomac Edison should directly allocate service center costs to jurisdictions when the service center has no operation that crosses state borders, and separate general buildings and structure costs between Maryland and West Virginia using a plant allocator for service centers that house operations that serve both states.[327] The Commission finds Mr. Baker's testimony convincing.

Another deficiency with Potomac Edison's JCOSS and COSS is the age of the studies, with five of the underlying studies outdated. Mr. Baker observed that the Company is classifying plant between demand and customer components using studies from 1986 through 1994.[328] The Company included a Pole Sample Study and a Zero Intercept Study each from 1986, as well as a 1993 study separating primary and secondary costs for conduit and conductors for FERC accounts 366 and 367. The inputs to Potomac Edison's outdated

[326] Baker Direct at 18, citing 583 FERC ¶ 61,091 (1978).
[327] Baker Surrebuttal at 4.
[328] Baker Direct at 20.

studies have likely changed in the decades since they were published, such that reliance on them could result in improper allocation among rate classes. As just one variable that has changed considerably, the number of Potomac Edison customers has doubled since the Company submitted its last litigated rate case in 1992.[329] As discussed below, the Commission will require that Potomac Edison file updated studies utilized in its JCOSS and COSS, such that all updated studies are current to within one year of the test year in the Company's next base rate case. Although Potomac Edison witness Oblack protested that the costs of the studies requested by Staff could be significant, the Commission finds that the studies are necessary to ensure that in the next rate case, proper allocation of costs to customers reflect current system conditions. Otherwise, the improper allocation of costs could unfairly burden certain customer classes, result in other system inefficiencies, and lead to cross subsidization.

Aside from its age, Mr. Baker questioned Potomac Edison's Zero Intercept Study, which imposed significant, and perhaps unwarranted, impacts upon the residential class's UROR. For example, he observed that removing the study from the COSS resulted in the residential class transitioning from being the largest under-earning class to a UROR of about 1. None of the Maryland investor-owned utilities currently utilize a minimum system study. BGE argued against inclusion of such a study in Case No. 9230, claiming "area peak demand loads are the true cost driver in the planning process for substations and feeder investment."[330] The Commission agreed, finding: "[t]he primary effect of a

[329] Baker Direct at 28. Potomac Edison's last rate case was filed in 1994 in Case No. 8652. However, that case resulted in a settlement agreement. Potomac Edison's last litigated rate case occurred in 1992 in Case No. 8496.

[330] Baker Direct at 25-26, citing *In the Matter of the Application of Baltimore Gas and Electric Company for Revisions in its Electric and Gas Base Rates*, Case No. 9230, Order No. 83907 at 92.

minimum system approach appears to be to re-allocate costs of a minimum level of distribution plant as customer-related."[331] Similarly, in Case No. 9424, Delmarva argued that minimum system studies are "an arduous undertaking" that "seek[] to hypothetically reconstruct the distribution system in a manner inconsistent with system planning and design principles."[332] Accordingly, the Chief Law Judge in that case granted the request to eliminate the requirement that Delmarva file a minimum system study in its future base rate case filings.[333] Nevertheless, as Staff witness Baker testified, SMECO and Choptank have used minimum system studies in their past cost of service studies. In its most recent rate case, SMECO agreed that if it files a minimum system study in conjunction with its next rate case, it will also provide a cost of service study without a minimum system study.[334] That compromise is appropriate in the context of the present case as well. When Potomac Edison files a cost of service study in its next rate case, it will have discretion to include a minimum system study. However, if it does so, it must also file a cost of service study without the minimum system study.

The Commission also finds reasonable Mr. Baker's compromise to partially weight the Zero Intercept Study in his COSS. In his proposal, a weight of one-third was given to the COSS with distribution depreciation functionalized and inclusive of the Zero Intercept Study and a weight of two-thirds was given to the COSS without the Zero Intercept Study.[335] Mr. Baker's compromise is reasonable because Maryland's other investor-owned

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[331] *Id*.
[332] Baker Direct at 26-27, citing Case No. 9424, Normand Rebuttal at 5.
[333] *In the Matter of the Application of Delmarva Power and Light Company for Adjustments to its Retail Rates for the Distribution of Electric Energy*, Case No. 9424, Proposed Order (Jan. 4, 2017) at 169-70.
[334] Baker Direct at 27, citing Stipulation and Settlement Agreement and Joint Motion for Approval of Settlement Agreement, Case No. 9456, *In the Matter of the Application of Southern Maryland Electric Cooperative, Inc. for Authority to Revise its Rates and Charges for Electric Service*, (Dec. 6, 2017) at 7, Condition 15.
[335] Baker Direct at 28.

utilities do not currently use minimum system studies in their cost of service studies, and because Potomac Edison's COSS is out of date. Accordingly, the COSS with the Zero Intercept Study should be given less weight. However, notwithstanding the testimony of OPC witness Pavlovic, there may be some costs associated with the electric distribution system that are imposed on the system that are not based on demand.[336] Therefore, the one-third weight to the COSS with the Zero Intercept Study is appropriate.

For these reasons, the Commission accepts Staff's proposed JCOSS and COSS. The Commission also accepts Staff's recommendations to require Potomac Edison to update its studies prior to the filing of a new rate case. Specifically, the Commission directs that, in conjunction with its next base rate case, Potomac Edison file updated studies utilized in both the JCOSS and the CCOSS, such that all updated studies are current to within one year of the test year in the Company's next base rate case.[337] Moreover, if Potomac Edison files a zero intercept study in its next rate case, the Company is directed to also submit a COSS without a zero intercept study, to enable consideration of the appropriateness of using such a study to allocate costs for Potomac Edison's service territory. The Company is also required to provide a COSS in its next base rate case that includes a labor allocator to better reflect the functionalization of general and intangible plant and to be more consistent with cost causation. The Company is also directed in its next rate case to submit testimony supporting or rejecting the use of the ACP methodology to allocate costs related to subtransmission and FERC Accounts 362 and 368 capacitors

[336] For example, Mr. Baker testified that issues such as customer location that are not correlated with demand may drive costs and that "[r]emoving the zero intercept method entirely from the cost of service study could partially result in unfair allocation of revenues to non-residential customers." Baker Surrebuttal at 17.
[337] *See* Tr. at 574-75 (Baker) and Baker Direct at 21-31 for reference to the five out-of-date studies that must be updated in Potomac Edison's next base rate case.

based on current system conditions and cost causation. Finally, Potomac Edison is required in its next rate case to provide three years of demand at transmission, subtransmission, primary, and secondary levels, as well as their resulting allocators that are used in the COSS.

F. Rate Design

Rate Design involves two functions: (i) the design of inter-class rates, which involves the assignment of revenue requirement between the various customer classes, and (ii) the design of intra-class rates, which involves the manner in which the class revenue requirement will be collected from customers. In order to determine how much of any rate increase (or decrease) should be assigned to a particular customer rate class, the Commission begins with the actual rates of return reflected in the COSS. These results are then translated into a UROR, which measures as a percentage the actual individual customer class rate of return compared to the utility's system average or overall rate of return.[338] This percentage is then compared with the actual earnings provided by that rate class, resulting in a UROR for each class.

A UROR of 1.00 signifies that a rate class has a return equal to the utility's overall rate of return. A UROR that is higher than 1.00 indicates that the class has a return (or contribution) that is greater than the system average, and a UROR that is lower than 1.00 indicates a class return that is less than average. If all customer rate classes have a UROR of 1.00, then each class is contributing equally to the utility's overall rate of return based upon its cost of service. As a matter of policy, the Commission strives to bring all classes closer to a UROR of 1.00 in each rate case, to reflect the cost causation from each class.

[338] *See In the Matter of the Application of Baltimore Gas and Electric Company for Adjustments to its Electric and Gas Base Rates*, Case No. 9326, 104 Md. P.S.C. 653, 699 (2013).

However, this goal is also tempered with notions of gradualism in order to avoid rate shock from the customers of any particular rate class.

Once the revenue requirement is apportioned among the various classes, intra-class rates may be designed. Almost all rate classes have a customer charge, which is designed to recover a portion of customer related costs.[339] The remaining costs are recovered through a variable charge on a per kilowatt hour ("kWh") basis.[340] Finally, some non-residential customers have a demand charge, which is designed to recover capacity costs.[341] Intra-class rate design is guided by important policy considerations, including gradualism, energy conservation, and economic impacts as well as cost causation.

Company witness Valdes provided testimony on behalf of Potomac Edison related to rate design. He stated that Potomac Edison had the following four objectives in developing its rate design proposal: (i) allocating the pro forma revenue increase to the various rate schedules to provide the necessary increase in revenues, using the going-level COSS as a guide; (ii) moving all rate schedules closer to a unity indexed rate of return; (iii) removing items from distribution rates that are legacy rate design items from the Company's last base rate case in 1994; and (iv) designing rates to minimize the shifting of customers from one rate schedule to another.[342] The Company's proposal raises several

[339] Staff witness McAuliffe defines a customer charge as "a fixed monthly charge for the purpose of collecting customer related costs [that] are not related to a customer's variable energy usage." He explained that most Maryland utilities do not recover all customer-related fixed costs in their customer charges. Staff Ex 20, Direct Testimony of Drew M. McAuliffe ("McAuliffe Direct") at 6,

[340] Staff witness McAuliffe defined an energy charge as "a charge that is based on the electricity usage of a customer and fluctuates with the amount of electricity used by a set dollar per kWh rate." He explained that this charge is intended to recover the utility's variable costs as well as any fixed costs not recovered through the customer or demand charges. McAuliffe Direct at 6-7.

[341] Staff witness McAuliffe defined demand charge as "a charge levied in proportion to the peak quantity of energy used by the customer. It varies with the customer's capacity load, not on the basis of usage. It seeks to recoup the costs that relate to operation, maintenance and investment." McAuliffe Direct at 5.

[342] Valdes Direct at 21.

rate design issues, including the appropriate revenue allocation, revisions to particular rate schedules (including to remove energy charges and to incentivize attrition), elevated customer charges, street lighting, Tariff revisions, and revenue allocation of the EDIS. Each of these is discussed and resolved below.

1. Revenue Allocation

Potomac Edison

Potomac Edison witness Valdes stated that his goal in allocating the pro forma revenue increase to the various rate schedules was to "bring all rate schedules as close as possible to an indexed ROR of 1.00 to minimize subsidies between rate schedules."[343] However, he acknowledged the need to achieve this goal gradually, pursuant to the ratemaking principle of gradualism. He testified that an immediate movement to unity for all rate schedules would result in revenue changes that are too drastic and could incentivize customers to transfer to different rate schedules, thereby disrupting the status quo of rate schedule billing and risking revenue erosion.

In accordance with his stated goals, Mr. Valdes proposed a two-step allocation process to allocate the pro forma revenue increase to the various rate schedules. First, he allocated a portion of the increase to under-earning rate schedules to move their UROR closer to unity.[344] He stated that there were only two rate schedules that were below a UROR of 1.00 (Schedule R, with an indexed ROR of 0.67, and Schedule PH and AGS, with an indexed ROR of 0.89).[345] Because Schedule R, the residential rate class, was furthest from unity, Mr. Valdes allocated 50% of the pro forma revenue increase to that

[343] Valdes Direct at 24.
[344] Potomac Edison used the term "indexed ROR" in lieu of UROR.
[345] Valdes Direct at 25.

schedule. He also allocated 5.48% of the pro forma revenue increase to Schedules PH and AGS. In the second step, Mr. Valdes allocated the remainder of the pro forma revenue increase to all rate schedules based upon the proportion of each rate schedule's revenue compared to total revenue. In this step, Mr. Valdes excluded any increase to Schedules G, C, PP, and the Hagerstown & Frederick special lighting contracts, because these rate schedules have indexed RORs well in excess of 1.0. Mr. Valdes testified that this two-step methodology resulted in "significant movement to a unity indexed ROR as compared to the going-level indexed ROR."[346]

Staff

Staff witness McAuliffe, Regulatory Economist for the Commission's Electricity Division, provided testimony addressing rate design. He emphasized four criteria that should be satisfied through the rate design process, which are (i) consumer rationing, (ii) avoidance of rate shock, (iii) attaining the revenue requirement, and (iv) fair cost apportionment.[347] He also stated that rate design should avoid undue discrimination, provide adequate revenue, and be fair to ratepayers. He observed that the Commission has also consistently encouraged energy conservation and the protection of low-income customers in the rate design process.

Mr. McAuliffe criticized Potomac Edison's revenue allocation proposal. He argued that Potomac Edison's step one was not performed in the manner most two-step allocations are made.[348] He stated that normally, the step one allocation is based on the revenue of each rate schedule compared to the total. However, Potomac Edison "instead selected

[346] Valdes Direct at 25.
[347] McAuliffe Direct at 3.
[348] McAuliffe Direct at 9.

arbitrary amounts of revenue to be allocated to the two customer rate schedules [Schedule R and Schedule PH and AGS]."[349] Mr. McAuliffe further stated that because Potomac Edison imposed such a large amount of revenue to allocate to the residential rate schedule (50%), the typical residential customer will experience a distribution bill increase of 26%, which may lead to rate shock.[350]

Mr. McAuliffe proposed an alternative rate design on behalf of Staff.[351] He stated that Staff's proposal involved a two-step allocation like Potomac Edison's. However, both allocations would be based on the revenue of the rate schedules. He also proposed using the COSS provided by Staff witness Baker rather than the one filed by Company witness Oblack to allocate revenue to the rate classes. Mr. McAuliffe stated that his proposed rate design would use the distribution revenue of each class without the Montgomery County Energy Tax and Franchise Tax surcharge, because the revenue collected from these taxes distorts the amount of distribution revenue collected from each schedule. Mr. McAuliffe recommended that step one would allocate 40% of the total revenue requirement to both the residential and PH and AGS rate schedules based on their share of total system revenue, because both schedules have a UROR of less than 1.00. Mr. McAuliffe stated that the lower allocation to the residential class was justified in part because of Potomac Edison's use of the Zero Intercept Study, which may have inaccurately decreased the residential class's UROR.[352] In the second step, he allocated revenue to all schedules based on their current share of total system revenue. Although Potomac Edison excluded Schedules G, C, H&F, and PP from the second step, Mr. McAuliffe included them because the change

[349] McAuliffe Direct at 9.
[350] McAuliffe Direct at 21.
[351] McAuliffe Direct at 21.
[352] McAuliffe Direct at 24.

in the COSS caused the URORs of these classes to drop significantly. Overall, Mr. McAuliffe found that Staff's revisions caused all classes to move closer to a UROR of 1.00 while mitigating rate shock and keeping rate growth gradual.

OPC

OPC witness Pavlovic stated that he did not oppose the Company's two-step Indexed Rate of Return procedure.[353] However, based on the indexed results of his correction of the COSS, Mr. Pavlovic disagreed with Potomac Edison's implementation of the procedure and the class distribution of OPC witness Effron's recommended revenue decrease that would result. Instead, Mr. Pavlovic recommended that the indexed rate of return results from the corrected COSS be used to distribute Mr. Effron's recommended revenue decrease. In particular, Mr. Pavlovic distributed none of OPC's proposed rate decrease to the one rate class (Schedule PH & AGS) that was significantly below the 10% band around 1.00. In the next step, he distributed a portion of the rate decrease to the rate classes with URORs within the 10% band (Schedules R and CA-CSH) such that their URORs remained within the 10% band and they each received an equal percentage decrease in revenue. Finally, Mr. Pavlovic distributed the remainder of the decrease to the rate classes with URORs significantly above the 10% band (Schedules C&G, PP and STLTNG) such that these classes saw roughly comparable reductions in their indexed rates of return and received equal percentage decreases in revenue.

[353] Pavlovic Direct at 15.

Party Responses

In his rebuttal testimony, Mr. Valdes opposed the revenue allocation proposals of Staff and OPC. He stated that the 50% step one allocation to residential customers was appropriate because Schedule R was the furthest from a unity indexed ROR.[354]

Commission Decision

The Commission has regularly employed a two-step process for the determination of inter-class rates. The two-step approach intends to balance the actual rates of return reflected in the utility's COSS and the principle of gradualism. The Commission has described this process as follows:

> We have developed a general policy of allocating rate increases using a two-step approach. *First*, a portion of the increase is allocated to under-earning classes to move their rates of return or URORs closer to the system average. In the second step, the remainder of any increase is apportioned to all customer classes based upon the proportion of their class revenues compared to overall system revenues.[355]

The Commission finds that Staff's revenue allocation best meets the rate design objectives of consumer rationing, avoidance of rate shock, attaining the revenue requirement, and fair cost apportionment. Although Staff and Potomac Edison both propose a two-step allocation, the Commission finds that Staff's version better reflects the principle of gradualism, especially as related to the residential class.[356] Potomac Edison's 50% step one allocation to the residential class, when coupled with other proposals that

[354] Valdes Rebuttal at 21.
[355] Case No. 9286, *In Re Potomac Electric Power Co., 103 Md. PSC 293, 352 (2012).*
[356] OPC's three-step rate design proposal was designed with the intention of providing a rate reduction to customers. The Commission does not find OPC's rate design appropriate under the circumstances discussed here that entail a rate increase.

impact residential customers, such as the Company's COSS, Zero Intercept Study,[357] and significant increase in customer charge, impose too severe of an immediate rate increase to residential customers. Staff's step one allocation of 40%, with a lower increase in the customer charge (discussed below), moves residential customers more gradually toward a UROR of 1.00. Staff acknowledges that the 40% step one increase to residential customers is a higher allocation than the Commission usually approves.[358] However, given that the residential class is significantly under-earning with a UROR of 0.67%, the Commission finds the 40% step one allocation appropriate.[359] Staff's two-step methodology also fairly apportions the increased revenue among the various rate classes and moves each class towards a unitized rate of return.

2. Revisions to Particular Rate Schedules

Potomac Edison

Mr. Valdes stated that he removed certain legacy rate design items that were included in Potomac Edison's last base rate case in 1994 when the Company was a vertically integrated utility. In particular, he removed declining block rates and added the collection of costs on a demand and customer charge basis rather than an energy basis. He argued that most distribution costs are demand and customer based and that distribution costs should be collected on a demand basis and through a customer charge where possible to ensure that all customers pay a minimum contribution to fixed costs. He further stated

[357] As Staff witness McAuliffe testified, Potomac Edison's Zero Intercept Study may have inaccurately decreased the residential class's UROR. McAuliffe Direct at 24.
[358] Staff Initial Brief at 33, n. 193.
[359] Using the reduced revenue requirement approved by the Commission, the UROR for the residential class becomes 0.87. The Commission still finds Staff's two-step allocation methodology, including the 40% step-one allocation, appropriate under the circumstances.

that declining block rates make little sense for Potomac Edison because its fixed costs do not decrease with increased electric consumption.[360]

Mr. Valdes proposed changes to Schedules G and C, which are general service rate schedules for non-residential, non-streetlighting customers. Mr. Valdes noted that Schedule G was closed to new customers as of November 26, 1991, and that the Company proposed to design Schedule C rates slightly higher than Schedule G "to permit the eventual elimination of Schedule C through customer attrition or a gradual transition of Schedule C customers to Schedule G."[361] Mr. Valdes also stated that the rate design for Schedule G results in a heavier emphasis on the customer charge and demand rates (approximately 58%) as compared to kWh rates, as well as the removal of declining rate blocks.

Mr. Valdes proposed changes to Schedule C-A, an all-electric general service rate schedule, as well as CSH, a subset of Schedule C-A for churches and schools. Mr. Valdes stated that this schedule, and its subset, have been closed to new customers since April 9, 1973. Potomac Edison's proposed rate design changes for these schedules include elimination of declining rate blocks and allocating a larger percentage of the pro forma revenue increase to eventually eliminate Schedule C-A and CSH and to serve their customers under Schedule G. Potomac Edison also introduced a customer charge to ensure that all customers pay a minimum contribution to fixed costs.

Mr. Valdes stated that Schedule PH is available to all non-residential, non-streetlighting customers with demands of 50 kW or greater.[362] Because the customers on

[360] Valdes Direct at 28.
[361] Valdes Direct at 29.
[362] Valdes Direct at 32.

this schedule all have meters capable of measuring demand, Potomac Edison proposed to collect all charges through demand rates and remove the declining rate blocks for this schedule. Mr. Valdes stated that Schedule AGS provides standby and maintenance power for customers with generating facilities. For this schedule, Potomac Edison also proposed to collect all charges through demand rates and remove the declining rate blocks. Similarly, for Schedule PP, which is a large power service rate schedule available to all non-residential, non-streetlighting customers with demands of 5,000 kW or greater and high-voltage facilities, Potomac Edison proposed to collect all charges through demand rates.

Staff

Mr. McAuliffe opposed Potomac Edison's proposals to artificially increase rates for Schedules C, C-A, and CSH, which are closed schedules, to encourage them to move to Schedule G.[363] He argued that the rate increase was disproportionate to the costs these customers imposed on the system, discriminatory, contrary to notions of cost causation, and would cause interclass subsidies. Mr. McAuliffe supported removing declining block rates in favor of uniform rates, noting that block rates discourage energy efficiency and do not reflect the accurate costs to serve the customers.[364] However, he supported the introduction of a customer charge on these schedules to mitigate the negative effects of removing the blocked rates.[365]

[363] McAuliffe Direct at 27.
[364] McAuliffe Direct at 28.
[365] McAuliffe Direct at 29. Mr. McAuliffe noted, for example, that moving a high-usage customer from a declining block rate to a flat kWh rate will lead to significant increase in the customer's bill. Low-usage customers would face the opposite result.

Mr. McAuliffe opposed removing the energy charge for various industrial rate schedules (Schedules PH, AGS, and PP), as proposed by Potomac Edison. He argued that charging a kW charge exclusively would "remove any incentive for these customers to conserve energy."[366] He also claimed that the Company's change would cause significant bill increases and decreases to particular customers and introduce intra-class subsidies between low load and high load factor customers. Instead, Staff proposed maintaining the energy charge for each class.

Party Responses

In his rebuttal testimony, Mr. Valdes stated that the elimination of Schedules C-A and the CSH subset was consistent with Company-proposed and Commission-approved methodology in past rate cases. Mr. Valdes also opposed Staff's proposal to maintain the energy charge for Schedules PH, PP, and AGS. He argued that the distribution costs for these schedules are not tied to or associated with kWh consumption, but are instead related to the number of customers or the demand a customer places on the distribution system. Mr. Valdes claimed that Staff's concern about energy conservation was misplaced because the costs on the distribution system for these customers stem from the demand they place on the system, rather than the kWh energy they consume.[367]

Staff witness McAuliffe argued that Potomac Edison was free to close the schedules to existing customers, but that it was discriminatory and contrary to good rate design principles to charge artificially higher prices to drive customers to a different schedule.

[366] McAuliffe Direct at 30.
[367] Valdes Rebuttal at 33.

Irrespective of past Commission cases allowing such a method, Mr. McAuliffe observed that the Commission has not addressed the issue in 25 years and should not approve it now.

Commission Decision

Potomac Edison has made numerous changes to several rate schedules in order to remove legacy rate design items that existed at the time or prior to Potomac Edison's last base rate case in 1994. The Commission accepts those proposed revisions with the caveats proposed by Staff witness McAuliffe. For example, the Commission agrees with Potomac Edison that declining block rates make little sense for the Company because its fixed costs do not decrease with increased electric consumption, such that the existing pricing structure does not accurately match the costs to serve the customers.[368] Declining block rates also discourage energy efficiency. Potomac Edison's proposal to remove declining block rates is therefore granted, subject to the adjustments recommended by Staff to increase the customer charge on these schedules to mitigate the negative effects of removing the blocked rates.[369]

Potomac Edison proposed to remove the energy charge entirely from certain rate classes (Schedules PH, AGS, and PP), and collect all needed revenue through the collection of costs on a demand and customer charge basis. The Commission denies this proposal, as removing the energy component entirely would eliminate the incentive for customers to conserve energy. Although Potomac Edison argues that its costs to serve these customers are based largely on demand on the system, the Commission finds that it would not be appropriate to remove all incentive to conserve kWh on a monthly basis. The Commission

[368] Valdes Direct at 28.
[369] McAuliffe Direct at 29.

is also concerned that the Company's proposal would cause significant bill increases and decreases to certain customers and introduce intra-class subsidies between low-load and high-load factor customers, as testified to by Staff witness McAuliffe.

The Commission also denies Potomac Edison's proposal to increase rates for closed Schedules C, C-A, and CSH in order to encourage existing customers to leave and join an open rate schedule. The proposed rates are intentionally disproportionate to the cost of service. As argued by Staff, they may also be discriminatory and cause interclass subsidies. The Commission therefore finds that it would be contrary to principles of cost causation to charge artificially high prices to drive customers to a different schedule.

3. Customer Charges

Potomac Edison

Mr. Valdes proposed to increase the residential customer charge from $5.00 per month to $7.70 per month. Mr. Valdes stated that a customer charge was not necessary for the special lighting contracts for the City of Hagerstown and City of Frederick because the relatively constant usage ensures a minimum contribution to fixed costs. Mr. Valdes also proposed to create a customer charge of $12.00 for commercial rate Schedules G, C, C-A, and CSH.

Staff

Mr. McAuliffe recommended that the residential charge be increased to $5.68, in place of Potomac Edison's proposed $7.70. He claimed that Potomac Edison failed to support the substantial 54% increase, which he characterized as a "drastic sudden increase" that could lead to rate shock. He also argued that the increase to $7.70 would disproportionately impact low-usage or low-income customers and was contrary to

Commission goals that encourage energy conservation, promote customer control over their bills, and provide value to net metering customers.[370] Staff similarly opposed the size of the customer charge for commercial rate Schedules G, C, C-A, and CSH. Mr. McAuliffe found Potomac Edison's proposed $12.00 charge to be excessive, given no customer charge currently exists for these schedules. Instead, Mr. McAuliffe proposed to introduce a customer charge of $4.00 for these schedules.[371]

OPC

OPC witness Pavlovic opposed Potomac Edison's proposed residential customer charge increase. He noted that this proposal represented a 54% increase to the residential customer charge and was contrary to the Commission's principle of gradualism. Mr. Pavlovic also corrected the residential customer charge calculation to be consistent with his proposed changes to the COSS as well as OPC witness Parcell's recommended rate of return, and found that Potomac Edison's existing $5.00 customer charge would change very little if OPC's recommendations were accepted. Consistent with the Commission's policy to minimize customer charges on the grounds of customer control and efficiency, Mr. Pavlovic recommended that the residential customer charge remain unchanged at $5.00.

Party Responses

Company witness Valdes provided rebuttal testimony addressing the customer charge.[372] He argued that OPC witness Pavlovic's calculation of a 54% increase in the customer charge was misplaced because the assessments of rate impact must take into

[370] McAuliffe Direct at 25.
[371] McAuliffe Direct at 28.
[372] Valdes Rebuttal at 27.

consideration the total bill impact, including distribution, transmission, and generation functions, rather than isolate the fixed charge itself. He further argued that focusing on the percentage impact on individual components of rates impairs the Commission's ability to introduce new rates, inhibits rate design changes by linking rate components to legacy rate design parameters, and does not take into account the net effect resulting from overall changes in customer bills. Mr. Valdes argued that the Company's proposed $7.70 charge would still be the lowest among all electric utilities in Maryland and would be based on fixed costs that are attributable to services and meters. He argued that a low customer charge risked intra-class subsidization. Regarding the non-residential customer charges, Mr. Valdes argued that they are consistent with cost causation, accurate price signals, and mitigating intra-class subsidization.[373]

Staff witness McAuliffe argued that the Company's proposed customer charge would have a significant impact on certain customers, especially low-income and low-usage customers, as well as those who are not able to change their usage patterns to mitigate a fixed monthly charge.[374]

Finally, in response to Company witness Valdes's argument that the Commission should focus on the entire bill impact rather than the customer charge, OPC witness Pavlovic argued that there is no logical nexus between distribution component costs and charges on the one hand, and transmission and generation costs and charges on the other, which are outside of the Commission's review in this distribution rate case.[375]

[373] Valdes Rebuttal at 27-28.
[374] McAuliffe Surrebuttal at 4.
[375] Pavlovic Surrebuttal at 12.

Commission Decision

The Commission denies Potomac Edison's proposal to increase the residential customer charge from $5.00 to $7.70. The 54% increase in the charge is too extreme to make in a single rate case. Additionally, the Commission is concerned that the increase to $7.70 could disproportionately impact low-usage customers who lack control over their monthly volumetric consumption. An increase of the magnitude proposed by Potomac Edison could also be inconsistent with goals of encouraging energy conservation and promoting control over customer bills. OPC's proposal to maintain the residential customer charge at $5.00 is inadequate, however. The Company has not updated its customer charge in over 25 years and the Commission finds that collecting fixed costs entirely or mostly through volumetric rates could cause intra-class subsidization. In balancing the competing interests and policy objectives related to fixed costs, the Commission finds that a residential customer charge of $5.70 strikes a reasonable balance.

The Commission likewise denies Potomac Edison's proposal to introduce a new customer charge of $12.00 to nonresidential rate schedules G, C, C-A, and CSH. Currently, these schedules have no customer charge, although they do have a minimum charge based on capacity. An increase in the customer charge for these classes from $0 to $12 is too sudden and is contrary to principles of gradualism. Nevertheless, consistent with past Commission decisions, customers in these classes should cover a portion of distribution system fixed costs through a customer charge. The Commission finds that Staff's proposal that these rate schedules pay a $4.00 fixed charge provides a fair resolution.

4. Street Lighting

Mr. Valdes stated that four of the street lighting rate schedules are legacy schedules closed to new customers. Specifically, Schedules OL and MSL have been closed since November 18, 1998, while Schedules AL and SL have been closed since September 9, 1985 and April 9, 1973, respectively. Mr. Valdes stated that the remaining street lighting rate schedules are available to all customers, with most customers gravitating to Schedule EMU. Street lighting rate schedules with similar elements to those on Schedule EMU were therefore set equal. Additionally, the Company proposed to close Schedule SL because no customers are currently served under it.

Mr. McAuliffe opposed Potomac Edison's revisions to the street lighting rate schedules that tied these schedules to the EMU lighting schedule.[376] He asserted that Potomac Edison's changes caused rates for some customers to increase by as much as 39%.[377] Staff proposed an alternative that based the rate change for lighting fixtures on the increase in revenue for the entire street lighting class.

In his rebuttal testimony, Mr. Valdes asserted that it is not sensible for an identical street light to receive a different rate merely because it is on a different rate schedule. Mr. Valdes provided explanations for three of the four Tariff language changes for which Staff requested information.

Commission Decision

The Commission is concerned that Potomac Edison's proposed changes to the street lighting rate classes will cause disruption in customer rates, including by increasing rates

[376] McAuliffe Direct at 33.
[377] McAuliffe Direct at 20, 33.

for some customers by as much as 39%. The Commission finds more reasonable Staff's proposal, which bases the rate change for lighting fixtures on the increase in revenue for the entire street lighting class.

5. Tariff Revisions

Mr. Valdes described several retail Tariff revisions the Company proposed in this proceeding.[378] He stated that the Company proposed to remove several legacy items associated with Potomac Edison's prior ownership of generation resources, when the Company was still a vertically integrated public utility. (The Tariff revisions are contained in PE Exhibit REV-18 and result in the enumeration of new Tariff designation Electric P.S.C. Md. No. 54). Mr. Valdes testified that the changes fall into three categories, including: (i) administrative changes that update Tariff headers and footers, eliminate reference to Allegheny Power, and change text to gender neutral terms; (ii) removal of expired Tariff pages; and (iii) updates of rate schedules to conform with the rate design proposed by the Company in this rate case.

Mr. McAuliffe testified that Staff did not oppose most of Potomac Edison's revisions. However, Staff questioned four proposed Tariff revisions, which Mr. McAuliffe stated were not supported by the Company.[379] During the hearing, Staff withdrew its objections to all but one of these proposed revisions.[380] The disputed Tariff revision involves a new process for determining if a customer payment is late. Currently, Potomac Edison uses the postmark on the payment envelope to determine whether or not the customer payment is late. However, the Company has proposed to change the process to

[378] Valdes Direct at 36.
[379] McAuliffe Direct at 17. Mr. McAuliffe referenced language related to (i) the customer guide for electric service, (ii) the CO-Generation rate schedule, (iii) new rate schedule SP, and (iv) late payments.
[380] Tr. at 605 (McAuliffe).

whether the payment is received no more than five days after it was due. Mr. McAuliffe challenged this revision, asserting that the five-day grace period removes the certainty of a postmark.[381] He expressed concern that bad weather could delay a payment mailed on or before the due date and result in a customer receiving a late payment penalty.

In his rebuttal testimony, Mr. Valdes contended that the five-day window for payment beyond the due date sufficed since the U.S. Postal Service's standard delivery time is three days. He argued that Staff's suggestion to allow as timely any payment made on or before the due date was "functionally not workable" because it would not eliminate any manual processing that the Tariff change was intended to reduce.[382]

Commission Decision

The Commission accepts the Tariff revisions discussed in this section, with the exception of the proposal to change the timeline for considering a customer payment late. Given that the U.S. Postal Service's standard delivery time is three days, the five-day window proposed by Potomac Edison in actuality is a two-day grace period, assuming the Postal Service delivers on schedule.[383] However, weather or other unforeseen events may delay the Postal Service's standard three-day service and render late a customer's bill that was mailed on or before the due date. That outcome would appear to be in contravention of the mailbox rule.[384] Under the record in this proceeding, the Commission does not find sufficient reason to accept Potomac Edison's proposed revision related to late payment.

[381] McAuliffe Direct at 18.
[382] Valdes Rebuttal at 40.
[383] Tr. at 366 (Valdes).
[384] See Tr. at 367.

6. Rate Design of EDIS

Potomac Edison

Finally, Mr. Valdes discussed rate design for the Company's EDIS.[385] Potomac Edison proposed that the costs of this program be recovered through a surcharge, as was approved for similar reliability programs run by BGE, Pepco, and Delmarva. Mr. Valdes proposed that the surcharge would recover the incremental investments and enhancements associated with the reliability program, as testified to by Company witness McGettigan. Cost recovery through the EDIS would consist of a revenue requirement for recovery of incremental O&M in the year incurred and a return on and of incremental capital placed in-service. The EDIS revenue requirement would be allocated to the various rate schedules on the basis of distribution plant, as provided in the COSS discussed by witness Oblack. Street lighting, however, would be excepted.[386] Mr. Valdes stated that the incremental costs do not vary based upon the amount of kWh energy consumed, so the costs should be collected through demand charges and/or customer charges. However, for rate schedules where customers do not have demand meters, a kWh energy rate would be used as a proxy. Because the sole use of a kWh rate would result in larger-than-average surcharge impacts on high-use customers, Mr. Valdes proposed that 50% of the EDIS revenue requirement would be collected through the kWh energy rate and 50% would be collected through a customer charge for rate schedules that do not require demand meters.

[385] Valdes Direct at 41.

[386] Valdes Direct at 43-44. Mr. Valdes observed that because street lighting has a low kWh usage, these rate schedules would bear a disproportionate surcharge impact if their allocation was based solely on distribution plant. Accordingly, their cost allocation was limited so that the surcharge rate was no more than twice the highest kWh surcharge rate from any other customer class.

Mr. Valdes estimated that the effect of the EDIS on a typical residential customer would be $0.39 per month plus an energy charge of approximately $0.73 per month.[387]

Staff

Mr. McAuliffe opposed Potomac Edison's rate design and cost allocation for the EDIS charge.[388] In particular, he contested the collection of costs through the customer charge and the demand charge. He asserted that none of the other surcharges discussed in this proceeding, including BGE's ERI, and Pepco and Delmarva's GRC, had any revenue collected through the monthly customer charge. BGE's surcharge was approved to be collected through a kWh energy charge only. In accordance with Commission approval of those surcharges, Mr. McAuliffe argued that the EDIS should be collected through the energy charges for all customer classes. Additionally, Mr. McAuliffe opposed Potomac Edison's proposal to base cost allocation of the EDIS surcharge on the distribution plant of each rate schedule. Instead, he recommended that the costs be allocated by the NCP of each class at both the primary and secondary level.[389]

OPC

OPC witness Pavlovic opposed Staff witness McAuliffe's proposal that the EDIS revenue requirement be allocated to the classes based on class NCP demand on Potomac Edison's primary and secondary lines and transformers.[390] He argued that allocation of the EDIS investment to customer classes based on demand is inconsistent with principles of cost causation. He noted that OPC witness Lanzalotta testified that only 3% of the EDIS

[387] Valdes Direct at 44.
[388] McAuliffe Direct at 34.
[389] Specifically, Mr. McAuliffe combined the primary and secondary NCP, giving 70% weight to the primary NCP and 30% to secondary NCP. McAuliffe Direct at 35.
[390] Pavlovic Rebuttal at 11.

programs' reliability benefits would accrue to Potomac Edison's residential customer class, with the remaining 97% accruing to the Company's commercial customer classes.[391] In contrast, Mr. McAuliffe's demand allocation would attribute 61% of the 2019 EDIS revenue requirement to the Companies' residential class, with only 39% attributed to the commercial classes.

Party Responses

In his rebuttal testimony, Mr. Valdes opposed Staff's proposed revisions to the EDIS rate design. He argued that the Company's proposed allocation on the basis of distribution plant is a better representative allocator than Staff's demand-related NCP allocator.[392] He also contested the removal of demand and customer charges, stating that the costs related to the four EDIS programs do not vary based upon the amount of kWh energy consumed.

Commission Decision

The Commission accepts the EDIS rate design as modified by Staff. None of the surcharges previously approved by the Commission for reliability programs has entailed the collection of revenue through a customer charge. BGE's ERI recovered all of the revenue for the program through an energy charge (kilowatt hour basis).[393] The Commission finds that the benefits of the EDIS will inure to all customer classes and finds unconvincing OPC's arguments that retail ratepayers will receive only paltry reliability benefits. Therefore, the Commission will approve the EDIS to be collected entirely

[391] Pavlovic Rebuttal at 12, citing Lanzalotta Rebuttal at 3.
[392] Valdes Rebuttal at 42.
[393] Tr. at 610 (McAuliffe).

through energy rates.[394] Additionally, the Commission finds reasonable Mr. McAuliffe's recommendation that the costs of the EDIS be allocated by the NCP of each class at both the primary and secondary level, rather than basing cost allocation of the surcharge on the distribution plant of each rate schedule. In order to effectuate Staff's proposed allocation of the EDIS surcharge, Potomac Edison is directed to provide projected kWh sales for all rate classes[395]

IV. CONCLUSION

Based upon our review of the record in this case, we find that the Application filed on August 24, 2018, by the Potomac Edison Company for a rate increase of $19,690,789 will not result in just and reasonable rates and is therefore denied. Instead, we find that based on a test year of the 12 months ending June 30, 2018, as adjusted above, the Company is authorized to file revised rates and charges for an increase in revenues of $6,199,378, which amount will result in just and reasonable rates to the Company and its customers. As allocated, this Order will result in an increase to the average monthly Standard Offer Service residential bill of **$2.13** (including the EDIS).[396] That amount represents an increase of 2.12% in the customer's total electric bill, or an increase of 9.72% in the distribution-only portion of the customer's bill. Our approval of the modified EDIS represents approximately $0.12 per month of the $2.13 increase for a typical Standard Offer Service residential customer. The Company shall file revised tariffs for such increase in accordance with the rate design and other decisions in this Order.

[394] As a result of the Commission's decision to approve Potomac Edison's EDIS without vegetation management, the revenue requirement for the first year of the EDIS will be $635,313.
[395] *See* McAuliffe Direct at 36.
[396] The average Standard Offer Service residential customer consumes approximately 1,000 kWh per month.

IT IS THEREFORE, this 22nd day of March, in the year Two Thousand Nineteen, by the Public Service Commission of Maryland,

ORDERED (1) That the Application of The Potomac Edison Company, filed on August 24, 2018 (as supplemented by the Company over the course of this proceeding), seeking an increase in its Maryland distribution rates of $19,690,789, is hereby denied, as discussed in the body of this Order;

(2) That Potomac Edison is hereby authorized to increase its Maryland distribution rates by no more than $6,199,378, for service rendered on or after March 22, 2019, consistent with the findings in this Order;

(3) That Potomac Edison's requests to modify certain Tariff provisions are granted to the extent discussed in the body of this Order;

(4) That Potomac Edison is directed to file tariffs in compliance with this Order with the effective dates prescribed herein, subject to acceptance by the Commission;

(5) That Potomac Edison's request for an Electric Distribution Investment Surcharge is granted, subject to the modifications and conditions contained within this Order, including that Potomac Edison file an annual report that contains:

(a) the status of each project and respective milestones completed and reliability benefits achieved;

(b) actual money spent to date on each project and respective milestone;

(c) the reconciliation of projected costs and recoveries that includes a true-up calculation of over- and under- recoveries; and

(d) a proposed rate for the EDIS for the subsequent year, including bill impact estimates.

(6) That regarding the Tax Cut and Jobs Act regulatory liability:

(a) Potomac Edison is directed to issue a second bill credit to customers to discharge the TCJA-related regulatory liability, the amount of which shall include carrying costs through the date the credit is made to the first group of customers, allocated to each customer class in accordance with the methodology adopted pursuant to Order 88860, with such credits rendered to all customers no later than the second billing cycle after the date of this Order; and

(b) Potomac Edison shall submit an informational filing to the Commission that discloses the actual refunds distributed to customers not more than 30 days after completion of the distribution of refunds;

(7) That a Phase II proceeding in this matter is hereby initiated. Within 18 months of the date of this Order, Potomac Edison shall file with the Commission a new depreciation study, as discussed in the body of this Order, in the Phase II proceeding;

(8) That in conjunction with Potomac Edison's next base rate case to be filed on or before the end of the initial four-year period of its EDIS programs, the Company shall file:

(a) updates to its JCOSS and COSS, such that all updated studies are current to within one year of the test year in the Company's next base rate case;

(b) a COSS without a zero intercept study, if Potomac Edison files a COSS with a zero intercept study in its next base rate case;

(c) a COSS in its next base rate case that includes a labor allocator to better reflect the functionalization of general and intangible plant;

(d) testimony supporting or rejecting the use of the ACP methodology to allocate costs related to subtransmission and FERC Accounts 362 and 368 capacitors based on current system conditions and cost causation; and

(e) three years of demand at transmission, subtransmission, primary, and secondary levels, as well as their resulting allocators that are used in the COSS; and

(9) That all motions or requests not granted herein are denied.

/s/ Mindy L. Herman

/s/ Michael T. Richard

/s/ Anthony J. O'Donnell
Commissioners

Appendix A

Potomac Edison Company
Case No. 9490

Revenue Requirement

Adjusted Rate Base	$461,681,230
Rate of Return	7.15%
Required Income	$33,010,208
Adjusted Operating Income	$28,661,293
Operating Income Deficiency	$4,348,915
Conversion Factor	1.4255
Revenue Requirement	$6,199,378

Rate Base

Per Books Balance	$421,368,629
Uncontested Adjustments	$29,197,954
Total Uncontested	$450,566,583
Contested Adjustments	
Reliability Projects - Post Test Year through Hearings	$21,307,808
Accumulated Depreciation Post Test Year Reliability Projects	($866,332)
Accumulated deferred income taxes Test Year Reliability Projects	($1,431,899)
Accumulated deferred income taxes Post Test Year Reliability Projects	($1,561,082)
Cash Working Capital	$274,000
Prepaid Balances	($1,180,000)
Accumulated Depreciation (Depreciation Accrual)	($3,075,540)
Jurisdictional COSS Allocations	($2,352,308)
Adjusted Rate Base	$461,681,230

Operating Income

Per Books Balance	$24,842,049
Uncontested Adjustments	$1,160,096
Uncontested Balance	$26,002,145
Contested Adjustments	
Storm Damage	$0
Pension/OPEB Expense	($128,192)
Rate Case Expenses	($35,720)
Holding Company Corporate Expense	($73,257)
Depreciation Expense on Post Test Year Reliability Projects	($627,939)
Interest Synchronization	($296,934)
Depreciation Expense (Depreciation Accrual)	$3,075,540
Employee Activity Costs	$3,433
SERP	$20,260
Incentive Compensation	$574,954
AFUDC	($103,849)
Jurisdictional COSS Allocations	$250,852
Adjusted Operating Income	$28,661,293

Tax Cuts and Jobs Act Regulatory Liability

Revenue (10/1/2018 - 3/22/2018)	($3,142,581)
Additional Revenue (1/1/2018 - 9/30/2018)	($23,322)
Total Revenue	($3,165,903)

Case No. 9490
The Potomac Edison Company
For the Twelve Months Ended June 30, 2018
Comparison Operations Revenue Requirement Positions
Electric Operations

As of 02/08/19

		Potomac Edison						STAFF						OPC					
Conversion	1.4255						1.4255						1.4255						
Tax Factor	1.0332					Net of Tax	0.7248						0.7248					Net of Tax	
ROR	7.75%	Rate	Operating	Tax Effect	Operating Income	Revenue	6.93%	Rate	Operating	Tax Effect	Net of Tax	Revenue	6.90%	Rate	Operating	Tax Effect	Operating Income	Revenue	
		Base	Income			Requirement		Base	Income		Operating Income	Requirement		Base	Income				
PE		$ 421,368,629	$ 24,842,049		$ 24,842,049	11,136,262		$ 421,368,629	$ 24,842,049		$ 24,842,049	6,218,762		$ 421,368,629	$ 24,842,049		$ 24,842,049	6,060,523	
Adj. No.	**Uncontested Adjustments**																		
1	Remove Pole Attachment Revenues	-	(2,111,253)	580,964	(1,530,289)	2,181,401		-	(2,111,253)	580,964	(1,530,289)	2,181,400		-	(2,111,253)	580,964	(1,530,289)	2,181,400	
2	Salaries and Wages	-	(251,586)	69,230	(182,356)	259,946		-	(251,586)	69,230	(182,356)	259,945		-	(251,586)	69,230	(182,356)	259,945	
3	Employee Savings Plan	-	(7,548)	2,077	(5,471)	7,799		-	(7,548)	2,077	(5,471)	7,799		-	(7,548)	2,077	(5,471)	7,799	
5	Remove Non-customer Advertising Expense	-	4,647	(1,279)	3,368	(4,801)		-	4,647	(1,279)	3,368	(4,801)		-	4,647	(1,279)	3,368	(4,801)	
6	Increase Postage Expense	-	(5,394)	1,484	(3,910)	5,573		-	(5,394)	1,484	(3,910)	5,573		-	(5,394)	1,484	(3,910)	5,573	
7	PSC Assessment Expense	-	(1,518)	418	(1,100)	1,568		-	(1,518)	418	(1,100)	1,568		-	(1,518)	418	(1,100)	1,568	
8	Medical Insurance Expenses	-	(18,471)	5,083	(13,388)	19,085		-	(18,471)	5,083	(13,388)	19,085		-	(18,471)	5,083	(13,388)	19,085	
9	Group Life Insurance Expenses	-	(4,776)	1,314	(3,462)	4,935		-	(4,776)	1,314	(3,462)	4,935		-	(4,776)	1,314	(3,462)	4,935	
13	Depreciation Expense on Test Year Reliability Projects	-	(657,290)	180,870	(476,420)	679,129		-	(657,290)	180,870	(476,420)	679,129		-	(657,290)	180,870	(476,420)	679,129	
15	Conservation Voltage Reduction Program	-	(192,242)	52,900	(139,342)	198,629		-	(192,242)	52,900	(139,342)	198,629		-	(192,242)	52,900	(139,342)	198,629	
16	Payroll Tax Salaries and Wages	-	(19,246)	5,296	(13,950)	19,886		-	(19,246)	5,296	(13,950)	19,886		-	(19,246)	5,296	(13,950)	19,886	
17	Amortization of Excess ADITs	-	2,281,990	-	2,281,990	(3,252,937)		-	2,281,990	-	2,281,990	(3,252,937)		-	2,281,990	-	2,281,990	(3,252,937)	
21	Federal Income Tax Synchronization	-	(457,910)	-	(457,910)	652,743		-	(457,910)	-	(457,910)	652,743		-	(386,147)	-	(457,910)	652,743	
22	Reliability Projects - Test Year	19,412,343	-	-	-	2,144,460		19,412,343	-	-	-	1,917,914		19,412,343	-	-	-	1,910,624	
24	Accumulated Depreciation Test Year Reliability Projects	(657,290)	-	-	-	(72,610)		(657,290)	-	-	-	(64,939)		(657,290)	-	-	-	(64,693)	
26	Plant Material and Supplies	10,442,901	-	-	-	1,153,616		10,442,901	-	-	-	1,031,745		10,442,901	-	-	-	1,027,823	
31	Uncollectible Expense	-	-	-	-	-		-	-	-	-	-		-	-	-	-	-	
32	Pro Forma Regulatory Assessment	-	-	-	-	-		-	-	-	-	-		-	-	-	-	-	
33	Pro Forma Maryland Gross Receipt Tax	-	-	-	-	-		-	-	-	-	-		-	-	-	-	-	
34	Pro Forma State Income Tax	-	-	-	-	-		-	-	-	-	-		-	-	-	-	-	
35	Pro Forma Federal Income Tax	-	-	-	-	-		-	-	-	-	-		-	-	-	-	-	
	Contested Adjustments																		
14	Depreciation Expense on Post Test Year Reliability Projects	-	(866,332)	238,393	(627,939)	895,117		-	(866,332)	238,393	(627,939)	895,117		-	90,000	(24,766)	65,234	(92,990)	
21	Deferred Federal Income Tax Synchronization	-	1,702,336	-	1,702,336	(2,426,650)		-	1,702,336	-	1,702,336	(2,426,650)		-	1,702,336	-	1,702,336	(2,426,650)	
23	Reliability Projects - Post Test Year through Hearings	21,307,808	-	-	-	2,353,850		21,307,808	-	-	-	2,105,184		(2,215,000)	-	-	-	(218,007)	
25	Accumulated Depreciation Post Test Year Reliability Projects	(866,332)	-	-	-	(95,703)		(866,332)	-	-	-	(85,592)		90,000	-	-	-	8,858	
28	Accumulated deferred income taxes Test Year Reliability Projects	(94,899)	-	-	-	(10,483)		(94,899)	-	-	-	(9,376)		(1,431,899)	-	-	-	(140,932)	
29	Accumulated deferred income taxes Post Test Year Reliability Projects	(103,379)	-	-	-	(11,420)		(103,379)	-	-	-	(10,214)		163,000	-	-	-	16,043	
	Prepaid Balances	-	-	-	-	-		-	-	-	-	-		(1,180,000)	-	-	-	(116,139)	
	Depreciation Accrual Rates	-	-	-	-	-		-	-	-	-	-		13,054,000	18,010,000	(4,955,902)	13,054,098	(17,323,574)	
	Allocations	-	-	-	-	-		-	-	-	-	-		(4,901,000)	240,000		240,000	(824,488)	
											-								
4	Storm Damage	-	(968,941)	266,628	(702,313)	1,001,135		-	-	-	-	-		-	(968,941)	266,628	(702,313)	1,001,134	
10	Pension/OPEB Expense	-	(176,859)	48,667	(128,192)	182,735		-	-	-	-	-		-	(176,859)	48,667	(128,192)	182,735	
12	Holding Company Corporate Expense	-	(101,068)	27,811	(73,257)	104,426		-	-	-	-	-		-	(101,068)	27,811	(73,257)	104,426	
11	Rate Case Expenses	-	(93,648)	25,770	(67,878)	96,760		-	(40,348)	11,103	(29,245)	41,689		-	(93,648)	25,770	(67,878)	96,759	
19	State Income Taxes	-	376,466	-		-		-	-	-	-	-		-		-	-	-	
20	Federal Income Taxes	-	879,220	-		-		-	-	-	-	-		-		-	-	-	
27	Cash Working Capital	313,937	-	-		34,680		256,601	-	-	-	25,352		313,937	-	-	-	30,899	
	AFUDC	-	-	-	-	-		-	(50,343)	13,853	(36,490)	52,016		-	-	-	-	-	
	Employee Activity Costs	-	-	-	-	-		-	4,737	(1,304)	3,433	(4,894)		-	-	-	-	-	
	SERP - Remove 50%	-	-	-	-	-		-	27,952	(7,692)	20,260	(28,881)		-	28,000	(7,705)	20,295	(28,930)	
	Incentive Compensation	-	-	-	-	-		-	793,231	(218,277)	574,954	(819,586)		-	881,000	(242,429)	638,571	(910,272)	
	Remove Non-Testimony Supported Jurisdictional Corrections Revenue	-	-	-	-	-		-	-	-	-	-		-	-	-	-	-	
	Remove Non-Testimony Supported Jurisdictional Corrections O&M Expense	-	-	-	-	-		-	-	-	-	-		-	-	-	-	-	
	Remove Non-Testimony Supported Jurisdictional Corrections Federal and State Income Taxes	-	-	-	-	-		-	-	-	-	-		-	-	-	-	-	
	Remove Non-Testimony Supported Jurisdictional Cash Working Capital	-	-	-	-	-		-	-	-	-	-		-	-	-	-	-	
											-								
	Jurisdictional COSS Flow Through Rate Base	-	-	-	-	-		(5,793,998)	-	-	-	(572,439)		-	-	-	-	-	
	Jurisdictional COSS Flow Through Depreciation Reserve	-	-	-	-	-		2,612,786	-	-	-	258,140		-	-	-	-	-	
	Jurisdictional COSS Flow Through Cash Working Capital	-	-	-	-	-		(10,125)	-	-	-	(1,000)		-	-	-	-	-	
	Jurisdictional COSS Flow Through Deferred Federal and State Tax Balance	-	-	-	-	-		839,029	-	-	-	82,895		-	-	-	-	-	
	Jurisdictional COSS Flow Through Operating Revenue	-	-	-	-	-		-	4,924	-	4,924	(7,019)		-	-	-	-	-	
	Jurisdictional COSS Flow Through O&M Expense	-	-	-	-	-		-	35,366	-	35,366	(50,414)		-	-	-	-	-	
	Jurisdictional COSS Flow Through Depreciation and Amortization Expense	-	-	-	-	-		-	309,017	-	309,017	(440,498)		-	-	-	-	-	
	Jurisdictional COSS Flow Through Taxes Other Than Income	-	-	-	-	-		-	18,460	-	18,460	(26,314)		-	-	-	-	-	
	Jurisdictional COSS Flow Through Federal and State Income Taxes	-	-	-	-	-		-	-	(117,060)	(117,060)	166,867		-	-	-	-	-	
	Jurisdictional COSS Flow Through Deferred Income Taxes	-	-	-	-	-		-	145	-	145	(207)		-	-	-	-	-	
					-	-													
18	Interest synchronization	-	(249,941)	-	(249,941)	356,287		-	(27,034)	-	(276,975)	394,823		-	(343,941)	-	(343,941)	490,282	
	Total	$ 471,123,718	$ 24,152,625		$ 24,152,625	$ 17,615,416		$ 468,714,074	$ 25,313,563		$ 25,880,995	$ 9,415,430		$ 454,459,621	$ 42,740,093				$ (10,443,615)

Exhibit B