ML 204346

ORDER NO. 87884

IN THE MATTER OF THE APPLICATION OF POTOMAC ELECTRIC POWER COMPANY FOR ADJUSTMENTS TO ITS RETAIL RATES FOR THE DISTRIBUTION OF ELECTRIC ENERGY	* * * *	BEFORE THE PUBLIC SERVICE COMMISSION OF MARYLAND CASE NO. 9418

Before: W. Kevin Hughes, Chairman
Harold D. Williams, Commissioner
Jeannette M. Mills, Commissioner
Michael T. Richard, Commissioner
Anthony J. O'Donnell, Commissioner

Issued: November 15, 2016

APPEARANCES

Peter E. Meier, Douglas E. Micheel, and Matthew K. Segers for Potomac Electric Power Company

Paula M. Carmody, Theresa V. Czarski, William F. Fields, Molly G. Knoll, Jacob M. Ouslander, and Joyce R. Lombardi for the Maryland Office of People's Counsel

Lloyd Spivak, Michael Dean, Peter A. Woolson and Annette B. Garofalo for the Public Service Commission Staff

Frann G. Francis and Nicola Whiteman for the Apartment and Office Building Association of Metropolitan Washington

Mark F. Sundback, Kenneth L. Wiseman, William M. Rappolt and Kevin Siqveland for Healthcare Council of the National Capital Area

Lisa Brennan for Montgomery County, Maryland

Mercia E. Arnold for POWERUPMONTCO

Jodi S. Schulz, Cynthia Walters and Debra Yerg Daniel for City of Rockville, Maryland

Whitney Cleaver Smith and James McGee for Prince George's County, Maryland

Heather Cameron for U.S. General Services Administration

N. Lynn Board for City of Gaithersburg

TABLE OF CONTENTS **Page**

I. INTRODUCTION AND EXECUTIVE SUMMARY

On April 19, 2016, Potomac Electric Power Company ("Pepco") filed with the Maryland Public Service Commission ("Commission") a request to increase its rates for electricity in the amount of $126,784,000.[1] Pepco has not increased its rates since July 2014, prior to its parent, Pepco Holdings, Inc.'s merger with Exelon Corporation. The Company's application for an increase was predominantly driven by the Company's request for recovery of its Advanced Metering Infrastructure ("AMI") investments, continued reliability infrastructure investments and the results of the Company's most recent depreciation filing[2]. Much of this increase, $60.9 million[3], is due to Pepco seeking to begin recovery for $97.2 million of capital investments made over the past six years in implementing new technology, its Advanced Metering Infrastructure system. The request also included $197.8 million[4] in base rates for cost recovery for the Company's ongoing reliability investments and an increase in the Company's authorized rate of return from 9.62% to 10.60%. The Company also requested a new extension of its Grid Resiliency Program, with a surcharge to concurrently recover costs in the amount of $31.6 million[5] for 2 years, or add approximately $15.8 million a year.

As in any rate case, we are required to balance the Company's recovery of its expenses and capital investments made to render safe and reliable service with the requirement that the rates it charges customers are "just and reasonable" and no more.

---

1 During the course of the case Pepco reduced its request to $102,751,000.
2 Pepco witness McGowan's direct testimony at 2.
3 Pepco witness McGowan direct testimony at 7.
4 Application filing April 19, 2016 at 2.
5 Pepco witness McGowan direct testimony at 5.

We have thoroughly reviewed Pepco'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 Pepco to increase its electric rates by $52,535,000.

In 2010, the Commission, and State and Federal policy makers, agreed that the various energy savings and operational efficiency benefits of the Advanced Metering Infrastructure (AMI) technology were in the public interest, and the Commission authorized Pepco to begin implementation of its AMI system. It deferred, however, cost recovery from ratepayers until Pepco could prove that it had delivered a cost beneficial system. The evidence presented by all of the parties indicated the Pepco's AMI system passed the cost beneficial requirement. Based on the cost beneficial determination, Pepco is entitled to begin recovering over the next ten years the amount it has expended to computerize its metering and billing systems. In doing so, we have carefully reviewed the prudency of Pepco's expenditures in deploying AMI, and have reduced its revenue requirement request for AMI by $5,338,000.

We have also carefully considered Pepco's request to collect $31.6 million in contemporaneous cost recovery from ratepayers for improvements to feeders and new reclosers on its distribution system in its proposed Grid Resiliency Plan. We have reserved concurrent cost recovery in the form of a surcharge to exceptional circumstances when we find that immediate improvement to reliability is needed. That is currently no longer the case for Pepco. Its own witness testified that these improvements were not necessary to meet Pepco's reliability targets for 2019. For this reason we have not required ratepayers to incur this additional cost.

Finally, the Company asserted in its Application that its return on equity during the test year (2015) was only 2.26%, far below its authorized rate of return of 9.62%. Consequently, the Company requested an increase in its return on equity to 10.60%. We 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 9.55% provides for a fair and appropriate return, and will allow Pepco to obtain any necessary capital investment at reasonable interest rates.

Our decision here to authorize Pepco an increase of $52,535,000 will result in an increase to the average monthly residential bill of $6.96, a 4.76% increase[6]. We do not grant any increase lightly, and we recognize that all Pepco customers, residential, commercial and industrial, will not welcome this increase. We are cognizant that particularly low-income customers and senior citizens on fixed incomes will be significantly impacted. As in prior 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.

II. BACKGROUND

On April 19, 2016, Potomac Electric Power Company ("Pepco" or the "Company"), now a subsidiary of Pepco Holdings LLC ("PHI"),[7] filed an Application for Adjustments to its Retail Rates for the Distribution of Electric Energy ("Application")

[6] This is based on an average residential use of 925 kwh/month based on Commission Exhibit 8.
[7] In March 2016, Pepco Holdings, Inc. (i.e., PHI) completed a merger with Exelon Corporation, which is headquartered in Chicago, Illinois and does business in 48 states, the District of Columbia, and Canada. Prior to the merger, PHI was a multi-state energy delivery company operating in the Mid-Atlantic region and serving approximately 2 million customers in Maryland, the District of Columbia, New Jersey, and Delaware. PHI subsidiaries include Pepco, Delmarva Power (a regulated electric and natural gas utility operating in Delaware and the Delmarva Peninsula), and Atlantic City Electric (a regulated electric utility delivering electricity in southern New Jersey), all of which remain separate companies following the merger. PHI, now Pepco Holdings LLC, is an Exelon company.

pursuant to §§ 4-203 and 4-204 of the Public Utilities Article of the *Annotated*, *Code of Maryland* ("PUA"), for authority to increase its rates and charges for electric distribution service in Maryland. The Commission partially approved Pepco's last application for an electric rate increase two and a half years ago in July 2014.[8] In this Application, Pepco initially asked the Commission for authority to increase its Maryland distribution rates and charges by approximately $126,784,000. The Company used a 12-month test year ending December 31, 2015, which at the time of filing included nine (9) months of actual data and three (3) months of forecasted data. Pepco also requested that the Commission approve an increased return on equity ("ROE") of 10.60%, asserting that the Company is currently earning an adjusted ROE of 2.26%, which is arguably well below its previously authorized level of 9.62%.[9] According to Pepco, if the rates in the Application were granted in full, the monthly impact of the rate increase on the average residential Standard Offer Service ("SOS") customer using 1,000 kilowatt-hours ("kWh") of electricity per month would be $15.80 per month. The Application contained a proposed rate effective date of May 19, 2016.[10]

On April 20, 2016, the Commission docketed the Application as Case No. 9418 and issued an order setting in a prehearing conference for purposes of establishing a procedural schedule, considering motions to intervene and any other preliminary motions. In the same order, the Commission suspended Pepco's proposed tariff revisions for a period of 150 days pursuant to PUA § 4-204. The Commission also required Pepco to publish an advertisement in a newspaper(s) in general circulation throughout its service

[8] *In re Potomac Electric Power Company*, Case No. 9336, Commission Order No. 86441 (July 2, 2014).
[9] April 19, 2016 Application at 4.
[10] April 19, 2016 Application at 4-5.

area at least twice prior to May 18, 2016, notifying interested persons of the prehearing conference.[11]

On May 23, 2016, the Commission held the prehearing conference. By Order No. 87569 issued that day, the Commission established a procedural and discovery schedule and extended the initial 150-day suspension period for the Company's tariff revisions for an additional 30 days, or until November 15, 2016. The Commission also granted petitions to intervene filed by: U.S. General Services Administration ("GSA"); City of Gaithersburg, Maryland ("Gaithersburg"); Montgomery County, Maryland ("Montgomery"); Prince George's County, Maryland ("Prince George's"); Mayor and Council of Rockville, Maryland ("Rockville"); Healthcare Council of the National Capital Area ("HCNCA"); POWERUPMONTCO of Montgomery County ("POWERUPMONTCO"); and Apartment and Office Building Association of Metropolitan Washington ("AOBA") (collectively, along with Pepco, Office of People's Counsel and Commission Technical Staff, the "Parties").

Pepco provided updates to its filing throughout the course of these proceedings. The Company provided a final update on September 8, 2016, to include a full year of actual data ending December 31, 2015.[12] The Company subsequently revised its requested revenue requirement to reflect not only actual results through August 2016 but also Pepco's willingness to accept five adjustments proposed of certain parties. In total, the Company reduced its initial position by approximately $24 million, inclusive of the accepted adjustments plus other true-ups and updates, to reach a final requested revenue

[11] *See* Order No. 87503.
[12] ML 198902.

requirement of $102,751,000. Pepco did not change its requested overall rate of return contained in its original application.

Numerous witnesses submitted written testimony on behalf of several parties in this proceeding. Along with its Application, Pepco sponsored the testimonies of: Kevin M. McGowan, Vice President of Regulatory Policy & Strategy for PHI, who testified on the general basis for the rate increase;[13] Karen R. Lefkowitz, Vice President of Smart Grid and Technology for PHI, who testified about the Company's AMI business case, its benefits and cost-effectiveness;[14] Mario A. Giovannini, Director of Energy Acquisition for PHI, who testified about the benefits of Pepco's AMI-enabled demand response initiatives and interval AMI data;[15] W. Michael VonSteuben, Special Projects Manager in the Regulatory Affairs Department of PHI, who testified about Pepco's revenue requirements, accounting issues, and ratemaking adjustments;[16] Christopher A. Nagle, Supervisor, Cost Allocation for Pepco, who testified about Pepco's jurisdictional and customer class cost of service studies ("COSS");[17] Joseph F. Janocha, Manager of Rate Economics for PHI, who testified regarding rate design and Pepco's proposed tariffs,

---

[13] Pepco Ex. 3, Direct Testimony of Kevin M. McGowan ("McGowan Direct"); Pepco Ex. 4, Rebuttal Testimony of Kevin M. McGowan (McGowan Rebuttal").

[14] Pepco Ex. 7, Direct Testimony of Karen R. Lefkowitz ("Lefkowitz Direct"); Pepco Ex. 8, Rebuttal Testimony of Karen R. Lefkowitz ("Lefkowitz Rebuttal"); Pepco Ex. 9, Surrebuttal Testimony of Karen R. Lefkowitz ("Lefkowitz Surrebuttal").

[15] Pepco Ex. 10, Direct Testimony of Mario Giovannini ("Giovannini Direct"); Pepco Ex. 11, Rebuttal Testimony of Mario Giovannini ("Giovannini Rebuttal"); Pepco Ex. 12, Surrebuttal Testimony of Mario Giovannini ("Giovannini Surrebuttal").

[16] Pepco Ex. 18, Direct Testimony of W. Michael VonSteuben ("VonSteuben Direct"); Pepco Ex. 19, Supplemental Direct Testimony of W. Michael VonSteuben ("VonSteuben Supplemental Direct"); Pepco Ex. 20, Rebuttal Testimony of W. Michael VonSteuben ("VonSteuben Rebuttal"); Pepco Ex. 21, Surrebuttal Testimony of W. Michael VonSteuben ("VonSteuben Surrebuttal").

[17] Pepco Ex. 29, Direct Testimony of Christopher A. Nagle ("Nagle Direct"); Pepco Ex. 30, Supplemental Direct Testimony of Christopher A. Nagle ("Nagle Supplemental Direct"); Pepco Ex. 31, Rebuttal Testimony of Christopher A. Nagle ("Nagle Rebuttal").

including the Grid Resiliency Charge ("GRC");[18] and William M. Gausman, Senior Vice President Strategic Initiatives for PHI, who testified about the Company's investments in reliability, its distribution construction program, and its proposal for a continuation of the Grid Resiliency Plan ("GRP").[19] Two additional witnesses testified on behalf of Pepco: Ahmad Faruqui, a Principal with The Brattle Group, who testified about the Company's use of energy management and conservation tools as a benefit of AMI;[20] and Robert B. Hevert, Managing Partner of Sussex Economic Advisors LLC, who testified regarding the Company's cost of equity.[21]

The Public Service Commission Technical Staff ("Staff") presented the testimonies of: Phillip E. VanderHeyden, Director of the Electricity Division, who testified regarding the return on equity and overall rate of return for determining Pepco's electric distribution rates and offered critique of Pepco's cost of capital testimony;[22] Loubens Blaise, a Regulatory Economist in the Electricity Division, who testified regarding the electric rate design and Pepco's GRC rider;[23] Dr. C. Shelley Norman, an Assistant Director in the Electricity Division, who testified regarding the cost of service

---

[18] Pepco Ex. 32, Direct Testimony of Joseph F. Janocha ("Janocha Direct"); Pepco Ex. 33, Supplemental Direct Testimony of Joseph F. Janocha ("Janocha Supplemental Direct"); Pepco Ex. 34, Rebuttal Testimony of Joseph F. Janocha ("Janocha Rebuttal").

[19] Pepco Ex. 16, Direct Testimony of William M. Gausman ("Gausman Direct"); Pepco Ex. 17, Rebuttal Testimony of William M. Gausman ("Gausman Rebuttal"). Pepco initially included with its Application the prepared direct testimony of Charles R. Dickerson, whose testimony covered the same topics as Mr. Gausman. On May 17, 2016, Pepco filed Mr. Gausman's Direct Testimony which adopted Mr. Dickerson's testimony, filed previously on April 19, 2016. Pepco advised the Commission that Mr. Dickerson was no longer an employee of PHI and was unavailable to present testimony in the proceedings.

[20] Pepco Ex. 13, Direct Testimony of Ahmad Faruqui ("Faruqui Direct"); Pepco Ex. 14, Rebuttal Testimony of Ahmad Faruqui ("Faruqui Rebuttal"); Pepco Ex. 15, Surrebuttal Testimony of Ahmad Faruqui ("Faruqui Surrebuttal").

[21] Pepco Ex. 5, Direct Testimony of Robert B. Hevert ("Hevert Direct"); Pepco Ex. 6, Rebuttal Testimony of Robert B. Hevert ("Hevert Rebuttal").

[22] Staff Ex. 19, Direct Testimony and Exhibits of Phillip E. VanderHeyden ("VanderHeyden Direct"); Staff Ex. 20, Surrebuttal Testimony of Phillip E. VanderHeyden ("VanderHeyden Surrebuttal").

[23] Staff Ex. 16, Direct Testimony and Exhibits of Loubens Blaise ("Blaise Direct"); Staff Ex. 17, Surrebuttal Testimony of Loubens Blaise ("Blaise Surrebuttal").

for Pepco's electric operations as well as AMI meter cost allocation;[24] Felicia L. Shelton, a Staff Engineer, who testified regarding Pepco's reliability, infrastructure replacement, automation, and other capital projects as well as associated rate base adjustments;[25] J. Andrew Dodge, Sr., Chief Engineer, who testified regarding Pepco's storm mobilization and mutual assistance costs associated with Winter Storms PAX and Jonas;[26] Daniel J. Hurley, Director of the Commission's Energy Analysis and Planning Division, who testified regarding the costs, benefits and cost-effectiveness of Pepco's AMI deployment;[27] and Mikhail Ratushny, a Staff Engineer, who testified regarding the benefits of Pepco's AMI program.[28] Additionally, Staff submitted both confidential and public testimony from Bion C. Ostrander, an independent regulatory consultant, who testified on behalf of Staff regarding Pepco's revenue requirements.[29]

The Office of People's Counsel ("OPC") presented the testimonies of: David J. Effron, an independent consultant specializing in utility regulation, who testified regarding Pepco's revenue requirements including rate base and operating income adjustments;[30] Dr. J. Randall Woolridge, Professor of Finance at Pennsylvania State University, who testified regarding the cost of capital for Pepco's regulated electric

---

[24] Staff Ex. 18, Direct Testimony and Exhibits of C. Shelley Norman, Ph.D. ("Norman Direct").

[25] Staff Ex. 14, Direct Testimony and Exhibits of Felicia L. Shelton ("Shelton Direct"); Staff Ex. 15, Surrebuttal Testimony of Felicia L. Shelton ("Shelton Surrebuttal").

[26] Staff Ex. 21, Direct Testimony and Exhibits of J. Andrew Dodge, Sr. ("Dodge Direct"); Staff Ex. 22, Surrebuttal Testimony and Exhibits of J. Andrew Dodge, Sr. ("Dodge Surrebuttal").

[27] Staff Ex. 24, Direct Testimony and Exhibits of Daniel J. Hurley ("Hurley Direct"); Staff Ex. 25, Surrebuttal Testimony of Daniel J. Hurley ("Hurley Surrebuttal").

[28] Staff Ex. 11, Direct Testimony of Mikhail Ratushny ("Ratushny Direct"); Staff Ex., 12, Surrebuttal Testimony of Mikhail Ratushny ("Ratushny Surrebuttal").

[29] Staff Ex. 26, Public Version Direct Testimony and Exhibits of Bion C. Ostrander and Staff Ex. 26C, Confidential Version Direct Testimony and Exhibits of Bion C. Ostrander (collectively, "Ostrander Direct"); Staff Ex. 27, Rebuttal Testimony of Bion C. Ostrander ("Ostrander Rebuttal"); Staff Ex. 28, Surrebuttal Testimony and Exhibits of Bion C. Ostrander ("Ostrander Surrebuttal").

[30] OPC Ex. 8, Direct Testimony of David J. Effron ("Effron Direct"); OPC Ex. 9, (Errata) Surrebuttal Testimony of David J. Effron ("Effron Surrebuttal").

distribution service and addressed its rate of return testimony;[31] Karl R. Pavlovic, a Senior Consultant and Managing Director of PCMG and Associates LLC, who testified regarding Pepco's electric class distribution costs of service, revenue requirement distribution, and rate design;[32] Peter J. Lanzalotta, a Principal with Lanzalotta & Associates, LLC, who testified regarding Pepco's distribution system planning and reliability matters;[33] Nancy Brockway, a former Commissioner of the New Hampshire Public Utilities Commission, who testified regarding ratemaking in connection with legacy meters, metrics-gathering in connection with Pepco's Smart Meter deployment, and Pepco's future AMI benefits;[34] Maximilian Chang, a Principal Associate with Synapse Energy Economics, who testified regarding the benefit-to-cost analysis for Pepco's AMI deployment;[35] and Paul L. Chernick, President of Resource Insight, Inc., who testified regarding some of the benefits Pepco asserts with its AMI investment.[36]

AOBA presented the testimonies of: Bruce R. Oliver, President of Revilo Hill Associates, Inc., who testified regarding Pepco's cost of capital, new billing system, cost of service, and cost-benefit analysis for AMI;[37] and Timothy B. Oliver, a Project Manager and Senior Rate Analyst for Revilo Hill Associates, Inc., who testified

---

[31] OPC Ex. 21, Direct Testimony of Dr. J. Randall Woolridge ("Woolridge Direct"); OPC Ex. 22, Rebuttal Testimony of Dr. J. Randall Woolridge ("Woolridge Rebuttal"); OPC Ex. 23, Surrebuttal Testimony of Dr. J. Randall Woolridge ("Woolridge Surrebuttal").

[32] OPC Ex. 18, Direct Testimony of Karl R. Pavlovic ("Pavlovic Direct"); OPC Ex. 19, Rebuttal Testimony of Karl R. Pavlovic ("Pavlovic Rebuttal"); OPC Ex. 20, Surrebuttal Testimony of Karl R. Pavlovic ("Pavlovic Surrebuttal").

[33] OPC Ex. 10, Direct Testimony of Peter J. Lanzalotta ("Lanzalotta Direct"); OPC Ex. 11, Surrebuttal Testimony of Peter J. Lanzalotta ("Lanzalotta Surrebuttal").

[34] OPC Ex. 12, Direct Testimony of Nancy Brockway ("Brockway Direct"); OPC Ex. 13, Surrebuttal Testimony of Nancy Brockway ("Brockway Surrebuttal").

[35] OPC Ex. 17, Direct Testimony of Maximilian Chang ("Chang Direct").

[36] OPC Ex. 14, Direct Testimony of Paul Chernick ("Chernick Direct"); OPC Ex. 15, Rebuttal Testimony of Paul Chernick ("Chernick Rebuttal"); OPC Ex. 16, Surrebuttal Testimony of Paul Chernick ("Chernick Surrebuttal").

[37] AOBA Ex. 29, Direct Testimony of AOBA Witness Bruce R. Oliver ("B. Oliver Direct"); AOBA Ex. 30, Surrebuttal Testimony of AOBA Witness Bruce R. Oliver ("B. Oliver Surrebuttal").

regarding Pepco's revenue increase distribution and non-residential rate design proposals.[38] Lastly, HCNCA presented the testimony of Richard A. Baudino, a regulatory consultant with Kennedy and Associates, who testified regarding Pepco's cost of equity, revenue requirements, cost and revenue allocation, and rate design.[39]

The Commission held evidentiary hearings in its offices on September 13, 14, 15, 16, 19, 20, 21, and 22, 2016. Additionally, evening public comment hearings were held on September 6 and 8, 2016, in Rockville, Maryland and Largo, Maryland, respectively, for the purpose of listening to public comments on the Application. Parties filed Initial Briefs on October 13, 2016, and Reply Briefs on October 26, 2016.

On September 9, 2016, prior to the start of the evidentiary hearings, Staff filed a Summary of Positions on Revenue Requirements (hereinafter, the "Chart") on behalf of the Parties. Staff filed a revised version of the Chart on September 30, 2016. The Chart reflects the Parties' final positions on Pepco's total revenue requirement. Pepco's final position requests a revenue requirement of $102,751,000 for its electric distribution operations. Staff recommends a revenue requirement of no more than $57,759,000, while OPC recommends a revenue requirement of no more than $53,075,000. AOBA recommends a revenue requirement of no more than $51,462,000, and HCNCA similarly recommends that Pepco receive no more than $55,930,000.

All of the evidence presented in this case, including the public's comments, has been thoroughly reviewed and carefully considered by the Commission in reaching the decisions in this Order.

---

[38] AOBA Ex. 28, Direct Testimony of AOBA Witness Timothy B. Oliver ("T. Oliver Direct").

[39] HCNCA Ex. 30, Direct Testimony of Richard A. Baudino ("Baudino Direct"); HCNCA Ex. 31, Rebuttal Testimony of Richard A. Baudino ("Baudino Rebuttal"); HCNCA Ex. 32, Surrebuttal Testimony of Richard A. Baudino ("Baudino Surrebuttal").

III. DISCUSSION AND FINDINGS

A. Advanced Metering Infrastructure (AMI)

1) Background

Case No. 9111

The Commission initiated Case No. 9111 in January 2007 to evaluate BGE's proposal to implement demand-side management and Advanced Metering Infrastructure. In March of 2007, Pepco filed a similar proposal in Case 9111 – its "Application for Authorization to Establish a Demand-Side Management ["DSM"] Surcharge and an Advance Metering Infrastructure Surcharge and to Establish a DSM Collaborative and an AMI Advisory Group".[40]

Pepco's Application described its "Blueprint for the Future", but lacked a timetable for deployment or a business case in support thereof. In June 2007, the Commission established a "collaborative process" to consider a series of issues related to an advanced metering initiative and demand side management programs for all utilities that had filed applications.[41] In Order No. 81637, the Commission finalized these issues and "direct[ed] all electric companies to develop and file comprehensive energy efficiency, conservation and demand reduction plans proposing programs designed to achieve usage reductions goals in total electric consumption for each electric company by calendar year 2015."[42]

Case No. 9207

Following this directive, Pepco and Delmarva Power & Light Company submitted a joint proposal to deploy AMI in Maryland and establish a regulatory asset to defer

---

[40] Case No. 9111, Item No. 13.
[41] Order No. 81148.
[42] Order No. 81637 at 1.

recognition of AMI-related incremental costs.[43] In approving the proposed system, "we recognize[ed] the potential of AMI to deliver substantial benefits to the Companies' customers".[44] These benefits included operational and maintenance benefits (O&M), such as eliminating manual meter readers, enabling remote service connections, improving billing activities, among others.

The Commission determined, as it had previously with BGE, that

> The majority of AMI-enabled cost savings projected by the Companies arise from PHI's predictions about the degree to which the dynamic pricing options they propose will motivate customers to reduce electricity usage during Company-declared critical peak demand periods, and the impact of that reduction on wholesale market prices.[45]

Although we authorized the deployment of Pepco's AMI system, we ordered Pepco to submit for Commission approval:

> (1) a comprehensive education plan with associated costs (to be implemented sufficiently in advance to maximize customer awareness);
> (2) a comprehensive set of metrics for all aspects of its AMI implementation, including installation and performance the system, incremental costs and benefits incurred, the effectiveness of its customer education plan and customer privacy and cybersecurity.[46]

We ordered Pepco to report their performance against these metrics and "appear for periodic hearings" to allow the Commission to evaluate its progress.[47]

Pepco had projected a benefits-costs-ratio of 2.696 after receiving funding from the United States Department of Energy.[48] After acknowledging that uncertainties are inherent in the PHI Companies' business cases, we nevertheless approved Pepco's

---

[43] The PHI Companies also sought to develop and submit certain dynamic pricing tariffs. However, the Commission did not approve this aspect of the proposal.
[44] Order No. 83571 at 1.
[45] *Id*. at 2. We noted that the PHI Companies had based their projections on a BGE pilot program but had done no pilots of their own.
[46] Order No. 83571 at 54.
[47] *Id.*
[48] *Id.* at 41.

request to establish a regulatory asset for incremental costs associated with AMI deployment to be offset "by known and quantifiable AMI-related cost savings.[49] We further observed that establishing a regulatory asset better synchronizes the timing of customer costs and benefits, "thereby providing an opportunity for ongoing review of the Proposal's cost-effectiveness in future rate cases."[50] We concluded that our determination regarding recovery of prudently-incurred AMI-related costs "will be informed by whether the Companies have, in fact, delivered a cost-effective AMI system, the individual and collective benefits of which are worth the ratepayers' investment."[51]

2) Pepco's Current Cost-Benefit Analysis

a. <u>Pepco's Position</u>

Pepco has installed 568,000 meters in Maryland. Only 1,100 customers chose to opt-out of receiving a smart meter, and this percentage is small enough to have no effect on their business case.[52]

Pepco provided several witnesses and thousands of pages of testimony and exhibits to substantiate its contention that its AMI system exceeds the cost-beneficial threshold we established in Case No. 9207. Specifically, Pepco contends that its customers receive \$3.54 in benefits for every \$1.00 invested in the system and for which it seeks recovery.[53] Those investments include \$93.3 million in capital costs as of the end of the test year.[54] As we directed in Order No. 83571, Pepco has deferred its costs (net of operational cost reductions) in a regulatory asset. Pepco includes this asset in its cost-

---

[49] *Id.* at 52.
[50] *Id.*
[51] *Id.* at 53.
[52] Lefkowitz Direct at 3.
[53] Application at 3; Lefkowitz Direct at 10-12, including Graph 1.
[54] Lefkowitz Direct at 16, Table B.

benefit analysis, the balance of which is $61 million as of October 31, 2016.[55] These deferred costs reflect "AMI-related incremental depreciation expense, AMI and Dynamic-Pricing-related deferred O&M savings as well as AMI and Dynamic-Pricing related deferred returns."[56]

Pepco also includes $35.975 million in incremental operational and maintenance costs for both deployment and post-deployment periods (2013 through 2023) in its business case.[57] For present value calculations, forecasted annual costs (revenue requirements) and benefits are discounted at Pepco's weighted average utility cost of capital, and benefits achieved prior to 2016 are elevated at the same rate.[58]

Pepco witness Ms. Karen Lefkowitz is Pepco's Vice President of Smart Grid and Technology for PHI, and she provides a comprehensive overview of Pepco's contention that its AMI system provides ratepayers a benefit-cost ratio of 3.54-1, higher than initially estimated when the Commission approved Pepco's initiative.[59]

Pepco's divides its AMI-related costs between:

> 1) Costs associated with the AMI system in the amount of $93.3 million, with $65.2 million attributed to the cost of the meters, $4.3 million associated with the communication network and $23.8 million associated with information technology;[60]
>
> 2) Recovery of deferred costs – those costs placed in a regulatory asset per our prior order and which total $61 million;[61] and
>
> 3) Ongoing O&M and capital costs, which are estimated to be $35,975,000 and $21,254,000 respectively between 2016 and 2023.[62]

---

55 *Id.* at 17.
56 McGowan Direct at 7-8.
57 *Id.* at 7.
58 Lefkowitz Direct at 14.
59 *Id.* at 13 (Table A)
60 *Id.* at 13, 16.
61 *Id.* at 13, 16-17.
62 *Id.* at 18. Tables D and E. Pepco's AMI deployment began in 2014. We ordered a ten-year depreciation period in Case No. 9207, a period which ends in 2023.

Pepco divides the benefits its AMI system provides into two categories: Operational Benefits and Demand-Side Related Savings. The chart below summarizes both sides of the ledger:

	Cumulative Cost Benefits	Present Value[63]
Costs[64]		
1. AMI System[65]	$ 93.3	$ 73.8
2. Recovery of Deferred Costs[66]	$ 61.0	$ 66.7
3. Ongoing O&M Costs[67]	$ 36.0	$ 27.1
4. Ongoing Capital Costs[68]	$ 21.3	$ 7.9
Total Costs	**$ 211.6**	**$ 175.5**
Benefits		
1. Operational		
a. O&M Benefits (as described in Table F)	$ 133.6	$ 122.9
b. Asset Optimization	$ 31.7	$ 23.6
c. PJM Mkt Revenues	$ 36.2	$ 35.2
d. Avoided T&D capital Expenditures		
i. CVR Initiatives[69]	$ 13.9	$ 10.3
ii. Dynamic Pricing Initiatives	$ 110.8	$ 94.9
iii. EMT Initiatives	$ 23.4	$ 20.0
	$ 148.1	$ 125.2
Total Operational Benefits	**$ 349.6**	**$ 306.9**
2. Demand Side Related Savings		
a. Conservation Voltage Reduction (CVR)		
i. Capacity & Energy Mitigation	$ 8.1	$ 5.3
ii. Avoided Capacity Energy	$ 68.9	$ 51.4
iii. Reduction in Air Emissions	$ 2.0	$ 1.5
	$ 79.1	$ 8.2
b. Dynamic Pricing (DP)		
i. Capacity & Energy Mitigation	$ 147.0	$ 150.6
ii. Avoided Capacity Energy	$ 43.5	$ 28.0
iii. Reduction in Air Emissions	$ 0.0	$ 0.0
	$ 190.5	$ 178.6
c. Energy Management Tools (EMT)		
i. Capacity & Energy Mitigation	$ 12.0	$ 9.7
ii. Avoided Capacity Energy	$ 79.4	$ 65.7
iii. Reduction in Air Emissions	$ 2.2	$ 1.8
	$ 93.7	$ 77.2
Total Demand Side Benefits	**$ 363.2**	**$ 314.1**
Total Benefits	**$ 712.9**	**$ 621.0**
Benefit Cost Ratio		**3.54**

Pepco further breaks down its operational benefits into 25 categories, generally described as O&M Benefits, Asset Optimization Benefits, PJM Market Revenues, and Avoided Transmission and Distribution Capital Expenditures. Ms. Leftowitz describes how each of these 25 categories benefits ratepayers, and we need not repeat them here.[70]

---

[63] Costs shown on a revenue requirement basis present value as of 11/1/2016
[64] Net of $705million ARRA grant.
[65] Capital costs as shown on Table B Present value figure as adjusted for depreciation and taxes.
[66] Deferred costs as of 10/31/16 ; 561 million as noted in table C.
[67] Refer to Table D.
[68] Refer to Table E.
[69] CVR costs of 52 million are netted from benefits.
[70] For these descriptions, see *generally* Lefkowitz at 26-47.

Pepco claims the avoided T&D capital expenditures of $125,237,000 as operational benefits derived from its demand side savings because reduced demand for electricity allows Pepco to defer construction of additional transmission and distribution assets.[71]

Witness Faruqui, using a "robust analytical method," calculated the degree to which AMI meters and AMI-enabled programs reduced electricity consumption within Pepco's service territory.[72] Specifically, Mr. Faruqui concluded that these tools reduced residential electricity consumption by 1.73%.[73]

Pepco Witness Giovannini calculated that AMI-enabled programs – specifically Conservation Voltage Reduction ("CVR"), Dynamic Pricing ("DP") and Energy Management Tools ("EMTs") – have produced or will produce $314,000,000 in demand-side savings for Pepco's customers between 2013 and 2023.[74]

These savings anticipate a significant reduction in overall energy use as well as during peak demands. By participating in the PJM capacity auctions, Pepco can sell demand reductions into the wholesale capacity markets and earn PJM capacity market revenue. Mr. Giovannini testified that this revenue totaled $12.8 million through year-end 2015.[75] Additionally, PJM has accepted Pepco's bid of DP-sourced dynamic pricing valued at $32.5 million through 2019.[76]

Pepco's Dynamic Pricing model includes the ability for customers to earn distribution credits on "Peak Savings Days" of $1.25 for each kWh by which they reduce

---

[71] Lefkowitz Direct at 45.
[72] Faruqui Direct at 2.
[73] *Id.*
[74] Giovannini Direct at 4.
[75] *Id.*at 7.
[76] *Id.*

electricity consumption, with capacity market revenue in excess of these credits flowing through the EmPower Maryland surcharge.[77] Mr. Giovannini conceded that these revenues will not be available after 2020 due to a change in PJM rules, but described a number options being investigated to replace this revenue stream after 2020.[78]

Pepco included "Avoided Capacity Costs" in its cost-benefit analysis because PJM's Base Residual Auction treats its dynamic pricing programs as a generation asset, thereby reducing the total cost of capacity for a specific PJM utility zone.[79] "Avoided energy costs" simply refers to the reduced amount of energy that customers purchase when consumption declines.[80]

"Capacity Price Mitigation" and "Energy Price Mitigation" work along similar lines. When DP programs reduce demand, this lowers the clearing price during PJM's Base Residual Auction or the real-time electricity price because demand decreases while the supply remain constant.[81]

Pepco claims that it analyzed these costs and benefits from the customer's perspective, using the annual revenue requirement to measure both the costs and the "quantified" benefits from 2016 through 2023.[82] Pepco seeks to recover these costs amortized over a ten-year period, which Pepco claims all parties agreed to in Pepco's

[77] *Id.*
[78] *Id.* at 9-10.
[79] *Id.* at 11-12.
[80] *Id.*at 13.
[81] *Id.*at 13-17.
[82] Pepco Initial Brief at 8.

latest depreciation case.[83] Pepco seeks to amortize its regulatory asset over five years.[84]

Pepco points out that, while there may be differences among the parties as to which costs or benefits should be included in the analysis, no party presents a business case that establishes that the system is not cost-effective.

b. Staff Response

Staff did not include in its evaluation of Pepco's business case several categories of benefits that were not "Core Benefits' as defined by Staff analysts. Staff Witness Hurley defined "Core Benefits" as "a benefit in the Business Case in Case No. 9207 and for which a reporting metric was developed in the Work Base Group Phase I or Phase IIA consensus metrics reporting guidelines."[85]

Based upon this definition, Mr. Hurley analyzed less than half of the benefits (and associated costs) claimed by Pepco.[86] Mr. Hurley concluded that Pepco's "Core Benefits" totaled $279 million with associated costs of $176 million, resulting in a benefit-cost ratio of 1.6-1.[87] Mr. Hurley and Staff Witness Ratushny therefore concluded that Pepco's AMI system was cost-beneficial exclusive of non-core benefits. Based upon these results, Staff concluded that "there is no evidence in the record that would support a finding that Pepco's AMI system is not cost-effective."[88]

c. OPC Response

OPC disagrees with many of Pepco's claimed benefits and costs, which it views as speculative or simply inaccurate. But even after adjusting for the many benefits and

---

[83] McGowan Direct at 6.
[84] McGowan Direct at 6.
[85] Hurley Direct at 20.
[86] Hurley Direct at 23. Compare the chart at Hurley Direct at 19 and Hurley Direct at 23.
[87] Hurley Direct at 25.
[88] Staff Initial Brief at 30.

costs that OPC finds dubious, its Witness Chang still concludes that a reasonable estimate of the benefits-costs is 0.99-1.00.[89] Mr. Chang conceded that this ratio is essentially "break-even" for ratepayers.[90] In fact, he also conceded that if he removed peak demand payments from his analysis (as we clearly ordered should be done in Case No. 9406), his ratio would increase 1.4 to 1, not very different from Staff's conclusion.[91] Therefore, OPC concluded that"[E]ven though the Company has greatly over-estimated the benefit-cost ratio for its AMI program, because the benefit-cost ratio found by OPC's analysis is so close to 1.0, OPC's revenue requirements witness, Mr. Effron, did not propose a disallowance to hold customers harmless from the amount of costs in excess of the benefits."[92]

d. Montgomery County Response

Montgomery County also contends that the Commission should approve the AMI system, concluding that "[t]here appears to be no dispute that Pepco has delivered a cost-effective Advanced Metering ("AMI") system."[93]

e. Healthcare Council of the National Capital Area Response

HCNCA did not submit a business case to support the conclusion that Pepco's AMI System was not cost effective. However, HCNCA argued that Pepco had the burden to establish cost-effectiveness for each class of customers separately and failed to do so (or even try) for commercial customers.[94] As a result, certain classes of

---

[89] OPC Witness Chang at 23.
[90] Tr. 1205 (Chang).
[91] Tr. 1210; Hurley Surrebuttal at 4.
[92] OPC Initial Brief at 41-42.
[93] Montgomery County Initial Brief at 7.
[94] HCNCA Initial Brief at 28.

commercial customers would likely shoulder a greater burden of the costs of AMI while being unable to receive many of the benefits.[95]

f. AOBA Response

In its Initial Brief, AOBA contended for the first time that Pepco's benefit-cost ratio should be reduced to 0.66-1.0. AOBA did not produce an affirmative business case that would support this reduced ratio, but did criticize several of Pepco's costs and benefits, including Mr. Faruqui's methodology, the exclusion of dynamic peak pricing rebates from the cost-benefit analysis and the likelihood that financing the second round of smart meters will be much higher due to inflation and the absence of federal funding.

3. Commission Decision

In light of the record evidence before us, we approve Pepco's requested recovery of its AMI costs. All parties that submitted a business case agree that Pepco has provided a cost-beneficial AMI system, and disagree only on the extent to which it is cost-beneficial.[96] We have not required utilities to establish a particular cost-benefit ratio, only that they demonstrate that their system is cost-beneficial – a pass/fail proposition. We therefore need not address specifically whether Pepco, Staff or OPC provided a cost-benefit ratio closer to our own liking because doing so would be a moot analysis. Our order authorizing the deployment of AMI and the creation of a regulatory asset for related incremental costs demanded that Pepco meet the cost-beneficial threshold, and the record contains evidence that they have done so.

While the Commission agrees that Pepco has "passed" the cost-benefit test, we make note that due to this investment in AMI, both residential and commercial customers

---

[95] As an example, businesses lack the flexibility to shift electricity usage during peak times or otherwise alter electricity consumption to the degree available to residential customers.

will experience additional costs on their monthly distribution bills. We note that Pepco has asserted, and Staff largely agrees, that AMI will result in significant operating and maintenance (O&M) and energy savings. It is imperative that these savings are noticeable and demonstrable to customers over the life of AMI. Just as the Commission expressed skepticism in some elements of the cost benefit analysis in reviewing BGE's AMI system[97], customers will want to see concrete savings to find value in their new meters. Therefore, Pepco should continue to demonstrate and communicate to its customers that its AMI program will result in direct monetary benefits and continue to develop ways to increase the types and amounts of direct monetary benefits that customers can receive in the future. We look forward to reviewing the Company's progress on this important customer issue.

Furthermore, as we stated in approving cost recovery of BGE's AMI investment[98], this Commission will remain vigilant with regard to Pepco fully utilizing smart grid technology to optimize the investment in AMI, and we expect Pepco to ensure that ratepayers realize a demonstrable return on their investment in smart grid technology. Regarding the company's avoided transmission and distribution capital expenditures (T&D), we require – as we did with BGE – that Pepco file a Distribution Investment Plan within twelve (12) months of the date of this Order that sets forth how the Company will accomplish these T&D goals. The required Plan shall analyze in detail the Company's strategy over the next five years for investing in its distribution system and shall include, among other things, specifics about how the Company's investment in smart meters will be utilized to improve the efficiency and effectiveness of the

[97] Hurley Direct at 10
[98] Order No. 87591 at 58.

distribution network. In addition, this Commission continues to believe AMI has great potential to give customers access to information, control, and cutting-edge services – some or many of which could be supplied by innovative third-parties.[99] For the customers' large investment in AMI to continue to be a success, Pepco and all distribution services companies must continue to unlock AMI's full value.

HCNCA claims that Pepco failed to establish cost-beneficial for each class of customers and failed to do so for commercial customers. However, the Commission language cited by HCNCA (from Case No. 9207, in which we initially approved Pepco's AMI deployment) states the opposite. The Commission wrote:

> And as the Companies own expert witness testified, Pepco's and Delmarva's small commercial customers are not expected to respond to dynamic pricing under the current Proposal, raising questions about whether the Proposal will be cost-effective for all classes of PHI even if it proves cost-effective on the whole.[100]

The Commission went on to identify several operational benefits that would accrue to commercial customers, but the Commission has never required that a utility demonstrate cost-effectiveness for every class of customers before it may recover its AMI costs. However, HCNCA raises legitimate concerns that commercial customers will pay a greater share of the costs of AMI than justified by the benefits they receive. As we discuss below, we have adopted a benefits-based allocation of AMI costs among rate classes, which should address many of the concerns HCNCA raises.

Waiting until its initial brief, AOBA contends that its criticisms of Pepco's purported benefits and costs results in a ratio of .66-1.0.[101] AOBA never submitted a written business plan to this effect, and this is not a minor omission. The other parties to

[99] The Commission looks forward to exploring this topic in Public Conference 44.
[100] Order No. 83571 at 43.
[101] AOBA Initial Brief at 39.

this case presented their view on this issue in accordance with the scheduling deadline. Had AOBA presented these parties with its own purported cost-benefit ratio and identified witnesses who would testify in support of that ratio, other parties would have had an opportunity to conduct discovery and cross-examine supporting witnesses as to their assumptions, including how the ratio would change if the Commission rejected some or all those assumptions.

We will nonetheless address most of AOBA's contentions. First, AOBA challenges Witness Faruqui's analytical model for estimates of load reduction due to Pepco's CVR and DP programs.[102] AOBA provides no witness or exhibit to support this contention. Rather, counsel for AOBA argues that his cross-examination was sufficient to demonstrate that Dr. Faruqui's conclusions are not tenable.[103] However, Dr. Faruqui provided a detailed explanation as to how he calculated load reduction while under oath.[104]

AOBA then contends that Pepco's legacy meters are not sunk costs, and the Commission should include the costs associated with the unamortized balance of legacy meters when analyzing AMI's cost-beneficial.[105] Although the treatment of Pepco's legacy meters is a legitimate issue in this case outside of our AMI analysis, we have already ruled in identical circumstances that these costs should not be included when we evaluated the cost-effectiveness of BGE's AMI system.[106] AOBA is aware of this, but seeks a *de novo* review of our prior ruling. However, OPC witnesses Chernick and Brockway made the same arguments that AOBA is making here, and we have already

[102] *Id.* at 28-30.
[103] *Id.* at 27-30.
[104] Tr. 565-569 (Faruqui).
[105] AOBA Initial Brief at 30-35.
[106] Order No. 87591 at 64.

addressed those arguments and concluded that the unamortized balance of BGE's legacy meters "constitutes a sunk cost that is not appropriately included in the cost-benefit analysis for this new initiative."[107] We agree with the testimony of Dr. Faruqui that "Costs related to prior decisions are not relevant to the cost-effectiveness of a new decision about new investments."[108]

AOBA also contends that Pepco's increased metering and billing costs should be included in the cost-benefit analysis, but several Pepco witnesses testified that these increased costs were unrelated to Pepco's AMI system, but rather related to the deployment of Pepco's new billing system.[109] Witness Lefkowitz was explicitly asked whether these increased expenses were related to AMI, and she testified that "those expenses that are cited by [AOBA witness] Oliver are not related to AMI."[110]

Finally, OPC seeks to re-raise the issue of whether limiting post-year costs for the AMI regulatory asset is appropriate.[111] OPC concedes that we have already addressed this issue in our order on rehearing in Case No 9406. In that order, we concluded that BGE could "defer post-test year smart grid costs in new smart grid regulatory asset so that it may properly seek recovery in a future base rate proceeding."[112] Although that decision is on appeal, we see no reason to re-visit our ruling at this time.

Cost Overruns

Mr. Hurley identifies several instances in which Pepco seeks recovery for AMI-related costs that are notably higher than originally estimated in Pepco's Application in

---

107 *Id.*
108 Faruqui Rebuttal at 9.
109 Lefkowitz Rebuttal at 10; VonSteuben Rebuttal at 39-40.
110 Tr. 327 (Lefkowitz).
111 Effron Direct at 5. (Testifying that the AMI regulatory asset should only include the deferred costs as of the end of the test year).
112 Order No. 87951 at 10; OPC Initial Brief at 11.

Case No. 9207, and the metrics that Pepco has been providing to Staff on a quarterly basis.[113] Overall, Mr. Hurley testified that Pepco "exceeded its expected forecast for capital cost for meters, communications infrastructure and IT by close to 20% ($161 million in actual spending vs. a forecast of $135 million)".[114] These costs overruns included:

> 1) increased labor costs: Pepco attributes these cost overruns to "increased time required to install transformer-rated meters as well as to perform remediation work for non-communicating meters";[115]
>
> 2) Communication network costs: These costs exceeded forecast primarily because the Communications network required 15,748 more communication devices (an increase of 300%) than projected. Pepco claims that PHI determined that these additional devices were needed for the security of the system.[116]
>
> 3) IT costs: Pepco exceeded its forecast IT costs by 38%. These overruns were attributed to cybersecurity. Specifically, Pepco installed Utility IQ Critical Operations Protector ("COP") which are hardware security modules that provide fail safe mechanisms for critical commands. The $3.9 million overrun breaks down as: $3.0 million for UIQ software and hardware and $.9 million for COP software and hardware.[117]

Pepco contends that cost overruns are not per se imprudent,[118] and the record contains no evidence that these particular overruns were imprudent.[119]

While it is true that cost overruns are not *per se* imprudent, and we will not disapprove these overruns (with one exception, discussed below), the Commission depends upon the accuracy of project estimates, or we lack any foundation upon which to

[113] Hurley Direct at 12; See also Ex. DJH-2, Hurley Direct at 50-51.
[114] Hurley Direct at 12.
[115] Lefkowitz Rebuttal at 6.
[116] Tr. 403 (Lefkowitz)
[117] Ex. DJH-2, Hurley Direct at 50-51.
[118] Pepco Initial Brief at 10-11; Lefkowitz Rebuttal at 5-6 ("[B]udget or forecasted target is an estimate based on facts known at the time, and spending more than budget is not per se imprudent.")
[119] Tr. 1600 (Hurley) ("You would agree with me, would you not, Mr. Hurley, that Staff has not proposed any adjustments to the specific AMI project for imprudence or cost overruns or the like; isn't that correct? Hurley: No, we have not.")

determine whether or not a proposed project should be approved to go forward. We understand that utilities cannot always estimate future costs with perfect accuracy, and we don't intend to subject good-faith estimates to unreasonable second-guessing, but when we rely upon estimates in approving a project, we do expect the estimates to be within a reasonable margin of error. The overruns that Mr. Hurley identifies are significantly higher than projected and, in future cases, we will more closely analyze similarly higher-than-forecast costs very closely

We disallow the cost over-run identified in Confidential Commission Exhibit 4. Pepco provided no basis upon which to recover these cost overruns. This is particularly so because the company recovered some portion of these cost overrun funds from the vendor but made a management decision to allocate only a small portion of the funds returned from the vendor to Pepco Maryland customers. We can see no basis upon which to require Pepco's Maryland ratepayers to absorb these cost overruns that were not returned to Pepco Maryland customers. Due to the confidential nature of the exhibit, we will only state that we disallow those expenses that were above the company's estimate, excepting that portion allocated to Pepco Maryland electric distribution.

Metrics

In Order No. 83571, we directed Pepco to provide Staff with detailed metrics, including incremental costs and benefits, budgets, performance of the AMI system, cybersecurity and other important aspects of the operation of the AMI system to allow Staff to monitor the performance of Pepco's AMI system.[120] Ms. Lefkowitz testified that

[120] Order No. 83571 at 54 and Ordering Paragraph 5.

Pepco has complied with these reporting metrics, and no party has claimed otherwise.[121] We ordered BGE to continue to provide these metrics going forward in Case No. 9406.[122]

OPC requests, and we agree, that Pepco continue to submit these reporting metrics to Staff going forward.[123] We therefore order that Pepco do so, and we will closely follow the data therein to ensure that Pepco's AMI system continues to provide value to its Maryland ratepayers.

B. Rate Base and Operating Income

Rate base represents the level of net investment the Company makes in plant and equipment in order to provide safe and reliable electric service to its customers. Operating income is derived based upon the revenues the Company receives for electric service minus the costs it incurs in providing service to customers. The parties have proposed various adjustments to the Company's unadjusted rate base and operating income during the test year. We have reviewed the record and accept the uncontested adjustments proposed by the Company. The undisputed portion of the rate base for the uncontested adjustments, is $7,659,000. The undisputed portion of operating income uncontested adjustments, is $9,380,000. The parties dispute certain proposed rate base and operating income adjustments and we resolve these issues below.[124]

1. RMA 1-4: "Reliability Plant" Additions

---

[121] Lefkowitz Direct at 7 – Mail-Log #s: 131260, 133571, 143602, 143602.
[122] Order No. 87591 at 66-67.
[123] Chang Direct at 3.
[124] *See* Appendix I for the Commission's calculation of the appropriate rate base and overall revenue requirement for rate making purposes; and Appendix II for operating income.

Safety and reliability are a foremost concern when we consider rate requests by utilities. In recent rate proceedings, the Commission has recognized that under appropriate circumstances, and when properly supported, adjustments to the historically accepted average test year may be warranted for safety and reliability investments and expenses, provided such investments or expenses do not generate additional utility revenues. Non-revenue producing safety and reliability investments, which we discuss in this section, generally serve existing customers rather than support new customers, which result in incremental utility revenues.

a. <u>Parties' Positions</u>

Pepco proposes four reliability ratemaking adjustments (RMAs). First, Pepco proposes RMA 1, which annualizes the effect of reliability projects that were added to Electric Plant In Service (EPIS) during this test period.[125] Pepco witness Mr. VonSteuben explained that this adjustment "reflects in EPIS the full value of those reliability projects added to plant, reduces [Construction Work In Progress] CWIP to the extent the projects were reflected in unadjusted test-year amounts, and removes actual retirements from both EPIS and accumulated depreciation.[126]

Second, Pepco proposes RMA 2 which adds to rate base those reliability projects that were placed in EPIS from January 2016 through August 2016, and for which actual data was made available prior to the evidentiary hearings.[127] Mr. VonSteuben argued that inclusion of RMAs 1 and 2 is consistent with similar RMAs proposed by Pepco in

[125] VonSteuben Direct at 13.
[126] VonSteuben Direct at 13.
[127] *Id.* at 13.

Commission Case Nos. 9286, 9311 and 9336, and with a similar RMA previously accepted by the Commission in Delmarva Power Case No. 9192.[128]

Third, Pepco proposes RMA 3 which "reflects the impact of known reliability projects in CWIP at the time of the hearings and that are forecasted to be placed into service from September 2016 to October 2016, prior to the rate effective date in (mid-November 2016)."[129] VonSteuben testified that these projects are not revenue generating and will be providing service to customers and placed into service for accounting purposes prior to the rate effective period commencing. VonSteuben also argued that "[i]nclusion of these projects is consistent with the Commission's decision on RMA 2 in Case No. 9336, where the Commission noted that it considered and included in rate base projects that were 'known and measureable.' "[130]

Last, Pepco proposes RMA 4 which "reflects the impact of the cost of additional known reliability projects that are forecasted to be expended prior to the rate effective date, providing service to our customers and will be placed into service for accounting purposes by year end December 2016."[131] VonSteuben argues that these projects will be providing service to Pepco customers the entire rate effective period and to not include them in the cost of service distorts the relationship of customers paying for services they are receiving.[132]

Generally speaking, the other parties addressing the reliability adjustments support Pepco RMA1 and RMA2. However, Staff witness Shelton noted that Staff reviewed the reliability projects included in RMAs 1 and 2 and identified several projects

---

[128] *Id.* at 13.
[129] *Id.* at 14.
[130] *Id.* at 15.
[131] *Id.* at 15.
[132] *Id.* at 15.

that did not appear to be related to reliability and as a result recommends that these projects be removed from RMA 1 and RMA 2.[133] Witness Shelton testified that Pepco was originally asked about these projects included in RMAs 1 and 2 on June 6, 2016 in a Staff Data Request No. 16-1. Specifically, Staff asked the Company to provide a detailed explanation of how those identified projects are reliability related. The Company response to Staff Data Request No. 16-1 stated "[a]ll of the replacement work is part of the overall reliability efforts. Physical security refers to the security the substation while work is being conducted." Ms. Shelton in her Surrebuttal noted that the Company failed to adequately respond to the inquiry initially and provided an update to the data request on August 10, 2016, which still did not clarify the nexus between these projects and reliability.[134] Ms. Shelton testified that Staff reassessed its review of the identified projects in light of the new information provided by the Company and found that the projects in question were never identified as reliability initiatives listed in Case Nos. 9240, 9361 or 9353.[135] Therefore, Staff continues to recommend these projects be removed from RMA 1 and RMA 2. In her Surrebuttal, Ms. Shelton noted that Pepco had provided updated cost data for RMA 1 and RMA 2. As a result of the updated cost data, Staff recalculated its reduction for RMA 1 and proposed that the reduction should be $471,122 instead of $1,891,091. Similarly, Staff modified its recommendation to reduce RMA 2 by $291,000 instead of $572, 000.[136]

[133] Ms. Shelton identified the following projects for removal from RMA1 and RMA2: "all street light related projects; replacement substation roofs; replacement of manhole roof; physical security of the substation; alarm cable replacement; Beckwith controller replacement; substation ventilation; and removal of poles/transformers/street light heads. Along with these Staff also removed an unidentified blanket project, capital storm restoration, and AMI field deployment due to insufficient information." Shelton Direct at 19.
[134] Shelton Surrebuttal at 2- 5.
[135] Shelton Surrebuttal at 3.
[136] *Id*.

OPC witness Effron did not propose similar adjustments to either RMA 1 or RMA 2. However, he made clear in his Surrebuttal that Pepco witness McGowan mischaracterized his proposed adjustments to the Company's reliability plant additions between 2015 and 2016. He testified that he does not recommend a blanket reduction of post test year reliability spend.[137]

Pepco witness Gausman rebutted Ms. Shelton's assertion that the eight projects identified above were not reliability related. He testified that "each of these activities is necessary to provide for the continued safe and reliable operations of the distribution system. Several of these projects would result in significant damage to substation equipment if this work was not performed and customers would be exposed to extended outages and increased cost."[138] Mr. Gausman's testimony then proceeded to provide a detail explanation of the eight projects and how they relate to reliability. Further, Mr. Gausman argued that "Pepco's actions relative to these projects were prudent and necessary to maintain a safe and reliable distribution system. In fact, it would have been irresponsible to forego performing this work and expose the distribution system to risk of additional damage as well as exposing customers to extended outages and safety hazards."[139]

Ms. Shelton did not dispute Mr. Gausman's assertion that these projects are needed to help maintain a safe and reliable distribution system. Rather, Ms. Shelton on cross examination stated that she was attempting to draw a distinction between reliability spending and just regular maintenance.[140] Specifically, Ms. Shelton stated that "It is my

[137] Effron Surrebuttal at 2.
[138] Gausman Direct at 3-4.
[139] Gausman Direct at 9.
[140] TR 1252:L1-6

opinion that reliability spending should upon completion have a direct impact on reliability, even a measurable impact on reliability."[141] Ms. Shelton on cross examination agreed that the eight projects identified may have an indirect impact on reliability but "should not be afforded the special treatment that's afforded reliability for rate-making adjustment items."[142] Moreover, Ms. Shelton clarified on cross examination that her "testimony does not disallow these items from going into rate base. It simply disallows the special treatment afforded to reliability rate-making adjustments."[143]

Regarding RMA 3 and RMA 4, Staff witness Ostrander stated that both RMA 3 and RMA 4 are considered not known and measurable, and these adjustments should be denied.[144] Mr. Ostrander provided four primary reasons he believed the Commission should reject Pepco's RMA 3 and RMA 4. First, he argued that "[t]he Commission has historically rejected these types of estimated/projected post hearing reliability plant additions adjustments in prior applicable rate cases."[145] Second, for this specific case, consistent with prior Commission decisions, the estimated/projected amounts are not known and measurable.[146] Third, the estimated/projected amounts are not shown to be used and useful.[147] Fourth, Pepco has not provided any new or compelling substantive and meaningful arguments or documentation to justify a departure from consistent prior Commission decisions in the past that have rejected these types of adjustments.[148]

OPC witness Effron testified that the Company's Adjustments 3 and 4 recognize reliability related plant additions after August 2016 and do not meet the Commission's

---

[141] TR 1252: L6-9; TR 1267:L4-9.
[142] TR 1267;L4-9 and 17-22
[143] TR 1270 L23 – 1271 L1-4.
[144] Shelton Direct at 19.
[145] Ostrander Direct at 13.
[146] *Id*.
[147] *Id*.
[148] *Id*.

known and measurable standards for inclusion in rate base. Mr. Effron noted that in Pepco Case No. 9336, the Company proposed virtually identical adjustments to its test year base rates to recognize post-test year plant additions. However, in that case the Commission found that the proposed adjustments was "not known and measurable, nor does it represent actual spending, which is a requirement to be included in rate base."[149] Therefore, Mr. Effron argued that RMA 3 and RMA 4 in the present case should be eliminated.[150]

b. <u>Commission Decisions</u>

In Pepco's most recent rate cases, Case Nos. 9311 and 9336, the Commission has accepted similar RMA 1 and RMA 2 adjustments for reliability plant additions for the test period and actual reliability investments for the post test period. We primarily have accepted these adjustments when the Company demonstrated that such investments meet objective standards for safety and reliability, have not generated additional utility revenues, and will provide service to existing rather than new customers.

As noted by Pepco, most of the parties agree with the vast majority of its reliability investments in RMA 1 and RMA 2. However, Staff Witness Shelton recommends a reduction to RMA 1 and RMA 2, arguing that for some projects the Company did not provide adequate information to show that they were reliability related. Further, we note that, while Mr. Gausman provided further explanation about how each of the eight projects related to reliability, the Company could not demonstrate how implementation of these projects had a measurable impact on reliability. Staff witness Shelton rightly points out that these projects as presented in this proceeding appear to

---

[149] Effron Direct at 4.
[150] *Id.* at 4.

involve regular maintenance and should not be afforded the special ratemaking treatment afforded reliability projects with measurable impact.

Considering Staff witness Shelton recommendation in relation to Commission practice for approving reliability plant additions, we accept Staff's recommendation of reducing RMA 1 by $471,122.

With respect to post test period reliability investments proposed in RMA 2, we will allow the inclusion of three months (January 2016 to March 2016) of post-test period reliability plant additions associated with RMA 2. Allowance of post-test period reliability expenses is an exception to the rule of allowing recovery only of reliability investments for historical test period. This exception was adopted several years ago as an attempt to incentivize the Company to make accelerated reliability infrastructure investments by allowing recovery of the expenses without waiting for another rate case. The Commission stated previously that it "departed from traditional ratemaking principles"[151] due to Pepco's poor reliability performance over the prior decade[152] and did not intend for this exception to become deemed as guaranteed or automatic. Thus, the Commission adopted in May 2012 comprehensive electric reliability regulations in COMAR 20.50.12.02 (also referred to as RM 43), which provides specific SAIDI and SAIFI standards intended to result in annual reliability improvements.[153]

In the present proceeding, Pepco witness Gausman testified to the tremendous improvements made in reliability such that the Company now meets or exceeds its SAIFI and SAIDI requirement. He noted that in 2015, customers experienced an improvement

[151] Case No. 9311, Order No. 85724 at 2
[152].Case No. 9240 Order No.84564
[153] Case No. 9311, Order No. 85724 at 2.

of 46% in SAIFI and 43% in SAIDI when compared to 2011 performance.[154] He further stated, "[o]ur continued investment in people and strengthening the electrical infrastructure and employing innovative technology has contributed to a historical best performance in both SAIDI and SAIFI for 2015."[155] Given Pepco's improved performance and in light of the significant increase in rates the Company is requesting, we no longer find that Pepco needs this reliability exception in whole. Therefore, our allowance of the three months of post-test period reliability investments for RMA 2 is reduced by the acceptance of Staff's reduction for the projects that do not impact the Company's reliability which generates a revenue requirement of $7,227,000.

Several parties have pointed out that RMA 3 and RMA 4 do not meet the Commission's standard for known and measurable and the reliability plant additions being proposed are not currently used and useful for the benefit of current customers. In keeping with our historical treatment of similarly proposed adjustments, we reject the Company's proposed RMA 3 and RMA 4 which reduces Pepco's revenue requirements by $2.1 million and $4.2 million, respectively.

2. <u>RMA 6: Incremental Costs Associated with Pepco's AMI's Deployment</u>

a. <u>Parties' Positions</u>

In Case No. 9207, the Commission stated that "at the time the Company has delivered a cost-effective AMI System, the Company may seek cost recovery in a base rate proceeding."[156] Pepco is seeking recovery of $97.2 million of capital investments

[154] Gausman Direct at 4.
[155] Gausman Direct at 4.
[156] Order No. 83571. See also McGowan Direct at 7.

that it made in AMI meters, communications equipment and other assets through rate base.[157] Additionally, the Company is seeking recovery of its $60.9 million regulatory asset that was established to defer various costs associated with its AMI system pursuant Order No. 83571.[158] Pepco witness VonSteuben proposed RMA 6 to recover its deferred AMI costs in rate base. "The deferred costs include: AMI-related incremental depreciation expense, AMI and Dynamic Pricing-related deferred Operation and Maintenance (O&M) expenses, AMI O&M Savings, as well as AMI and Dynamic Pricing-related deferred returns."[159] In addition to the AMI deferred costs in the regulatory asset, RMA 6 reflects ongoing AMI O&M and depreciation expenses that should be included in the Company's cost of service in the rate effective period.[160] In his rebuttal testimony, Mr. VonSteuben noted that the Company presented the deferred AMI balances into four timeframes: a) from inception through December 2015 (end of the test year); b) from January 2016 to June 2016; c) from July 2016 to August 2016; and d) from September 2016 to October 2016.[161] Mr. VonSteuben noted that the financial data for timeframes A through C was known and measurable at the time of the hearings.[162]

Mr. VonSteuben testified that Pepco is seeking recovery of $3,818,000 of ongoing O&M, savings and depreciation in RMA 6. He argued that recovery would be appropriate because the test year does not reflect these expenses due to AMI-related costs/savings being deferred under Commission Order No. 83571.[163] The Company, although initially requested AMI deferred regulatory asset recovery on a 5-year

[157] McGowan Direct at 7.
[158] *Id.*
[159] VonSteuben Direct at 16.
[160] *Id.*
[161] VonSteuben Rebuttal at 29-30.
[162] VonSteuben Rebuttal at 30.
[163] *Id.*

amortization basis, agreed with Staff Witness Ostrander and OPC witness Effron to change the proposed amortization period from 5 to 10 years.[164]

Staff Witness Ostrander in his Surrebuttal stated that to be consistent with the Commission's Errata Order No. 87591 in the recent BGE rate case[165], he has disallowed Pepco's post-test year AMI Regulatory Asset costs. However, Mr. Ostrander does acknowledge that "Pepco is allowed to seek recovery of these same costs in a 'future' deferred AMI Regulatory asset cost established after this proceeding."[166] Specifically, Mr. Ostrander points out that the Commission's Rehearing Order in Case No. 9406 modified the original Errata Order by recognizing "that recovery of these costs as future expenses may be more expensive to ratepayers than allowing such costs to be set up in a future regulatory asset and subject to amortization over a period of years. Therefore, the Commission's Rehearing Order allows these costs to be set up in a future regulatory asset so that Pepco may seek recovery of these costs in a future rate case (although recovery is not guaranteed)."[167]

Regarding the treatment of the post-test year costs related to AMI Ongoing Expenses/Savings, Mr. Ostrander stated that in his direct testimony he had proposed removal of all post-test year Ongoing Expenses/Savings because he was unable to determine how the Commission specifically treated those costs in the BGE Case No. 9406.[168] In his surrebuttal, Mr. Ostrander acknowledged that in the Commission's Errata Order in BGE Case No. 9406, the Commission had allowed AMI Ongoing Expense post-

---

[164] *Id.* at 32. The 10-year amortization period is consistent with the Commission's decision in BGE Case No. 9406. *See* VonSteuben Rebuttal at 33.
[165] Ostrander Surrebuttal at 10. Commission Errata Order No. 87591, BGE CN 9406, issued June 3, 2016, pp. 70-71.
[166] Ostrander Surrebuttal at 15.
[167] *Id.* at 15-16.
[168] Ostrander Surrebuttal at 17.

test period costs in the BGE Case No. 9406.[169] Mr. Ostrander thus agreed to accept Pepco's Ongoing Expense/Savings; however, in his surrebuttal testimony, Mr. Ostrander stated that he would deny approximately $2.5 million of those net expenses because Pepco failed to provide adequate supporting documentation and calculations to support most of its AMI ongoing expenses. He would allow actual test period ongoing expenses of $44,021 and ongoing depreciation expenses of $1,265,913, but he would disallow the remaining $2,508,066 not specifically identified by the company."[170]

b. Commission Decision

Consistent with our decision in BGE Case No. 9406, we reject Pepco's adjustment to include post-test year AMI Regulatory Asset costs in rate base and instead adopt Staff's and OPC's position to remove post-test year AMI costs from rate base and place them in a new regulatory asset for potential recovery in a future base rate proceeding.[171] We adopt for Pepco what we stated in that case about BGE's new regulatory asset, which is that the new regulatory asset is restricted to the post-test year AMI costs identified in the instant proceeding and that we reserve judgment on whether a return on this new regulatory asset is appropriately included, as such a burden is borne by the Company at the time it seeks recovery.[172] Also, we accept the parties' consensus position to adopt a 10-year amortization of the AMI regulatory asset. Regarding AMI Ongoing Expenses, we accept Mr. Ostrander's recommendation to remove certain net ongoing expenses due to inadequate supporting documentation. As with all items included in customer rates, the Company has the burden of proof to justify the level of

[169] Ostrander Surrebuttal at 18-19.
[170] Ostrander Surrebuttal at 20-21.
[171] Order No. 87695 at 10-11.
[172] Order No. 87695 at 10, FN 16.

recovery that it seeks. Here, it did not sufficiently demonstrate the actual amounts of net ongoing expenses for significant portions of the cost recovery requested, and so we deny that portion of the company's request as identified by Mr. Ostrander.

3. RMA 7: Legacy Meters

a. Parties' Positions

The Company's proposed RMA 7 amortizes the net book value of the retired legacy meters over 10 years.[173] Initially, the Company's adjustment included "a return on" the undepreciated value of the legacy meters. In his rebuttal testimony Mr. VonSteuben noted that, in light of the Commission's August 10, 2016 decision (Order No. 87710 in Case No. 9385), the Company withdrew its adjustment requesting a "return on" the unamortized legacy meters but it continued to support the use of a 10 year amortization period unlike the Commission's recent decision amortizing the undepreciated value of the legacy meters over 15 year period.[174] Pepco argues that the Commission approved a 10-year amortization of legacy meters in the BGE rate case, Errata Order No. 87591.[175] Additionally, Pepco notes that "[n]o party has presented any evidence as to why Pepco should be treated any differently" from BGE.[176] The Company also argues that allowing customers to repay the cost of the legacy meters over 15 years as opposed to 10 years with no return on the investment results in a higher financial cost to the Company.

---

[173] VonSteuben Direct at 17.
[174] Case No. 9385, Order No. 87710, Petition for Rehearing pending.
[175] Pepco Initial Brief at 35.
[176] *Id*.

Staff, OPC, Montgomery County, and HCNCA support the Commission's decision to adopt a 15-year amortization period to recover the unamortized balance of the legacy meters. HCNCA pointed out that "the public Service Commissions of Delaware and the District of Columbia have authorized 15-year amortization periods for the regulatory assets associated with legacy meters."[177]

b. Commission Decision

We agree with the Company that, in general, we treat our utilities the same unless there are facts that support different treatment. In this instance there are no such facts to support treating Pepco differently than BGE. Accordingly, we adopt the Company's position to amortize the unamortized balance of legacy meters over 10 years.

4. RMA 9 and 10: Tax Compensation Carrying Costs and its Reversal

a. Parties' Positions

Pepco is an affiliate of Pepco Holdings, Inc. ("PHI"), and Pepco's financial results became part of PHI's consolidated tax return. In 2013, Pepco sustained tax losses that other members of PHI used to offset their taxable income. Payment from PHI for the 2013 tax losses was not received by Pepco until September 2014. In Pepco's last base rate case, Case No. 9336, the Commission would normally have reduced Pepco's rate base by the amount of the tax compensation payment it received from PHI. Pepco, however, received the tax compensation after the Commission issued its order in Phase I of Case No. 9336, and the Commission in Phase II required Pepco to accrue carrying costs on the reimbursement.[178] The carrying costs compensate ratepayers for the time

[177] HCNCA Initial Brief at 40.
[178] Case No. 9336, Phase II, *Potomac Electric Power Company*, Order No. 86711, November 13, 2014, at 26.

value of the tax compensation payment that was due but not paid at the time of the last base rate case.[179] The Commission's order explained this matter as follows:

> We conclude that the 2013 tax compensation payment Pepco received in September 2014 should be reflected in Pepco's next rate case, calculated consistent with the calculation of RMA 8 in this proceeding. In this way the payment can and will be reflected on a known and measurable basis. However, we will require Pepco to increase the adjustment by including carrying costs at its currently authorized overall rate of return from the date Pepco received the payment in September 2014 through the expected order date in its next base rate case whenever it is filed. In this way an accurate known and measurable adjustment can be made and customers will receive the full value of the tax compensation payment. Thus, customers will not be disadvantaged by the timing of Pepco's rate proceedings.[180]

Pepco calculated the required carrying costs from September 2014 through October 2016, when it expected the Commission's Order to be issued in the present base rate case. In RMA 9, Pepco has amortized the carrying costs over three years, resulting in an increase to the Company's pre-tax income in this case of $1,761,000. Pepco RMA 10 reversed the effect of RMA 9 and eliminated the carrying costs on the tax compensation payment.

In its Order in Case No. 9336, the Commission acknowledged Pepco's right to present "expert testimony and legal argument" that carrying costs should not be added to the adjustment for the tax loss compensation payment that the Company received from PHI members.[181]

---

[179] *See Healthcare Council of the National Capital Area*, Initial Brief at 39.
[180] Order No. 86711 (Nov. 13, 2014), p. 26 (footnotes deleted).
[181] *Id.*

In his direct testimony, Pepco witness McGowan challenged the Commission's order to pay carrying charges on the grounds that it constituted disfavored "single issue ratemaking,"[182] which, he claimed, the Commission "only ... considered because it provided a benefit to customers." The tax compensation payment received in 2014 was "singled out for ... a carrying cost," while state and local tax payments, Mr. McGowan stated, were made "over the same time frame" but not given any special treatment.[183] Further, witness McGowan asserted that carrying charges were imposed on Pepco only because of the date the tax compensation payment was paid.[184]

People's Counsel's witness Effron opposed Pepco's attempt to avoid the carrying charges imposed by the Commission in Case No. 9336, Phase II. Witness Effron argued that, as ratepayers have been paying a return on plant additions that gave rise to the net operating losses since Case No. 9336 went into effect, "it is reasonable to give the benefit of the return on those payments from the time they were received until the rates in the present case go into effect."[185] Therefore, witness Effron recommended elimination of Pepco's proposed RMA 10, which would reverse the effect of the carrying costs accrued. He also did not oppose amortizing the carrying costs.[186] OPC witness Effron also recommended that the Company provide to the Commission notice of the compensation it received for its 2015 NOLCs as soon as that number is known.[187]

Staff witness Ostrander also rejected RMA 10, and opposed Pepco's amortization of its carrying charges. He interpreted the Commission's Order in Case No. 9336, Phase

[182] McGowan Dir. at 20-21.
[183] *Id.*
[184] *Id.*
[185] Effron Dir. at 13.
[186] *See* Effron Dir. at 13-14.
[187] Effron Dir. at 13-14.

II as requiring ratepayers to receive the "full value" of the tax compensation payment Pepco received, without reference to the timing of Pepco's rate cases. Mr. Ostrander noted that amortization would cause delay in itself, and "that compounded carrying charges would need to be applied to the delayed carrying charges to again make sure that customers are not disadvantaged."[188] He also responded to Pepco's assertion that amortization of its tax loss reimbursement was appropriate due to tax loss reimbursement being rare, by noting that Pepco has been recording net operating losses (and thus tax losses) since 2012.[189]

Witness Ostrander would therefore increase carrying charge income by $3,169,000 to reflect the total amount of carrying charges through the end of the test period, December 31, 2015.[190] Witness Ostrander stated that should the Commission amortize the carrying charge over a number of years, "it will be necessary to set up a regulatory liability account to offset rate base and reflect the unamortized balance over the amortization period."[191]

In his rebuttal testimony, Pepco witness McGowan reiterated the Company's concern that the Commission's imposition of carrying costs on its tax loss reimbursement was single issue ratemaking. He maintained "that a utility's revenue requirement is based on the utility's aggregate costs, rather than on certain specific costs related to an isolated portion of its business."[192] Isolating Pepco's tax payments could also cause the

[188] *Id.* at 44-45.
[189] Ostrander Rebuttal at 40.
[190] Ostrander Dir. at 43.
[191] *Id.* at 44.
[192] McGowan Rebuttal at 36-37.

Commission to ignore offsetting and therefore underestimate revenue requirements, Mr. McGowan claimed.[193]

Witness McGowan's rebuttal testimony also opposed Staff witness Ostrander's position that the tax payment should be credited to Pepco in one year. Witness McGowan argued instead that the Commission imposed carrying charges in order to mirror the actual tax compensation payments made to Pepco. As those payments are now known and measurable, according to witness McGowan, it does not matter if the Company records its carrying costs or not.[194]

Pepco witness VonSteuben, in his rebuttal testimony, contested Staff witness Ostrander's proposed one-year amortization of tax compensation carrying costs. "A 1 year amortization of an extremely high dollar amount ... would inappropriately provide the full credit to the customer until distribution rates are reset," according to witness VonSteuben.[195]

Witness McGowan also addressed Staff witness Ostrander's assertion that if the Commission rejected RMA 10 the Commission should also reject Pepco's position that the carrying costs should be amortized over three years. Amortization is appropriate, Pepco witness VonSteuben argued, "given the unusual and infrequent nature" of this ratemaking adjustment, and because of the high dollar amount of the adjustment.[196]

In his surrebuttal testimony, Mr. Effron stated that Mr. VonSteuben's arguments on rebuttal had not persuaded him that Pepco's accrued carrying costs should be eliminated. He reiterated that the Commission required Pepco to accrue carrying costs in

---

[193] *Id.* l at 37.
[194] *Id.* at 37-38.
[195] VonSteuben Rebuttal at 35.
[196] *Id.*

Case No. 9336 "so that customers would receive the full value of the tax compensation payment and would not be disadvantaged by the timing of Pepco's rate proceedings."[197]

b. Commission Decision

No intervenor favored Pepco's position on this issue.

The Commission also sees no persuasive argument that it should essentially nullify the relevant section of its Order in Case No. 9336, Phase II and cancel Pepco's carrying cost accruals for tax loss reimbursements. The Commission rejects Pepco's argument that assignment of carrying costs in this context is single issue ratemaking. Tax reimbursement is simply one of many operating income issues the Commission must address in the course of a base rate case, approaches to the various issues necessarily differ, and assignment of carrying charges was a reasonable and necessary response to uncertainty about the amount of PHI's reimbursement to Pepco in 2013. Pepco has not pointed to any "offsetting considerations" that the Commission has missed by imposing carrying costs on Pepco's late tax reimbursements.[198] The Commission likewise sees no reason to amortize the carrying charge amount, as Pepco requests, as Pepco received the full benefit of PHI's payment at one time, and equal treatment of ratepayers is appropriate. The Commission also wishes to avoid the possibility, referred to in Staff witness Ostrander's testimony, that compounded carrying charges could become necessary.

Therefore, the Commission declines to accept Pepco's proposed RMA 10 and makes no change to its ruling on this issue in Case No. 9336 which accepts RMA 9.

---

[197] Effron Surrebuttal at 8.
[198] *See* McGowan Rebuttal at 37.

5. RMA12: Pepco Employee Salary and Wage Increases

a. Parties' Positions

The Company proposed RMA 12 that adjusts O&M expense to annualize employee salary and wage increases which occurred in the test period.[199] Mr. VonSteuben explained that "during the test period, there was a 3.00% increase for management employees effective March 1, 2015 and a 2.50% increase for union/bargaining unit employees effective June 1, 2015."[200] Additionally, this adjustment reflects "wage increases of 2.40% for the March 1, 2016 management increase and the contractual 3.00% increase for bargaining unit employees effective June 1, 2016,"[201] which are for the post-test period. The Company argued that this adjustment was in keeping with a long-standing historical precedent for Commission approval of this adjustment beginning with Case No. 8315, and most recently approved an identical uncontested adjustment in Case No. 9336.

Staff witness Ostrander proposes to remove Pepco's two post-test year period pay increases that take place in 2016. Mr. Ostrander removed the amounts related to the 2.4% management pay increase effective March 1, 2016 and the 3% union pay increase effective June 1, 2016.[202] Mr. Ostrander testified that Pepco's pay increase adjustment does not make any offsetting reductions in payroll costs to reflect reductions in headcount and related payroll savings after December 31, 2015 for both merger-related savings and AMI-related savings.[203] Mr. Ostrander noted that Pepco's payroll increase adjustment was clearly not intended to reflect only an annualization of 2015 payroll, because if so

[199] VonSteuben Direct at 20
[200] *Id*.
[201] VonSteuben Direct at 20.
[202] Ostrander Direct at 52-53.
[203] *Id.* at 53.

Pepco would have only included its two 2015 pay increases in its adjustment,[204] which Mr. Ostrander does not challenge. Here, Pepco also annualizes two payroll increases that take place in 2016.

HCNCA supports Staff's recommendation and argues that the Commission should reject both: 1)the two post test period pay increases because the Company failed to make any offsetting reductions in payroll costs to reflect reductions in headcount; and 2)related payroll savings after December 31, 2015 for both the merger-related savings and AMI-related savings.[205]

b. Commission Decision

Consistent with previous decisions, we accept annualization of wage increases that occurred during the test period ending December 31, 2015 and the post-test period proposed increase since they are known and measurable during the rate effective period. However, we caution the Company in future rate cases that it must provide more detailed documentation demonstrating that offsetting reductions in headcount and other related payroll savings were included in its wage adjustment.[206]

6. RMA 15: Executive and Incentive Compensation

a. Parties' Positions

The Company proposed RMA15 to remove from the test period all allocated executive incentive expenses such as the Executive Incentive Compensation Plan (EICP) and the Long Term Incentive Plan (LTIP) of the top five ("Top 5") Pepco Holding executives as well as the EICP and LTIP expenses related to financial goals of other executives. However, Mr. VonSteuben in his direct testimony stated that the Company

[204] Ostrander Surrebutal at 46.
[205] HCNCA Initial Brief at 43.
[206] Order No. 87591 at 70, FN 314

disagrees with this adjustment because retention of talented and qualified top level executives is an important component of the Company's total executive compensation and are likely to continue to be so in the future.[207] In his rebuttal testimony, Mr. Von Steuben elaborated that with this adjustment "the Company removes $2.9 million expense of related to the named executives and $1.9 million related to financial goals."[208] Therefore altogether, the Company was removing $4.8 million in RMA 15[209] which Mr. VonSteuben stated would result in $2.5 million remaining in cost of service associated with customer-focused goals.[210] The Company thus noted that it reserves the right to seek recovery of these costs in future rate case filings.[211]

Staff witness Ostrander acknowledged that the Company removed $3 million of incentive expenses related to the financial goals of the Top 5 Pepco Holding executives as well as other executives. However, in addition, to Pepco's adjustment, Mr. Ostrander recommends removing an additional $1,559,531 and contends that Pepco is unable to prove that amount is tied to either financial-related or customer-focused goals.[212] Mr. Ostrander further explained that "the purpose for this adjustment is to remove incentive compensation costs that reward executives for achieving certain financial-related goals that do not provide specific quantifiable measurable benefits to customers."[213] Mr. Ostrander pointed out that Staff DR 20-6 asked the Company "to explain and provide calculations that show executive incentive costs allocated between " 'financial-related' goals and criteria and 'non-financial related/customer-focused' goals and criteria and

[207] VonSteubent Direct at 21.
[208] VonSteuben Rebuttal at 45.
[209] *Id.*
[210] VonSteuben Rebuttal at 45.
[211] VonSteubent Direct at 21.
[212] Ostrander Direct at 59.
[213] *Id.*

reconcile these amounts with Pepco's proposed adjustment of $3,001,000 which is intended to remove incentive costs tied to financial-related goals and criteria." [214] Mr. Ostrander contends that Pepco failed to provide specific documentation that would show whether their recommended adjustment was the appropriate amount of incentive expenses tied to financial-related goals.

Pepco witness Mr. VonSteuben stated that the Company agreed that costs related to financial goals should be removed. Additionally, the Company agrees that costs related to customer-focused goals should be included in the Cost of Service.[215] Mr. VonSteuben further identified the customer-focused goals include: Affirmative Action; Customer Satisfaction; Reliability; Capital Spend; NERC Compliance; and LTIP Time-based Goal.[216] Mr. Ostrander did not refute these categories as being customer-focused.

Nonetheless, Mr. Ostrander points out that even in Mr. VonSteuben's rebuttal testimony he continued to rely on the Company's response provided in Staff DR 20-6 without adding any information.[217] Therefore, Mr. Ostrander stated that he does not propose any revisions to his adjustment to reduce the Company's proposal by $1,560,000.[218]

HCNCA supports Staff's adjustment and proposed that "the Commission should direct Pepco to remove an additional $1,559,531 from incentive expenses that Pepco has failed to demonstrate are tied either to financial related or customer-focused goals."[219]

[214] *Id*.
[214] *Id*.
[215] VonSteuben Rebuttal at 44.
[216] *Id*.
[217] Ostrander Surrebuttal at 52.
[218] *Id*. at 51.
[219] Healthcare Council of the National Area Initial Brief at 45.

HCNCA further noted that removal of the $1,559,531 would be consistent with the executive costs removed in Case Nos. 9311 and 9336.[220]

b. Commission Decision

The Commission has recognized in Case No. 9311 that both the Company and ratepayers benefit from the qualified executives the Company attracts and retains through its executive incentive compensation packages. However, we believe that the Company should only be allowed to recover non-financial-related goal expenses to the extent that the Company can demonstrate that they provide benefits to Maryland ratepayers. Here the company proposed RMA 15 which reduces its revenue requirement by approximately $3 million which Pepco found to be related to financial goals of the Top 5 executives as well as the financial goals for the remainder executives. Staff argues that an additional $1.6 million should be reduced because the Company did not provide additional support documentation to show these expenses were customer-focused related. We find in Staff DR 20-6 that the Company did provide sufficient documentation delineating financial related expenses of the Top 5 as well as the other Company executives. Additionally, the Company identified the non-financial customer-focused goals and described the percentage of payouts. Therefore, we accept the Company's proposed adjustment RMA 15 that reflects a reduction in the Company's proposed revenue requirement of $3,067,000.

7. RMA 16: Supplemental Executive Retirement Program

a. Parties' Positions

The Company proposed RMA 16 to reflect a 50% reduction of the Pepco's Supplemental Executive Retirement Plan (SERP) expense incurred during the test period.

[220] *Id*.

To support this adjustment, Mr. VonSteuben cited Order No. 86441 from Case No. 9336 where the Commission accepted Staff's recommendation to disallow 50% of SERP and found that "shareholders and ratepayers both benefit from the highly qualified executives the Company says it uses SERP to attract and retain."[221] Mr. VonSteuben noted that the Company continues to disagree with any level of reduction in SERP but nonetheless offered this adjustment to be consistent with Commission precedent.

Staff witness Ostrander recommended that the Commission should remove 100% of the SERP costs and testified that there are now some new circumstances and facts to support his recommendation. First, Mr. Ostrander noted that although the Commission has adopted the 50% disallowance in Pepco's two most recent cases it acknowledged in Case No. 9336 that appropriate funding for SERP costs continues to be an evolving issue to be reviewed in future cases.[222] Second, Mr. Ostrander points out that executive and management incentive payments have increased substantially in the past two years compared to three years ago and are having an increasingly significant impact on revenue requirements.[223] Third, Staff DR 22-6 asked several questions for the Company to explain how either a 50% reduction in SERP costs in the Maryland jurisdiction or 100% removal of SERP in the Pepco's DC and Delaware jurisdictions negatively or adversely impacted the Company's ability to attract or retain executives. The Company's response merely asserts that "[m]ost peer utility companies offer SERP benefit, so it is important that Pepco offers a comparable compensation and benefit package." But the Company does not provide specific documentation to support its assertion. Pepco's response noted that "to date, the Company has not performed any analysis on how employees or new

[221] VonSteuben Direct at 22.
[222] Ostrander Direct at 62.
[223] *Id*.

recruits would react if certain benefits were offered by our competitors and no longer offered by Pepco."[224] Fourth, two neighboring jurisdictions, DC and Delaware have disallowed 100% of SERP costs. Fifth, Mr. Ostrander argues that SERP only benefits a small group of key executives and Pepco has not provided documentation to quantify any measurable benefit to customers from SERP.[225] Last, Mr. Ostrander argued that the Commission should apply the same focus – in the present proceeding - of taking measures to "ease rate shock to the fullest extent possible when it adopted a 10-year amortization of the AMI-related regulatory asset" as it did in BGE Case No. 9406 and disallow 100% of SERP in Pepco's Maryland jurisdiction.

HCNCA agreed with Staff that Pepco had not provided sufficient documentation to demonstrate that SERP-related payments to executives have provided quantifiable benefits to its Maryland customers. Therefore, HCNCA argues that Pepco's failure to provide sufficient documentation, coupled with recent decisions by DC and Delaware Public Service Commissions to disallow 100% of Pepco's SERP recovery, should cause the Commission to take a harder look at SERP.[226]

b. <u>Commission Decision</u>

Although the Company may be correct in noting that the Commission has disallowed 50% of SERP expenses in Pepco's two most recent cases, we find that Staff has astutely pointed out that there are some new circumstances to be considered. Most significantly, we find it telling that, after two neighboring jurisdictions recently disallowed 100% of Pepco's related SERP costs for DC and Delaware, the Company has

[224] Ostrander Direct at 62 citing Staff DR 22-6.
[225] *Id*. at 62.
[226] HCNCA Initial Brief at 45-46.

not performed any analysis to support its continued claim that SERP benefits help the Company to attract and retain qualified executive level talent.

In the present proceeding, Staff DR 22-6 set forth several questions in light of this changed circumstance to elicit more detailed information from Pepco to support recovery of SERP. However, as noted above, the Company failed to offer additional documentation or quantifiable information supporting its position and even responded that it had not performed any analysis on whether if it could retain or attract qualified key executives if Pepco no longer offered SERP as part of its executive compensation package. Therefore, given that the Company has not met its burden of proof and in light of similar action taken in DC and Delaware, we accept Staff's recommendation to disallow 100% SERP expenses.

8. RMA 23: Winter Storm Pax

a. Parties' Positions

The Company proposes RMA 23 which amortizes over five years the expenses for the February 2014 Winter Storm PAX preparation costs.[227] Mr. VonSteuben testified that this is consistent with the treatment of 2013 Winter Storm Preparation Costs in Case No. 9336 where the unamortized balance is included in rate base.[228]

Staff witness Dodge noted that to support Winter Storm PAX, PHI requested 400 Full Time Equivalents ("FTE's") and only received 303 FTEs. Forty FTE's were deployed in the Pepco region.[229] Mr. Dodge recommended that the allocated mutual assistance costs for the Pepco Region be reduced from 67.11 % to 13% which he calculated by dividing the 40 FTEs deployed to the Pepco Maryland Region by the total

[227] VonSteuben Direct at 23-24.
[228] *Id*.
[229] Dodge Direct at 4.

number of mutual assistance resources secured (303 FTEs).[230] He argued that the remaining costs should be allocated to the other PHI affiliates that benefited from the use of the resources. Mr. Dodge also recommended that estimated storm costs of $120,149 for Winter Storm PAX should be excluded from the amount of expenses that the Company is allowed to recover. Last, Mr. Dodge recommended that Pepco should file for review and approval by the Commission, a copy of its process and procedures for tracking, verifying, auditing and processing external mutual assistance crews and associated costs.[231]

The Company argued that the costs represented in Winter Storm Pax "are no different from the costs for the March 2013 Nor'easter that were approved in Order No. 86441. Like Winter Storm Pax, the March 2013 Nor'easter ultimately did not affect the Pepco service territory."[232] Here they point out that "the Company's method for allocating storm preparation costs for storms (like Pax and the March 2013 Nor'easter) that ultimately do not affect the Pepco region is a ratio based on the number of Pepco Maryland customers relative to the total number of customers in the entire Pepco region."[233] The Commission approved the allocation method in Case No. 9336.

b. <u>Commission Decision</u>

We have reviewed the testimony and evidence presented and find that Pepco followed its approved procedures and processes for storm preparation during Winter Storm PAX, which included using weather forecasts from two outside weather services, considering the fact that the Governor had issued a State of Emergency in advance of

[230] *Id*.
[231] *Id*. at 6.
[232] Pepco Initial Brief at 48-49.
[233] *Id*. at 49.

Pax, and participating as a member of multiple mutual assistance organizations to identify its need for assistance.[234] For these reasons, coupled with the fact that Winter Storm Pax was similar to the March 2013 Nor'easter, the Commission accepts Pepco's RMA 23.

9. RMA 24: Winter Storm Jonas

a. Parties' Positions

Consistent with the treatment of 2013 Major Storms Preparation costs in Case No. 9336, the Company recommended RMA 24 which defers and amortizes over five years the expenses incurred for January 2016 storm (a.k.a. "Winter Storm Jonas") costs.[235] Pepco witness Gausman testified that the Company incurred costs in the preparation for Winter Storm Jonas which was forecasted to severely impact Pepco service territory.[236] He noted that prior to the storm Governor Hogan issued an Executive Order declaring a state of emergency on January 21, 2016 and therefore the Company began storm preparedness activities, including obtaining external resources of 1,057 personnel and 345 vehicles and internal resources of 1,035 personnel and 260 vehicles.[237] Mr. Gausman stated that Pepco was seeking to recover the incremental costs of bringing mutual assistance crews to the area, housing and feeding those crews and sending them back to their local companies.[238]

Staff witness Dodge reviewed Pepco winter storm Jonas adjustment and raised several concerns. First, he testified that "Pepco received 315 FTE's but did not deploy any of the resources to the Pepco region, yet assigned 47.6 % (49.6%) of the costs for the

[234] Dickerson Direct at 22-26.
[235] VonSteuben Direct at 24.
[236] Gausman Direct at 22.
[237] *Id*.
[238] Gausman Direct at 23.

external resources to the Pepco region."[239] Second, Mr. Dodge noted that even though Winter Storm Jonas occurred in January 2016, the Company was still processing invoices and using invoice estimates in its revenue requirements. For instance, Pepco had indicated in Staff DR 18-11 that its Rokstad invoice was in the process of being paid and that the Emera-Maine invoice for a $246,400 was still pending.[240] Last, Mr. Dodge expressed concerns about Pepco's ability to provide comprehensive tracking, invoicing and reconciliation processes. Mr. Dodge recommended that Pepco's allocation of mutual assistance costs should be reduced from 47.6% (49.6%) to 0% and if the Company is allowed to recover any storm invoice costs then the Commission should direct it to develop and file for review and approval a methodology for equitably assigning mutual assistance costs in its service testimony.[241] In addition to the arguments made by Mr. Dodge for removing costs associated with Winter Storm Jonas, Mr. Ostrander pointed out that "an argument could be made to remove all of the 2016 post-test period related costs of Jonas storm because they are post test period and do not meet the historical test period concept.[242]

b. <u>Commission Decision</u>

Pepco rightly noted that Winter Storm Jonas was classified as a major storm and it had an impact on the region.[243] The costs incurred and deferred to the regulatory asset are similar to other major storms over the past couple of years such as the June 2012 Derecho and the October 2012 Hurricane Sandy.[244] The Commission approved storm costs in both

---

[239] Dodge Direct at 8.
[240] *Id*.
[241] *Id*. at 13-14.
[242] Ostrander Direct at 58.
[243] Pepco Initial Brief at 50.
[244] *Id*.

of these situations in Case No. 9311, Order No. 85724.[245] In the present proceeding, Pepco indicated that Governor Hogan had issued a state of emergency signaling to Pepco and other Maryland utility companies to begin preparation for a major storm, including securing mutual assistance from internal and external resources as well as other preparation activities. To minimize the impact of major storms like Winter Storm Jonas on Maryland customers, we find that recovery of Pepco's RMA 24 costs is appropriate and we therefore reject Staff's recommendation.

10. RMA 25: Synergies and Costs to Achieve Merger

a. Parties' Positions

On March 23, 2016, the Public Service Commission of the District of Columbia approved the merger between Pepco Holdings Inc. and Exelon Corporation and the merger closed shortly thereafter. "RMA 25 includes an estimate of Pepco Maryland's share of synergies relating to the Exelon-Pepco Holdings Inc. merger, net of its amortized Costs to Achieve ("CTA")[246] The Company proposed RMA 25 to represent a "reduction to test period O&M expense to reflect conditions expected to be present in the first year following the close of the merger."[247] The Company argues that in order for the customers receive benefits of merger-related savings that the Company plans to achieve during the rate effective period it must propose that the CTA be deferred and placed into a regulatory asset and amortized over five-years with the unauthorized balance in rate base.[248]

[245] *Id*.
[246] VonSteuben Direct at 24.
[247] VonSteuben Direct at 24.
[248] Pepco Initial Brief at 51.

In his rebuttal, Mr. McGowan stated that Pepco is committed to passing 100% of all net merger-related synergy savings onto its customers.[249] He further notes that the model for passing on these savings was established by the Commission in prior rate cases following Exelon's merger with Constellation Energy and Pepco's treatment of merger-related synergies follows that established model. [250] Mr. McGowan testified that the Company's proposal takes the "year one" savings and costs-to-achieve from the established analysis to make an adjustment to the Company's current revenue requirement, leaving future year's savings and costs to achieve to be handled in future rate cases.[251] This results in initial savings being matched with costs to achieve those savings. To minimize rate increase in the initial period, Pepco proposes to amortize the year one costs to achieve over five years to ensure that customers receive a net benefit.[252]

Staff witness Ostrander recommended that $4 million of pre-close merger costs be removed from total merger costs of $22 million, to start with $18 million to be amortized over 5 years. Mr. Ostrander removed the $4 million because Pepco claimed that it did not incur any merger costs or savings prior to close of the merger transaction on March 23, 2016 and that it did not include any merger costs or savings in the revenue requirement of this case.[253] Additionally, Mr. Ostrander amortized total merger costs and savings over 5 years instead of using Pepco's approach to amortize merger costs over 5 years but only use Year 1 savings. Mr. Ostrander argued that his approach "ensures that customers will receive the same levelized amount of net savings regardless of whether

[249] McGowan Rebuttal at 48.
[250] *Id*.
[251] *Id*.
[252] *Id*.
[253] Ostrander Direct at 38.

Pepco does or does not file a rate case for the next 5 years…"[254] Staff claims that the Company's method, unlike its approach, "backend loads savings and frontloads costs, while Staff's approach will ensure that customers receive the same levelized…"[255] In his rebuttal, Pepco witness McGowan testified that Mr. Ostrander's proposal "is not based on any Commission precedent, excludes known and measurable costs and attempts to use all five years of estimated savings and costs to create a 'net regulatory asset.' "[256] Montgomery County agrees with Staff witness Ostrander "that it is reasonable to allow certain reasonable estimated merger costs and savings in the revenue requirement because there is no other good alternative that will provide some immediate and deserved benefit to customers as a result of the merger."[257]

OPC witness Effron also suggests a modification to Pepco's treatment of merger synergies and CTA. Basically, Mr. Effron's approach indicates that due to the timing of the close of the merger, i.e., March 23, 2016, the "Year 1" would end March 24, 2017. Since the rate effective year begins around November 1, 2016, the rate year will contain approximately five months of Year 1 merger-related synergies and seven months of Year 2 merger-related synergies. OPC noted that "[t]his treatment makes ratepayers responsible for all of the costs which pre-date the rate effective period, but does not credit the ratepayers with any of the savings accrued during the same period."[258] OPC criticized this approach as "unfair because the timing of the costs and savings are such that the costs are front-loaded while the majority of the benefits accrue in later years."[259]

[254] *Id*. at 39.
[255] Staff Brief at 14.
[256] McGowan Rebuttal at 49.
[257] Montgomery County Initial Brief at 10.
[258] OPC Initial Brief at 17
[259] *Id*. at 17

OPC pointed out that its proposal mirrors the Commission's treatment of this issue the BGE rate case.[260]

b. Commission Decision

We support Pepco's commitment to pass 100% of all the net merger-related synergy savings to customers as soon as possible. Both Staff witness Ostrander and OPC witness Effron agree that merger synergy costs are front loaded and merger synergy savings are back-ended, and that an adjustment is needed to ensure that current ratepayers are able to realize more of the benefits within the rate effective period. We agree, as stated by Montgomery County, that Mr. Ostrander's proposal will protect ratepayers from the risk of losing the synergies if Pepco does not file a rate case every year the estimated synergies are occurring."[261] We therefore accept Staff's proposal to amortize total merger costs and savings over 5 years which will reduce the revenue requirement by $4,776,000.

11. RMA32: New Billing System Transition Costs

a. Parties' Positions

Pepco witness VonSteuben testified that "on January 5, 2015, PHI replaced the two legacy billing systems with a single, state of the art, customer relationship management and billing system."[262] The new system accommodates the daily business transactions for Pepco's regulated customers in each of its jurisdictions.[263] Mr. VonSteuben testified that the Company added supplemental Customer Service and Billing representatives in order to maintain customer service during the transition to the

---

[260] *Id*. at 17
[261] Montgomery County Initial Brief at 11.
[262] VonSteuben Rebuttal at 37.
[263] *Id*.

new system.[264] Additionally, Pepco retained some technical resources to support the system deployment.[265] The new billing system is operating and providing the Company with more timely and accurate billing as well as the ability to perform payment processing on a daily basis.[266]

Staff witness Ostrander and OPC witness Effron noted that Pepco testified its 2015 expenses included approximately $7,277,000 million of transition costs related to the new billing system and recorded in Account 903. Both Staff and OPC recommended that because these transition costs are significant and non-recurring they should be removed from test period expenses. However, they recommended two different approaches for how the Company should recover this expense. Staff witness Ostrander recommended that the $7,277,000 million be amortized over a period of five years to include one year of amortization in the test period and the remaining unamortized costs in a regulatory asset subject to future amortization.[267] OPC witness Effron recommended removing the $7,277,000 million transition expense entirely.[268]

b. <u>Commission Decision</u>

The Company identified a $16.7 million expense associated with the new billing system, of which approximately $7.3 million were non-recurring transition costs.[269] As we have done with other large non-recurring expenses such as major storm expenses, we agree with Staff's adjustment to amortize the $7.3 million over 5 years with the unamortized costs placed in a regulatory asset.

[264] *Id*.
[265] *Id*.
[266] *Id*. at 38.
[267] Ostrander Direct at 48; Ostrander Surrebuttal at 41.
[268] Effron Direct at 18-19; Effron Surrebuttal at13
[269] VonSteuben Rebuttal at 40.

12. RMA 33: Legacy Billing System Transition Costs

a. Parties' Positions

The Company's response in an OPC DR 10-6 indicated that Pepco Maryland's expense associated with the legacy customer information system in 2015 was $1,382,000. Mr. VonSteuben in his rebuttal testimony clarified that this legacy billing expense will decrease to $107,000 in 2016, and an additional $562,000 of the original $1,382,000 will continue to support other Company IT initiatives."[270] Thus, the net reduction to expense is $713,000, which Mr. VonSteuben proposes to establish as a regulatory asset being amortized over five years and the unamortized balance be placed in the Company's rate base.[271]

Staff witness Ostrander proposes that the $713,000 remaining amount of legacy billing be written off because customers should not be required to pay for two billing systems at the same time and the $713,000 is a relatively minor amount.[272] OPC witness Effron agreed with the Staff but offered different rationale. Specifically, Mr. Effron noted that Pepco's response to OPC DR 10-5 identified $8.4 million of legacy Customer Information System ("CIS") expenses are presently being recovered in rates based on a test year consisting of the 12 months ended September 30, 2013 in Case No. 9336. By, 2015, these expenses associated with the legacy billing system had decreased to $1,382,000 and will decrease further to $107,000 as noted above.[273] Mr. Effron points out current rates already include a level of legacy billing system expenses that Pepco is

[270] Effron Surrebutal at 12.
[271] VonSteuben Rebuttal at 43.
[272] Ostrander Surrebuttal at 43.
[273] Effron Surrebuttal at 14.

no longer incurring.[274] He further argues that "the Company is seeking to establish a regulatory asset for transition costs that were not recovered in rates but does not want to credit customers for costs that have been and are being recovered in rates no longer being incurred."[275] For these reasons, OPC finds that there is no justification to create the regulatory asset proposed by the Company and to allow it would result in double recovery for the Company.[276]

b. Commission Decision

We accept the position of Staff and OPC to disallow the Company from establishing a regulatory asset for these continued legacy billing system costs and to allow cost recovery on that asset in the future. Mr. VonSteuben indicated in his testimony that Pepco utilized the legacy billing system in a "read only" mode during the system transition to the new customer billing system and would maintain it for the foreseeable future because it contains key historical information.[277] Since the new billing system now performs all of main transactions to support Pepco customers and the Company is currently collecting in rates for legacy billing system expenses that are no longer being incurred, we agree that allowing the Company to establish a regulatory asset and to recover that asset in the future may result in double recovery.

13. Restated Deferred Storm Costs

a. Parties' Positions

OPC witness Effron testified that the Company's test year rate base included a

[274] *Id*.
[275] *Id*.
[276] *Id*.
[277] VonSteuben Direct at 41.

Regulatory Asset balance of $14,035,000, which consists almost entirely of unamortized deferred storm damage costs incurred between 2010 and 2013.[278] He noted that the deferred storm costs are being amortized over five years with $9.2 million of the amortization reflected in the test year for this proceeding.[279] Mr. Effron pointed out that the amortization of storm damage costs for three past storms will be complete during 2017 (the rate effective period). Specifically, the February 2010 deferred storm coast will be complete in April 2017; the amortization of the January 2011 deferred storm costs will be complete in July 2017 and the amortization of the Hurricane Irene (August 2011) deferred storm costs will be complete in July 2017. Mr. Effron recommended that the Company's amortization expense "will be significantly less than the amortization recorded during the 2015 year" and therefore it should be reduced to the remaining balance as of the date when rates established in this case will go into effect.[280] Mr. Effron warned that, if the actual amortization recorded in the twelve months ended December 31, 2015 is not modified, the Company will over recover the remaining balance of deferred storm damage costs if the rates in this case remain in effect beyond July 2017.[281] Mr. Effron recommended that the balance of these deferred storm costs remaining as of October 31, 2016 be amortized over three years.

In his rebuttal, Mr. VonSteuben argued that OPC's adjustment to restate approved deferred storm amortization costs "undermines every single Commission order" in which the following regulatory assets were granted: February 2010 storm, January 2011 storm

[278] Effron Direct at 14.
[279] *Id*.
[280] Effron Direct at 15.
[281] *Id*.

and Hurricane Irene."[282] The Company contended that the Commission in each of its orders approving the deferred storm damage costs found: 1) that the Company had prudently incurred the expense; and 2) the Company has a right to recover the deferred storm damage costs over a time period that has been deemed reasonable. Mr. VonSteuben pointed out that OPC's adjustment would effectively lengthen recovery of these expenses by three years, which moves away from what the Commission has deemed as a "reasonable" time.

b. <u>Commission Decision</u>

We have, as correctly argued by the Company, fully adjudicated the deferred storm damage costs for each of the three storms being raised by OPC and found that the expenses in each case were prudently incurred and that the Company was entitled to recover the expense over a reasonable period of time which was determined to be five years. However, we accept OPC's adjustment because it will protect ratepayers from over-recovery.

14. <u>NOLC Adjustment</u>

a. <u>Parties' Positions</u>

The Internal Revenue Service ("IRS") rules permit Pepco to accumulate federal tax losses in an accounting balance referred to as a Net Operating Loss ("NOL"). The Company's NOL that can be used in some other tax reporting periods in the future as an offset to taxable income is referred to as the Net Operating Loss Carryforward ("NOLC" or "NOL"). In December 2015, at the end of the test year in this case, Pepco offset federal

[282] VonSteuben Direct at 27-28.

back taxes for the years 2003-2011 with $18,585,000 of its NOLC balance ("the IRS Settlement").

Pepco witness McGowan testified on cross-examination that the IRS Settlement was "hopefully" a once in a generation event, eliminating eight years of Pepco's back taxes.[283] Further, he stated that the reduction in rate base resulting from the IRS Settlement will continue into the rate effective period, will not be reversed, and will be known on "day one" that the new rates go into effect.[284]

Mr. McGowan stated in his rebuttal testimony, however, that the IRS Settlement "caused an immediate reduction in the NOL balance in December 2015." As this "was a one time reduction that will not occur in future years," witness McGowan concluded that "it would be improper to use this reduction to adjust the Company's average test year rate base."[285] Adjustments to average test year rate base should only occur to account for ongoing or forecasted reductions, according to witness McGowan.[286] The Company's initial brief repeated witness McGowan's assertion that "one time" reductions, such as resulted from the IRS Settlement, should not be used to reduce "average" ongoing revenue requirements.[287] OPC witness Effron, however, proposes to reduce Pepco's cumulative NOLC balance by $18.6 million (reducing the average test year to the closing balance) resulting in a corresponding reduction in rate base and a $2 million reduction in the revenue requirement."[288] OPC reasoned that, as it is agreed that the amount of the

[283] Tr. at 94.
[284] *Id.* at 94-95; 98.
[285] McGowan Rebuttal at 38.
[286] *Id.*
[287] Pepco In. Br. at 38.
[288] OPC In. Br. at 14.

IRS Settlement is known, the closing balance in rate base should reflect the entire IRS Settlement.[289]

b. Commission Decision

We agree with People's Counsel that the non-recurring IRS Settlement amount should be fully reflected in Pepco's NOLC account and therefore in the closing balance of Pepco's rate base. The amount of the IRS Settlement is known, and its effects will continue through the rate effective period of the current case. Our treatment of this issue is consistent with our treatment of the payment for Pepco's tax losses made by PHI in 2014. In each case, Pepco was a party to a large transaction that impacted its financial picture. In each instance we find that it is just and reasonable to pass the benefit of those transactions on directly to ratepayers, and therefore we reduce the revenue requirement by $2,000,000.

15. Overtime Adjustment

a. Parties' Positions

Staff witness Ostrander recommended an adjustment to normalize overtime pay expenses due an unexplained overtime pay increase in the Company's revenue requirement. Mr. Ostrander explained that he used the six year period from 2010 to 2015 and applied the same method of averaging overtime costs over a six year period, net of storm costs, that the Commission adopted in Case No. 9286 when Pepco included significant unexplained payroll expenses.[290] Mr. Ostrander also mentioned that he

[289] *Id.*
[290] Ostrander Surrebuttal at 52.

proposed a similar adjustment in Pepco Case No. 9311 to remove significant unexplained overtime payroll increase and the Commission adopted the adjustment.[291]

Pepco witness VonSteuben acknowledges that there had been some changes in the Company that would cause additional overtime expense including increased inspection and maintenance associated with the inspection program in Case No. 9240 as well as RM43 compliance.[292] Mr. VonSteuben agreed that normalization should be use for setting rates when an expense has been volatile over a period of years.[293] With regard to the overtime payroll expenses he stated that he continued to support the test period level of overtime expense proposed by the Company but with the changes in the Pepco's maintenance programs since 2012, a three year normalization of overtime expenses would be more appropriate that a six-year period.[294]

b. Commission Decision

Given that the Company acknowledges that there have been some changes which would contribute to the significant increase in overtime expense and does not strongly oppose Mr. Ostrander's normalization approach, we will accept OPC's adjustment using the 2010 to 2015 six-year normalization approach as previously adopted by this Commission.

16. Outside Legal and Professional Expenses

a. Parties' Positions

Staff witness Ostrander stated that he removed $250,000 of outside legal expenses as a placeholder subject to true-up because Pepco has not provided information that was

[291] Ostrander Surrebuttal at 52.
[292] VonSteuben Rebuttal at 19.
[293] *Id*. at 18.
[294] *Id*. at 19.

requested in Staff DR 17-14 to show that Pepco revenue requirement did not include any merger-related legal expenses.[295] Staff DR 17-14 asked the Company to provide specific information about the amount of outside and in-house legal expense by account used in broad categories. Mr. Ostrander stated that Pepco's response did not provide the requested information. Therefore, Mr. Ostrander argued that the Company has the burden of proof which it did not meet. He also noted that the Commission has in two previous cases adopted reduced outside legal fees that appeared to be excessive. Mr. Ostrander does not argue in this proceeding that the legal fees are excessive but he contends that some of the legal fees could be non-recurring if they are merger-related. Since Pepco did not provide sufficient responses to Staff DR 17-14, Mr. Ostrander proposed a $250,000 reduction in legal expenses.

Staff also proposed removal of $1,000,000 of outside professional expenses as a place holder subject to true-up because again Pepco did not provide sufficient information on a timely basis.[296] Specifically, Mr. Ostrander indicates that he requested information that would allow him to compare outside professional expenses for 2014, 2015 and 2016 to help identify any unusual, excessive or nonrecurring outside professional expenses.[297]

The Company argued that it has provided Staff with a great deal of information on outside professional expenses including a list of all vendors that had test period level expenses of at least $100,000.[298] Mr. Ostrander noted that the Company did in fact identify when responding to Staff DR 39-7 total merger related expenses of $882,206

[295] Ostrander Direct at 65.
[296] *Id.* at 66.
[297] *Id.*
[298] Pepco Initial Brief at 56.

with $222,985 related to Pepco Maryland expenses.[299] The Company indicated that they considered these expenses as underlying support for its proposed reduction of $1,000,000 in outside consulting expenses.

b. Commission Decision

The Company has the burden of proof in recovering outside legal services in base rates. Pepco cited a 2010 Commission decision allowing recovery of some outside legal fees[300], but in that case, the Commission wrote that "recovery of outside legal fees is not assured in the future, unless cost-justified by Pepco in comparison to staffing the work in-house."[301] The Commission has rejected outside legal expenses in recent Pepco cases.[302] We reaffirm today that we do not generally allow recovery of outside legal expenses unless there is good justification, and Pepco did not persuade us that we should do so in this case. Therefore, the Commission will accept Staff's $250,000 reduction for outside legal expenses.

17. RMA 28: Cash Working Capital (CWC)

The Company proposed RMA 28 to adjustment the Company's cash working capital allowance to reflect the use of adjusted cost of service amounts, including proforma interest expense. Cash working capital is generally calculated with a lead lag study. The lead lag study is recognized as an accurate method of determining cash working capital because it is based on a detailed analysis of company specific data. This method estimates the timing difference between 1) when the company renders and receives payment for its services (revenue lag) versus 2) when the Company incurs and

---

[299] Ostrander Surrebuttal at37.
[300] Pepco Initial Brief at 55-56.
[301] Order No. 83516 at 30.
[302] Case 9311, Order No. 85724 at 64; Case No. 9286, Order No. 85028 at 68.

pays its operating expenses (expense lag). In the present proceeding, we have determined that the recalculated cash working capital reduces the revenue requirement by $558,000.

18. Allowance for Funds Used During Construction (AFUDC)

AFUDC is computed by multiplying the rate of return authorized by the Commission in this case by the average balance of test period Construction Work in Progress ("CWIP") accruing AFUDC. Our adjustment to AFUDC relates to the Commission's allowance for Pepco's RMA 2 in this proceeding. The adjustment reduces the revenue requirement by $3,985,000.

19. Interest Synchronization

Interest synchronization is the procedure that is used to adjust the Company's interest deduction for State and federal income taxes which results from various ratemaking decisions. The interest deduction is calculated by multiplying the rate base by the weighted cost of debt. The resulting interest is then multiplied by the State and federal income tax rates to arrive at the operating income adjustment. Based upon the ratemaking decisions in this Order, the appropriate interest synchronization results in a decrease in the revenue requirement of $769,000.

C. Initiate Another Grid Resiliency Plan

1. Parties' Positions

In addition to the revenue requirement, Pepco is requesting approval for an additional $31.6 million of new incremental investments through the Grid Resiliency Program that is consistent with the current program approved on Case No. 9311 with a slight expansion.[303] The Company wants to continue the program with new incremental investments in feeder improvements and in recloser technology to further improve and

[303] McGowan Direct at 8.

accelerate reliability performance during both normal weather as well as during storm conditions.[304]

The Company initially implemented the Grid Resiliency Program in 2014 and 2015, in which Pepco was authorized to spend $24 million to accelerate the hardening of 24 distribution feeders. The Company reported that the work on these feeders was fully completed and placed in service by the end of 2015.[305] Company witness McGowan testified that as a result of the initial Grid Resiliency Program the Company has experienced SAIFI improvement of 73% and SAIDI improvement of 97% on these feeders including all outage events.[306] In the present case, the Company is proposing to initiate another GRP and perform work on an additional 24 feeders at a capital cost of $24.0 million, and install 1,000 single phase reclosing devices at capital cost of $7.6 million for a total request of $31.6 million. The Company noted that the work for the GRP extension would be performed in 2017 and 2018.[307]

Staff recommended that the Commission not approve the proposed GRP for 2017-2018 and recommends that the GRC surcharge should also be eliminated.[308] Specifically, Staff commented that the GRP does not appear to have been well planned or executed. Staff witness Shelton commented that project managers typically are expected to manage their project costs within plus or minus 10% of the estimated budget. Here, Ms. Shelton noted that since there were large differences between the actual costs and the approved estimated costs, the Company's recovery for 2014 GRP should be limited.[309]

[304] *Id*.
[305] *Id*.
[306] McGowan Direct at 9.
[307] *Id*.
[308] Shelton Direct at 8.
[309] *Id*.

Specifically, Staff argued that Pepco's recovery for 2014 GRP be reduced by $1,365,353, the amount of expenditures that exceeded 10 % above their estimates.

Montgomery County agrees with Staff witness Shelton's position and determined that while the County advocates for improved reliability and resiliency it does not believe that the GRP extension is the only way to achieve that goal.[310] The HCNCA also agrees with Staff and Montgomery County. HCNCA argued that the GRC was intended to be a temporary, according to the task force that proposed it.[311] "The GRC should not be continued on an indefinite basis; to do so would make a mockery of the representations that were originally offered to justify it."[312]

2. Commission Decision

We initially approved the Grid Resiliency Program and related surcharge as a response to the public outcry over wide spread power outages throughout the state of Maryland caused by the Derecho storm which exposed the vulnerability of the Maryland's electric distribution system. The Governor appointed the Grid Resiliency Task Force (GRTF) specifically to deal with this crisis, and it recommended that such reliability spending surcharges may be appropriate.[313] It was that backdrop that the Commission approved the GRC. Permitting concurrent cost recovery for reliability investments was to encourage our utilities to accelerate upgrades to their infrastructure and address the immediate need to commit resources to improve the electric distribution system's reliability and resiliency. We find it was effective in doing that. Given the improvements in reliability and resiliency testified to by Mr. Gausman and the fact that

[310] Montgomery County Initial Brief at 3-4.
[311] HCNCA Initial Brief at 46.
[312] HCNCA Initial Brief at 46.
[313] Order No. 85724 at 133-164

on cross examination Mr. Gausman testified that none of the projects being proposed are needed to meet reliability standards in COMAR[314], we reject the Company's proposal for another Grid Resiliency Plan . Additionally, we will not disallow the greater than 10% budget overruns that Staff recommended.

D. <u>Cost of Capital</u>

Pepco's cost of capital, or overall rate of return ("ROR"), consists of its return on equity ("ROE") and return on the cost of long-term debt. The ROR is the rate at which the Company has an opportunity to earn a return on its investment in order to attract and retain investors in a competitive market. While the cost of debt can be directly observed, as debt instruments are generally issued subject to fixed, predetermined interest rates, Pepco's return on equity, however, requires more analysis. Pepco is now a subsidiary of Pepco Holdings LLC and does not issue its own stock, so the market-based rate of return on equity is unobservable. Instead, the Company's ROE is calculated using several methodologies, some of which require the use of a group of companies deemed comparable in risk to Pepco—i.e., a proxy. The resulting ROE should comport with requirements of *Bluefield*[315] and *Hope*[316], wherein the Supreme Court ruled that a utility's rate of return on equity must be comparable to returns earned on investments of similar risk, sufficient to ensure confidence in the Company's financial integrity, maintain and support the Company's credit, and attract investment in its securities.

The Commission looks to the analyses of the parties, which vary in methodology and approach. Notably, different analytical approaches can impact ROE in different

---

[314] Volume III, Tr. p. 648:11-22

[315] *Bluefield Waterworks & Improvement Co. v. Pub. Serv. Comm'n of W. Va.*, 262 U.S. 679, 692-93 (1923).

[316] *Fed. Power Comm'n v. Hope Natural Gas Co.*, 320 U.S. 591, 603 (1944).

ways. While no party opposed Pepco's cost of debt, the parties presented differing estimations regarding an appropriate ROE. A discussion of those analyses and the parties' proposed ROEs and RORs follows.

1. Company Position

Pepco witness Hevert[317] proposed a return on Pepco's common equity ranging from 10.00% to 10.75%, with a final recommendation of 10.60%.[318] Mr. Hevert based his ROE recommendation, in part, on data from 23 proxy companies he selected from those identified as electric utility companies by the investment research firm, Value Line.[319] Furthermore, all of his proxy companies had investment grade senior bond or corporate credit ratings from S&P.[320] The list included both vertically integrated companies and companies that engaged only in electric transmission and distribution.[321]

In calculating Pepco's ROE, Mr. Hevert applied five analytical approaches: two variants of discounted cash flow ("DCF"); two variants of the capital asset pricing model ("CAPM"); and a "bond yield plus risk premium" ("RP") approach. He also considered additional factors, such as capital market conditions and Pepco's flotation costs.[322]

---

[317] Mr. Hevert previously testified on behalf of Pepco in the Company's last rate case, Case No. 9336, regarding the Company's cost of capital.

[318] Hevert Direct at 52.

[319] Mr. Hevert excluded from his proxy list: companies that did not consistently pay quarterly cash dividends; companies whose regulated operating electric income over the three most recently reported fiscal years was less than 60% of total regulated operating income; and companies known to be involved in a merger or other significant transaction. He also expressly excluded Exelon Corporation, PHI's new parent company. Hevert Direct at 11-12.

[320] All of Mr. Hevert's proxy companies had been covered by at least two utility industry equity analysts. Hevert Direct at 12-13.

[321] Mr. Hevert commented that there are no "pure play" state jurisdictional electric transmission and distribution ("T&D") companies to be used as a proxy for Pepco in Maryland. Hevert Direct at 12.

[322] Hevert Direct at 15.

Mr. Hevert began his analysis with the constant growth DCF method, which applies the general DCF theory that a stock's current price represents the present value of all its expected future cash flows—namely, its dividends and growth—and assumes several constant elements.[323] He used stock price data from multiple periods, expected dividend yield data, and earnings per share ("EPS") growth estimates from Zacks, First Call, and Value Line.[324] He reported the mean and mean high results from his calculations but excluded mean low results, arguing that they were "well below" a reasonable ROE estimate and thus highly improbable.[325] Mr. Hevert's unadjusted constant growth DCF results produced a mean range of 9.19% to 9.27% and a mean high range of 9.95% to 10.02%.[326]

Mr. Hevert gave less weight to his constant growth DCF results because, in his view, the model's underlying assumptions might not reflect current market conditions.[327] Instead, he included a multi-stage DCF approach that he believed could better account for different growth rates over three distinct stages of growth—near, intermediate, and long-term growth.[328] Mr. Hevert's unadjusted multi-stage DCF analysis resulted in a mean

[323] *Id.* at 16.
[324] *Id.* at 17, 21.
[325] *Id.* at 21.
[326] *Id.* at 19.
[327] *Id.* at 20. Mr. Hevert testified that recently observed low payout ratios were unlikely to remain constant. He also noted that under the constant growth DCF model, relatively low dividend yield should be associated with relatively high growth rates. Accordingly, "[i]f those relationships do not hold, the model's results should be viewed with some caution." *Id.* at 21.
[328] *Id.* at 23. In the multi-stage DCF model, cash flow over the first two stages comprised the expected dividend data. In the third stage, cash flow equaled both the stock's dividends and its "terminal price", which Mr. Hevert defined as the "expected price at which the stock will be sold at the end of the period…." *Id.* at 22. He calculated the terminal price by dividing the expected dividend by the difference between the cost of equity (i.e., discount rate), and a long-term expected growth rate of 5.35%, which was based on the real Gross Domestic Product growth rate of 3.25% for the period from 1929-2014 plus inflation at a rate of 2.04%. *Id.* at 22, 24-25.

low range of 9.72% to 9.94%, a mean range of 10.19% to 10.41%, and a mean high range of 10.72% to 10.94%.[329]

Mr. Hevert also performed two versions of the CAPM, which added a risk premium to a basic risk-free return to compensate investors for any systematic or non-diversifiable risk associated with the security.[330] Mr. Hevert's risk-free return for his CAPM analysis was based on three different long-term Treasury estimates.[331] He developed forward-looking market risk premiums and used beta coefficients to gauge non-diversifiable risk—that is, the relative volatility of company stock returns with respect to the overall market.[332] Mr. Hevert calculated and reported mean market risk premiums ranging from 9.65% to 11.88%.[333]

In addition to the standard CAPM, Mr. Hevert also evaluated Pepco's common equity requirements under the empirical form of the CAPM analysis ("ECAPM"). The ECAPM contained a 75% weighting of the product of the beta coefficient and the calculated market risk premium, plus a 25% weighting of the market risk premium by itself, unaffected by the beta coefficient.[334] The ECAPM purportedly adjusted the CAPM

---

[329] *Id.* at 26.
[330] *Id.* at 28. The CAPM formula contains four components and is expressed as: $k = r_f + \beta(r_m - r_f)$, where k is the required ROE for a security, β is the Beta coefficient for that security, r_f is the risk-free rate of return, and r_m is the expected return on the market as a whole. Regarding r_f, a stock that tends to respond less to market movements has a Beta less than 1.0, while stocks that tend to be more volatile than the market have Betas greater than 1.0. *Id.* at 28-29.
[331] Mr. Hevert used (1) the current 30-day average yield of 2.96% on 30-year U.S. Treasury bonds, (2) the near-term projected 30-year Treasury yield of 3.45%, and (3) the long-term projected 30-year Treasury yield of 4.65%. *Id.* at 30.
[332] For his market risk premium estimates, Mr. Hevert used a DCF analysis to estimate the market required return by combining expected dividend yields with the projected earnings growth rates, and then subtracted the current 30-year Treasury yield. *Id.* at 30-31.
[333] *Id.* at 32.
[334] *Id.* at 29. The ECAPM formula can be expressed as: $k_e = r_f + 0.75\beta(r_m - r_f) + 0.25(r_m - r_f)$. *Id.*

results upward for low beta stocks.[335] His ECAPM model produced a mean ROE range of 10.63% to 12.50%.[336]

Mr. Hevert applied one final risk premium approach to evaluate Pepco's common equity requirements—the bond yield plus risk premium method. Like the CAPM approach, the cost of equity under this method comprised a base rate (i.e., bond yield) plus an additional amount to account for risk.[337] Mr. Hevert used a base rate consisting of the current long-term 30-year Treasury yield and added an "equity risk premium" which he calculated based on historical, authorized returns for electric utilities from January 1, 1980 to January 15, 2016.[338] Mr. Hevert calculated an ROE range between 10.04% and 10.47%.[339]

Following his ROE analysis, Mr. Hevert then made several adjustments to his ROE range to further account for Pepco's specific business risks. First, he added twelve basis points to Pepco's ROE to account for flotation costs—namely, those costs associated with PHI's two most recent issuances of common stock.[340] Mr. Hevert explained that the flotation costs factored into the Company's capital costs and were incurred over time and mostly prior to the test year.[341] Mr. Hevert reasoned that common equity remained on the Company's balance sheet indefinitely and, therefore, the return on the equity would be subject to dilution in perpetuity.[342]

---

335 *Id.* at 29-30.
336 *Id.* at 32.
337 *Id.* at 32-33.
338 Mr. Hevert defined the Equity Risk Premium as the difference between the historical Cost of Equity, or ROE, and the then-prevailing long-term Treasury yields. *Id.* at 33.
339 *Id.* at 35.
340 A basis point is 0.01 percent.
341 Hevert Direct at 36. Mr. Hevert noted that PHI incurred $22,736,874 in cumulative issuance costs for its two most recent issuances. Hevert Direct, Schedule RBH-7.
342 *Id.* at 37.

Mr. Hevert also made adjustments for a changing capital market environment and, more specifically, the possibility of rising interest rates after the Federal Reserve completed its Quantitative Easing initiative in 2014 and subsequently raised the Federal Funds rate in December 2015. He explained that in view of the Federal Reserve's ongoing rate normalization process, investors could perceive greater opportunity for economic growth, which could lead to increases in growth rates, interest rates and dividend yields. This, in turn, would produce higher ROE estimates under a DCF model. He also discussed potential increases in equity market volatility following the Federal Reserve's conclusion of its quantitative easing policy, testifying that near-term market volatility recently increased in 2015, and equity risk is currently higher than historical average levels.[343] Mr. Hevert concluded that these factors, among others, reflected changing market conditions.[344]

With regard to the Company's capital structure, Mr. Hevert calculated the average capital structure for each of his proxy companies over the last eight quarters. The overall mean common equity ratio for the proxy companies was 52.78% (with a range of 46.50% to 66.01%) and the mean long-term debt ratio was 47.22%.[345] He therefore concluded that Pepco's proposed capital structure of 49.55% common equity and 50.45% debt was appropriate and consistent with the capital structures of the proxy companies.[346]

In his Rebuttal Testimony, Mr. Hevert updated his calculations for his DCF, CAPM, and RP cost of equity analyses with data through June 30, 2016. He applied those analyses to a revised version of his proxy group as well as a "combined proxy

[343] *Id.* at 43-44.
[344] *Id.* at 50.
[345] *Id.* at 51.
[346] *Id.* at 52.

group" that consisted of the proxy companies proffered by the opposing parties' witnesses.[347] He also refuted the analyses and recommendations of the other parties' witnesses.

Lastly, Pepco witness Kevin M. McGowan stated that Pepco is requesting an overall rate of return of 8.01%, based on Pepco's capital structure and Mr. Hevert's cost of capital analysis.[348] Mr. McGowan stressed that the Company's capital structure was calculated in the same manner accepted by the Commission in the Company's previous rate cases. He stated that Pepco's 49.10% common equity ratio was within the Company's target 50% and was further consistent with industry practices and averages.[349]

2. <u>Other Parties' Positions</u>

a. AOBA

AOBA witness Bruce Oliver adopted Pepco's proposed capital structure but noted that it was neither reflective of Pepco's average capital structure during the test year nor indicative of what Pepco would employ during the rate effective period.[350]

Mr. Oliver criticized Mr. Hevert's recommended ROE as being overstated and driven by analyses and scenarios that failed to reflect costs for risk investments comparable to Pepco's distribution utility operations.[351] He criticized Mr. Hevert's CAPM and ECAPM analyses as being inappropriately high and challenged Mr. Hevert's bond yield plus risk premium analysis.[352]

---

[347] *Id.* at 101.
[348] McGowan Direct at 10.
[349] *Id.* at 10-11. Mr. McGowan explained that to maintain a minimum equity ratio within the range of 49% to 50%, PHI makes equity contributions into Pepco while Pepco makes dividend payments to PHI.
[350] B. Oliver Direct at 10-11.
[351] *Id.* at 13. Mr. Oliver observed that Mr. Hevert's ROE recommendations before various regulatory commissions over the last three years have been, on average, 77 basis points higher than the actual ROEs approved by those commissions. *Id.* at 15.
[352] *Id.* at 16-17.

With regard to Mr. Hevert's DCF analysis, Mr. Oliver chided Mr. Hevert for introducing the multi-stage DCF approach, which he had not previously employed in Pepco's prior rate cases. Mr. Oliver argued that this additional approach offered little, if any, additional insight into the costs of comparable risk investments.[353] He likewise criticized Mr. Hevert for asymmetrically removing his "mean low" and "median low" ROE estimates from his results, which biased his ROR recommendation upward.[354]

Mr. Oliver performed his own DCF and CAPM analyses on Mr. Hevert's proxy group and averaged the two results.[355] This average served as the lower bound of his ROE range. For the upper bound, Mr. Oliver took Mr. Hevert's ROE recommendation, eliminated the 12-point flotation cost adjustment, and further adjusted the ROE downward to reflect the average adjustment made by sister regulators in recent proceedings, an adjustment he referred to as a "Regulators' Adjustment Factor".[356] Mr. Oliver established an ROE range from 8.76% to 9.71%.[357] Based on this range, Mr. Oliver recommended an ROE of 9.25%, which corresponded closely with the average of witness Hevert's mean constant growth DCF results.[358]

Mr. Oliver urged the Commission to reject Pepco's request for flotation costs and testified to several shortcomings in Mr. Hevert's argument for the adjustment. He pointed out that post-merger Pepco will no longer issue publicly traded common stock. He further argued that a 12 basis point upward adjustment would result in over-recovery

[353] *Id.* at 14.
[354] *Id.* at 21.
[355] *Id.* at 25-26.
[356] *Id.* at 26.
[357] *Id.* at 25-26.
[358] *Id.* at 26.

insofar as it would significantly exceed any flotation costs experienced by Mr. Hevert's proxy companies in recent periods.[359]

Mr. Hevert analyzed Bruce Oliver's recommended ROE estimates for Pepco and challenged Mr. Oliver's "Regulators' Adjustment Factor", his DCF analysis, and the CAPM and market risk premium estimates.[360] Mr. Hevert responded to Mr. Oliver's criticisms regarding his methodologies, defending his DCF results and inclusion of the multi-stage DCF model.[361] Mr. Hevert also disagreed that there was no need for a flotation cost adjustment, arguing that excluding the costs would lead to drops in growth rate and ROE. He further maintained that Exelon's acquisition of Pepco did not negate the need to recover these costs.[362]

Mr. Oliver submitted Surrebuttal Testimony addressing, among other things, Mr. Hevert's objection with regard to the "Regulators' Adjustment Factor". Mr. Oliver also defended his CAPM analysis and repeated his objection to Pepco's request for a flotation cost adjustment, arguing that the request was unsupported under PHI's cost allocation manual.[363]

b. HCNCA

HCNCA witness Baudino recommended that the Commission approve a ROE of 9.00%.[364] He offered no comment on Pepco's proposed capital structure.

With regard to the market environment, Mr. Baudino pointed out that interest rates have generally declined since 2008, and the U.S. economy is currently in a low

---

[359] *Id.* at 24.
[360] Hevert Rebuttal at 23.
[361] *Id.* at 26.
[362] *Id.* at 32.
[363] B. Oliver Surrebuttal at 7-8.
[364] Baudino Direct at 3.

interest rate environment that favors lower risk regulated utilities.[365] He cautioned the Commission against raising ROE in anticipation of higher interest rates that may or may not occur.[366] Additionally, Mr. Baudino observed that, as a matter of financial health and overall risk, the Company was low cost and low risk with strong A/A senior secured bond ratings. He further reasoned that the completion of the Pepco-Exelon merger "has removed substantial uncertainty from Pepco's credit outlook."[367]

Mr. Baudino performed both constant growth DCF and the CAPM analyses in estimating his ROE recommendation. His proxy group comprised 12 electric companies with "A" or better bond ratings that further had at least 50% of their revenues from electric operations.[368] For his DCF analysis, Mr. Baudino calculated an average dividend yield for his proxy group and in addition to expected growth rates, which he calculated using two different methods.[369] Mr. Baudino's mean DCF results ranged from 8.64% to 8.87%.[370] For his CAPM analysis, Mr. Baudino developed both forward-looking and historical-based CAPM ROEs. He used median growth rate estimates, an adjusted historical market risk premium,[371] and a risk free rate..[372] Mr. Baudino's forward-looking CAPM results ranged from 8.03% to 8.28%, while his historical CAPM results ranged from 6.02% to 7.49%.[373]

---

[365] *Id.* at 5, 8, 10.
[366] *Id.* at 10.
[367] *Id.* at 13.
[368] Mr. Baudino excluded companies that no longer paid dividends as well as companies that were either recently or currently involved in significant merger transactions. Baudino Direct at 19-20.
[369] *Id.* at 21-24.
[370] *Id.* at 25.
[371] *Id.* at 29-30. Mr. Baudino adjusted his historical market risk premium to account for substantial growth in the price/earnings ("P/E") ratio for stocks from 1980 through 2001. Mr. Baudino did not believe that P/E would continue to increase in the future. *Id.* at 30.
[372] *Id.* at 30.
[373] *Id.* at 31.

Mr. Baudino's recommended ROE of 9.0% placed Pepco at the top of his DCF ROE range, rounded upward. He did not rely on his CAPM model but, instead, used it to further support the reasonableness of his ROE recommendation.[374]

Mr. Baudino raised several challenges to Pepco witness Hevert's ROE analyses, which in his view inflated Pepco's investor-required return.[375] He criticized Mr. Hevert for including in his proxy group three companies that are currently involved in significant merger activities.[376] He also criticized Mr. Hevert for ignoring his own constant growth DCF results, which served to overstate his recommended ROE.[377] With regard to Mr. Hevert's multi-stage DCF model, Mr. Baudino found no support for Mr. Hevert's underlying assumptions and concluded that investors were not likely to use the model.[378] Mr. Baudino also critiqued Mr. Hevert's CAPM analysis[379] and disagreed with the applicability of Mr. Hevert's ECAPM model, arguing that investors were unlikely to use this formulation to "correct" CAPM returns for electric utilities.[380]

With regard to Mr. Hevert's bond yield risk premium analysis, Mr. Baudino questioned the wisdom in relying on such an approach, referring to it as a "blunt instrument" for estimating ROE and suitable only for providing "general guidance on the current authorized ROE for a regulated electric utility."[381] Lastly, as with the other parties save Pepco, Mr. Baudino recommended against an adjustment for flotation costs, reasoning that current stock prices likely already account for such costs.[382]

---

[374] *Id.* at 32.
[375] *See* Baudino Direct at 3.
[376] Baudino Direct at 35.
[377] *Id.* at 35-36.
[378] *Id.* at 38.
[379] *Id.* at 40-42.
[380] *Id.* at 42.
[381] *Id.* at 43.
[382] *Id.* at 37.

In his Rebuttal Testimony, Mr. Hevert responded to Mr. Baudino's proxy group critique and defended his DCF analyses and particularly his preference for the multi-stage DCF model over constant growth DCF in this matter.[383] Mr. Hevert analyzed Mr. Baudino's ROE analyses and disagreed with several aspects of his CAPM analysis, including his use of historical market risk premiums insofar as CAPM was a forward-looking analysis.[384] Mr. Hevert also refuted Mr. Baudino's characterization of his bond yield plus risk premium model and argued that the model provided a sound method for quantifying the relationship between the cost of equity and changing interest rates.[385] He also responded to Mr. Baudino's critique against a flotation cost adjustment, claiming that the net proceeds received by Pepco were below market price of the offerings as a result of the direct issuance costs.[386]

Mr. Baudino submitted Surrebuttal Testimony updating his ROE analysis with updated market data.[387] The updated analysis still supported his initial ROE recommendation of 9.0%.[388]

c. OPC

OPC witness Dr. Woolridge adopted Pepco's proposed capital structure and long-term debt cost rate.[389] His main contention was in the calculation of Pepco's ROE. Dr. Woolridge applied the constant growth DCF and CAPM methods to develop a recommended ROE for Pepco of 8.65%, which was at the upper end of his equity cost

[383] Hevert Rebuttal at 85, 87.
[384] *Id.* at 96.
[385] Hevert Rebuttal at 98.
[386] *Id.* at 100.
[387] Baudino Surrebuttal at 2.
[388] *Id.* at 3.
[389] Woolridge Direct at 4.

rate range of 7.9% to 8.65%.[390] When Pepco's capital structure and senior capital cost rates are taken into consideration, Dr. Woolridge calculated an overall rate of return (ROR) of 7.05% for Pepco's electric distribution utility operations.[391]

Dr. Woolridge selected 31 electric utilities as his proxy group (the "Electric Proxy Group"), using different criteria than Pepco witness Hevert used to select his 23 comparables (the "Hevert Proxy Group").[392] He performed his analyses using both the Electric Proxy Group and the Hevert Proxy Group.[393]

Dr. Woolridge relied primarily on his DCF analysis for his ROE determination, finding that the DCF method provided the best measure of equity cost rates for utilities. He also performed the CAPM analysis but put less weight on its results because the CAPM provided a "less reliable indication of equity cost rates for public utilities."[394] In performing his DCF calculation, Dr. Woolridge did not rely exclusively on the earnings per share forecasts, opining instead that the appropriate growth rate in the DCF model was the dividend growth rate.[395] He argued that long-term EPS growth rate forecasts of Wall Street securities analysts were known to be overly optimistic and upwardly biased.[396] Therefore, according to Dr. Woolridge, the DCF growth rate should be adjusted downward to correct for any upward bias.[397] As applied to both Dr. Woolridge's Electric Proxy Group and the Hevert Proxy Group, the DCF analyses produced the same equity cost rate of 8.65%.[398]

---

390 *Id.* at 4-5.]
391 *Id.* at 5.
392 *Id.* 30-31.
393 *Id.* at 10.
394 *Id.* at 43.
395 *Id.* at 53.
396 *Id.* at 53-54.
397 *Id.* at 54.
398 *Id.* at 59.

Dr. Woolridge also performed a CAPM study. Using standard CAPM components, Dr. Woolridge determined an equity cost rate of 7.9% for the Electric Proxy Group and 8.1% for the Hevert Proxy Group.[399] Given the results of his DCF and CAPM analyses, Dr. Woolridge calculated an ROE range of 7.90% to 8.65% for both proxy groups. Because he relied primarily on the DCF model, however, he chose a final ROE recommendation at the upper end of the range and concluded that the appropriate ROE was 8.65%[400]

Additionally, Dr. Woolridge testified regarding capital market conditions, arguing that capital costs have declined since the Commission last addressed Pepco's ROE in 2014. Since 2014, although economists predicted an increase in long-term interest rates in response to the ending, they were wrong and interest rates declined.[401] He noted that the 30-year Treasury yield, which was 4.0% in 2013, declined to 2.5% over the next year. Currently, the 30-year Treasury yield is 2.5%.[402] According to Dr. Woolridge, long-term trends reflect more slowed growth in annual economic production and income. He expected to see the cost of capital decline, thereby keeping interest rates low.[403]

Beyond interest rates, Dr. Woolridge also testified that authorized ROEs for electric utilities have generally decreased since Pepco's last rate case. He cited data from Regulatory Research Associates indicating that "authorized ROEs for electric utilities have declined from an average of 10.01% in 2012, to 9.8% in 2013, to 9.76% in 2014, to 9.58% in 2015, and to 9.86% in the first quarter of 2016."[404]

---

[399] *Id.* at 69.
[400] *Id.* at 70.
[401] *Id.* at 6.
[402] *Id.* at 7.
[403] *Id.* at 26.
[404] *Id.* at 8.

After presenting his own ROE analysis, Dr. Woolridge critiqued Mr. Hevert's ROE analysis, criticizing him for basing his analyses and recommendations on "the speculative and oft-disproven assumption of higher interest rates and capital costs."[405] Dr. Woolridge argued that this upward bias also carried into the substance of Mr. Hevert's DCF, CAPM, and risk premium analyses. Dr. Woolridge also found no basis for a flotation cost adjustment.[406]

Dr. Woolridge criticized Mr. Hevert's DCF equity cost estimates for, among other things, giving little, if any, weight to his constant growth DCF results and employing in his multi-stage DCF analysis a terminal growth rate that was not reflective of prospective U.S. economic growth.[407] He objected to Mr. Hevert's reliance on the ECAPM approach, which he pointed out has not been theoretically or empirically validated, and he faulted Mr. Hevert's CAPM analysis for using market risk premiums that were based on "the upwardly-biased long-term EPS growth rate estimates of Wall Street analysts."[408] Lastly, Dr. Woolridge dismissed Mr. Hevert's bond yield plus risk premium analysis as inflating the equity cost rate. He disagreed with Mr. Hevert's use of an excessive risk premium derived from historic authorized ROEs and Treasury yields, which, according to Dr. Woolridge, did not reflect investor behavior but, rather, Commission behavior.[409]

In reviewing Dr. Woolridge's ROE analysis, Mr. Hevert challenged the reasonableness of OPC's recommendation, pointing out that Dr. Woolridge's recommended ROE was 90-135 basis points lower than the recent average returns for electric utilities and 110 basis points lower than the ROEs most recently authorized by

[405] *Id.* at 76.
[406] *Id.* at 97-98.
[407] *Id.* at 78.
[408] *Id.* at 87-88.
[409] *Id.* at 96.

the Commission in June 2016 for BGE's electric and natural gas operation.[410] Mr. Hevert also disagreed with Dr. Woolridge's proxy group selection and argued that the companies were not sufficiently comparable to Pepco.[411]

Mr. Hevert criticized Dr. Woolridge's DCF analyses and results as incompatible with current market conditions and inconsistent with the underlying assumptions of the DCF model.[412] He also noted that he was unable to replicate Dr. Woolridge's analyses.[413] Mr. Hevert disagreed with Dr. Woolridge's contention that dividend and book value growth rates were the appropriate measures of expected growth, insisting instead that earnings growth was "the fundamental driver of the ability of pay dividends."[414] In response to Dr. Woolridge's critique of Pepco's DCF analysis, Mr. Hevert defended his multi-stage approach.[415]

Mr. Hevert also objected to Dr. Woolridge's CAPM analysis, arguing that the resultant cost of equity of 7.90% was unreasonable and "unduly low".[416] Notwithstanding the fact that Dr. Woolridge did not rely on his CAPM analysis in formulating his ROE recommendation, Mr. Hevert questioned the validity and relevance of Dr. Woolridge's equity risk premium estimates, arguing that "such important elements of his CAPM analysis contradict each other…."[417] Mr. Hevert then addressed in detail Dr. Woolridge's criticism of his own (Hevert's) CAPM and bond yield plus risk premium analyses. Mr. Hevert disagreed with Dr. Woolridge's position on Pepco's request for

---

[410] Hevert Rebuttal at 33.
[411] Hevert Rebuttal at 35.
[412] *Id.* at 37.
[413] *Id.* at 54.
[414] *Id.* at 50.
[415] *Id.* at 55-60.
[416] *Id.* at 63.
[417] *Id.* at 67.

flotation costs.[418] He rejected Dr. Woolridge's argument that flotation costs for electric utility companies should result in a reduction to the equity cost rate, countering that flotation costs are "true and necessary costs to the issuer" and that denial of their recovery would deny the Company a portion of its expected return.[419]

Dr. Woolridge provided Surrebuttal Testimony responding to Mr. Hevert's Rebuttal Testimony on the topics of changes since Pepco's last rate case, the subjectivity and reasonableness of Dr. Woolridge's ROE recommendation, various DCF analysis issues raised by Mr. Hevert, capital market conditions, and the trend in state authorized ROEs.[420] Dr. Woolridge defended his application of the DCF model and further addressed Mr. Hevert's arguments concerning the multi-stage DCF model.[421]

Dr. Woolridge rejected Mr. Hevert's suggestion that "nothing has changed" since the last rate case.[422] In that regard, Dr. Woolridge reiterated his position that capital costs and interest rates have declined in recent years and are at historic low levels. Furthermore, they would likely remain low with "sluggish economic growth and low inflation."[423] He pointed out that the average authorized ROE for electric utility delivery or distribution companies specifically also declined from 9.85% in 2011 to just over 9.2% in 2015.[424] In view of an average ROE of just over 9.0%, Dr. Woolridge argued that "an earned ROE of about 9.0% is more than adequate to meet investors' return requirements."[425]

---

[418] *Id.* at 82.
[419] *Id.* at 82-83.
[420] Woolridge Surrebuttal at 1-2.
[421] *Id.* at 1-2, 8.
[422] Woolridge Surrebuttal at 2; *see also* Hevert Rebuttal at 3.
[423] Woolridge Surrebuttal at 18.
[424] *Id.* at 23.
[425] *Id.* at 26.

d. Staff

Staff witness VanderHeyden recommended that Pepco's cost of equity should be 9.57% and its overall rate of return should be 7.51%.[426] He accepted Pepco's proposed capital structure.[427]

Regarding proxy groups, he testified that a utility's return should be comparable to other companies of similar risk. Mr. VanderHeyden observed that Pepco, as an electricity provider, was solely a distribution company, devoid of any generation or transmission assets in its rate base. Given the few stand-alone electric distribution companies from which to form a representative proxy group, Mr. VanderHeyden included companies from Value Line's Electric East, Central, and West groups, noting that many of them had other operations, such as generation and non-regulated businesses.[428] In total, Mr. VanderHeyden's proxy group consisted of 32 companies.[429]

Mr. VanderHeyden employed both DCF and CAPM methodologies to calculate an average ROE for Pepco.[430] For his DCF analysis, Mr. VanderHeyden used closing stock prices and dividend data from Yahoo Finance and annual earnings growth data from Value Line for the period ending in 2020 to 2021.[431] He excluded the dividend growth results from his DCF calculation because in his opinion, many utilities would be unable

[426] VanderHeyden Direct at 2.
[427] *Id.* at 9.
[428] *Id.* at 8.
[429] Mr. VanderHeyden removed PPL Corporation from his proxy group because of its recent spinoff transaction. VanderHeyden Direct at 8-9. He also excluded companies with a market capitalization under $1Billion as well as Exelon Corporation. *Id.* at 9.
[430] VanderHeyden Direct at 10.
[431] *Id.* at 11. Mr. VanderHeyden explained that he chose to use earnings growth information over dividend growth data in his DCF calculation for growth over time because as utilities undertake heavy spending on reliability, many of them would be "unable or unwilling to boost dividends significantly…." *Id.* at 12. Instead, the "earnings reinvested in plant would be expected to drive higher earnings in the future…." *Id.*

or unwilling to increase dividends while spending heavily on reliability improvements.[432] Mr. VanderHeyden's DCF analysis resulted in an individual ROE of 9.36%, which reflected the proxy group average.[433] For his CAPM analysis, Mr. VanderHeyden calculated an ROE of 9.78% for Pepco.[434]

Mr. VanderHeyden did not include an adjustment for flotation cost in his ROE estimate in this matter. He testified that the Commission clearly instructed in previous orders that an award for flotation costs would be granted only based on verifiable costs of issuing new stock.[435] He pointed out that Pepco has not issued any additional stock since its last rate case No. 9336. In that regard, Pepco's cost of capital testimony reflected only the Company's cost of issuing stock in 2008 and 2012. Mr. VanderHeyden also reasoned that insofar as Pepco was purchased by Exelon, PHI's flotation costs would have been absorbed in Exelon's purchase price if PHI was purchased at a value greater than its book value.[436]

Mr. VanderHeyden critiqued Mr. Hevert's cost of capital analysis. Regarding Mr. Hevert's DCF analysis, he noted that Mr. Hevert performed two variants of the DCF model and chose the multi-stage DCF results over the constant growth DCF results. Mr. VanderHeyden testified that his own DCF results fell within Mr. Hevert's results under constant growth DCF but not under his multi-stage analysis.[437]

Mr. VanderHeyden stated that unlike Pepco he did not use the ECAPM method because he did not find it necessary to use an adjustment for beta in this case that would

---

[432] VanderHeyden Direct at 12.
[433] *Id.* at 10, 13.
[434] *Id.* at 14.
[435] *Id.* at 17.
[436] *Id.* at 18.
[437] *Id.* at 19.

have compensated investors with higher returns for non-utility risk.[438] Mr. VanderHeyden further noted that ECAPM was not a mainstream method. Additionally, he questioned Mr. Hevert's use of a size adjustment in his ECAPM method and its validity under current market conditions.[439]

He also criticized Mr. Hevert's application of the bond yield plus risk premium method, characterizing it as an incomplete indicator of investor's required return because the historical authorized returns granted by state commissions may be higher or lower than the returns on market equity that current investors expect.[440] According to Mr. VanderHeyden, Pepco failed to demonstrate a reliable connection between the previously authorized returns and a current investor's expectations.

Dr. Woolridge in his Rebuttal Testimony raised several purported errors by Mr. VanderHeyden, including: (1) inconsistencies in the composition of his proxy group; (2) asymmetrical elimination of low-end observations in his DCF results; (3) a flawed measure of equity risk premium for his CAPM analysis.[441] Dr. Woolridge also pointed out that Mr. VanderHeyden apparently changed his ROE methodologies in this proceeding and chose not to use two approaches previously employed by him in prior rate cases—namely, the Internal Rate of Return ("IRR") and Risk Premium Build Up ("RP") methods.[442]

Contemporaneous with Dr. Woolridge's Rebuttal, Mr. Hevert presented numerous criticisms of Mr. VanderHeyden's ROE testimony in his Rebuttal Testimony. He too objected to Mr. VanderHeyden's proxy group selection and challenged his DCF and

---

[438] *Id.* at 20.
[439] *Id.* at 21.
[440] *Id.* at 22.
[441] Woolridge Rebuttal at 2.
[442] *Id.* at 2-3.

CAPM calculations. Mr. Hevert noted that while Staff's constant growth DCF analysis was generally consistent with his own analysis, his (Hevert's) constant growth DCF analysis was 26 basis points higher than Mr. VanderHeyden's estimate.[443] Furthermore, Mr. Hevert faulted Mr. VanderHeyden for not including in his ROE analysis an ECAPM model as previous Staff witnesses have done in past rate cases.[444] Mr. Hevert also continued to defend his own use of the utility risk premium model, arguing that under the *Hope* and *Bluefield* standards, utility commissions set the authorized ROE equal to investors' expected return.[445]

Lastly, with regard to flotation costs, Mr. Hevert disagreed with Staff's reasoning that Pepco's recent acquisition by Exelon negated the need to adjust for flotation costs.[446] He argued that the dilution of equity remained unaffected by any acquisition premium paid by Exelon.[447]

In his Surrebuttal Testimony, Mr. VanderHeyden responded to Dr. Woolridge's concerns and defended: (1) the composition of his proxy group composition; (2) his choice not to use the IRR and Risk Premium Buildup methods to develop ROE in this case; (3) his elimination of several low-end DCF ROEs that he believed were inappropriate for his analysis; and (4) his use of historical market risk premium in his CAPM analysis.[448]

Mr. VanderHeyden also provided surrebuttal response to Mr. Hevert's critiques regarding: (1) certain companies included in the proxy group; (2) election of the CAPM

[443] Hevert Rebuttal at 13-14.
[444] *Id.* at 16-17.
[445] *Id*. at 20.
[446] *Id*.at 21.
[447] *Id*.at 22.
[448] VanderHeyden Surrebuttal at 3-10.

method over the ECAPM approach; (3) the need for flotation expense as a requirement for a flotation ROE adjustment; and (4) the validity of authorized ROE as a risk premium method.[449]

Mr. VanderHeyden testified that Staff's and Pepco's DCF results were "more or less the same" and that the difference in final recommended ROE was due to Mr. Hevert's use of multi-stage DCF, ECAPM with CAPM and his use of a risk premium method based on awarded returns.[450] Accordingly, the parties' similarities become apparent once the Commission removes the flotation adder, the ECAPM, and the comparable earnings methods and then averages Pepco's constant growth DCF with Staff's CAPM.[451]

Mr. VanderHeyden summarized the parties' ROE recommendations in the following table:[452]

Table 1 – Summary of ROE Calculations

Method and Adjustments	**PEPCO**	**Staff**	**AOBA**	**HCNCA**	**OPC**
DCF	8.84%-9.60%	9.36%	8.82%	8.64-8.87%	8.65%
DCF Mult.-Stg.	9.20%-10.55%	n/a	n/a	n/a	n/a
CAPM	8.92%-13.01%	9.78%	8.70%	6.02%-8.28%	7.90%-8.10%
ECAPM	9.24%-13.45%	n/a	n/a	n/a	n/a
Utility RP	10.04%-10.39%	n/a	n/a	n/a	n/a
RAF	n/a	n/a	9.71%	n/a	n/a
Flotation Adj.	12 bp	n/a	n/a	n/a	n/a
ROE Recommendation	**10.60%**	**9.57**	**9.25%**	**9.00%**	**8.65%**

[449] *Id*. at 11-21.
[450] *Id*. at 11.
[451] *Id*.
[452] *Id*. at 3.

3. **Commission Decision**

We begin by observing that none of the parties object to Pepco's current capital structure ratio of 49.55% common equity to 50.45% long-term debt. We therefore accept it for our analysis along with the uncontested cost of long-term debt of 5.48%.

The parties' final ROE recommendations in this case range from 8.65% to 10.6%, with Pepco proffering the highest ROE and OPC the lowest. In terms of total revenue requirement, the parties' spread reflects a total difference of approximately $49.7 million. In reviewing the parties' proposed ROEs, we note that they are supported by extensive analysis applying, in some cases, multiple methodologies. Nevertheless, the witnesses have also relied on subjective judgment as to the quantitative inputs, the analysis methodologies performed—whether DCF, CAPM, risk premium, or any combination (or variant) thereof, and in some cases a decision to exclude specific results. The fact that the parties applied more than one methodology is not itself a fault. We have stated in prior rate cases that we are not willing to rule that there can be only one correct method for calculating an ROE. Indeed, the complexity of this subject cannot be captured by a single mathematical formula.

In its three most recent rate cases,[453] the Company consistently requested an ROE of 10.25% or greater. Each time we declined to adopt the Company's recommendation in view of the economic and risk factors faced by the Company at the time. This time is no different. We have considered Pepco's status as a monopolistic provider of electric distribution service in an economically stable service territory, its heavily residential

---

[453] *See In the Matter of the Application of Potomac Electric Power Company for Authority to Increase its Rates and Charges for Electric Distribution Service*, Case No. 9286; *In the Matter of the Application of Potomac Electric Power Company for an Increase in its Retail Rates for the Distribution of Electric Energy*, Case No. 9311; *In the Matter of the Application of Potomac Electric Power Company for Adjustments to its Retail Rates for the Distribution of Electric Energy*, Case No. 9336.

customer base, the completion of the recent merger between PHI, Pepco's parent holding company, and Exelon Corporation, and the fact that the Company does not own generation. We are also mindful of investor perception of utilities constituting low-risk investments. Thus, we are once again presented with the question of what has changed since we last established a just and reasonable ROE for Pepco that would now justify a higher return?

Our current reality is that interest rates have generally declined since 2008 and have since remained persistently low. Indeed, interest rates have remained at historic lows for nearly a decade and even fallen since the last rate case.[454] Not surprisingly, long-term Treasury yields have also declined. As OPC witness Dr. Woolridge pointed out, the downward trend in long-term rates, despite the Federal Reserve's decision to terminate its bond buying program and increase the Federal Fund rate range, reflects more slowed growth in annual economic production and income.[455] Accordingly, insofar as investors rely on current market data, the data do not support Pepco's proposed increase but, rather, favor a lower cost of capital than Pepco's current authorized ROE of 9.62%.

Additionally, we consider Pepco's current state of financial health and note in particular its strong secured bond rating, which indicates low risk. In this regard—i.e., the risk facing the Company's electric distribution operations in Maryland—we conclude that Pepco's situation has not changed in a manner that would justify an increase in ROE. First, Pepco continues to operate in a low-interest rate environment. Second, before the Exelon-PHI merger, Moody's characterized PHI, Pepco's parent holding company, as

---

[454] *See, e.g.*, HCNCA Ex. 30 at RAB-2.
[455] Hevert Direct at 22-25.

having a "low business risk profile."[456] The merger itself was characterized as "credit positive".[457] Post-merger, we find that Pepco continues to constitute a low-risk investment. Third, the Company is a monopoly provider of electric distribution service in a stable service territory in Maryland, which allows several utility-friendly policies (e.g. customer charges, decoupling, etc.) and does not own generating facilities. From a risk standpoint, Pepco has not had any difficulty securing debt financing. Even Mr. Hevert acknowledged that the merger could provide benefits towards the Company's ability to attract future capital, which would further reduce the Company's risk level.[458] These developments, among others, all point to a lower ROE for Pepco.[459]

We are not persuaded by Pepco's argument that an ROE lower than the respective returns we recently authorized for BGE's electric and gas utility operations[460] would conflict with our prior conclusion regarding electric and gas utility risk.[461] We note that Order No. 85374, which serves as the basis for Pepco's argument, was issued over three years ago, and our statement there was comparative in nature, made for the purpose of according separate treatment to BGE's electric and gas operations, as opposed to combining both operations to reach an appropriate return. We did not attempt in that case to establish a floor for all future ratemaking. Indeed, our decision in this case is based on consideration of the record before us and the facts particular to this case. To that end, we examine and decide each utility's rate application on its own merits to ensure not only that the utility is operating in the interests of the public, but also that its rates are "just and

[456] HCNCA Ex. 30 at 12.
[457] HCNCA Ex. 30 at 13.
[458] *See* Hr. Tr. at 310.
[459] Mr. Hevert's recommended ROE of 10.6% is not sustained by Exelon's own projected return of the impact of the PHI acquisition on earnings per share. Hr'g Tr. at 39.
[460] *See* In re BGE Rate Application, Case No. 9406.
[461] *See* Pepco Br. at 61 (quoting an excerpt from Order No. 85374).

reasonable." Again, we agree that, in general, we treat our utilities the same unless there are facts and circumstances that support different treatment, which we do here.

Our decision today most closely aligns with Staff's recommendation of 9.57%, although we do not expressly reach the same conclusion as Staff. We find that a slightly lower ROE of 9.55% is both adequate and appropriate for Pepco, considering the risks associated with its electric distribution service in Maryland, the current capital market environment, and the fact that Pepco has not issued any new stock since its last rate case. Looking forward, Pepco has not demonstrated that it will issue new stock or incur any flotation costs in the rate effective year.[462] Insofar as PHI previously issued stock and distributed proceeds to Pepco and other subsidiaries, PHI has since merged with Exelon Corporation. Following completion of the merger, Pepco does not take the position that it will begin issuing stock or that Exelon will issue stock on its behalf. We conclude, therefore, that Pepco has not established any direct connection to any verifiable costs associated with any new equity to be issued by Exelon in the rate effective year. Accordingly, we deny Pepco's request for a flotation cost adjustment. For the same reasons, we also find that the previous flotation adjustment of 7 basis points awarded in Pepco's last rate case is no longer appropriate.

We further note that while Mr. VanderHeyden's recommendation reflects a simple average of his DCF and CAPM, his ROE analysis does not precisely reflect the IRR and Risk Premium Buildup ("RP Buildup") methods performed in Case No. 9406. Mr. VanderHeyden explained that both IRR and RP Buildup methods "are impacted

---

[462] Pepco itself did not issue common stock; rather, its parent holding company, PHI, held all of the Company's equity.

significantly by current financial market conditions."[463] We find, however, that current market conditions would also have a significant impact on Mr. VanderHeyden's CAPM analysis.

On cross-examination regarding downward trends in ROE, Mr. VanderHeyden testified that "bond yields . . . have an impact in at least one of the methods . . . used [to estimate ROE]."[464] He observed that bond yields have been trending downward over time, which is consistent with the observations of Mr. Baudino and Dr. Woolridge. Mr. VanderHeyden further testified that had he incorporated current 2016 Treasury data into his analysis, it would have driven his CAPM result lower by as much as 20 or 30 basis points.[465]

We agree that current market conditions favor a cost of equity that is lower than Pepco's currently approved ROE of 9.62%. But how much lower? Historically, we have generally followed the principle of gradualism when implementing major rate design changes that have a potentially adverse impact on a particular class of customers. Gradualism prescribes that sudden and dramatic shifts in rate design should be avoided. We find that gradualism works both ways and would be appropriate in this instance to lessen the impact on the company and investors. Relative stability in rates is an important ratemaking goal—for ratepayers and utilities alike. As Mr. VanderHeyden explained regarding returns on equity, "[o]ne of the properties of our rate making process is that awarded ROEs do not instantly respond to market changes. Awarded ROEs

[463] VanderHeyden Surrebuttal at 6.
[464] Tr. at 1427.
[465] Tr. at 1430-31. Mr. VanderHeyden testified that on July 5, 2016, Yahoo! Finance reported 30-year U.S. Treasuries at 2.13%. VanderHeyden Direct at 15 n.13.

should make gradual movements."[466] Implementing gradual movement will "encourage an environment that does not surprise investors with changes that impact them adversely."[467]

An ROE of 9.55% is a two-basis point downward adjustment from Staff's recommendation. It also maintains Pepco's currently approved ROE after removing the previously awarded seven-basis point flotation adjustment. We believe the market can sustain this ROE. Dr. Woolridge testified that, on a national level, the average authorized ROE for electric utility and gas distribution companies is around 9.5.[468] For electric distribution companies specifically, the average authorized ROE was 9.39 percent for the first half of 2016.[469] It is unlikely, therefore, that the ROE we authorize today will scare investors or hurt Pepco's access to credit. Even when we reduced the Company's ROE in 2012, Pepco nevertheless generated $450 million in new long-term debt.[470]

We find that a return on equity of 9.55% for Pepco's electric distribution operations falls within the DCF, CAPM, and ECAPM ranges reported by Pepco witness Hevert, and, in particular, falls towards the upper end of his constant growth DCF range. This ROE further complies with the standards under *Bluefield* and *Hope*. It is comparable to the returns investors expect to earn on investments of similar risk in the current market. It is sufficient to assure confidence in Pepco's financial integrity and enable the Company to receive a fair return commensurate with its risk. It is further adequate to sustain Pepco's credit so that the Company can continue to attract needed

[466] *Id*. at 4.
[467] VanderHeyden Direct at 7.
[468] Woolridge Surrebuttal at 22.
[469] Woolridge Surrebuttal at 23.
[470] Case No. 9311, Order No. 85724 at 104.

capital in a low-interest rate environment and provide safe and reliable service to its customers.

When applied to its capital structure, Pepco's overall rate of return will be 7.49%, as shown in the following chart:

Type of Capital	% of Total Capital	Embedded Cost Rate	Weighted Cost Rate
Long-Term Debt	50.45%	5.48%	2.76%
Common Equity	49.55%	9.55%	4.73%
Total/Overall ROR	100.00%		7.49%

E. <u>Cost of Service</u>

1. <u>Parties' Positions</u>

Pepco presented its COSS and its class cost of service ("CCOSS") through the testimony of Mr. Nagle. Mr. Nagle's methodology in developing Pepco's COSS and CCOSS methods were consistent with prior Commission orders.[471] In fact, Staff Witness Norman recommended use of Pepco's jurisdictional COSS without modification.[472] However, Pepco's CCOSS continued to allocate 100% of AMI costs to those classes that received AMI meters.[473] Although Pepco's CCOSS was consistent with similar past cases accepted by the Commission, those cases did not fully address the new issues raised by AMI costs.

[471] Norman Direct at 2.
[472] Norman Direct at 2; Staff Initial Brief at 21.
[473] Tr. 1048-49 (Norman).

Rather than adopting Pepco's CCOSS, Ms. Norman proposed an alternate allocation for AMI costs across customer classes.[474] First, Staff observes that Pepco provided portrayals of the many benefits of AMI, including the significant "energy and demand management outcomes from which all customer classes benefit."[475] Only 25% of the AMI benefits are exclusive to classes receiving AMI meters. Therefore, Staff contends that Pepco is ignoring the claimed system-wide benefits when it allocates AMI costs only to classes that received meters.[476]

Pepco concedes that AMI may provide benefits across rate classes that may not align with the traditional cost-based allocation approach used for metering plant. However, it maintains that its approach remains superior to a benefits-based approach, which disregards cost causation.[477] Mr. Nagle testified that meters are installed for each customer based solely on the contingent that energy must be measured.[478]

Staff responds, persuasively in our view:

> Traditional meters were already providing measurements of customer consumption. If AMI was meant to provide only consumption measurement, no upgrade would have been cost justifiable. Pepco is not only demanding AMI customer classes pay for the consumption measurement they already had, but for the incremental costs that provide new benefits to all customer classes. The application of traditional strict cost causation criteria is no longer equitable when allocating this dynamic new technology; Residential and other AMI metered classes should not pay exclusively for system wide benefits.[479]

---

[474] Norman Direct at 2. OPC urged the Commission to reject Pepco's COSS because OPC believed that Pepco failed to include a significant amount of data made available to it through AMI. OPC ultimately supported the adoption of the CCOSS described by Staff, as we have. OPC Initial Brief at 33-35.
[475] Staff Initial Brief at 22. *See also*, Leftkowitz Direct at 13, Table A, reproduced *supra*.
[476] Staff Initial Brief at 22.
[477] Pepco Initial Brief at 63; Nagle Rebuttal at 3.
[478] Nagle Rebuttal at 4.
[479] Staff Initial Brief at 22.

Instead, Staff proposes a hybrid approach that spreads AMI costs across all rate classes receiving benefits from AMI, but weights more heavily those classes that share in the additional benefits exclusive to those who actually receive an AMI meter.[480]

2. <u>Commission Decision</u>

In Case No. 9406, OPC's witness Wallach proposed a benefits approach for allocating AMI costs among rate classes. By allocating these costs on the basis of traditional cost causation principles rather than on the basis of expected benefits, he contended the ECOSS over-allocates costs to the residential class. Although we recognized that this approach had merit, we agreed with Staff Witness Norman that "an approach based on benefits is not viable in this proceeding given the lack of information." We stated that "with a more detailed analysis of the benefits approach allocation of costs, we may consider utilizing it in future rate cases."[481]

We believe there is sufficient information in the present case. Based upon the record before us, the weighted average proposed by Staff Witness Norman more equitably distributes the AMI costs we have approved in this case. As Ms. Norman explained, "to the extent that the incremental costs of AMI meters are incurred to support load shaping and conservation programs and goals, they could be classified and allocated accordingly."[482] To the extent that AMI costs are allocated based on demand or energy volumes, costs will rise for smaller customers and decline for larger customers.[483]

Table 11 of Ms. Norman's direct testimony describes the relative rate of return for each rate class based upon three allocation methodologies – Pepco's proposal as filed,

---

[480] *Id.* at 22-23.
[481] Case No. 9406 at 184.
[482] Norman Direct at 20.
[483] *Id.* at 21.

Demand based, and Energy based.[484] Ms. Norman proposes a weighted average allocation of these three results for AMI-related costs.[485] After calculating the relative rates of return pursuant to her proposed weighted average allocation, the proposed alternative allocation approach adjusts each class RROR to more accurately represent the costs and benefits of AMI plant. We believe Ms. Norman's hybrid approach most fairly spreads the costs and related benefits of AMI throughout the Pepco service territory.

F. Rate Design

Rate Design involves two functions: (1) the design of inter-class rates, which involves the assignment of revenue requirement between the various customer classes, and (2) 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, we begin with the actual rates of return reflected in the jurisdictional cost of service (COSS). These results are then translated into a relative rate of return, 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.[486] An RROR of 1.0 signifies that a rate class has a return equal to the utility's overall rate of return. An RROR that is higher than 1.0 indicates that the class has a return (or contribution) that is greater than the system average, and an RROR that is lower than 1.0 indicates a class return that is less than average. If all customer rate classes have an RROR of 1.0, then each class is contributing equally to the utility's overall rate of return based upon its cost of service. As a matter of

[484] *Id.* at 22.
[485] *Id.* at 22-23.
[486] *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).

policy, the Commission strives to bring all classes closer to an RROR of 1.0 in each rate case, to reflect the cost causation from each class. 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 fixed utility costs, such as the cost of meters. Additionally, Pepco customers have an energy charge, which is designed to recover variable costs. That is, each customer's bill has a fixed, monthly customer charge and volumetric, per-kilowatt hour ("kWh") charges. Intra-class rate design is guided by important policy considerations, including gradualism, energy conservation, economic impacts, as well as cost causation.

1. <u>Revenue Allocation</u>

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 company's COSS and the principle of gradualism.[487] 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.[488]

---

[487] The parties do not contest the proposed allocation of non-AMI costs. This order addresses only the allocation of AMI-related costs.

[488] Case No. 9286, *In Re Potomac Electric Power Co., 103 Md. PSC 293, 352 (2012).*

Step One

For the first step, Pepco has proposed a 25% allocation of the increased rates to residential and other under-earning classes.[489] Pepco Witness Janocha explains the rationale for this decision:

> 1) Limit the maximum percentage increase to any one of these rate schedules to 1.5 times the overall average percentage increase;
> 2) Ensure that the final proposed UROR for a rate class with an existing UROR above 1.0 does not increase, nor move to a level below 1.0;
> 3) Ensure that the final proposed UROR for a rate class with an existing UROR below 1.0 does not decrease nor move to a level above 1.0.[490]

Witness Janocha notes that this approach is consistent with prior orders by the Commission in Case Nos. 9331 and 9336.[491]

Staff testified that in this case an 18% allocation to under-earning classes is more equitable. Obviously, strict fairness to every ratepayer would require that every ratepayer have a RROR of 1.0, and analysts do their best to avoid inter-class subsidies. However, as Staff Witness Blaise explains, such an approach would regularly result in rate shock to one or more classes. Therefore, Staff proposes an 18% allocation to underperforming classes (R, RTM, and GS-LVR).[492] Witness Blaise explains this particular percentage by testifying that he ran "over fifty different scenarios" to determine the best allocation approach to recommend, and 18% "provided a balanced set of RRORs and allocation proportions. That is, it doesn't unduly strain any one class by allocating too much revenue towards any one class in an excessive manner."[493] Additionally, this percentage

---

[489] Janocha Direct at 6-7; Schedule (JFJ) – 1.
[490] *Id.* at 6
[491] *Id.* at 4.
[492] Blaise Direct at 17.
[493] Blaise Direct at 17-18.

is consistent with prior Commission cases in which the Commission determined a 15% allocation to be appropriate.[494]

We agree and adopt the 18% first step allocation recommended by Witness Blaise, which represents a more gradual movement toward system parity than Pepco's recommended 25%.

Step Two

The remaining 82% of the awarded revenue requirement increase should be allocated to all classes, except GT-3B and TN, as these classes are significantly over-earning.

2. Customer Charges

Customer charges intend to cover the costs incurred by a utility for fixed charges. As with allocating costs between rate classes, determining the proper ratio between customer, volumetric and demand charges requires balancing many competing variables. It is important that customers who cause certain costs incur those costs, but the principle of gradualism applies here as well. Additionally, policy concerns must also guide the Commission, such as energy conservation incentives and the effect of an increased surcharge on low income customers. With these principles in mind, we believe the record in this case supports a gradual increase in the customer charges.

Pepco proposes to increase the charge for its residential customers from its current $7.39 to $12.00.[495] This would represent a 62.38% increase, and Pepco's residential customers would be paying a customer charge far in excess of similarly situated customers in other Maryland service territories. For example, in Case No. 9406, we

[494] Case No. 9299, Order No. 85374 at 98.
[495] Janocha Direct at 8.

raised BGE's customer charge from $7.50 to $7.90.[496] Pepco frames this as a concession to gradualism, claiming that its COSS actually supports an increase to $22.85.[497]

Staff proposes that the Commission increase the customer charge for Pepco's residential customers from its current $7.39 to $7.85, a $0.46 increase.[498] Witness Blaise supports this recommendation in part by noting that a $7.85 charge "would not significantly change the proportion of revenue derived from fixed charges, which is currently 19.61%."[499]

OPC contends that we should not order any increase in customer charges, but rather let the residential customer charge remain at $7.39. In the alternative, OPC supports Staff's recommendation as a viable alternative to requiring additional information from Pepco.[500]

We believe an increase slightly lower than Staff's recommendation is appropriate in this case, and we have concluded that residential customer charges should increase to $7.60. Determining the appropriate increase is not an exact science, but rather the balancing of many considerations. In arriving at this increase, we place emphasis on Maryland's public policy goals that intend to encourage energy conservation. Maintaining relatively low customer charges provides customers with greater control over their electric bills by increasing the value of volumetric charges. No matter how diligently customers might attempt to conserve energy or respond to AMI-enabled peak pricing incentives, they cannot reduce fixed customer charges.

---

[496] Order No. 87591 at 193. This represents a 5.3% increase.
[497] Janocha Direct at 8-9.
[498] Blaise Direct at 20. This would represent a 6.2% increase. OPC Initial Brief at 37.
[499] Blaise Direct at 20.
[500] OPC Initial Brief at 37.

Additionally, lower customer charges provide more value to net metering customers. The terms of most utility tariffs typically require a customer to pay the monthly customer charge regardless of the amount of energy produced. However, for energy billed, the customer pays only for energy that is used, netted against any generation produced by the customer.

With all of these factors in mind, we have determined to increase the residential customer charge from its current $7.39 to $7.60, approximately halfway between Staff's proposal ($7.85) and OPC's proposal (remaining at $7.39). As the chart below demonstrates, the customer charges paid by Pepco's residential customers remain comparable to similarly situated customers of other Maryland electric utilities:

Residential (R) Customer Charges in Maryland	
Company	**Monthly Customer Charge**
Choptank	$10.25
SMECO	$9.50
STATEWIDE AVERAGE	$8.00
Delmarva	$7.94
BGE	$7.90
PEPCO - Current	$7.39
PE	$5.00

An increase from $7.39 to $7.60 represents a 2.84% increase, and we have concluded that it is reasonable to raise the rates of other classes by a similar percentage.

This ruling will result in the following customer charges:

RS – $7.60
RTM – $16.31
GS-LV-$11.32
MGT-LV – $42.51
MGT-3A – $40.37
GT-LV – $345.42
GT-3B – $313.08
GT-3A – $324.33
TMRT – $3443.58

The average residential customer will see a 4.76% increase in their monthly bill or approximately $6.96. We believe this is reasonable in light of the significant investment Pepco has made in AMI and in improving reliability overall. We also wanted to emphasize the recent increase in customer control of their electricity consumption by minimizing the extent to which they are subject to fixed charges while balancing that goal with Pepco's right to recover its fixed customer costs.

3. Volumetric and Demand Elements

In its Reply Brief, AOBA contends:

> As initially proposed by Pepco, the Company would place increases ranging from 90% to 106% on these classes' demand charges.
>
> Thus, as reductions in kWh use and improved energy efficiency are state-wide goals in Maryland, Pepco's focus on increasing demand charges and eliminating volumetric charges for commercial customers is inconsistent with achievement of state-wide EmPOWER Maryland objectives.

In Order No. 85028 (Case No. 9286), we held that :

> On this record we find that the rate increase and any BSA assignment should be allocated to the customer, volumetric, and demand elements based upon the same percentage increase as the class percentage increase in rates. In our opinion, this strikes an appropriate balance between principles of cost causation and energy conservation. This allocation will essentially maintain the

> intra-class rate relationships as they exist today. Additionally, this allocation is consistent with principles of gradualism. Therefore, the Company is directed to file tariffs consistent with these findings. We also direct the Company to file an update to its COSS, which reflects the rate increase authorized herein and that shows the new class rates of return and the new unitized rates of return.[501]

After we determine the revenue requirement for each class (through the 2-step allocation methodology) and set the customer (fixed) charge, the utility recovers the remainder of the revenue through the class's energy and demand charges. Pepco proposes to recover all of the remaining revenue through the demand charge. However, we will affirm our prior ruling that the charges should be increased equally.

G. Miscellaneous

Staff recommended that the Company be required to implement a comprehensive reliability planning process which includes: a cost-benefit analysis of each of the Company's reliability programs; weather normalization of the Company's historical system reliability performance; and projection of the Company's overall system reliability performance based on the group of projects/programs being undertaken.[502] We agree with Pepco that Staff's recommendation "does not make the engineering and construction process more efficient or offer greater customer protections"[503] and do not accept Staff's recommendation of requiring a comprehensive reliability planning process at this time. Pepco witness Gausman noted that a cost benefit analysis is not needed to determine the value of reliability projects.[504] However, as pointed out by Mr. Gausman,

---

[501] Order No. 85028 at 130.
[502] Shelton Direct at 3.
[503] Gausman Rebuttal at 12.
[504] *Id.* at 14.

the Company is required to report its reliability as ordered by the Commission in Case No. 9240.[505]

Additionally, the Staff noted that Pepco's vegetation management cost per mile is high compared to other Maryland utilities and recommended Pepco to solicit vegetation cost management best practices from the other Exelon Utilities and actively re-structure the Company's vegetation management contracts in order to reduce cost. Staff also recommended that Pepco submit a quarterly vegetation management report to Staff. We agree that Pepco should seek out and employ best practices for vegetation management from other Exelon utilities. Additionally, we accept Staff's recommendation that Pepco submit a quarterly vegetation management report to Staff with the components outlined by Staff witness Shelton in her direct testimony.[506]

Staff also noted that Pepco is adjusting the restoration time for customer outages if AMI data shows a restoration time earlier than what the crew entered as the restoration time. However, it did not appear that Pepco was making a systematical adjustment to show if the meter shows a time later than what the crew entered. We accept Staff's recommendation that Pepco make use of AMI meters to accurately adjust restoration time, but also direct the Staff to form a working group to review the current practice in more detail.

Last, we urge Pepco to evaluate "non-wires" alternative resources, like demand response, energy efficiency, storage, and other smart grid resources, as part of any assessment of proposed substantial distribution system investments.

[505] *Id.* at 17.
[506] Shelton Direct at 3.

IV. CONCLUSION

Based upon our review of the record in this case, we find that the Application filed on April 19, 2016, by Potomac Electric Power Company for a rate increase of $126,784,000 will not result in just and reasonable rates and is therefore rejected. Instead, we find that based on a test year of the twelve months ending December 31, 2015, as adjusted above, the Company is authorized to file revised rates and charges for an increase in revenues of $52,535,000, which amount will result in just and reasonable rates to the Company and its customers. As allocated, the increase in the overall residential bill will be approximately 4.76%, which is $6.96 per month on average. The Company shall file revised tariffs for such increase in accordance with the rate design and other decisions in this Order.

IT IS THEREFORE, this 15th day of November, in the year Two Thousand and Sixteen, by the Public Service Commission of Maryland,

ORDERED: (1) That the Application of Potomac Electric Power Company filed on April 19, 2016, seeking to increase distribution rates for electric service by $126,784,000 in its Maryland service territory, is hereby denied;

(2) That Potomac Electric Power Company is hereby authorized, pursuant to § 4-204 of the Public Utility Companies Article, *Annotated Code of Maryland,* to file tariffs for the distribution of electric energy in Maryland, which shall increase rates by no more than $52,535,000, for service rendered on and after November 15, 2016, subject to acceptance by the Commission; and which shall otherwise be consistent with the findings of this Order;

(3) That Pepco is hereby required to file a Distribution Investment Plan within twelve (12) months of the date of this Order that sets forth how the Company will accomplish its T&D goals, analyzing in detail the Company's strategy over the next five years for

investing in its distribution system including, among other things, specifics about how the Company's investment in smart meters will be utilized to improve the efficiency and effectiveness of the distribution network;

(4) That Pepco is hereby required to continue to provide Staff with detailed metrics including incremental costs and benefits, budgets, performance of the AMI system, cybersecurity and other important aspects of the operation of the AMI system as set forth in Order No. 83571; and

(5) That all motions not granted herein are denied.

/s/ W. Kevin Hughes

/s/ Harold D. Williams

/s/ Jeannette M. Mills

/s/ Michael T. Richard

/s/ Anthony J. O'Donnell
Commissioners

APPENDIX I

POTOMAC ELECTRIC POWER COMPANY
CASE 9418

Revenue Requirement
($000's)

Rate Base	$	1,636,944
Rate of Return		7.49%
Required Income	$	122,607
Adjusted Income	$	91,967
Income Deficiency	$	30,640
Conversion Factor		58.32%
Revenue Requirement	**$**	**52,535**

Rate Base
($000's)

Per Books Balance	$	1,596,664
Uncontested Adjs.	$	(7,659)
Uncontested Balance	**$**	**1,589,005**
Annualization of Test Year Reliability Plant Closings	$	20,664
Post Test Year Reliability Closings (Jan thru Aug 2016)	$	15,514
AMI Regulatory Asset Amortization	$	29,188
Reflection of 50% SERP Liability and Expense	$	(9,826)
Winter Storm PAX	$	366
Winter Storm Jonas	$	926
Reflection of Synergies and CTA	$	8,704
NOLC Adjustment	$	(17,155)
Billing System Transition Costs	$	3,906
Pro Forma Impact to Cash Working Capital Allowance	$	(4,347)
Adjusted Rate Base	**$**	**1,636,944**

APPENDIX II

POTOMAC ELECTRIC POWER COMPANY
CASE 9418

Operating Income
($000's)

Per Books Balance	$	97,241
Uncontested Adjs.	$	(9,380)
Uncontested Balance	**$**	**87,861**
Annualization of Test Year Reliability Plant Closings	$	(2,027)
Post Test Year Reliability Closings (Jan thru Aug 2016)	$	(3,053)
AMI Regulatory Asset Amortization	$	(3,768)
Legacy Meter Regulatory Asset Amortization	$	(5,049)
Tax Compensation Carrying Costs	$	1,890
Annualization of Wage Increases	$	(1,554)
Exclusion of Executive Incentive Costs	$	1,789
Reflection of 50% SERP Liability and Expense	$	2,154
Winter Storm PAX	$	(81)
Winter Storm Jonas	$	(206)
Reflection of Synergies and CTA	$	3,439
Restate Deferred Storm Costs	$	2,065
OT Adjustment	$	1,234
Outside Legal	$	149
Outside Professional	$	133
Annualization of Late Payment Revenues	$	321
Billing System Transition Costs	$	3,472
Legacy Billing Costs	$	425
Tax Effect of Proforma Interest Expense	$	449
AFUDC Synchronization	$	2,324
Net Operating Income	**$**	**91,967**