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**ERRATA**

**ORDER NO. 87591**

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| IN THE MATTER OF THE APPLICATION OF BALTIMORE GAS AND ELECTRIC COMPANY FOR ADJUSTMENTS TO ITS ELECTRIC AND GAS BASE RATES | * * * * * * * * | BEFORE THE PUBLIC SERVICE COMMISSION OF MARYLAND<br>____________<br>CASE NO. 9406<br>____________ |

Before: W. Kevin Hughes, Chairman
Harold D. Williams, Commissioner
Anne E. Hoskins, Commissioner
Jeannette M. Mills, Commissioner
Michael T. Richard, Commissioner

Issued: June 3, 2016

APPEARANCES

Daniel P. Gahagan, Beverly A. Sikora, Damon L. Krieger and Daniel W. Hurson for Baltimore Gas & Electric Company

Margaret M. Witherup, David Beugelmans and Todd R. Chason of Gordon Feinblatt LLC for the Maryland Energy Group and W.R. Grace & Company

Matthew W. Nayden and Jason Foltin, with H. Russell Frisby, Jr., John McCaffrey and Matthew Smilowitz of Stinson Leonard Street, LLP, for the Mayor and City Council of Baltimore

Leslie Romine, Jennifer Grace and Janice Flynn for the Public Service Commission Staff

Paula M. Carmody, Theresa Czarski, William Fields, Jacob Ouslander, Joseph Cleaver, Gary L. Alexander and Joyce R. Lombardi for the Maryland Office of People's Counsel

Steven M. Talson and Sondra McLemore for Maryland Energy Administration

Matthew Dunne for U.S. Department of Defense and Federal Executive Agencies

Lisa Brennan for Montgomery County, Maryland

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# I. INTRODUCTION AND EXECUTIVE SUMMARY[1]

Baltimore Gas and Electric Company ("BGE" or "the Company") filed with the Maryland Public Service Commission ("the Commission") a request to increase its rates for gas and electricity in the amount of $224.5 million.[2] This unusually large request included a base increase of $53.1 million which included an increase in the Company's authorized rate of return and cost recovery for the Company's ongoing reliability and public safety investments. The request also included six years of ongoing investment in Advanced Meter Infrastructure ("AMI") in the amount of $140.7 million which the Company now sought to begin recovering in base rates. Finally, the request included a proposed $30.7 million increase related to Baltimore City's decision to raise conduit fee lease rates, which BGE requested to recover through a separate bill rider. Any one of the items would constitute a substantial increase in rates.

Our obligation in this case under the Public Utilities Article is to determine "just and reasonable rates" for the service BGE renders its customers. Under Supreme Court case law, we are also obligated to ensure that the Company has the opportunity to earn a return on its investment that permits it to remain financially sound and able to maintain credit and attract capital.[3] This requires a delicate balancing of competing interests, and presents among the most challenging tasks to any Commission. We have thoroughly reviewed BGE's Application and carefully considered all of the evidence presented in

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[1] Commissioners Harold D. Williams and Anne E. Hoskins issued a Concurring Statement; Commissioners Harold D. Williams and Michael T. Richard Dissent in Part. See attached Statements.

[2] The requested rate increase was updated by BGE throughout the course of the proceeding and reflects actual results through February 2016. This includes a 115.6 million in its electric distribution revenue requirement, a $78.2 million increase in its gas distribution revenue requirement, and a $30.7 million increase associated with the increased costs related to Baltimore City's conduit lease and maintenance fee.

[3] *Bluefield Co. v. Pub. Serv. Comm'n,* 262 U.S. 679 (1923) and *Fed. Power Comm'n v. Hope Natural Gas Co.,* 320 U.S. 591 (1944).

this case as well as the comments rendered at the five evening public hearings. Based on this comprehensive review, we authorize BGE to increase its electric rates by $41.762 million and its gas rates by $47.776 million, for a total of $89.538 million.

In August 2010, the Commission unanimously granted BGE's request to proceed with deployment of AMI, noting in particular "smart-grid technology's ability ultimately to lower energy bills, improve customer service and relieve peak-time pressure on the transmission and distribution infrastructure."[4] In its decision, the 2010 Commission denied the Company's request to recover some costs during the roll out of the new smart meters and instead directed the Company to defer recovery of all costs until it could prove it had delivered a cost-beneficial system. At that time, the Commission did not want ratepayers to bear the risk that AMI would not provide benefits in an amount that exceeded the cost of the system. The consequence of this decision over a five year period has been to defer rate base recovery of almost all meters and metering infrastructure. This deferral of AMI costs, coupled with a relatively short depreciation life (10 years) for smart meters that the Commission adopted, has resulted in a large outstanding investment of $345 million for which BGE now seeks recovery.[5] However well intentioned the Commission's decision was, we must now deal with the potential rate shock of allowing six years of investments to be included in base rates.

After careful review of the case before us, we find compelling evidence that BGE's AMI system is cost beneficial to its customers. We conservatively estimate that customers will receive $1.28 on a net present value basis for every $1 invested in the

[4] Order No. 83531 at 49.
[5] Butts Supplemental Direct at 3; $503 million in total AMI expenditures are offset by U.S. DOE grant, resulting in a net outstanding investment of $345 million through September 2015.

AMI system. While we authorize recovery of certain costs BGE incurred in deploying AMI, we have taken steps to lessen the potential impact on residential customers by authorizing BGE to amortize AMI cost recovery over 10 years rather than five. In addition, we have carefully reviewed the contested adjustments and prudency of the expenses BGE incurred in deploying AMI. As detailed herein, we have reduced by $47.8 million the $140.7 million BGE requested in connection with its AMI deployment.

We have similarly undertaken a thorough review of the case before us with respect to the requested rate increase attributable to Baltimore City's decision to increase the fees it charges users of the City-owned underground conduits, including BGE, from $0.9785 per linear foot to $3.33 per linear foot effective November 1, 2015. It did so in order to go from repairing the conduit system as problems arose – a reactive maintenance program – to a proactive maintenance program. If upheld and implemented, this would increase BGE's conduit fee by $30.7 million per year. Despite several months of discussions between the parties, the evidence before us reflects continuing uncertainties about the increased conduit fee. BGE sued the City regarding the increased conduit fee, raising questions about the City's commitment to spend conduit fee revenues only on actual costs of conduit maintenance, the appropriate true-up mechanism, and the scope and speed of the proposed proactive maintenance program. The parties reached agreement on some guiding principles and are attempting to settle the matter via mediation, but unresolved issues remain and the litigation is ongoing. The City is just now taking initial steps to implement its proactive maintenance program.

In this case BGE asks to recover $30.7 million per year of the conduit lease fee increase in the rate effective period, and also requests to recover $18.97 million of the increased lease fee for the period of November 2015 through June 2016 when the rates authorized in this case will go into effect. After careful consideration for the reasons set forth herein, we find that these requested post-test year adjustments are not known and measurable and we deny their recovery in this case.[6] We urge BGE and Baltimore City to reach a resolution that ensures that BGE customers will pay an appropriate conduit fee that accurately reflects the necessary costs of providing electric distribution services.

Based on the record in this case, we find that maintaining BGE's return on equity (ROE) of 9.75% for its electric operations and 9.65% for its gas distribution services allows for a fair and appropriate return. Consistent with recent cases, the ROEs we approve will continue to provide BGE with ample opportunity to obtain necessary capital at reasonable rates. In addition, we adopt BGE's original capital structure submitted with its application which includes a common equity ratio of 51.9%. Furthermore, we authorize recovery of post-test year reliability spending through the evidentiary hearings, as well as inclusion of infrastructure expenditures for BGE's Strategic Infrastructure Development and Enhancement ("STRIDE") program.

In summary, we authorize an increase in BGE's electric rates of $41.762 million and its gas rates by $47.776 million, for a total of $89.538 million. This will result in an increase to the average monthly bill of $2.67 for a residential electric customer and $4.86 for a residential gas customer.[7] This is significantly less than BGE's proposed increase of $7.05 per month (not including the conduit fee surcharge) for an electric customer and

[6] We continue to allow BGE to continue to recover in rates the approximately $10 million per year in conduit lease fees it has been paying.
[7] The average residential monthly bill increase is based on an electric customer using 925 kWh per month and a gas customer using 57 therms per month.

$8.01 per month for a gas customer.[8] We are cognizant, however, of the effect any rate increase will have on BGE's ratepayers. In particular, we acknowledge and remain deeply concerned about the burdens that increased rates place on limited-income customers. We have strived to limit the rate impact in this case while allowing the Company to invest in safety and reliability and continue to modernize its distribution systems for the benefit of its customers.

[8] BGE Initial Brief at 5.

## II. BACKGROUND

On November 6, 2015, BGE filed an application for Adjustments in Electric and Gas Base Rates and Other Tariff Revisions ("Application"), 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 the retail distribution of electricity and natural gas in Maryland. BGE's last electric and gas rate increase requests were partially approved in December 2014.[9] In its Application, BGE used a 12-month test year ending November 30, 2015, with nine (9) months of actual data and three (3) months of projected data, and stated that its evidence supported a $135.2 million increase in its electric distribution revenue requirement and a $77.8 million increase in its gas distribution revenue requirement. Based upon updated actual data for the full test year filed on January 5, 2016, BGE revised its requested electric revenue requirement increase to $117.1million and its requested gas revenue requirement increase to $78.8million.[10] BGE further revised its requested revenue requirement to reflect actual results through February 2016 and the impact of the Exelon/PHI merger synergies net of costs to achieve incurred through February 2016, so that its requested electric revenue requirement is $115.6 million and its requested gas revenue requirement is $78.2 million.[11]

A number of parties filed written testimony in this proceeding. BGE sponsored the testimony of Mark D. Case, Vice President for Regulatory Policy and Strategy,

[9] *Re Baltimore Gas and Electric Company, Case No. 9355, Proposed Order of the Public Utility Law Judge (December 4, 2014).*
[10] Staff filed a Comparison Chart of the Parties for BGE's Electric and Gas Operations ("Comparison Chart or Chart"), March 25, 2016.
[11] BGE Initial Brief at 5; BGE Exhibit 26.

testified on a general basis for the rate increase;[12] William B. Pino, Director of Energy Acquisition and Demand Response Market Operations, testified regarding Smart-Grid enabled programs that produce energy and peak demand reductions and result in customer savings;[13] Michael B. Butts, Director of AMI Business Transformation, testified regarding the history and current status of BGE's Smart Grid and detailed the operational benefits and costs of the program ;[14] David M. Vahos, Vice President, Chief Financial Officer and Treasurer, testified about the revenue requirements, the Company's proposed capital structure and overall cost of capital, and the increase in Baltimore City conduit fees;[15] John C. Frain, Director, Regulatory Strategy and Revenue Policy, testified about gas and electric rate designs;[16] and David E. Greenberg, Manager of Rate Administration, testified about the Calendar Year ("CY") 2014 Company Recommended Gas Actual Embedded Cost of Service Study and the CY 2014 Company Recommended Electric Actual Embedded Cost of Service Study.[17] An additional witness testified on behalf of BGE: Adrien M. McKenzie, Vice President of FINCAP, Inc., provided an independent assessment of the fair rate of return that BGE should be authorized to earn

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[12] BGE Ex. 28, Prepared Direct Testimony of Mark D. Case ("Case Direct"); BGE Ex. 29, Prepared Rebuttal Testimony of Mark D. Case ("Case Rebuttal").

[13] BGE Ex. 14, Prepared Direct Testimony of William B. Pino ("Pino Direct"); BGE Ex. 15, Prepared Rebuttal Testimony (Corrected version) of William B. Pino ("Pino Rebuttal"); BGE Ex. 16 Prepared Surrebuttal Testimony of William B. Pino ("Pino Surrebuttal").

[14] BGE Ex. 3, Prepared Direct Testimony of Michael B. Butts ("Butts Direct"); BGE Ex. 4, Prepared Supplemental Direct Testimony of Michael B. Butts ("Butts Supplemental Direct"); BGE Ex. 5, Prepared Rebuttal Testimony of Michael B. Butts ("Butts Rebuttal").

[15] BGE Ex.21 Prepared Direct Testimony of David M. Vahos ("Vahos Direct"); BGE Ex. 22, Prepared Supplemental Direct Testimony of David M. Vahos (Vahos Supp. Direct); BGE Ex. 23, Prepared Rebuttal Testimony of David M. Vahos ("Vahos Rebuttal"); BGE Ex. 24, David M. Vahos Updated exhibits for February 2016; BGE Ex. 25, Prepared Surrebuttal Testimony of David M. Vahos ("Vahos Surrebuttal").

[16] BGE Ex. 18, Prepared Direct Testimony of John C. Frain ("Frain Direct"); BGE Ex. 19, Prepared Supplemental Direct Testimony of John C. Frain ("Frain Supp. Direct"); BGE Ex. 20, Prepared Rebuttal Testimony of John C. Frain ("Frain Rebuttal").

[17] BGE Ex. 9, Prepared Direct Testimony of David E. Greenberg ("Greenberg t Direct"); BGE Ex. 10, Prepared Rebuttal Testimony of David E. Greenberg ("Greenberg Rebuttal").

on its investment in providing electric and gas delivery service customers and;[18] additionally, Dr. Ahmad Faruqui, a Principal with The Brattle Group, testified in support of BGE's request to recover costs for its Smart Grid deployment.[19]

The Office of People's Counsel ("OPC") presented the testimony of David J. Effron, an independent consultant specializing in utility regulation, who testified regarding the revenue requirements including rate base and pro forma operating income adjustments of BGE;[20] Jonathan F. Wallach, Vice President of Resource Insight, Inc., who testified regarding electric revenue increase to the residential class, electric cost of service study, proposal to increase customer charges for electric Schedule R customers and proposal to recover Baltimore's conduit fees;[21] Peter J. Lanzalotta, a Principal with Lanzalotta & Associates, LLC, who testified regarding BGE's reliability and storm restoration matters;[22] J. Randall Woolridge, Professor of Finance at Pennsylvania State University, who testified regarding the cost of capital for electric & gas distribution services and evaluate BGE's rate of return testimony;[23] Nancy Brockway, former Commissioner of New Hampshire Public Utilities Commission, who testified regarding

[18] BGE Ex.6 Prepared Direct Testimony of Adrien M. McKenzie ("McKenzie Direct"); BGE Ex. 7, Prepared Rebuttal Testimony of Adrien M. McKenzie ("McKenzie Rebuttal"); BGE Ex. 8, Prepared Surrebuttal of Adrien M. McKenzie ("McKenzie Surrebuttal").
[19] BGE Ex. 17, Rebuttal Testimony of Dr. Ahmad Faruqui ("Faruqui Rebuttal").
[20] OPC Ex. 29, Direct Testimony of David J. Effron; OPC Ex. 30, Surrebuttal Testimony of David J. Effron ("Effron Surrebuttal").
[21] OPC Ex. 23, Public Version Direct Testimony of Jonathan F. Wallach OPC Ex. 23A and Confidential Version Direct Testimony of Jonathan F. Wallach (collectively "Wallach Direct"); OPC Ex. 24, Rebuttal Testimony of Jonathan F. Wallach ("Wallach Rebuttal"); OPC Ex. 25, Surrebuttal Testimony of Jonathan F. Wallach ("Wallach Surrebuttal").
[22] OPC Ex. 34, Public Version Direct Testimony of Peter J. Lanzalotta OPC Ex. 34A Confidential Version Direct Testimony of Peter J. Lanzalotta ("Lanzalotta Direct"); OPC Ex. 35, Public Version Surrebuttal Testimony of Peter J. Lanzalotta OPC Ex. 35A, Confidential Version Surrebuttal Testimony of Peter J. Lanzalotta ("Lanzalotta Surrebuttal").
[23] OPC Ex. 20, Direct Testimony of J. Randall Woolridge ("Woolridge Direct"); OPC Ex. 21, Rebuttal Testimony of J. Randall Woolridge ("Woolridge Rebuttal"); OPC Ex. 22, Surrebutal Testimony of J. Randall Woolridge ("Woolridge Surrebuttal").

AMI installation process, BGE's customer AMI Education Plan, cyber security and privacy protections, and policy considerations related to legacy meters;[24] Maximillan Chang, who is a Principal Associate at Synapse Energy Economics, testified regarding the benefit-to-cost analysis for Smart Grid development and deployment;[25] Additionally, Paul Chernick presented testimony on behalf of OPC. Mr. Chernick, President of Resource Insight, Inc., testified regarding the some of the benefits BGE asserts with its Smart Grid investment.[26]

The Maryland Energy Group ("MEG") presented the testimony of Richard A. Baudino, a consultant with J. Kennedy and Associates, who testified regarding class cost of service, revenue allocation, rate design and tariff issues, and BGE's proposed Rider 5.[27] MEG also presented the testimony of Yitzchak Raphaeli, Process Manager for American Sugar Refining, Inc., who testified regarding reasonable utility rates for industrial, institutional and other large energy uses.[28]

The Public Service Commission Technical Staff ("Staff") presented the testimony of Patricia M. Stinnette, Director of the Accounting Investigations Division, who testified regarding revenue requirements;[29] Yulia Poberesky, Public Utility Auditor, who also

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[24] OPC Ex. 38, Direct Testimony of Nancy Brockway ("Brockway Direct"); OPC Ex. 39, Surrebuttal Testimony of J. Nancy Brockway ("Brockway Surrebuttal").
[25] OPC Ex. 26, Direct Testimony of Maximillan Chang ("Chang Direct"); OPC Ex. 27, Rebuttal Testimony of Maximillan Chang ("Chang Rebuttal").
[26] OPC Ex. 31, Public Version Direct Testimony of Paul Chernick OPC Ex. 31A and Confidential Version Direct Testimony of Paul Chernick (collectively "Chernick Direct"); OPC Ex. 32, Rebuttal Testimony of Paul Chernick ("Chernick Rebuttal"); OPC Ex. 33, Public Version Surrebuttal Testimony of Paul Chernick, OPC Ex. 33A, Confidential Version Surrebuttal Testimony of Paul Chernick ("Chernick Surrebuttal").
[27] MEG Ex. 2, Direct Testimony and Exhibits of Richard A. Baudino ("Baudino Direct"); MEG Ex. 3, Rebuttal Testimony of Richard A. Baudino ("Baudino Rebuttal"); MEG Ex. 5, Surrebuttal Testimony of Richard A. Baudino ("Baudino Surrebuttal").
[28] MEG Ex. 1, Direct Testimony of Yitzchak Raphaeli ("Raphaeli Direct").
[29] Staff Ex. 27, Corrected Direct Testimony and Exhibits of Patricia M. Stinnette ("Stinnette Direct");; Staff Ex. 28, Surrebuttal Testimony and Exhibits of Patricia M. Stinnette ("Stinnette Surrebuttal").

testified regarding revenue requirements;[30] Dr. C. Shelley Norman, a Regulatory Economist in the Electricity Division, who testified about the cost of service for the electric operations of BGE;[31] Jason Cross, a Regulatory Economist in the Telecommunications, Gas and Water Division, who testified about the cost of service for the gas operations of BGE;[32]Amanda Best, Assistant Director of the Division of Energy Analysis and Planning, who testified about the cost of capital, cost of equity structure and rate of return for the gas operations of BGE;[33] Craig Taborsky, Assistant Chief Engineer, who testified regarding the engineering aspects of BGE's use of Baltimore City's conduit;[34] Loubens Blaise, a Regulatory Economist in the Electricity Division, who testified regarding the electric rate design and proposed tariff changes;[35] Tanu Jeffrey Pongsiri, a Regulatory Economist in the Electricity Division, who testified regarding the gas rate design and proposed tariff changes;[36] Philip VanderHayden, Director of the Electricity Division, who testified on an overall rate of return for determining BGE's electric distribution rates and offered critique of BGE cost of capital testimony;[37] Jennifer Ward, Regulatory Economist in the Electricity Division, who testified on an

[30]Staff Ex. 25, Corrected Direct Testimony and Exhibits of Yulia Poberesky ("Poberesky Direct"); Staff Ex. 26, Staff Ex. 26, Surrebuttal Testimony and Exhibits of Yulia Poberesky ("Poberesky Surrebuttal").

[31] Staff Ex. 34, Public Version Direct Testimony and Exhibits of Dr. C. Shelley Norman , Staff Ex. 34A Confidential Version Direct Testimony of Dr. C. Shelley Norman (collectively "Norman Direct"); Staff Ex. 35, Rebuttal Testimony and Exhibits of Dr. C. Shelley Norman ("Norman Rebuttal"); Staff Ex. 36 Surrebuttal Testimony of Dr. C. Shelley Norman ("Norman Surrebuttal")..

[32] Staff Ex. 22, Direct Testimony and Exhibits of Jason Cross ("Cross Direct"); Staff Ex. 23,Surrebuttal Testimony of Jason Cross ("Cross Surrebuttal").

[33] Staff Ex. 24, Direct Testimony of Amanda Best ("Best Direct").

[34] Staff Ex. 33, Public Version Direct Testimony and Exhibits of Craig Taborsky and Staff Ex. 33A Confidential Version Direct Testimony and Exhibits of Craig Taborsky ( "Taborsky Direct").

[35] Staff Ex. 44, Direct Testimony and Exhibits of Loubens Blaise ("Blaise Direct"); Staff Ex. 45, Rebuttal Testimony and Exhibits of Loubens Blaise ("Blaise Rebuttal"); Staff Ex. 46, Surrebuttal Testimony and Exhibits of Loubens Blaise ("Blaise Surrebuttal").

[36] Staff Ex. 44, Direct Testimony and Exhibits of Tanu Jeffrey Pongsiri ("Pongsiri Direct"); Surrebuttal Testimony and Exhibits of Tanu Jeffrey Pongsiri ("Pongsiri Surrebuttal").

[37] Staff Ex. 47, Direct Testimony and Exhibits of Philip VanderHayden ("VanderHayden Direct"); Staff Ex. 48, Surrebuttal Testimony and Exhibits of Philip VanderHayden ("VanderHayden Surrebuttal");

appropriate cost of equity and an overall rate of return for determining BGE's gas distribution rates;[38] and Daniel Hurley, Director of the Commission's Energy Analysis and Planning Division, who testified regarding the costs, benefits and cost-effectiveness of BGE Smart Grid Initiative.[39]

The Department of Defense and all other Federal Executive Agencies ("DOD/FEA") presented the testimony of Dennis W. Goins, owner of Potomac Management Group, who testified regarding the recovery of Baltimore City conduit fees through Local Government Owned Conduit Charge and BGE's eligible conservation program costs;[40] and David Shpigler, an Executive Consultant at Excergy, who testified regarding certain rate base and operating income adjustments and the overall revenue requirement.[41]

The Mayor and City Council of Baltimore ("City") presented the testimony of William M. Johnson, Director of Baltimore City Department of Transportation, who testified in support of the City's position that BGE should be permitted to recover in rates the Baltimore City conduit lease fees;[42] Lindsay Wines, Deputy Director, Administration, Baltimore City Department of Transportation, who testified in support of the City's position that expenses BGE should be permitted to recover in rates for

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[38] Staff Ex. 42, Direct Testimony and Exhibits of Jennifer Ward ("Ward Direct"); Staff Ex. 43, Surrebuttal Testimony and Exhibits of Jennifer Ward ("Ward Surrebuttal");

[39] Staff Ex. 37, Direct Testimony and Exhibits of Daniel Hurley ("Hurley Direct"); Staff Ex. 38, Rebuttal Testimony and Exhibits of Daniel Hurley ("Hurley Rebuttal"); Staff Ex. 39, Surrebuttal Testimony and Exhibits of Daniel Hurley ("Hurley Surrebuttal").

[40] DOD/FEA Ex. 3, Direct Testimony and Exhibits of Dennis W. Goins ("Goins Direct").

[41] DOD/FEA Ex. 1, Direct Testimony Errata and Exhibits of Daniel Shipigler ("Shipigler Direct"); DOD/FEA Ex.2, Surrebuttal Testimony Errata and Exhibits of Daniel Shipigler ("Shipigler Surrebuttal");

[42] City Ex. 2, Direct Testimony and Exhibits of William M. Johnson ("Johnson Direct"); City Ex. 3, Rebuttal Testimony of William M. Johnson ("Johnson Rebuttal").

Baltimore City conduit lease fees;[43] and Dale Kessinger, a Consulting Principal and co-founder of Clearspring Energy Advisors LLC, who testified regarding cost allocation issues related to the proposed recovery of conduit lease expenses.[44] Staff, OPC, MEG, DOD/FEA, and the City filed direct testimony on February 8, 2016. The Company filed supplemental direct testimony on January 5, 2016 updating the Company's direct testimony for actual data for the full test year. Parties filed rebuttal testimony on March 4, 2016 and surrebuttal testimony on March 18, 2016. The Commission conducted evidentiary hearings at its offices on March 29-31, April 1, 4-8, 11-12, and held evening public comment hearings throughout the Company's service territory in Anne Arundel County, Baltimore County, Howard County, Harford County and Baltimore City, and on March 3, 7, 9, 16, 17, respectively. Parties filed Initial Briefs on April 29 and Reply Briefs on May 13, 2016.

Prior to the start of the evidentiary hearings on March 25, 2016, the Staff filed, on behalf of the parties, a Summary of Positions on Revenue Requirements (hereinafter, the "Chart").[45] The Chart reflects BGE's final purported revenue deficiencies of $117,123,000 for electric distribution operations and $78,890,000 for gas distribution operations. Staff's final position reflects an electric revenue requirement deficiency of $86,280,000 and a gas revenue deficiency of $66,161,000, while OPC's final position reflects an electric revenue deficiency of $66,155,000 and a gas revenue deficiency of $62,978,000.

[43] City Ex. 4, Direct Testimony and Exhibits of Lindsey M. Wines ("Wines Direct");
[44] City Ex. 5, Direct Testimony and Exhibits of Dale Kessinger ("Kessinger Direct"); City Ex. 6, Rebuttal Testimony of Dale Kessinger ("Kessinger Rebuttal").
[45] Staff filed a Comparison Chart of the Parties for BGE's Electric and Gas Operations ("Comparison Chart or Chart"), March 25, 2016.

The Commission has thoroughly reviewed all of the evidence presented, including the comments received at the five public hearings in reaching the decisions in this Order.

## III. DISCUSSION AND FINDINGS

### A. Smart Grid Initiative

#### 1. ***Benefit-Cost Analysis***

When the Commission granted the Company's request to proceed with deployment of its advanced metering infrastructure (or smart grid initiative) in Case No. 9208, the Commission directed that the Company defer recovery of costs until the Company had delivered a cost-effective system.[46] According to the Company's application, the Company deferred incremental costs of approximately $160 million through November 2015 in a smart grid regulatory asset,[47] for which the Company is seeking to recover $140 million in rate relief in this proceeding.[48] The Company is proposing to amortize the smart grid regulatory asset over a five year period.

**Party Positions**

***BGE***

The Company submits that its smart grid System is cost-effective. After applying a grant from the U.S. Department of Energy, the net cost of the smart grid Initiative is $344 million.[49] Its benefits include smart grid enabled programs such as BGE Smart Energy Rewards ("SER") and BGE Smart Energy Manager ("SEM") that allow customers to manage their energy usage more efficiently.[50] BGE states that smart grid

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[46] *Re Baltimore Gas and Electric Company, 101 MD PSC 401, 420 (2010).*
[47] Direct Testimony of Mark D. Case, November 6, 2015 ("Case Direct") at 21.
[48] Direct Testimony of David M. Vahos, November 6, 2016 ("Vahos Direct") at 5; Supplemental Direct Testimony of David M. Vahos, January 5, 2016 (Vahos Supplemental Direct") at 2.
[49] Case Direct at 24.
[50] Case Direct at 24.

has led to an enhanced customer experience and improved outage restoration, with future applications likely.[51]

BGE witness Butts testified that BGE's smart grid deployment began in April 2012 and ended in September 2015.[52] Mr. Butts further testified that BGE did not initially design its communication plan and deployment schedule to accommodate customers who desired to opt-out of a smart metering device installation, and that BGE assumed that it would be able to exercise all of its standard rights to terminate service in the event a customer did not grant access to an indoor or otherwise inaccessible meter for installation of a smart metering device.[53] Therefore, BGE estimates that the cost to install smart metering devices increased by approximately $16.6 million as a result of customers' ability to defer a smart metering installation or not respond to BGE's multiple attempts to schedule installation.[54] According to Mr. Butts, the original deployment schedule called for all smart metering devices to be installed in a contiguous fashion but because so many non-responsive customers required another field visit, BGE continued to experience cost impacts from the opt-out proceedings, even after the Commission Order allowed BGE to assess fees on a customer's bill or terminate service for failure to grant access to an indoor or otherwise inaccessible meter.[55]

As more fully explained by Company witnesses Butts and Pino, the Company's position is that smart grid benefits exceed costs by a ratio of 2.3 on a nominal basis.[56] In other words, BGE claims that for every $1.00 in costs, BGE customers will realize

[51] Case Direct at 26.
[52] Prepared Direct Testimony of Michael B. Butts, November 6, 2015 ("Butts Direct") at 21.
[53] Butts Direct at 24-25.
[54] Butts Direct at 25.
[55] Butts Direct at 25-26.
[56] Vahos Supplemental Direct at 4.

approximately $2.30 in benefits.[57] According to Company witness Vahos, Operating Income Adjustment 22 provides for an annual level of Smart Grid incremental operational savings, ongoing costs, and regulatory asset amortization based on Smart Grid deferrals through the end of the test period.[58] Mr. Vahos testified that Operating Income Adjustment 22 reflects the $17.5 million in operational savings customers will realize during the test year, and provides for additional operational savings of $5.2 million projected for the rate-effective period (June 2016 through May 2017), for a total of $22.7 million in operational savings reflected in the calculation of revenue requirement.[59] Operating Income Adjustment 23 reflects amortization of the projected amounts deferred in the smart grid regulatory asset from the end of the test year through May 2016, and Rate Base Adjustment 6 adjusts rate base to reflect the smart grid regulatory asset based on a thirteen-month average as of May 2016.[60] Mr. Vahos stated that upon Commission approval of these adjustments, BGE will cease deferring a return on its unrecovered regulatory asset, thereby saving customers money.[61] Mr. Vahos claims that if the Commission does not approve these adjustments in this proceeding, BGE would continue to record a return on the smart grid regulatory asset and seek recovery of the remaining unrecovered costs in a future proceeding.[62]

The Company maintains that a five year amortization period is consistent with other regulatory asset amortization periods approved by the Commission.[63]

[57] Vahos Supplemental Direct at 4.
[58] Vahos Direct at 11.
[59] Vahos Supplemental Direct, Exhibits at 28.
[60] Vahos Direct at 11.
[61] Vahos Direct at 14.
[62] Vahos Direct at 14.
[63] Vahos Direct at 13.

***OPC***

OPC witness David J. Effron testified about the deferred smart grid costs. In conjunction with the recovery of the smart grid costs, the Company has included net smart grid plant in service and the smart grid regulatory asset in its test year rate base. The smart grid regulatory asset includes deferred operation and maintenance expenses, deferred depreciation expense, deferred property taxes, deferred return on smart grid plant, and carrying charges on the cumulative balance of the regulatory asset itself.[64] The smart grid regulatory asset, net of applicable ADIT, is included in the test year rate base.

Mr. Effron notes that BGE did not offset smart grid operational savings against its calculation of the deferred operation and maintenance expenses included in the smart grid regulatory asset.[65] Instead, the benefits of smart grid operational savings have been reflected in the Company's test year cost of service in prior rate cases. Mr. Effron states, however, that the savings credited to ratepayers based on test year costs have lagged the Company's actual realization of smart grid operational savings.[66] He opined that the excess of the operational savings achieved over the amount credited to ratepayers should be offset by the deferred smart grid costs included in the recoverable smart grid regulatory asset.[67] He estimated that reducing the smart grid operational savings as recommended by Mr. Lanzalotta would reduce the overall electrical operational savings by 6.7%. With that modification, reflecting smart grid operational savings over and above the savings already reflected in rates reduces the smart grid regulatory asset by

[64] Direct Testimony of David J. Effron, February 8, 2016 ("Effron Direct") at 7.
[65] Effron Direct at 7.
[66] Effron Direct at 8.
[67] Effron Direct at 9.

$16,170,000, which would result in a reduction in the Company's electric rate base, net of accumulated deferred income taxes, of $9,643,000.[68]

Mr. Effron opined that the five year amortization period proposed by the Company imposes an unreasonable short term burden on customers and does not properly match the costs and benefits of the smart grid initiative.[69] He recommended a 10 year amortization period as reasonable and as achieving a better matching of smart grid costs and benefits.[70] This would result in a reduction of $21,486,000 to the Company's electric amortization and $8,778,000 to the Company's gas amortization.[71] Mr. Effron noted that the Company included smart grid rate year savings as a credit to the smart grid revenue requirement, which he adjusted based on Mr. Lanzalotta's recommendation to reduce the savings attributable to reductions to storm restoration costs, thereby increasing smart grid electric expenses by $1,042,000.[72]

In surrebuttal, OPC witness Effron responded to the citing by Company witnesses of language from page 38 of Order No. 85381 that "[t]he only direct savings that customers forego during the deployment years if we do not approve a tracker are the $15 million in reduced meter reading costs that BGE would pass through." Mr. Effron notes that the Company witnesses infer from this language that it was the Commission's intent that customers would permanently forego $15 million in reduced meter reading costs related to the smart grid program as compared to the tracker method.[73] Instead, Mr. Effron believes that the Commission's reference to the $15 million in reduced meter

[68] Effron Direct at 10-11.
[69] Effron Direct at 23.
[70] Effron Direct at 23-24.
[71] Effron Direct at 24.
[72] Effron Direct at 25.
[73] Surrebuttal Testimony of David J. Effron, March 21, 2016 ("Effron Surrebuttal") at 9.

reading costs foregone by customers "during the deployment years" reflects that it was the intent of the Commission only that the savings would be foregone over the time frame that the smart grid assets were being deployed, not permanently.[74] Mr. Effron points out that the very next sentence of the Order is "[w]hile having to wait to realize these savings is less than ideal, overall we believe the customer is better off for not having had to pay $160 million in surcharges in advance to achieve those savings."[75]

The testimony of OPC witness Nancy Brockway addresses: (a) customer care issues with the installation process; (b) the sufficiency of BGE's Education Plan; (c) whether AMI is providing customers with the superior electric customer experience promised by BGE; (d) the status of cyber security and privacy protections; and (e) policy considerations related to legacy meters.

Ms. Brockway discusses the issues of customer resistance to BGE's smart meter initiative, hard-to-access meters, and non-responsive customers, and the resulting opt-out orders.[76] Pointing to BGE's reported installation rates over the years of deployment, Ms. Brockway does not agree that the Commission's opt-out orders have had a substantial impact on BGE's smart grid deployment and its achievement of the installations per its 2010 business plan.[77] Ms. Brockway finds unsatisfactory BGE's explanation for its failure to complete meter installation, noting that BGE has often had difficulties reaching all of its customers when it is trying to contact them or gain access to their premises.[78] Ms. Brockway recommends that the Commission keep the reporting mechanism open

[74] Effron Surrebuttal at 10.
[75] Effron Surrebuttal at 10.
[76] Direct Testimony of Nancy Brockway, February 8, 2016 ("Brockway Direct) at 11-15.
[77] Brockway Direct at 14.
[78] Brockway Direct at 14.

until the hard-to-access issues reach zero percent, or at least as close to zero as can be obtained, and that BGE be required to continue reporting on opt-out numbers.[79]

Although Ms. Brockway agrees that BGE has fulfilled the literal terms of its communication and customer education plan ("Plan"), Ms. Brockway notes that the Plan did not prevent the customer resistance to the installation of the meters.[80] Ms. Brockway opines that the Plan is too limited and does not provide customers a usable understanding of customer awareness of and engagement with the data made available through communicating interval meters.[81]

Ms. Brockway believes that all of the new functionalities of smart meters have not been realized. She testified about cyber security risks and privacy issues. She recommends that additional functionalities such as the ability to remotely control lights, refrigerators, thermostats, door locks, water usage, washing machines, and robot vacuums be delayed until there is a greater understanding of the extent to which risks can be eliminated or at least greatly reduced, and until the general public has expressed an interest in these new functions.[82]

Lastly, Ms. Brockway concurred with the conclusion of OPC witness Maximilian Chang that the $48 million in unrecovered capital assets associated with retired legacy meters should be disallowed.[83] Alternatively, Ms. Brockway recommends that the costs of the BGE smart grid initiative be allocated equitably between stockholders and

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[79] Brockway Direct at 15.
[80] Brockway Direct at 17.
[81] Brockway Direct at 17.
[82] Brockway Direct at 32.
[83] Brockway Direct at 33.

customers, which she opined would be consistent with Commission Order No. 83531.[84] Ms. Brockway stated that to permit BGE to recover a full return "on" and "of" its legacy meters and its AMI meters would allow two sets of meters in rate base, one of which is no longer used and useful, creating a double recovery of metering costs.[85] She noted that at least two other commissions, California and Kansas, have denied 100% return of and on legacy meters.

On surrebuttal OPC witness Brockway maintains that there has been customer resistance to installation of smart meters. Ms. Brockway opines that BGE should have anticipated that customers would want an "opt-out," as well as the difficulties in gaining access to customer premises.[86] Ms. Brockway testified that almost immediately from the time that deployment of smart meters began, there were consumer demands for opt-out, and utilities in other jurisdictions were getting demands from customers for the ability to opt-out.[87] Ms. Brockway also maintains that BGE should be directed to continue collecting and reporting metric information regarding the smart grid system.[88]

Ms. Brockway believes the filing of the present rate case operates to supersede the settlement agreement reaching in Case No. 9355, and thus the fact that the settlement agreement identified a 10-year amortization period for legacy meter accounting does not bind OPC to agree to the Company's cost recovery proposal in this case.[89]

[84] Brockway Direct at 33.
[85] Brockway Direct at 34.
[86] Surrebuttal Testimony of Nancy Brockway, March 21, 2016 ("Brockway Surrebuttal") at 4-5.
[87] Brockway Surrebuttal at 4.
[88] Brockway Surrebuttal at 5-6.
[89] Brockway Surrebuttal at 7.

With regard to recovery of abandoned legacy meters, Ms. Brockway testified that not all plant assets are accorded 100% recovery *of* and *on* their undepreciated balances.[90] She opined that because BGE retired an entire class of operable meters at one time, of its own volition, for a program whose benefits are as of yet unproven, puts these costs in a different category from run-of-the-mill plant assets such as wooden poles.[91]

OPC witness Peter J. Lanzalotta reviewed portions of the Company's testimony related to planning, reliability and storm restoration matters. Mr. Lanzalotta concluded that electric service reliability has improved greatly over recent years due to factors other than AMI, including changes in reliability-related regulations in RM-43, and a big increase in reliability-related spending over the period 2013-2015.[92] Mr. Lanzalotta compared the average annual customer interruptions for the period of 2008 through 2012 with the annual average customer interruptions for 2013-2014 (both with no exclusions for major outage events)[93] and determined that annual customer interruptions have decreased by more than 40%.[94] Mr. Lanzalotta opined that with more than a 40% reduction in customer interruptions, the need for truck rolls is reduced and outage duration is reduced because there are more than 40% fewer customers to restore to service.[95] Therefore, he concluded that the savings attributed to avoided truck rolls and

[90] Brockway Surrebuttal at 9.
[91] Brockway Surrebuttal at 9.
[92] Direct Testimony of Peter J. Lanzalotta, February 8, 2016 ("Lanzalotta Direct") at 5.
[93] "Major outage event" means an event during which:
(a) Both:
(i) More than 10 percent or 100,000, whichever is less, of the electric utility's Maryland customers experience a sustained interruption of electric service; and
(ii) Restoration of electric service to any of these customers takes more than 24 hours; or
(b) The federal, State, or local government declares an official state of emergency in the utility's service territory and the emergency involves interruption of electric service. COMAR 20.50.01.03.
[94] Lanzalotta Direct at 13-14.
[95] Lanzalotta Direct at 14.

to reduced storm restoration duration should be reduced by at least 40%.[96] Lastly, Mr. Lanzalotta discussed the likelihood of avoided transmission costs due to AMI.

On surrebuttal, OPC witness Lanzalotta responded to BGE witness Butts' criticism of his recommended 40% reduction in storm-related savings due to reduced truck rolls. Mr. Lanzalotta opined that the Company's increased reliability is reducing the number of customer interruptions resulting from weather conditions, and that what used to be major events may not always rise to those levels of customer interruptions in the future.[97] Mr. Lanzalotta stated that the benefits attributable to avoided truck rolls and the resultant reduced outage duration are substantially undercut by the reductions in the number of customer interruptions being experienced as a result of the increasing reliability of the Company's distribution system.[98]

OPC witness Maximilian Chang opined that the Company's benefit-cost analysis of the smart grid initiative was flawed. Mr. Chang believes that the Company overstated both market-side and operational benefits attributable to the smart grid program. Mr. Chang does not believe Smart Energy Manager (SEM) benefits should be included in the benefit-to-cost analysis because the savings could have been achieved without the smart grid investments.[99] Mr. Chang believes that the smart grid-enabled tools available through the SEM platform have not materially impacted energy savings.[100] Mr. Chang

[96] Lanzalotta Direct at 14.
[97] Surrebuttal Testimony of Peter J. Lanzalotta, March 21, 2016 ("Lanzalotta Rebuttal") at 5.
[98] Lanzalotta Surrebuttal at 4.
[99] Direct Testimony of Maximilian Chang, February 8, 2016 ("Chang Direct") at 9-10.
[100] Chang Direct at 13.

also believes that the Company has overstated demand and energy savings attributable to the Smart Energy Rewards (SER) program due to free-ridership issues.[101]

Mr. Chang reviewed the costs of the smart grid initiative, including in his benefit-cost analysis legacy meter costs, which he believes to be consistent with the Commission's guidance in Order Nos. 83410 and 83531 in Case No. 9208.[102] Mr. Chang raised concerns about the costs associated with failed meters[103] and the Company's difficulty in completing installations.[104] Mr. Chang believes that the Company should have reasonably foreseen some difficulty with non-responsive customers given the Company's 30 percent incompletion rate for field jobs.[105]

Mr. Chang also raised concerns about the treatment of bill credits.[106] Mr. Chang stated that his organization has reconsidered its determination of the treatment of bill credits paid to participants of the SER program; where he used to consider the credits as intra-customer transfers, as the Company does, participants of the SER program experience real costs associated with thermal comfort and are being compensated for providing a service in the form of load reductions.[107]

When Mr. Chang used alternate inputs developed by OPC and included legacy meter costs, the benefit-cost ratio is below one (0.75).[108] Mr. Chang further noted that the Company's meter failure rate is twice as high as originally projected, though currently

[101] Chang Direct at 14-15.
[102] Chang Direct at 18.
[103] Chang Direct at 19-20.
[104] Chang Direct at 20-23.
[105] Chang Direct at 20-22.
[106] Chang Direct at 23-24.
[107] Chang Direct at 23-24.
[108] Chang Direct at 30.

the Company does not have to report meter failures in its quarterly reports.[109] Mr. Chang recommended that the Commission consider disallowing $193 million of the Company's costs, in order to break even.[110] He further recommended that the Commission require BGE to provide a revenue requirement impact assessment and regular analyses of the cost-effectiveness of the smart grid initiative going forward.[111]

On surrebuttal, Mr. Chang adjusted his benefits calculation somewhat. He made an adjustment of $21 million to the estimate of free ridership that both he and OPC witness Chernick made; an adjustment of $1 million for the emergency strike price as described in witness Chernick's surrebuttal testimony; and an adjustment of $1 million for calculations in Unforced Capacity as described in Mr. Chernick's surrebuttal testimony.[112] Mr. Chang also updated his estimate of SEM program costs based in part on corrected Company testimony.[113] Mr. Chang continues to recommend that the cost of legacy meters be included in the benefit-cost analysis, which he states is consistent with the Commission's inclinations in Order No. 83410.[114] Mr. Chang's updated analysis indicated that the Company's smart grid initiative remains not cost effective with a present value benefit-cost ratio of 0.82 (benefits of $609 million, costs of $745 million). Mr. Chang maintains that the Commission should disallow the $136 million difference between OPC's estimate of costs and benefits (hold harmless credit).

OPC witness Paul Chernick reviewed some of the benefits BGE asserted are provided by the Smart Energy Rewards (SER) and Smart Energy Manager (SEM)

[109] Chang Direct at 30.
[110] Chang Direct at 30.
[111] Chang Direct at 30.
[112] Surrebuttal Testimony of Maximilian Chang, March 21, 2016 ("Chang Surrebuttal") at 3.
[113] Chang Surrebuttal at 6.
[114] Chang Surrebuttal at 7.

programs, as well as incremental savings from the pre-existing PeakRewards (PR) program. Mr. Chernick concluded that the benefits claimed by BGE are overstated due to over a dozen distinct errors.[115]

Mr. Chang addressed the estimation of load reductions. Mr. Chernick addressed the effect of the load reductions on the BGE zonal peak forecast and capacity obligation. Mr. Chernick testified that BGE's model does not reflect well the development of the PJM forecasts that drive capacity obligations, and that the SER load reductions are not likely to reduce peak forecasts.[116] Mr. Chernick noted that BGE's estimates of savings are based on the PJM 2015 Forecast of load growth, which averages about 6% higher than the current 2016 forecast.[117] In addition, Mr. Chernick believes BGE misestimated the load reductions due to the SER by ignoring the free riders in the program.[118] Mr. Chernick would estimate that the actual load effect of the SER is the change in total load from all eligible SER-only customers, excluding the PR customers, which would reduce BGE's estimates of the SER peak reductions by about 50% in 2014 and 30% in 2013 and 2015.[119] The resulting reduction in peak loads would reduce the present value of avoided capacity cost by about $30 million, demand-side price mitigation by about $20 million, and avoided T&D by about $50 million.[120]

Mr. Chernick opined that due to the structure of the PJM forecasting model, the effect of the SER and PR load reductions on BGE's capacity obligation is likely to be tiny, and the effect of SEM load reductions is likely to be substantially lower than BGE

115 Direct Testimony of Paul Chernick, February 8, 2016 ("Chernick Direct") at 7.
116 Chernick Direct at 10.
117 Chernick Direct at 10.
118 Chernick Direct at 10.
119 Chernick Direct at 15.
120 Chernick Direct at 15.

assumes.[121] Mr. Chernick claims that BGE's estimates of the reduction in the PJM forecasts due to the SER were about 50 to 70 times larger than the reduction actually produced by the PJM forecasting model.[122] Mr. Chernick also believes that BGE is overstating the reduction in capacity obligation from the SEM by a factor of 3.[123]

Mr. Chernick identified a total of five errors in BGE's analysis of capacity price mitigation: (1) the SEM will affect the PJM capacity requirement and the price of capacity much less than BGE assumes; (2) the load forecast that BGE uses to estimate the amount of capacity that Maryland customers will bear is much higher than PJM's current forecast; (3) BGE assumes that prices for Delmarva will always be affected by BGE loads in future Base Residual Auctions[124] ("BRAs"); (4) the coefficients that BGE uses to convert load reductions and cleared resources to price reductions is grossly overstated; and (5) the price reduction from adding the BGE program resources to the capacity auctions are often less than the reduction from adding generation or other premium resources.[125] Mr. Chernick offered corrected price-mitigation coefficients which would decrease BGE's claimed price-mitigation benefits by over $170 million.[126] He summarized that the SER and PR programs are unlikely to produce any meaningful capacity-price benefits; the SEM may produce some price benefits, but substantially less

[121] Chernick Direct at 20.
[122] Chernick Direct at 23.
[123] Chernick Direct at 24.
[124] The Base Residual Auction is conducted to allow for the procurement of resource commitments to satisfy the PJM region's unforced capacity obligation for the Delivery Year and allocates the cost of those commitments to Load Serving Entities (LSEs) through a Locational Reliability Charge. http://www.pjm.com/~/media/markets-ops/rpm/rpm-auction-info/rpm-base-residual-auction-faqs.ashx.
[125] Chernick Direct at 26.
[126] Chernick Direct at 37.

than BGE assumes, since BGE overstated the sensitivity of the load forecast to recent load reductions and the response of price to reductions in forecast load.[127]

Mr. Chernick identified four problems common to BGE's estimates of transmission and distribution (T&D) benefits: (1) BGE's inability to identify any projects in the years in which BGE claims large avoided capital costs; (2) BGE's inability to produce any documents demonstrating that its T&D planners actually reflect the SER and PR load reductions claimed; (3) the mismatch between the timing of the SER and PR load reductions and the timing of the peak loads driving T&D investment; and (4) BGE's failure to annualize the avoided capital costs.[128]

Mr. Chernick identified eight problems in BGE's estimate of the value of avoided transmission: (1) BGE computes the $/kW avoided costs from the total cost of its 250 kV and 500 kV transmission system, priced as if it were all constructed in 2015; (2) BGE includes as import capability transmission facilities that are not associated with imports, but for delivery to customers (or export) of energy from generation in the BGE zone; (3) BGE does not divide the costs of these facilities by the load in the BGE zone, but by the zone's import capability; (4) reductions during the incentive hours on Energy Savings Days (ESDs) are unlikely to have affected transmission planning or costs; (5) BGE cannot identify the hours whose loads affected the allocation of costs of any transmission projects to the BGE zone; (6) BGE was unable to identify the type of load (by location or timing) for its past or projected transmission projects; (7) while BGE assumes that one megawatt of load reduction would reduce the required import capability by one megawatt, BGE does not know how PJM determines the required import capability; and

[127] Chernick Direct at 37.
[128] Chernick Direct at 38.

(8) BGE's import capability estimate of 6,527 MW is not taken from PJM's Regional Transmission Expansion Plan ("RTEP"), but from the Capacity Emergency Transmission Limit (CETL) reported in the 2018/19 BRA planning parameters.[129] Mr. Chernick stated that the improved methodology of dividing the escalated transmission cost by BGE's forecast peak, rather than the 2018/19 CETL, would reduce the $/MW value by 8% using the 2017/18 forecast and 11-14% using the forecasts for 2013-2015, when BGE claims $86 million in transmission investments were avoided.[130] With regard to distribution, Mr. Chernick identified evidence regarding the effect of reductions in peak substation loads due to the load reductions from SER and PR programs, concluding that it is unlikely that there have been or will be any avoided transmission or distribution investments from BGE's demand-response programs.[131]

Mr. Chernick notes that the most important factors in BGE's estimates of energy revenues are the annual number of non-emergency hours in which the programs would operate, the forecast of locational marginal price (LMP) in those hours, the annual number of emergencies in which the programs would operate, the number of hours per emergency during the program operation, and the assumed price in the emergency hours.[132] He found two problems with BGE's assumptions. His first observation was that BGE extrapolates the emergency price from a 2014 price for emergency energy in extreme winter conditions, including spiking gas prices.[133] His second was that BGE assumes that two of the four ESDs for the SER each year will be called on days that turn

[129] Chernick Direct at 42-46.
[130] Chernick Direct at 47.
[131] Chernick Direct at 47-49.
[132] Chernick Direct at 50.
[133] Chernick Direct at 50.

out to be emergency events, even though just one summer emergency event has occurred in the last three years and there is no assurance that BGE will know a day in advance that an emergency will be called by PJM.[134] If the number of emergency ESDs is corrected from 2 to 0.5 the SER and PR revenues are annually reduced by about $13 million, while introducing the summer emergency price to the last actual value reduces revenues another $1 million.[135]

Mr. Chernick stated that he identified three significant problems with BGE's analysis of avoided energy costs: (1) assuming that the avoided energy cost is equal to the standard-offer rate; (2) ignoring load shifting in the SER and PR programs; and (3) including in the SER savings customers who decrease their use due to random variation, but excluding any offset for the customers who increase their usage for the same reasons.[136] Mr. Chernick believes that the avoided energy cost should represent only the energy portion of the standard-offer price, which based on his estimate and calculation would reduce the avoided energy costs by 30%, or about $40 million.[137] He also believes that the energy avoided costs would be offset by load-shifting to hours outside the incentive period for SER, which would reduce the present value of the avoided energy costs by over $2 million and the energy price mitigation by $1 million.[138]

Mr. Chernick disagrees with BGE's treatment of ignoring the SER rebates for SER participants under the rationale these payments are not costs, noting that even half of

[134] Chernick Direct at 51.
[135] Chernick Direct at 52.
[136] Chernick Direct at 52.
[137] Chernick Direct at 53-54.
[138] Chernick Direct at 54-55.

the incentive payment would have a present value of $48 million.[139]

Mr. Chernick identified problems in BGE's analysis of energy price mitigation based on errors discussed above. In his opinion, most importantly, BGE erred in assuming that the BGE zone is the only load that affects prices in the BGE, Pepco, Delmarva and AP zones.[140] He conducted his own analysis which would reduce the energy price mitigation by 79%, or $80 million.[141] Table 10 in Mr. Chernick's direct testimony summarizes the system benefits based on his recommended adjustments.

On surrebuttal, OPC witness Chernick addresses various technical issues and makes corrections to his direct testimony. Mr. Chernick notes that BGE witnesses were correct with regard to double-counting of free riders in his testimony and in OPC witness Chang's testimony.[142] Additionally, Mr. Chernick increased the present value of the SER capacity price mitigation by about $0.9 million, due to an error.[143] Lastly, Mr. Chernick accepted BGE witness Pino's adjustment based on the PJM emergency price.[144]

Witness Chernick disagrees with BGE witness Pino's rebuttal testimony. Mr. Chernick states that he did not replace the emergency price for energy during emergencies with the lower LMP as Mr. Pino claims.[145] Mr. Chernick states that he did not use PJM data relevant to the PJM Load Forecast in correcting BGE's estimate of the reduced load at T&D peaks, but rather he used actual data on the lack of coincidence of the SER and PR load reductions with the T&D peak hours.[146] Witness Chernick

[139] Chernick Direct at 56-59.
[140] Chernick Direct at 60.
[141] Chernick Direct at 65-66.
[142] Surrebuttal Testimony of Paul L. Chernick, March 21, 2016 ("Chernick Surrebuttal") at 2.
[143] Chernick Surrebuttal at 2-3.
[144] Chernick Surrebuttal at 3.
[145] Chernick Surrebuttal at 4.
[146] Chernick Surrebuttal at 4.

contends that BGE witness Pino double-counted the savings from load reductions in that saving energy does not avoid capacity charges in addition to the capacity charges avoided by peak reductions.[147]

Mr. Chernick testified that BGE made assertions in rebuttal that were unsupported.[148] With respect to the frequency of emergency pricing, Mr. Chernick notes that PJM called the short-lead-time load management resources only four times in the nine-year period studied, and contends that Mr. Pino's claim that the SER program would have been eligible for seven emergency events over the past ten year is misleading.[149] Mr. Chernick takes issue with Mr. Pino's apparently unsupported assertion that he understated the LMP during future non-emergency ESD hours.[150]

Mr. Chernick notes that BGE witnesses did not respond to his direct testimony that the peak time rebates pay customers to suffer discomfort and inconvenience and are therefore costs in a cost-effective analysis.[151] He states that the peak-time rebate in the SER differs from the rebates paid by utilities in energy-efficiency programs in that rebates in energy efficiency programs are designed to offset part of the cash cost of measures, while the peak-time rebates pay the customer for unknown cash costs and unquantified discomfort.[152]

Mr. Chernick takes issue with BGE witness Pino's treatment of increases in load before and after the SER incentive hours.[153] He also takes issue with BGE witness Faruqui's claim that free ridership within the participant group is offset by those

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[147] Chernick Surrebuttal at 5-6.
[148] Chernick Surrebuttal at 10.
[149] Chernick Surrebuttal at 11.
[150] Chernick Surrebuttal at 12.
[151] Chernick Surrebuttal at 14.
[152] Chernick Surrebuttal at 15.
[153] Chernick Surrebuttal at 17-23.

customers in the participant group that actually increased load during ESDs.[154] Mr. Chernick contends that BGE's definition of "participant" for the SER program is someone whose usage is lower in the ESD than in the comparison days, while in most energy-efficiency and load-management programs, customers opt in and become participants.[155] He concludes that the BGE rebuttal does not offer any reason to believe that the free-rider effect is any less than his initial estimate of 30%.[156]

Mr. Chernick contends that this proceeding is not bound by the Commission's preapproval of energy-efficiency programs in Case No. 9154 and involves a very different type of load reduction (for the SER) than the energy-efficiency load reductions.[157]

In his surrebuttal testimony, OPC witness Lanzalotta explained his recommended 40% reduction in storm-related savings due to reduced truck rolls and performed his calculation using 2015 data. Mr. Lanzalotta calculated that the annual number of customer interruptions (CI) in the years 2013-2015 was 48.32% less than the average customer interruptions (CI) in the period 2008-2012.[158]

***<u>Department of Defense</u>***

David Shpigler testified on behalf of the U.S. Department of Defense and all other federal executive agencies ("DOD"). DOD witness Shpigler noted that the aim of a smart grid system is to reduce operating expenses through the use of advanced

[154] Chernick Surrebuttal at 24.
[155] Chernick Surrebuttal at 24-25.
[156] Chernick Surrebuttal at 29.
[157] Chernick Surrebuttal at 36-37.
[158] Surrebuttal Testimony of Peter J. Lanzalotta, March 21, 2016 at 3.

automation equipment.[159] Thus, he found it inconceivable that the efficiency gains that BGE claims to support through use of its smart grid system would result in even higher O&M expenses.[160] Mr. Shpigler recommended that the Commission disallow BGE's proposed inclusion of the incremental O&M expense in revenue requirements. With respect to BGE's proposed amortization of its smart grid regulatory asset, Mr. Shpigler opined that a 10-year amortization is more appropriate and provides for a matching between the smart grid asset recovery and the associated regulatory asset recovery.[161] He stated that the service life of the smart grid assets are likely to provide service for a minimum of 10 years, and likely significantly longer than that.[162] He further noted that the majority of utilities across the country have approved amortization periods longer than BGE's proposed 5 years, and provided the examples of Pacific Gas & Electric (20 years), Commonwealth Edison (10 years), and Texas-New Mexico Power (7 years).[163] He testified that smart grid technology often features a service life in the range of 10 to 15 years.[164] Mr. Shpigler also recommended an adjustment based on increased availability of working capital that he believes will be realized from the deployment of smart meters.[165] Lastly, Mr. Shpigler recommended an adjustment to the conversion factor that is applied to revenue requirement in order to "gross-up" for expected taxes and uncollectible customer accounts.[166] Mr. Shpigler proposed that BGE's proposed gross-up conversion factor be adjusted to reflect BGE's uncollectible experience over the past

[159] Direct Testimony of David Shpigler, February 8, 2016 ("Shpigler Direct") at 6.
[160] Shpigler Direct at 6.
[161] Shpigler Direct at 8.
[162] Shpigler Direct at 8.
[163] Shpigler Direct at 9.
[164] Shpigler Direct at 9.
[165] Shpigler Direct at 11 *et seq.*
[166] Shpigler Direct at 14 *et seq.*

three years, and be adjusted to account for a reduction in the amount of unpaid electric and gas bills, or uncollectible accounts.[167] Mr. Shpigler stated that industry experience has demonstrated that reductions in uncollectible accounts associated with deployment of automated disconnect and related devices are typically in excess of 50%, though he cited no authority in his testimony.[168]

On surrebuttal, DOD witness Shpigler stated that because rates are set for the rate year, cost recovery should take into account the reasonableness of requested O&M costs, not based on some future period, but specifically for the rate year.[169]

***Staff***

Daniel J. Hurley prepared Staff's analysis of the costs, benefits, and cost-effectiveness of the Company's smart grid initiative. Mr. Hurley concluded that the cost estimates used by the Company are reasonable.[170] Staff divided the benefits into core benefits - benefits that were included in the original business case and which have an approved reporting metric developed through the work group process or have been accepted in the EmPOWER Maryland cases cost-benefit analysis, and additional benefits – benefits that were developed outside of the work group process and do not have an approved reporting metric.[171] Based on Staff's analysis of the costs and core benefits, Staff calculated a benefit-cost ratio of 1.37, indicating that the AMI project is cost-effective using the core benefits alone.[172]

[167] Shpigler Direct at 15.
[168] Shpigler Direct at 17.
[169] Surrebuttal Testimony of David Shpigler, March 21, 2016 (Shpigler Surrebuttal") at 7.
[170] Direct Testimony and Exhibits of Daniel J. Hurley, February 8, 2016 ("Hurley Direct") at 2.
[171] Hurley Direct at 2.
[172] Hurley Direct at 2.

Staff generally supports the Company's calculation of Operations Benefits, comprised of Operations and Maintenance ("O&M") Savings and Avoided Capital Costs, however Staff disagrees with the 3% inflation rate used by the Company; Staff instead used a 2.3% inflation rate based on a 15-year average from 2001-2015, the same rate that is used for increasing future costs in the EmPOWER Maryland cost effectiveness analysis.[173] Staff did not recommend any change to the Company's calculation of avoided Transmission and Distribution ("T&D") costs noting that the Company has consistently applied the cost savings for transmission and distribution in the cost effectiveness analysis for the PeakRewards program implementation in 2008 through the cost effectiveness analysis for the EmPOWER Maryland programs.[174]

Staff reviewed the Supply Side Benefits as well. With regard to Capacity Price Mitigation, Staff noted that the Company followed the methodology approved by the Commission in Order No. 87082. Staff has no major concerns with the calculation.[175] Staff also reviewed and finds reasonable the Company's assumptions with respect to the calculation of energy revenue.[176] Staff also finds the assumptions used to determine the energy price mitigation reasonable but cautions that any drop in the estimate energy savings for SER and SEM will result in a lower energy price mitigation value.[177]

Staff does not necessarily agree with the Company's assumption of energy use and demand reduction of 1.5%. If the energy reduction held constant at 0.99%, the net present value of the energy conservation benefit would drop from $137 million to $100

[173] Hurley Direct at 13.
[174] Hurley Direct at 13-14.
[175] Hurley Direct at 16.
[176] Hurley Direct at 17.
[177] Hurley Direct at 18.

million, and the present value of the energy price mitigation benefit would drop from $101 million to $70 million.[178] The resulting total benefit-cost ratio would drop from 1.37 to 1.26 (still above 1.0).[179]

In Staff's opinion, Avoided Capacity Cost – Demand, Capacity Price Mitigation – Demand and PeakRewards Operability are the most reliable of the additional benefits.[180] Staff would eliminate the Conservation Voltage Reduction ("CVR") benefit because in Mr. Hurley's opinion it is unclear whether the Company would have attempted to achieve the same amount of savings with a non-AMI CVR solution, as well as the Customer Reliability, Reduced Theft and Storms benefits because of the many assumptions built into the calculation of these benefits that are uncertain.[181]

On Surrebuttal, Staff witness Hurley made one modification. Staff believes that OPC witness Chernick made reasonable arguments to lower the value of the Energy Price Mitigation benefit, which lowers the benefit from $101 million to $18 million.[182]

***<u>BGE Response to Various Positions</u>***

On rebuttal, BGE witness Mark D. Case stated that OPC's proposed adjustments to provide customers with operational savings achieved in between BGE rate cases from 2012 to 2016 is an attempt to re-litigate an already settled issue.[183] Also, OPC witness Effron's computation includes costs that have not been incurred and therefore are not even included in BGE's cost of service yet.[184] Mr. Case maintains that the recovery of

[178] Hurley Direct at 20.
[179] Hurley Direct at 20.
[180] Hurley Direct at 22.
[181] Hurley Direct at 24-25.
[182] Surrebuttal Testimony and Exhibits of Daniel J. Hurley, March 21, 2016 ("Hurley Surrebuttal") at 2-3.
[183] Prepared Rebuttal Testimony of Mark D. Case, March 4, 2016, ("Case Rebuttal") at 6.
[184] Case Rebuttal at 16.

retired legacy meter costs over 10 years was resolved with the settlement agreement in Case No. 9355.[185] Mr. Case stated that the inclusion of sunk costs in the cost-benefit analysis would contradict the cost-effectiveness determinations of energy efficiency and demand response programs in EmPOWER Maryland proceedings.[186] He stated that including SER bill credits as a cost contradicts OPC's positions regarding PeakRewards program bill credits in Case No. 9154 and the SER bill credits in Case No. 9208 as well as the Commission's standards in the EmPOWER Maryland proceedings to assess whether energy efficiency and demand response programs should be approved as cost-effective.[187] Mr. Case contends that legacy meters should be treated as all other plant assets and remain in rate base to ensure full recovery of costs.[188] He states that to do otherwise would penalize a utility for replacing an asset not fully depreciated, even if the new technology provided savings and other benefits to its customers.[189] Lastly, Mr. Case notes that OPC's proposed revenue requirements do not incorporate the full impact of the $136 million OPC proposes in write-offs, but would impact BGE's rates for 10 years because OPC proposes to amortize the disallowances and credits over 10 years.[190]

BGE witness Vahos also testified in rebuttal on these matters. He believes the language in Order No. 83531 in Case No. 9208 is clear and that the Commission specifically directed BGE to defer into a regulatory asset the <u>net</u> depreciation and amortization costs related to meters and excluded the word "net" in its directive to defer

[185] Case Rebuttal at 6.
[186] Case Rebuttal at 6-7.
[187] Case Rebuttal at 7.
[188] Case Rebuttal at 18.
[189] Case Rebuttal at 19.
[190] Case Rebuttal at 22.

the incremental costs to implement the smart grid.[191] Mr. Vahos compared the language in Order No. 83531 in Case No. 9208 with the language in Pepco's smart grid Order. Mr. Vahos notes that Pepco (and Delmarva) proposed to defer into a regulatory asset all operational savings as an offset to incremental costs, and that the Commission approved that proposal.[192] BGE contends that the plain language of the two orders was clear in that the utilities would either flow operational savings through to customers during deployment or defer operational savings until incremental cost recovery was determined, but not both.[193] As further support, BGE notes that the Commission in Order No. 83531 went on to state that "the only direct savings the customers forego during the deployment years if we do not approve a tracker are the $15 million in reduced meter reading costs that BGE would pass through."[194] Mr. Vahos also believes OPC witness Effron's $31 million disallowance is duplicative of OPC's recommended disallowance of smart grid costs over benefits.[195] Lastly, Mr. Vahos responded to DOD witness Shpigler's testimony.

Company witness Pino indicated in rebuttal that OPC made errors in its calculation of market-side benefits. Mr. Pino contended that OPC double counted the free-ridership effects on the benefits associated with the SER program, that OPC erred in applying a free-ridership reduction to the energy quantity settled with PJM in the determination of wholesale energy revenue associated with the SER program, and that OPC neglected to adjust the Installed Capacity to Unforced Capacity in the capacity price

[191] Prepared Rebuttal Testimony of David M. Vahos, March 4, 2016 ("Vahos Rebuttal") at 12.
[192] Vahos Rebuttal at 13.
[193] Vahos Rebuttal at 14.
[194] Vahos Rebuttal at 14.
[195] Vahos Rebuttal at 15.

mitigation benefit.[196] In Table 1 of his rebuttal testimony, Mr. Pino noted the cases in which the Commission has recognized the methodologies BGE used in this case for capacity price mitigation, avoided T&D cost, and avoided capacity cost.[197] Mr. Pino agreed that OPC's recommendation to adopt the 2016 PJM load forecast is reasonable, that adoption of OPC's recommended updated forward wholesale energy prices is reasonable, and that the modifications made by OPC to the energy price mitigation methodology are reasonable.[198] Mr. Pino agreed that there is some load shifting by SER participants but stated that the problem is measuring it.[199] Mr. Pino testified that the sum of energy consumption increases before and after the SER pilot events was about 10% of the sum of energy consumption reduction occurring with the event period.[200]

BGE submitted rebuttal testimony of Michael B. Butts responding to, *inter alia*, OPC witnesses Brockway and Lanzalotta's testimonies, and to Staff witness Hurley's testimony.[201] BGE submitted rebuttal testimony of Dr. Ahmad Faruqui in which he responded to OPC witnesses Chang and Chernick with respect to free ridership, opined that inclusion of the undepreciated book value of legacy meters as a cost in the cost-effectiveness analysis would be inappropriate, that SER bill credits should not be considered as a cost, and that the Company should be permitted full recovery of its investment in legacy meters.[202]

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[196] *See* Rebuttal Testimony of William B. Pino, March 4, 2016 ("Pino Rebuttal").
[197] Pino Rebuttal at 10.
[198] Pino Rebuttal at 20, 22.
[199] Pino Rebuttal at 21.
[200] Pino Rebuttal at 21.
[201] *See* Prepared Rebuttal Testimony of Michael B. Butts, March 4, 2016 ("Butts Rebuttal").
[202] *See* Rebuttal Testimony of Ahmad Faruqui, March 4, 2016 ("Faruqui Rebuttal").

In surrebuttal, Company witness Pino continues to argue that the cost-effectiveness framework that the Commission approved in Case No. 9154 applies to both energy conservation and demand response programs.[203]

***Testimony at Hearings***

***BGE***

At the hearings in this matter, BGE witnesses were cross-examined by the parties and the Commission. BGE witness Butts testified that the additional AMI expenditures of $16.6 million he mentioned in his pre-filed direct testimony were additional expenditures due to both opt-out customers and non-responsive customers.[204] BGE witness Butts testified about potential additional future uses of the Company's smart grid system.[205] Mr. Butts also testified about how the smart grid system better enables and lowers the cost of its conservation voltage reduction ("CVR") program.[206] With regard to the useful life of the smart meters, Mr. Butts explained that the system is to be supported and not be obsolescent for 15 years; he believes the equipment itself can last 15 years or longer.[207] When questioned about the number of meters yet to be installed, Mr. Butts explained the devices that are in exception status and what the Company is doing to reduce the number in that category.[208] Mr. Butts believes that BGE's opt-out rate (4 percent) is higher than Pepco's (1 percent) due to an active group of citizens opposed to smart meters that petitioned customers in BGE's service territory.[209] He testified that the

[203] *See* Prepared Surrebuttal Testimony of William B. Pino, March 21, 2016 ("Pino Surrebuttal").
[204] Transcript of proceedings ("Tr.") at 31-32.
[205] Tr. at 33-35.
[206] Tr. at 38-39.
[207] Tr. at 41.
[208] Tr. at 45-47.
[209] Tr. at 47-48.

ongoing costs in BGE's cost effectiveness analysis are related to trained call center personnel.[210] Mr. Butts indicated that the updated figure for the cost of the entire deployment of the smart grid initiative is $503 million, which includes not only meters, but also several IT systems and two-way communication infrastructure.[211] And, after at least another $300 million is invested in subsequent years, Mr. Butts testified that the benefits of the smart grid initiative exceed those costs on a 2 to 1 net present value basis.[212] Mr. Butts explained how Commission Orders which allowed customers to opt-out resulted in increased installation costs.[213] Mr. Butts explained his calculation of the storm savings benefits of reducing the length of storms and avoided truck rolls.[214]

On cross examination by OPC, BGE witness Pino admitted that no BGE witness provided testimony disputing OPC witness Chernick's conclusion that BGE's peak time rebate program will not result in any distribution avoided cost.[215] When asked about Mr. Chernick's testimony regarding PJM's re-simulation of its load model to estimate savings from BGE's peak time rebate program, Mr. Pino disputed Mr. Chernick's conclusion that there is very little value in the SER program from the perspective of peak load reduction.[216] Mr. Pino discussed the transition that will occur in the PJM market when base resources expire at the end of Delivery Year 2019-2020; BGE will be exiting the supply market and becoming a demand-only resource. Mr. Pino discussed BGE's approximately 800-megawatt demand response (DR) portfolio, of which nearly half is SER that Mr. Pino believes is providing PJM an extremely valuable service for grid

[210] Tr. at 48-49.
[211] Tr. at 49.
[212] Tr. at 50.
[213] Tr. at 65-68.
[214] Tr. at 78-80.
[215] Tr. at 239-240.
[216] Tr. at 247.

reliability.[217] Mr. Pino argued that PJM will rationally have to adjust its load forecasts when PJM sees a "cliff" in the peak demand coming out of the supply market and into a peak demand reduction.[218] Mr. Pino stated that there are two ways for customers to save money – in the allocation of the residential capacity obligation based on peak load share, and then once PJM recognizes lower purchases, PJM will buy less capacity.[219] Mr. Pino admitted, however, that Mr. Chernick's testimony reflects how PJM currently performs load forecasting with respect to non-monetized demand response.[220] Mr. Pino testified about BGE possibly extending SER to be an annual product, as well as other ideas the Company has considered, so as to qualify as a Capacity Performance[221] product.[222] He admitted that the surcharge for the PTR bill credits includes wholesale revenue from PJM, which operates to reduce that surcharge.[223]

Mr. Pino testified as to BGE's position of not including thermal discomfort or inconvenience experienced by customers, or voluntary measures taken by customers, as costs in its cost-effectiveness analysis.[224] Mr. Pino testified that the $1.25 per kilowatt hour rebate in the SER program is not compensation paid to customers, but rather a

[217] Tr. at 248.
[218] Tr. at 249-250.
[219] Tr. at 253-255.
[220] Tr. at 257-258.
[221] On December 12, 2014, in FERC Docket No. ER15-623, FERC approved PJM's Capacity Performance proposal, which was designed to provide greater assurance of delivery of energy and reserves during emergency conditions, including through the establishment of substantial charges for non-performance. *PJM Interconnection, L.L.C.*, 151 FERC ¶ 61,208 (2015). Several intervening parties to that docket protested that PJM's Capacity Performance construct would "create[] unnecessary barriers to entry to demand response" and "functionally eliminate[]" the participation of demand response in PJM's capacity market. 151 FERC ¶ 61,208 at PP 61-62. Although PJM proposed to temporarily retain its existing capacity product (referred to as "Base Capacity,") FERC approved PJM's plan to quickly replace Base Capacity with Capacity Performance over the next few PJM capacity auctions. For the 2020-2021 Delivery Year (the auction for which is held in May 2017), PJM will procure 100 percent of the region's capacity resources as Capacity Performance resources. *Id*. at P 28. (Check cite – FERC Order at P. 28?)
[222] Tr. at 343-346.
[223] Tr. at 347.
[224] Tr. at 284-288.

financial incentive for customers to reduce load in the form of a transfer payment paid by all customers to a subgroup of customers.[225] Mr. Pino explained that BGE's benefit/cost test is not a strict total resource cost ("TRC") test in that it included avoided air emissions cost as a benefit, which the Commission in Order No. 87082 directed to be included in a societal cost test.[226]

Mr. Pino admitted that BGE does not account for load shifting prior to an energy savings event day, or deferral of usage after the savings event is over; BGE's believes that the amount of energy reduction is not very material as compared to the peak demand reduction, which is the focus of the SER.[227] Mr. Pino testified that about one-third of BGE customers have online accounts and are using the SEM portal.[228] Mr. Pino maintained that the Company's estimate of savings from SEM is conservative.[229]

In his oral testimony, BGE witness Faruqui more fully explained the regression analysis that is done on the SER participant group, and how it is applied on all summer days so as to understand how changing weather conditions affect customer loads.[230] The result BGE calculated was that on average customers lower their energy use by 17.7 percent on energy savings days.[231] Dr. Faruqui discussed the different methods of defining cost-effectiveness, and confirmed his written testimony that he does not believe the cost effectiveness analysis in this case should include a cost for the imposition on customers for their change in behavior, and that transfer payments are not counted as

[225] Tr. at 289.
[226] Tr. at 320-322.
[227] Tr. at 351-352.
[228] Tr. at 353-354.
[229] Tr. at 355-362.
[230] Tr. at 404-406.
[231] Tr. at 406-412.

costs in the TRC perspective.[232] Dr. Faruqui stated that there is no way to measure the cost of imposition on customers that is practical in a TRC test calculation.[233] Dr. Faruqui testified that in his opinion, the Commission should have a consistent methodology for how it treats rebates in efficiency and demand response programs as both types of programs are based on incentivizing customers to change behavior.[234]

Dr. Faruqui discussed how upgrading to smart meters before legacy meters were fully recovered may represent an extraordinary expenditure, but that the benefits of the new technology should not be delayed.[235] In Dr. Faruqui's opinion, whether the cost of legacy meters should be considered in the cost-effectiveness analysis, and whether you allow a return on legacy meters that are no longer being used, are two separate issues.[236]

BGE witness Vahos testified at the hearings on several issues including cost recovery of the smart grid regulatory asset. Mr. Vahos testified that if the Commission were to direct that the regulatory asset be amortized over a ten-year period, the revenue requirement would be reduced by approximately $28 million.[237] Mr. Vahos testified that it is appropriate for the Commission to consider gradualism as another aspect of its decision-making process, and that a 10-year life would be reasonable.[238] When questioned as to why post-test year smart grid costs should be treated differently than legacy meters put into service in the past, Mr. Vahos testified that it is his position that if the Company does not get recovery of the full regulatory asset in this proceeding, then it will have a regulatory asset leftover, and that the residual regulatory asset would continue

[232] Tr. at 418-427.
[233] Tr. at 451.
[234] Tr. at 437-438.
[235] Tr. at 439-443.
[236] Tr. at 464-465.
[237] Tr. at 849-850.
[238] Tr. at 850.

to accrue a return.[239] So even though the post-test year portion of the regulatory asset is an estimate, Mr. Vahos believes that it is best to not continue to accrue carrying costs into a future rate case.[240]

BGE witness Case expounded upon Company Exhibit 31.[241] Mr. Case noted that other commissions around the country are investing in smart grid technology, and that BGE has things that other commissions do not – the $200 million DOE grant and significant market side benefits.[242] Mr. Case mentioned qualitative and service benefits and modernization of the grid as preparation for new technologies as unquantified benefits in addition to the economic benefits that were quantified in this case.[243] Mr. Case explained that the Company is seeking recovery of the legacy meter costs and a return at the Company's authorized cost of capital for that investment.[244] Mr. Case testified that the settlement in Case No. 9355 established that BGE would recover the cost of the legacy meters over a ten-year amortization.[245] Mr. Case concurred that 15 years is a reasonable estimation for the useful life of the new smart meters, but believes that in 2010 in Case No. 9208, the Commission expressed a preference to use a shorter depreciable life because the smart grid technology was so new.[246] Mr. Case defended the Company's request that customers be required to pay for the new meters as well as the residual unrecovered cost of the old legacy meters.[247] Mr. Case explained how in each rate case that has been filed since deployment of the new system whatever level of

[239] Tr. at 851.
[240] Tr. at 851-852.
[241] Tr. at 978 *et seq.*
[242] Tr. at 1053.
[243] Tr. at 1053.
[244] Tr. at 1082-1083.
[245] Tr. at 1086-0187.
[246] Tr. at 1088.
[247] Tr. at 1092.

savings the Company had achieved at that point in time was flowed through to ratepayers.[248] Mr. Case also discussed the proxy approach the Company used to calculate avoided transmission and distribution costs, because the alternative requires a very complex analysis.[249]

***<u>OPC</u>***

OPC witness Maximilian Chang explained that in his written testimony he was trying to clarify the difference between what is done in a cost effectiveness screening versus what is done in a program implementation, however, he conceded that he did not know specifically how incentive payments are treated in the PeakRewards program.[250] On cross-examination, Mr. Chang also conceded that many of tools associated with the SEM program cannot be utilized with legacy meters.[251] Mr. Chang believes demand response cost effectiveness is an evolving area in the electric utility sector and that California has started treating bill credits as a proxy for participant cost.[252] Mr. Chang admitted that if his estimate of disallowed benefits in the amount of approximately $700 million ($280 million for SEM, $176 million for avoided T&D, $249 million in market benefits) contained an error on the order of five percent, or $35 million, and if the Commission did not agree that peak time rebate costs should be included in the cost effectiveness analysis, the benefit-cost ratio would be 1.0.[253] Mr. Chang believes that the

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[248] Tr. at 1094-1095.
[249] Tr. at 1101-1102.
[250] Tr. at 1420-1421.
[251] Tr. at 1423-1425.
[252] Tr. at 1431.
[253] Tr. at 1436-1438.

Commission in 2010 in Case No. 9208 indicated that the cost of legacy meters would be a consideration in a cost-effectiveness analysis.[254]

On cross-examination by the Commission, OPC witness David J. Effron discussed the complexities of extending the depreciable life of the smart meters from 10 years to 15 years when in the Company's benefit-cost analysis, benefits are being considered over a 10-year horizon.[255] OPC witness Effron testified that extending the depreciable life of smart meters from 10 to 15 years would not have any impact on the present value cost of the meters, but that the remaining balance to be recovered on which the Company would earn a return would be greater years in the future.[256] Mr. Effron stated that if the Commission were to extend the depreciable life of smart meters to 15 years, while continuing to look at benefits over 10 years, per the Company's benefit-cost analysis, ratepayer costs would be reduced in the short term, however, ratepayers would pay more later due to accumulating interest.[257]

OPC witness Paul Chernick believes that in Order No. 87802 when the Commission approved the Variable Resource Requirements (VRR) methodology to calculate capacity price mitigation as presented by the EmPOWER planning group, the Commission approved it for the purposes of that round of EmPOWER program analysis.[258] Similarly, Mr. Chernick testified that the Commission was clear in Order No. 87213 that its decision to approve the VRR methodology applied to that round of the EmPOWER program, that it was open for review at the next peer review, and that the

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[254] Tr. at 1450-1451.
[255] Tr. at 1575, *et seq.*
[256] Tr. at 1576.
[257] Tr. at 1576.
[258] Tr. at 1585-1586.

Commission would take other steps to avoid inappropriate emphasis on demand response due to an excessive capacity price mitigation calculation.[259] Mr. Chernick acknowledged that the Commission approved the Phase II-A metrics report on December 11, 2012, which included a benefit for avoided transmission and distribution.[260] In his opinion there is a difference between a metric report which reflects potential savings based on assumptions, and actual reduction in transmission and distribution needs.[261] Mr. Chernick still takes issue with the Company's analysis of the benefits of the SER program because the Company's regression analysis is performed after removing customers whose usage appeared to have increased, and therefore in his opinion the Company has not properly accounted for the effect of free ridership.[262] When asked about his calculation of a reduction to benefits based on load shifting, Mr. Chernick contended that the data to better estimate the percentage reduction was not provided by BGE despite the fact that it is available from smart meters.[263] Mr. Chernick stated that his estimates are the best he could do with the data he was provided, and he believes them to be more reliable estimates than the Company's estimates.[264] When asked about the difference between the EmPOWER program and the smart grid initiative, Mr. Chernick stated that we now have better information on how the market works, how the load forecasting works, and the timing of the load reductions and how they intersect with the peaks.[265] Mr. Chernick stated that many of his points about avoided T&D and avoided capacity and capacity price mitigation are greatly reduced or go away entirely if there is load

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[259] Tr. at 1586.
[260] Tr. at 1588.
[261] Tr. at 1589.
[262] Tr. at 1590-1595.
[263] Tr. at 1595-1599.
[264] Tr. at 1600-1601.
[265] Tr. at 1607.

reduction over many hours, however, he believes the SER program is only hitting some of the high load hours.[266] Mr. Chernick stated that demand response is not energy, but that if SEM operates as the Company states it will, the conservation effects will produce some real savings.[267]

On cross-examination, OPC witness Brockway discussed possible treatment for the recovery of legacy meters, noting that in the case from California she cited in her pre-filed testimony, the California commission permitted an amount of recovery on legacy meters but reduced the rate of return applicable to the unamortized balance, thereby disallowing full recovery on the asset, treatment which Ms. Brockway described as extraordinary.[268] Ms. Brockway acknowledged that a part of the settlement agreement in BGE's recent depreciation proceeding, Case No. 9355, the parties agreed to a ten-year recovery period for legacy meter costs, based on a depreciation schedule that was attached to and incorporated into the settlement agreement.[269]

***Staff***

Staff witness Patricia Stinnette confirmed her recommendation that the Commission allow the actual costs in the smart grid regulatory asset which are known through February 2016.[270] Ms. Stinnette's opinion is that costs from March to May of 2016 would go into the same regulatory asset to be considered at the Company's next rate

[266] Tr. at 1605.
[267] Tr. at 1606.
[268] Tr. at 1829-1830.
[269] Tr. at 1836-1837.
[270] Tr. at 1626.

case, and that costs after June 4, 2016 (the date of the Order in this case), would no longer go into a regulatory asset.[271]

On cross examination by OPC, Staff witness Daniel Hurley testified that in addition to the TRC cost effectiveness analysis, the Commission considers other factors such as bill impact in accordance with PUA §7-211, and does not approve large incentives for programs if the bill impact is too high.[272] Mr. Hurley testified that in this case the Commission can consider the rebate costs, not in the TRC cost effectiveness analysis, but in the context of the bill impact.[273] Mr. Hurley acknowledged that in order for the capacity obligation to be reduced as BGE predicts, PJM has to recognize the load reduction capability.[274] Mr. Hurley testified that while he did not investigate whether the benefits attributable to the SEM program could be achieved without smart meters, he understands that BGE's smart grid initiative was designed with smart meters being an enabling part of the program, which is why the costs of the program have not been recovered yet.[275] Mr. Hurley distinguished the SEM program from Potomac Edison and SMECO programs that provide high energy users with behavior reports not enabled by smart meters.[276] Mr. Hurley believes that the Commission, after consideration of all the testimony from all the parties in this case, will determine whether there is a risk that avoided costs will not occur as predicted, however, in his opinion, the risk is very low.[277]

Mr. Hurley testified that the working group took the AMI metrics from Case No. 9208 and from the PeakRewards program and adopted them in EmPOWER and the

[271] Tr. at 1626-1627.
[272] Tr. at 1873.
[273] Tr. at 1875-1876.
[274] Tr. at 1885.
[275] Tr. at 1889.
[276] Tr. at 1890.
[277] Tr. at 1903.

Commission approved the metrics for use in the EmPOWER program. Mr. Hurley stated that Staff has always taken the position that benefits across energy efficiency, demand response and AMI programs should be treated consistently, so as to avoid inconsistent results.[278] Mr. Hurley acknowledged that the benefits from CVR were part of the Phase II-B metrics that were supported by Staff but that did not become a consensus document approved by the Commission.[279] Mr. Hurley agreed that calculating the avoided cost associated with CVR as a benefit is more conservative than focusing on the energy savings from CVR.[280] The Phase II-B methodologies filing also noted the potential for other benefits such as reduction in unaccounted for energy, direct load control operational effectiveness, reduction in storm restoration due to meter pinging, and reduction in bad debt, which Mr. Hurley expects will be supported by information obtained through the smart grid in the future.[281]

Mr. Hurley opined that if the cost-benefit analysis was extended to 15 years, there could be higher benefits, with only the same ongoing costs.[282] With regard to the free ridership issue, Mr. Hurley noted that PJM does not factor in free ridership.[283] Mr. Hurley testified that he monitors the quarterly smart meter costs as part of his analysis of the smart meter deployment, and that he does not recommend that the Commission disallow any of the costs in this case, including the costs associated with the customer education plan.[284]

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[278] Tr. at 1905-1906.
[279] Tr. at 1914-1915.
[280] Tr. at 1916.
[281] Tr. at 1915 *et seq.*
[282] Tr. at 1930-1931.
[283] Tr. at 1931-1932.
[284] Tr. at 1935-1936.

## Commission Decision

Six years ago the Commission granted the Company's request to proceed with deployment of its Advanced Metering Infrastructure ("AMI" or smart grid initiative) in Case No. 9208, subject to certain conditions. Specifically, the Commission ordered the deferred recovery of smart grid-related costs until such time as the Company had delivered a cost-effective system.[285] Deferred cost recovery was deemed appropriate by the Commission in 2010 as a means to allocate risks between the Company and its customers while also synchronizing the costs borne by customers most closely with the onset of benefits.[286] While the Commission adopted this deferred cost recovery structure with the intention of protecting customers from the possibility that they would pay for an AMI system found ultimately to be not cost-beneficial,[287] that decision has yielded unintended consequences. However well-intentioned the 2010 Commission decision regarding cost deferral was, we now must rule on the recovery of several years' of accumulated deferred AMI costs, with the potential of causing rate shock upon incorporation of prudently-incurred smart grid-related costs into base rates. Further, it is evident based on public comments received in advance of the evidentiary hearings that some degree of disconnect persists among ratepayers regarding smart grid cost recovery

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[285] Order No. 83531 at 50, ¶2. Further, the Commission noted that at the time the Company delivered a cost-beneficial AMI system, the Company could seek cost recovery in base rates. *Id.* Thus, we reject any party's assertion that the instant proceeding was not the appropriate forum in which to assess whether BGE's AMI initiative is cost-beneficial. We note that although the term "cost-effective" was used in Order No. 83531, the proper term is "cost-beneficial" since the Commission is conducting a cost-benefit analysis that compares costs to benefits expressed in dollar values.

[286] *Id.* at 35.

[287] The Commission stated that "[b]y directing cost recovery through a properly structured regulatory asset, recovered in base rates, we find that customers are appropriately protected against the possibility that they will pay in full for an AMI system that would not be cost-effective." *Id.* at 47.

and the realization of benefits derived from the AMI initiative.[288] In short, while a portion of market-side benefits and operational savings from the Company's AMI deployment began flowing through to customers immediately in rate cases over the past six years, the cost recovery of the underlying enabling infrastructure remained deferred and subject to additional carrying costs. An alternative approach could have been to allow partial cost recovery over the past six years, in concert with the phase-in of benefits derived from AMI deployment. However, the 2010 decision cannot be undone.[289] Thus, we are now charged with determining whether the Company has satisfied its burden of proof regarding the delivery of a cost-beneficial AMI system; the Commission has previously recognized that the Company is entitled to recover the prudently-incurred costs associated with the smart grid initiative, as well as an appropriate return.[290]

As an initial matter, we note that several of the metrics used to quantify benefits, both operational benefits and market-side benefits, are metrics that are reported quarterly in Case No. 9208, metrics that arose out of working group meetings in consensus documents submitted to the Commission for approval. Many of the metrics have been used in the EmPOWER proceedings as well, for purposes of screening prospective energy efficiency programs in the context of cost-effectiveness determinations. Thus, we agree that many of the categories themselves – Operational Savings, Avoided Transmission and Distribution Infrastructure, Avoided Capital Expenditures, DOE Grant,

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[288] We note that the Company bears at least some responsibility for this disconnect, likely attributable to deficiencies in its customer education efforts. While this shortcoming does not speak to the threshold question of whether the AMI system is cost-beneficial, it does impact a prudency determination regarding recovery of customer education-related costs, discussed *infra*.
[289] We acknowledge the uncertainties the Commission faced given that AMI was a relatively new technology in 2009 when BGE's proposal was first filed. As Judge Nazarian observed, "Unlike hindsight, foresight is not 20/20." Newell v. Johns Hopkins Univ., 215 Md. App. 217, 220 (2013).
[290] Order No. 83531 at 38.

Capacity Revenue, Capacity Price Mitigation, Energy Revenue, Energy Price Mitigation, and Energy Conservation – are the categories of core benefits that should be quantified as part of the necessary cost-benefit analysis.

As Staff pointed out, some of the other benefits the Company included in its analysis constitute benefits that were either established as non-consensus AMI metrics or developed outside the AMI working group process altogether. Staff termed these "Additional Benefits," which included valuations of: operational savings associated with storms; customer reliability/reduced theft; conservation voltage reduction (CVR); avoided capacity costs; and avoided emissions.[291] Staff articulated clearly, however, that it was not saying that these categories were of no benefit; rather, Staff did not assign a value to these Additional Benefits in large part because they were not needed to verify that the Company's smart grid initiative is cost-beneficial. While we recognize the value in Staff's conservative approach to this analysis, we find that a utility should not be limited to the aforementioned categories of core benefits in an attempt to demonstrate that its AMI system is cost-beneficial. Indeed, we find that should the record support inclusion of additional benefits in a cost-benefit analysis, as it does to some extent here, nothing in this Order or in Commission Order No. 83531 requires a wholesale disallowance of the additional benefit categories.

Two overarching adjustments to the benefits quantified by the Company in its analysis were presented for our consideration: the removal of Smart Energy Manager

[291] We note, however, that several of these benefits were defined subsequent to the AMI working group process by methodologies accepted by the Commission in the EmPOWER proceedings. For example, in a July 2015 Commission Order, we found it appropriate to adopt an Itron quantified business-as-usual value equivalent for the non-energy benefit category of avoided air emissions, defined as $0.002/kWh of energy savings. Order No. 87082 (July 16, 2015) at 15, note 70.

(SEM) derived benefits from all categories; and the use of an alternative inflation rate. OPC witness Chang removed the benefits of the Smart Energy Manager (SEM) program from all benefit categories because he believes that these benefits could have been achieved without smart meters. Mr. Chang acknowledged, however, that many SEM tools would not be available without smart grid interval data.[292] Moreover, to negate the benefits of the SEM program runs contrary to the Commission's explicit authorization of BGE to proceed with its smart grid initiative in Case No. 9208 given that the SEM program is part of the Company's integrated smart grid system. We therefore decline to apply OPC's suggested reduction in benefits and thus begin our category-by-category review of the Company's analysis assuming the inclusion of SEM benefits in each.

The second overarching adjustment presented for our consideration pertained to the inflation rate used by the Company in calculating its operational benefits; BGE assumed an inflation rate of three percent (3%). Staff does not believe a 3% inflation rate is appropriate and instead used an inflation rate of 2.3% based on a 15-year average from 2001-2015. We accept Staff's recommendation to use an inflation rate of 2.3% because it incorporates a significant time period over which the fluctuation of inflation rates is smoothed out.

Utilizing an inflation rate of 2.3%, and opting for now to adopt Staff's conservative approach of analyzing core benefits, as discussed more fully below, we accept Staff's calculation of benefits for Operational Savings of $174 million.

For the Avoided Transmission and Distribution infrastructure categories, BGE used the marginal unit cost approach as a proxy for the long-term value of the avoided

[292] And the Company is not able to disaggregate the savings associated with the individual tools. Tr. at 1422.

T&D on a present value basis. The Company computed benefits of $115 million and $87.8 million for Avoided Transmission and Distribution, respectively. Staff accepted the Company's analysis,[293] recommending the Commission apply benefits of $94 million and $72 million to these categories. The marginal unit cost methodology utilized by BGE and Staff has served as a component of cost-effectiveness analysis in front of the Commission since the inception of the PeakRewards program and was used for quarterly metrics reporting in Case No. 9208; further, it has been used repeatedly in the evaluation of other utility companies' direct load control programs. Most recently, this methodology for valuing avoided T&D infrastructure was adopted as part of the Commission's proceeding on cost effectiveness in Order No. 87082, issued on July 16, 2015.[294] While OPC now asserts that the marginal unit cost approach results in overstated benefits (OPC recommended severe reductions to these numbers to $8 million and $6 million, respectively), we note that OPC has previously recommended adoption of the marginal unit cost approach to valuing avoided T&D.[295] OPC has not adequately explained its shift in reasoning, and has not convinced us that its current analysis is based on a workable methodology that produces more reliable results such that we should shift from our recent approval of the marginal unit cost approach. Given that no party has articulated a persuasive distinction between the application of the avoided T&D cost-

[293] Staff's recommended quantification of avoided T&D benefits differs from the Company's valuation due to the alternative inflation rate adopted by Staff, as discussed previously.

[294] *See* Order No. 87082 (July 16, 2015) at 10, stating that, "We find that the values derived from the Avoided Cost Study performed by Exeter Associates on behalf of MEA and the Power Plant Research Project ("PPRP") for avoided energy costs were appropriately adopted…" (citing ML#157744: *EmPOWER 2015 – 2017 Cost Effectiveness Framework* (Aug. 19, 2014)at 9-10).

[295] OPC recommended adoption of the avoided T&D infrastructure cost methodology in the 2015 EmPOWER proceeding on cost effectiveness. *See* ML##163617: *Office of People's Counsel Comments on EmPOWER Maryland* (Jan. 30, 2015) at 6, stating OPC's recommendation to "[a]dopt working group values, based on method and results from Exeter Associates study" for energy capacity, RPS compliance, avoided T&D, avoided water, and avoided heating fuel.

effectiveness assumption approved in our July 2015 EmPOWER proceeding and the avoided T&D cost-effectiveness assumption relied on by the Company in the instant proceeding,[296] we decline to deviate from what has been a consensus position in the EmPOWER docket.

We do note, however, that there is room for expanded avoided T&D benefits as part of the Company's continued commitment to realizing additional benefits stemming from smart grid deployment. Although in this proceeding we accept the method BGE used to compute avoided T&D infrastructure as a proxy for avoided T&D benefits in evaluating whether the smart grid initiative is cost beneficial, we will remain vigilant with regard to BGE fully utilizing smart grid technology to optimize its planning efforts for future T&D investment. We expect BGE to ensure that ratepayers realize a demonstrable return on their investment in smart grid technology. Therefore, as a condition of accepting BGE's calculation of avoided T&D infrastructure in the cost-benefit analysis, we will require that BGE file a Distribution Investment Plan within twelve (12) months of the date of this Order that sets forth how the Company will accomplish this goal. 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 distribution network. In addition, the Company is directed to include as part of our next RM43 reliability metrics proceeding (during which SAIDI and SAIFI standards will be established for years 2020

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[296] In fact, the avoided cost study that served as the basis for the EmPOWER cost effectiveness assumptions recommended that "avoided T&D be analyzed in the same way as is being done for the AMI proceeding." ML#157744: *EmPOWER 2015 – 2017 Cost Effectiveness Framework* (Aug. 19, 2014) at 10.

– 2023), an assessment of how AMI infrastructure is being incorporated into the distribution system plan and the role it is playing in supporting the network.

Of the remaining operational benefits categories, the parties did not dispute the Company's valuation of either the Avoided Capital Expenditures or the DOE Grant Benefit. With respect to the category of Avoided Capital expenditures, however, Staff applied its recommended inflation rate to arrive at a slightly lower benefit figure of $36 million, which we will accept based on our prior acceptance of Staff's 2.3% inflation rate. The parties accepted the Company's computation of a net present value of $60.2 million for the benefit associated with the DOE grant, and we will accept this amount as well.

After tallying the above operational benefit values for Operational Savings, Avoided T&D, Avoided Capital Expenditures, and the DOE Grant benefit, we arrive at Operational Benefits derived from the smart grid initiative of at least $436.2 million on a net present value basis, which importantly does not include amounts for categories that Staff designated as Additional Benefits. Of these additional categories, we note that OPC did not challenge the Company's benefit computations for Conservation Voltage Reduction (CVR) (Avoided Cost of Program), valued at $49.6 million on a net present value basis. Previously, the Commission directed all Maryland electric utilities to develop CVR programs due primarily to the large energy savings that can be achieved, as well as the high cost-effectiveness rating of the program.[297] We accept BGE's position that as a result of the smart grid initiative, BGE has avoided costs associated with a

[297] Order No. 84569 (Dec. 22, 2011) at 12.

standalone CVR system, and we find it appropriate to include these avoided costs as a benefit in our analysis.[298]

We note also that OPC did not dispute the Company's computation of other operational benefit categories deemed as Additional Benefits by Staff; specifically the quantification of benefits associated with increased customer reliability, reduced theft, and reduced consumption on inactive meters. Collectively, these operational benefits were valued by the Company at $161.6 million on a net present value basis, and thus their inclusion would significantly increase the total operational benefits attributable to BGE's smart grid imitative. While we decline at this time to recognize this category of Additional Benefits in our assessment of BGE's cost-benefit analysis (instead opting for now to adopt Staff's conservative approach), we note that the aforementioned benefits will likely be realized and supported by the Company with future data collection. We concur with Staff that the benefits derived from AMI with respect to enhanced customer reliability, reduced theft, and reduced consumption on inactive meters are certainly not valued at zero.

Similar to Operational Benefits, some of the Market Side Benefits were developed outside of the AMI working group process and do not have a consensus reporting metric stemming from that process, although the Commission has ruled previously on several of the methodologies in other contexts. The Market Side Benefits that *do* have an approved reporting metric developed jointly by the AMI working group include Capacity Revenue,

[298]BGE noted that it computed the benefit in this category based on avoided capital costs of $61.8 million but did not take credit for the energy and demand reductions associated with a CVR system, which the Company's representatives testified would have resulted in a larger benefit figure. Tr. at 1028-1030; Tr. at 1104-1105.

Capacity Price Mitigation, Energy Revenue, Energy Mitigation, and Energy Conservation.

Consistent with the methodology and reporting metric developed by the AMI working group, the parties accepted the Company's calculation of Capacity Revenue benefits of $42.6 million, which we also accept. OPC, however, contested the Company's calculation of the Capacity Price Mitigation benefit on the same bases generally as were asserted in last year's EmPOWER proceedings regarding cost-effectiveness screening methodologies. The Commission was unpersuaded at that time by OPC's position, and in July 2015, in Order No. 87082, the Commission accepted the majority's recommended DRIPE methodology, which BGE has relied on in this case to compute the Capacity Price Mitigation benefit derived from AMI.[299] We remain unconvinced by OPC's reasoning in regard to this issue, and note further that OPC did not offer any persuasive basis on which to distinguish our prior decision from the instant case. Further, Staff urged that the Commission should use consistent methodologies across energy conservation and demand response programs; we find it appropriate to do so, unless a reasoned and persuasive distinction can be articulated. Accordingly, we will accept for purposes of the cost-benefit analysis discussed here that Capacity Price Mitigation offers a benefit of $159 million on a net present value basis.[300]

For the category of Avoided Capacity Costs, OPC contested the Company's calculation of this benefit and Staff did not include this category in its analysis after deeming it an Additional Benefit. Although OPC agreed that there is some Avoided

[299] Pursuant to Order No. 87213, the Commission denied OPC's petition for rehearing with respect to the adopted Capacity DRIPE methodology.
[300] Note that because we have accepted Staff's recommended inflation rate, the net present value of this benefit equates to $159 million as opposed to the Company's calculation of $212.6 million.

Capacity Cost benefit and Staff observed that the benefit was not zero, we concur at this time with Staff's conservative approach to this category and note that we need not include this benefit in our analysis in order to find the Company's smart grid initiative cost-beneficial. We understand from BGE witnesses that the Company's calculation of Avoided Capacity Costs hinges on PJM adjusting its forecast once PJM fully transitions its demand response programs from the supply side to the demand side of its wholesale capacity market.[301] Accordingly, we direct BGE to file within six (6) months a plan for how the Company intends to tackle this issue with PJM in order to bring about the necessary adjustment to PJM forecasts in the future.

In calculating the Energy Revenue benefit, BGE assumed two emergency events per summer season while OPC proposed one-half of an event per summer season. Although Staff found the Company's forecast to be reasonable, Staff modeled the effect of lowering the number of emergency events from 2 to 1 per summer. We find the assumption of 1 event per summer reasonable and in line with our conservative approach to this analysis, and thus we accept an Energy Revenue benefit of $11 million on a net present value basis.

The benefit computed for Energy Price Mitigation was similarly contested. OPC submitted an analysis that incorporated different regressions than BGE's analysis. Staff agreed that OPC witness Chernick made reasonable arguments to reduce the value of this benefit to $18 million. BGE too conceded that OPC's analysis was reasonable.

[301] This Commission has been working, and will continue to work, with PJM to find ways to preserve Maryland's demand response programs, so that they are not severely diminished under PJM's proposed new paradigm.

Accordingly, we will accept a benefit of $18 million on a net present value basis for Energy Price Mitigation.

The benefit computed for Energy Conservation was also contested. OPC argued that the value of this benefit was overstated because of outdated wholesale energy prices, and because the Company's analysis did not properly account for load shifting and free riders. Thus, OPC witness Chernick reduced the value of this benefit to $95 million. BGE agreed that it would be appropriate to use updated forward wholesale energy prices and further conceded that there may be some reduction in the benefit due to load shifting, acknowledging that there was 10% load shifting in its SER pilot program. BGE maintained, however, that its regression analysis properly accounts for free riders, and Staff asserted that the issue of free ridership was moot in this context.[302] Therefore, while we decline to adjust the Company's calculated benefit due to potential free ridership for the reasons asserted by BGE and Staff, we will reduce BGE's benefit figure of $137 million for potential load shifting by the 10% BGE acknowledged, to $123 million on a net present value basis.

After tallying the above market-side benefit values for Capacity Revenue, Capacity Price Mitigation, Energy Revenue, Energy Price Mitigation, and Energy Conservation, we arrive at Market Side Benefits derived from the smart grid initiative of at least $353.6 million on a net present value basis, which does not include amounts for categories that Staff designated as Additional Benefits. Staff deemed the categories of Avoided Capacity Costs and Avoided Emissions as Additional Benefits, and while recognizing that the value of these categories was not zero, declined to include either

[302] Tr. at 1931 – 1932.

category in its assessment of the Company's cost-benefit analysis. OPC too conceded that these remaining two categories of market-side benefits represented net positives for customers, and if we accepted OPC witness Chernick's position on Avoided Capacity Cost benefits, we could add $9 million to the tally of market-side benefits attributable to the Company's smart grid initiative. Moreover, OPC accepted the Company's computed benefit for Avoided Emissions of $3.9 million. We decline, however, at this time to include a valuation of either Avoided Capacity costs or Avoided Emissions in our assessment of the Company's cost-benefit analysis, noting instead that this conservative approach supports an ultimate conclusion that the Company has delivered a cost-beneficial AMI system.

Given that no party contested the costs of the Company's smart grid initiative on a quantitative basis, we accept that the Company's actual costs associated with AMI deployment are $653.8 million. This amount does not include the unamortized balance of the legacy meter asset, which we believe constitutes a sunk cost that is not appropriately included in the cost-benefit analysis for this new initiative. We also find it inappropriate, for the reasons stated by the Company in the record, to include SER bill credits as a cost in the cost-benefit analysis. We instead view these bill credits as transfer payments. OPC did not persuade us that there was particular justification for its change in position on this issue, or a reasoned basis for the Commission to deviate from an analysis OPC endorsed, and the Commission accepted, in the recent past.

As we stated above, Operational Benefits attributable to the Company's smart grid initiative equal or exceed $485.8 million.[303] Further, we find that Market Side Benefits stemming from BGE's AMI system equal or exceed $353.6 million. As part of this valuation, we did not include the Company's computed value for certain Additional Benefits within the Company's Operational Savings category – benefits associated storms (reducing the length of storms and avoided truck rolls) or reduction in uncollectible write-offs. We also did not include any value for the Additional Benefits associated with enhanced customer reliability, reduced theft, or reduced consumption on inactive meters; nor did we include a valuation of the Additional Benefits on the market side of Avoided Capacity Costs and Avoided Emissions. We concur with Staff that incremental benefits in these areas have and will likely continue to accrue to customers moving forward; however, we also agree with Staff that a review of additional data regarding these benefits may be warranted prior to assigning a value to these categories. We anticipate and expect that the Avoided Capacity Cost benefits predicted by the Company will materialize, and avoided Emissions benefits will prove valuable as well. However, taking Operational Benefits of $485.8 million and minimum Market Side Benefits of $353.6 million, we reach a conservative benefit figure of $839.4 million, which is well above the AMI initiative stated costs of $653.6 million. Accordingly, we find that the Company has delivered a cost-beneficial AMI system.[304]

We also recognize that there is evidence in the record that the smart grid technology will produce benefits in the future that BGE did not attempt to measure in the

[303] Operational Savings of $174M + Avoided T&D of $166M + Avoided Capital Expenditures of $36M + CVR Avoided Costs of $49.6M + DOE Grant Benefit of $60.2M = $485.8M, not including any amount for Reduction in Uncollectible Write Offs.
[304] Given this finding, we do not need to consider OPC's suggestion regarding a "hold harmless" credit.

instant proceeding. BGE witness Case testified that the next iteration of the Smart Energy Manager program will include a rates module that will allow customers to see how much their bill might go up or down if they moved from a flat rate to BGE's time-of-use rate[305], which could lead to adjustments out of the peak period into the off-peak period yielding direct cost savings to participating customers and indirect benefits to all ratepayers associated with the mitigated system peak demand.[306] New pricing options are enabled by smart meters, as well as measurement of solar output from homes and businesses. Thus, while OPC provided testimony that benefits attributable to the smart grid initiative were overstated, BGE testified about the areas in which the Company believes its analysis to be conservative and further offered examples in which currently unquantified benefits may continue to accrue and develop.[307]

### 2. ***Continued Reporting of Metrics***

OPC advocated for the continued collection and quarterly reporting of metric information regarding the smart grid initiative, as well as customer opt-out information. BGE has indicated a willingness to continue to report on smart grid-related metrics that

[305] Tr. at 1082.
[306] Tr. at 1079-1080.
[307] As set forth above, the benefit associated with CVR was calculated as an avoided cost benefit, whereas the Company's representatives testified that including the energy and demand reductions associated with a CVR system would have resulted in a larger benefit figure. In addition to CVR, BGE noted that Smart Energy Manager benefits were calculated without gas residential customers. Mr. Case stated that the Company is seeing a benefit from gas customers of roughly two-thirds that of electric residential customers. In addition, Mr. Case indicated that the Company is rolling out the SEM program to commercial customers which he believes will produce additional benefits. Tr. at 1046-1047.

the Commission deems worthwhile.[308] We see no reason that this rate case would operate to halt the reporting that is ongoing in Case No. 9208, or further reporting in that case. The Company shall continue to report metrics as it has been in Case No. 9208, as well as provide additional reports as directed by the Commission.

### 3. ***Cost Prudency Review***

Although we find that BGE has proven that it has delivered a cost-beneficial AMI system, based on the costs BGE has and will incur as compared to the benefits that have materialized and will continue to materialize, we are still required under PUA §4-101 to set just and reasonable rates based only on necessary and proper expenses. Indeed, in Order No. 83531, issued in August 2010, the Commission noted in its authorization of BGE's AMI deployment that the Commission's "recognition of a regulatory asset is not an advance determination that all costs related to the Initiative are prudent. We recognize that 'prudent' does not mean 'clairvoyant' or 'perfect,' and that a proper prudency review should not subject the Company to an unfair, post hoc nickeling-and-diming. But we also will not deem any costs as 'prudent' in advance – the appropriate time to determine prudence is when recovery of the regulatory asset is sought."[309] Thus, as part of this case, the parties were expected to present evidence as to the prudency of the costs for which BGE is seeking recovery.

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[308] We note that in BGE's most recent Case No. 9208 filing, the Company reported that 49,212 residential customers were subject to BGE's opt-out fees, reflecting an opt-out rate of 4%. ML 190683 at 12. Although some of these customers have chosen affirmatively to reject a smart meter, a significant number of customers have been auto-enrolled into opt-out status - and consequently billed a $75 upfront fee and a recurring $5.50 monthly fee. We remain very concerned about the large number of auto-enrolled customers who BGE has not reached and remind the Company of its continuing obligation to serve these customers and provide them with access to smart meters.

[309] Order No. 83531 at 39.

Staff found reasonable both the deployment and post-deployment costs as calculated by the Company, noting that the deployment costs align closely with the metrics reported as part of the Phase I metrics in Case No. 9208, filed on a quarterly basis. OPC provided testimony disputing the prudency of the Company's customer education efforts. We agree that the Company's customer education efforts were not as successful as we expected in educating customers about the benefits of smart meters. Although BGE fulfilled the literal terms of its communication and customer education plan, the plan did not prevent customer resistance to the installation of the meters. We agree with OPC that BGE should have been able to anticipate that there would be a degree of customer resistance to smart meters given the experiences of other utilities in other jurisdictions; in fact, the Commission noted in 2010 that deployments in other states were expected to supply lessons on how not to deploy AMI and how not to (mis)communicate with customers.[310] The Company submitted that $16.6 million in costs associated with its smart grid initiative were related to customers affirmatively opting out of smart meter installations and customers who were non-responsive to BGE's outreach efforts. Because BGE should have been able to better anticipate that some customers would want to opt out of having smart meters installed in their homes, which would have allowed the Company to have an appropriate strategy for dealing with those customers ahead of deployment, we do not find it appropriate to pass on to ratepayers the resulting costs associated with these additional outreach efforts. Similarly, we agree with OPC that BGE's explanation for its failure to reach all of its customers is unsatisfactory. BGE has previously had difficulties reaching all of its customers when trying to contact

[310] *Id.* at 47-48.

them or gain access to their premises. BGE's customer education plan can be seen as deficient to the extent customers failed to respond to its requests to install smart meters in their homes. Therefore, we will disallow $16.6 million in costs that the Company stated were additional costs incurred related to the opt-out proceedings and resulting Commission decisions.[311] The resulting rate base and operating income adjustments are summarized in the next section.

Lastly, we disagree with our dissenting colleagues' characterization of our decision with respect to AMI cost recovery; chiefly, we take issue with their depiction of the Company's demonstrated benefits derived from the smart grid initiative as speculation and claimed benefits. On the contrary, the extensive operational and market-side benefits accepted in our assessment of the Company's cost/benefit analysis – valued conservatively at $839.4 million on a net present value basis – are grounded in methodologies accepted repeatedly by this Commission and routinely used by public utility commissions nationwide. Indeed, OPC was an active participant in the development of these methodologies and assumptions over the past six years. Furthermore, we note that by using OPC's own preferred methodologies, the cost/benefit ratio of BGE's AMI system ranges between 0.94 and 1.14 when excluding the SER bill credits as a cost in the cost/benefit analysis.[312] In short, we find that the Company has

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[311] OPC does not agree with the Company's suggestion that the Commission's opt-out orders are to blame for BGE's rate of installation of smart meters.

[312] As discussed in this section, the SER bill credits constitute a "transfer payment." It would upend well-settled principles of cost-effectiveness testing adopted by the Commission if transfer payments were included in a cost-benefit analysis as OPC proposes. Tr. at 437-438.

delivered a cost-beneficial AMI system, and thus is entitled to cost recovery of prudently-incurred costs associated with the smart grid initiative, as well as an appropriate return.[313]

## B. Adjustments to Rate Base and Operating Income

Rate base represents the investment a company makes in plant and equipment to provide safe and reliable electric service to its customers. Operating income is derived from the revenues the Company receives for electric service less the prudently incurred costs of providing service to customers. Adjustments to the Company's rate base request were offered, accepted or disputed by the various parties. We have reviewed the record and accept many of the uncontested[314] rate base and operating income adjustments, and resolve the disputed adjustments below.[315]

### 1. ***Smart Grid Initiative Adjustments***

#### a. *OIA 23/RBA 6: Smart Grid Regulatory Asset Post-Test Year*

We reject the Company's proposed Operating Income Adjustment 23 and Rate Base Adjustment 6. We disagree with BGE witness Vahos' conclusion that if the Company is not permitted to recover Smart Grid costs that are incurred after the test period and before the effective date of the new rates, BGE would be required to keep those costs in a regulatory asset. In Order No. 83531 in Case No. 9208, the Commission deferred cost recovery until BGE could offer proof that it had delivered a cost effective system. When it filed this base rate case, BGE submitted proof that it had delivered a cost-beneficial system, based on the test year ending November 30, 2015. We have

[313] Order No. 83531 at 38.
[314] OIA 26 addresses BGE's uncontested adjustment for its 2016 wage increase. Although we do not deny the adjustment, we ask that parties address wage increases outside the test period in the next rate case.
[315] *See* Appendix I for the Commission's calculation of the appropriate rate base, operating income and overall revenue requirement for rate making purposes.

determined that BGE is entitled to cost recovery of its smart grid initiative, however, that determination does not render all of BGE's costs prudent, nor does it mean that BGE is entitled to post-test year expenses as part of this rate case given the historical test year approach. Allowance of post-test year expenses is an exception to the rule, for such items as reliability spend. Costs related to BGE's smart grid system will continue to accrue. These ongoing costs, and costs that were incurred subsequent to the test year in this case, are to be expensed as normal expenses. These expenses may be recovered in future base rate proceedings to the extent they fall within the test year for those case(s).[316]

b. *Amortize Smart Grid Regulatory Asset Over 10 Years*

Although we find that BGE has shown the smart grid system to be cost-beneficial, we are extremely concerned about the level of increase that ratepayers will experience based on this Order. We believe it is appropriate to take steps to ease rate shock to the fullest extent possible. Therefore, we direct BGE to amortize the smart grid regulatory asset over 10 years as proposed by the parties in this case and which BGE conceded was reasonable. This results in an operating income adjustment of $10,051,000[317] for electric and an operating income adjustment for gas of $4,019,000.[318]

We will not, however, modify the depreciable life of the smart grid assets from 10 years to 15 years, despite the testimony at the hearings that the smart grid technology may have a useful service life of at least 15 years. A utility that is only in the preliminary

[316] In fact, we note that OIA 22 effectively provides for an appropriate amount of annual O&M expenses in the rate effective period (Vahos Direct at 12) meaning that BGE will recover its annual O&M expenses based on actual 2015 expenses going forward even if BGE does not file a rate case for over a year.
[317] Regulatory asset balance of $168,537,266 as of November 30, 2015 (Vahos Supplemental Direct, Exhibits at 28).
[318] Regulatory asset balance of $67,394,298 as of November 30, 2015 (Vahos Supplemental Direct, Exhibits at 28).

stages of deployment of smart grid technology may wish to consider whether 15 years is appropriate for the depreciable life of its new assets, but that is not the situation with BGE.

c. *Accrued Smart Grid Operational Savings*

BGE contends that the language in Order No. 83531 in Case No. 9208, as well as the Pepco Order in Case No. 9207, is clear in that the utilities were provided a choice to either flow operational savings through to customers during deployment or to defer operational savings until incremental cost recovery was determined, but not both. However, the "flow-through" that BGE proposed in Case No. 9208 was a tracker mechanism. As it turns out, BGE filed rate cases in each of the intervening deployment years, and, thus, operational savings flowed through to customers (though with lag as Mr. Effron points out) in the subsequent rate effective periods. However, BGE has not presented evidence that this type of "flow-through" was anticipated and understood by the parties in Case No. 9208, or formed the basis for the Commission's decision in Order No. 83531. Indeed, we do not believe such evidence exists.

We agree with OPC that the excess of the operational savings achieved over the amount credited to ratepayers should be offset by the deferred smart grid costs included in the recoverable smart grid regulatory asset. Ratepayers should not be worse off than they would have been under a tracker mechanism. BGE claims that this adjustment is unfair, yet BGE has not offered a reasonable explanation for why it should be given the preferential treatment of retaining a portion of the benefit of the smart grid savings for shareholders as compared to Pepco, whose ratepayers will receive credit for all of the smart grid savings. Although components of the smart grid regulatory asset were disclosed in the intervening rate cases filed during deployment, the regulatory asset did not affect the rates determined in those cases; thus, this adjustment does not, contrary to BGE's contention, constitute retroactive ratemaking. Accordingly, for electric we will make a downward adjustment to rate base of $9,643,000 and, consistent with our decision to amortize the smart grid regulatory asset over ten years, an operating income adjustment of $964,000.[319] The adjustments for gas are a downward adjustment to rate base of $4,639,000 and an operating income adjustment of $464,000.

### d. *Return on Legacy Meters*

While we will allow the Company to recover the cost *of* its legacy meters that were retired as part of the Company's smart grid initiative, we find it is not appropriate for the Company to earn full recovery by earning a return *on* the unamortized balance of the legacy meters. We acknowledge that in Case No. 9355 the Commission approved as just and reasonable the rates resulting from a "black box" settlement between the parties, embedded in which was the question of a return *of* and *on* the legacy meters.[320] Despite serving as a signatory to the Case No. 9355 settlement, OPC now requests that this Commission disallow a full return of and on legacy meters, and the issue is squarely before the Commission. We find that these assets are in a different category from other assets in that the legacy meters were retired all at once while they still had useful life. Therefore, we agree with OPC that the Company is not entitled to full recovery *on* the

[319] We note that in making his calculations, Mr. Effron reflected Mr. Lanzalotta's 40% reduction to the savings attributed by BGE to reduced storm restoration costs, which reduced the overall electric operational savings by approximately 6.7%. Although we do not accept Mr. Lanzalotta's proposal, as set forth below, we incorporate Mr. Effron's 6.7% reduction because the record evidence is that while BGE disagreed with Mr. Effron's proposed adjustment, BGE did not dispute his calculation of accrued smart grid operational savings. Tr. at 742.

[320] In a "black box" settlement, the parties agree on the result without disclosing or agreeing on the various components.

unamortized balance of the legacy meters.[321] OPC describes its position as an equitable split between ratepayers and shareholders and we concur. Accordingly, rate base will be adjusted downward in the amount of $46,495,000 for electric, and for gas, rate base will be adjusted downward by $2,193,000.[322]

e. *<u>Other Contested Adjustments</u>*

Since we have found that the Company has delivered a cost-beneficial AMI system, as set forth above, OPC's proposed adjustment for a "hold harmless" credit is moot. OPC also proposed an operating income adjustment based on its theory that the savings attributable to reductions in storm restoration costs are overstated by the Company by 40%. Although we did not assign a value to the benefit associated with reductions in storm restoration costs for purposes of the cost-benefit analysis, some reductions have likely been the result of other reliability investments and distribution system upgrades. While a reduction in actual storm restoration costs might be appropriate, we are not convinced that it is correct to correlate the computed 40% reduction in customer interruptions (during milder weather years)[323] to a 40% reduction in the savings attributed to avoided truck rolls. Moreover, as OPC noted, the Company accounted for this to a degree, and thus, Mr. Lanzalotta's 40% reduction on top of the Company's reduction would be inappropriate. For these reasons, we cannot accept OPC's proposed operating income adjustment for rate year smart grid savings.

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[321] We are not adopting what we see as an extreme position on the part of OPC; we are not adjusting recovery of the costs *of* the meters themselves, only the return *on* these assets.

[322] Uses the 13-month average balance per Chang Direct, Exhibit OPC Data Request 13 (Item No.: OPCDR13-01). BGE opposed OPC's position on this issue, but did not dispute the figure that OPC discussed in both written and oral testimony for the unamortized balance. We recognize that this figure might be reduced for ADIT, however, since BGE did not provide that information, the unamortized 13-month balance will be deducted from rate base in order to disallow a return *on* this asset.

[323] Butts Rebuttal at 22.

DOD recommended disallowing the smart grid O&M expenses in the test year because smart grid O&M expenses exceed O&M savings for that same period. As set forth above, we accept, as OPC and others did, the Company's methodology of a 10-year projection of costs and benefits. Based on this approach, smart grid O&M expenses are not expected to exceed O&M savings over the long run. The Commission did not, as part of Case No. 9208, require that smart grid O&M savings exceed O&M expenses for any one year. Moreover, the Commission's prior Order contemplated that the cost-benefit analysis would take into account market-side benefits in addition to operational savings.[324]

DOD also recommended an adjustment based on the effect of smart grid deployment on working capital. BGE testified that there are benefits to smart grid beyond those presented in this case, benefits yet to be fully developed and realized. We agree that BGE should investigate whether smart grid technology can optimize billing as Mr. Shpigler believes, in order to reduce working cash capital needs going forward.[325] We direct BGE to submit a report within sixty (60) days outlining the Company's findings and invite other parties to comment on that report within thirty (30) days of its submission.

Lastly, DOD recommended adjustments based on the "gross-up" conversion factor. While Mr. Shpigler's adjustment was based on an unsupported claim that industry experience is that smart grid reduces uncollectible accounts by more than 50%, BGE did compute a benefit associated with a reduction in uncollectible write offs, a benefit that

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[324] *See, e.g.* Order No. 83531 at 46-47.

[325] For purposes of this case, cash working capital is based on the test year and BGE's current billing practices, so no adjustment is warranted.

appears to increase every year after deployment.[326] Thus, the uncollectible rate utilized in this case, based on actual test year data, is likely to decrease during the rate effective period. Therefore, we direct BGE, in its next rate case, to support its computed benefit for reduction in uncollectible write offs in future years with actual data, which should reflect a reduction in the uncollectible rate as compared to the actual uncollectible rate utilized in this case. And since BGE has projected the benefit associated with a reduction in write-offs for uncollectible accounts, we think it is appropriate for BGE to compute a projected uncollectible rate for the rate-effective period for our consideration. We will then make a finding as to whether an appropriate "gross-up" conversion factor should be used. In the interim, we reject DOD's proposed adjustment as not fully supported.

f. Disallowed Costs

The result of disallowing $16.6 million in costs that the Company incurred and attributed to the opt-out proceedings and resulting Commission decisions is, for electric, a rate base reduction of $3,549,000 and an operating income adjustment of $710,000.[327] For gas, there will be a rate base reduction of $1,401,000 and an operating income adjustment of $280,000.[328]

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[326] Reduction in uncollectible write offs is one of the operational savings benefits; according to BGE, the operational savings benefits will continue to increase in value every year through 2025.

[327] This calculation uses the average balance of the smart grid regulatory asset, net of taxes, and assuming 71.7% attributable to electric per Vahos Supplemental Direct, Exhibit DMV-6 Actual Deferred Smart Grid Costs. We find it is appropriate to disallow this amount in costs incurred during the test period given Mr. Butts' reference to Order No. 86727, which was issued on November 25, 2014. *See* Butts Direct at 25.

[328] Assumes 28.3% attributable to gas per Vahos Supplemental Direct, Exhibit DMV-6 Actual Deferred Smart Grid Costs.

### 2. ***Baltimore City Conduit Fees (OIA 28, 29, 30; RBA 7, 8)***

The City of Baltimore ("City") owns and maintains an underground conduit system that contains utility-related equipment and cables.[329] BGE is the largest user of the conduit system and occupies approximately 12.4 million linear feet of conduit space.[330] BGE electric assets in the conduit system include electric cables, switches, transformers, street lighting cable, and communication cable.[331] All users of the conduit system, including BGE, pay to the City on a semi-annual basis a lease and maintenance fee based upon linear feet of occupancy.[332] The Baltimore City Board of Estimates approved an increase in the fees for all users from $0.9785 per linear foot to $3.33 per linear foot, effective November 1, 2015.[333] BGE's position is that the City is only permitted to charge a fee to BGE that is reasonably related to the actual expenses incurred by the City in maintaining the conduit system.[334] On October 16, 2015, BGE brought suit against the City to prevent improper use by the City of the conduit fee revenues and to place constraints on the City's ability to set the conduit fee in the future.[335]

BGE asserts that operating Income Adjustment 28 reflects a known and measurable increase in costs during the rate-effective period, as compared to the level of conduit expenses in the test year.[336] Operating Income Adjustment 29 provides for amortization over five years for the expenses related to the conduit rate increase during

[329] Vahos Direct at 16.
[330] Vahos Direct at 17.
[331] Vahos Direct at 17.
[332] Vahos Direct at 17.
[333] Vahos Direct at 17.
[334] Vahos Direct at 18.
[335] Vahos Direct at 18.
[336] Vahos Direct at 19.

the 7-month period between the effective date of the conduit increase on November 1, 2015 and the rate-effective period commencing in early June 2016.[337] Rate Base Adjustment 7 establishes a regulatory asset for the $15.4 million net increase in Baltimore City conduit fees incurred during the 7-month period between the effective date of the conduit rate increase on November 1, 2015 and the rate-effective period commencing in early June 2016.[338] These adjustments show the effect of treating the conduit fee increase as a base rate item.[339] Operating Income Adjustment 30 and Rate Base Adjustment 8 eliminate the impacts of Operating Income Adjustments 28 and 29 as well as Rate Base Adjustment 7 should the conduit fee increase instead be recovered through a rider as proposed by BGE. BGE proposed two versions of this rider: Option A would apply the charge only to customers who live in Baltimore City; Option B would apply the charge to all electric distribution customers regardless of jurisdiction.[340]

**Party Positions**

***BGE***

BGE believes that it is most appropriate to recover the incremental conduit fees through a rider.[341] A rider ensures that if adjustments are made to the fees as a result of the pending litigation or other reasons, customers will pay only the actual costs of maintaining the conduit system.[342] In his supplemental direct testimony, BGE witness Vahos provided an update on the status of the pending litigation. Mr. Vahos noted that

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[337] Vahos Direct at 20. We note that the test period in this case ended November 30, 2015, however, the Company treats the entire conduit fee increase as a post-test year event; apparently because the Company disputed the amount invoiced by Baltimore City, the Company did not accrue this expense on its books during the test year.
[338] Vahos Direct at 20.
[339] Vahos Direct at 20.
[340] Prepared Direct Testimony of John C. Frain, November 6, 2015 ("Frain Direct") at 3.
[341] Direct Testimony of Mark D. Case, November 6, 2015 ("Case Direct") at 29.
[342] Case Direct at 29.

the Circuit Court recognized that the parties' current contract requires an annual "true-up" of revenues and expenses to ensure that BGE only pays its pro rata share of the actual costs incurred by the City to operate and maintain the underground conduit system.[343] Mr. Vahos claims that the Circuit Court's recognition of the required "true-up" process further supports the need for a rider because the rider mechanism will ensure that customers receive the benefit of any funds returned to BGE as a result of the "true-up."[344]

On surrebuttal, Mr. Vahos responded to MEG witness Baudino's position that the Commission should disallow recovery of the increase in conduit fees during the November 2016-June 2016 time period, contending that BGE has met the standard for recovery of these post-test year costs as known, measurable and significant costs.[345]

***City of Baltimore***

Three witnesses submitted written testimony on behalf of the Mayor and City Council of Baltimore (the "City"). Mr. William M. Johnson, Director of the Baltimore City Department of Transportation ("DOT") testified that the parties are still operating in part under a 2008 Agreement in Principle which includes the concept of a "true-up" mechanism, however, Mr. Johnson testified that the true-up process was not clearly developed.[346] Mr. Johnson testified that in 2015, the DOT assessed its operations for conduit maintenance and concluded that a more proactive and preventative maintenance program was required for the conduit system instead of the "reactive" manner in which it historically conducted maintenance on the conduit system, making repairs as problems

[343] Prepared Supplemental Direct Testimony of David M. Vahos, January 5, 2016 ("Vahos Supplemental Direct") at 12.
[344] Vahos Supplemental Direct at 12.
[345] Vahos Surrebuttal at 9.
[346] Direct Testimony of William M. Johnson ("Johnson Direct") at 6.

arose.[347] Mr. Johnson testified that the City does not intend to use revenues from the conduit lease fees for city services and programs other than those related to operation and maintenance of the conduit system.[348] Mr. Johnson testified that the $3.33 per linear foot rate was developed based on the professional judgment of the DOT concerning the level of maintenance required by the aging conduit system.[349]

Lindsay M. Wines, Deputy Director of Administration for the City DOT also testified on behalf of the City. Ms. Wines testified that in addition to operating maintenance costs, the conduit lease fee was calculated to incorporate capital maintenance projects such as replacement of aged conduit system manhole covers and street restoration necessitated by conduit system repairs.[350] The $3.33 conduit lease fee also includes an annual amount for an emergency reserve and overhead (overhead costs include expenses incurred by other City agencies such as Legal, Fiscal, Contract Administration, and Human Resources).[351]

Ms. Wines testified that all revenue generated by the conduit lease fees charged to entities using the City's conduit system is accounted for separately in the City's Conduit Enterprise Fund ("Conduit Fund") which is audited annually by the City's Department of Audits and KPMG, LLP.[352] Ms. Wines explained that amounts are only transferred from the Conduit Fund to the City's General Fund so that appropriate amounts can be allocated to the budgets of the various departments or agencies supporting the operation of the

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[347] Johnson Direct at 6-7.
[348] Johnson Direct at 13.
[349] Johnson Direct at 14.
[350] Direct Testimony of Lindsay M. Wines ("Wines Direct") at 7.
[351] Wines Direct at 7-8.
[352] Wines Direct at 11.

conduit system and the administration of the Conduit Fund.[353] Ms. Vines also testified as to how the true-up process has operated since 2008, stating that BGE has implemented the true-up by reducing its second semi-annual conduit lease payment each fiscal year by a true-up payment estimated by BGE for the prior fiscal year, and then performing a reconciliation based on the City's Comprehensive Annual Financial Report ("CAFR") once it is released.[354]

Dale A. Kessinger addressed cost allocation issues related to the recovery of the conduit lease fees.

***OPC***

Jonathan Wallach testified on behalf of OPC with regard to the recovery of increased Baltimore City conduit fees. Given the unique circumstances in this case, specifically uncertainty with regard to the outcome of litigation, OPC witness Wallach found the Company's proposal to recover incremental conduit fees through a separate surcharge reasonable.[355] Mr. Wallach states, however, that BGE has not offered any justification for why exceptional treatment of conduit fees should continue once litigation has been finally resolved, and that instead surcharge recovery should be temporary.[356] Noting that the Company currently recovers conduit fees from all ratepayers, Mr. Wallach opined that it is not reasonable to recover the increased conduit fees solely from Baltimore City ratepayers.[357] On rebuttal, Mr. Wallach added that if the fee increase is recovered from all ratepayers through BGE's proposed surcharge mechanism, then all

[353] Wines Direct at 13.
[354] Wines Direct at 14.
[355] Direct Testimony of Jonathan Wallach, February 8, 2016 ("Wallach Direct").
[356] Wallach Direct at 21.
[357] Wallach Direct at 21-22.

ratepayers would be held harmless regardless of an eventual court ruling through the surcharge true-up mechanism.[358]

***<u>Department of Defense</u>***

DOD witness Dennis Goins recommended that because the Commission has a responsibility to protect ratepayers from paying rates to recover costs that BGE cannot demonstrate are just and reasonable, the Commission reject BGE's electric Rider 5 as proposed.[359] Instead, Dr. Goins recommended that the Commission require BGE to treat incremental City conduit fees as a deferred expense until the ongoing conduit fee litigation between BGE and the City is resolved (including a determination of appropriate conduit charges and terms of service).[360] Under his recommended approach, once the litigation is resolved, the Commission can then adjust the accumulated deferred expense (including a reasonable carrying charge) to reflect conduit rate adjustments (if any) resulting from the litigation and BGE can then be allowed to recover the deferred expense as well as future conduit fees using a Commission-approved rate recovery mechanism.[361]

***<u>Maryland Energy Group</u>***

MEG witness Richard Baudino recommended that the Commission disallow the Company's request to collect $18.97 million of increased Baltimore City conduit fees during the period of November 2015 through June 2016.[362] In his opinion, BGE is attempting to overcome the normal operation of regulatory lag for one isolated expense

[358] Rebuttal Testimony of Jonathan Wallach, March 4, 2016 ("Wallach Rebuttal") at 3.
[359] Direct Testimony of Dennis W. Goins, Ph.D., February 8, 2016 ("Goins Direct") at 8-10.
[360] Goins Direct at 10.
[361] Goins Direct, p 10.
[362] Direct Testimony and Exhibits of Richard A. Baudino, February 8, 2016 ("Baudino Direct") at 3.

item, which is inappropriate.[363] Mr. Baudino explained that revenues and expenses should be measured and annualized for known and measurable changes within the test year, so with respect to the increased conduit fees BGE should be allowed to collect the annualized difference between the existing level of conduit fees in base rates and the higher level of these fees that began on November 1, 2015 since it was still within BGE's test period.[364] However, Mr. Baudino stated that BGE should only be allowed to collect the increased conduit fees when new rates become effective in this case.[365] He further stated that BGE should not be allowed to pick and choose one of its cost elements that increased during the test year and then try to collect this increase before rates become effective later this year, either through a rider or regulatory deferral.[366] Mr. Baudino pointed out that BGE should be able to keep any refund from the City of excessive fees within the 7-month period of November 2015 through June 2016.[367]

***Staff***

Staff witness Patricia M. Stinnette discussed the prudency of the Company spending on City conduit charges and matters related to the accounting treatment of conduit-related monies. Staff witness Craig Taborsky discussed the engineering issues associated with the City's conduit. Staff witness Loubens Blaise discussed appropriate rate design for recovery of either total or partial conduit fees from ratepayers if the Commission chooses to accept the proposal to recover increased costs via a rider. Staff

[363] Baudino Direct at 12.
[364] Baudino Direct at 12-13.
[365] Baudino Direct at 13.
[366] Baudino Direct at 13.
[367] Baudino Direct at 14.

witness C. Shelley Norman, Ph.D, discussed the proposal to treat these costs as distinct from other Company-incurred costs, as well as the allocation of the costs.

Witness Stinnette explained that as an initial matter the conduit costs must be a prudent expense that provides used and useful service to customers.[368] Because the City wants to recover all of the costs of making capital improvements to its conduit before or during the year the costs are actually incurred, the accounting may not be appropriate or consistent with regulatory principles.[369] However, Ms. Stinnette went on to indicate her agreement with the period BGE used for the proposed rider if the costs are recoverable.[370] Ms. Stinnette recommended a CPI-U five year average of 1.82% instead of the proposed 2.75% for the July 2016 through June 2017 period.[371] Ms. Stinnette agrees with Option A for the rider noting that a similar mechanism is used for the Montgomery County Fuel Surcharge, applicable only to Montgomery County residents.[372]

Witness Craig Taborsky described the City conduit system, explained modes of failure of the conduit lines, and described some of the operational and maintenance issues associated with the underground conduit. Witness Taborsky indicated that BGE provided a confidential preliminary analysis estimating costs to enhance inspection, maintenance, and repair of the conduit which has significant differences in both the costs and method required for a proactive maintenance program.[373] Mr. Taborsky opined that the City studies for the proposed conduit work may not be specifically limited to the reliability,

[368] Corrected Direct Testimony and Exhibits of Patricia M. Stinnette, February 18, 2016 ("Stinnette Direct") at 8.
[369] Stinnette Direct at 8-9.
[370] Stinnette Direct at 9.
[371] Stinnette Direct at 10. CPI-U is CPI-Urban according to Ms. Stinnette's testimony at the hearing. Tr. at 1628.
[372] Stinnette Direct at 10.
[373] Direct Testimony of Craig Taborsky, February 8, 2016 ("Taborsky Direct") at 8.

safety, and maintenance of the system but rather include growth and enhancements.[374] Mr. Taborsky stated that if the system is being expanded to accommodate broadband networks, for example, then those customers should pay a greater share of the overall expense, because BGE customers should not be required to pay for work that is caused by and will benefit broadband customers and/or the City in general.[375] Mr. Tabosky concluded that the additional yearly charge of $30.7 million requires further justification before the cost can be flowed through to ratepayers in base rates; it must be shown to be prudently incurred.[376]

Staff witness C. Shelley Norman, Ph.D., explained that currently, the conduit rental fees are treated as other utility costs associated with maintenance of underground lines, and recovered from ratepayers throughout the utility service territory in base rates.[377] Dr. Norman noted that all other conduits within the BGE territory are owned and operated by the Company, with expenses recovered from ratepayers across the territory in distribution base rates.[378] Dr. Norman reviewed the pending litigation between BGE and the City and believes that the basis of the Company's complaint is that BGE does not believe that the City has demonstrated that the increased fees will be used solely for the operation and maintenance of the conduit.[379]

Dr. Norman explained that there are other bill amounts charged only to customers served in certain jurisdictions.[380] BGE recovers local taxes from ratepayers in Anne Arundel, Baltimore and Prince George's counties, and Baltimore City, as well as the

[374] Taborsky Direct at 9.
[375] Taborsky Direct at 9.
[376] Taborsky Direct at 9.
[377] Direct Testimony of C. Shelley Norman, Ph.D., February 8, 2016 ("Norman Direct") at 27.
[378] Norman Direct at 27.
[379] Norman Direct at 27.
[380] Norman Direct at 30.

Montgomery County Fuel Energy Tax surcharge.[381] Dr. Norman testified that these tax amounts are not specifically directed towards the provision of utility service in those jurisdictions.[382] She further testified that BGE does not charge geographically differentiated rates for any costs not designated as taxes.[383] She stated that in general, for reasons of equity and complexity, regulators do not typically analyze or require locational cost estimates within utility territory, instead differentiating rates by only territory-wide class characteristics.[384]

Although Dr. Norman could not find points of clear comparison in this jurisdiction or others, she stated that there are some previous policies and decisions to rely upon.[385] New service extensions or modifications may be charged to users requesting new investments.[386] More relevant, infrastructure requirements imposed on utilities by jurisdictions have in the past been deemed to be beyond those needed to provide quality service and have been thus excluded from recovery in rates.[387] The capital costs associated with undergrounding of utility equipment in parts of Annapolis was an issue in the 1980s. The work was characterized as "municipal" and deemed to have been to a substantial degree done for aesthetic reasons. Dr. Norman claimed recovery in base rates was found to be inequitable because the excess undergrounding costs would not provide substantial benefit to ratepayers generally, but rather primarily benefitted those residing in the historic areas where the relocation occurred. Dr. Norman noted a similar issue in the pending litigation - that improving the conduit for non-utility

[381] Norman Direct at 30.
[382] Norman Direct at 30.
[383] Norman Direct at 30.
[384] Norman Direct at 31.
[385] Norman Direct at 31.
[386] Norman Direct at 31.
[387] Norman Direct at 31.

purposes, in particular increased network infrastructure, has been considered the reason for spending on some sections of the conduit.[388] Dr. Norman stated that if spending on the conduit were not driven by utility needs, the inclusion of these costs in rates could lead to BGE customers being assessed a significant burden of costs associated with work they did not request, their electricity use did not cause a need for, they do not benefit from, and which may not be closely related to the service they receive.[389]

Dr. Norman testified that the utility equipment within the conduit system is part of a network operated and maintained by BGE for the benefit of the service territory.[390] She stated that while in general the equipment in City conduits serve City customers, some City customers are served by overhead lines and some customers outside of the City are served by circuits and equipment partially located within City conduits.[391]

Although the City and the Company agree that increased work needs to be done to maintain the conduit system to an acceptable standard, each has its own analysis of ways to enhance inspection, maintenance and repair activities.[392] Dr. Norman found that it is not clear from the data available which improvements considered by either party most improve the utility service received by ratepayers.[393] Dr. Norman noted that the existing true-up process utilized by the parties has not been sufficient to resolve disputes regarding whether or not expenses are truly related to conduit maintenance.[394] She concluded that the record does not allow her to make a clear determination regarding which amounts of the conduit lease fee increase might be related to the provision of

[388] Norman Direct at 33-34.
[389] Norman Direct at 34.
[390] Norman Direct at 35.
[391] Norman Direct at 35.
[392] Norman Direct at 35.
[393] Norman Direct at 36.
[394] Norman Direct at 38.

improvements desired by the City but are not necessary for maintenance of the conduit system adequate to meet BGE's needs.[395] Thus, she believes she must allow for the possibility that some portion of the requested rate increase is related to purposes extending beyond those of the provision of utility service.[396]

Dr. Norman stated that an interim solution to the situation of being required to make a determination regarding disputed third party costs which are currently being litigated in another venue is to include incremental costs in a rider.[397] She recommended a rider be allowed for customers within the City, with the Company being required to bring the matter before the Commission within thirty days of reaching an agreement with the City or of a decision in the pending litigation, as well as in any future rate cases that may occur prior to a full resolution of this issue.[398] She stated that any agreement between the Company and the City should detail responsibilities and methods for assessing needs, determining prioritization, locations and timing of work, accounting for capital and operational costs and an annual true-up process, managing shared space within the conduit system, and determining appropriate actions to improve and remediate conditions within the system to serve utility needs.[399] Dr. Norman noted that in accordance with long standing ratemaking principles, only costs determined to be reasonably and prudently incurred and directly related to the provision of utility service may be included in base rates applicable system-wide.[400]

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[395] Norman Direct at 39.
[396] Norman Direct at 39.
[397] Norman Direct at 40.
[398] Norman Direct at 40.
[399] Norman Direct at 40-41.
[400] Norman Direct at 41.

Dr. Norman stated that on an ongoing basis, recovery of costs for used and useful infrastructure in isolation is not consistent with regulatory best practices, but she believes the current situation presents an appropriate exception; thus she does not believe recovery of the conduit fees via a rider constitutes inappropriate single issue ratemaking.[401] Dr. Norman recommended that the Company be required to bring any requests to increase or decrease the rider rate, as a result of CPI adjustments, rate changes, late fees, an annual true-up, or any other reason, before the Commission for review and consideration.[402] Lastly, Dr. Norman recommended that the large amount proposed to be recovered in the first year of the rider should be mitigated by spreading recovery of the November 2015-June 2016 amounts over five years, as the Company proposed.[403]

On surrebuttal, Dr. Norman stated that Baltimore City witness Johnson mischaracterized her testimony regarding agreements or contracts between the City and the Company.[404] Dr. Norman does not intend for the Commission to dictate terms of any agreements between the City and BGE; rather the Commission may review any contracts or agreements entered into by the Company as part of its provision of regulated electric distribution services.[405] She requests that the Company be directed to bring any agreement with the City before the Commission, and report on how the various underlying disputes have been resolved, to aid the Commission in determining the appropriate allocation of conduit lease cost responsibility going forward.[406] She notes that Staff has a duty to recommend positions that protect customers from unjust and

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[401] Norman Direct at 41.
[402] Norman Direct at 42.
[403] Norman Direct p. 42.
[404] Surrebuttal Testimony and Exhibits of C. Shelley Norman, Ph.D, March 21, 2016 (“Norman Surrebuttal”) at 3.
[405] Norman Surrebuttal at 3.
[406] Norman Surrebuttal at 3.

unreasonable charges, which requires information about the nature and composition of any proposed charges, in order to ensure that the City is not taking advantage of its apparent monopoly power to unfairly assess charges that are socialized across the BGE service territory.[407] Absent such information and review, Dr. Norman recommends that costs be paid by those who, firstly, can hold decision makers accountable for their choices, and, secondly, will benefit from any improvements over and above those needed to support adequate and efficient provision of electrical distribution services.[408]

Dr. Norman notes that the Company has testified that it seeks a process, through the litigation, to monitor the City's expenditures.[409] Thus, Dr. Norman envisions a process by which conduit costs would be assigned to a Rider 5-A, where incremental costs are distributed locally to Baltimore City ratepayers unless and until they can be moved to socialization through a territory wide Rider 5-B.[410] This process would permit treatment of conduit lease costs incurred to provide adequate electric distribution services in a manner consistent with other necessary system expenses, while excluding "municipal project" costs from general rates.[411]

***Testimony at Hearings***

*BGE*

Mr. Vahos testified that while the Company supports the change from Baltimore City's reactive conduit maintenance program to a proactive maintenance program, the current litigation has to do with the scope and speed of the proposed proactive

[407] Norman Surrebuttal at 5-6.
[408] Norman Surrebuttal at 6.
[409] Norman Surrebuttal at 7.
[410] Norman Surrebuttal at 8.
[411] Norman Surrebuttal at 8.

maintenance program, and the City's commitment to actual costs of conduit maintenance only, and to perform true-ups.[412] Mr. Vahos testified that he proposed the alternative of the Company purchasing the City's conduit system.[413] According to Mr. Vahos' testimony, on December 18, 2015, BGE disbursed a payment in the amount of $4,875,448.28, the difference between the rate of $0.9785 per liner duct foot (that BGE had paid) and the amount the City had invoiced, which incorporated the increased rate beginning November 1, 2015.[414] Mr. Vahos testified that on March 23, 2016, BGE paid the City $18,987,785 on the second semi-annual invoice for fiscal year 2016, which incorporated a true-up of $1,825,366.76 for fiscal year 2015.[415] Mr. Vahos testified that historically the true-up is based on taking the City's independently audited financial statements and subtracting from the amount the Company paid the actual amount the City spent on the conduit system maintenance.[416] However, during the time period until BGE receives the audited financial statement, which can be two years, BGE uses an estimate based on past experience. Thus, the $1,825,366.76 true-up was based on the fact that the City spent roughly 30 percent below what the City charged BGE in prior years.[417] BGE's method for taking a true-up, which does not take into account monies reserved into the next fiscal year for an ongoing project, is one of the disputed issues in the litigation between the parties.[418]

Mr. Vahos testified that the Company is still proposing two options, Option A and Option B for Rider 5 for incremental conduit fees, though once the Company was able to

[412] Tr. at 615, *et seq*.
[413] Tr. at 617.
[414] Company Exhibit 22, Vahos Supplemental Direct at 12.
[415] Tr. at 627.
[416] Tr. at 629-630.
[417] Tr. at 630.
[418] Tr. at 635-640.

get two important concessions through the litigation in Circuit Court – that the increased conduit fees will only be used for actual costs of maintaining the conduit system and that there will be a true-up mechanism for returning amounts not spent – he now believes Option B is more reasonable.[419] However, Mr. Vahos also testified as to his doubt that the City could accelerate from a $15 million program to a $50 million program in one year,[420] and that there will come a time when the City does not need $50 million per year to maintain the conduit system, even on a proactive basis.[421] Mr. Vahos acknowledged that over the past 11 years, from 2004 when the rate was $0.27 per linear foot to 2015, when the rate was $0.98 per linear foot, the conduit fee increased approximately 365 percent, yet BGE never previously approached the Commission and proposed a rider to collect these fees.[422] He also acknowledged that the existing true-up mechanism is not specific as to timing, and that the audited financial statements that provide the basis for a fiscal year true-up come out as much as two years after the end of a fiscal year.[423] Mr. Vahos explained that because the Company does not have the audited financial statements, the Company estimates what the true-up will be for the fiscal year in question, and takes a credit against the second semi-annual bill from the City for the amount of that estimated true-up.[424] When BGE receives the audited financial statements, the estimated true-up is corrected to an actual true-up.[425] Mr. Vahos confirmed that the true-up only addresses the amount the City actually spent according to

[419] Tr. at 686-699.
[420] Tr. at 690-691.
[421] Tr. at 707.
[422] Tr. at 701-702.
[423] Tr. at 773.
[424] Tr. at 782.
[425] Tr. at 782.

its audited financial statements as compared to the amount BGE paid.[426] There is nothing in the current true-up mechanism that allows BGE to review for prudency the projects that the City has planned for the next year, or for a review of the projects that were completed in the prior year.[427] Lastly, if the credit that BGE takes off the second semi-annual invoice is not during a test year, that credit goes back to the Company, not ratepayers.[428]

With regard to the mediation that is to take place in the pending litigation between the City and the Company, BGE witness Case testified that the Company wants, as a result of the mediation, to obtain a level of comfort that the $3.33 per linear foot conduit fee is the proper charge based on the work the City is proposing.[429]

***City of Baltimore***

City witness Johnson testified about how the City's procurement process requires that the Department of Transportation have the "cash in hand" to fund a contract before it may execute that contract.[430] Mr. Johnson explained how the City encumbers the funds for a project.[431] Mr. Johnson agrees that there should be a process of reconciliation that takes place on a regular basis, but he does not agree that an annual true-up process makes sense because many projects cannot be completed in one year; he spoke of a three-year period.[432] Mr. Johnson confirmed that the $3.33 fee should decrease over time.[433] Mr. Johnson indicated that he has heard rumors but otherwise is unfamiliar with a plan on the

[426] Tr. at 782-786.
[427] Tr. at 820-828.
[428] Tr. at 862-863.
[429] Tr. at 1061.
[430] Tr. at 1149-1150.
[431] Tr. at 1151.
[432] Tr. at 1156-1163.
[433] Tr. at 1163-1165.

part of the City to use the underground conduit system for broadband purposes.[434] Mr. Johnson discussed the historical approach of these O&M costs being in base rates and stated that he does not understand why there would be a different approach of a surcharge simply because the fee is based on proactive maintenance as opposed to reactive maintenance.[435] Mr. Johnson testified that while it is possible all of the funds the City has received could become encumbered in this fiscal year, it is also possible that the City will still be in the process of executing the contracts that would encumber those funds into the next fiscal year.[436] Mr. Johnson explained that the City is trying to get to 12 to 15 percent of the conduit system each year, but may only have enough resources to complete between 10 and 12 percent, which is not enough to do all of the work that is identified but at least enough inspection resources to be able to perform an assessment of damages in order to re-prioritize the capital plan for future years.[437] Mr. Johnson stated that the City intends to bring in a program management firm to conduct much of the assessment of the conduit system.[438] He does not see the process of accountability with regard to the conduit fund to be any different than the City's routine process of accountability for all of the federal funds the City receives.[439]

***Maryland Energy Group***

On cross-examination by the Company with regard to his recommendation to disallow the Company's proposed recovery of increased conduit fees between November 2015 and June 2016, MEG witness Baudino explained that there is always a time period

[434] Tr. at 1186-1187.
[435] Tr. at 1190-1191.
[436] Tr. at 1224-1225.
[437] Tr. at 1228-1229.
[438] Tr. at 1223, 1250.
[439] Tr. at 1252-1253.

between the end of the test period and the rate-effective period during which the Commission adjudicates the case and decides what rates will be going forward, and that many things change between the end of a test period and the rate effective period – costs can go up or down and revenues can go up or down, but the Commission needs to be able to make its determination based on what is known as of the end of the test period.[440] Mr. Baudino testified that the conduit fee is a recurring cost, set at whatever level is determined to be reasonable, but that since it is ongoing, it is not extraordinary, and thus, in his opinion the Company should not be permitted to jump normal regulatory lag for this item.[441]

***Staff***

Staff witness Norman explained that Staff wants to investigate the City's proposed conduit maintenance program to determine whether or not the proposed level of spending is appropriate and necessary for the efficient and economical provision of reliable electrical distribution service. Option A for Rider 5 is proposed by Staff as an interim solution pending the development of an adequate review process.[442] Dr. Norman noted that Staff would not suggest what the City should do with regard to its conduit system; Staff would simply evaluate the conduit expense for inclusion in rates.[443] However, until the conduit maintenance costs can be examined for their prudency and for their appropriateness and for whether or not they are necessary to the efficient and economical operation and provision of reliable electric distribution service, it is Staff's

[440] Tr. at 1404.
[441] Tr. at 1407-1408.
[442] Tr. at 1688.
[443] Tr. at 1697.

position that they should be considered separately because they cannot be evaluated.[444] Staff's position that these costs be treated differently is based on the size of the increase in conduit fees that BGE has been assessed, and the fact that the costs are for work that has not yet been done, which typically gives rise to a higher level of scrutiny.[445]

Dr. Norman testified that once Staff has the information and can review the conduit fee expense in sufficient detail, Staff would support a move to socialization of the costs that are found to be appropriate and necessary for the reliable and efficient provision of electric distribution service.[446] Dr. Norman agreed that a hybrid approach with both Option A and Option B in place simultaneously might be less challenging under retroactive ratemaking constraints.[447] Dr. Norman conceded that under Option A, it is possible that City customers could pay for costs associated with the increased conduit fee that do not bear any relation to the provision of electric service, and that under Option B, customers outside of Baltimore City could pay costs related to Baltimore City projects and not related to the provision of anyone's electric service, neither of which are ideal outcomes.[448] Dr. Norman acknowledged that there is not much precedent for how to handle the situation of the City conduit fee, however, if the conduit system is being improved to a degree beyond that which is necessary, that is a decision the City would be making related to things other than electrical distribution services.[449] That is why, in her opinion, the costs of such work should be paid by those who can hold decision-makers

[444] Tr. at 1705.
[445] Tr. at 1706.
[446] Tr. at 1718.
[447] Tr. at 1724.
[448] Tr. at 1724-1725.
[449] Tr. at 1727.

accountable for their choices.[450] Alternatively, Dr. Norman agreed that the conduit fee could simply be part of the Company's regular O&M expense.[451] Dr. Norman testified that it is Staff's position that once there is a resolution regarding how the conduit maintenance work is to be evaluated, the conduit fee could move into base rates and remain there.[452]

Dr. Norman testified that, given the uncertainty surrounding the proper amount of the conduit fee, directing BGE to put the conduit fee expense into a regulatory asset would be an option, noting that a regulatory asset could become substantial in size if the matter was not resolved quickly.[453] Dr. Norman also confirmed that the Commission could disallow the cost.[454]

**Commission Decision**

We spent several days' worth of the hearings in this case embroiled in questioning and testimony related to the Baltimore City conduit system. BGE and the City are currently involved in litigation in which BGE's stated objectives are to develop a process in which it collaborates with the City on the size, scope and priorities of the City's proposed proactive maintenance plan and becomes comfortable that the newly increased conduit fee is appropriate to pass on to ratepayers. BGE's stated objectives comport with PUA §4-101, which provides that just and reasonable rates take into account only those expenses that are necessary and proper. The Court of Appeals of Maryland has described the Commission's ratemaking role as one of determining "what rates the utility should be

[450] Tr. at 1725-1729.
[451] Tr. at 1794.
[452] Tr. at 1794.
[453] Tr. at 1799-1801.
[454] Tr. at 1809.

allowed to charge in future years to cover prudent expenses…." *OPC v. Md. Pub. Serv. Comm.*, 355 Md. 1 (1999). Thus, the Commission must determine whether the expenses for which the Company seeks recovery in rates, including those associated with the Baltimore City conduit fee, are prudent.

In reviewing a utility company's expenses, we utilize a historical test year approach.[455] The test year in this case is the 12 months ending November 30, 2015. The Company has proposed several adjustments to the actual test year book data, including adjustments to operating income and rate base to reflect changes resulting from the increased Baltimore City conduit fee. Adjustments to the actual test year book data are made in order to develop the most likely set of financial conditions the utility will face during the rate effective period. However, these adjustments are typically for unusual events that occurred during the actual test year period, or for known and measurable changes that will occur within a given time period after the end of the test year.[456]

We disagree with the Company contention that Operating Income Adjustment 28 reflects a known and measurable increase in costs. Litigation between BGE and the City about the increased conduit fee is ongoing. Despite the parties' agreement on some general principles and attempts to mediate the dispute, BGE witness Vahos indicated that the litigation process could take years before it is fully resolved.[457] The parties disagree as to how the true-up process should work. We note that historically, BGE has been calculating an estimated true-up of thirty percent (30%) of the City's second semi-annual invoice. For the past few years, the City's actual annual spend was approximately 15%

[455] *See Bldg. Owners and Mngrs Ass'n v. Pub. Serv.Comm'n,* 93 Md.App. 741 (1992).
[456] *See, e.g.* Case No. 9326, Order No 86060 at 14-15; Case No. 9336, Order No. 86441 at 21.
[457] Tr. at 798.

less than the amount collected in conduit lease fees.[458] Company witnesses testified that they anticipate a large true-up associated with the new lease rate, given that the City cannot accelerate from its current spend of about $10 million per year to such a larger program of over $40 million in one year.[459] Indeed, there was testimony to indicate that the City is not very far along in its planning process for implementing its proactive maintenance program. Witness Johnson stated that the City was only just now obtaining approval to issue an RFP (request for proposal) for the program manager contract, under which an entity would perform the assessments of the conduit that the City needs before it can even begin to prioritize proactive maintenance work.[460] Then, according to BGE, there will come a time when the City does not need the amount of the increased fee per year to maintain the conduit system, even on a proactive basis. In addition, the elements of the increased conduit fee are also not yet known, such as the amount of the "emergency reserve fund" and "overhead" to be assigned to other City agencies. .

We recognize that no Party proposed disallowing the Company's proposed adjustment to recover increased conduit fees in the rate effective period.[461] The Parties, apparently in reaction to the Company's proposal, largely offered comments on whether they believed one version of a rider or another was reasonable. We are not bound by the proposals of the Parties in the case, however. We are guided by our statutory mandate

[458] We note that no party has objected to BGE continuing to collect in base rates the prior conduit lease fee of approximately $0.98 per linear foot, even though that amount has not been fully spent by the City in recent years.

[459] We are unpersuaded by BGE's argument that the increased conduit lease fee is known and measurable simply because the City has invoiced BGE and BGE is under an obligation to pay the City's invoice. It is uncontested that the net conduit fee amount – that is, the amount that will have been paid after the appropriate true-up – is not known, and even difficult to estimate, at this time.

[460] Tr. at 1174.

[461] We note that DOD recommended rejecting the rider but suggested placing the increased conduit fee amounts in a regulatory asset, which could allow recovery of those amounts in the future.

and sound regulatory principles. The Company proposed a rider mechanism for the very reason that the incremental conduit lease fee expense is not known and measurable. Applying sound regulatory principles, we will not allow an adjustment to the Company's test year expenses for an expense that is not known and measurable, and thus disallow proposed Operating Income Adjustment 28.

The Company also proposes to recover in rates the post-test year expenses for the 7-month period between the effective date of the conduit rate increase on November 1, 2015 and the rate-effective period commencing in early June 2016. We will disallow Operating Income Adjustment 29 and Rate Base Adjustment 7 because, for the reasons set forth above, the change in costs associated with the Baltimore City conduit fee are not known and measurable during this period,[462] and for the additional reason that BGE has not supported its request to overcome the normal operation of regulatory lag for this one isolated expense item. While the Commission has allowed post-test year adjustment for particular types of expenses, such as reliability expenses, such adjustments must be known and measurable as of the time of the hearings and are still exceptions to the historical test year approach. Here, the increased conduit fees are not known and measurable, and they are a basic operating expense that does not warrant an exception to the historical test year approach.

While it is not within the Commission's jurisdiction to determine the amount of the Baltimore City conduit lease fee, it is the within the Commission's jurisdiction – and

[462] Mr. Vahos testified that the City had not started the proactive maintenance program even as of the hearings in this case. Tr. at 785. Director Johnson testified that the RFP for project planning had not yet been issued. Therefore, we seriously doubt that much of the fee increase paid by BGE for this period will be spent during this period, meaning that most of the increased amount paid for this period should be returned in a true-up.

indeed, it is the Commission's responsibility to Maryland ratepayers – to ensure that just and reasonable rates include only those expenses that are necessary and proper. Our task with regard to the increased conduit lease fee is the same as with all expenses for which a utility seeks cost recovery – to determine whether the conduit lease fee expense, or a portion thereof, is reasonably related to the provision of safe and efficient electricity service such that it is appropriate for BGE to include the expense in rates, and if so, when and how any such amount should be apportioned among ratepayers. What we would like to see is for the City and BGE to negotiate a reasonable lease rate that as closely as possible reflects BGE's use of the City's conduit system on a going forward basis. Particularly because the City's stated purpose is to engage in a proactive maintenance program, we believe the City should be able to plan the necessary inspection and maintenance work to be performed and manage the amount of funds it receives for that maintenance work accordingly.

We understand that whatever rate the City and BGE might negotiate as fairly compensating the City for BGE's use of the City's conduit system might increase at a later date, for inflation or other reasons. However, we believe that there could be a set rate for a given period of time that would more closely resemble a typical operating expense, as opposed to an atypical expense that requires separate regulatory treatment. We are not suggesting that there not be a true-up; rather, we envision that the results of a true-up might be to adjust the conduit lease rate prospectively, if BGE and the City determine that the City is collecting too much revenue as compared to what it spends to proactively maintain the conduit, and thus has reserves beyond that which is necessary or reasonable.

When the Company elects to file its next base rate case, and the corresponding test year for the rate case, is up to BGE. The litigation (or mediation) between BGE and the City will be further along and potentially finalized by the time of the next rate case, and BGE will be able to provide conduit lease fee information based on a City-developed proactive conduit maintenance plan[463] such that the amount of the conduit fee expense is known and measurable. We will conduct a prudency determination at that time and BGE will need to be able to support the amount of the conduit lease fee that is reasonably related to the provision of safe and efficient electricity service and demonstrate that it properly reflects the ongoing cost of service. If the evidence shows that the City is charging BGE an excessive or inappropriate conduit fee, we will consider all options to ensure that all BGE ratepayers are not paying for non-utility expenses.[464]

### 3. ***<u>OIA 2: Defer and Amortize Gains / Losses on Sale of Real Estate</u>***

BGE witness Vahos testified that OIA 2 reflects the deferral of the August 2015 gain on the sale of real estate and the related amortization of the net gain in accordance with the FERC Uniform System of Accounts. BGE realized a gain of $1,007,000 on real estate sold in 2015. The Company proposed to amortize the net gain of the sale of real

[463] We believe that given BGE's technical capabilities and its knowledge of the conduit system, it is appropriate for BGE to seek to play a collaborative role throughout the program's planning and implementation.

[464] Use of a rider could potentially allow charges above and beyond those found to be reasonably related to the provision of safe and efficient electricity service to be assigned to City residents if such charges are found to represent an "excess investment". *See Re Baltimore Gas and Electric Company*, 80 MD PSC 112, Case No. 8127, Order No. 68240 (1989), *citing* Order No. 56351 (1966) in which the Commission adopted the following policy: "Whenever electric utilities in the State are required by local zoning, ordinance or by other exercise of the police power of a local subdivision to construct an electric line underground at a cost substantially higher than the cost to construct the same line overhead using acceptable standards of utility line construction, then in the absence of the proof of unusual circumstances, and [sic] annual fixed charges needed to support the excess investment shall be imposed on all of the utility's customers receiving service *in the geographic area and/or the local subdivision to which the regulation or ordinance is applicable as a whole.*"

estate during the test year over a two-year period, pursuant to Commission Case No. 7695.[465]

OPC witness Effron opposed BGE's proposed adjustment. Mr. Effron observed that BGE reflected only three months of annual amortization because the gain began on September 1, 2015, when there were only three months remaining in the test year.[466] Mr. Effron testified that because BGE will be amortizing the gain annually going forward from the test year, the pro forma operating income should reflect annual amortization of the full gain.[467] Accordingly, Mr. Effron recommended an annual amortization of $504,000 (representing an increase of $378,000 above the amortization of $126,000 reflected by BGE), resulting in an increase in the electric after-tax net operating income of $225,000.[468]

On rebuttal, Mr. Vahos testified that BGE's adjustment is consistent with Commission precedent that the amortization of deferred gains and losses included in operating income be amortized over 24 months commencing on the effective date of the gain/loss.[469] Mr. Vahos noted that in previous rate cases, it consistently applied the same amortization schedule to real estate sales, irrespective of when the 24-month amortization happened to commence, and that changing that methodology as Mr. Effron suggested would be tantamount to changing Commission practice.[470] OPC replied that Mr. Effron's

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[465] Vahos Direct at 44. In companion RBA 5, the Company reflects the unamortized gain on real estate which is being amortized into operating income for ratemaking purposes over a two year period. *Id.* at 56.
[466] Effron Direct at 14.
[467] Effron Direct at 15, Effron Surrebuttal at 15.
[468] Effron Direct at 15.
[469] Vahos Rebuttal at 39, citing PSC Order Nos. 70476, 80460, 83907, and 85374.
[470] Vahos Rebuttal at 39.

adjustment is consistent with the numerous annualization adjustments that the Company has proposed.[471]

**Commission Decision**

We decline to accept Mr. Effron's recommendation to amend BGE's adjustment to reflect annual amortization of the full gain from the sale of real estate. We find (and OPC does not appear to dispute) that BGE's adjustment is consistent with Commission precedent that the amortization of deferred gains and losses included in operating income be amortized over 24 months *commencing on the effective date of the gain/loss*. BGE has followed this practice and we have approved it through various rate cases, including those cited by BGE above. *See also* Case No. 7695, Order No. 66273, *Baltimore Gas and Electric Co.*, 74 Md. PSC 249, 265 (July 1, 1983). Mr. Effron's adjustment would require a change in Commission practice, which we decline to require at this time. We note that if we did change Commission practice in this case, when utilities filed adjustments that involved real estate *losses*, the ratepayers would be disadvantaged by Mr. Effron's adjustment. Accordingly, we accept BGE's Operating Income Adjustment 2 as filed resulting in an operating income reduction of $526,000 for BGE's electric operations.

**4. *OIA 8: Annualize Certain Regulatory Asset Amortization Periods Revised in Case No. 9355***

In Order No. 86757, the Commission accepted the unanimous settlement agreement in Case No. 9355, involving BGE's 2014 application for a rate increase.[472]

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[471] OPC Initial Brief at 47.

Part of that settlement included the continued amortization of certain generation-related regulatory assets from the 1999 Restructuring Settlement in Case Nos. 8794/8804.[473]

In OIA 8, BGE adjusted the amortization expense to reflect the full annual effect of the revision to the amortization schedule for Case No. 8794/8804 regulatory assets agreed to by the parties in Case No. 9355. That revision affected the amortization of Case No. 8794/8804 regulatory assets included in rate base.

OPC witness Effron testified that the Case No. 8794/8804 regulatory assets not in rate base are now nearing the end of their recovery period.[474] He calculated that by May 31, 2016, the remaining balance of the Case No. 8794/8804 regulatory assets not in rate base will be $14.8 million, and that the amortization of that balance will be complete by the end of year 2017. Mr. Effron observed that if the rates established in this case are in effect beyond the end of 2017, when recovery is complete, then BGE will over-recover costs. He therefore recommended that the remaining Case No. 8794/8804 regulatory assets not in rate base as of May 31, 2016 be amortized over three years, consistent with how the rate case expenses associated with the present rate case are treated in OIA 20. Mr. Effron's recommendation would result in a reduction to the annual amortization expense of $4,314,000 and an increase to pro forma electric operating income of $2,573,000.[475]

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[472] Case No. 9355, *In The Matter Of The Application Of Baltimore Gas And Electric Company For Adjustments To Its Electric And Gas Base Rates.*

[473] The referenced cases addressed rates and other issues related to BGE's electric restructuring. Case No. 8794, *In the Matter of BGE's Proposed (A) Stranded Cost Quantification Mechanism; (B) Price Protection Mechanism; and (C) Unbundled Rates* and Case No. 8804, *In the Matter of the Petition of People's Counsel for a Reduction in the Rates and Charges of BGE*, 90 MD PSC 197 (1999).

[474] Effron Direct at 18-19.

[475] Effron Direct at 19.

Mr. Vahos opposed Mr. Effron's recommended adjustment. He observed that OPC was a signatory to the settlement agreements discussed above. He further asserted that "[s]ince this asset is not in rate base, the Company is undeniably harmed relative to the terms of the restructuring settlement agreement."[476]

**Commission Decision**

We accept BGE's Operating Income Adjustment 8, which adjusts the amortization expense to reflect the full annual effect of the revisions to the amortization schedules in Case No. 8794/8804 regulatory assets, which were in turn agreed to by the parties in Case No. 9355. Although Mr. Effron makes an important point that the assets may be fully amortized by the end of year 2017, we note that that date is more than a year and a half from the beginning of the rate effective period in June 2016. Given BGE's predilection for filing rate cases nearly annually, we find OPC's recommendation unnecessary.[477] Additionally, we find persuasive Mr. Vahos' testimony that the amortization schedules were previously agreed to in settlements. Accordingly, we accept BGE's adjustment. This results in an operating income adjustment of $177,000 for BGE's electric operations.

**5.** ***<u>OIA 13: Annualize Allowance for Funds Used During Construction to Reflect Requested Returns</u>***

In OIA 13, BGE witness Vahos annualizes the allowance for funds used during construction ("AFUDC") included in unadjusted operating income at the 7.46% electric rate of return and 7.41% gas rate of return agreed to in the Case No. 9355 settlement

[476] Vahos Rebuttal at 38.
[477] Additionally, the Commission's Staff will track any over recovery of assets and the Commission will determine the appropriate treatment of any such over recovery in BGE's next rate case.

agreement, to reflect a level that is consistent with the 7.74% and 7.69% rates of return for electric and gas, respectively, that are supported by BGE.[478] Staff witness Poberesky adjusted AFUDC to reflect Staff's proposed weighted cost of capital.[479]

No party disputed BGE's methodology for making the adjustment, however, OIA 13 is impacted by other adjustments that have been contested. Pursuant to the other decisions that have been made in this Order, OIA 13 as revised results in an operating income reduction of $92,000 for BGE's electric operations and an operating income reduction of $81,000 for BGE's gas operations.

### 6. ***<u>OIA 19: Annualize CVR Costs Since Case No. 9355</u>***

Maryland's electric utilities are required by Commission regulations to delivery electric distribution service to their customers within certain voltage parameters.[480] However, customers at the higher end of the voltage band tend to consume more energy than customers at the lower end.[481] BGE's Conservation Voltage Reduction ("CVR") program lowers overall electric consumption by reducing the voltage delivered to appliances such as air conditioners, without negatively affecting their functionality.[482]

BGE witness Vahos testified that pursuant to Commission Order No. 84756 in Case No. 9153, the Company has been deferring O&M expenses, depreciation expense, property taxes and return associated with its CVR program[483] into a regulatory asset and

[478] Vahos Direct at 46.
[479] Poberesky Direct at 5.
[480] *See* COMAR 20.50.07.02.
[481] Tr. at 37.
[482] Tr. at 37 (Butts).
[483] BGE's CVR program reduces electric consumption by reducing the voltage delivered to appliances such as air conditioners, without negatively affecting their functionality. *See* Hearing Transcript at 36 (Butts).

amortizing the regulatory asset over two years upon approval in a base rate case.[484] Mr. Vahos testified that BGE followed (and the Commission approved) that practice in Case Nos. 9299 and 9326. In the present proceeding, OIA 19 recovers the amortization of the CVR costs incurred subsequent to August 2014 (the end of the test year in Case No. 9355) through the end of the test year in this proceeding (November 2015) over a two-year period. This adjustment also provides for the reversal of certain CVR-related deferrals (*i.e*. depreciation, property taxes, and returns) in the test year in order to recover ongoing expenses and return.[485]

OPC witness Effron recommended that OIA 19 be modified. He observed that the revenue requirement in Case No. 9355 included approximately $1.1 million of CVR costs and that amortization of $547,000 per year commenced in December 2014.[486] He further noted that at the start of the rate effective period, the remaining balance to be amortized will be only $274,000. He concluded that if the rates established in this case are in effect for more than six months, BGE will over-recover the CVR costs authorized for recovery in Case No. 9355.[487] He therefore recommended that the costs remaining at the start of the rate effective period be amortized over two years, which would result in annual amortization of $137,000 in lieu of the $547,000 proposed by BGE.[488]

In response, Mr. Vahos observed that BGE already eliminated the amortization of deferred costs that were completed in the test year through OIA 9 (a point that OPC does not contest). However he argued that it would be inappropriate to extend the two-year

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[484] Vahos Direct at 51.
[485] Vahos Direct at 48.
[486] Effron Direct at 16.
[487] Tr. at 1567.
[488] Effron Direct at 16-17.

amortization period for remaining CVR costs through a re-set of the two-year amortization period commencing on May 2016, as proposed by Mr. Effron.[489] Mr. Vahos further argued that Mr. Effron's recommended treatment of CVR costs would be inconsistent with the Commission-accepted amortization period in previous proceedings.

Mr. Effron rejoined that BGE has offered no other mechanism to avoid the over-recovery of CVR costs that he has testified could occur pursuant to OIA 19.[490]

**Commission Decision**

We agree with Mr. Effron that BGE's proposed adjustment carry's a very high probability of over recovery of certain CVR costs. Case No. 9355 included about $1.1 million of CVR costs that commenced amortization at a rate of $547,000 per year beginning in December 2014. Only $274,000 of unamortized assets will remain at the start of the rate effective period. As Mr. Effron testified, if BGE declines to file a new rate case for more than six months after the beginning of the rate effective period, the Company will over recover. Accordingly, we adopt OPC's recommendation to modify Operating Income Adjustment 19 by amortizing the costs remaining at the start of the rate effective period over two years. That modification results in annual amortization of $137,000 in lieu of the $547,000 proposed by BGE. Our decision results in an operating income reduction of $1,040,000 for BGE's electric operations.

[489] Vahos Rebuttal at 38.
[490] Effron Surrebuttal at 15.

### 7. *OIA 21: Recover Exelon Business Service Company Compensation in OIA 11*

*BGE Position*

In Order No. 86060 in Case No. 9326, the Commission disallowed a portion of the related costs for long term incentive compensation plans "on the basis that the plans failed to clearly show a nexus between the plans' metrics and ratepayer value."[491] In that Order the Commission required that prior to a future rate filing, the Company should be prepared to "to demonstrate the extent to which incentive compensation plans include operational metrics related to BGE, and how such metrics deliver value to BGE ratepayers."[492] In this proceeding, BGE proposed uncontested Operating Income Adjustment 11, which reflects compliance with the Commission's decision in Case No. 9326 in Order No. 86060 where the Commission "authorize(d) BGE to recover 50% of its Restricted Stock plan and only 40% of its LTIP costs related to the Performance Share and One Time Bridge Award."[493] For those programs that have not changed[494], witness Vahos testified that through OIA 11, BGE is excluding BGE and Exelon Business Services Company ("BSC") long-term compensation costs at the same percentages disallowed by the Commission in Case No. 9326.[495]

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[491] Vahos Direct at 30.
[492] *Re Baltimore Gas and Electric Company,* 104 MD PSC 653, 681 (2013)..
[493] Poberesky Direct at 4.
[494] Vahos Direct at 31 explained that Case 9326 BGE's long term incentive compensation programs were" (1) Restricted Stock and (2) Performance Share program. Beginning in 2014, BGE took steps to better align its long term incentive compensation plans with operational performance. In 2014, for Key Managers and Vice Presidents, BGE replaced the long term incentive compensation programs considered by the Commission in Case No. 9326 with two new programs: (1)the Long Term Performance Program ("LTPP") and the Long Term Cash Award Program ("LTPCA").
[495] Vahos Direct at 30.

Mr. Vahos argued, however, that because the services provided by Exelon BSC are no different than services provided by unaffiliated third party vendors, the Commission should reconsider its prior decision to disallow a portion of the costs allocated to BGE associated with Exelon BSC's long-term incentive compensation programs.[496] Mr. Vahos argued that BGE should be allowed to fully recover the costs of long term incentive compensation because these "costs are only one of many costs that Exelon BSC incorporates into what it charges BGE and other Exelon companies for the range of shared services that Exelon BSC provides."[497] And the same would be true of any third party vendor providing these services to the Company, according to Mr. Vahos. "In other words, the cost of employee compensation would be included with all other costs of operating the business in the prices charged to BGE for the vendor's services, in addition to the profit margin," which Exelon BSC does not charge BGE.[498] BGE's proposed OIA 21 would permit recovery of the costs of Restricted Stock and Performance Share Award programs for Exelon BSC employees.[499] With OIA 21, the Company seeks to recover $2.7 million of the compensation associated with Exelon BSC long-term incentive plans.[500]

*Staff Position*

Staff witness Yulia Poberesky recommended that the Commission reject BGE's OIA 21 for several reasons. First, in Order No. 86060, the Commission did not differentiate the authorized portion of Restricted Stock plan and Performance Share

[496] Vahos Direct at 30-31
[497] Vahos Direct at 33.
[498] Vahos Direct at 34.
[499] Vahos Direct at 35.
[500] Vahos Direct at 35.

expenses applicable to BGE employees and Exelon BSC employees. The same adjustment percentages should be used for BGE employees and Exelon BSC employees, as BGE did with OIA 11.[501] Ms. Poberesky also noted that "BGE did not provide clear evidence, via analysis or other support, showing a cost benefit to BGE customers by using Exelon BSC employees, as opposed to using a vendor… to warrant this adjustment."[502] Thus, Staff recommended disallowing BGE OIA 21.

*OPC Position*

OPC witness Effron testified that the real issue "is not whether Exelon can pay its employees the incentive compensation that it deems appropriate, but rather the extent to which such incentive compensation should be recoverable from ratepayers."[503] Mr. Effron recommended that the Commission reject OIA 21 because Exelon has not made the necessary showing for the inclusion of this expense in its revenue requirement.[504]

**Commission Decision**

Based on the foregoing, we do not find that BGE has provided the necessary support for us to reconsider our decision in Order No. 86060. Therefore, we accept the recommendation of Staff and OPC, and disallow BGE Operating Income Adjustment 21.

### 8. *OIA 34: Tax Impact on Interest Synchronization*

Interest synchronization refers to the procedure whereby the interest deduction used for Federal income tax treatment is synchronized with the interest component of the return on rate base to be recovered from ratepayers. The interest deduction is calculated

[501] Poberesky Direct at 5.
[502] Poberesky Direct at 5.
[503] Effron Direct at 13.
[504] OPC Initial Brief at 46.

by multiplying the rate base by the weighted cost of debt.[505] The resulting interest is then multiplied by the State and federal income tax rates to arrive at the operating income adjustment. In this case, the parties do not contest that an interest synchronization adjustment is necessary to reflect the tax effect of pro forma interest. Furthermore, the calculation is uncontested as to methodology. Therefore, using a capital structure including a 51.9 percent equity ratio, as determined herein, we find that the appropriate interest synchronization results in an electric operating income reduction of $2,177,000 and a gas operating income adjustment of $18,000.

#### 9. ***RBA 9: Cash Working Capital***

Cash working capital ("CWC") represents the amount of investor supplied cash a company requires in order to provide the funds necessary to operate the business on a day to day basis.[506] The amount of CWC required is determined by a lead/lag study, which measures the difference between the company's revenue lag and its expense lag. The revenue lag measures the average number of days from the date service is rendered to the date payment for such service is received. The expense lag represents the number of days from the incurrence of an expense to the date the company pays the expense. Once the revenue and expense lags are determined, the CWC requirement is calculated by applying the net lag to the average daily amount of operating expense.[507]

BGE witness Vahos presented the Company's requirements regarding CWC based on BGE's most recent Lead/Lag Study on 2014 actual payments and revenue

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505 Effron Direct at 25-26.
506 Vahos Direct at 59.
507 Poberesky Direct at 3.

collections.[508] The results of the Study are presented in BGE Exhibit DMV-8. Mr. Vahos calculated, for example, a revenue lag of 47.0 days.[509] He also determined expense lags for numerous categories of expenses. The parties do not contest BGE's methodology for determining CWC. However, CWC is affected by other operating income adjustments being contested.

Based on the Commission's determinations in the other sections of this Order, BGE's CWC requirement will be decreased in the amount of $4,466,000 for the Company's electric operations and decreased in the amount of $218,000 for its gas operations.

### 10. ***<u>Accumulated Deferred Income Taxes - Bonus Depreciation</u>***

The Protecting Americans from Tax Hikes Act of 2015 ("PATH Act") extends 50% bonus depreciation on Accumulated Deferred Income Taxes ("ADIT") through the year 2017.[510] It allows taxpayers to take immediate income tax deductions for 50% of qualifying plant additions.[511] Although the Act was not signed into law until December 18, 2015, it expressly provides for retroactive effect to January 1, 2015.

OPC witness Effron observed that BGE reflected the impact of the extension of bonus depreciation for 2015 and 2016 on ADIT offsets to pro forma plant additions in

[508] Vahos Direct at 63.
[509] Vahos Direct at 64.
[510] Tr. at 725-26. OPC witness Effron described ADIT as the "cumulative effect of taxable temporary differences." Effron Direct at 3. ADIT results from differences in the rates at which an asset is depreciated for tax versus ratemaking purposes. For example, BGE may elect an accelerated method of depreciation for tax purposes that provides for a higher depreciation expense in the early years compared to the straight-line method used for rate purposes. Because the net deferred tax liability represents income tax expenses that have been recognized but not paid, ADIT is treated as a deferred tax liability. The balance represents a non-investor source of cash that is available to the utility and is deducted from utility plant in service in the determination of rate base. *Id*. at 4.
[511] Effron Direct at 4. Mr. Vahos testified that the PATH Act will allow BGE to deduct as expense for tax purposes 50% of applicable 2015 plant additions, rather than record them as plant-in-service, resulting in reduced taxable income and reduced tax payable. Effron Rebuttal at 31.

RBAs 1 and 2, but the Company did not reflect the impact of the PATH Act on the balance of ADIT on BGE Exhibit DMV-6.[512] Mr. Effron testified that BGE should have adjusted the average ADIT balance throughout the test year based on the retroactive application of the Act. To remedy that omission, Mr. Effron reflected the impact of 50% bonus depreciation on ADIT related to AMI plant additions and other electric and gas plant additions for January 2015 through November 2015.

Mr. Vahos retorted on behalf of BGE that the Company did not receive any cash benefit from 2015 bonus depreciation during the test year (given that the law was not signed until December 2015), making an adjustment for that period inappropriate. Additionally, he argued that Mr. Effron's pro forma adjustment would violate the matching principle, which requires that all rate base and operating income components associated with an ADIT adjustment be adjusted consistently. Mr. Vahos claimed that if bonus depreciation is carried forward into the rate-effective period as proposed by Mr. Effron, then additional depreciation expense and rate base related to the 2015 plant additions should also be carried forward.[513] Mr. Vahos calculated that making this further adjustment would result in an increase to BGE's revenue requirements of $13.3 and $2.1 million for electric and gas, respectively.[514]

In his Surrebuttal testimony, Mr. Effron testified that as a result of the PATH Act, the tax depreciation associated with BGE's 2015 plant additions included in the Company's rate base was increased.[515] In other words, the 2015 bonus depreciation authorized by the PATH Act directly affected the tax attributes of plant included in

[512] Effron Direct at 4.
[513] Vahos Rebuttal at 31-32.
[514] Vahos Rebuttal at 30, Tr. at 731.
[515] Effron Surrebuttal at 3.

BGE's test year rate base. With regard to Mr. Vahos' testimony that BGE never received any cash benefit from the PATH Act during the test year, Mr. Effron retorted that BGE "is able to reflect the effect of 2015 bonus depreciation in subsequent estimated tax payments, and the additional cash resulting from the 2015 bonus depreciation will be available to the Company during the rate effective period."[516] He concluded that "[t]his is a known and measurable change that should be incorporated into the determination of the Company's revenue requirement."[517] Responding to Mr. Vahos' argument that the proposed adjustment violates the matching principle, Mr. Effron stated that he is "only proposing to recognize the effect of 2015 bonus depreciation on the average balance of ADIT for the test year."[518]

Mr. Effron argued that his proposal is consistent with the Company's inclusion of the average test year balance of plant in service in the Company's rate base and depreciation on that plant in test year expenses. Mr. Effron observed that he did not propose to annualize the effect of bonus depreciation to reflect the increased balance of ADIT as of November 30, 2015, making it unnecessary to state plant in service as of the end of test year or to annualize depreciation expense based on the end of test year plant in conjunction with his ADIT adjustment.

During the hearing, Mr. Vahos testified that despite the retroactive nature of the PATH Act, he did not restate BGE's balance sheets. "[W]e, as financial reporting experts, we don't go back and reopen prior periods and restate events simply because they

[516] Effron Surrebuttal at 4.
[517] Effron Surrebuttal at 4.
[518] Effron Surrebuttal at 4.

passed a law that is retroactive in nature."[519] Nevertheless, he stated that BGE does intend to take the benefits of bonus depreciation for 2015, which will likely lead to tax benefits (a reduction in taxes paid) when BGE files its 2016 return.[520] Mr. Effron agreed with that assessment, stating "Any subsequent estimated payments after the extension of the bonus depreciation in December 2015 would in effect capture the benefit of the extension of the bonus depreciation."[521]

During questions by the Commission, Staff witness Stinnette was asked whether any precedent existed that addressed how bonus depreciation should be treated given the explicit retroactive language contained in the PATH Act. Although Ms. Stinnette was unaware of any precedent at the time, she stated that she could provide an answer in response to the Commission's bench data request. On April 19, 2016, Staff filed a response to the Commission's inquiry, stating that only one state – Michigan – has had a proceeding addressing this issue, though no order had been issued.[522] Nevertheless, the utility in that case provided the impact on Deferred Federal Income Tax and reduced debt and equity 50/50.[523] Based on Ms. Stinnette's communications to the National Association of Regulatory Utility Commissioners, Staff further provided that "many Commissions are expecting companies to take a retroactive tax implementation and reflect it in the rate base deferred tax account." Finally, Staff stated that the Staff of the Virginia State Corporation Commission plans to recognize the retroactive change in tax

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[519] Tr. at 727.
[520] Tr. at 728, 887.
[521] Tr. at 1562.
[522] Michigan Public Service Commission, Case No. U-17999 – DTE Energy.
[523] Staff April 19, 2016 Response at 7.

law for ratemaking purposes, with the increase in ADIT resulting in a rate base deduction and reduced cost of service.

**Commission Decision**

We find that it is appropriate to reflect the impact of the 50% bonus depreciation on ADIT conferred by the PATH Act related to AMI plant additions and other electric and gas plant additions for January 2015 through November 2015. Accordingly, we accept Mr. Effron's recommendation to require BGE to adjust the average ADIT balance throughout the test year based on the retroactive application of the Act.

We are not persuaded by BGE's argument that it never received any cash benefit from 2015 bonus depreciation during the test year. The record demonstrates that BGE was or will be able to immediately deduct more depreciation expense for plant in service in calendar year 2015 from its 2015 tax payments than it would have been able to do absent the Act.[524] Whether that is acknowledged through a reduced 2015 quarterly tax payment or first quarter 2016 true up is not the critical consideration for ratemaking purposes.[525] Mr. Vahos confirmed that BGE does intend to take advantage of the benefits of bonus depreciation for 2015, which will likely lead to a reduction in taxes paid when BGE files its 2016 return.[526] Additionally, as OPC notes, the PATH Act "changed the tax attributes of the plant in service in 11 of the 12 months constituting the Company's test

[524] Tr. at 887.
[525] Mr. Effron confirmed during the hearing that: "Any subsequent estimated payments after the extension of the bonus depreciation in December 2015 would in effect capture the benefit of the extension of the bonus depreciation." Tr. at 1562.
[526] Tr. at 728, 887.

year."[527] We find that BGE ratepayers should receive some value from this tax reprieve, which was specifically made retroactive by Congress.[528]

We are likewise unpersuaded by BGE's argument that Mr. Effron's adjustment violates the matching principle. Mr. Vahos testified that if bonus depreciation is carried forward into the rate-effective period, then additional depreciation expense and rate base related to 2015 additions should also be carried forward, leading to an increase in BGE's revenue requirements of $13.3 for the Company's electric operations and $2.1 million for its gas operations. Nevertheless, we agree with Mr. Effron that BGE's proposal to include additional depreciation is unnecessary because he is merely proposing to recognize the effect of 2015 bonus depreciation on the average balance of ADIT for the test year. In other words, Mr. Vahos' argument assumes that Mr. Effron is making an adjustment in the rate effective period, which would invoke the matching principle. However, Mr. Effron did not do that – his changes were only to the test year.[529] We also agree with OPC that the Commission's decision here is consistent with its decision in a previous case related to the 1981 Economic Recovery Tax Act of 1981.[530]

Accordingly, we adopt OPC's recommendation on this issue, which results in a rate base reduction of $9,425,000 for BGE's electric operations and a reduction of $3,061,000 for its gas operations.

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[527] OPC Initial Brief at 38.

[528] *See* Tr. at 729, where Mr. Vahos refers to bonus depreciation as "a nice treat, nice Christmas present for us as a company and the customers."

[529] During the hearing, Mr. Vahos appears to have conceded that Mr. Effron did not propose to make adjustments in the rate effective period. Tr. at 731-32.

[530] *Re Baltimore Gas and Electric Company*, Case No. 7574, Order No. 65648, 73 Md.PSC. 61 (1982).

### 11. ***Riverside Remediation Accrual***

BGE accrued to expense $2.0 million based on its estimate of costs to investigate and remediate environmental issues at BGE's Riverside site, which housed a former gas purification plant.[531] Mr. Vahos testified that the accrual represented the minimum amount of expense it would take for BGE to complete the investigation and remediation. The estimated Riverside costs were charged to expense because they did not meet the criteria stated in the relevant accounting standards as to when environmental treatment costs may be capitalized.[532]

OPC witness Effron testified that it is not appropriate to include this accrual as an expense in the Company's gas revenue for three reasons: (i) The accrual does not represent an actual cost incurred by the Company – it is merely an accrual for *estimated* costs that the Company may incur in the future; (ii) including this item in test year expenses inappropriately treats it as a cost that will be incurred annually on a recurring basis; and (iii) it has not been demonstrated that these costs meet the Commission's established standards for recovery through rates. The treatment of this item as an ordinary annual expense is not appropriate for ratemaking purposes.

Mr. Vahos responded that BGE has paid $196,000 through November 2015 in actual investigation costs.[533] Additionally, he listed a series of actions BGE believes will be necessary to remediate the Riverside site, and explained that the remediation costs will be spent in accordance with BGE's legal obligation to comply with State and Federal environmental laws.

[531] Vahos Rebuttal at 35.
[532] Effron Direct at 21.
[533] Vahos Rebuttal at 35.

**Commission Decision**

We will disallow BGE's accrual related to the investigation and remediation of the Riverside site. We agree with Mr. Effron that the accrual does not represent an actual cost incurred by the Company, but is rather an estimation for costs the Company expects to incur in the future. Moreover, including the accrual in test year expenses inappropriately treats it as a cost that will be incurred annually on a recurring basis. Accordingly, BGE is directed to eliminate the accrual from the pro forma test year gas operation and maintenance expenses.

We acknowledge Mr. Vahos' argument that the Company is acting to comply with State and Federal law, but BGE's treatment of the remediation costs is not appropriate in this instance. We accept Mr. Effron's recommendation that BGE will be authorized to establish a deferred charge account for the investigation and remediation costs associated with Riverside. After the funds are expended, we will determine the extent to which such costs are recoverable from customers and the appropriate period over which those costs should be amortized. Our decision results in an operating income adjustment of $1,193,000 for BGE's gas operations.

### *12. OIA 35: PHI Merger Costs and Savings*

During the hearing, BGE witness Vahos responded to the Commission's questions regarding whether the merger consummation between Exelon and PHI resulted in any savings for BGE customers during the rate-effective period. He answered the questions using Company Exhibit 26, which presents calculations related to the synergies and costs to achieve merger benefits relative to the PHI merger.[534] Specifically, he testified that certain synergy savings could be measured and captured during the rate-effective period pursuant to the known and measurable standard and passed through to customers. Mr. Vahos estimated approximately $4 million in synergy savings in the first year after the merger (Year 1). He also stated that the Company proposed to set up a regulatory asset to capture the costs to achieve the merger benefits, which would yield a $1.2 million amortization cost.[535] The net benefit to customers at this time would therefore be approximately $2.8 million. Mr. Vahos further testified that the merger synergies would "ramp up over time."[536] Through Operating Income Adjustment 35, BGE proposed to account for the Year 1 projected net synergy savings to BGE customers during the rate year.

OPC objected to BGE's proposed handling of Exelon-PHI merger costs. OPC observed that one of the Commission's primary rationales for approving the merger was the synergy savings that Exelon projected would inure to Pepco and BGE ratepayers. OPC also noted that Mr. Vahos forecast that the synergy savings would increase markedly over time, at least for several years. Specifically, the Year 2 projected merger savings would increase to $10.3 million and the Year 3 merger benefits would reach $11.8 million.[537] OPC argued that allowing BGE to use the Year 1 projected merger benefits could be inequitable to BGE ratepayers if BGE failed to file a new rate case for more than approximately one year. In that event, Exelon shareholders would reap the increased net merger benefits instead of the ratepayers.

[534] Tr. at 953- 954.
[535] Tr. at 954.
[536] Tr. at 954.
[537] OPC Reply Brief at 17, citing Tr. at 1526. (Vahos).

OPC further lamented the asymmetry between the Company's proposed treatment of costs to achieve *vis-a-vis* merger benefits. OPC noted that BGE proposed to track all costs to achieve in a regulatory asset, so that they are recovered dollar for dollar, regardless of when the next rate case is filed, while some merger benefits that should be passed through to ratepayers may slip between rate cases and go to shareholders.

BGE responded that the Company's treatment of synergies and costs to achieve follow the Commission's typical practice. Mr. Vahos further noted that it is possible that some costs to achieve will not be collected in this rate case, though he acknowledged that the regulatory asset proposal will ensure that all costs to achieve are eventually collected.

OPC proposed two solutions to the apparent asymmetry. First, it suggested that OIA 35 reflect the projected Year 2 savings of $10.3 million, in lieu of the $4 million BGE proposed. Alternatively, OPC recommended that BGE reflect the last two months of Year 2 merger savings (option 2). OPC observed that the Exelon/PHI merger began on March 24, 2016 and the rate effective period in this proceeding commences in the beginning of June, 2016. Therefore, the rate year (June 2016 through June 2017) will overlap the Year 2 merger year (March 24, 2017 through March 24, 2018) by two months.[538] Accordingly, OPC recommended that the rate year synergy savings be modified such that they reflect 10/12 of Year 1 and 2/12 of Year 2.[539]

**<u>Commission Decision</u>**

The Commission accepts BGE's OIA 35 as adjusted by OPC's alternative two. OPC is correct that one of the primary reasons the Commission approved the Exelon-PHI

[538] Specifically, the overlap will be March 24, 2017 through May 31, 2017.
[539] OPC Reply Brief at 21.

merger was because of the synergy savings Exelon projected would pass through to Pepco and BGE ratepayers.[540] We are very concerned that the timing of BGE's next rate case could jeopardize synergy savings that BGE professed would inure to Maryland ratepayers. We also are concerned about the seeming asymmetry between BGE's proposed treatment of costs to achieve and synergy savings.

We find that OPC's alternative two provides an equitable solution and a fair compromise between the positions of BGE and OPC. OPC's first proposal – to fully reflect Year 2 savings – extends our reach beyond what is known and measurable. Alternative two, however, includes two months of Year 2 merger benefits that are within the rate year. Additionally, Mr. Vahos acknowledged that this approach was reasonable. *See* Tr. at 1527 stating "I follow your logic. Yes, I think that would be reasonable." We will also approve BGE's request for a regulatory asset to track its costs to achieve that accrue after the rate year and review those costs, in conjunction with merger benefits, in the next rate case. Our decision results in an operating income adjustment of $1,543,000 and a rate base adjustment of $197,000 for BGE's electric operations and an operating income adjustment of $660,000 and a rate base adjustment of $85,000 for the Company's gas operations.

## C. Cost of Capital

### 1. ***Return on Equity***

The cost of capital is a utility's overall rate of return ("ROR"), which is the sum of the weighted returns the utility must earn on its stock (equity) and bonds (debt) to

[540] Order No. 86990 at pp. 1, 4, 10 fn. 35, 66, 80, 81.

attract investors in those securities. Unlike return on debt, which is directly observable, return on equity ("ROE") must be estimated based on market data. No party opposed the cost of preference stock, short-term or long-term debt proposed by the Company. However, witnesses for BGE, OPC and Staff presented differing estimations regarding an appropriate ROE.

**Party Positions**

*BGE*

BGE witness Vahos requested that BGE receive an overall rate of return of 7.74% for electric and 7.69% for gas based on BGE's embedded cost of debt and preference stock as well as the returns on equity requested by BGE witness McKenzie.[541]

Mr. McKenzie presented BGE's case regarding the fair rate of return on equity that the Company requested it be authorized to earn on its investment in providing electric and gas utility service. Generally, he cautioned that regulatory signals – such as those sent by the Commission through its orders – are a major driver of investors' risk assessment for utilities.[542] He stated: "When investors are confident that a utility has reasonable and balanced regulation, they will make funds available even in times of turmoil in the financial markets."[543] He performed several quantitative analyses to estimate the cost of equity for separate reference groups of electric and gas utilities. Those analyses included the discounted cash flow ("DCF") model, the empirical form of Capital Asset Pricing Model ("ECAPM"), and an equity risk premium approach based on

[541] Vahos Direct at 28.
[542] McKenzie Direct at 6.
[543] McKenzie Direct at 6.

allowed ROEs for electric and gas utilities.[544] He also tested his recommended ROEs for BGE's electric and gas utility operations against alternative ROE benchmarks for his proxy groups, including application of the traditional Capital Asset Pricing Model ("CAPM.") Finally, he reviewed his utility quantitative analyses by applying the DCF model to a select group of low risk non-utility firms.

Mr. McKenzie testified that current capital market conditions are not representative of what investors expect in the future because they continue to reflect the Federal Reserve's "unprecedented monetary policy actions in the aftermath of the Great Recession."[545] Due to heightened risk, he argued that investors have repeatedly sought the "safe haven" of U.S. government bonds.[546] As a result of federal policies and volatility, Treasury bond yields have fallen significantly. He labeled current bond yields resulting from the Federal Reserve's policies "an anomaly" when compared to historical experience.[547] He further warned that historically low interest rates were not expected to continue, and that investors "continue to anticipate that interest rates will increase significantly from present levels."[548] He concluded that the long-term cost of capital will be substantially higher over the 2016 to 2020 time period.[549]

Mr. McKenzie testified about the risks of attrition, which he defined as "the deterioration of actual return below the allowed return that occurs when the relationships

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[544] McKenzie Direct at 4.
[545] McKenzie Direct at 13. For example, Mr. McKenzie pointed to the Federal Reserve's holdings of Treasury bonds and mortgage-backed securities of more than $4 trillion, an all-time high. McKenzie Direct at 17.
[546] McKenzie Direct at 13.
[547] McKenzie Direct at 14.
[548] McKenzie Direct at 15.
[549] Mr. McKenzie alluded to FERC's upward adjustment of its DCF range to compensate for what it considered unrepresentative market conditions and the risk of increased interest rates in the future. McKenzie Direct at 21.

between revenues, costs, and rate base used to establish rates do not reflect the actual costs incurred to serve customers during the period that rates are in effect."[550] Mr. Case testified that BGE has faced a consistent pattern of under-earning relative to its authorized return on equity in recent years, as a result of factors such as rising costs and flat customer growth.[551] He argued that those imbalances are exacerbated as the regulatory lag increases between the time when the data is used to establish rates and the date when rates go into effect. He testified that attrition and regulatory lag have been persistent problems for BGE over the last five years, resulting in the Company being unable to earn its authorized ROE.[552]

Given the risk of attrition, Mr. McKenzie questioned the Commission's reliance on a historic test year, arguing that investors are concerned about what can be expected in the future, "not what they might expect in theory if a historical test year were to repeat."[553] Mr. Case testified similarly, stating that in times of significant infrastructure investment and rising costs, relying on a historic test year "results in a poor matching of distribution rates with the actual cost of providing service during the rate effective period."[554]

In order to ensure that BGE's investors earn a return that is fair and commensurate with its authorized return, Mr. McKenzie urged the Commission to

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550 McKenzie Direct at 7.

551 Case Direct at 32. Mr. Case calculated that BGE has experienced a revenue shortfall of nearly 25% below its combined authorized return on equity, on average. Case Direct at 33.

552 McKenzie Direct at 8. Although Mr. McKenzie stated that his discussion of attrition is synonymous with regulatory lag as that term is used by BGE's other witnesses, he discussed both terms in his Direct Testimony. *Id*. at 7-8, n. 4.

553 McKenzie Direct at 7.

554 Case Direct at 31-32.

approve an ROE "from the upper end of my range of reasonableness."[555] Case testified that "authorizing an ROE for BGE that is within the upper end of his range of reasonableness … is actually necessary under *Hope* and *Bluefield*" because of regulatory lag and the Commission's use of a historic test year.[556]

Mr. McKenzie utilized quantitative methods to estimate the cost of common equity for BGE's electric and gas operations. In doing so, he developed a list of 21 companies derived from Value Line's[557] electric utility industry groups that he determined were representative of BGE's electric operations and that would constitute his electric proxy group.[558] Similarly, he developed a list of ten publicly traded firms in Value Line's Natural Gas Utility industry to constitute his gas proxy group.[559] For his electric proxy group, he claimed that he developed a "conservative risk profile," in line with the Commission's judgment that BGE represents a lower-risk investment than the average utility.[560] Nevertheless, he did not remove utilities from his electric proxy group that own and operate generation assets. He further testified that adjustment mechanisms and cost trackers, such as BGE's Strategic Infrastructure Development and Enhancement ("STRIDE") surcharge and its Electric Reliability Investment ("ERI") initiative, had become increasingly prevalent in the utility industry in recent years and were comparable to those of his utility proxy groups.[561]

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[555] McKenzie Direct at 9.
[556] Case Direct at 5.
[557] As Mr. VanderHeyden explained, Value Line Investment Survey and other data provided by Value Line, Inc. provide a well-known source of data that can reasonably be expected to represent the information known to the general body of investors. VanderHeyden Direct at 5.
[558] McKenzie Direct at 23.
[559] McKenzie Direct at 25-26.
[560] McKenzie Direct at 27, citing Order No. 85374 at 64.
[561] McKenzie Direct at 28.

Among other tools, Mr. McKenzie utilized the DCF analysis to estimate the cost of common equity to BGE. The DCF model is designed to replicate the market valuation process that sets the price investors are willing to pay for a share of a company's stock. The model estimates the cash flows investors expect to receive from the stock through future dividends and capital gains.[562] Because common stocks are more risky than investments in long-term bonds, Mr. McKenzie eliminated DCF results that in his opinion were not sufficiently higher than the yield available on less risky utility bonds.[563] Specifically, he eliminated eight low-end DCF estimates ranging from 5.4% to 6.9%.[564] However, Mr. McKenzie did not eliminate any high-end DCF values for the electric group, finding that "there is no objective benchmark analogous to the bond yield averages used to eliminate illogical low-end values."[565] After eliminating values he deemed illogical, Mr. McKenzie's constant growth DCF model produced an ROE range of 9.3% to 9.7% for BGE's electric operations.[566] Similarly, Mr. McKenzie's constant growth DCF analysis produced an ROE range of 8.8% to 10.4% for BGE's gas operations.[567]

Mr. McKenzie also evaluated BGE's common equity requirements through the ECAPM model, a variant of the traditional CAPM. The CAPM analysis determines an equity risk premium for a particular stock based on its relative risk against the overall stock market.[568] Using this model, the relevant risk of an asset (such as an individual

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[562] McKenzie Direct at 34. Mr. McKenzie noted that the DCF model can be set forth mathematically (in its simplified "constant growth" form) as $k_e = D_1/P_0 + g$, where $k_e$ equals the cost of common equity, $D_1$ represents the expected dividend per share, $P_0$ is equal to the current price per share, and g is equal to the investors' long-term growth expectations. McKenzie Direct at 34-35. *See also* VanderHeyden Direct at 11.
[563] McKenzie Direct at 41.
[564] McKenzie Direct at 43-44.
[565] McKenzie Direct at 44.
[566] McKenzie Direct at 10.
[567] McKenzie Direct at 11.
[568] VanderHeyden Direct at 17.

stock), is its volatility relative to the market as a whole.[569] That model uses the beta coefficient to measure a utility's stock price volatility relative to the market, and reflects the tendency of a stock's price to follow changes in the market.[570] Mr. McKenzie employed the ECAPM variant as a result of empirical tests that demonstrate that low-beta securities earn returns somewhat higher than CAPM would predict and that high-beta securities earn less than predicted.[571] Additionally, Mr. McKenzie added a "size premium" to the ECAPM result to account for research that indicates that the ECAPM does not fully account for differences in rates of return attributable to firm size.[572] Mr. McKenzie's ECAPM analysis produced an ROE range of 10.5% to 10.8% for his electric group.[573] Similarly, Mr. McKenzie's ECAPM analysis produced an ROE range of 10.3% to 12.18% for his gas group.

Mr. McKenzie additionally utilized a utility risk premium approach to estimate BGE's common equity requirements. The risk premium method estimates the additional return investors require to forgo the relative safety of bonds and to bear the higher risks associated with common stocks, and then adds this equity risk premium to the current yield on bonds.[574] Mr. McKenzie based his estimates of equity risk premium on surveys of previously authorized ROEs. He testified that when interest rates are high, equity risk

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[569] McKenzie Direct at 46. The CAPM can be expressed mathematically as $R_j = R_f + B_j(R_m – R_f)$ where $R_j$ is the required rate of return for stock j, $R_f$ is the risk-free rate, $B_j$ is the beta, or systematic risk, for stock j, and $R_m$ is the expected return on the market portfolio. 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. McKenzie Direct at 46.
[570] McKenzie Direct at 25.
[571] McKenzie Direct at 47. The ECAPM adjusts for this phenomenon through the following weighted formula:
$R_j = R_f + 0.25(R_m – R_f) + 0.75[B_j(R_m – R_f)]$.
[572] McKenzie Direct at 49.
[573] McKenzie Direct at 10.
[574] McKenzie Direct at 51.

premiums narrow, but when interest rates are low, as they are now, the risk premiums become greater.[575] Mr. McKenzie's risk utility premium approach produced an ROE range of 10.0% to 11.1% for electric utilities.[576] Similarly, Mr. McKenzie's risk utility premium approach produced an ROE range of 9.60% to 10.6% for gas utilities.[577]

Based on the results of his analyses, Mr. McKenzie recommended a range of 9.7% to 10.9% for BGE's electric operations.[578] Similarly, he recommended a range of 9.6% to 10.8% for BGE's gas operations.[579] Given the risk of attrition and other economic factors, he recommended an ROE in the upper range of reasonableness of 10.6% for BGE's electric utility operations and an ROE of 10.5% for the Company's gas utility operations.[580]

Mr. McKenzie's final ROE recommendations include a ten basis point adjustment for flotation costs.[581] He explained that when equity is raised through the sale of common stock, there are costs associated with floating the new equity securities in the form of legal, accounting and printing costs as well as the fees and discounts paid to compensate brokers for selling the stock to the public.[582] Mr. McKenzie observed that while debt flotation costs are recorded on the books of the utility and amortized over the life of the issue, that is not the case for equity issuance costs. He testified that unless they

[575] McKenzie Direct at 52. Mr. McKenzie opined that today's unprecedented low bond yields implied "a sharp increase in the equity risk premium that investors require" to accept the added risk of utility common stocks vs. bonds. McKenzie Direct at 53.
[576] McKenzie Direct at 10.
[577] McKenzie Direct at 11.
[578] McKenzie Direct at 10.
[579] McKenzie Direct at 11.
[580] McKenzie Direct at 9-10. Specifically, Mr. McKenzie chose 10.6% for BGE's electric operations as the midpoint of the upper end of his ROE range. McKenzie Direct at 11. His calculation for BGE's gas operations employed a similar methodology. McKenzie Direct at 12.
[581] McKenzie Direct at 11, 60. For example, the addition of flotation costs increased his gas ROE range from his original 9.5% to 10.7% range, to 9.6% to 10.8%.
[582] McKenzie Direct at 55.

are accounted for, such as through an upward adjustment to the cost of equity, the utility's revenue requirement will not fully reflect all of the costs incurred for the use of investors' funds.[583] Mr. McKenzie further testified that an adjustment for flotation costs associated with past equity issues is appropriate even when the utility is not contemplating any new sales of common stock.

Finally, Mr. McKenzie utilized alternative tests to demonstrate that the results of his primary ROE analyses were reasonable. Specifically, he used the traditional CAPM analysis, an expected earnings approach, and a DCF analysis for a select group of low-risk, non-utility firms to confirm the reasonableness of his results. In Mr. McKenzie's opinion, the alternative benchmarks he utilized confirmed the reasonableness of his recommended ROE ranges of 9.7% to 10.9% for BGE electric and 9.6% to 10.8% for BGE's gas operations.[584]

*Staff*

Mr. VanderHeyden, Director of the Commission's Electricity Division, provided testimony on behalf of Staff on BGE's electric distribution service. Regarding proxy groups, he testified that a utility's return should be comparable to other companies of similar risk. In that regard, he observed that BGE is solely a distribution company and does not include any generation or transmission assets in its rate base.[585] Unfortunately, few companies are organized as stand-alone electric distribution companies, making a perfectly representative proxy group difficult to achieve. Mr. VanderHeyden noted that

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[583] McKenzie Direct at 55-56.
[584] McKenzie Direct at 68-69.
[585] VanderHeyden Direct at 8.

many of Value Line's electric utility groups have other operations, such as generation and non-regulated businesses.

Mr. VanderHeyden derived his electric utility proxy group primarily from the proxy group utilized by BGE witness Mr. McKenzie. However, Mr. VanderHeyden removed Duke Energy, NextEra Energy, and PPL Corporation from that group, because of their recent or proposed mergers or spinoffs.[586]

Mr. VanderHeyden derived his recommended ROE for BGE by averaging the results of his DCF and CAPM results, after excluding the results from certain methods that he concluded were outside of a reasonable range. He also utilized the Internal Rate of Return/Discounted Cash Flow method ("IRR/DCF") and the Risk Premium Buildup Method.

Regarding the DCF, Mr. VanderHeyden used data from Value Line to obtain the annual dividend for each year. However, given the significant investment in reliability spending for many electric utilities, Mr. VanderHeyden excluded the low dividend growth results from his DCF calculation because in his opinion, many utilities would be unable or unwilling to increase dividends while spending heavily on reliability improvements.[587] Mr. VanderHeyden also excluded companies from his DCF with earnings growth rates outside a reasonable range. For example, he removed El Paso Electric Co. and Edison International because their calculations indicated an ROE less

[586] VanderHeyden Direct at 8.
[587] VanderHeyden Direct at 12.

than 7%.[588] Using the DCF method, Mr. VanderHeyden calculated an ROE of 9.66% for BGE.[589]

The IRR/DCF method is a type of DCF that focuses on the capital appreciation of an investment. It determines an ROE based solely on the dividend projections and the change in the price of a stock over a fixed period.[590] Specifically, it is calculated on the projected capital gain on the stock and the dividend projections over a four-year period.[591] Mr. VanderHeyden calculated the IRR/DCF by averaging the IRR results for each of the companies in his electric proxy group. Using this method, Mr. VanderHeyden calculated an ROE of 9.44%.

The Risk Premium Buildup Method calculates the ROE for a given investment by adding a risk-related premium to the return on a riskless investment. The Risk Premium Buildup Method adds to the market's ROE (for example, the S&P 500) two components, (i) an equity risk premium, and (ii) the risk-free rate, which here was represented by the 30-year Treasury bond.[592] This method produced an ROE of 7.5% for the industry category of "electric services industry group," which is similar to, but not the same as, Mr. VanderHeyden's electric proxy group.[593]

Finally, using the CAPM method, Mr. VanderHeyden calculated an ROE of 9.71% for BGE.[594] He reached his final recommendation of 9.68% for BGE's electric

[588] VanderHeyden Direct at 13.
[589] VanderHeyden Direct at 10.
[590] VanderHeyden Direct at 13-14.
[591] The IRR/DCF differs from the traditional DCF in this regard. In the traditional DCF method, the present value is the result of a continuing stream of dividends. Mr. VanderHeyden characterized the IRR/DCF as providing "a short-term view of investor returns, but [one which] may not properly account for the longer-term utility investor expectations." VanderHeyden Direct at 15.
[592] VanderHeyden Direct at 15.
[593] VanderHeyden Direct at 15.
[594] VanderHeyden Direct at 17.

operations based on the average of his DCF and the CAPM analyses. He excluded the RP Buildup Method because its results "are outside of the range of recent rate orders and do not reflect current investor expectations."[595] He excluded the IRR/DCF because it is based on similar data as the DCF method and including both would overweight dividend yield based methods. Finally, he chose to average the DCF and CAPM results because "it is reasonable to weight differently determined results equally using the assumption that no single method is superior."[596]

Mr. VanderHeyden testified against BGE's request to be authorized an ROE that reflects flotation costs. He argued that the Commission has been clear in previous orders that an award for flotation costs would be granted only based on verifiable costs of issuing new stock. Because BGE has not provided information in its Application on these threshold issues, Mr. VanderHeyden recommended against an adjustment for flotation costs to BGE's ROE.[597]

Mr. VanderHeyden recommended a rate of return of 7.46% for BGE's electric operations. That figure is based on his ROE recommendation discussed above as well as BGE's capital structure calculations regarding long-term debt, short-term debt, preferred stock, and common stock.

Mr. VanderHeyden critiqued the cost of capital analysis provided by BGE witness Mr. McKenzie. Mr. VanderHeyden noted that the DCF analyses conducted by BGE and Staff were "close"[598] in results, with the primary difference being BGE's use of the

[595] VanderHeyden Direct at 19.
[596] VanderHeyden Direct at 19.
[597] VanderHeyden Direct at 21, citing Commission Order No. 86441 at 88.
[598] Mr. VanderHeyden observed that Mr. McKenzie's DCF produced an average result of 9.4% compared to Staff's 9.66%. Nevertheless, Mr. McKenzie used the DCF midpoint of 9.7%.

midpoint for its result. Mr. VanderHeyden observed that unlike BGE, he did not use the ECAPM method. That is because he found the use of an adjustment for beta to be unnecessary in this case and also because the ECAPM method "was not a mainstream method."[599] Additionally, Mr. VanderHeyden objected to Mr. McKenzie's use of a size adjustment in his ECAPM method, seeing no merit for such an adjustment with regard to regulated utilities in Maryland. Mr. VanderHeyden also characterized Mr. McKenzie's risk premium analysis as incomplete because the historical authorized returns granted by state commissions may be higher or lower than the returns on market equity that current investors expect.[600]

Finally, Mr. VanderHeyden testified that he would revise Mr. McKenzie's results by using the average of his complete proxy group rather than taking a midpoint, yielding a result of 9.4%. He would exclude the risk premium and ECAPM analyses. He would then average the 9.4% with his CAPM result of 9.71%, which would result in a final ROE of 9.55%.[601] Mr. VanderHeyden concluded that BGE's cost of equity capital is 9.68% and that the Company's overall rate of return is 7.46%.[602]

Jennifer Ward, Regulatory Economist within the Commission's Telecommunications, Gas, and Water Division, testified on behalf of Staff regarding cost of capital for BGE's gas distribution service. She calculated her recommended ROE using the traditional DCF and CAPM analyses. In assembling her proxy group, she started with the recommended gas proxy group of Mr. McKenzie and made two changes. First, she removed Piedmont Natural Gas from the group, observing that Piedmont is

[599] VanderHeyden Direct at 23-24.
[600] VanderHeyden Direct at 26.
[601] VanderHeyden Direct at 27.
[602] VanderHeyden Direct at 2.

currently subject to a pending acquisition with Duke Energy. Ms. Ward testified that the pending acquisition creates market expectations that may skew the results of the ROE analysis. Second, she conducted an outlier analysis to eliminate any outlier growth rates from the proxy group, and removed NiSource and New Jersey Resources from her recommended proxy group.[603] Ms. Ward testified that the resulting proxy group matched BGE's risk profile. She observed that BGE is a public utility company that is widely regarded as having a low credit risk, receiving a Moody's credit rating of A3 for its long term debt.[604] The gas proxy group also exhibits a low risk profile, with five of the seven companies in the group receiving credit ratings from Moody's of A3 or higher.

In her DCF analysis, Ms. Ward did not rely exclusively on dividend per share growth rates, but followed FERC practice in also considering the short term dividend yield and the long term economic growth rate. Ms. Ward's DCF analysis resulted in an ROE of 9.62%.[605] Ms. Ward also conducted a CAPM analysis. Because she found that current economic conditions have resulted in unusually low interest rates, she used the mean of the projected 30-year note yields for the time period 2015 through 2019 to more accurately capture the future expectations of investors and anticipated interest rate increases in the near future.[606] Ms. Ward testified that it was not appropriate to make an explicit size adjustment in her CAPM analysis, as Mr. McKenzie had done. She explained that using beta coefficients for each proxy group company incorporates the risk of a company to a well-diversified portfolio, thereby embedding in the beta coefficient a

[603] Ward Direct at 7.
[604] Ward Direct at 8.
[605] Ward Direct at 11.
[606] Ward Direct at 12.

size adjustment and making further adjustment unnecessary and inappropriate.[607] Ms. Ward also declined to use a risk premium method similar to Mr. McKenzie. She stated that authorized returns from a diverse group of state commissions often reflect issues specific to a particular utility, geographic area, or regulatory environment, making awarded ROEs a poor proxy for a specific risk profile.

Ms. Ward testified against BGE's request for flotation costs. She stated that Staff asked BGE to provide evidence of any incurred expenses, investments, or fees related to flotation costs, and the Company responded that it "does not issue publicly traded common stock and, therefore, will not incur flotation costs directly."[608] She concluded that without evidence of known and measurable costs, she cannot recommend an allowance for flotation costs.

Ms. Ward adjusted her recommended ROE based in part on reduced risk to BGE as a result of its STRIDE initiative. Ms. Ward testified that STRIDE authorizes BGE to accelerate cost recovery related to certain gas infrastructure investments, thereby reducing the Company's risk. The program allows BGE to more quickly recover certain infrastructure expenses and improve cash flows, while improving the safety of aging infrastructure and reducing leakages.[609] She determined that attributing a precise value to the reduction in risk from STRIDE was difficult, but testified that it was appropriate to acknowledge the reduced risk by recommending an ROE equal to the lower end of her range of reasonableness.[610]

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[607] Ward Direct at 14.
[608] Ward Direct at 16.
[609] Ward Direct at 16-17.
[610] Ward Direct at 17.

Ms. Ward concluded that the range of reasonableness for BGE's ROE is 9.62% to 9.81%. Based on that range, she determined that an ROE of 9.60% will adequately compensate BGE for the risks associated with the provision of gas service in Maryland.[611] Furthermore, she calculated that an overall rate of return of 7.41% for BGE is adequate and appropriate.[612]

*OPC*

Dr. J. Randall Woolridge testified on behalf of OPC. He adopted BGE's proposed short-term debt, long-term debt, and preferred stock costs rates. His main contention was in the calculation of BGE's ROE. Dr. Woolridge applied the DCF and CAPM methods to proxy groups of publicly-held electric utilities and gas distribution companies to determine an equity cost ratio of 8.7% for BGE's electric operations and an equity cost ratio of 8.6% for BGE's gas operations.[613] He testified that these recommendations were on the upper end of his equity cost rate range of 8.1% to 8.7%. When BGE's capital structure and senior capital cost rates are taken into consideration, Dr. Woolridge calculated an overall rate of return of 6.75% for BGE's electric utility operations and 6.70% for BGE's gas distribution operations.[614]

Dr. Woolridge relied primarily on the DCF analysis for his ROE determination, finding that the DCF method provides the best measure of equity cost rates for public

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[611] Although it appears that Ms. Ward's final recommended ROE is below the bottom of her range of reasonableness, she testified that her practice is to round to the nearest 0.05, which led to her recommended ROE for BGE's gas operations of 9.60%. Tr. at 1962.
[612] Ward Direct at 4.
[613] Woolridge Direct at 4.
[614] Woolridge Direct at 4.

utilities.[615] He also performed the CAPM analysis, but put less weight on its results because the CAPM provides a "less reliable indication of equity cost rates for public utilities," in his opinion.[616] In deriving the DCF growth rate forecast for his proxy group, Dr. Woolridge did not rely exclusively on the earnings per share forecasts, arguing that "it is well known that the long-term [earnings per share] growth rate forecasts of Wall Street securities analysts are overly optimistic and upwardly biased."[617] The DCF analysis for Dr. Woolridge's electric proxy group produced an equity cost rate of 8.7% and for his gas distribution proxy group produced an equity cost rate of 8.6%.[618] Using the CAPM analysis, Dr. Woolridge determined a cost of equity for the electric proxy group of 8.10%. For the gas proxy, he calculated a cost of equity of 8.30%.[619] Given the results of his DCF and CAPM analyses, he computed an equity cost rate range of 8.1% to 8.7% for the electric proxy group and 8.3% to 8.6% for the gas proxy group.[620] Because he relied primarily on the DCF, he chose a final ROE recommendation at the upper end of the range and concluded that the appropriate equity cost rate is 8.7% for BGE's electric operations and 8.6% for the Company's gas operations.

Dr. Woolridge observed the return the Commission has authorized for BGE has been consistent over the years. In Case Nos. 9326 and 9299, the Commission authorized an ROE of 9.75% for BGE's electric operations and 9.60% for BGE's gas distribution operations. Dr. Woolridge testified that since December 13, 2013, when Case No. 9326

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[615] Woolridge Direct at 36. Given the utility industry's relative stability, maturity of demand for utility services, and regulated nature, Dr. Woolridge testified that the utility business is in the steady-state or constant-growth stage of the three-stage DCF, making it well-suited to the DCF analysis. Dr. Woolridge Direct at 40.
[616] Woolridge Direct at 37.
[617] Woolridge Direct at 47.
[618] Woolridge Direct at 51.
[619] Woolridge Direct at 60-61.
[620] Woolridge Direct at 61.

was decided, BGE has become "an even lower risk investment operating in an even lower interest rate environment."[621]

Dr. Woolridge argued that capital costs have declined since the Commission last addressed BGE's ROE. Although he acknowledged that the Federal Reserve ended its Quantitative Easing III bond buying program in 2014, the "dire predictions of higher long-term rates have proved to be 100 percent wrong."[622] He noted that the 30-year Treasury yield, which was 3.88% on December 13, 2013, declined to the 2.5% range in early 2015 and remained below 3.0% for the remainder of 2015.[623] Similarly, long-term rates were not impacted by the Federal Reserve's decision to increase the target rate for Federal Funds. Dr. Woolridge observed that "there is no direct link between the federal funds rate and long-term interest rates."[624] Regarding his prediction for long-term rates, he argued that slowing economic growth coupled with significant and growing "stored wealth that is available to fund investments" will keep interest rates low for the foreseeable future.[625] He testified that U.S. GDP growth remains low by historic standards, inflationary expectations remain low in this country, and global economic growth is slowing, with Europe stagnant and China slowing significantly.[626] He also testified that economists have consistently over-forecast interest rate increases and that "interest rates have not fulfilled the predictions."[627] Finally, addressing Mr. McKenzie's warning that a sudden interest rate increase is just around the corner, Dr. Woolridge

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[621] Woolridge Direct at 6.
[622] Woolridge Direct at 6.
[623] Woolridge Direct at 6.
[624] Woolridge Direct at 15-16.
[625] Woolridge Direct at 18-20. He referred to this phenomenon as "more wealth chasing few opportunities for investment rewards," and alluded to Ben Bernanke's characterization of the phenomenon as a "global savings glut." Woolridge Direct at 20.
[626] Woolridge Direct at 23.
[627] Woolridge Direct at 14.

testified that: “Investors would not be buying long-term Treasury bonds or utility stocks at their current yields if they expected interest rates to suddenly increase, thereby producing higher yields and negative returns.”[628]

Beyond interest rates, Dr. Woolridge testified that BGE is in a better position because of its credit rating. Dr. Woolridge testified that BGE’s credit rating has improved since its last rate case, from Baa1 to A3.[629] Dr. Woolridge also claimed that authorized ROEs for electric utilities and gas distribution companies around the country have decreased since BGE’s last rate case. He cited data from Regulatory Research Associates indicating that authorized ROEs for gas distribution companies have declined from 9.94% in 2012, to 9.68% in 2013, to 9.78% in 2014, and to 9.60% in 2015.[630] Similarly, the authorized ROEs for gas distribution companies have declined from 9.94% in 2012 to 9.60% in 2015, according to the same source.

Dr. Woolridge criticized BGE’s Mr. McKenzie’s cost of capital evaluation. First, he argued that Mr. McKenzie improperly eliminated low-end equity and cost rate results that he determined were too low. Second, Dr. Woolridge argued that Mr. McKenzie “relied excessively on the overly optimistic and upwardly biased earnings per share growth rate forecasts of Wall Street analysts.”[631] Third, Mr. McKenzie made several errors regarding his CAPM analysis, including using the ECAPM in place of the traditional analysis, making an unwarranted size adjustment, and using an inflated market risk premium that does not reflect current market fundamentals. Specifically, Dr. Woolridge argued that Mr. McKenzie’s use of an expected stock market return of 11.7%,

[628] Woolridge Direct at 24.
[629] Woolridge Direct at 7, referencing Moody’s January 30, 2014 rating upgrade.
[630] Woolridge Direct at 7.
[631] Woolridge Direct at 8.

based primarily on analysts' earnings per share growth projections, was unrealistic.[632] Dr. Woolridge also criticized Mr. McKenzie's utility risk premium model because (i) the approach is a gauge of state commission behavior and not investor behavior; (ii) the methodology produces an inflated measure of the risk premium; and (iii) state commission authorized returns have been greater than necessary to attract investors.[633] Like Staff witness Mr. VanderHeyden, Dr. Woolridge criticized Mr. McKenzie for including a flotation cost adjustment "without identifying any flotation costs actually paid by BGE."[634]

*Party Responses*

BGE and OPC submitted rebuttal testimony regarding cost of capital. Mr. Vahos testified that OPC witness Woolridge's recommended ROEs of 8.7% and 8.6% for electric and gas should be rejected because they would be lower than any of the 332 ROEs granted to an electric or gas utility by a state commission over the last five years.[635] Mr. Vahos also observed that Dr. Woolridge's current recommendation is even lower than OPC's 9.0% ROE proposal in Case No. 9336, which was rejected by the Commission as too low in its July 2014 order.[636]

Mr. Vahos criticized Staff witness Ward for including in her ROE recommendation a negative adjustment for STRIDE. Mr. Vahos explained that the gas proxy groups in this proceeding already reflect the market's perception of gas infrastructure cost recovery programs like STRIDE. He noted that a recent Edison

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[632] Woolridge Direct at 9.
[633] Woolridge Direct at 11.
[634] Woolridge Direct at 11.
[635] Vahos Rebuttal at 23. *See also* McKenzie Rebuttal at 23.
[636] Vahos Rebuttal at 24, citing Case No. 9336, Order No. 86441 at 87.

Electric Institute report found that 37 of 50 states in the U.S. use gas capital cost trackers. Additionally, he downplayed the importance of STRIDE, stating 2015 STRIDE revenues were only 1% of total gas distribution revenues.[637] In an apparent criticism of her rounding practice, Mr. Vahos denigrated Ms. Ward for recommending an ROE that is below her range of reasonableness, not just on the lower end of her range.[638] Mr. Vahos warned that authorizing a low ROE could hurt the Company's credit rating, given that credit rating agencies view cash flows as one of the most important aspects of a company's financial position since they are essential to meeting debt obligations.[639] Mr. Vahos reiterated his concern that the Commission should authorize ROEs from the upper end of BGE's proposed ranges of reasonableness in order to address the phenomenon of attrition, or regulatory lag. Mr. Vahos maintained that neither OPC nor Staff presented any evidence on this issue.

In his Rebuttal Testimony, Mr. Case reiterated his position that since 2012, BGE has under-earned its authorized ROE by approximately 25%, due in part to the Commission's practice of utilizing a historic test period. He criticized OPC's "extreme" ROE position and asked that the Commission approve a return that incorporates the Company's position on attrition.[640]

Mr. McKenzie's Rebuttal Testimony presented numerous criticisms of the ROE testimony of Staff witnesses VanderHeyden and Ward as well as OPC witness Woolridge. He claimed that Ms. Ward underestimated the dividend yield component of the DCF model by relying improperly on dividends for a past period (2015), rather than

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[637] Vahos Rebuttal at 25.
[638] Vahos Rebuttal at 25.
[639] Vahos Rebuttal at 27-28.
[640] Case Rebuttal at 32.

for the year-ahead period (2016).[641] Mr. McKenzie also disagreed with Ms. Ward's use of dividend per share growth projections in lieu of his utilization of earnings per share.[642] He found fault with Mr. VanderHeyden and Ms. Ward for ignoring a size adjustment when applying the CAPM analysis.[643]

Mr. McKenzie reiterated his support for the ECAPM methodology, arguing that financial research has documented a downward bias in CAPM estimates for low beta industries like rate-regulated utilities. Mr. McKenzie also testified that other Staff witnesses have employed the ECAPM analysis in past proceedings.[644] Mr. McKenzie defended his use of the utility risk premium model, arguing that it provides meaningful insight into current investor expectations of a reasonable ROE, contrary to the contentions of the Staff witnesses.[645] Mr. McKenzie disagreed with Staff's recommendation not to include an adjustment for flotation costs, stating that the relevant financial literature has recognized that a flotation cost adjustment in all future years is required even if no further stock issuances are contemplated.[646] Mr. McKenzie also disagreed with Ms. Ward's decision to apply to BGE's gas operations the lower end of her reasonable ROE range as a result of BGE's STRIDE rider, referring to her adjustment as an "ROE penalty."[647] He observed that many companies in the proxy group had mechanisms similar to STRIDE, concluding that "there is no basis to distinguish between

[641] McKenzie Rebuttal at 5-6.
[642] McKenzie Rebuttal at 6-7.
[643] McKenzie Rebuttal at 9-10.
[644] Mr. McKenzie referenced previous BGE (Case No. 9326) and Pepco (Case No. 9336) rate cases. *Id*. at 11.
[645] McKenzie Rebuttal at 12-13.
[646] McKenzie Rebuttal at 14.
[647] McKenzie Rebuttal at 15.

BGE and its industry peers on the basis of [such] regulatory mechanisms."[648] Finally, Mr. McKenzie criticized the Staff witnesses for failing to address regulatory lag, claiming that there has been a chronic shortfall between BGE's authorized ROE and its actual earned returns. He reiterated his position that the attrition problem warrants an ROE at the upper end of the range of results.

Mr. McKenzie chastised OPC's Dr. Woolridge for recommending ROEs that he considered "extreme outliers."[649] He noted that Dr. Woolridge's proposed ROEs are at least 100 basis points lower than the currently authorized ROEs for BGE's utility operations, and that they are approximately 100 basis points less than the Staff's recommendations in this case. He also accused Dr. Woolridge of ignoring clear evidence of investors' expectations of higher interest rates as well as the implications of widening yield spreads between utility and Treasury bonds, which in Mr. McKenzie's opinion demonstrates that investors' required risk premium for common stocks over Treasury bonds has increased.[650] Mr. McKenzie also challenged Dr. Woolridge's determination that interest rates have fallen, arguing that unlike risk-free Treasury rates, the premium for public utility debt has increased.[651]

Mr. McKenzie criticized Dr. Woolridge's methodology for creating proxy groups as well as his focus on market to book ratios. He specifically disagreed with Dr. Woolridge's requirement that a company derive at least 50 percent of its revenues from regulated utility operations.[652] Mr. McKenzie claimed that Dr. Woolridge erred in

[648] McKenzie Rebuttal at 17.
[649] McKenzie Rebuttal at 4.
[650] McKenzie Rebuttal 42-43.
[651] McKenzie Rebuttal at 26-27.
[652] McKenzie Rebuttal at 25.

applying his DCF analysis by failing to illuminate and discard illogical data, alleging that he relied upon "a mishmash of historical and projected growth rates over varying time periods" for earnings, dividends, and book values."[653] Mr. McKenzie claimed that Dr. Woolridge could have obtained almost any DCF result based on the data he cited.

Finally, Mr. McKenzie argued that Dr. Woolridge's CAPM results were unreliable because they were based on a "hodge-podge of historical data that fail to reflect forward-looking expectations."[654] Mr. McKenzie argued the CAPM analysis is *ex ante* and must be applied using data that reflects the expectations of actual investors in the market. Mr. McKenzie concluded that Dr. Woolridge's results are "downward biased, unreliable, and should be ignored."[655]

In his Rebuttal Testimony, OPC's Dr. Woolridge testified that Staff's VanderHeyden erred in his ROE analysis by (i) failing to consider or evaluate the riskiness of BGE relative to other electric utilities; (ii) arbitrarily eliminating the results of the IRR/DCF and Risk Premium Buildup methods (which produced lower ROEs) and instead relying exclusively on the higher DCF and CAPM results; (iii) using in his DCF analysis inappropriate growth rates and relying on two high-end outliers that skew the distribution of ROE results; and (iv) utilizing a flawed measure of the equity risk premium in his CAPM analysis.[656]

Dr. Woolridge also critiqued Ms. Ward's testimony, arguing that she erred by eliminating two low-end DCF ROEs (New Jersey Resources and NiSource), but failed to

[653] McKenzie Rebuttal at 41.
[654] McKenzie Rebuttal at 4.
[655] *Id*.
[656] Woolridge Rebuttal at 5. Dr. Woolridge took aim at Mr. VanderHeyden's proxy group, arguing that he erred by including ITC Holdings, which is an electric transmission company, not a traditional electric utility company. Dr. Woolridge argued that as a result, ITC has a risk profile that is higher than BGE's. Woolridge Rebuttal at 7.

eliminate corresponding high-end returns.[657] He also criticized her for erroneously using historical annual stock returns in her CAPM analysis to measure an *ex ante* equity risk premium.

In his Surrebuttal Testimony, Mr. McKenzie defended his as well as Staff's cost of capital analyses from the criticisms of Dr. Woolridge. He stated that the proxy groups BGE and Staff selected reflected a conservative risk profile.[658] He also stated that Mr. VanderHeyden properly excluded the results of his risk premium build-up method, notwithstanding the objections of Dr. Woolridge. He also defended Mr. VanderHeyden's use of earnings per share and his elimination of low-end DCF estimates in his DCF analysis.

Dr. Woolridge provided Surrebuttal Testimony responding to BGE's witnesses on the topics of changes since the last rate case, capital market conditions, equity cost rate issues, and credit ratings. Dr. Woolridge testified that authorized ROEs for electric utilities and gas distribution companies have decreased since BGE's last rate case, to an average of 9.58% for electric utilities and 9.60% for gas distribution companies in 2015.[659] Regarding future interest rates, Dr. Woolridge observed that in BGE's last rate case (Case No. 9326), BGE's cost of capital witness projected dire warnings of imminent rate increases, a prediction that did not come to fruition.[660] Dr. Woolridge stated that the cost of long-term capital did not increase significantly in the years after BGE's last rate case. He also claimed that Mr. McKenzie erred by assuming (i) that investors share economists' erroneous views that higher interest rates are approaching; and (ii) that these

[657] Woolridge Rebuttal at 15.
[658] McKenzie Surrebuttal at 2.
[659] Woolridge Surrebuttal at 5-6.
[660] Woolridge Surrebuttal at 7.

views are incorporated into the investors' decision making. Regarding methodology, Dr. Woolridge defended his use, and/or criticized Mr. McKenzie's application, of proxy groups; constant-growth DCF analysis; application of the CAPM; application of the bond yield risk premium method; inclusion of flotation cost adjustment; and final ROE recommendations.

In his Surrebuttal Testimony, Staff witness VanderHeyden defended his ROE analysis from Dr. Woolridge's criticisms regarding: (i) analysis of BGE's riskiness relative to the proxy group; (ii) removal of the IRR/DCF and Buildup methods; (iii) reasonableness of the DCF Results, including composition of the proxy group, use of Value Line equity growth rates, removal of outliers, and skewed results; and (iv) CAPM analysis, including use of historical market risk premium. Mr. VanderHeyden also provided Surrebuttal response to Mr. McKenzie's critiques regarding: (i) lack of a size adjustment in the CAPM analysis; (ii) election of the CAPM method over the ECAPM analysis; (iii) the validity of authorized ROE as a risk premium method; (iv) the need for flotation expense as a requirement for a flotation ROE adjustment; and (v) the lack of a specific adjustment for BGE's regulatory lag.

Mr. VanderHeyden testified that the results of Staff's and BGE's DCF results were very similar and that the difference in final ROE recommendation stemmed mainly from Mr. McKenzie's use of ECAPM instead of CAPM, and his use of a risk premium method based on awarded returns.[661] Additionally, Mr. McKenzie added 10 basis points for flotation costs and 30 basis points to reduce regulatory lag. In response to BGE's position that Staff had not addressed regulatory lag, Mr. VanderHeyden testified that the

[661] VanderHeyden Surrebuttal at 11-12.

Commission has already approved programs that improve regulatory lag, such as BGE's ERI, and that "an explicit upward adjustment is not necessary."[662] Additionally, Mr. VanderHeyden observed that in the past the Commission has rejected ROE adjustments related to current market conditions due to BGE's rapid filing of rate cases.[663] Mr. VanderHeyden further stated that the case has not been made that BGE is unique with regard to other utilities and regulatory lag. "The delay between investment and recovery is a known circumstance in regulated industries and is an expected characteristic of regulated utility investment."[664]

Staff witness Ward filed Surrebuttal testimony defending her elimination of two low-end DCF ROEs. She also stated that she corrected her DCF analysis in response to Mr. McKenzie's Rebuttal Testimony regarding the appropriate year to measure the dividend yield, but her change did not affect her final recommended ROE for BGE's gas distribution of 9.60.[665] Despite Dr. Woolridge's criticism, Ms. Ward defended her use of a historical market return to calculate CAPM. Finally, Ms. Ward explained that she chose her recommended ROE from the lower end of her range of reasonableness, due to an adjustment she made to account for the risk reducing effects of STRIDE.[666] Ms. Ward testified that STRIDE provides a very specific cost recovery mechanism that allows BGE to recover carrying costs in real-time, unlike the traditional rate making processes where the carrying costs are carried by the utility until the regulatory asset is put into rate base.

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[662] VanderHeyden Surrebuttal at 18.
[663] VanderHeyden Surrebuttal at 18, citing Case 9299, *Re Baltimore Gas and Electric Company,* 104 MD PSC 64, 102 (2013).
[664] VanderHeyden Surrebuttal at 19.
[665] Ward Surrebuttal at 4.
[666] Ward Surrebuttal at 7.

She testified that this mechanism provides significant risk reduction to BGE that is unlike mechanisms used by other utilities in BGE's proxy group.

**Commission Decision**

Staff witness Cross observed that pursuant to regulatory principles, regulated utilities are allowed the opportunity to recover the costs of prudently incurred debt financing and to earn a return on equity financing. The total rate at which utilities are allowed to recover financing costs is referred to as the rate of return, which in turn is determined by summing the products of the long-term debt, short-term debt, preferred stock, and common equity.[667]

No party in this proceeding disputed the proposed costs of short-term debt, long-term debt, or preference stock proposed by the Company, leaving as the only issue before us the appropriate return on equity. Witnesses for BGE, Staff, and OPC presented markedly different recommendations regarding the appropriate ROEs for the Company's electric and gas operations.[668]

The Supreme Court set forth the fundamental elements for determining a fair return on the investments of a regulated utility in the cases *Bluefield Waterwork* and *Hope Natural Gas*.[669]

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[667] Cross Direct at 13.

[668] Even though BGE in fact has no publicly traded common stock and Exelon Corporation is the Company's only shareholder (McKenzie Direct at 32), we find it appropriate to continue our policy of determining separate returns on equity for BGE's electric operations and gas distribution services. That decision is consistent with our past precedent. *See* Case No. 9230, finding "gas and electric services are separable on the Company's books, and have different financing needs." Case No. 9230, *In the Matter of the Application of Baltimore Gas and Electric Company for Revisions in its Electric and Gas Base Rates,* 102 MD PSC 74, 104 (2011).

[669] *Bluefield Co. v. Pub. Serv. Comm'n*, 262 U.S. 679, 693 (1923) ("The return should be reasonably sufficient to assure confidence in the financial soundness of the utility and should be adequate, under efficient and economical management, to maintain and support its credit and enable it to raise money necessary for the proper discharge of its public duties."); and *Fed. Power Comm'n v. Hope Natural Gas*

In those cases, the Court found that a return on equity should be: (i) comparable to returns investors expect to earn on investments of similar risk; (ii) sufficient to assure confidence in the company's financial integrity; and (iii) adequate to maintain and support the company's credit and to attract capital.[670] After having reviewed and considered the witnesses' testimony in view of the *Bluefield* and *Hope* decisions, we find that an ROE of 9.75% for BGE's electric operations and 9.65% for BGE's gas distribution services are fair and appropriate returns.

We start our discussion by observing that the witnesses used different methodologies and assumptions to estimate BGE's cost of equity. That is not a criticism. As Company witness Mr. McKenzie explained, the cost of common equity "cannot be observed directly, it is a function of the returns available from other investment alternatives and the risks to which the equity capital is exposed."[671] The determination of a fair ROE therefore requires a degree of discretion from the cost of capital expert. For example, he or she must choose which model or models to employ, how to assemble the most representative proxy group, and whether or how to exclude outliers from the analysis, to name just a few of the parameters. As OPC witness Dr. Woolridge explained, "estimating the cost of equity capital requires a degree of subjectivity in a number of areas, including the selection of models, the inputs for the models, and the measurement of the inputs for the model."[672]

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*Co.*, 320 U.S. 591, 603 (1944) ("the return to the equity owner should be commensurate with returns on investments in other enterprises having corresponding risks. That return, moreover, should be sufficient to assure confidence in the financial integrity of the enterprise, so as to maintain its credit and to attract capital."

[670] *See* Woolridge Direct at 2-3 and McKenzie Direct at 5.

[671] McKenzie Direct at 33.

[672] Woolridge Surrebuttal at 19.

The ROE witnesses used various analyses to estimate the appropriate return on equity for BGE's electric and gas distribution operations, including the DCF model, the IRR/DCF, the traditional CAPM, the ECAPM, and risk premium methodologies. Although the witnesses argued strongly over the correctness of their competing analyses, we are not willing to rule that there can be only one correct method for calculating an ROE. Neither will we eliminate any particular methodology as unworthy of basing a decision.[673] The subject is far too complex to reduce to a single mathematical formula.[674] That conclusion is made apparent, in practice, by the fact that the expert witnesses used discretion to eliminate outlier returns that they testified were too high or too low to be considered reasonable, even when using their own preferred methodologies.

The ROEs we approve for BGE's electric and gas distribution operations are consistent with what we have approved in recent years. In Case No. 9299, decided on February 22, 2013, the Commission issued an order approving an ROE of 9.75% for BGE's electric utility operations and 9.60% for BGE's gas distribution operations.[675] BGE filed its next rate case promptly on May 17, 2013, initiating Case No. 9326. In that proceeding, decided on December 13, 2013, the Commission approved the same ROEs for the Company's electric and gas operations.[676] The Commission reasoned that BGE was a "low-risk investment" based upon its status as a monopoly provider of electric and gas distribution service, its lack of ownership of any generating facilities, and its stable

[673] For example, although we agree with Staff that BGE's risk premium analysis is somewhat circular (since it considers the ROEs issued by other state regulators), we find the analysis helpful in determining a just and reasonable return.
[674] This decision is consistent with our prior precedent, where we stated: "We find all of these analytical tools helpful and will not rely on any one to the exclusion of the others in making our decision." Case No. 9326, Order No. 86060 at 76.
[675] Case No. 9299, *In the Matter of the Application of Baltimore Gas and Electric Company for Adjustment in its Electric and Gas Base Rates*, 104 MD PSC 64, 98 and 102 (2013).
[676] Case No. 9326, *Re Baltimore Gas and Electric Company*, 104 MD PSC 653, 695 (2013).

service territory with a BSA mechanism.[677] The Commission also found that the "low interest environment" provided BGE with "ample opportunity to obtain necessary capital at reasonable rates."[678] BGE's most recent rate case prior to the current proceeding was Case No. 9355, filed on July 2, 2014. That case resulted in a "black box" settlement among the parties to the proceeding, with many rate-specific details left out of the settlement. Nevertheless, the settlement provided overall rates of return for the Company and stated that the costs of equity used to determine those rates of return were 9.75% for electric and 9.65% for gas.[679] The ROEs approved today are consistent with the returns granted in Case Nos. 9299, 9326 and 9355. Rate stability is an important ratemaking goal – for ratepayers and utilities alike.[680] As Mr. VanderHeyden testified regarding returns on equity, it is important that the Commission "make gradual changes, and otherwise encourage a regulatory environment that does not surprise investors with changes that impact them adversely."[681] We believe this decision supports those laudable goals.

Beyond the importance of rate stability, the record in this case does not support a dramatically different ROE. We find that BGE continues to constitute a low-risk investment. Its status as a monopoly provider of electric and gas distribution service in a stable service territory has not changed. The Company does not own generating

[677] *Id.* at 694.. The BSA refers to BGE's Bill Stabilization Adjustment mechanism, which decouples sales of electricity from BGE's revenues. The mechanism produces risk mitigating benefits for the Company.
[678] *Id*.
[679] Case No. 9355, *Re Baltimore Gas and Electric Company*, 105 MD PSC 596, 602, n. 28 (2014).
[680] VanderHeyden Direct at 3.
[681] VanderHeyden Direct at 7.

facilities, which lowers its risk, and it enjoys other risk-reducing attributes such as the ERI initiative, the BSA decoupling mechanism, and the STRIDE surcharge.[682]

BGE has ample access to capital on good terms. Indeed, we find nothing in the record to support the notion that BGE has faced restricted or impaired access to capital under its existing rates of return. It is true that BGE's witnesses have warned of an impending storm of interest rate hikes.[683] Perhaps interest rates will increase in the future, but a sudden and dramatic increase in interest rates does not appear imminent.[684] For example, even though the Federal Reserve ended its Quantitative Easing III bond buying program in 2014, the country has not seen a significant increase in rates.[685] To the contrary, Dr. Woolridge demonstrated a slight decrease in interest rates in that timeframe and he provided compelling evidence that long-term interest rates will remain low for the foreseeable future.[686]

We decline BGE's request for a specific upward adjustment to its ROE to compensate for flotation costs. In BGE's last fully litigated rate case, we rejected BGE's request for flotation costs, reasoning that the Company had not presented any evidence

[682] Staff witness Ward and BGE witness McKenzie disagreed over whether the risk-reducing STRIDE surcharge warranted the granting of a lower ROE. Ms. Ward recommended an ROE on the lower range of her range of reasonableness, while Mr. McKenzie argued that many other gas utilities (including those in the proxy groups) possess similar mechanisms that allow for the recovery of infrastructure replacement costs. We will not make a specific downward adjustment as a result of the STRIDE mechanism, but rather consider it among many of the other factors that demonstrate to us the reasonableness of a 9.65% ROE for BGE's gas distribution operations.

[683] *See* McKenzie Direct at 15.

[684] This is not the first time the Commission has heard from BGE the dire warning that interest rates were on the verge of a steep ascent. In Case No. 9299, we responded to that argument by stating: "Whether the historic low interest rates are the result of a sluggish economy gradually recovering from a devastating recession, or are the consequence of artificial government interference in financial markets as testified by [BGE's witness], or both, they are … current reality." Case No. 9299, 104 MD PSC at 102 (internal quotations omitted). Our finding in this proceeding is the same. A low interest environment is our current reality.

[685] Dr. Woolridge Direct at 6.

[686] Dr. Woolridge Direct at 18-20. Although Dr. Woolridge provided valuable testimony to the Commission, we found his ultimate ROE recommendations too low to constitute a just and reasonable return for the Company.

that it had incurred the costs and therefore did "not satisfy the known and measurable principle."[687] Staff witness VanderHeyden correctly observed that in cases where we have awarded an ROE adjustment for flotation costs, the utility was able to provide specific evidentiary support of actual costs incurred.[688] For example, in Case No. 9336, we granted Pepco's request, stating: "We have consistently awarded flotation costs based on the verifiable costs of issuing new stock."[689] That is not the case here, where BGE has merely presented argument that investors are entitled to an adjustment for flotation on an ongoing basis whether or not the Company actually incurs such costs. We reject that argument.[690]

We also deny BGE's request for a specific adjustment to counter the effects of attrition. We find BGE's arguments on this topic unpersuasive for several reasons. First, BGE's argument amounts to a thinly veiled attack on the Commission's long-standing practice of using a historic test year to determine just and reasonable rates. *See* McKenzie Direct at 7, stating investors are concerned about what can be expected in the future, "not what they might expect in theory if a historical test year were to repeat."[691] But this Commission has consistently regulated through a historic test year because it best balances the financial needs of the regulated utility with the interests of the ratepayers in efficient and cost-effective service. It is true that the test year is unlikely to repeat itself exactly. However, the use of the test year provides the utility with a powerful incentive to control costs going forward, so that it earns or even exceeds its

[687] Case No. 9326, 104 MD PSC at 695.
[688] VanderHeyden Surrebuttal at 17.
[689] Case No. 9336, *In the Matter of the Application of Potomac Electric Power Company for Adjustments to its Retail Rates for the Distribution of Electric Energy*, 105 MD PSC 329, 370 (2014).
[690] *See* OPC Initial Brief at 55, n. 235, observing that "[t]he Commission has consistently rejected *theoretical* flotation costs." (Emphasis in original).
[691] McKenzie Direct at 7.

authorized ROE. To simply grant a utility all of its costs and disregard the test year would eviscerate that incentive.

Second, although BGE complains that it cannot earn its authorized return in an environment of rising costs, its implicit assumption that costs will always be rising is unpersuasive. BGE has spent a significant amount of ratepayer money improving the reliability of its distribution system in compliance with Commission regulations, and it has expended considerable funds building new infrastructure through installation of the AMI system. Although those expenditures are important, there is no reason to believe that that level of infrastructure spending will continue indefinitely, or even accelerate as the Company seems to argue, such that the Commission must grant to BGE an elevated ROE that is adjusted upward for so-called regulatory lag. It is within BGE's power to control its spending and thereby earn its ROE.

Third, BGE's arguments suggest a right to a *guaranteed* return, an argument we reject. *See* McKenzie Direct at 9, stating in relation to his attrition argument: "Central to the determination of reasonable rates for utility service is the notion that owners of public utility properties are protected from confiscation." It is not confiscatory to acknowledge that a regulated utility is not guaranteed a specific return. As Mr. VanderHeyden explained, the ROE is a specific calculation that is used at the time rates are set in a base rate case through the use of a historic test year.[692] The setting of an authorized ROE "does not represent an entitlement to a particular level of return over any period of time. Rates are not continuously recalculated to provide the awarded ROE."[693] In other words, in this State, rates are not based on a formula that raises and lowers revenue in order to

[692] VanderHeyden Direct at 2.
[693] VanderHeyden Direct at 2.

ensure the utility that it achieves its awarded ROE. Instead, in the interest of rate stability, rates are fixed with each case. And just as importantly, the "utility's earnings are variable based on the success of management in controlling costs and operating conditions."[694]

Finally, we deny BGE's attrition argument because the Company has filed cases on a very frequent basis. To the extent costs increase, including the surge in interest rates predicted by BGE witnesses, the Company may file a new rate case to address the changed environment.[695] In that regard, we look to our decision in Case No. 9299, where we stated: "Especially given BGE's recent predilection for filing rate cases frequently with the Commission, we see no value in awarding an anomalously high ROE during a time of historic low interest rates because of the risk that interest rates could increase several years in the future." [696]

In conclusion, we find that a return on equity of 9.75% for BGE's electric operations and 9.65% for BGE's gas distribution services complies with the standards established by *Hope* and

*Bluefield*. Those returns are comparable to returns investors expect to earn on investments of similar risk, as demonstrated through the use of the witnesses' proxy groups. They are sufficient to assure confidence in BGE's financial integrity, enabling the Company's investors to receive a fair return commensurate with risk. And the returns are adequate to maintain and support BGE's credit and to attract needed capital, as the

[694] VanderHeyden Direct at 3.
[695] *See* VanderHeyden Surrebuttal at 19: "BGE has filed rate cases on an almost annual schedule that allows the Company to rapidly increase rates in response to new investments. With this and other aspects of the rate setting process, there is no need to make an additional upward adjustment to BGE's ROE to reduce regulatory lag."
[696] 104 MD PSC at 102.

Company has successfully done with its existing returns. Given that BGE is a low-risk company, we are convinced that the returns authorized today will attract the necessary capital in the current low-interest rate environment to meet its statutory duty to provide safe and reliable service to its customers.[697]

### 2. *Capital Structure*

**Party Positions**

*BGE*

In his Direct Testimony (submitted on November 6, 2015), Mr. Vahos projected BGE's capital structure as of November 30, 2015. On the electric side, he stated that BGE's capital structure would be: 39.1% long-term debt; 5.3% short-term debt; 3.7% preference stock; and 51.9% common equity.[698] He made the same projections for the gas side. From those calculations, he derived embedded cost rates and weighted costs for each category of capital, as reproduced below.

**BGE's Requested Electric Rate of Return**

| | Capital Structure | Embedded Cost Rates | Weighted Cost |
|---|---|---|---|
| Long-term debt | 39.1% | 4.95% | 1.94% |
| Short-term debt | 5.3% | 0.80% | 0.04% |
| Preference stock | 3.7% | 7.02% | 0.26% |
| Common Equity | 51.9% | 10.60% | 5.50% |
| | **100%** | | **7.74%** |

[697] We were likewise unpersuaded by Dr. Woolridge that BGE's ROEs should be lower.
[698] Vahos Direct at 29.

**BGE's Requested Gas Rate of Return**

| | Capital Structure | Embedded Cost Rates | Weighted Cost |
|---|---|---|---|
| Long-term debt | 39.1% | 4.95% | 1.94% |
| Short-term debt | 5.3% | 0.80% | 0.04% |
| Preference stock | 3.7% | 7.02% | 0.26% |
| Common Equity | 51.9% | 10.50% | 5.45% |
| | **100%** | | **7.69%** |

BGE requested an embedded cost rate of common equity for its electric business of 10.60% and an embedded cost rate of common equity for its gas business of 10.50%. Mr. Vahos requested that the Commission approve BGE's overall rate of return for electric of 7.74% and overall rate of return for gas of 7.69%.[699] Mr. Vahos observed that it is the Commission's practice to use the actual end of test year capital structure as the approved capital structure for the utility. Acknowledging that his November 6, 2015 testimony contained projections, he stated that BGE "will update this table with actual November 30, 2015 data when the results become available."[700]

On January 5, 2016, Mr. Vahos filed his Supplemental Testimony, which presented actual test year financial data for the twelve months ending November 30, 2015. One significant change in BGE's capital structure is the update in the common equity ratio from 51.9% to 53.7%. BGE's current requested capital structure is presented below:

**BGE's Requested Electric Rate of Return**

| | Capital Structure | Embedded Cost Rates | Weighted Cost |
|---|---|---|---|
| Long-term debt | 40.0% | 4.95% | 1.98% |
| Short-term debt | 2.5% | 0.44% | 0.01% |
| Preference stock | 3.8% | 7.02% | 0.27% |
| Common Equity | 53.7% | 10.60% | 5.69% |
| | **100%** | | **7.95%** |

[699] Vahos Direct at 28-29.
[700] Vahos Direct at 28.

**BGE's Requested Gas Rate of Return**

| | Capital Structure | Embedded Cost Rates | Weighted Cost |
|---|---|---|---|
| Long-term debt | 40.0% | 4.95% | 1.98% |
| Short-term debt | 2.5% | 0.44% | 0.01% |
| Preference stock | 3.8% | 7.02% | 0.27% |
| Common Equity | 53.7% | 10.50% | 5.64% |
| | **100%** | | **7.90%** |

*Staff*

Jason A. Cross, Regulatory Economist in the Commission's Division of Telecommunications, Gas and Water, provided testimony on behalf of Staff on BGE's capital structure. He stated that utilities operate in regulated environments where regulators must balance the interests of shareholders and ratepayers. One of the matters regulators must balance is the utility's debt equity ratio – a highly leveraged company faces a higher risk of default and can incur higher costs of debt, while a utility with a high percentage of equity becomes expensive for ratepayers. Mr. Cross warned that it is important for the regulator to scrutinize the relationship between the capital structures of the parent company and the utility to ensure that the financial integrity of the utility is not being compromised.[701]

Mr. Cross observed that on January 5, 2016, BGE updated its capital structure to reflect its actuals as of November 30, 2015. The updated capital structure moved upward from 51.9% to 53.7% common equity. Mr. Cross testified that "BGE's proposed capital structure is substantially more underleveraged than the capital structures recently approved for BGE by the Commission."[702] He emphasized that BGE's "equity-heavy capital structure continues a trend of increasing equity ratios in BGE's capital structure"

[701] Cross Direct at 14.
[702] Cross Direct at 16.

over the Company's last four rate cases.[703] Mr. Cross further testified that Staff conducted a trend analysis on BGE's common equity ratio over the 18 reporting quarters between June 2011 and September 2015 and found a statistically significant positive slope, demonstrating that BGE's equity position is increasing over time.[704]

Mr. Cross also testified regarding the detriments of high equity ratios. First, he testified that high common equity ratios may result in captive rate payers being burdened with higher rates, since common equity is the most expensive component of a utility's capital structure.[705] He observed, for example, that BGE's proposed equity cost on gas operations of 10.50% is more than two times the proposed cost of its long-term debt of 4.95%. Second, Mr. Cross warned that when a utility has a higher common equity position than its parent, the parent has the ability to shift the financial risk of the corporation onto ratepayers. Because credit agencies view the stability of a company as a whole, the parent company has an incentive to increase the utility's equity position (whose higher cost is paid for through ratepayers) in order to increase its own debt ratio without facing the attendant reduction in credit rating it would otherwise face.[706] Staff compared Exelon's long-term debt ratio compared to that of BGE over the last four reporting quarters and determined that the potential exists for indirect risk shifting from Exelon to BGE, given that Exelon is "substantially more leveraged than BGE."[707] Mr. Cross concluded that "[t]his consistent and substantial difference in leverage may be a

[703] Cross Direct at 16.
[704] Cross Direct at 17.
[705] Cross Direct at 19.
[706] Cross Direct at 20.
[707] Cross Direct at 20-21.

sign that Exelon is shifting some risk indirectly to BGE."[708]

Despite the trend, Mr. Cross did not conclude that the Commission should take action to reduce BGE's equity ratio, noting that the common equity ratios in Ms. Ward's proxy group were similar, with an average common equity ratio of 53.36%. Nevertheless, Mr. Cross advised that the Commission "monitor closely BGE's capital structure going forward to ensure ratepayers aren't unfairly burdened in the future."[709]

*OPC*

OPC witness Dr. Woolridge stated in his Direct Testimony that he would adopt BGE's initial capital structure, but with the caveat that BGE's relatively high equity ratio of 51.9% "presents a lower level of financial risk than the proxy group companies."[710] In particular, Dr. Woolridge observed that BGE's proposed capitalization of 51.9% has a higher common equity ratio (and therefore less financial risk) than the averages of the two proxy groups he used in his ROE analysis.[711] Dr. Woolridge also adopted BGE's recommended senior capital cost rates.

*Party Responses*

Mr. Vahos presented Rebuttal Testimony on behalf of BGE, stating that the Company's equity ratio in this proceeding is in line with its proxy group and that it is consistent with industry benchmarks.[712] Mr. McKenzie stated that BGE's proposed

[708] Cross Direct at 21.
[709] Cross Direct at 19.
[710] Woolridge Direct at 11.
[711] Woolridge Direct at 28.
[712] Vahos Rebuttal at 29.

capital structure, with 53.7% common equity, falls within the ranges of comparable gas distribution companies, as demonstrated in his gas proxy groups.[713]

In his Rebuttal Testimony, OPC's Dr. Woolridge opposed BGE's updated capital structure, proposed by the Company with its other updates for the test year. Dr. Woolridge testified that he would not adopt the updated capital structure due to its excessive common equity ratio of 53.70%, which he noted is about five percentage points higher than the averages of his two proxy groups.[714] Specifically, Dr. Woolridge stated that the median common equity ratios of his electric and gas proxy groups are 48.6% and 47.9%, respectively. Dr. Woolridge also argued that Staff witnesses VanderHeyden and Ward erred in accepting BGE's updated capital structure without conducting any study to determine if it was appropriate for electric utility or gas distribution companies.

In his Surrebuttal Testimony, Company witness Vahos stated that BGE's actual equity ratio of 53.7% is consistent with the equity ratios of the proxy groups used by BGE witness McKenzie in determining BGE's appropriate ROE. He also cited past decisions that reflect the Commission's preference for utilizing a utility's actual end-of test year capital structure in determining the appropriate capital structure in base rate cases.[715] Mr. Vahos further argued that the primary reason BGE's equity ratio has increased in recent years is because it was required to comply with the ring-fencing requirements provided in Commission Order No. 84698 in Case No. 9271 (the Exelon-

[713] McKenzie Rebuttal at 22.
[714] Dr. Woolridge Rebuttal at 2.
[715] Vahos Surrebuttal at 2-3. He cites Case Nos. 9230, 9299, and 9326, where BGE's actual test year ending capital structure was accepted by the Commission.

Constellation merger), which constrained BGE's ability to issue dividends.[716] BGE did not issue dividends between 2012 and 2014, which Mr. Vahos argued led to a higher equity ratio. Mr. Vahos argued that comparison of BGE's actual equity ratio to OPC's proxy groups is unreliable given the flawed methodology Dr. Woolridge used in picking the proxy groups. Finally, Mr. Vahos testified that the ring fencing provisions required by the Commission in Case Nos. 9173 and 9271 created distance between BGE and its parent company for purposes of credit rating separation, thereby mitigating the concerns articulated by OPC regarding cost shifting.[717]

Mr. Cross filed Surrebuttal Testimony opposing OPC's recommendation to utilize BGE's equity ratio as filed in the Company's original Application. Mr. Cross testified that the Commission's preference has been to utilize the actual equity ratio absent evidence that the ratio would be unduly burdensome to ratepayers and that OPC has provided no such evidence.[718]

**Commission Decision**

BGE is correct that the Commission's practice is to utilize a utility's actual test-year-ending capital structure when determining its authorized rate of return in a base rate proceeding.[719] We have often stated: "It is our long-standing policy to base the utility's

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716 Mr. Vahos explained that without the ability to pay a dividend, all of BGE's earnings were retained in equity, thereby increasing the Company's equity ratio over that time period. Nevertheless, BGE began issuing dividends again 2015. Vahos Surrebuttal at 5.

717 Vahos Surrebuttal at 5-6.

718 Cross Surrebuttal at 2-3.

719 BGE Initial Brief at 53. *See also* Vahos Surrebuttal at 2-3, citing Case Nos. 9230, 9299, and 9326, where BGE's actual test year ending capital structure was accepted by the Commission.

return on its actual capital structure absent evidence that the actual capital structure would impose an undue burden on ratepayers."[720]

Nevertheless, the practice is not immutable. We have required the use of a capital structure other than the actual end-of-test year capital structure proposed by the company where the circumstances have warranted it, such as with regard to Washington Gas and Light ("WGL"). In Case No. 9104, WGL proposed a hypothetical capital structure with a common equity ratio of 56.02%. The Commission rejected the equity-heavy capital structure and approved instead WGL's year-end actual capital structure with a common equity ratio of 53.02%. (*See* Hearing Examiner's Proposed Order finding "the Company's percentage of common equity of 56.02 percent is too large and will burden ratepayers with excessive equity. … WGL has failed to meet its burden to justify such a large increase in the common equity percentage in its proposed capital structure."[721] In Case No. 9267, the Commission adopted WGL's actual capital structure over Staff's objection, but informed WGL that absent proactive measures to increase its leverage, it would consider reducing its common equity ratio for rate making purposes in future cases.[722] In Case No. 9322, WGL proposed a capital structure with a common equity ratio of 60.80%, which the Commission rejected as overly burdensome. The Commission held that "the cost imposed by WGL's high equity ratio is out of proportion

[720] Case No. 9311, *In the Matter of the Application of Potomac Electric Power Company for an Increase in its Retail Rates for the Distribution of Electric Energy*, 104 MD PSC 292, 347 (2013).
[721] Case No. 9104, *In the Matter of the Application of Washington Gas Light Company for an Increase in Rates and Charges for Gas Service and to Implement a Performance-Based Rate Plan*, Oct. 5, 2005 Proposed Order of Hearing Examiner at 42.
[722] Case No. 9267, *In the Matter of the Application of the Washington Gas Light Company for Authority to Increase Its Existing Rates and Charges and to Revise Its Terms and Conditions for Gas Service*, Order No. 84475.

to that of other utilities" and imputed a capital structure of 53.02% common equity.[723] Part of the Commission's rationale for reducing WGL's common equity in that case was that WGL's non-regulated parent company "has been able to leverage much of its non-utility, competitive affiliate risk onto WGL and its ratepayers."[724] Additionally, the Commission observed that if WGL successfully reduced its equity ratio, "the award of a high equity ratio now would enable WGL to reap a windfall because its rates would be based on an excessive equity ratio that far exceeds [its] actual capital structure."[725] (Internal quotations omitted).

In the present case, BGE has significantly increased its equity ratio from 51.9%, as reported in Mr. Vahos' November 6, 2015 Direct Testimony, to 53.7%, as stated in his January 5, 2016 Supplemental Testimony.[726] We find troublesome the substantial increase of 180 basis points in slightly over two months, especially given the magnitude of infrastructure that the Company has moved into rate base in this proceeding. Mr. Cross testified on behalf of Staff that "BGE's proposed capital structure is substantially more underleveraged than the capital structures recently approved for BGE by the Commission."[727] He explained that the Company's "equity-heavy capital structure continues a trend of increasing equity ratios in BGE's capital structure" over the Company's last four rate cases. That trend is illustrated in the chart below.[728]

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[723] Case No. 9322, *In the Matter of the Application of Washington Gas Light Company for Authority to Increase Its Existing Rates and Charges and to Revise Its Terms and Conditions for Gas Service*, Order No. 86013 at 9.
[724] Order No. 86013 at 11.
[725] Order No. 86013 at 11.
[726] Vahos Direct at 29.
[727] Cross Direct at 16.
[728] Cross Direct at 16.

**Common Equity Ratios in Last Six BGE Rate Cases**[729]

| Case No. | Year | Common Equity Ratio |
|---|---|---|
| 9036 | 2003 | 48.40 |
| 9230 | 2010 | 51.93 |
| 9299 | 2012 | 48.40 |
| 9326 | 2013 | 51.05 |
| 9355 | 2014 | 52.30 |
| 9406 | 2015 | 53.70 |

Moreover, Staff's trend analysis over 18 reporting quarters of BGE's common equity ratio demonstrates a statistically significant increase in BGE's equity position over time.[730]

At the time of filing of his Direct Testimony, Dr. Woolridge's position was that BGE's actual capital ratio of 51.9% should be accepted, with the caveat that BGE presented a lower level of financial risk than his proxy group companies. However, after reviewing Mr. Vahos' Supplemental Testimony with the substantial change in capital structure, he argued that BGE's equity ratio should be set at the number provided by the Company when it filed its Application.[731] He observed that BGE's proposed common equity ratio is approximately five percentage points higher than the averages of his two proxy groups.[732] In its Initial Brief, OPC further stated that the Company's equity ratio is outside the range authorized in Maryland's last several electric rate cases or the averages for other electric companies.[733]

Overly high equity ratios impose significant burdens on ratepayers. As Mr. Cross testified, high common equity ratios may result in captive rate payers being burdened with higher rates, since common equity is the most expensive component of a utility's

[729] From Cross Direct at 17.
[730] Cross Direct at 17.
[731] Woolridge Direct at 11.
[732] Dr. Woolridge Rebuttal at 2.
[733] OPC Initial Brief at 61, citing Tr. at 1468.

capital structure.[734] Clearly BGE's authorized 9.75% return for electric and 9.65% return for gas are substantially above BGE's long-term debt of 4.95%. Additionally, when a utility has a higher common equity position than its parent, the parent has the ability to shift the financial risk of the corporation onto ratepayers.[735] Indeed, the potential of risk shifting was a significant driver in the Commission's decision to disallow WGL's proposed capital structure in the proceedings cited above. In the present case, Staff found that the potential exists for indirect risk shifting from Exelon to BGE, given that Exelon is "substantially more leveraged than BGE."[736] We concur with Staff's observation. Additionally, during the hearing, Mr. Cross conducted calculations that revealed that the burden to ratepayers of accepting BGE's updated capital structure, rather than its original one, is in the range of $4.5 to $4.6 million.[737] We find that cost imposes an undue burden on ratepayers.

In defense of BGE's position, Mr. Vahos argued that the Company's equity ratio increased as a direct result of it compliance with Commission-mandated ring-fencing provisions, which the Commission required as part of its approval of the Exelon-Constellation merger.[738] Specifically, Mr. Vahos claimed that BGE's high equity ratio stemmed from merger conditions that prohibited the Company from issuing dividends between 2012 and 2014, thereby driving upward retained earnings. Nevertheless, Mr. Vahos' defense does not explain the sudden increase in the Company's common equity

[734] Cross Direct at 19.
[735] Cross Direct at 20.
[736] Cross Direct at 20-21. Mr. Cross concluded that "[t]his consistent and substantial difference in leverage may be a sign that Exelon is shifting some risk indirectly to BGE." *Id*. at 21.
[737] Tr. at 1488.
[738] Vahos Surrebuttal at 5. Commission Order No. 84698 in Case No. 9271 (the Exelon-Constellation merger) provided at page 113, Condition 31: "BGE to Retain Internally Generated Equity Through 2014: BGE will not pay a dividend on BGE's common shares through the end of 2014."

that was revealed to the Commission through his Supplemental Testimony, only about two months after the Company's initial Application. During that time, BGE was authorized to and did issue dividend payments.[739] Indeed, BGE was not prohibited from issuing dividends throughout all of calendar year 2015, which comprises ten months of the test year. If, as BGE implies, it is able to lower its equity ratio in the near future, the Company would be reaping a windfall because its rates would be based on an excessive equity ratio that exceeds its actual capital structure. Especially given the large amount of infrastructure the Company has placed into rate base in this proceeding, we find that result would be inequitable. Accordingly, we accept OPC's position that BGE's updated capital structure be rejected, and instead we adopt BGE's original capital structure which includes 51.9% common equity.

## D. Cost of Service Studies (COSS)

The purpose of a cost of service study ("COSS") is to determine the costs a customer class, or in some cases a jurisdiction, imposes upon a company. Costs may be directly assigned or allocated based upon various allocation methodologies. Once costs are assigned, then class (and jurisdictional) rates of return can be developed, which are used to design customer rates. The Commission uses the results from cost of service studies ("COSSs") as a guide in developing appropriate customer class rates.

### <u>Party Positions</u>

*<u>BGE</u>*

Company witness Greenberg presented BGE's Calendar Year 2014 Company Recommended Electric Actual Cost of Service Study Proformed ("ECOSS") and the

[739] Tr. at 161, 764, and 1317.

Calendar Year 2014 Company Recommended Gas Actual Cost of Service Study Proformed ("GCOSS"). He noted that the Company's Studies were adjusted: "to reflect the base rate increases agreed to in the Unanimous Stipulation and Settlement Agreement ("Settlement Agreement") in Case No. 9355, which was accepted by the Commission in Order No. 86757."[740] Additionally, the studies have been adjusted to reflect the impact of Smart Grid costs on 2014.[741]

Mr. Greenberg stated that the "overall objective of BGE's 2014 ECOSS and GCOSS is "to present a fair allocation of costs responsibility among the customers classes based on the contribution of each class to total system costs during calendar year 2014..."[742] He stated that information from the ECOSS and GCOSS provides (1) a framework to help determine how the total revenue requirement should be recovered from each rate schedule based upon the proposed base revenue increase, and (2) a guide to proper rate design of Delivery Prices, Demand Prices and monthly Customer Charges.[743] According to Mr. Greenberg, in an ECOSS and GCOSS system costs are identified by customer class through a three-step process: (1) Functionalization; (2) Classification; and (3) Allocation.[744]

Functionalization is the process of dividing rate base and expenses into components as they relate to the operation of the Company.[745] BGE functionalizes its electric delivery service assets and expenses as transmissionor distribution operations,

[740] Greenberg Direct at 2-3.
[741] *Id*.
[742] Greenberg Direct at 4.
[743] Greenberg Direct at 4-5.
[744] Greenberg Direct at 6.
[745] *Id*.

excluding electric supply costs from the ECOSS.[746] Electric transmission costs which are subject to the Federal Energy Regulatory Commission ("FERC") are not included in the ECOSS for the purpose of distribution service ratemaking before the Commission.[747] BGE functionalizes its gas delivery service assets and expenses as production, storage or distribution operations, excluding gas commodity costs from the GCOSS.[748]

Classification is the process of separating the gas and electric functionalized rate base and expenses into classifications that relate to how costs are caused.[749] For example, distribution-related costs are classified between demand and customer-related components whereas demand-related costs are driven by customer class coincident peak ("CP") or non-coincident peak ("NCP") demand levels; and customer-related costs are driven by the number and costs of customers connecting to the gas mains and/or electric transformer and the requirements for the utility to service those customers (i.e., metering, meter reading, account processing, and billing systems).[750] Occasionally, distribution costs are classified as energy-related due to their variable nature.[751]

The final step in the cost of service study is Allocation, "in which rate base and expenses in each of these classified cost categories are assigned to customer classes according to customer load impositions on the distribution system, customer classes according to customer load impositions on the distribution system, customer connection requirements, and/or customer usage."[752]

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[746] Greenberg Direct at 6.
[747] Greenberg Direct at 6.
[748] Greenberg Direct at 6.
[749] Greenberg Direct at 7.
[750] *Id*.
[751] *Id*.
[752] Greenberg Direct at 7.

Mr. Greenberg testified that the Company made two adjustments to the recommended ECOSS and GCOSS in this proceeding: (1) adjusted the distribution revenue in order to reflect the approved rates from Order No. 86757 in Case No. 9355 so that ECOSS and GCOSS reflect delivery, demand, and customer charges as if the most recently approved rates were in effect a full calendar year not just the last two weeks of December, and (2) adjusted the ECOSS and GCOSS so that BGE's Smart Grid Initiative are appropriately reflected in each class' relative rate of return.[753] Mr. Greenberg explained that in order to fairly allocate cost responsibility for the Smart Grid Initiative among customer classes, an adjustment is needed to both ECOSS and GCOSS to reverse the deferral of incremental Smart Grid related depreciation, amortization, return and property taxes that would otherwise have been reflected on the income statement in 2014.[754]

In addition to these changes, Mr. Greenberg testified that the 2014 ECOSS and GCOSS made one "notable change in methodology from the studies filed in the last rate case proceeding, Case No. 9355."[755] Specifically, in the Settlement Agreement in Case No. 9355, BGE agreed to provide in the next electric rate case "(1) a five (5) year comparison of annual systems class demand allocators and allocations; and (2) a study of how any trends or changes affect the relative rates of return of the various electric rate classes."[756] BGE conducted the study for electric demands as requested by the Commission and provided the results in Company Exhibit DEG-5. BGE voluntarily conducted the same study for gas and provided those results in Company Exhibit DEG.

[753] Greenberg Direct at 9. *See also* Greenberg Direct at 10.
[754] Greenberg Direct at 10
[755] Greenberg Direct at 11.
[756] Greenberg Direct at 11.

Based on the results of these studies, BGE decided to utilize in its recommended ECOSS and GCOSS demand allocators based upon the five-year average of the BGE customer class non-coincident peak demand (NCP) and coincident peak demand (CP). Mr. Greenberg asserted that use of the five-year average demand allocator along with the inclusion of the Smart Grid costs and the rates approved in Case No. 9355 have impacted the class relative rates of return (RROR) by moving certain classes towards the system average rate of return while moving others further away from the system average rate of return. Mr. Greenberg also testified that "use of the five year demand allocators has improved the returns of certain weather sensitive schedules that would have otherwise received a larger demand related costs allocation due to abnormally cold weather in 2014.[757] The charts below compare the Company's proposed 2014 ECOSS and GCOSS relative rates of return in this proceeding to the relative rates of return filed in Case No 9355.

[757] Greenberg Direct at 12.

**Table 1. ECOSS and GCOSS Relative Rate of Returns**
**Pro Forma 2013 vs Pro Forma 2014**

| | ECOSS RROR | |
|---|---|---|
| Schedule | 2013 Filed | 2014 Proposed Uses 5-Year Demand Allocator Results |
| R | 0.75 | 0.69 |
| RL | 1.26 | 0.85 |
| G* | 1.05 | 1.00 |
| GS | 2.25 | 2.23 |
| GL | 1.41 | 1.58 |
| P | 0.88 | 1.08 |
| SL | 1.59 | 1.97 |
| PL | 3.27 | 3.92 |
| T | 7.18 | 6.90 |
| SYSTEM TOTAL | 1.00 | 1.00 |

*includes Schedule GU

| | GCOSS RROR | |
|---|---|---|
| Schedule | 2013 Filed | 2014 Proposed Uses 5-Year Demand Allocator Results |
| D | 1.06 | 0.99 |
| C | 0.88 | 1.01 |
| ISS | 0.81 | 0.94 |
| IS | 0.90 | 1.15 |
| PLG | 7.88 | 8.79 |
| SYSTEM TOTAL | 1.00 | 1.00 |

Mr. Greenberg explained that the ECOSS was developed to allocate costs to individual classes and then “match” distribution revenues from each rate class with rate base and expenses allocated to the given class.[758] Mr. Greenberg emphasized the

[758] Greenberg Direct at 15.

importance of understanding NCP and CP when allocating ECOSS. He noted that "use of the NCP in the allocation of demand-related distribution investment is the generally accepted methodology in the ECOSS development"[759] and that electric NCP demands for residential class are typically driven by weather sensitive house cooling load, which generally occurs during the summer months.[760] In 2014 the residential NCP occurred during January due to the extremely cold winter weather.[761] The NCP winter peak indicates that the residential demand is driven by electric resistance heating load whereas, historically, the residential NCP has been driven by summer cooling load.

The GCOSS is developed to allocate costs to individual classes and the "match base revenues derived from each rate class with rate base and expenses allocated to the given class.[762] For GCOSS, demand-related costs are allocated to customer classes based on CP and NCP demands. The CP allocator is the firm class' contribution to the total firm service send out on the day of the year with the highest firm send out (January 7, 2014).[763] The NCP allocator is based on each class' (including Schedule IS and Schedule ISS) highest hourly demand.[764] In other words, it is the maximum hourly demand observed during the winter months of every class regardless of the hour or the day.[765] Each class's contribution to the NCP is calculated by dividing that class' maximum hourly demand during the winter months by the sum of every class' maximum hourly demand.[766]

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[759] Greenberg Direct at 17.
[760] Greenberg Direct at 17.
[761] Greenberg Direct at 19.
[762] Greenberg Direct at 19.
[763] Greenberg Direct at 31.
[764] Greenberg Direct at 32.
[765] Greenberg Direct at 32-33.
[766] Greenberg Direct at 33.

For ECOSS, all Smart Grid costs are classified as customer-related, assigned the CUST370DIR allocator and are allocated to customer classes based upon corresponding smart meter replacement costs. For the 2014 ECOSS, the Company used smart metering data in the determination of demand measures (CP and NCP) in the Schedules R, RL G, GS and GL customer classes.[767] For GCOSS, all Smart Grid costs are classified as customer-related, assigned the CUST381DIR allocator and allocated to customer classes based upon corresponding smart metering device replacement costs.[768] In GCOSS, Smart Grid costs are allocated to Schedule D and Schedule C.[769]

Mr. Greenberg noted that given the penetration of smart metering devices in 2014, there is no longer a need for traditional sampling methods for these classes due to the large volume of Smart Grid data points.[770]

In the ECOSS, the Company measures residential customer peak kW demand (Schedule R, Schedule RL) in aggregate on an hourly basis. Similarly, the Company measured all small commercial customer peak demand (Schedule G and Schedule GS) in aggregate on an hourly basis and the individual peaks for these schedules are determined at the time of the total small commercial peak.

Under the Company's recommended ECOSS and GCOSS, the customer class rate base dollar allocations and the corresponding class rate of return ratios to system average return are depicted in the charts below.

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[767] Greenberg Direct at 25.
[768] Greenberg Direct at 31.
[769] Greenberg Direct at 31.
[770] Greenberg Direct at 25. *See also* Greenberg at 33.

**Table 2. Comparison of Rate Base Dollar allocation and Class Rate of Return Ratios for 2014 Recommended ECOSS and GCOSS**

| | 2014 ECOSS | |
|---|---|---|
| Schedule | Rate Base | RROR |
| R | 1,565.2 | 0.69 |
| RL | 128.8 | 0.85 |
| G* | 292.8 | 1.00 |
| GS | 9.8 | 2.23 |
| GL | 565.2 | 1.58 |
| P | 203.7 | 1.08 |
| SL | 66.0 | 1.97 |
| PL | 25.6 | 3.92 |
| T | 2.1 | 6.90 |
| SYSTEM TOTAL | 2,859.2 | 1.00 |

*includes Schedule GU

| | 2014 GCOSS | |
|---|---|---|
| Schedule | Rate Base | RROR |
| D | 737.7 | 0.99 |
| C | 300.9 | 1.01 |
| ISS | 6.1 | 0.94 |
| IS | 60.6 | 1.15 |
| PLG | 0.03 | 8.79 |
| SYSTEM TOTAL | 1,105.3 | 1.00 |

*OPC*

OPC witness Wallach argued that "contrary to the cost causation principles, the ECOSS does not allocate Smart Grid Initiative costs to customer classes commensurate with the allocation of Smart Grid benefits to those classes."[771] Therefore, he indicated that the ECOSS over allocates Smart Grid costs to the R and RL classes. Mr. Wallach contends that given that Smart Grid costs represent the bulk of the Company's requested revenue requirement increase, it would not be reasonable to allocate the requested

[771] OPC Initial Brief at 67 citing Wallach Direct at 22-23.

increase on the basis of the ECOSS. Rather he recommended that the revenue increase be allocated along the rate classes, except for Schedule T and Schedule PL classes, in proportion to each class's base distribution revenues under current rates.[772]

Mr. Wallach noted that BGE's Smart Grid Initiative was a discretionary program and the Company justified its spending on the Smart Grid Initiative in Case No. 9208 primarily on the basis of the economic benefits that would result from the Smart Grid investment. Specifically, in Case No. 9208, the Company argued that "despite the very significant cost of this proposed initiative, the benefits to customers are several times greater, conservatively estimated by BGE to be $2.6 billion over the life of the project, along with considerable additional benefits to reliability, service quality, and environmental objectives."[773] Since the primary driver behind BGE incurring the Smart Grid costs were the purported benefits that would be brought to customers, Mr. Wallach testified that "the equitable allocation would be one where each customer class's allocation of Smart Grid costs would be no more than that class's share of the system-wide benefits."[774] Mr. Wallach explained that the approach of allocating Smart Grid costs commensurate with benefits is consistent with NARUC definition of cost causation.[775]

Mr. Wallach suggested that because BGE did not incorporate a reasonable analysis of the forecasted economic benefits from the Smart Grid in the cost allocations, he developed a simplified allocation approach to the residential class of the operational and market benefits claimed by the Company for 2014.

[772] OPC Initial Brief at 67 citing Wallach Direct at 11.
[773] OPC Initial Brief at 67-68.
[774] Wallach Surrebuttal at 4.
[775] OPC Initial Brief at 68.

Mr. Wallach proposed to "allocate all of the avoided capacity and energy-conversation benefits to the residential class"[776] and "for all other operational or market benefits, he estimated the residential class's share of 2014 savings using appropriate allocators from the 2014 ECOSS."[777] Based on his approach, Mr. Wallach estimated that about 66% of 2014 operational and market benefits will flow to residential customers[778] which are substantially less than the share of the Smart Grid costs allocated to the residential class in BGE's 2014 ECOSS which is 81%.[779] Therefore, Mr. Wallach strongly argues that the Commission should reject the BGE's proposed allocation of the requested revenue increase to the residential class. "Instead, the revenue increase authorized by the Commission should be allocated among all rate classes except for Schedule T and PL classes in proportion to each class's base distribution revenues[780] under the current rates."

*Staff*

Staff witnesses Norman and Cross presented testimony on the Company's 2014 ECOSS and GCOSS. For the ECOSS, Ms. Norman does not support the Commission adopting the proposed five-year average demand allocator at this time. She testified that in Case No. 9355 the data was requested based on concerns expressed in an earlier proceeding that changes in RROR of the classes may be the result of shifts in load responsibility among the classes and the Commission may need a regulatory policy on

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776 OPC Initial Brief at 69.
777 OPC Initial Brief at 69.
778 OPC Initial Brief at 69.
779 OPC Initial Brief at 70.
780 OPC Initial Brief at 70.

how cost responsibility is established in the face of declining demand.[781] According to Ms. Norman the study of the five-year average demand allocators was requested to provide understanding of "the drivers of changes in demand across customer classes and the subsequent impact on allocation of costs."[782] Ms. Norman contends that while the five-year study is informative there are no clear trends that are readily identifiable in the five year data provided.[783] Mr. Cross concurs with Ms. Norman's assessment of the applying the five-year study for 2014 GCOSS. Neither Staff witnesses Norman nor Cross endorsed the use of the five-year average demand allocator at this time. Specifically, Ms. Norman explained during cross examination that "We don't have a clear understanding of what's driving those changes in demand. They [BGE] didn't perform that analysis…[sic] we don't know what's being smoothed out here and how relevant it is to changes that the company might have in their cost in the test year as opposed to previous years. And absent that knowledge we're reluctant to change at this time"[784] For these reasons, Staff recommended adoption of the RROR shown in the charts below for BGE 2014 ECOSS and GCOSS.

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[781] Staff Brief at 56.
[782] Staff Brief at 56.
[783] Staff Brief at 56.
[784] Staff Brief at 57.

**Table 3. Staff Recommended ECOSS and GCOSS Relative Rate of Returns**[785]

| Schedule | 2014 Staff Recommended ECOSS 1-Year Demand Allocator |
|---|---|
| R | 0.67 |
| RL | 0.65 |
| G* | 1.15 |
| GS | 1.53 |
| GL | 1.64 |
| P | 1.08 |
| SL | 1.95 |
| PL | 3.78 |
| T | 6.93 |
| SYSTEM TOTAL | 1.00 |

*includes Schedule GU

| Schedule | 2014 Staff Recommended GCOSS 1-Year Demand Allocator |
|---|---|
| D | 0.96 |
| C | 1.02 |
| ISS | 1.33 |
| IS | 1.35 |
| PLG | 10.49 |
| SYSTEM TOTAL | 1.00 |

*MEG*

MEG witness Baudino did not oppose BGE's use of the five year average allocation factors in its 2014 ECOSS and GCOSS.[786] Mr. Baudino did note that since Company witness Greenberg testified that using the five-year average NCP and CP allocators for the ECOSS and GCOSS "provide for an appropriate allocation of demand-

[785] *See* Norman Direct at 19 and Cross Direct at 9.
[786] Baudino Direct at 5.

driven costs that incorporate demand patterns over a long time horizon" the five year study may provide the Commission with helpful information when used in conjunction with the standard one year study.[787] Mr. Baudino proposed that the Commission direct BGE to continue to provide the five year study and the year-by-year comparisons in future rate cases for both ECOSS and GCOSS.[788]

**Commission Decision**

The Commission uses cost of service studies *as a guide* in developing customer class rates. The Company presented both a 2014 Recommended ECOSS and GCOSS, which incorporated a five-year average demand allocator for determining the relative rates of return for each class. Additionally, the Company's 2014 Recommended ECOSS and GCOSS adjusted the ECOSS and GCOSS so that BGE's Smart Grid Initiative costs are appropriately reflected in each class' relative rate of return.

Staff opposed adoption of the five-year average demand allocator at this time because there is simply not enough evidence to determine what may be driving the changes in demand and because "the study does not address trends in peak demand across classes overtime in sufficient detail to allow Staff to recommend adopting the averaged allocator."[789] MEG did not oppose use of the five-year average demand allocator study and agreed that the information may be useful when used in conjunction with the one-year study. Therefore, MEG requested that the Commission direct BGE to continue to

[787] Baudino Direct at 5 and 19.
[788] OPC Brief at 11.
[789] Staff Brief at 57

provide the five year study and the year-by-year comparisons in future rate cases for both ECOSS and GCOSS.[790]

Based upon the record we find that BGE has not provided sufficient evidence for us to abandon the traditional one-year demand allocator study for the proposed five-year demand allocator study. Therefore, we adopt Staff's recommended RROR based on the traditional one-year allocator study and direct BGE to continue to provide the five-year demand allocator study for both electric and gas in future rate cases.

Second, we note that OPC's witness Wallach offers a benefits approach for allocating the Smart Gird Initiative costs among rate classes. According to Mr. Wallach, by allocating the Smart Grid costs on the basis of traditional cost causation principles rather than on the basis of expected benefits, the ECOSS over-allocates costs to the residential class. While there may be some merit to this approach, the Commission agrees with Staff witness Norman that "an approach based on benefits is not viable in this proceeding given the lack of information."[791] Nonetheless, with a more detailed analysis of the benefits approach allocation of costs between rate classes, we may consider utilizing it in future rate cases.

### E. Rate Design

Rate design involves two functions: (1) the design of inter-class rates, which involves the assignment of the 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

[790] OPC Brief at 11.
[791] Staff Brief at 60.

much of any rate increase (or decrease) should be assigned to a particular customer rate class, we begin with the actual class rates of return reflected in the cost of service study ("COSS"). These results are then translated into a relative rate of return ("RROR"), 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.[792] A RROR of 1.0 signifies that a rate class has a return equal to the utility's overall rate of return. A RROR that is higher than 1.0 indicates that the class has a return (or contribution) that is greater than the system average and a RROR that is lower than 1.0 indicates a class return that is less than average. If all customer rate classes have a 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 policy, the Commission strives to bring all classes closer to a 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, BGE customers have an energy charge, which is designed to recover variable costs. Finally, some non-residential customers have a demand charge, which is designed to recover capacity costs. Intra-class rate design is guided by important policy considerations,

[792] *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).

including gradualism, energy conservation, economic impacts, as well as cost causation.[793]

In this case, BGE proposes significant increases in fixed monthly customer charges and proposes higher than average allocations of cost among various customer classes. The Company asserts that the installation of smart metering devices for residential and small commercial customers has effectively eliminated any difference between the costs to serve residential electric customers under Schedules R and RL and small commercial customers under Schedules G[794] and GS.[795] As a result, under BGE's rate design proposals in this case, the bulk of the Company's proposed rate increases for electric and for gas customers would be borne by residential and small commercial customers.

For reasons that will be discussed in greater detail below, we reject: the Company's proposed 37.5 percent increase in the Schedule R (residential) customer charge; the Company's proposed 34.3 percent increase in the Schedule G (small commercial) customer charge; and the Company's proposed 13.3 percent increase in the Schedule D (residential gas) customer charge. Also, by rejecting the Company's proposal to adjust customer class relative rates of return (RRORs) using five-year average cost of service data, and accepting Staff's RROR adjustments – which are based on Commission precedent – we further moderate the impact of the allocation of the Company's electric and revenue increases on all customers.

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[793] *Id.*
[794] Schedule G includes Primary (GP) and Unmetered (GU) services.
[795] BGE Initial Brief at 69. BGE recognizes that the Commission has been reluctant to approve large changes in customer charges in the past, but insists that now that the Company is attempting to recover the costs of Smart Grid (which BGE asserts is "largely customer-related in nature") it is appropriate to take a larger step in aligning customer charges with actual costs. BGE Reply Brief at 72.

OPC notes, and we agree, that contrary to cost-causation principles, the ECOSS does not allocate Smart Grid Initiative costs to customer classes commensurate with the allocation of Smart Grid benefits to those classes.[796] Therefore, we allocate the revenue increase authorized in this case among all rate classes, except Schedules T and PL, in proportion to each class's base distribution revenues under current rates.[797] We turn now to address specific inter- and intra-class revenue allocation adjustments.

### 1. ***Electric and Gas Customer Charge Adjustments***

*BGE*

BGE witness Frain proposed that certain residential and commercial class customer charges be increased – based on the results of the Company's 2014 electric and gas cost of service studies (ECOSS and GCOSS), including the impact of the deployment of smart metering devices.[798] According to Mr. Frain, at present – except for electric rate Schedules PL and PLG – the rate schedules for all customer classes include a volumetric component that covers a significant amount of the distribution portion of the customer bill.[799] He adds that while a significant portion of the costs supporting both the electric and gas distribution systems are demand-related, only a few customer schedules

[796] *See* OPC Initial Brief at 67. The ECOSS over-allocates Smart Grid costs to the R and RL rate classes. *Id.*

[797] MEG questioned whether the Commission has ever allocated the costs of specific investments based on benefits. Tr. at 1359. However, Mr. Wallach commented further that to the extent that the driver of a "discretionary investment" were the expected benefits, then the costs associated with that investment should be allocated "commensurate with" the expected benefits. *Id.* at 1361, 1371. He insists that what caused the smart grid costs to be incurred by BGE were "the expectation of benefits" and those benefits (he opines) are shared by customer classes other than the classes which have smart meters installed in their premises or on their locations. *Id.*

[798] BGE Ex. 18, Frain Direct at 7.

[799] *Id.* at 9. (At present approximately 80 percent of residential electric customers' fixed costs and approximately 65 percent of residential gas customers' fixed cost are recovered through volumetric charges; much higher, he submits, than the ECOSS and GCOSS support being recovered through volumetric rates.) *Id.*

(typically those customers with high usage) actually have demand elements in their rate design.[800]

He opines that increasing the customer charges for residential and small commercial electric and gas customers, as BGE proposes, would not substantially affect the current price signals to these customers (the price signals that encourage or discourage energy efficiency).[801] According to witness Frain, the customer charge adjustments proposed by BGE in this case shift (on average) 3 percent of residential electric customers' costs from variable commodity costs to fixed charges. Residential gas customers' fixed charges increase by 1 percent as compared with current rates and by 3 percent based on new rates, without the proposed increased customer charge.[802]

The Company proposes to achieve its customer charges adjustments by increasing the fixed customer charges for Schedules R and G to the level of Schedules RL and GS respectively, and increasing the fixed customer charge for the Schedule D gas rate class.[803] Specifically, the Company proposes to increase residential and small commercial electric and gas customers: Electric Schedule R from $7.50 to $12.00; Electric Schedule G from $11.50 to $17.50; and Gas Schedule D from $13.00 to $15.00.

Under BGE's proposal, residential electric customers' customer charge would increase $4.50 per month, residential gas customers' customer charge would increase $3.00 per month. The Company also proposes increasing the customer charge for

[800] *Id.* at 9. Most residential and small commercial meters, Mr. Frain noted, have not historically measured demand. *Id.*
[801] *Id.* According to witness Frain, "even if the entire distribution portion of the bill was a fixed charge, the customer would still receive appropriate price signals to encourage energy efficiency through their commodity savings; [noting that] approximately 70 percent of am average residential electric customer's bill was commodity-related and approximately 30 percent was distribution-related in 2014." *Id.*
[802] *Id.* at 12 (Table 1).
[803] *Id.* at 13.

Schedule G, a schedule that serves small commercial customers, from $11.50 per month to $17.50 per month. Witness Frain nonetheless maintains that the bill impact of the Company's proposed customer charge increases is minimal.

According to Mr. Frain, the monthly bill impact for a Schedule R residential customer under the Company's proposal, using 930 kWh per month (on a weather normalized basis), would be about $0.33 more if the Company's proposed customer charge increase (and other ratemaking adjustments) is accepted.[804] Similarly, with respect to residential gas customers, Mr. Frain testifies that at a consumption level of 57 therms per month, "a Schedule D customer is economically indifferent" to the Company's proposed customer charge increase.[805]

In defense of the Company's proposed customer charge adjustments, witness Frain restates that under the Company's current rate structure, a large portion of these fixed costs are instead recovered through the variable charges on a customer's bill and that customers with higher than average usage are subsidizing the fixed costs of those customers with lower than average usage.[806] He insists that BGE's proposed customer charge increases should work towards reducing the intra-class inequities between the recovery of fixed and variable costs.[807] He concludes that the Company's proposal "improves intra-class equity while still balancing other goals of the rate design process, as well as energy efficiency objectives."[808]

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[804] *Id.* at 14.
[805] *Id.* at 15.
[806] *Id.* at 16.
[807] *Id.*
[808] *Id.* at 17.

BGE witness Frain testified that the proposed allocation of BGE's requested electric revenue increase is based primarily upon the relative returns of each customer class calculated in the Calendar Year 2014 ECOSS.[809] Likewise, the rate design (allocation) for the proposed gas revenue increase is based primarily upon the relative returns of each customer class calculated in the Calendar Year 2014 GCOSS.[810]

According to BGE, the current functionalized customer component cost levels for certain electric and gas customer classes warrant an increase in the level of fixed customer charges.[811] Witness Frain emphasizes that this is demonstrated "especially in light of the Smart Grid costs now included in the customer component of the [ECOSS and GCOSS] studies."[812] Accordingly, he proposes to eliminate the difference in the fixed customer charges for Time-of-Use ("TOU") and non-TOU electric customer classes and increasing the fixed customer charge for the residential gas customer class.[813]

*Staff*

Staff witness Blaise recommends that the customer charge for BGE Schedule R be increased only from $7.50 to $7.90 per month. He notes that BGE's attempt to equalize both the customer and volumetric charges under Schedule R, particularly with significant proposed increase in the residential-customer customer charge, does not comport with principles of gradualism and the energy policy goals instituted under EmPOWER MD.[814] Limiting the residential-customer customer charge increase to $0.40

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[809] *Id.* at 2-3.
[810] *Id.* at 3. Both studies were developed as discussed in the testimony of BGE witness Greenberg.
[811] *Id.*
[812] *Id.*
[813] BGE witness Frain estimates that there are about 55,000 TOU customers remaining on the BGE system. Tr. at 553.
[814] Staff Ex. 44, Blaise Direct at 2.

per month, and instead capturing the incremental increase in volumetric charges, witness Blaise concludes is "fair to the Company, [and] consistent with the principles of gradualism."[815] Staff urges that this approach provides customers more control over their bills and promotes policy goals of energy efficiency as outlined in the EmPOWER Maryland Act.[816]

Witness Blaise also proposed a slight increase in the Schedule G customer charge, allowing BGE to collect $0.071 in customer charge revenue for every dollar the Company collects in volumetric charges, proposing to increase the Schedule G customer charge from $12.50 to $12.64.[817] Staff also proposed increasing the Schedule GS customer charge from $17.50 to $19.23.[818]

In response to BGE's proposed gas customer charge adjustment, Staff witness Pongsiri opposed increasing the Schedule D customer charge from $13.00 to $15.00. Instead, he recommends an increase to $14.00, representing a 7.7 percent increase in the gas Schedule D customer charge – as compared to the Company's proposed 15.4 percent increase.[819] Based on a sensitivity study of the impact of customer charges on low-income customer bills, Mr. Pongsiri's testimony suggests that his recommended increase in the customer charge from $13.00 to $14.00 as compared to BGE's proposal to increase

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[815] *Id.*

[816] *Id.* at 17. Staff also notes that increasing the Schedule R customer charge to $12.00 as BGE proposes, would move BGE's residential electric service customer charges to the highest among Maryland utilities. Tr. at 515-517.

[817] *Id.* at 16. Increasing the customer charge by 9.9 percent. Staff notes that not only does BGE propose to increase Schedule R and G customer charges, the Company also proposed increases to the volumetric charge for Schedules R and RL. Staff calculates that, if approved, the Company's proposed rate adjustments to these customer classes would lead to the collection of 88.1 percent of the total allocation of the new revenue proposes by BGE being assessed to these classes. Staff Ex. 44 at 9; Staff Initial Brief at 67.

[818] Staff Ex. 44, Blaise Direct at 17.

[819] Staff Ex. 31, Pongsiri Direct at 10-11.

the Schedule D customer charge to $15.00 results in an average savings of $0.17 per month (assuming customer consumption remains unchanged).[820]

*OPC*

OPC opposes BGE's proposal to increase the Schedule R customer charge from $7.50 to $12.00, and instead recommends an adjustment that would increase the Schedule R customer charge by the same percentage increase in revenues allocated to Schedule R.[821] OPC strongly protests that the Company's proposed increase in the residential customer charge would "dampen price signals to consumers" with respect to reducing energy usage, disproportionately and inequitably increase bills for the Company's smallest residential customers, "and exacerbate the subsidization of larger residential customer's costs by … low-usage customers.[822]

The Company did not propose customer charge adjustments for any of its large commercial and industrial electric and gas customers, therefore neither MEG nor DOD/FEA commented on this issue.

**Commission Decision**

The Company proposes to increase various class customer charges. OPC opposed BGE's proposed sharp increase in the residential customer charge, and Staff recommended only a nominal increase. The present composition of the Company's

[820] *Id.* at 14. (During the hearing, Mr. Pongsiri allowed that a Schedule D customer charge of $13.50 would also be acceptable to Staff. Tr. at 1648.)
[821] OPC Initial Brief at 70. (OPC insists that BGE's proposal would unreasonably shift costs to the customer charge that are more appropriately recovered through energy charges. *Id.*)
[822] OPC Ex. 23, Wallach Direct at 3-4. Mr. Wallach estimated that as much as 66 percent of the costs of BGE's smart meter initiative is being applied to the residential class, but opined that those costs should not be run through the Company's COSS. Tr. at 1367. He insists that regardless the allocator, the output is incorrect because the input costs are too high to begin with. *Id.* at 1368. (He argues that the Commission should not rely on the COSS to allocate smart grid costs, but instead allocate the Company's revenue increase in the same percentage amount to all classes. *Id.* at 1368.)

customer charges includes: administrative costs (such as billing and customer care), gas and electric meter costs, gas regulator costs, and the costs associated with the electric service connection from the transformer to the meter.[823] Witness Frain testified that while BGE's current customer charges for the residential electric and gas classes and the small commercial electric classes recover a portion of the fixed costs incurred in serving customers, they are not set at a level to recover all of the fixed costs.[824] He further insists that since fixed costs also have increased as a result of the deployment of smart metering devices, it is also reasonable to move the current customer charges towards the level supported in the 2014 ECOSS and GCOSS.[825] OPC notes, however, that the ECOSS over-allocates smart grid costs to Schedules R and RL, and thus overstates the contribution of smart grid costs to the fixed costs that serve the residential class.[826] Not all of BGE's AMI investments are fixed costs.

### 2. ***Electric Customer Charges***

Based on the record in this case, we find that residential customer charges should be increased at this time only nominally, as recommended by Staff. We accept Staff's proposal of $0.40 increase to $7.90 per month. Staff's proposed increase will not significantly change the proportion of revenue derived from the customer charge, which is currently 19.4 percent of Schedule R revenues.[827]

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[823] BGE Ex. 18, Frain Direct at 11.
[824] *Id.*
[825] *Id* at 11; *See* BGE Reply Brief – Table 3 at 71.
[826] OPC Initial Brief at 71.
[827]Staff Direct, Blaise at 14. (Under Staff's proposal, the bill impact of a $0.40 increase in the Schedule R customer charge is estimated to be about 3.7 percent. *Id.* at 13. According to Mr. Frain, the overall RROR increase proposed by the Company for Schedule R would evidence as about a 5 percent increase in the customer's total bill. Tr. at 558.

The large increase proposed by BGE raises concerns related to the Commission's principles of gradualism. In this case, BGE proposes a 60 percent increase in the Schedule R customer charge but only a 6.3 percent increase in the volumetric charge.[828] Under Staff's proposal, the bill impact of a $0.40 increase in the Schedule R customer charge is estimated to be about 3.7 percent, and according to Mr. Frain, the overall RROR increase proposed by the Company for Schedule R would result in about a 5 percent increase in the customer's total bill.[829] *Id.* at 558. We find that limiting the Schedule R customer charge to $7.90, which according to Staff amounts to a 3.7 percent increase, keeps the customer charge within the 5 percent proportionality that BGE proposes for all of its RROR adjustments. Therefore, we reject BGE's proposal to substantially increase residential and non-residential customer charges.

We find that a modest increase in the Schedule G customer from $11.50 to $12.10, which is slightly below Staff's proposal, but consistent with the Company's 5 percent overall RROR adjustments is reasonable and supported by the record in this case. In adjusting the Schedule G customer charge, we note that Schedule G serves small commercial customers, which in many ways are similar to residential customers. This decision, with respect to Schedule R and Schedule G customer charges will afford residential and small commercial customers a better opportunity to control their monthly

[828] Tr. at 549. Mr. Frain responds that by comparing average residential customer bills with and without the Company's proposed increase in the Schedule R customer charge, Exhibit JCF-1 shows only a $0.34 difference in the average bill. *Id.* at 550. Even though the Company is proposing to increase the Schedule R customer charge from $7.50 to $12.00, the average Schedule R customer would not see a $4.50 increase in his monthly bill, *per se*. *Id.*
[829] *Id.* at 558.

bills by controlling their energy usage. Our decision, in this case, is consistent with EmPOWER Maryland goals and with our decision in BGE's last base rate case.[830]

Staff also proposed increasing the Schedule G (and GP) monthly customer charge from $11.50 to $12.64 and increasing the Schedule GS customer charge from $17.50 to $19.23.[831] On the basis of symmetry and in recognition of the principle of gradualism, for the reasons limiting the Schedule G (and GP) customer charge to $12.10, in proportion to the overall RROR adjustments that we adopt in this case. For Schedule GS we approve an increase in the customer charge for this rate schedule to $18.40, consistent with the proportional increase for other electric customer charge adjustments adopted in this case. Accordingly, we approve electric customer charge adjustments as follows:

**Table 1: Electric Schedule Customer Charge Adjustments[832]**

| Customer Class | Current | Approved |
|---|---|---|
| Schedule R | $ 7.50 | **$ 7.90** |
| Schedule G | $11.50 | **$12.10** |
| Schedule GP (Primary) | $11.50 | **$12.10** |
| Electric – Schedule GS | $17.50 | **$18.40** |

### *3.* ***Residential-Schedule D Gas Customer Charge***

We reject BGE's proposal to increase Schedule D customer charge from $13.00 to $15.00 and determine that there should no increase in the customer charge for this schedule, leaving it at the current $13.00 per month charge. We note that the unlike the Schedule R (residential electric) customer charge, the Schedule D (residential gas)

[830] No proposal was presented to increase or decrease the customer charge associated with Schedule GS.
[831] Staff Ex. 44, Blaise at 17.
[832] The customer charges for rate schedules RL, GS, GU, GL (Secondary), GL (Primary), P and T remain unchanged.

customer charge was increased in at the Company's request in 2005, and more recently gas customers are also paying fixed monthly STRIDE charges.[833] In Case No. 9036, we allowed a modest increase in the Schedule D customer charge based on Staff's observation at that time that residential customer costs were decreasing. However, in this case we believe that holding the line on gas customer charges during the rate-effective period for this case will permit gas customers to have better control of their gas bills, allowing them the opportunity to wisely manage their gas usage. This decision is also in keeping the Commission precedent.

### 4. ***Allocation of Electric Revenue Increase***

*BGE*

BGE proposes apportioning any revenue increase authorized by the Commission in this case such that each customer class' relative rate of return ("RROR") moves toward or within +/- 10 percent around the system average rate of return.[834]

In applying step-one of the "two-step" process adopted in Case Nos. 9299 and 9326, BGE witness Frain proposes moving Schedule R to a RROR of 0.90 and Schedule RL also to a RROR of 0.90. With the exception of Schedule T, the Company does not propose decreasing the class revenue contributions of the classes that are over-earning (or over-contributing) by more than 10 percent of the system average rate of return.[835] According to witness Greenberg's ECOSS analysis, Schedule T customers contribute a 6.90 RROR towards the system average rate of return. Witness Frain notes in his

[833] In 2005. BGE proposed increasing the Schedule D customer charge from $12.35 to $13.25. The Commission approved an increase in the Schedule D customer charge to $13.00. *Re Baltimore Gas and Electric Company*, Case No. 9036, 96 Md. P.S.C. 334, 369 (2005).
[834] BGE Ex. 18, Frain Direct at 18.
[835] *Id.*

testimony that in Case No. 9326 the Commission reduced Schedule T's revenue by 10 percent in recognition of its "continued" disproportionately high RROR.[836] Here, BGE proposes reducing Schedule T revenues by 25 percent in step one.[837]

BGE proposes allocating all remaining revenue in proportion to the adjusted test year base distribution revenues, with the exception of Schedules PL and T (whose current RRORs are already 3.92 and 6.90 respectively).[838] The upward movement of the Schedule R RROR from 0.69 to 0.90 and the Schedule RL RROR from 0.85 to 0.90 results in an unadjusted step-one allocation of 28 percent (or $38.5 million) of the total revenue increase to the Schedule R and RL customer classes.[839] The step-two proportional allocation of the rate increase to all classes with the exception of Schedules PL and T result in an additional unadjusted increase to Schedule R and RL customers.[840] Witness Frain notes that the Delivery Service Charge in each rate schedule increases corresponding to the inclusion of "eligible costs".[841]

*Staff*

Staff recommends the Commission-approved two-step methodology for allocating revenues.[842] In step-one, Mr. Blaise allocates 17 percent of the Company's new revenues toward Schedules R and RL (which he notes are BGE's under-earning rate classes). Then, in step-two, he proposes distributing the remaining revenue among all classes

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[836] *Id.* at 19.
[837] *Id.*; BGE Initial Brief at 66.
[838] *Id.* The Company's combined step-one and step-two adjustments are shown in witness Frain's Table 5.
[839] *Id.* at 21.
[840] *See*, BGE Ex. 18, Frain Direct at 23. (Exhibit JCF-8 contains the breakdown of costs, by rate schedule, that the Company proposes adding to rate base and their associated revenues).
[841] *Id.*
[842] The two-step approach to rate design was upheld by the Commission in *In the Matter of the Application of Baltimore Gas and Electric Company for Revisions in Its Electric and Gas Base Rates* (Case No. 9230).

except Schedules SL, PL and T.[843] He urges that his proposed allocation approach moves all classes closer to the system's RROR in a gradual way.[844] He selected 17 percent for step-one as the "optimal allocation" of the new revenue requirement to avoid rate shock and for fairness to ratepayers. This selection, Mr. Blaise notes also helps increase the RROR of the under-earning classes and reduces cross-subsidization without causing rate shock.[845] Staff also notes that the upward movement of the Schedule R RROR from 0.69 to 0.90 represents a greater than 50 percent increase in the Schedule R RROR.[846]

Staff witness Norman testifies that the Company's ECOSS is consistent in methods and results with those submitted and relied upon in previous BGE rate cases. She supports the use of the ECOSS approach as a part of the ratemaking process in this case. However, she recommends reliance on the ECOSS results based on 2014 demand factors, consistent with previous cases, rather than the five year average demand allocators developed and used by BGE in this case.[847]

For gas rates, Staff witness Pongsiri's also calculated the Company's gas rate schedule RRORs using the Commission-approved two-step methodology. Mr. Pongsiri computed before and after RROR for BGE's gas rate schedules, after making "additional rate adjustments," based on Staff witnesses Norman and Cross, and relying on GCOSS results based on 2014 demand allocators – instead of the five-year average demand allocators proposed by BGE.[848]

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[843] Staff Ex. 44, Blaise at 9. Staff witness Blaise maintains that his rate design approach is aimed at addressing any potential issues of inter- and intra-class imbalances "while avoiding any disproportionate increase that would negatively impact the Company's customers." *Id.*
[844] *Id.*
[845] *Id.* at 10-11.
[846] Tr. at 523.
[847] Staff Ex. 34, Norman Direct at 3.
[848] Staff Ex. 31, Pongsiri Direct at 8-9.

According to witness Pongsiri, allocating a step one increase to Schedule D is problematic; Schedule D already accounts for 70 percent of base revenues, and receives 70 percent of the revenue increase through step two. A step one increase to Schedule D, witness Pongsiri opines would push the class RROR close to the system average but would be inconsistent with the principle of gradualism.[849]

### 5. ***<u>Assignment of Electric Rate Increase by Schedule</u>***

#### *a. <u>Schedules R and RL</u>*

BGE proposes to recover a significant portion (62 percent) of the proposed rate increase by increasing the customer charges for Schedule R customers.[850] The Company also proposes "aligning" the Delivery Service Charges for Schedules R and RL, which would also increase the current effective rates for those rate schedules once the remaining proposed revenue increase is allocated.[851] Witness Frain estimates that the Delivery Service Charge adjustment for Schedule R (residential electric) customers using (weather normalized) 930 kWh per month would increase the customer's total monthly bill by 5.8 percent (or $7.64) per month.[852]

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[849] *Id.* at 9. Additionally, Mr. Pongsiri opines that "if Schedule C is not allocated any of the recommended revenue increase in the first step, the RROR of Schedule C would drop from earning more than the system average to less than the system average." *Id.*

[850] BGE Ex. 18, Frain Direct at 23.

[851] *Id.* at 24. BGE Reply Brief at 70. (BGE insists that the limited increases recommended by Staff and OPC will only further increase the disconnect between the fixed costs to serve customers and the fixed rates the Company can charge them.)

[852] *Id.* Witness Frain maintains that he is proposing to align Schedule R and Schedule RL charges now that smart meters are being used to serve both types of customers. Tr. at 513-516, 552, 608.

*b. Schedules G, GS and GU*

BGE proposes to increase the customer charge from $11.50 to $17.50 for Schedule G customers.[853] As with Schedule R, the Company also proposes "aligning" the Delivery Service Charges for Schedules G (secondary service) and Schedule G (primary service), Schedule GS and for Schedule GU, which would also increase the current effective rates for those rate schedules once the remaining proposed revenue increase is allocated.[854]

c. *Schedule GL*

The Company proposes allocating 70 percent of the Schedule GL revenue increase to Demand Charge (increasing the Demand Charge from $3.69 per kW to $4.39 per kW, capturing $15.2 million of the proposed revenue increase for Schedule GL) and the remaining 30 percent to the Delivery Service Charge (increasing the Delivery Service Charge for secondary service from $0.01561 per kWh to $0.01866 per kWh, and increasing the Delivery Service Charge for primary service from $0.01614 per kWh to $0.01791 per kWh), generating $6.4 million in revenues.[855]

*d. Schedules P and T and Schedule SL (Street Lighting)*

The Company proposes recovering the entire proposed increase of $7.0 million in revenues from Schedule P customers by increasing the Demand Charge from $2.85 per kW to $4.28 per kW. Under Schedule T, the Company proposes to decrease the Delivery Service Charge from $0.00349 per kWh to $0.00300 per kWh.[856] BGE proposes an

[853] BGE Ex. 18, Frain Direct at 25.
[854] *Id.* at 25-26.
[855] *Id.* at 26-27.
[856] BGE Ex. 18, Frain Direct at 28.

increase the Schedule SL Delivery Service Charge from $0.00595 per lamp-watt to $0.00648 per lamp-watt, and recover the remaining revenue requirement for Schedule SL via proportionate increases in facilities charges (for cable, lamp fixtures and poles) as well as maintenance charges.[857]

*Staff and OPC*

Staff recommends that the Company's proposal to reduce revenue collection from Schedule T by 25 percent be rejected, and that Schedules T, PL and Schedule SL should not be allocated any new revenues.[858] OPC witness Wallach also opposes any new revenue allocation to Schedules T and PL, but supports allocation of some new revenue allocation to Schedule SL.[859] Although Staff accepts that Schedule T is technically over earning, witness Blaise anticipates that based on the frequency of BGE rate cases – given the current trajectory – he expect Schedule T will, at some point reach the level of the system average.[860] Mr. Blaise also noted that a number of considerations are involved in designing rates, including customer with high and low usage. Therefore, he kept the current billing determinants for the customer charge, demand charge and volumetric charge the same, and allocated the revenue distribution among each component rather than apply all of the new revenue to the demand portion of the bill.[861]

[857] *Id.* at 29.
[858] Staff Ex. 44, Blaise Direct at 2.
[859] Generally, OPC witness Wallach recommends that smart grid costs be allocated based on the benefits to each rate class, but the analysis of whether each class benefits from smart grid, and to what extent, has not been performed. See Tr. at 212-213, Greenberg.
[860] Tr. at 2012. Given the frequency of rate cases, assuming no increases in the Schedule T revenue distribution, he anticipates that we will get to parity with the system within the next few years. *Id.*
[861] *Id.* He commented further that if the billing determinants are retained as is, the intra-class inequity will not be as severe as if all billing proportions were adapted to BGE's proposal. *Id.* at 2017-2018.

*MEG*

MEG supports BGE's proposed revenue allocation, including the Company's proposed 25 percent reduction to Schedule T and opposes Staff's proposal that would hold Schedule T's revenue allocation constant.[862] MEG also supports BGE's proposal to collect the entire Schedule P increased revenue requirement through the Schedule P demand charge, arguing that Staff's proposal to increase the Schedule P distribution charge 10.8 percent and the Schedule P demand charge 5.1 percent would send inaccurate price signals to Schedule P customer that energy is more expensive than it is.[863]

*DOD/FEA*

DOD/FEA supports BGE's recommendation to allocate 100 percent of any revenue requirement increase to the Schedule P demand charge.[864] DOD/FEA notes that large power users should have their costs align with the cost of service in order that those customers may more effectively navigate in an unbundled market.[865]

*Staff Rebuttal*

In Rebuttal, Mr. Blaise continues to oppose a BGE's proposed reduction in Schedule T revenues, because he asserts, "[his] allocation methodology gradually moves all rate schedules closer to the system's RROR."[866] Mr. Blaise opposes MEG's support of BGE's proposal with regard to Schedule P, and also opposes MEG witness Baudino's endorsement of BGE's rate design recommendation for Schedule T. He notes that, if

[862] MGE Ex. 1, Baudino Direct at 3; MEG Initial Brief at 4-5, 6; Tr. at 1396. He agreed, however, that if Schedule T rates were not reduced by 25 percent, as BGE proposes, "other things being equal" the RROR for Schedule T would tend to decline after rates went into effect for other classes. *Id.* at 1398.
[863] MEG Initial Brief at 7-8.
[864] DOD/FEA Initial Brief at 17.
[865] *Id.*
[866] Staff Ex. 45, Blaise Rebuttal at 2. Mr. Blaise's recommended electric rate design approach "decreases Schedule T's RROR to 4.47 from the current 6.93." *Id.*

accepted, BGE's proposal "will lead to intra-class inequities by disproportionately shifting a significant portion of the revenue burden onto the demand portion of the bill."[867]

Mr. Blaise agrees with OPC witness Wallach's opposition to new revenue allocation to Schedule T and PL; however, he opposes OPC's recommendation to distribute some new revenue to Schedule SL.[868]

## Commission Decision

In considering rate design, regulators, including this Commission, counter-balance the principles of cost causation, gradualism, reasonableness and overall fairness to each rate class. We have also considered price-signaling, especially as certain rates may encourage or discourage energy conservation.

We are mindful of the competing interests of the various customer classes and the need to design rates in a fair and gradual manner. Consistent with our decision in BGE's last rate case in Order No. 86757, except for those classes that are significantly over-earning, the record in this case supports our continued use of the rate design process two-step process to allocate the Company's increased revenue requirements. In doing so, we adopt a gradual approach to allocating the electric revenue requirements adopted in this case. We believe a more gradual movement toward unity for these classes is best, and therefore in step-one **we adopt Staff's recommendations**, based on the Company's 2014 ECOSS.[869]

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[867] *Id.* at 3. Staff's proposal, Mr. Blaise urges, "slightly decreases the class revenue share of the demand charge, from 50 percent to 47.4 percent, and increases the volumetric charge from 46.1 percent to 48.5 percent." *Id.*
[868] *Id.*
[869] Staff Ex. 44, Blaise Direct at 9.

By taking this more gradual approach, we better align the electric rate Schedules R and RL with the system average return. In step-one, Staff allocated 17 percent of its proposed revenue requirement increase to Schedules R and RL (the two under-earning classes). In step-two, Staff allocated the remaining revenue requirement increase among all the classes, except Schedules SL, PL and T.[870] Therefore, **the revenue requirement we approve produces the following RROR's:**

**Table 2: After Step-Two RRORs For Electric Rates**

| R | RL | G/GU | GS | GL | P | T | SL | **PL** |
|---|---|---|---|---|---|---|---|---|
| **0.75** | **0.71** | **1.11** | **1.46** | **1.53** | **1.04** | **5.71** | **1.61** | **3.11** |

We conclude that this decision strikes an appropriate balance among the rate classes while bringing all classes closer to the system-wide rate of return. **This modification** of Staff's RRORs strikes the appropriate balance between principles of cost causation and energy conservation.[871]

### *6. <u>Allocation of Gas Revenue Increase</u>*

As with allocating the proposed electric rate increase, BGE proposes apportioning any revenue increase authorized by the Commission in this case such that "each customer class' rate of return [relative rate of return ("RROR")] moves toward or within … +/- 10 percent around the system average rate of return."[872] Since all classes are either over-earning or already within +/- 10 percent of RROR, the Company does not propose a step-

[870] *Id.*
[871] *Cf. Re Potomac Electric Power Company* [Case No. 9286, Order No. 85028 at 130]; 103 Md. P.S.C. 293, 355.
[872] BGE Ex. 18, Frain Direct at 29.

one increase for any of its gas rate classes. The Company also does not propose decreasing for classes that are over-earing relative to the RROR.[873]

*a.* *Schedule D*

The Company proposes recovering $14.7 million of its proposed $54.6 million Schedule D gas rate revenue increase by increasing the Schedule D customer charge from $13.00 to $15.00.[874] The remainder would be recovered by increasing the Schedule D Delivery Price.[875]

*b.* *Schedule C*

Schedule C accounts for $19.2 million in gas revenues. The Company proposed different increases for the first block of service (the first 10,000 therms per month) and for the second block (all therms over 10,000 therm per month).[876]

*c.* *Schedule IS, ISS*

The Company proposes allocating 50 percent of the proposed revenue increase to the Schedule IS Demand Price and 50 percent to the Delivery Price. In order to do so, in the Company's case-in-chief, witness Frain proposed a Demand Price increase from $0.5301 per therm to $0.6865 per therm, and proposed a Delivery Price increase from $0.0460 per therm to $0.0520 per therm, resulting in a 32.1 percent increase in the demand price and a 11.7 percent increase in the delivery price.[877] In its case-in-chief, for

[873] *Id.* at 30. Unlike electric Schedule T, gas Schedule PLG (which has a RROR of 8.79) also was not proposed to be reduced.
[874] *Id.* at 34.
[875] *Id.* In the Company's case-in-chief, witness Frain estimated that for a Schedule D customer using 57 therms per month, these rate adjustments will increase the total monthly bill by 11.3 percent or $7.56.
[876] *Id.* at 34-35. In the Company's case-in-chief, witness Frain proposed a first-block increase from $0.2938 to $0.3879 per therm. For the second block (all therms over 10,000 therm per month), BGE proposes to increase the current effective rate from $0.1428 per therm to $0.1940 per therm.
[877] BGE Exhibit JCF-4, Sheet G-5.

Schedule ISS, the Company proposed increasing the Demand Price from \$0.7005 per therm to \$0.8661 per therm, and proposes increasing the Delivery Price from \$0.0872 per therm to \$0.0935 per therm, resulting in a 23.4 percent increase in the demand price and a 13.3 percent increase in the delivery price.[878]

*d.* *Schedule PLG*

Unlike electric Schedule T, the RROR for gas Schedule PLG (8.79) is not proposed to be reduced. BGE notes that Gas Private Area Light (PLG) is a very small customer class that is closed to new customers. (It is, however, significantly over-earning). Witness Frain opines that not reducing the PLG's RROR serves as a "disincentive" to those customers to keep their "continuously-burning" gas lamps in service.[879]

*Staff*

For purposes of allocating increase in gas revenues, witness Pongsiri recommends allocating 3 percent of Staff's proposed revenue requirement to Schedule C; the remaining 97 percent of the revenue increase he recommends allocating in step two to all schedules except Schedule PLG.[880]

[878] *Id.* The per therm demand charge and per therm delivery charge reflect those included in the Company's case-in-chief, and not necessarily the rates adopted in this order. Optional Firm Delivery Service ("OFDS") and Distribution Interruption Penalty ("DIP") Prices are calculated based on an effective volumetric demand rate, based on the total class demand revenue and total class volumes. The Company proposes DIP prices, calculated by multiplying the first block OFDS Prices by 1.5, and the Excessive Use Interruption Penalty Prices – calculated by multiplying the proposed block OFDS Prices by 2. *Id.* at 36. See also, BGE Exhibit JCF-4, Sheet G-6.
[879] *Id.* at 37. Schedule PLG applies to a total of 14 customers.
[880] Staff Ex.31, Pongsiri Direct at 18.

*MEG*

With regard to the Company's proposed gas cost revenue allocation under Schedule IS, MEG submits that the Schedule IS is earning a class rate of return that falls outside the +/- 10 percent rate of return band, and therefore "should receive a lower than system average percentage revenue increase in this proceeding."[881] MEG recommends that the Commission reject BGE's proposed revenue allocation for Schedule IS, but adopt the Company's proposal to collect any approved revenue allocation for Schedules IS and ISS, by apportioning 50 percent to the demand charge and 50 percent to the delivery charge.[882]

**Commission Decision**

Consistent with our decision in BGE's last rate case in Order No. 86757, and with this decision with respect to electric rate design, except for those classes that are significantly over-earning, the record in this case supports our continued use of the rate design two-step process to allocate the Company's increased revenue requirements. In doing so, as with the electric rate design, we adopt a gradual approach to allocating the gas revenue requirements adopted in this case. We believe a more gradual movement toward unity for these classes is best, and therefore in step-one **we adopt Staff's recommendations**, based on the Company's 2014 GCOSS.

By taking this more gradual approach, we better align the Schedules IS, ISS and PLG with the system average return. We conclude that this decision strikes an

[881] MGE Ex. 1, Baudino Direct at 4.
[882] MEG Initial Brief at 9.

appropriate balance among the rate classes while bringing all classes closer to the system-wide rate of return.

BGE does not propose allocating the increase in gas revenues to any class in step-one, because all classes are either over-earning or are already within the +/-10 percent band of the system average.[883] Staff witness Pongsiri notes, however, that Schedule D accounts for approximately 70 percent of gas rate base revenues, and thus receives 70 percent of the revenue increase that would generally be allocated in step-two.[884] He notes also that if no new revenues are allocated to Schedule C in step-one, the Schedule C RROR would drop below the 1.0 system average.[885] Therefore, Staff proposes allocating 3 percent of the Staff recommended gas revenue increase to Schedule C only. The remaining 97 percent is allocated to in step-two to all gas rate schedules, except Schedule PLG, based on the proportion of each class's share of total distribution revenues.[886] In doing so, Staff adopts a gradual allocation of the gas revenue requirements in this case. We find that this more gradual movement is best, and therefore we **again adopt Staff's recommendations**, based on the Company's 2014 GCOSS. Therefore, we **modify** Staff's after step-two RRORs as follows:

**Table 2A: After Step-Two RRORs For Gas Rates**

| D | C | ISS | IS | PLG |
|---|---|---|---|---|
| **0.978** | **1.010** | **1.210** | **1.218** | **6.963** |

[883] Staff Ex.31 at 7.
[884] *Id.* Staff witness Pongsiri observes that while assigning a step-one increase to Schedule D would push the Schedule D class's RROR closer to the system average (from 0.96 to 1.001), this would lead to rates for the residential class that is inconsistent with the principle of gradualism. *Id.*
[885] *Id.*
[886] *Id.*

### *7. Rollover of Energy Efficiency Charges*

BGE witnesses Case introduced the issue of the Company's proposed recovery of energy efficiency costs in base rates.[887] According to witness Case, at present the Company energy efficiency program costs are visible (or transparent) to customers, however, the benefits of these programs are "not easily determinable by a customer" and according to BGE "certainly not as visible as the EmPOWER MD surcharge on monthly bills."[888] Under the present construct, the Company contends that although the total customer bill is lower than it otherwise would be, the EmPOWER MD surcharge continues to grow. Moving reviewed and approved charges from the surcharge into base rates would lower the surcharge, and would eliminate what the Company characterizes as a "misleading" representation of the surcharge (which doesn't reflect the offsetting benefits of the programs).[889]

BGE witness Case also noted that disparity between the transparency of the costs and benefits of the utility efficiency programs was a topic addressed in the 2015 EmPOWER Maryland Work Group Summary Report – noting that participants had chosen not to propose more 2015-17 portfolio spending due to concerns about increasing charges on customer bills.[890] The Company proposes to move $218,315 in unamortized

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[887] BGE Ex. 28, Case Direct at 40. (The Company's proposal "that eligible costs currently being recovered through the electric and gas Energy Efficiency Charge for which actual spend has been reviewed and approved by the Commission be moved into base rates.")
[888] *Id.*
[889] *Id.* at 40-41.
[890] *Id.* at 41.

electric energy efficiency costs into rate base and $31,331 in unamortized gas energy efficiency costs into rate base for a total electric/gas rate base increase of $249,647.[891]

BGE witness Frain opined that the EmPOWER Maryland charge on a customer bill could be seen as misleading, as the surcharge itself only reflects costs and does not reflect the offsetting benefits of the programs.[892] In response, the Company proposed that, during each base rate case, eligible costs currently being recovered through the EmPOWER Maryland charges (Electric Rider 1 and Gas Rider 2) for which actual spend has been reviewed and approved by the Commission be moved from the EmPOWER Maryland charges into base rates.[893]

*Staff*

Staff witness Best opposes with BGE's proposal to move the through September 2014 eligible gas energy efficiency costs (currently recovered through Gas Rider 1) into base rates.[894] Ms. Best notes that as a line item surcharge brings awareness to the EmPOWER program. By having the charge listed on the bill, she notes a customer is informed that the EmPOWER program exists, which may prompt the ratepayer to participate.[895]

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[891] BGE Exhibit DMV-6 (Actual). The rate design – by customer class – allocation of the proposed energy efficiency-related base rate increase is set forth in BGE witness Frain's Exhibit JCF-8, for Electric Tariff Supplement 570 and Gas Tariff Supplement 412.

[892] BGE Initial Brief at 70; BGE Ex. 18, Frain Direct at 40.

[893] *Id.* In response to the Commission's concern about considering BGE's request outside of the EmPOWER Maryland process, in collaboration with the other utilities, Mr. Frain suggested that the Commission could make the decision in this case and apply the decision in other utility-specific cases as they occur. Tr. at 559.

[894] Staff Ex. 24, Best Direct at 2.

[895] *Id.* Under BGE's proposal, there would be no change in the cost recovered, but the surcharge itself would be lower. *Id.*

*DOD/FEA*

DOD/FEA witness Dr. Goins asserts that the Company should continue recovering its conservation program costs through the applicable energy efficiency riders and the EmPOWER Maryland charge.[896]

**Commission Decision**

Nearly all parties, including Staff, OPC and DOD/FEA oppose BGE's proposal to move recovery of energy efficiency costs into base rates by moving the current electric (Rider 1) and gas (Rider 2) surcharges into base rates. Staff notes that the Company's proposal for recovery of these costs is inconsistent with the EmPOWER Maryland cost recovery of other utilities.[897] OPC also asserted that acceptance of BGE's proposal would reduce transparency of the EmPOWER Maryland program.[898]

We agree with Staff, OPC and DOD/FEA that energy efficiency costs should continue to be reflected on customer bills and recovered through the established electric and gas) EmPOWER Maryland surcharges. We disagree that the EmPOWER Maryland surcharges are in any way seen as misleading, and have through our May 87575 EmPOWER Order, directed an EmPOWER work group to evaluate options to better reflect the benefits of EmPOWER programs.[899] Rather, we agree with Staff that the line

[896] *Id.* at 16.
[897] Staff Initial Brief at 31. Staff emphasizes that uniformity in the treatment of the EmPOWER Maryland programs across all utilities whenever possible is preferable. *Id.*
[898] OPC Initial Brief at 73; OPC Ex. 26, Chang Direct at 29.
[899] Order No. 87575 (May 26, 2016) at 43-45 OR: *In the Matter of Potomac Edison Company d/b/a Allegheny Power's Energy Efficiency, Conservation and Demand Response Programs Pursuant to the EmPOWER Maryland Energy Efficiency Act of 2008, In the Matter of Baltimore Gas and Electric Company's Energy Efficiency, Conservation and Demand Response Programs Pursuant to the EmPOWER Maryland Energy Efficiency Act of 2008, In the Matter of Potomac Electric Power Company's Energy Efficiency, Conservation and Demand Response Programs Pursuant to the EmPOWER Maryland Energy Efficiency Act of 2008, In the Matter of Delmarva Power and Light Company's Energy Efficiency, Conservation and Demand Response Programs Pursuant to the EmPOWER Maryland Energy Efficiency*

item surcharge brings awareness to the EmPOWER Maryland program, encourages recognition of energy efficiency measures and may well prompt customers to participate in these programs, which advances the goals of the EmPOWER Maryland Act. Accordingly, the Company's energy efficiency costs shall continue to be reflected through the electric and gas surcharges, and the Company's proposal to move these costs into base rates is rejected.

#### ***8. <u>2016 Smart Energy Rewards (SER) and Smart Energy Manager (SEM) Costs</u>***

BGE intends to begin recovering prospective SER and SEM program cost through its 2016 EmPOWER MD charge.[900] However, the Company requests that electric Rider 2 and gas Rider 1 rates be revised to reflect recovery of SER and SEM program costs to be spent for the remainder of 2016, when new base rates become effective as the result of the Commission's decision in this case.[901] The Company proposes to begin recovering prospective SER and SEM costs annually through the Energy Efficiency Charge, with a subsequent rollover in to rate base of costs/expenditures that have been reviewed and approved by the Commission.[902] BGE intends to recover *between rate case-eligible*

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*Act of 2008, In the Matter of Southern Maryland Electric Cooperative, Inc.'s Energy Efficiency, Conservation and Demand Response Programs Pursuant to the EmPOWER Maryland Energy Efficiency Act of 2008, In the Washington Gas Light Company's Energy Efficiency, Conservation and Demand Response Programs Pursuant to the EmPOWER Maryland Energy Efficiency Act of 2008* (Case Nos. 9153-9157, 9362; Order No. 87573, May 26, 2016) at 43-45.

[900] According to BGE witness Mark Case, "[f]rom 2013 through the summer of 2015, participating customers have earned approximately $28 million in BGE Smart Energy Rewards bill credits by reducing their energy usage on Energy Savings Days." BGE Ex. 28, Case Direct at 8. He notes also that "[t]he BGE Smart Energy Manager program has also been effective with participating customers expected to experience an average energy reduction of 1.4% in 2015." *Id.*

[901] BGE Ex. 18, Frain Supplemental Direct at 7. As with the roll over of energy efficiency costs, the Company maintains that this will more closely align the cost recovery from these programs with the associated benefits. *Id.* However, the Company will continue to defer SER and SEM costs into a regulatory asset as an incremental costs to deploy Smart Grid. *Id.*

[902] *Id.* at 8.

energy efficiency costs (including SER and SEM program costs) through electric Rider 2 and gas Rider 1.[903]

In its Initial Brief, BGE notes that no party in this proceeding has contested the Company's proposal to recover SER and SEM program costs starting in the rate-effective period through the EmPOWER Maryland Charges.[904] Therefore, the Company's proposal with respect to recover SER and SEM program costs for the rate-effective period through the EmPOWER Maryland charges is accepted.[905]

Based on the decisions set forth in this order, for average monthly usage of 925 kWh, the BGE residential electricity customer will experience an estimated $2.67 per month increase in electric distribution costs. For the BGE residential gas customer using an average of 57 therms per month, the monthly bill will increase $4.86 per month.

**IT IS THEREFORE**, this 3rd day of June, in the year Two Thousand Sixteen, by the Public Service Commission of Maryland,

**ORDERED** (1) That the Application of Baltimore Gas and Electric Company, filed November 6, 2015 (as supplemented by BGE over the course of this proceeding), seeking an increase in its electric distribution revenue requirement of $115.6 million and an increase in its gas distribution revenue requirement of $78.2 million, in addition to the creation of a rider to pass through the increased costs related to Baltimore

[903] *Id.* at 9.
[904] BGE Initial Brief at 72.
[905] However, as noted above we decline to have these charges rolled over into base rates.

City's conduit lease and maintenance fee, is hereby denied;

(2) That Baltimore Gas and Electric Company is hereby authorized to increase electric distribution rates by no more than $ 41.762 million and to increase gas distribution rates by no more than $47.776 million, for service rendered on or after June 4, 2016, consistent with the findings in this Order;

(3) That Baltimore Gas and Electric Company is directed to file tariffs in compliance with this Order with the effective dates prescribed herein, subject to acceptance by the Commission; and

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

*/s/ W. Kevin Hughes*

*/s/ Harold D. Williams*

*/s/ Anne E. Hoskins*

*/s/ Jeannette M. Mills*

*/s/ Michael T. Richard*
Commissioners

**Baltimore Gas and Electric Company**
**Case No. 9406**
**Electric Operations**

**Revenue Requirement**
($000's)

| | |
|---|---|
| Adjusted Rate Base | $2,915,925 |
| Rate of Return | 7.28% |
| Required Operating Income | $212,279 |
| Adjusted Operating Income | $188,132 |
| Operating Income Deficiency | $24,147 |
| Conversion Factor | 1.7295 |
| Revenue Requirement | $41,762 |

**Rate Base**
($000's)

| | |
|---|---|
| Per Books Balance | $2,924,893 |
| Uncontested Adjustments | $64,413 |
| Total Uncontested | $2,989,306 |
| | |
| Contested Adjustments | |
| Average Balance of Smart Grid Regulatory Asset | $0 |
| Cash Working Capital | ($4,466) |
| Accumulated Deferred Income Taxes - Bonus Depreciation | ($9,425) |
| Accrued Smart Grid Operational Savings | ($9,643) |
| Smart Meter Installation Opt-Out Increased Costs, net of tax | ($3,549) |
| Retired Legacy Meters | ($46,495) |
| Case No. 9361 Merger Costs to Achieve Regulatory Asset | $197 |
| Adjusted Rate Base | $2,915,925 |

**Operating Income**
($000's)

| | |
|---|---|
| Per Books Balance | $243,155 |
| Uncontested Adjustments | ($64,633) |
| Uncontested Balance | $178,522 |
| | |
| Contested Adjustments | |
| Defer and Amortize gains/losses on sale of Real Estate | ($526) |
| Annualize Certain Regulatory Asset Amortization Periods revised in Case No. 9355 | $177 |
| Annualize AFC to Reflect Requested Returns | ($92) |
| Annualize CVR Costs since Case No. 9355 | ($1,040) |
| Recover Exelon Business Service Company Compensation in OIA 11 | $0 |
| Amortize Smart Grid Regulatory Asset Deferrals Post-Test Year | $0 |
| Tax Impact on Interest Synchronization | ($2,177) |
| Amortize Smart Grid Regulatory Asset Over 10 years | $10,051 |
| Accrued Smart Grid Operational Savings | $964 |
| Smart Meter Installation Opt-Out Increased Costs Over 10 years | $710 |
| Case No. 9361 Merger Synergies and Costs to Achieve Amortization | $1,543 |
| Adjusted Operating Income | $188,132 |

**Baltimore Gas and Electric Company**
**Case No. 9406**
**Gas Operations**

**Revenue Requirement**
($000's)

| | |
|---|---|
| Adjusted Rate Base | $1,225,250 |
| Rate of Return | 7.23% |
| Required Operating Income | $88,586 |
| Adjusted Operating Income | $61,229 |
| Operating Income Deficiency | $27,357 |
| Conversion Factor | 1.7464 |
| Revenue Requirement | $47,776 |

**Rate Base**
($000's)

| | |
|---|---|
| Per Books Balance | $1,181,626 |
| Uncontested Adjustments | $55,051 |
| Total Uncontested | $1,236,677 |
| | |
| Contested Adjustments | |
| Average Balance of Smart Grid Regulatory Asset | $0 |
| Cash Working Capital | ($218) |
| Accumulated Deferred Income Taxes - Bonus Depreciation | ($3,061) |
| Accrued Smart Grid Operational Savings | ($4,639) |
| Smart Meter Installation Opt-Out Increased Costs, net of tax | ($1,401) |
| Retired Legacy Meters | ($2,193) |
| Case No. 9361 Merger Costs to Achieve Regulatory Asset | $85 |
| Adjusted Rate Base | $1,225,250 |

**Operating Income**
($000's)

| | |
|---|---|
| Per Books Balance | $77,680 |
| Uncontested Adjustments | ($23,004) |
| Uncontested Balance | $54,676 |
| | |
| Contested Adjustments | |
| Annualize AFC to Reflect Requested Returns | ($81) |
| Recover Exelon Business Service Company Compensation in OIA 11 | $0 |
| Amortize Smart Grid Regulatory Asset Deferrals Post-Test Year | $0 |
| Tax Impact on Interest Synchronization | $18 |
| Riverside Remediation Accrual | $1,193 |
| Amortize Smart Grid Regulatory Asset Over 10 years | $4,019 |
| Accrued Smart Grid Operational Savings | $464 |
| Smart Meter Installation Opt-Out Increased Costs Over 10 years | $280 |
| Case No. 9361 Merger Synergies and Costs to Achieve Amortization | $660 |
| Adjusted Operating Income | $61,229 |

**Concurring Statement Of**
**Commissioner Harold D. Williams and**
**Commissioner Anne E. Hoskins**

We join in the Commission's Order in Case 9406,[1] but write separately to elaborate and clarify our views on two issues: the proposed Baltimore City conduit fee increase; and the impact of this and previous rate increases on limited income customers.

First, it is our expectation that BGE and Baltimore City will redouble their efforts to work together to find the most cost-effective approach for rehabilitating the conduit system, which is essential for ensuring reliable electric service. When BGE returns to the Commission to seek cost recovery for its pro rata share of prudent, actual costs incurred by the City to operate and maintain the underground conduit system,[2] the cost recovery should be shared by all BGE ratepayers.[3] Just as this Commission has authorized rate increases from all ratepayers across the BGE territory to pay for other reliability-related infrastructure upgrades that provide geographically-focused benefits (notably STRIDE, Electric Reliability Initiative and Howard County reliability projects[4]), the cost of necessary reliability upgrades in electric delivery infrastructure in Baltimore City should

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[1] In a separate statement, Commissioner Williams dissents, in part, to Order No. 87591.

[2] In a court filing, Baltimore City acknowledged that "the City has a contractual obligation to reimburse BGE for conduit lease fee payments that are not spent on maintaining the conduit system." Norman Direct, CSN-18 (Memorandum of Law in Opposition to [BGE's] Motion for a Preliminary Injunction, filed November 25, 2015 at 26).

[3] An option to impose cost recovery solely on Baltimore City ratepayers ("Option A") is not supported by Commission precedent and practice. Footnote 464 in today's Order mistakenly relies on *In Re Baltimore Gas and Elec. Co.*, Case No. 8127, Order No. 68240 (1989), which actually reinforces the concerns raised by OPC and the City of Baltimore regarding assessing a subset of customers based on a decision made by their local government. The 1989 Order noted a previous Commission Order involving infrastructure upgrades in Annapolis that "rejected surcharging BG&E's Annapolis customers, because the City, not those customers, caused the cost to be incurred" and concluded that such "a surcharge would be an inequitably burdensome assessment on that group of ratepayers."

[4] *See* Case No. 9291 (Phase I and Phase II) (addressing complaint from Howard County and approving an investment plan to fortify feeders located only in Howard County, some of which were not in violation of RM43 standards or listed among BGE's "poorest performing feeders").

be borne by all BGE ratepayers. By the end of our hearings, only Commission Staff continued to support assessing Baltimore City customers through "Option A", but even they acknowledged that "regulators do not typically analyze or require locational cost estimates within utility territory, differentiating rates by only territory-wide class characteristics."[5] For example, BGE's significant expenses on tree trimming benefit residents in tree-lined suburbs much more so than residents who live in row houses in West Baltimore or commercial businesses on North Avenue, yet all ratepayers contribute to recovery of this reliability-based expense. A key strength of our electric system is that it is universal -- it connects everyone and in doing so makes our society and economy much stronger. It is not only the customers who live or operate businesses in Baltimore who will suffer if the conduit system is not repaired,[6] but also those who commute to Baltimore for jobs and who visit the City for arts and culture and health care. Instead of pitting one set of customers against another, we urge participants in the regulatory process to work together to find cost-effective ways to modernize our energy infrastructure, making it safe, reliable and sustainable for all customers.

Our second concern relates to the disparate impact repeated rate increases is having on Maryland's limited-income customers. Over the past 3 years, the average residential BGE ratepayer's base distribution charges have increased $9.09 per month for

[5] Norman Direct at 31. *See* BGE Initial Brief at 43-44, which stated, "BGE believes that the Commission should authorize recovery through Option B." *See also* BGE witness Vahos' testimony where he agreed that Option B was "more reasonable" than Option A. Tr. 686 at 12-15. OPC and Baltimore City opposed Option A.

[6] If the Commission accepted BGE's original "Option A" proposal to recover the cost only from Baltimore City ratepayers, the average residential Baltimore City ratepayer would see a monthly bill increase of $8.75. Frain Direct at 39. This would be extremely burdensome for some of the poorest customers in Maryland.

electric service and $11.70 per month for gas service.[7] In addition, customers face additional infrastructure investment charges through STRIDE (for gas customers) and ERI riders. We have supported rate increases to the extent they have funded necessary upgrades in BGE's distribution network, including investments in a smarter grid which promise better service and a path to a more sustainable electric system (with opportunities for electric transportation, demand response, energy efficiency and distributed renewable energy). However, we are concerned that we are reaching a tipping point for many residents of limited income. While Maryland offers financial support programs, they are insufficiently funded, and serve less than one-third of income-qualified customers.[8] It is time for Maryland to consider new universal service models,[9] including legislation that clarifies the Commission's authority to consider ability to pay when allocating rate increases among and between rate classes. Without legislative and regulatory reform, we risk undermining the inherent strength of our electricity system: its ability to bring power and light to everyone.

*/s/ Harold D. Williams*

*/s/ Anne E. Hoskins*
Commissioners

[7] Case No. 9299, Order No. 85374 (Feb. 2013): electric, $3.33; gas, $2.70.
Case No. 9326, Order No. 86060 (Dec. 2013): electric, $2.13; gas $0.73.
Case No. 9355, Order No. 86757 (Dec. 2014): electric, $0.96; gas $3.41.
Case No. 9406, Order No. 87591 (June 2016): electric, $2.67; gas $4.86.

[8] Office of People's Counsel, Comments on Office of Home Energy Program's Fiscal Year 2015 Annual Report on the Electric Universal Service Program at 2 (ML # 186418).

[9] *See, e.g.*, Pennsylvania's Customer Assistance Program (http://www.rhls.org/pa-utility-law-project/pa-low-income-utility-assistance-programs/) and the California Alternate Rates for Energy (CARE) Program (http://www.cpuc.ca.gov/General.aspx?id=976). *See also* Public Conference 27, Commission Staff's filing of the *Affordable Energy Plan*, November 1, 2012 (ML # 143460).

**Dissenting Statement, In Part, Of**
**Commissioner Harold D. Williams And**
**Commissioner Michael T. Richard**

While we fully support the decisions of our colleagues with regard to the majority of this order, we are unconvinced that AMI has been proven to be cost-effective. Consistent with Order Nos. 83410 and 83531, we agree with OPC and DOD that based on the evidence presented, ratepayers should not be required to pay in full at this time for these investments. As DOD observes, the Commission conditioned the approval of BGE's AMI case, requiring BGE to demonstrate that it has delivered the benefits that make the project cost effective. We also agree with DOD that "something is amiss" and we would be far more confident in AMI's effectiveness if we were discussing rate reductions rather than a rate hike. While the company may suggest that any challenge to its benefits-cost analysis amounts to "post hoc nickeling and diming," in Order No. 83531, the Commission found it important to note that these investments would undergo proper review. If the final systems fell short of being cost effective, the Commission would determine the cost recovery outcome that the public interest requires.

Although we agree with BGE that investing in new technologies can be beneficial, we fully expect, and our ratepayers deserve, that those investments be delivered as promised and provide meaningful bill savings for all customers.[1] We believe that OPC thoroughly and fairly evaluated BGE's AMI. They called attention to

[1] Order No. 83410 at 6. When the Commission approved BGE's second attempt at a smart meter case, the Commission further noted that it "'views cost-effectiveness as requiring a real rate of return of ratepayers' investment, measured by meaningful bill savings for all ratepayers,' and we do not view the outcomes of the TRC or other California Manual tests as dispositive or binding…'" Order No. 83531 at 31, n. 153, citing *In the Matter of Baltimore Gas and Electric Company's Energy Efficiency, Conservation and Demand Response Programs Pursuant to the EmPower Maryland Energy Efficiency Act of 2008*, Order No. 82384, Case No. 9154 (December 31, 2008) (quoting Commission Letter Order to BGE, Item No. 10, June 18, 2009 Administrative Meeting, Maillog No. 108061 (August 18, 2008)).

speculation and claimed benefits that in many cases did not necessarily rely on AMI or may have been achieved at lower costs. We agree with OPC and believe it was an error for BGE to not consider the treatment of legacy meters and the SER credit costs in their cost-effectiveness analysis. And we believe that OPC's "hold-harmless" approach would have more fairly allowed BGE to recover the 82 cents of each dollar spent for those tangible benefits OPC identified. Although this approach would still have resulted in a rate increase (albeit lower), it could have given BGE an incentive to continue to work to prove the AMI infrastructure performance and savings and therefore to seek future recovery on the $136 million in OPC's disallowed costs.

Unfortunately, the majority's decision will result in higher rates for ratepayers than we would have granted, including Maryland's most vulnerable residential customers, such as low-income households and the elderly. As anticipated in the dissents from Order Nos. 86200 and 87264, for those vulnerable ratepayers who exercised their right to opt out of having a smart meter installed, the result is even more impactful; they will be charged a higher distribution rate even after they pay a fee that disproportionately impacts them.[2]

While we do not agree with the majority's cost-effectiveness finding and advocated for OPC's "hold harmless" position, we do join in the decision to disallow $47.8 million in costs requested for AMI deployment – most notably the $16.6 million in costs attributable to customers' ability to opt-out of receiving a smart meter, agree that

[2] We further believe the Commission's decision in the instant case should reflect the same standard advocated in the dissent from Order No. 87264: "one that is 1) based on the evidence presented; and, 2) is most favorable for Maryland customers." Order No. 87264 at 3.

BGE's customer education efforts were flawed, and concur with our colleagues on all other AMI direction provided in the order.

Looking down the road, now that BGE, and other state utilities have developed, or are at various stages of developing AMI infrastructure, we hope to be convinced that smart meters are, in fact, cost-effective and beneficial to ratepayers. In the future, we would expect to see BGE and all utilities come to the Commission to offer rate reductions to offset the very real and very significant costs of AMI. We anticipate that the utilities will prove that AMI is the best and most cost-effective means to achieve savings that are noticeably greater than "what was possible pre-SGI deployment."[3] And in the future, it is our expectation that utilities will rely less on "rote" and theoretical calculations for AMI cost-effectiveness[4] and look for ways to establish new methodologies that demonstrate real and hard dollar savings to ratepayers from this costly statewide investment. We do not believe it is unreasonable for policymakers and Commissioners alike to be open to continuously challenge and update these tools which often have significant financial consequences to our citizens.

*/s/ Harold D. Williams*

*/s/ Michael T. Richard*
Commissioners

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[3] DoD Reply Brief at 4.
[4] We agree with OPC, for example, that "[r]ote calculations of an 'avoided cost' number using a screening methodology that is applied to [an] entire suite of programs that encompass energy efficiency, conservation and demand side programs" do not constitute reliable evidence in determining cost-effectiveness. OPC Reply Brief at 8.