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An Exelon Company

May 15, 2020

Via Electronic Filing

Andrew S. Johnston, Executive Secretary
Public Service Commission of Maryland
William Donald Schaefer Tower
6 St. Paul Street, 16th Floor
Baltimore, Maryland 21202-6806

Re: Application of Baltimore Gas and Electric Company for an Electric and Gas Multi-Year Plan

Dear Mr. Johnston:

Baltimore Gas and Electric Company (the "Company") files electronically on this date its Application for an Electric and Gas Multi-Year Plan.

As required by the provisions of the Code of Maryland Regulations ("COMAR") 20.07.04.07, the Company concurrently files herewith the Direct Testimony and Exhibits of its witnesses – Mark D. Case, David M. Vahos, Adrien M. McKenzie, Ajit Apte, Robert D. Biagiotti, A. Christopher Burton, Tamla A. Olivier, Mark Warner, Jason M. B. Manuel, April M. O'Neill and Lynn K. Fiery – together with Supplement 650 to P.S.C. Md. E-6 (Electric) and Supplement 467 to P.S.C. Md. G-9 (Gas), in accordance with the provisions of COMAR 20.70.04.09.

The Company also files electronically on this date the Supplemental Information required by the Commission's April 18, 1983 Secretarial Letter Order and the Multi-Year Plan ("MYP") Filing Requirements as adopted by the Commission in Order No. 89482. Note that several of the MYP Filing Requirements are Confidential and will be provided separately.

Although the Commission's March 16, 2020, Operational Notice has waived the requirement to provide paper copies of this filing, the Company will be providing a limited number of paper copies of this filing to the Commission as a courtesy and additional paper copies can be provided upon request. The Maillog number assigned to this filing will be indicated above for your reference.

Respectfully submitted,

John D. Corse

John D. Corse

JDC/mjg
cc: Leslie M. Romine, Staff Counsel
Paula M. Carmody, People's Counsel

IN THE MATTER OF THE APPLICATION OF BALTIMORE GAS AND ELECTRIC COMPANY FOR AN ELECTRIC AND GAS MULTI-YEAR PLAN	* * * * * * * *	**BEFORE THE PUBLIC SERVICE COMMISSION OF MARYLAND** **CASE NO. __________**

<u>APPLICATION OF BALTIMORE GAS AND ELECTRIC COMPANY FOR AN ELECTRIC AND GAS MULTI-YEAR PLAN AND OTHER TARIFF REVISIONS</u>

Pursuant to §§ 4-203 and 4-204 of the Public Utilities Article of the Annotated Code of Maryland ("PUA") and Public Service Commission of Maryland ("Commission") Order No. 89482, BALTIMORE GAS AND ELECTRIC COMPANY ("BGE" or the "Company") submits the application for a multi-year plan ("MYP") proposing electric and gas base distribution rates to be effective January 1, 2021; January 1, 2022; and January 1, 2023.[1] In support of its Application, BGE states:

ONE: BGE is a public service company under the PUA and is subject to Commission regulation. The Company provides electric and gas service to a population of more than 3.1 million in Baltimore City and in all or part of ten counties in Central Maryland. Electric service is provided to more than 1.3 million customers across an electric service territory of 2,300 square miles. Gas service is provided to more than 680,000 customers across a gas service territory of more than 800 square miles.

[1] Order No. 89482 was issued in Case No. 9618 on February 4, 2020.

TWO: After evaluating various alternatives to the historical test year approach traditionally used in setting base rates in Maryland, the Commission issued Order No. 89226, which initiated Case No. 9618, and directed a Working Group to provide recommendations regarding the content, process and structure of an initial MYP filing in Maryland. On December 20, 2019, the Working Group filed an Implementation Report providing its recommendations to the Commission. In Order No. 89482, the Commission set forth the framework for an MYP pilot program including, among other things, the minimum filing requirements for an MYP application and a process through which actual costs are reconciled to the costs in an MYP application. In a letter filed with the Commission on March 5, 2020, the Company expressed its willingness and desire to serve as the Pilot Utility.[2]

THREE: Under the provisions of PUA §5-303, BGE has the affirmative duty of furnishing utilities, services, and facilities which are safe, adequate, just, reasonable, economical and efficient, considering the conservation of natural resources and the quality of the environment.

FOUR: BGE has continued to make significant investments in its electric and gas distribution systems and these investments are producing positive results for BGE's customers. Since 2014, BGE has delivered first quartile 2.5 Beta CAIDI results and in 2019 BGE delivered first quartile 2.5 Beta SAIFI results as well.[3] BGE has also consistently delivered first decile gas emergency response times, responding to 99.97 percent of emergencies within less than an hour in 2019.

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[2] Mail Log #228461.

[3] CAIDI is the Customer Average Interruption Duration Index and SAIFI is the System Average Interruption Frequency Index.

BGE's customers are recognizing the impacts the Company's investments are having on service. Customer satisfaction among residential customers has continued to rise and has reached an all-time high, with more than 90 percent of residential customers reporting they are satisfied with BGE and the service we provide. For the past three years, J.D. Power has ranked BGE first among electric utilities in its East Large Segment, and first among gas utilities in the East Region for the past two years for business customer satisfaction.[4] Further, BGE's 2019 customer satisfaction scores from Escalent were the best ever on record.

BGE's efforts and investments are also helping Maryland address the challenges of climate change. Through the EmPOWER Maryland programs, BGE assists its customers in using energy more efficiently, reducing the need for additional power generation. In the last year alone, the Company's EmPOWER energy efficiency programs helped customers save more than 841,000 MWh of electricity and 5.4 million therms of natural gas. The energy efficiency measures installed in just 2019 will result in more than 6.2 million MWh in avoided generation over their lifetime. These energy savings equate to a reduction in greenhouse gas ("GHG") emissions of nearly 4.4 million metric tons of carbon dioxide equivalents ("CO2e") or removing approximately 935,000 vehicles from the road for one year. BGE's work under its MYP will continue the impressive environmental benefits Maryland and BGE's customers will realize. BGE's gas upgrade projects completed during the plan years 2021-2023 will produce lifetime GHG emission reductions of nearly 1.1 million metric tons CO2e, the equivalent of eliminating 1.3 billion pounds of coal burned. BGE's MYP electric vehicle programs will similarly benefit the environment by

[4] For the past two years, BGE ranked number one for Customer Satisfaction for Business Natural Gas Service in the J.D. Power East Region Gas Utility Business Customer Satisfaction Study.℠

supporting over 1 billion electric vehicle miles over the next 15 years, and for every electric vehicle mile, the air in Maryland will be 75 percent cleaner than if gas cars were driven.

FIVE: Under the provisions of PUA § 4-101, BGE is entitled to an operating income yielding, after a deduction for necessary and proper expenses, a reasonable return upon the fair value of its property, which must be adequate to assure confidence in the financial soundness of the utility, to maintain and support its credit, and to enable it to raise the capital necessary for the proper discharge of its duties as a public service company.

SIX: BGE's present electric and gas base rates will be neither just nor reasonable over the MYP period and will not yield a reasonable return on the fair value of BGE's property devoted to electric delivery or gas service. The requested increases are also needed for the Company to continue to provide safe and reliable service to our customers and to maintain the financial health of the Company. These requested increases will allow BGE to continue to provide tangible benefits to its customers while also promoting public safety, the economy of the state, and providing important environmental quality and natural resources conservation benefits.[5]

SEVEN: In the testimony and exhibits supporting this application, BGE provides evidentiary support for electric revenue deficiencies of $109.0 million, $156.1 million and $203.8 million in 2021, 2022 and 2023, respectively, and gas revenue deficiencies of $65.9 million, $76.2 million and $109.7 million in 2021, 2022 and 2023, respectively.[6]

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[5] PUA § 5-303.

[6] The revenue deficiencies are based on an overall rate of return on investment of 7.20 percent for both BGE's electric and gas operations and a return on equity of 10.25 percent.

However, in light of the impacts of the COVID-19 pandemic, BGE is not proposing an increase to electric and gas base distribution revenues in 2021 or 2022 and is proposing increases in 2023 of $140.4 million for electric and $94.9 million for gas. BGE is able to avoid increasing electric and gas base distribution revenues in 2021 and 2022 by lowering a proposed performance adder to its recommend return on equity by 15 basis points (from 10.25 percent to 10.10 percent); revising the manner in which major outage event restoration expense are recovered, accelerating the provision of certain tax benefits to customers and extending the amortization periods for certain regulatory assets – all while continuing to invest in its systems and operations and support the rebuilding of the economy in Central Maryland.

EIGHT: If granted in full, the requested rate relief would result in no changes to customer bills in 2021 and 2022 and, in 2023, an overall increase of 4.8 percent in total electric bills and 9.5 percent in total gas bills. However, the impact in 2023 will vary from rate schedule to rate schedule and from customer to customer. The total bill for an average residential customer receiving both electric and gas service from BGE is expected to increase in 2023 by $12.87 per month (or about 8.3 percent) to a total bill of about $167.83.[7] However, even with the impact of the requested rate relief, the total 2023 bill for an average residential customer receiving both electric and gas service from BGE will be 22 percent lower than 2008. This reflects the impact of significantly lower average energy usage facilitated by BGE's EmPOWER Maryland programs and a decline in commodity costs.

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[7] The average combined residential electric and gas customer bill impact is based on an average monthly usage of 609 kWh and 56 therms, respectively.

NINE: In accordance with Order No. 89542 in Case No. 9639, BGE has established a regulatory asset to record any incremental impacts related to the COVID-19 pandemic. For purposes of this filing, BGE has included the framework for recovery of incremental COVID-19 costs. The Company's intent is to continue to track all COVID-19 related incremental costs and will update the applicable adjustments at the time of the evidentiary hearings in this proceeding once the Company gains a better understanding of the level and timing of incremental COVID-19 costs.

TEN: Included with the Company's Application are proposed revisions to certain pages within the Company's Electric and Gas Service Tariffs designated "Supplement 650 to P.S.C. Md. E-6 (Electric)" and "Supplement 467 to P.S.C. Md. G-9 (Gas)," respectively, to become effective June 14, 2020. *Inter alia*, the revised tariff pages reflect the proposed electric and gas rates at January 1, 2021; January 1, 2022; and January 1, 2023, as well as new electric and gas Riders to effectuate certain reconciliations that are consistent with the MYP structure outlined by the Commission in Order No. 89482.

ELEVEN: This Application is supported by the prepared direct testimony and exhibits of Mark D. Case, Vice President of Regulatory Policy and Strategy for BGE; David M. Vahos, Senior Vice President, Chief Financial Officer and Treasurer for BGE; Adrien M. McKenzie, President of Financial Concepts and Applications, Inc.; Ajit Apte, Vice President of Technical Services for BGE; Robert D. Biagiotti, Vice President of Electric Operations for BGE; A. Christopher Burton, Vice President of Gas Operations for BGE; Tamla A. Olivier, Senior Vice President of Customer Operations for BGE; Mark Warner, Vice President of Gabel Associates, Inc.; Jason M. B. Manuel, Manager of Revenue Policy for BGE; April M. O'Neill, Principal Rate Analyst for BGE; and Lynn

K. Fiery, Manager of Rate Administration for BGE; which have been simultaneously filed herewith.[8]

TWELVE: This Application is supported by voluminous data submissions required by the Commission's April 18, 1983 Secretarial Letter Order, which provides that the supplemental filing requirement is "a possible means to expedite Commission proceedings by providing as much relevant data as possible at the beginning of the proceeding thereby obviating or diminishing the need for subsequent time consuming and costly data requests." See binder labeled "Supplemental Information." This Application is further supported by additional filing requirements adopted by the Commission in Order No. 89482 after determining that the requirements proposed by the Working Group were reasonable with certain modifications. See binder labeled "MYP Filing Requirements."

THIRTEEN: On March 4, 2020, the Company filed with the Commission public and confidential versions of: (1) its Cost Allocation and Transfer Pricing Manual ("CAM") for 2020, in accordance with the Code of Maryland Regulations 20.40.02.07B; and (2) the independent audit opinion of SB & Company ("SBC"), which was prepared by SBC following an examination of the CAM pursuant to the provisions of PUA § 4-208.[9]

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[8] The Company provided Part 1 of the Direct Testimony of David M. Vahos, as well as the Direct Testimony of Adrien M. McKenzie, April O'Neill and Jason Manuel to Staff, OPC and other interested persons on March 2, 2020. The Company provided the Direct Testimony of Mark Warner on April 24, 2020.
[9] BGE's CAM and CAM audit filing was submitted under Mail Log #228935.

WHEREFORE, Baltimore Gas and Electric Company requests that the Commission permit the rates filed herewith to become effective as filed.

Respectfully submitted,

John D. Corse

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Attorney for Applicant
Baltimore Gas and Electric Company

May 15, 2020

Before the Maryland Public Service Commission

Case No.________

Prepared Direct Testimony of

Mark D. Case

On Behalf of

Baltimore Gas and Electric Company

May 15, 2020

List of Issues and Major Conclusions

The following is a summary list of the issues and major conclusions addressed in the Prepared Direct Testimony of Mark D. Case:

- Consistent with Order No. 89482 in Case No. 9618, BGE is proposing a Multi-Year Plan ("MYP") covering the three years of 2021, 2022 and 2023, based upon the Company's budget, including the budgeted capital and operations and maintenance ("O&M") plans and spend. The electric and gas work plans include capital expenditures in each of the MYP years which are lower than the 2019 capital expenditure levels, and the ongoing O&M costs reflect a nominal 0.5% annual growth rate compared to 2019.

- In light of the COVID-19 pandemic, the Company is not proposing in this MYP base distribution revenue increases for 2021 and 2022 and is proposing an increase in 2023. As explained further by Company Witness Vahos, this proposal is accomplished through a series of proforma revenue requirement adjustments to accelerate certain tax benefits, revise how BGE recovers major outage event restoration expenses, suspend regulatory asset amortization in 2021, and extend the amortization periods of certain existing regulatory assets. BGE is also reducing the performance adder it proposed to the recommended return on equity ("ROE"). The performance adder is appropriate based upon BGE's outstanding reliability, customer satisfaction, and gas response results. The Company is now recommending a ROE of 10.1%.

- The requested MYP revenue requirements and base distribution rates result in no increase to customer bills in 2021 and 2022. In 2023, the requested base distribution revenue increase results in a 4.8% increase on total electric bills and 9.5% in total gas bills. The average combined electric and gas residential customer will see an 8.3% increase in 2023, for an average annual growth rate of 2.8% over the MYP period, as supported in the Direct Testimony of Company Witness Fiery. However, even with the impact of the requested rate relief, the total 2023 bill for an average residential customer receiving both electric and gas service from BGE will be 22% lower than in 2008.

- BGE has also included in the Direct Testimony of Company Witness Warner a benefit cost analysis that shows the Company's electric vehicle program offerings, approved by the Commission in 2019, provide a strong benefit/cost ratio of 2.63 on a portfolio basis. Based on a market-wide Societal Cost Test that considers all costs and benefits, benefits exceed costs by a factor of 3.10. BGE respectfully requests that the Commission approve recovery of the EV program costs to begin in this MYP.

- A recent economic study of BGE's MYP shows that BGE's planned investments and activities will contribute more than $15.3 billion of economic value to Maryland's economy, more than $2.8 billion in labor income and almost $900 million in state and local tax revenues. BGE is also focused on delivering environmental benefits to customers. In 2019 alone, BGE's EmPOWER Maryland energy efficiency programs helped customers save more than 841,000 MWh of electricity and 5.4 million therms of natural gas. And over the MYP, BGE's gas projects, including STRIDE, will produce lifetime greenhouse gas emission reductions of nearly 1.1 metric tons of CO_2e, the greenhouse gas equivalent of a reduction of 1.3 billion pounds of coal burned. BGE's electric vehicle programs will similarly benefit the environment by supporting over 1 billion electric vehicle miles over the next 15 years, resulting in an estimated displacement of 4.8 billion gallons of gasoline.

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I. QUALIFICATIONS

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. My name is Mark D. Case, and my business address is 2 Center Plaza, 110 West Fayette Street, Baltimore, Maryland 21201.

Q. WHAT IS YOUR POSITION WITH BALTIMORE GAS AND ELECTRIC COMPANY?

A. I am employed by Baltimore Gas and Electric Company ("BGE" or the "Company") as Vice President of Regulatory Policy and Strategy. In that capacity I am responsible for the following functions: regulatory administration and pricing; strategy; electric and gas energy supply; PJM load settlement and wholesale market interfaces; customer choice programs; and energy efficiency and demand response programs.

Q. PLEASE DESCRIBE YOUR BUSINESS EXPERIENCE AND EDUCATIONAL BACKGROUND.

A. I hold a Bachelor of Science Degree (magna cum laude) in Mechanical Engineering from the University of Maryland and a Master's Degree in Administrative Science from Johns Hopkins University. I am a graduate of the Rutgers Program for Management Development, the Executive Management Program at Penn State University, and the 2004 Leadership Maryland Program. I began my career at BGE in 1982 and have held numerous leadership positions since 1987. Recent positions include Manager of Organization Performance; Vice President of Business Performance, Strategy and Regulatory Services; and, since June 2015, Vice President of Regulatory Policy and Strategy.

Q. ARE YOU INVOLVED WITH ANY CIVIC ORGANIZATIONS?

A. Yes, I am. I currently serve on the boards of the Galesville Heritage Society and the Baltimore Municipal Golf Corporation. I was previously a board member of the Habitat for Humanity of the Chesapeake Region, the Maryland Strategic Energy Investment Fund, and the Baltimore Museum of Industry. I am a member of the Edison Electric Institute State Regulatory Affairs Executive Advisory Committee. I am also an active supporter of the United Way of Central Maryland.

Q. HAVE YOU PREVIOUSLY TESTIFIED BEFORE THIS COMMISSION?

A. Yes. Please see Company Exhibit MDC-1 for a list of the proceedings in which I testified before the Maryland Public Service Commission (the "Commission").

II. <u>PURPOSE OF DIRECT TESTIMONY</u>

Q. WHAT IS THE PURPOSE OF YOUR DIRECT TESTIMONY?

A. My Direct Testimony is offered in support of BGE's request for approval of a Multi-Year Plan ("MYP") which will set new electric and gas base rates and revenues for the 2021-2023 MYP period. In light of the COVID-19 pandemic, BGE is not proposing electric and gas base distribution revenue increases in 2021 or 2022 and is proposing to increase base distribution revenues in 2023, while still executing the Company's proposed electric and gas work plans set forth in the Company's direct testimony.[1]

[1] See the Direct Testimony and Exhibits of Company Witnesses Apte, Biagiotti, Burton, Olivier, and Vahos for the details of the Company's proposed electric and gas work plans.

First, I will briefly describe the Company's overall business and introduce the other witnesses for the Company who will participate in this proceeding and briefly describe the nature of their testimony.

Second, I will set forth BGE's requested plan for an MYP, including how the Company is addressing the impacts of the COVID-19 pandemic.

Third, I will explain how the Company's proposed MYP conforms to the MYP structure outlined by the Commission in Order No. 89482.

Fourth, I will discuss the environmental benefits of certain Company programs, including its electric vehicle ("EV") programs, and the method for EV portfolio cost recovery.

Fifth, I will provide an overview of the Company's economic development efforts and a recent economic study performed on the proposed MYP.

Sixth, I will discuss customers satisfaction and the Company's involvement with the communities that it serves.

III. OVERVIEW OF BALTIMORE GAS AND ELECTRIC COMPANY

Q. MR. CASE, PLEASE DESCRIBE BGE'S BUSINESS.

A. BGE was founded in 1816 as the United States' first gas light utility. More than two hundred years later, the Company has evolved into an electric transmission and distribution and gas distribution company. BGE serves over 1.3 million electric customers and more than 680,000 gas customers across the Company's central Maryland service area. BGE's electric service area of 2,300 square miles and gas service area of more than 800 square miles encompass the City of Baltimore, as well as all or parts of 10 counties in central Maryland with an estimated population of more than 3.1 million people.

BGE delivers electricity to its customers over approximately 1,300 circuit miles of transmission lines and nearly 27,000 circuit miles of distribution lines. BGE operates and maintains approximately 150 miles of gas transmission-rated pipeline, over 7,400 miles of gas distribution mains, almost 6,400 miles of local gas services, two peak-shaving plants, and 12 gate stations with the connected upstream interstate pipelines to deliver gas to customers.[2] For customers who do not select alternative energy providers under BGE's retail customer choice programs, BGE is also the default energy supplier.

IV. INTRODUCTION OF WITNESSES

Q. MR. CASE, WHAT OTHER WITNESSES WILL TESTIFY ON BEHALF OF BGE IN SUPPORT OF THIS REQUEST FOR RATE RELIEF?

A. In addition to my testimony, the following 10 witnesses will present testimony and exhibits on behalf of BGE: [3]

David M. Vahos, Senior Vice President, Chief Financial Officer and Treasurer for BGE, will provide in this proceeding a Part 1 and Part 2 of his testimony, which presents financial data supporting the Company's request for additional electric and gas revenues, including several proforma adjustments for 2021 and 2022 that allow the Company to maintain electric and gas base distribution revenues at their current levels in those years.

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[2] All statistics provided are as of December 31, 2019.

[3] The Company provided Part 1 of the Direct Testimony of David M. Vahos, as well as the Direct Testimonies of Adrien M. McKenzie, April O'Neill and Jason Manuel to Staff, OPC and other interested persons on March 2, 2020. The Company provided the Direct Testimony of Mark Warner on April 24, 2020.

Mr. Vahos presents the Company's proposed capital structure and overall cost of capital for its electric and gas operations. He will also discuss the Company's annual planning and budgeting process and how this supports the MYP, as well as certain categories of capital and operations and maintenance ("O&M") expenditures supporting the Company's proposed electric and gas work plans.

Adrien M. McKenzie, President of Financial Concepts and Applications, Inc. ("FINCAP"), will present an independent assessment of the fair rates of return on equity ("ROE") that BGE should be authorized to earn on its investments in providing electric and gas delivery service to customers. Mr. McKenzie also examines the reasonableness of BGE's proposed capital structure.

Ajit Apte, Vice President of Technical Services for BGE, describes the Company's capital and O&M for 2021-2023 for planning, managing, and overseeing electric distribution system capacity planning, implementing smart grid and other innovative programs, executing large, complex electric and gas distribution projects and reliability programs and maintaining the reliability of the electric distribution system, including vegetation management.

Robert D. Biagiotti, Vice President of Electric Operations for BGE, describes the capital and O&M for 2021-2023 necessary to support the safe and reliable operations and maintenance of the electric distribution system and to support new service connections, as well as for certain categories related to the substations on BGE's electric distribution system.

A. Christopher Burton, Vice President of Gas Operations for BGE, describes the gas operating areas of BGE and reviews gas capital and O&M expenditure categories as they relate to those areas.

Tamla A. Olivier, Senior Vice President of Customer Operations for BGE, describes the Customer Operations areas of BGE and reviews the capital and O&M expenditure categories as they relate to those areas, as well as how BGE has delivered outstanding customer satisfaction scores for the past three years.

Mark Warner, Vice President at Gabel Associates, Inc, will present and explain the methodology and results of the cost benefit analysis that was performed regarding BGE's electric vehicle program portfolio.

Jason M. B. Manuel, Manager of Revenue Policy for BGE, will present and explain the 2019 Gas Cost of Service Study. Mr. Manuel also addresses the Company's compliance with the gas cost of service study directives agreed to in the Settlement Agreement approved by the Commission in Case No. 9610.

April M. O'Neill, Principal Rate Analyst for BGE, will present and explain the 2019 Electric Cost of Service Study. Ms. O'Neill also addresses the Company's compliance with the electric cost of service study directives agreed to in the Settlement Agreement approved by the Commission in Case No. 9610.

Lynn K. Fiery, Manager of Rate Administration for BGE, will present the allocation of the requested electric and gas revenue increases among BGE's customer classes as well as the rate design for each customer class that will produce the requested increase to electric and gas revenues over the MYP period. Ms. Fiery also proposes new electric and gas

Riders which address certain reconciliations that are consistent with the MYP structure outlined by the Commission in Order No. 89482.

V. OVERVIEW OF BGE'S RESPONSE TO THE PANDEMIC AND MYP REQUEST

Q. PLEASE EXPLAIN BGE'S RESPONSE TO THE COVID-19 PANDEMIC?

A. First, let me start by acknowledging that the Company is filing this MYP during the COVID-19 pandemic, which has had widespread impacts on Maryland and BGE's customers. We do not take this lightly and believe the investments reflected in the MYP can help support Maryland's recovery from the pandemic. In light of this, the Company has gone to extensive lengths to develop an MYP filing that provides customers greater time before being faced with an increase in electric and gas base distribution bills. BGE must continue to invest in its systems and operations to provide safe and reliable service to its customers, which will help support the recovery of the economy of Central Maryland and provide necessary employment opportunities. BGE is not proposing to increase the base distribution portion of customer bills during the first two years of the MYP period. However, BGE will invest approximately $2.8 billion in capital and $2.1 billion in O&M in order to execute its electric and gas work plans over the MYP. The Company is able to avoid increasing the base distribution portion of customer bills 2021 and 2022 by decreasing the proposed performance adder to the recommended return on equity and, as explained further by Company Witness Vahos, by proposing a series of proforma adjustments to accelerate certain tax benefits, revise how BGE recovers major outage event restoration expenses, suspend regulatory asset amortization in 2021, and extend the amortization periods of certain existing regulatory assets.

Additionally, as will be discussed later in my testimony, an economic impact study, which is attached to my testimony as Exhibit MDC-2, shows that the Company's proposed MYP will have substantial positive benefits to the Maryland economy over the MYP period.

At BGE, safety is our top priority. As part of our commitment to safety, we are closely monitoring developments related to the COVID-19 pandemic and taking appropriate precautions to protect the health and safety of our employees, contractors, and customers. To ensure the safety of our customers and employees, employees who are able to work remotely are now doing so. We are also requiring employees who need to interact with customers to wear masks, and employees who work on electrical and gas equipment also have additional equipment to perform their jobs safely, such as rental vehicles to allow for social distancing when traveling to job sites, portable hand-washing stations, and fire retardant masks and overalls. BGE has also suspended customer service disconnections and the imposition of new late payment charges until at least July 1, 2020.[4]

BGE, Constellation and the Exelon Foundation are contributing $1.0 million to support Maryland relief organizations and small businesses, including the United Way of Central Maryland 211 Call Center and the Maryland Food Bank. Additionally, BGE is making a $1.5 million contribution to the Fuel Fund of Maryland to assist limited income residential customers with their bills in 2020 and will be providing $1.0 million in funding this year to county-administered business pandemic relief funds in central Maryland to

[4] The suspension of disconnections and imposition of late payment charges applies to residential customers and qualifying business customers.

assist small businesses that have been challenged by the economic hardships of the COVID-19 pandemic response.

Q. WHAT IS BGE'S SPECIFIC REQUEST FOR RATE RELIEF IN THIS PROCEEDING?

A. Chart 1 below provides a summary of BGE's requested electric and gas revenue requirements for the three-year MYP period for the calendar years of 2021–2023, as supported by the Direct Testimony of Company Witness Vahos, and as enabled by the reduced ROE performance adder, modified approach to major outage event restoration expense recovery, accelerated tax benefits and regulatory asset adjustments proposed therein:

Chart 1 – Revenue Requirement Summary

MYP Revenue Requirement Summary
($ in Millions)

	MYP 2021	MYP 2022	MYP 2023
Electric:			
Cumulative Electric Incremental Revenue Requirement Before Benefits and Adjustments	$ 109.0	$ 156.1	$ 203.8
Total Benefits and Adjustments	(109.0)	(156.1)	(63.4)
Annual Electric Incremental Revenue Requirement Including Benefits and Adjustments	**$ -**	**$ -**	**$ 140.4**
Gas:			
Cumulative Gas Incremental Revenue Requirement Before Benefits and Adjustments	$ 65.9	$ 76.2	$ 109.7
Total Benefits and Adjustments	(65.9)	(76.2)	(14.8)
Annual Gas Incremental Revenue Requirement Including Benefits and Adjustments	**$ -**	**$ -**	**$ 94.9**
Total Revenue Impact on Customers Bills	**$ -**	**$ -**	**$ 235.3**

As the Company is not proposing an increase to base distribution revenues in 2021 or 2022 and Company Witness Fiery is not proposing to change the revenue allocation among customer classes in 2021 and 2022, the result of the Company's proposal is that the base distribution portion of customer bills will not increase in 2021 or 2022. In 2023, total electric bills will increase 4.8% and total gas bills will increase 9.5% as a result of the

Company's proposal. Average residential combined customer bills will see an 8.3% increase in 2023, for an average annual growth rate of 2.8% over the MYP period, as supported in the Direct Testimony of Company Witness Fiery. However, even with the impact of the requested rate relief, the total 2023 bill for an average residential customer receiving both electric and gas service from BGE will be 22% lower than 2008. This reflects the impact of significantly lower average energy usage facilitated by BGE's EmPOWER Maryland programs, and a decline in commodity costs.

It is important to note that this proposal will still allow the Company to execute the electric and gas work plans underlying the MYP rate request. And while the Company needs to continue making investments and incurring the ongoing costs to execute these plans, the total capital expenditures in each of the MYP years are lower than 2019 capital levels, and the ongoing O&M costs reflect a nominal 0.5% annual growth rate from 2019.

Q. MR. CASE, WOULD YOU PLEASE OUTLINE THE COMPANY'S PLANNED CAPITAL AND O&M EXPENDITURES OVER THIS MYP?

A. Yes. The budgets associated with the capital and O&M workplans supported by the Direct Testimonies of Company Witnesses Apte, Biagiotti, Burton, Olivier and Vahos are shown in Chart 2 below.

Chart 2 – Summary of Capital and O&M MYP Budgets[5]

Capital

	MYP Period 2021F	2022F	2023F	Totals 2021-2023
Apte	$ 217,392,989	$ 198,048,473	$ 204,245,784	$ 619,687,246
Biagiotti	$ 218,268,868	$ 242,200,524	$ 244,789,895	$ 705,259,287
Burton	$ 294,192,406	$ 324,144,855	$ 299,831,429	$ 918,168,690
Olivier	$ 13,944,406	$ 9,431,381	$ 9,577,780	$ 32,953,567
Vahos	$ 203,465,907	$ 212,739,907	$ 174,622,440	$ 590,828,254
Total	$ 947,264,576	$ 986,565,140	$ 933,067,328	**$ 2,866,897,044**

O&M

	MYP Period 2021F	2022F	2023F	Totals 2021-2023
Apte	$ 38,999,435	$ 39,569,612	$ 40,767,593	$ 119,336,640
Biagiotti	$ 133,130,108	$ 136,865,064	$ 139,501,018	$ 409,496,190
Burton	$ 91,553,991	$ 88,210,783	$ 86,535,682	$ 266,300,456
Olivier	$ 111,456,230	$ 110,877,626	$ 110,782,016	$ 333,115,872
Vahos	$ 352,434,970	$ 353,694,117	$ 355,473,626	$ 1,061,602,713
Total	$ 727,574,734	$ 729,217,202	$ 733,059,935	**$ 2,189,851,871**

Q. WHAT KINDS OF PROJECTS ARE CONTEMPLATED IN THE COMPANY'S MYP?

A. Examples of the more than 300 capital projects and maintenance programs during the MYP period detailed in the testimony and exhibits of other Company witnesses include:

- **Enhancing energy infrastructure** supporting the growth of important economic development sites, such as the continued grid enhancements to the Tradepoint Atlantic Redevelopment site.
- **Installing smart automation equipment** to more quickly identify and circumvent damage to the electric grid and reduce the frequency and duration of power outages.

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[5] The chart above includes certain capital and O&M expenditures for items such as the transmission portion of common expenditures, and below-the-line costs such as charitable contributions. These expenditures *are* included in the testimony and exhibits of Company witnesses supporting the Company's MYP capital and O&M plans *but are not* included in the capital and O&M amounts requested for recovery in the Company's MYP distribution revenue requirements in the Part 2 of the Direct Testimony of Company Witness Vahos. With those items excluded, the requested MYP period total O&M is $2.1 billion and capital is $2.8 billion.

- **Replacing outmoded technologies,** such as limited capacity 4kV electric systems to improve reliability, enable greater adoption of solar energy and electric vehicle charging and increased capacity in areas where redevelopment adds additional customer demand.
- **Preparing the grid for extreme weather** with continued tree trimming and vegetation management to ensure power line clearance and improve reliability during extreme weather events.
- **Modernizing the gas pipeline system** to enhance safety and reliability and reduce carbon dioxide emissions, including converting older lower pressure systems to more updated higher pressure systems and installing other safety equipment to better serve customers.

Importantly, the work to be undertaken by the Company between 2021 and 2023 will also help provide, as I discuss later in my testimony, a stable foundation upon which Maryland's economy can rebuild.

Q. PLEASE EXPLAIN THE COMPANY'S PROPOSED PERFORMANCE ADDER TO ITS PROPOSED ROE.

A. In Part 1 of Company Witness Vahos' Direct Testimony, BGE proposed a 10.25% ROE, which was based on the 9.9% ROE recommended by Company Witness McKenzie and adjusted upwards for a performance adder of 35 basis points to a ROE of 10.25%, which is the midpoint of the upper end of Company Witness McKenzie's range of recommended ROEs. In light of the COVID-19 pandemic and to avoid base distribution revenue increases in 2021 and 2022, BGE is now proposing a 10.1% ROE, based upon Company Witness McKenzie's recommended 9.9% ROE and a reduced performance adder of 20 basis points. As explained in the Part 1 of the Direct Testimony of Company Witness Vahos and the Direct Testimonies of Company Witnesses Apte, Biagiotti, Burton and Olivier, the Company has exhibited exemplary service, reliability, and efficiency for many years. In fact, since 2014, BGE has delivered first quartile 2.5 Beta CAIDI results and, in

2019, BGE delivered first quartile 2.5 Beta SAIFI results as well.[6] BGE is also committed to providing safe and reliable gas service and has consistently delivered first decile gas emergency response times, responding in 2019 to 99.97% of emergencies within less than an hour. In 2019 BGE delivered its best-ever gas emergency average response time, responding to gas emergencies in less than 22 minutes on average. Over the last several years, BGE has also replaced more than 210 miles of its vintage and aging pipeline infrastructure including cast iron and bare steel mains and more than 40,000 metallic gas services, about 25,000 of which were low pressure services. As part of that replacement work, BGE has made significant progress in reducing the low pressure gas system, eliminating more than 200 miles of low pressure main, or about 15% of the low pressure main on the gas system.

In addition to the Company's exceptional operating performance, as discussed later in my testimony, the Company has achieved superior customer service scores. As discussed by Company Witness Olivier, customer satisfaction among residential customers has continued to rise and has reached an all-time high, with more than 90% of residential customers reporting they are satisfied with BGE and the service we provide. For the past three years, J.D. Power has ranked BGE first among electric utilities in its East Large Segment, and first among gas utilities in the East Region for the past two years, for business customer satisfaction.[7] Further, BGE's 2019 customer satisfaction scores from Escalent were the best ever on record. BGE believes that consistent excellent operating performance

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[6] CAIDI is the Customer Average Interruption Duration Index and SAIFI is the System Average Interruption Frequency Index.

[7] For the past two years, BGE ranked number one for Customer Satisfaction for Business Natural Gas Service in the J.D. Power East Region Gas Utility Business Customer Satisfaction Study.℠

and customer satisfaction should positively impact the ROE authorized by the Commission.

Q. IS A PERFORMANCE ADDER CONSISTENT WITH THE ECONOMIC RATIONALE UNDERLYING TRADITIONAL RATE OF RETURN / RATE BASE REGULATION?

A. Yes. As discussed in the Direct Testimony of Witness McKenzie, the goal of regulation is to achieve a similar result as would exist in a competitive market. In competitive markets, high-performing companies that combine outstanding service with reasonable prices are generally able to benefit from efficient operations by realizing higher rates of return for their shareholders.

Consistent with this logic, the Commission has observed that "[i]n a competitive market, for which regulation is intended to be a substitute, [a utility's] continuing poor reliability would cause it to lose business and profits to its competitors," and that the allowed ROE should consider a utility's standard of reliability and service quality.[8] The Commission concluded that it would not allow "a monopoly distribution company, to reap growing profits while it provides subpar service to customers."[9] Therefore, it follows that an upward adjustment should also be considered for exemplary performance.

Q. HAS THE COMMISSION ALLOWED FOR THE ESTABLISHMENT OF A REGULATORY ASSET TO ADDRESS COSTS ASSOCIATED WITH THE COVID-19 PANDEMIC?

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[8] Case No. 9286, Order No. 85028 (Jul. 20, 2012) at 108.
[9] *Id.* at 109.

A. Yes. On April 9, 2020, the Commission issued Order No. 89542, in response to the pandemic and the emergency orders issued by Maryland Governor Hogan. The Commission acknowledged that the pandemic and the emergency executive orders may have significant financial implications on Maryland utilities and service providers. To minimize these adverse financial impacts, the Commission authorized each utility to create a regulatory asset to record the prudently incurred incremental costs related to the COVID-19 pandemic.[10]

Q. HAS THE COMPANY ESTABLISHED A REGULATORY ASSET FOR INCREMENTAL COSTS RELATED TO THE COVID-19 PANDEMIC?

A. Yes. The Company has established a regulatory asset to track and recover costs associated with the Company's response to the COVID-19 pandemic per Order No. 89542. As explained by Company Witness Vahos in Part 2 of his Direct Testimony, the Company has already deferred certain costs into this regulatory asset and expects to continue to incur additional costs over the course of 2020 and into the MYP period. Such costs include enhanced cleaning services and supplies, masks and other protective equipment as well as the waived late payment and service applications fees. It is also expected that the Company will incur higher uncollectible write-offs; however, these are difficult to estimate at this time. As such, Company Witness Vahos proposes a framework for recovery of this regulatory asset, and the Company will update the related costs at the time of the evidentiary hearings in this proceeding.

[10] Case No. 9639, Order No. 89542.

VI. CASE NO. 9618 AND BGE'S PROPOSED MYP

Q. PLEASE DISCUSS CASE NO. 9618 AND THE COMMISSION'S EVALUATION OF IMPLEMENTING ALTERNATIVE RATE MAKING PLANS.

A. In order to evaluate alternatives to the historical test year approach traditionally used in setting base rates in Maryland, the Commission initiated Public Conference 51 ("PC51") to allow affected stakeholders and interested persons to submit information and comments on the various alternative rate plans implemented in other states."[11] Following the submission of written comments and a public conference, the Commission issued Order No. 89226, which initiated Case No. 9618, and directed a Working Group to provide recommendations regarding the content, process and structure of an initial MYP filing in Maryland. On December 20, 2019 the Working Group filed an Implementation Report ("Implementation Report") providing its recommendations to the Commission. On February 4, 2020, the Commission issued Order No. 89482 (the "MYP Order") establishing the framework for an MYP pilot program.

Q. PLEASE DISCUSS THE MYP FRAMEWORK THAT THE COMMISSION ESTABLISHED IN THE MYP ORDER?

A. The Commission approved the filing of an MYP application to serve as the basis for a pilot program to gain additional experience and lessons learned regarding MYP filings. In doing so, the Commission recognized that

> …a properly constructed MRP can result in just and reasonable rates and yield several benefits over time. Among these benefits, the Commission determined that the use of MRPs could shorten the cost recovery period,

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[11] See PC 51, Exploring the Use of Alternative Rate Plans or Methodologies to Establish New Base Rates for an Electric Company or Gas Company, Notice of Public Conference (Mail Log # 223975) (issued February 14, 2019).

> provide more predictable revenues for utilities and more predictable rates for customers, spread changes in rates over multiple years, and decrease administrative burdens on regulators by staggering filings over several years.[12]

The structure of the Commission-approved MYP framework also provides that, among other things, "…the reconciliation of the Pilot Utility's costs will be conducted by three processes: (1) an annual informational filing, (2) a consolidated reconciliation and prudency review in a subsequent rate case, and (3) a final reconciliation and prudency review after the conclusion of the Pilot MRP rate-effective period."[13]

Q. MR. CASE, HAS THE COMMISSION ALSO DETERMINED MINIMUM FILING REQUIREMENTS FOR AN MYP?

A. Yes. In the MYP Order, the Commission set forth minimum filing requirements for an MYP, apart from regulations that may be set forth by the Commission in the future. This Order directs that the Pilot Utility MYP proposal: (1) contain all of the filing requirements found in Item 2 of the Report, as modified in the MYP Order; (2) allow up to three future rate-effective years with an agreement to "stay out" for that period; (3) contain specific criteria for any "off-ramp" process (i.e., extraordinary circumstances outside the utility's control that would warrant the Commission's intervention to modify or terminate the MYP); (4) track the accuracy of the utility's forecast; (5) have an annual informational filing which the Commission may use as the basis for mid-cycle MYP adjustments; and (6) contain adequate reporting requirements.[14]

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12 Order No. 89842 at 1, Order No. 89826 at 54.

13 Case No. 9618, Order No. 89482, p. 37.

14 Case No. 9618, Order No. 89482, p. 3.

Q. MR. CASE, HAS BGE MET THESE MINIMUM FILING REQUIREMENTS IN THIS FILING?

A. Yes. BGE's proposed MYP, and the Direct Testimony of Company Witness David Vahos specifically, includes a historic test year which serves as the basis of comparison for the forecasted rate-effective period of 2021-2023. Additionally, BGE's filing (1) contains all of the requirements included in Item 2 of the Case No 9618 Implementation Report (as modified by the MYP Order); (2) proposes rate adjustments for the three-year MYP period of 2021-2023 and a commitment that BGE will not file for a base distribution rate increase to be effective prior to the end of the MYP period; and (3) proposes an "off ramp" process. The Company is proposing to satisfy items (4), (5) and (6) through the various filings and reconciliations, including the Annual Informational Filings and the Reconciliation process. Exhibit MDC-3, which I walk through in more detail later in my testimony, outlines the timeline for the various deliverables, reporting filings, and processes, consistent with the Commission's filing requirements and the timeline laid out in the MYP Order.

Q. MR. CASE, WHY DID BGE VOLUNTEER TO BE THE PILOT UTILITY?

A. As a combined electric and gas utility and the largest utility in the state, BGE believes that it provides the optimal pilot opportunity for the Commission to address how MYPs will impact both electric and gas utilities and their respective customers, providing valuable guidance for future MYPs. BGE agrees with the Commission when it determined that an MYP, structured as directed in the MYP Order, can and will deliver meaningful benefits for customers. Specifically, in Order No. 89226 the Commission determined that the use of MYPs could shorten the cost recovery period, provide more predictable revenues for utilities and more predictable rates for customers, spread changes in rates over multiple years, and decrease administrative burdens on regulators by staggering filings over several years.[15] Furthermore, the forward-looking nature of an MYP will allow more visibility into the work plans of the Company, instead of the after-the-fact review in traditional ratemaking, allowing for a better alignment of strategic priorities between BGE and its stakeholders.

Q. DOES THE MYP PROCESS PRESERVE THE OVERSIGHT OF THE COMMISSION AND STAKEHOLDERS?

A. Yes. The proposed MYP process fully preserves the Commission's and stakeholders' oversight. The Commission and stakeholders will have the opportunity to review the Company's performance under the MYP in each of the three years as a result of the Annual Informational Filings as well as the Reconciliation process. In fact, the information about the Company's investments and activities provided in the Direct Testimonies and Exhibits of Company Witnesses Apte, Biagiotti, Burton, Olivier and Vahos, along with the Annual Informational Filings, will expand the information the Commission and stakeholders currently receive under the traditional ratemaking regime. The Company will also file annual project lists with anticipated capital infrastructure investments. The additional filings that the Company envisions being provided as part of an MYP are presented in Exhibit MDC-3.

Q. MR. CASE, PLEASE NOW EXPLAIN EXHIBIT MDC-3.

A. I will start with the annual project lists, which will be provided at least 60 days prior to the beginning of the MYP rate-effective year, except for the 2021 project list which will be

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[15] Order No. 89226, page 54.

provided 60 days after a Commission order in this proceeding. Following a Commission order in this proceeding in December 2020, rates for 2021, the first MYP year, will become effective on January 1, 2021. Shortly afterwards, the Company will file the 2021 project list. Consistent with Order No. 89482 and the Implementation Report, the annual project lists will include updated information on project work to be done in the following year, at the same level of detail as provided in the capital budgets included in exhibits to the Direct Testimonies of Company Witnesses Apte, Biagiotti, Burton, Olivier and Vahos. The Company plans to file the second annual project list data for 2022 capital project work by November 1, 2021. On January 1, 2022, rates for the second MYP year will become effective. By April 1, 2022, the Company will file the first Annual Informational Filing for the 2021 MYP year which will, at minimum, include exhibits and supporting information comparing forecasted data to actual data at the summary revenue requirement level (as shown in Company Exhibits DMV-2E and 2G), as well as the rate base and operating income line item level (as shown in Company Exhibits DMV-3E and 3G), and category data for capital and O&M results. Consistent with Order No. 89482, the Company anticipates discovery on the Annual Informational Filing being open for a 60-day period, providing stakeholders with an opportunity to better understand the actual results. This same annual process for the 2023 annual project list and 2022 Annual Informational Filing would occur. In 2023, BGE will file an application requesting new base rates to be effective January 1, 2024. Included in that rate case will be a reconciliation of 2021 and 2022 MYP rates based on the 2021 and 2022 Annual Informational Filings previously submitted to the Commission. This consolidated reconciliation provides an opportunity for a review of the 2021 and 2022 actual investments and costs. A final reconciliation for this 2021-2023 MYP would then be filed by May 1, 2024, which would reconcile the 2023 MYP rates.

Q. IS BGE PROPOSING ANY PERFORMANCE INCENTIVE MECHANISMS ("PIMs") AS A PART OF ITS MYP?

A. No. The Company is not proposing any PIMs to be included as part of its proposed MYP as Phase 2 of the PC51 Working Group is still underway. The PC51 Working Group is still working to establish performance mechanisms and how to integrate those mechanisms into an MYP. Additionally, during Phase 2 of the PC51 Working Group, Commission Staff recommended that PIMs not be included in the pilot MYP to allow the Commission and parties to focus on the structure of the MYP without the additional complexities of PIMs and associated financial adjustments. The Commission in its MYP Order did not require the Pilot Utility to include performance metrics or incentive mechanisms as part of its MYP. Furthermore, the report on Phase 2 of the PC51 Working Group will not be filed until June 17, 2020, and an order on PIMs as a result of the Phase 2 Working Group process would not be expected until well into this proceeding's schedule. Therefore, BGE has not proposed any PIMs in this proceeding.

Q. IS THE COMPANY PROPOSING A STAY OUT PROVISION AND OFF-RAMP AS PART OF THIS MYP?

A. Yes. Consistent with Order No. 89482, the Company agrees to not file a rate case during the 2021–2023 MYP period for new base distribution rates to be effective prior to January 1, 2024. Additionally, in accordance with the MYP Order, the Company will file a traditional rate case or a new MYP application at least 210 days prior to January 1, 2024, the end of this MYP period.[16] BGE is also proposing that the Commission approve an off-ramp through which any party, including the Commission on its own motion, may file a petition to re-open and review the Company's MYP if there is sufficient evidence that there is an issue that cannot be resolved through another avenue available under the MYP. The off-ramp provision would protect customers and the Company from extraordinary circumstances outside the control of the utility that occur during the MYP period. Such situations may include, but are not limited to: changes in law, natural disasters, cyber or terror attacks, major economic events, or other circumstances that would warrant the Commission's intervention to modify or terminate the MYP.[17] The off-ramp provision would allow parties to propose modifying the MYP to mitigate the impacts of the unforeseen circumstance or to propose terminating the MYP. If a petition is filed, the requesting party should include a recommended proposal, timeline and procedural schedule as part of its petition.

Q. HOW DOES THE COMPANY PROPOSE EXTRAORDINARY COSTS WOULD BE TREATED IF THEY OCCUR DURING THIS MYP?

A. Consistent with the MYP Order, in order to provide more transparency and accountability, BGE will seek Commission approval to defer in a regulatory asset, in the year in which those costs were incurred, any extraordinary costs incurred over the course of the MYP for consideration by the Commission.[18]

[16] Case No. 9618, Order No. 89482, p. 4.

[17] Order No. 89482, p. 30.

[18] Order No. 89482, p. 38.

<u>VII. ENVIRONMENTAL BENEFITS, EV CHARGING PROGRAM AND COST RECOVERY</u>

Q. MR. CASE, IN WHAT WAYS IS BGE WORKING TO BENEFIT THE ENVIRONMENT AND ADDRESS CLIMATE CHANGE?

A. As the largest utility in Maryland and a subsidiary of Exelon Corporation ("Exelon"), the nation's leading provider of clean energy, BGE recognizes the critical role we play in improving the environment and helping Maryland and our customers address the challenges of climate change. This includes the many ways we assist our customers in using energy more efficiently through the EmPOWER Maryland programs, reducing the need for additional power generation. In the last year alone, our suite of EmPOWER energy efficiency programs helped customers save more than 841,000 MWh of electricity and 5.4 million therms of natural gas. The energy efficiency measures installed in just 2019 will result in more than 6.2 million MWh in avoided generation over their lifetime. These energy savings equate to a reduction of nearly 4.4 million metric tons of carbon dioxide equivalents ("CO2e") or removing approximately 935,000 vehicles from the road for one year. Add to those results BGE's upgrades to its natural gas system through the STRIDE program and other natural gas projects, which significantly reduce direct greenhouse gas emissions. Looking ahead, the gas main and service projects in 2021-2023 that are discussed in the testimony of Company Witness Burton will produce lifetime greenhouse gas ("GHG") emission reductions of nearly 1.1 million metric tons of CO2e, the equivalent of eliminating 1.3 billion pounds of coal burned.

BGE also focuses on reducing the effects of our own operations on the environment. The Company's environmental management system has been International

Standards Organization 14001 certified since 2012. This voluntary compliance with the international gold standard for environmental management systems encompasses BGE's management of the natural gas and electric systems, as well as its vehicle fleet, and facilities. In addition, BGE makes significant charitable contributions to environmental initiatives.

Q. DOES THE COMPANY OFFER ANY ELECTRIC VEHICLE PROGRAMS?

A. Yes. In an effort to encourage electric vehicle ("EV") adoption in the state to help promote Maryland's energy goals to achieve the adoption of 300,000 zero-emission electric vehicles ("ZEVs") by 2025,[19] BGE established an EV portfolio approved by the Commission in Case No. 9478, Order No. 88997. BGE's EV portfolio includes offerings for residential and multifamily customers, as well as utility-owned charging stations available to the general public.

Q. PLEASE PROVIDE AN OVERVIEW OF THE RESIDENTIAL AND MULTI-FAMILY EV CHARGING PROGRAM OFFERINGS THAT BGE PROVIDES.

A. The Company's approved residential EV program provides a $300 rebate for up to 1,000 residential customers that purchase and install eligible Level 2 ("L2") EV smart chargers after July 1, 2019. BGE is also offering as part of its residential program an EV-Only Time of Use ("TOU") rate, beginning May 1, 2020.[20]

BGE's approved multi-family EV program offerings include a rebate for 50% of the cost of eligible EV charging equipment and installation costs of up to $5,000 for L2

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[19] Maryland Department of Transportation., Electric Vehicle Infrastructure Council Annual Report, December 31, 2017, p. 3, available at: http://www.mdot.maryland.gov/newMDOT/Planning/Electric_Vehicle/Documents/EVIC_2017_Annual_Report_Final_12-31-2017.pdf

[20] Mail Log# 228728, Letter Order dated April 1, 2020.

EV chargers and up to $15,000 for direct current fast chargers ("DCFC"), for a total maximum incentive of $25,000 per site. The maximum number of rebates available under this program is 700. BGE also offers a "Demand Charge Credit Program" to multi-family, workplace, and fleet installations. Under the Demand Charge Credit Program, a demand charge bill credit is provided for 50% of the maximum nameplate capacity for the new L2 and DCFC chargers installed. The credit is applied to the customer's bill for a period of 30 months, or through the end of December 2023, whichever comes first.

Q. PLEASE PROVIDE AN OVERVIEW OF THE APPROVED COMPANY-OWNED PUBLIC CHARGING STATIONS AND MANAGED CHARGING PROGRAM INCLUDED AS PART OF BGE'S EV PORTFOLIO.

A. BGE's EV portfolio also includes a utility-owned public EV charging network that will ultimately include 500 EV chargers installed on government-owned or controlled sites in the Company's electric distribution service area. These chargers are owned and operated by BGE and are available for use by the general public. As of May 5, 2020, the Company has completed the installation of 43 chargers across our territory with an additional 153 sites currently in the planning or design phases.

Q. HOW IS BGE PROPOSING TO RECOVER THE COSTS OF ITS EV PORTFOLIO?

A. Consistent with the cost recovery method approved by the Commission in Order No. 88997, BGE has deferred certain EV operational and maintenance costs incurred to date in a regulatory asset in rate base.[21] The regulatory asset, and associated amortization, is

[21] Case No. 9478, Order No. 88997, pp. 75-77.

included in the 2021-2023 MYP revenue requirements supported by Part 2 of the Direct Testimony of Company Witness Vahos. The program costs being deferred include costs associated with rebates, program administration, program operation, education and outreach. Capital expenditures for equipment and IT infrastructure, and associated costs such as depreciation, are not being deferred, but are included as rate base or as part of operating income, as appropriate.

Q. HAS THE COMPANY PREPARED A BENEFIT COST ANALYSIS IN THIS PROCEEDING TO EVALUATE ITS EV PORTFOLIO?

A. Yes, Company Witness Warner, an energy, environmental, and public utility consultant, has conducted a benefit cost analysis ("BCA") of the Company's EV portfolio offerings. This analysis, which combines several test approaches, and its results are discussed in detail in his direct testimony.

Q. MR. CASE, WILL YOU BRIEFLY SUMMARIZE THE RESULTS OF THE BCA?

A. Yes. The BCA results show that BGE's EV portfolio is highly cost-effective with the benefits significantly outweighing the costs in the market-wide Societal Cost Test ("SCT") and each of the offering-specific merit tests. As explained in Company Witness Warner's Direct Testimony, a portfolio view, which presents a composite view of net benefit across all the utility offers, provides a strong benefit/cost ratio of 2.63. A sensitivity analysis that considers only the monetized impacts on ratepayers (without emission benefits) was also considered for the portfolio, resulting in a net benefit ratio of 1.76. And based on a market-wide SCT that considers all costs and benefits, in the case where most residential charging happens in off-peak times (as encouraged by BGE's TOU-only and EV whole house rate offerings) benefits exceed costs by a factor of 3.10. Based on these outcomes, and the positive benefit/cost ratio resulting from the other merit tests, the BGE program delivers a strong net benefit for utility ratepayers and other impacted sub-populations.

Q. ARE THERE ANY OTHER BENEFITS OF BGE'S EV PROGRAMS YOU WISH TO HIGHLIGHT?

A. Yes. The analysis showed that in BGE's service territory over the period from 2020-2035, EVs will account for 112.2 billion electrically-powered miles, resulting in an estimated displacement of 4.8 billion gallons of gasoline. The Company's EV portfolio will also provide reductions in GHG emissions. The BCA showed that a total of 69.9 billion pounds of carbon dioxide are projected to be avoided over the period, along with 163.3 million pounds of NOx. Additionally, the analysis showed that for every electrically-fueled mile in BGE's service territory it is projected that the emissions impact will be 75% improved than for the equivalent gasoline-fueled mile (on average over the 2020-2035 period).

Q. WHAT OTHER EFFORTS HAS BGE UNDERTAKEN TO PROMOTE EVS?

A. In addition to the approved EV programs, the Company is pursuing the electrification of its own fleet. BGE, for 2020, has ordered 15 additional Chevy Bolts resulting in a total electric fleet of 19 EVs (17 Chevy Bolts and 2 Proterra buses). BGE also anticipates adding 42 Jobsite Energy Management System ("JEMS") units for its heavy truck fleet. JEMS units are an integrated plug-in system powered by application-specific battery packs that allow operators to control the cabin temperature without running the engine, thus reducing emissions and fuel consumption that would have occurred due to idling.

Q. DOES BGE'S EV PORTFOLIO PROVIDE ANY BENEFITS TO CUSTOMERS, THE COMMUNITY, AND THE ENVIRONMENT?

A. Yes. BGE's EV portfolio provides several benefits to customers, the community, and the environment. For instance, participating customers will receive a direct monetary benefit through the available rebates which will also help to alleviate any price barriers for the installation of smart EV chargers. Additionally, all ratepayers will see benefits as more EV usage and charging is implemented in BGE's territory as the increase in distribution revenues related to EV charging will foster lower electric distribution rates for all ratepayers. The Company-owned public charging stations also provide benefits to the community by making EV charging more readily available which helps to alleviate concerns regarding "range anxiety" and promotes the further adoption of EVs in BGE's service territory. Further, an increase in EV usage will also have a positive benefit on the environment and the community through cleaner air as a result of reduced GHG emissions.

VIII. ECONOMIC DEVELOPMENT

Q. MR. CASE, WILL THE MYP SPUR ECONOMIC DEVELOPMENT IN BGE'S SERVICE TERRITORY AND THE STATE OF MARYLAND?

A. Yes. BGE recognizes the importance of a strong Maryland economy. A recent 2020 economic impact study produced by the Economic Alliance of Greater Baltimore, which is provided as Exhibit MDC-2, looked at the direct economic contributions of BGE's gas and electric distribution investments for the MYP years of 2021-2023, as well as the indirect and induced effects of those investments. The study shows that BGE's planned investments and activities proposed in the MYP will contribute more than $15.3 billion of economic value to Maryland's economy, more than $2.8 billion in labor income and almost $900 million in state and local tax revenues. Our procurement of technical materials, office equipment and services totals more than $2.8 billion, helping to create and support a total of 26,700 full-time jobs in the state over the MYP period. In fact, the study found that BGE's investments spur the creation of 2.31 non-BGE jobs for every BGE job created and have a total economic multiplier of at least 1.5 times the initial output across the State of Maryland.

Q. MR. CASE, ARE THERE ANY OTHER WAYS IN WHICH BGE SUPPORTS ECONOMIC DEVELOPMENT IN ITS SERVICE TERRITORY?

A. Yes. Another way BGE helps to support the economy is through our Smart Energy Economic Development Program – known as the SEED Program. This program was launched in the fall of 2015 and is managed in partnership with our local economic development partners and the Maryland Department of Commerce. The program encourages new and expanding companies to choose central Maryland as the place to do business by lowering gas and electric delivery charges, and, for facilities within a designated Maryland Enterprise Zone, reducing the upfront cost of BGE-related service construction. To date, BGE's SEED program has assisted over 100 new and expanding businesses in central Maryland. These businesses range from small, two-person-owned cafés to global companies bringing their large enterprises to the state.

IX. BGE CUSTOMER SATISFACTION AND COMMUNITY INVOLVEMENT

A. CUSTOMER SATISFACTION

Q. MR. CASE, WHAT HAS BEEN BGE'S RECENT EXPERIENCE WITH CUSTOMER SATISFACTION?

A. The investments that BGE makes in its gas and electric distribution systems not only increase public safety and reliability of service, but also increase job opportunities, including those to minority suppliers, create programs that are protective of the environment, enable BGE to offer energy savings and limited income assistance programs, and help BGE provide excellent customer service to its customers. This customer service extends beyond the day-to-day utility work as well, through the commitment of BGE and its employees to give back to the communities we serve. BGE has been recognized for its achievements in these areas. Overall, more than 90% of our residential and business customers are satisfied with the service we provide. In fact, customer satisfaction levels are at an all-time high, with J.D. Power's 2017, 2018 and 2019 Electric Utility Business Customer Satisfaction Study ranking BGE Highest in Customer Satisfaction with Business Electric Service in the East among Large Utilities. Also, J.D. Power's 2018 and 2019 Gas Utility Business Customer Satisfaction Study ranked BGE Highest in Customer Satisfaction with Business Natural Gas Service in the East among Large Utilities. BGE has also been recognized for best in class business customer engagement in the leading study of utility industry brand health and business customer experience released by Escalent, a top human behavior and analytics firm. The 2019 study, Cogent Syndicated Utility Trusted Brand & Customer Engagement™: Business, included BGE among 18

Utility Business Customer Champions—utilities that scored highest nationally in-service satisfaction, brand trust, and product experience.

Q. HAS BGE RECENTLY RECEIVED ANY AWARDS OR RECOGNITION THAT DEMONSTRATE ITS COMMITMENT TO EXCELLENCE AND CUSTOMER SERVICE?

A. Yes. BGE continues to be an industry leader in energy delivery, and the Company has been widely recognized for its emergency response, safety programs, customer outreach, energy efficiency programs, demand response programs, and environmental responsibility. In addition to the awards I mentioned earlier, BGE has received numerous other awards and recognition. In 2019, BGE received the following awards:

- Partner of the Year Sustained Excellence Award – Energy Efficiency Program Delivery from EPA Energy Star® in April 2019
- Marketing Excellence Awards Email Integrated Campaigns – B2C in the Natural Gas Safety category from the Baltimore Chapter of the American Marketing Association in May 2019
- Best in Maryland in the Integrated Communications in the Natural Gas Safety category from the Public Relations Society of America in December 2019
- Energy Award for Outstanding Achievement in the Energy Efficiency Residential Marketing category from the Association of Energy Services Professionals in December 2019

B. POSITIVE IMPACTS ON MARYLAND COMMUNITIES

Q. MR. CASE, IN WHAT WAYS DOES BGE POSITIVELY IMPACT THE COMMUNITIES IT SERVES?

A. It is important to BGE that the Company and its employees contribute to the Maryland communities it serves beyond economic impacts and environmental initiatives. As a public utility, BGE has a relationship with every resident and every business in its service area, and BGE wishes to establish connections beyond that customer-utility relationship. BGE wants to work hand-in-hand with its communities to transform them, to help them grow, to make them safer, and to work with our youth in a positive way, because they are our future. These all create a lasting impact to make our neighborhoods better places to live and work. As I mentioned earlier, BGE has received several awards for its achievements, but the greater reward for the Company is to see our communities succeed while working in partnership with them to do so.

Q. WOULD YOU PLEASE ELABORATE ON BGE'S INVOLVEMENT IN THESE COMMUNITIES?

A. As I discussed earlier in my testimony, BGE is making significant contributions to support the communities in its service territory as the COVID-19 pandemic impacts each and every one of the Company's more than 1.3 million customers. One hundred percent of these contributions will go directly to address the negative impacts of the COVID-19 pandemic on the Maryland region's communities, workforce, and vulnerable populations.

Additionally, in 2019, BGE's shareholders donated $5 million to 408 eligible non-profit organizations located within the BGE service area that focus on education, environmental protection and awareness, community development (including advances in safety and emergency management), and arts and culture. All of BGE's charitable donations are made with shareholder dollars.

Two additional examples of BGE giving back to the communities it serves are the BGE Green Grants and the BGE Emergency Response and Safety Grants, both of which are awarded annually. Through BGE's Green Grants, nonprofit organizations that focus on energy efficiency, pollution prevention, environmentally-focused community engagement, conservation and education, can receive grants to enhance and promote environmental stewardship and natural resource responsibility in communities throughout BGE's central Maryland service area. Last year, BGE awarded more than $300,000 in these grants to 63 nonprofit organizations, bringing BGE's six-year total of Green Grants support to nearly $2.3 million. The BGE Emergency Response and Safety Grants support nonprofit emergency response and public safety organizations throughout BGE's service area who share the Company's commitment to the safety of the residents of central Maryland. As of 2019, BGE has provided more than $2 million to 398 emergency response organizations.

Education is an important part of BGE's charitable giving and in 2017, BGE launched the BGE Scholars Program and BGE Bright Ideas Teacher's Grants. The BGE Scholars Program invests up to $45,000 annually to support nine students from across BGE's central Maryland service area to attend the college or university of their choice. Each student receives scholarships of up to $5,000 annually for up to four years. The primary focus of BGE's Bright Ideas Teachers Grants is on strengthening math, science, and innovative technology education. Recognizing that the future of the Company and our communities depends on our youth, BGE is actively partnering with local organizations that nurture children's educational development. The education grant program for teachers is an opportunity for teachers to receive funding for supplies needed to support science, technology, engineering, and math ("STEM") or innovative technology projects. Under this program, BGE has awarded 150 grants totaling $69,000, with plans to continue to grow this program in the future.

Workforce development, which will be discussed further later in my testimony, is a large area of focus and several nonprofits support those efforts such as South Baltimore Learning Center, Junior Achievement and the Maryland Business Roundtable for Education and their work with middle school STEM education. These are just some of the organizations focusing their efforts on education that BGE, through its shareholders, supports financially. Examples of the arts and cultural organizations that BGE supports are the Baltimore Symphony Orchestra, Center Stage, Baltimore School for the Arts, American Visionary Art Museum and Baltimore Office of Promotion & the Arts' Free Fall program providing free access the month of October to over 200 arts and culture venues throughout Baltimore.

Q. WHAT ELSE DO BGE EMPLOYEES DO TO IMPROVE THE MARYLAND COMMUNITIES THAT THE COMPANY SERVES?

A. BGE employees help to improve Maryland communities in part by assisting individuals in need in financial and non-financial ways. BGE's annual Employee Giving Campaign contributed $1.4 million in 2019 to support hundreds of 501(c)(3) charities of our employees' choosing, as well as the United Way of Central Maryland. BGE matches employees' pledges 50 cents on the dollar to the United Way of Central Maryland. The match dollars are directed to the United Way in support of their Impact Fund to support basic needs programming as well as education initiatives. Through individual gifts, fundraisers, and volunteer events, BGE is one of the leading contributors to the mission of the United Way of Central Maryland.

The Exelon Foundation Matching Gifts program also allows BGE and other Exelon employees to request matching grants for personal contributions made to other eligible non-profit organizations according to program guidelines. Matching grants are dollar for dollar, up to $5,000 annually per employee. Additionally, under the Exelon Dollars for Doers grants, employees who volunteer their time can earn donations from Exelon, up to $700 each year, for their favorite non-profit organizations.

Beginning in 2015, BGE initiated an annual process that enables BGE employees to nominate a Cause Initiative, a charitable organization that the Company and its employees will support for that year. Each year since then, hundreds of employees have shown their support by participating in external fundraising activities including weekend walks and internal fundraising activities such as the BGE Softball Classic and the BGE Smart Energy Open golf tournament, as well as numerous smaller activities such as bake sales and raffles, raising hundreds of thousands of dollars for the selected charity. Past Cause Initiatives have included the American Heart Association, the March of Dimes, the United Way, the American Diabetes Association and the Susan G. Komen Race for the Cure. In 2019, the Cause Initiative was the Cal Ripken, Sr. Foundation, which focuses on helping under-served youth achieve their full potential, and the $371,000 BGE raised was used by the foundation towards a new youth development park in Baltimore City.

The National Alliance on Mental Illness ("NAMI"), a non-profit whose mission is to break the silence to help improve the lives of people with mental illness and their families, had been selected as the BGE's 2020 Cause Initiative. While BGE will continue to support NAMI, already providing $40,000 in direct grants and encouraging employees to participate in NAMI fundraising activities, including a virtual walk later this spring, BGE has decided to refocus its 2020 Cause Initiative to COVID-19 relief efforts. Employees are currently being encouraged to look for opportunities to volunteer independently, in particular to support critical community issues, such as the severe shortage of blood and empty shelves at food banks, and to support organizations digitally, including United Way 211 Maryland Helpline, Business Volunteer Maryland, and Maryland Unites. Further, employees are hosting and/or participating in virtual volunteer group activities, such as socializing virtually while creating cloth face coverings for healthcare workers.

In addition, BGE employees are currently serving on the boards of more than 165 local charities and community organizations: for example, the United Way of Central Maryland, Baltimore Community Foundation, Maryland Food Bank, Port Discovery Children's Museum, Maryland Zoo in Baltimore, the Kennedy Krieger Institute, Paul's Place, The Franciscan Center, St. Vincent de Paul of Baltimore, Habitat for Humanity, the B&O Railroad Museum, the Maryland DC Audubon Society, the Baltimore Polytechnic Foundation, Meals on Wheels of Central Maryland, and the St. Joseph Medical Center Foundation.

C. DIVERSITY AND INCLUSION, WORKFORCE DEVELOPMENT, AND SUPPLIER DIVERSITY

Q. HOW DOES BGE SUPPORT DIVERSITY AND INCLUSION WITHIN THE COMPANY?

A. BGE strives to hire and promote individuals who represent the communities that we serve. This takes into account many factors, including but not limited to ethnic diversity. This commitment starts at the top, as BGE's executive leadership team is 64% diverse. Supporting diversity and inclusion also involves creating a workforce that reflects the communities we serve. One way we do this is through having diverse slates of candidates and diverse interview panels when we have job openings. Our goal is to always find the best person for the job and a more diverse selection process makes this possible. BGE's Smart Energy Workforce Development focuses on the recruitment of qualified and diverse talent into our entry-level positions. Through this program, BGE partners with local workforce development agencies and local career technology education high schools to create this talent pipeline. In late 2017, BGE hired the first three employees from this program into our transmission and substation team. In 2018, BGE hired nine additional program participants into our fleet and overhead lines departments. In late 2019/early 2020, BGE hired three additional students into fleet, overhead lines and customer operations.

The Company's commitment to diversity and inclusion is further fostered within BGE through its support of what are known as Employee Resource Groups, or ERGs. ERGs are voluntary groups led by employees to facilitate a diverse and inclusive workplace. BGE ERGs consists of groups that are devoted, for example, to the interests of African-Americans, Asian-Americans, Latino-Americans, veterans, women, individuals with disabilities, the LGBTQ community and multi-cultural and multi-national employees. Importantly, BGE's parent company Exelon was the first utility to sign the Obama White House's Equal Pay Pledge. Other recent recognitions and distinctions for the Exelon companies include the following:

- Named among Top 50 Companies for Diversity by DiversityInc, 2017-2019
- Forbes America's Best Employers for Diversity, 2018-2020
- Voted Best for Veterans company by the Military Times, 2013-2019
- Human Rights Campaign Best Places to Work, 2011-2020 – scoring a perfect 100%

- Joined the UN's He-for-She initiative, in 2017, pledging $3 million to develop new STEM programs for girls and young women and improve the retention of women at Exelon companies by 2020
- Ranked 24th on DiversityInc's list of Top 50 companies for diversity, 4th of the Top 10 for companies for diverse leadership, and 10th for the Top 17 companies in hiring for veterans, 2018-2019
- Member of the Billion Dollar Roundtable, a national organization that recognizes corporations who have achieved at least $1 billion in annual spend with minority and women-owned businesses. Exelon was the first utility and energy services company to achieve this coveted recognition.

Q. WHAT HAS BGE DONE IN THE AREA OF WORKFORCE DEVELOPMENT?

A. BGE has engaged in workforce development in many ways. I would like to cover a few initiatives that BGE has implemented.

- ***BGE's Smart Energy Workforce Development Programs***. This program seeks to recruit and hire a workforce that reflects the communities we serve. Our Smart Energy Workforce Development Program focuses on developing a qualified and diverse talent pipeline, particularly in entry-level positions. The program focuses on industry-required Construction and Skilled Trades ("CAST") test preparation and on ensuring entry-level opportunities are more widely communicated, including to diverse communities. As a result of this program, there are currently 12 Baltimore City high school graduates employed full-time in BGE operational areas.
- ***BGE Workforce Collaborative:*** This is the newest component of the BGE Smart Energy Workforce Development Program. The BGE Workforce Collaborative was launched in September 2019 in partnership with Civic Works. This program

provides construction labor training, job readiness and employability skills training and wrap-around support services for participants. Program graduates have the option to participate in interviews with BGE Contractors for entry-level positions. The first cohort of 13 participants graduated in November 19, 2019, and 12 are currently employed full time with a BGE contractor or within the construction industry. Since the inception of the program and until the recent COVID-19 crisis, new cohorts would begin approximately every eight weeks, and 38 participants have completed the program. The participants are typically unemployed or underemployed at the start of the training program.

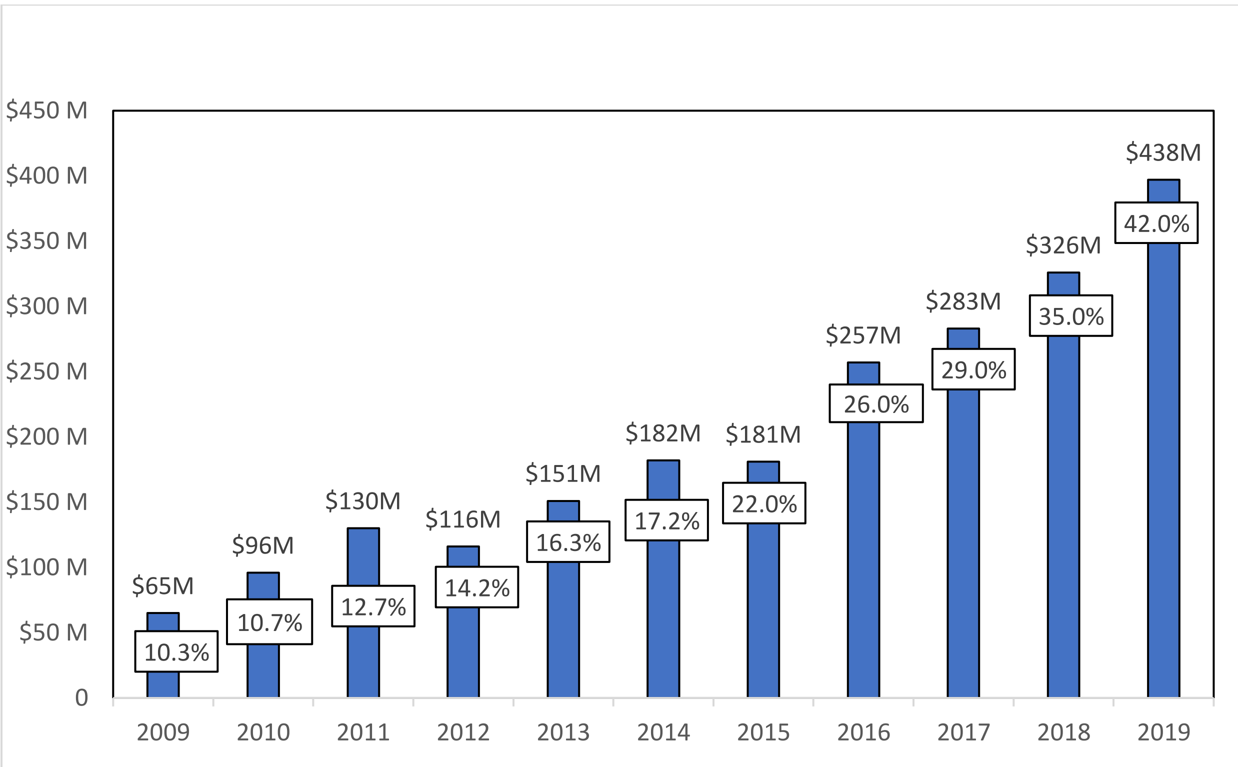
- ***High school internship/recruiting:*** Since 2016, BGE has partnered with four Baltimore City high schools: Mergenthaler Vocational-Technical ("Mervo"), Edmonson-Westside, Carver Vo-Tech, and Green Street Academy, to develop a pipeline of candidates for utility-related work. BGE annually hosts a "Youth Energy Day" for students and teachers from vocational/technical high schools where BGE provides hands-on demonstrations of operational activities from the field organizations. BGE also hosts annual visits by more than 200 construction, computer-aided design, engineering and automotive technology high school students at various BGE facilities. Since 2016, BGE has hosted 133 students as part of the high school summer internship program; 12 former high school interns are currently full-time employees in BGE operational areas. BGE continues to offer this program this year, however, in light of the COVID-19 pandemic, the program will be implemented virtually for candidates to participate remotely.

- ***Baltimore City Schools – Plumbing Program:*** BGE is a longtime supporter of Baltimore City Schools' Career and Technology Education ("CTE") programming and extended its commitment by funding a teacher position in support of the launch of a plumbing program at Mervo. The launch of this program brings the plumbing CTE pathway back to Baltimore City Schools and supports industry needs and the current operational outlook.
- ***Community-based CAST test preparation***. This program utilizes a train-the-trainer approach to provide CAST Test Prep materials to local workforce development organizations. The primary organization, the South Baltimore Learning Center, hosts community-based CAST Test Prep courses, which prepare participants for the test that must be passed to be considered for many of the open entry-level positions within BGE.
- ***Job postings and job fairs***. BGE posts open positions on a multitude of job posting sites, including those focused on people with disabilities and minorities, along with state agencies. BGE has participated in the Afro Career and Education Fairs, as well as the Work Baltimore, the Society of Women Engineers and Recruit Military job fairs.

Q. HOW DOES BGE SUPPORT MINORITY SUPPLIERS?

A. For BGE, helping the Maryland-Washington, DC region's diversity-certified suppliers grow and become more competitive is smart business. Stronger businesses mean a stronger economy and stronger communities. BGE, with the full support and backing of Exelon, maintains a very robust and successful supplier diversity program. In 2019, BGE disbursed 42% of its overall spend with diverse suppliers. This represents $438 million in goods and services purchased from diversity-certified suppliers, a $112 million (or 34%) increase over 2018 total diverse supplier spend. 326 Maryland businesses (based on the remit to address information provided by suppliers) accounted for $217 million or 50% of BGE's total supply managed diverse spend. The following Chart 3 reflects BGE's advancement of the inclusion of diverse suppliers over the past ten years from 10.3% to 42.0% of total procurement spend:

Chart 3 – Diversity Spend



Q. ARE THERE ANY SPECIFIC PROGRAMS SPONSORED BY BGE TO SUPPORT ITS SUPPLIER DIVERSITY EFFORTS?

A. Yes. In July 2013, BGE launched a supplier development program, called at that time Focus 25, in further support of the Commission's diverse supplier inclusion goals and, more specifically, the goal set forth in the February 6, 2009 Memorandum of

Understanding between the Commission and BGE to achieve a 25% level of diverse supplier spend. In 2017, BGE rebranded this supplier development program as Focus Forward, and like its predecessor, it seeks to provide a select group of diversity-certified suppliers with the tools and knowledge to attain the next level of growth in their businesses through on-going one-on-one mentorship and technical assistance workshops highlighting business development processes, safety policies, and an understanding of BGE sourcing processes. In September 2019, the fifth "class", comprised of 10 members, started the Company's supplier development program bringing the total to 51 minority, women and veteran-owned companies, many located in BGE's central Maryland service area, all of which are now better equipped to compete for contracts with BGE. Since 2014, BGE has spent more than $1.6 billion with diverse suppliers, including participants in the Focus 25/Focus Forward program. Participants in the program have worked as prime and subcontractors on BGE's gas and electric systems. They include but are not limited to, Tucker Construction Group, M. Luis Construction, Delta Utility Services, Anchor Construction, and Day and Sons, Inc.

BGE has also partnered with Johns Hopkins University in leading BLocal, a multi-company effort to use the collective might of corporate purchasing and hiring to support city residents and minority and women-owned businesses. The initial group of 25 participating businesses has now grown to 28 and BLocal purchases were $97 million in 2018 alone, greatly exceeding the three-year goal of infusing at least $69 million into the Baltimore economy. As part of BGE's overall BLocal commitment to diversity and inclusion, BGE has done the following:

- Shared best practices on how to develop minority, women and locally-owned businesses and build capacity within disadvantaged and underdeveloped segments of our community; and
- Established a diverse business empowerment process dedicated to developing relationships with Maryland's minority, women, and veteran-owned business communities to ensure BGE has access to a talented, diverse group of suppliers that reflects our customer base.

D. SOLICITATION OF COMMUNITY INPUT AND ENGAGEMENT

Q. HOW DOES BGE SEEK COMMUNITY INPUT REGARDING ITS PLANNED PROGRAMS AND INITIATIVES?

A. BGE recognizes that the work we do impacts customers and entire communities. This is why we spend time and resources sharing information about our projects, programs and initiatives in a number of ways. These include community meetings, project-letters, web announcements, social media notifications, and more. Nearly every method of communication we use allows for customers to provide feedback, express any concerns and ask questions.

To demonstrate the importance and value to the Company of this real-time feedback and these relationships, another way BGE engages communities is through our ongoing discussions with BGE customers who participate in our stakeholder group discussions, which formally began in 2015, when we invited a diverse group of business, civic, government and faith-based leaders to serve on our Community Advisory Council. Meeting approximately every quarter, BGE utilizes the council to discuss new developments and pursuits ranging from innovative pilot programs BGE is proposing to considering changes to existing programs. Our participants provide important feedback and input that helps shape our future direction. Additionally, the council provides an opportunity for BGE to better understand the customers we serve and seek additional opportunities to partner with others to meet the needs of our customers.

In 2017, BGE created additional councils to better ensure diversity of thought is captured. Our goal is to have strong representation of our customer base from across our service area, including Baltimore City and Anne Arundel, Baltimore, Calvert, Carroll, Cecil, Frederick, Harford, Howard, Montgomery and Prince George's Counties. BGE also launched a very specialized council – our Large Customer Smart Energy Council, which represents our largest segment of commercial customers. This group advises us on our current programs, offers recommendations for new technologies, and ways to further improve our service to large business customers. In 2018, BGE established the Smart Energy Education Advisory Council to solicit input from educational institutions and professionals on such topics as workforce development and STEM.

Lastly, in addition to these face-to-face conversations, BGE is taking our outreach and engagement opportunities to new heights through our innovative online community, which was designed to provide BGE with powerful insights by collecting additional online input from our customers. This input, through our online hub, helps BGE create and launch better products and programs, better understand the customer journey, and improve the customer experience.

BGE believes in the importance of stakeholder engagement and wants to ensure we have the customer voice included in the conversation. It is an important part of our Customer Focus core value. As we prepare to introduce innovations to our customers and stakeholders, we are committed to ensuring the communities we serve are well-informed and that their voices are heard throughout the development process.

I would also like to mention BGE’s enhanced gas safety public awareness campaign. BGE uses newspaper, radio, television and the internet as ways to convey important gas safety messages. We also conduct outreach to stakeholders across our service area including local officials and agency staff, emergency responders, and even elementary school children. One of the most novel ways we get the word out to children on natural gas safety is through a comic book featuring Captain Mercaptan, BGE's fictional natural gas safety superhero, first introduced in 2014. In the comic book, he teaches children how to recognize a natural gas leak and what steps to take when they smell gas. Captain Mercaptan's name is derived from "mercaptan," a safety additive that BGE and other utilities put in natural gas to give it a distinctive rotten egg odor to make natural gas easier to detect. Each year, BGE conducts a contest for students at elementary schools in its service area to illustrate gas safety messages featuring Captain Mercaptan. BGE awards $10,000 to the winning school towards a school enrichment project, with several smaller tier prizes to other schools. In the contests held since January 2014, BGE has awarded $245,000 to schools in the BGE service territory. The teacher from the top winning school is also awarded $500 to use for classroom supplies.

Additionally, BGE’s Wires Down Video Challenge educates elementary school-aged children on the importance of practicing electrical safety. Elementary school teachers in public and private elementary schools across BGE's electric service area are encouraged to work with their classes to submit 30 to 45-second videos of their interpretation of BGE's popular "Wires Down" electrical safety commercial. Schools have a chance to win between $1,000 and $10,000 in grant funding for enrichment projects. Since the Wires Down Video Challenge began in 2012, BGE has awarded more than $205,000 to 51 elementary schools across central Maryland. In 2019, we began a partnership with a local television meteorologist to amplify these important messages. As the celebrity judge of both contests, her contributions towards educational awareness about natural gas and electric safety on-air, along with messages on social media channels, has added new excitement to the programs.

X. CONCLUSION

Q. MR. CASE, ARE THERE ANY FINAL REMARKS THAT YOU WOULD LIKE TO MAKE?

A. BGE respectfully requests the Commission approve the MYP proposed in this filing to allow BGE to make the appropriate expenditures to maintain the electric and gas delivery systems in 2021-2023 so that we can continue delivering safe and reliable service to customers. We recognize the significant impacts the COVID-19 pandemic is having on our customers and Maryland, and request the Commission approve the adjustments and the 10.1% ROE, inclusive of the performance adder, proposed by the Company in order to avoid base distribution revenue increases in 2021 and 2022, with an increase in 2023.

Q. MR. CASE, DOES THIS CONCLUDE YOUR DIRECT TESTIMONY?

A. Yes, it does.

SUMMARY OF PREPARED TESTIMONY

Mark D. Case

Baltimore Gas and Electric Company, Vice President of Regulatory Policy and Strategy

Case Number	**Nature of Proceeding**
RATE CASES:	
Case No. 9406	Electric and gas base rate increase
Case No. 9484	Gas base rate increase
Case No. 9610	Electric and gas base rate increase
OTHER CASES:	
Case No. 8520, *et al*	Electric fuel rate charges
Case No. 8700	BGE’s Gas Market Based Rates Program
Case No. 8709	Inquiry into the natural gas brokering operations of BNG, Inc.
Case No. 9052	Rate Stabilization and Market Transition
Case No. 9063	Optimal structure for electric standard offer service
Case No. 9089	BGE’s application for a Qualified Rate Order to finance rate stabilization costs
Case No. 9096	BGE’s appropriate recovery of depreciation expense in cost of service
Case No. 9099	BGE’s proposed opt-in Rate Stabilization Plan pursuant to Senate Bill 1
Case No. 9154	BGE’s EmPOWER Maryland programs
Case No. 9208	BGE’s deployment of a Smart Grid Initiative
Case No. 9221	BGE’s request for recovery of cash working capital costs associated with the Company’s Standard Offer Service mechanisms
Case No. 9331	BGE’s application for approval of a gas Strategic Infrastructure Development and Enhancement (“STRIDE”) plan and associated cost recovery mechanism
Case No. 9468	BGE’s application for a second STRIDE plan and associated cost recovery mechanism

Economic Impact of Baltimore Gas and Electric's Planned Investments & Activities – 2021 to 2023

April 2020

Prepared for:

BGE®

An Exelon Company

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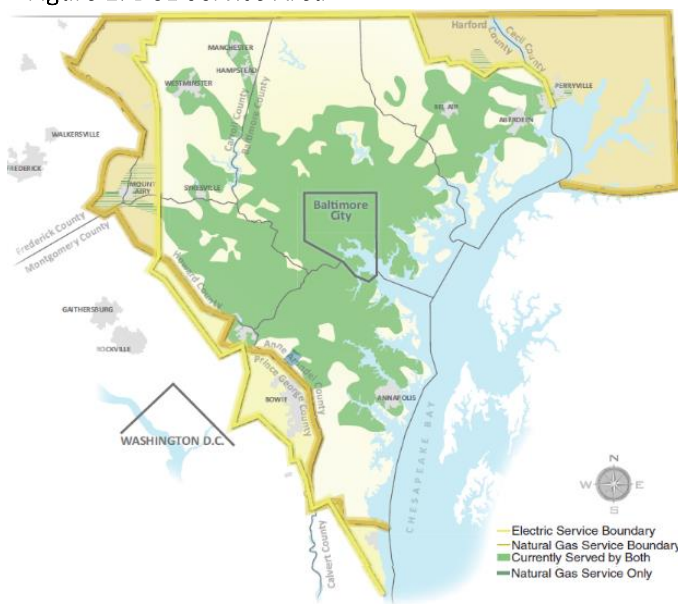
Contents

Introduction

Baltimore Gas and Electric Company (BGE) serves electricity and natural gas customers across an economically and geographically diverse 2,300-square-mile area in Central Maryland. Residents of Baltimore City and all or part of ten Central Maryland counties receive utility service from BGE.

Figure 1: BGE Service Area



Source: BGE, 2020

BGE engaged the Economic Alliance of Greater Baltimore (EAGB) to estimate the potential economic contributions of BGE's planned investments and activities for the years 2021-2023, as part of its multi-year plan (MYP) initiative.

This economic impact study accounts for the potential direct economic contributions of BGE's gas and electric distribution investments for the years 2021-2023, as well as the indirect and induced effects of those investments. The indirect effects include BGE's expected spending on non-labor inputs, while the induced effects derive from increased economic activity from workers' income (both BGE employees and those of BGE's contractors/suppliers). The report finds evidence of significant economic impact from BGE's proposed investments, with thousands of jobs created by each of the direct, indirect, and induced effects.

To analyze the potential impact of BGE's proposed non-labor spending, labor spending, employment count, and revenue for 2021-2023, EAGB utilized the IMPLAN model to estimate the aggregate economic impacts within the following study areas:

- The State of Maryland
- BGE's Service Area (the eleven jurisdictions where BGE provides electric and/or gas service)
- All other Maryland Jurisdictions with Direct BGE Impact (seven employee home counties)

Figure 2: BGE 2021-2023 Estimated Data Inputs

BGE Background Data Summary *Estimates 2021-2023 for Gas & Electric Distribution Services*			
Estimate	**2021**	**2022**	**2023**
Headcount Employment	2,990	2,990	2,990
Labor Spending	$482,710,731	$486,447,253	$494,838,775
Non-Labor Spending	$1,120,297,787	$1,153,912,247	$1,104,855,701
Revenue	$1,807,607,253	$1,843,759,398	$1,880,634,586

Source: BGE, 2020. BGE's 2021 to 2023 revenue figures were inflated from 2019 actual revenue, using the standard 2% per annum expected inflation rate.

This report summarizes the results of economic impact analyses for each of these geographies for each of the years 2021-2023. The discussions of economic impacts throughout this report are separated by activity and by geographic study area.

Key Terms and Concepts

There are three key effects that together make up the aggregate economic impact of BGE activities, all of which are covered by this report. They include:

Direct Effect: Economic activities directly associated with BGE's gas and electric distribution business. These include directly employed workforce, wages paid, non-labor spending, and annual revenue. For the years 2021 through 2023, BGE's gas and electric distribution revenue figures were inflated from 2019 actual revenue, using the standard 2% per annum expected inflation rate.

Indirect Effect: Second-order economic activities of industries that respond to BGE demand generated by the direct economic activities. These industries supply goods and services to BGE. For BGE's gas and electric distribution operations, the indirect impact includes the company's capital investments and operations and maintenance expenditures. Examples of industries that experience indirect impact from BGE's gas and electric investments include natural gas, construction, engineering, and legal services.

Induced Effect: Refers to the economic activities generated by spending from workers supported by the direct and indirect effects of BGE activities. As full- and part-time workers employed by BGE or a BGE-supported industry use their income on typical household consumption, they create additional economic activity. Workers that use their income to purchase retail, housing, banking, and food services support the employment and wages of workers in those industries.

The sum of direct, indirect, and induced effects represents the total economic impact.

The direct, indirect, and induced effects can be measured in several different ways. The following economic factors are used in this report and, as distinct measures, should not be combined to estimate total economic impact:

Employment: the number of jobs supported

Labor Income: the dollars paid as wages and benefits to workers (for direct effects), as well as proprietor's income (for indirect and induced effects)

Output: the market value of goods produced or services provided, frequently reflected as total revenue or sales in businesses

Tax Generation: the state and local taxes and fees generated, including sales, property, income, and several other tax and fee categories

This analysis was conducted based on BGE's commuter shed, or where BGE employees reside, because the location of residence determines wage expenditures on local industries. As a result of this distinction, the induced impacts that the 271 BGE employees residing outside the state of Maryland have on their communities are not included in this report. Note that BGE generates additional induced impacts on the states of Pennsylvania, Delaware, and Virginia; states immediately bordering the commuter shed.

Total Economic Impacts, 2021-2023

The nation's oldest regulated utility, BGE provides customers with reliable gas and electric utility service across the Central Maryland region. The company is one of the 25 largest private employers in the state.

For the years 2021 through 2023, BGE's gas and electric distribution operations are expected to generate $15.3 billion in total economic output, $2.8 billion in labor income, and 26,702 jobs within the BGE Service Area (see Figure 3 below).

The approximately $5.1 billion per year of total output that BGE's gas and electric distribution services have on the Service Area is remarkable. This number can be compared to the total *direct* output of the legal services industry at $6.0 billion, the full-service restaurant industry at $5.5 billion, or the nursing and community care industry at $4.0 billion. Each year, BGE's gas and electric distribution networks support just over 1.3% of the Service Area's total economic output of $385 billion.

Summary Table: Service Area and State of Maryland

Figure 3: BGE Total Economic Impact, 2021-2023

Total Economic Impact of BGE Planned Investments & Activities, 2021-2023				
Study Area & Impact	**Direct**	**Indirect**	**Induced**	**Total**
BGE Service Area				
Employment*	8,039	9,576	9,087	**26,702**
Labor Income	$1,312,015,038	$928,653,602	$520,338,022	**$2,761,006,663**
Output	$10,223,072,801	$3,581,575,016	$1,524,131,207	**$15,328,779,024**
Maryland				
Employment*	8,157	9,651	9,151	**26,958**
Labor Income	$1,331,247,293	$933,895,612	$523,018,517	**$2,788,161,422**
Output	$10,242,305,056	$3,609,318,776	$1,533,261,038	**$15,384,884,869**

Source: IMPLAN 2021, 2022, and 2023 coefficients based on EAGB analysis of BGE Data.
*Total three-year employment in labor years. Divide by three for average yearly employment impact.

Figure 4 details the projected economic impacts for each year: 2021, 2022, and 2023. BGE's total economic impact for distribution-related services is expected to be highest in 2022 due to strong labor and non-labor spending. In each year, BGE directly accounts for 2,719 jobs across the State of Maryland. However, BGE's economic impacts increase job counts across the State of Maryland by almost 9,000 each year, with over 3,000 jobs created through both indirect and induced means.

Figure 4: BGE Economic Impacts by Year, 2021-2023

Economic Impact of BGE Planned Investments & Activities, 2021				
Study Area & Impact	**Direct**	**Indirect**	**Induced**	**Total**
BGE Service Area				
Employment	2,680	3,204	3,045	**8,929**
Labor Income	$432,599,140	$312,691,246	$174,365,512	**$919,655,898**
Output	$3,360,501,140	$1,216,379,203	$510,733,687	**$5,087,614,029**
Maryland				
Employment	2,719	3,229	3,066	**9,015**
Labor Income	$438,940,421	$314,474,279	$175,262,513	**$928,677,213**
Output	$3,366,842,421	$1,225,850,905	$513,788,742	**$5,106,482,069**

Economic Impact of BGE Planned Investments & Activities, 2022				
Study Area & Impact	**Direct**	**Indirect**	**Induced**	**Total**
BGE Service Area				
Employment	2,680	3,295	3,057	**9,032**
Labor Income	$435,947,762	$317,618,694	$175,066,581	**$928,633,037**
Output	$3,433,616,329	$1,217,006,595	$512,783,669	**$5,163,406,594**
Maryland				
Employment	2,719	3,321	3,078	**9,118**
Labor Income	$442,338,130	$319,390,904	$175,958,386	**$937,687,420**
Output	$3,440,006,697	$1,226,369,484	$515,821,096	**$5,182,197,278**

Economic Impact of BGE Planned Investments & Activities, 2023				
Study Area & Impact	**Direct**	**Indirect**	**Induced**	**Total**
BGE Service Area				
Employment	2,680	3,077	2,985	**8,741**
Labor Income	$443,468,136	$298,343,661	$170,905,929	**$912,717,727**
Output	$3,428,955,332	$1,148,189,217	$500,613,851	**$5,077,758,401**
Maryland				
Employment	2,719	3,101	3,006	**8,825**
Labor Income	$449,968,742	$300,030,430	$171,797,617	**$921,796,789**
Output	$3,435,455,938	$1,157,098,386	$503,651,199	**$5,096,205,523**

Source: IMPLAN 2021, 2022, and 2023 coefficients based on EAGB analysis of BGE Data.

Understanding the Process of Impact

The primary role and first responsibility of BGE is the distribution of electricity and natural gas to residents and businesses located in Central Maryland. In the years 2021 through 2023, these activities are expected to generate over $5.5 billion in direct revenue, much of which will be distributed as salary and benefits totaling over $1.3 billion to BGE's 2,719 Maryland-based gas and electric distribution employees. An additional $3.4 billion will be paid out in the form of non-labor spending to BGE's network of suppliers across the state and around the world.

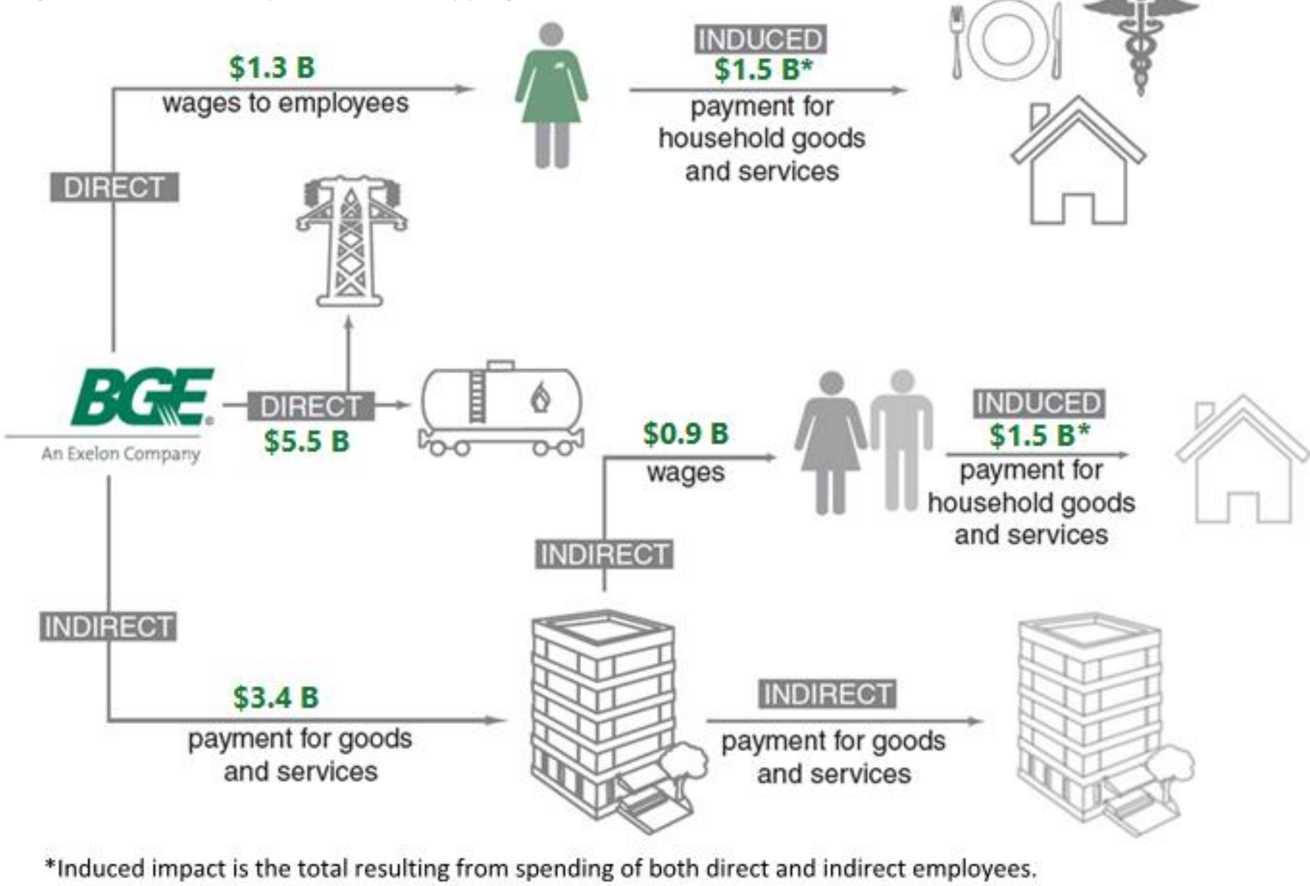
Figure 5: Key Impact Indicators, 2021-2023

BGE 2021-2023 Distribution Investments/Activities	
Total Service Area Economic Impacts	
Employment:	26,702
Labor Income:	$2.76 billion
Output:	$15.33 billion
State & Local Taxes:	$887.40 million

Source: IMPLAN, 2020

The economic activity created by BGE's demand for goods and services from local suppliers and BGE employees' demand for household goods generates economic activity throughout the regional economy. The expected 2021-2023 household spending increase related to BGE's distribution services totals over $1.5 billion, derived from the $1.3 billion in direct salaries and benefits and the nearly $1 billion distributed by BGE's suppliers to their respective workforces.

Figure 6: Economic Impact Process Mapping (Three-Year Totals within Service Area)



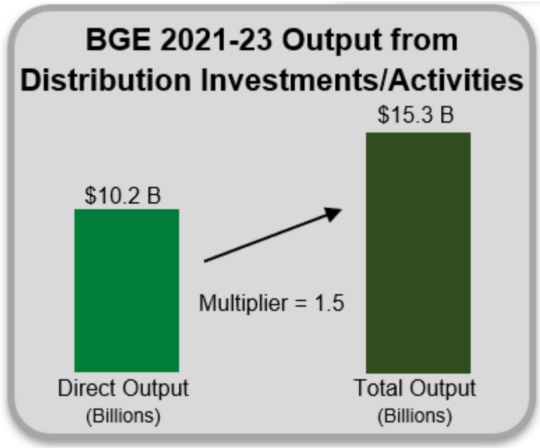
Source: BGE, 2020; IMPLAN, 2020

BGE's Economic Multiplier

For every direct job that BGE creates within its eleven-jurisdiction Service Area, there is a corresponding increase of 2.26 non-BGE jobs across the region. Furthermore, for every dollar of direct revenue for BGE's gas and electric distribution network, indirect and induced effects lead to an additional $0.50 of output for Maryland businesses.

BGE's economic impacts were distributed through nearly every industry in the service area, with Professional, Scientific, and Technical Services, Food Service, Real Estate Services, and Hospitals seeing the largest employment benefit. Real Estate Services, Wholesale Trade Businesses, and Banking and Credit Intermediation saw the largest impact in output.

Figure 7: Projected Output Multiplier



Source: IMPLAN, 2020

County-by-County Economic Impacts

As the effects of BGE's general operations are followed through the State of Maryland, the company's economic impacts grow. Analyzing the whole of the state allows the model to include employees that reside outside of the service area, increasing the net impacts of BGE general operation activities. Additionally, a portion of what is considered leakage – wages and spending that result from BGE outlays to firms located outside the study area – is captured.

Economic contributions to counties across the State of Maryland varied based on the level of BGE employment and activity within each county, as well as the size and structure of the local economy. BGE supported the greatest number of jobs and output in Baltimore County due to nearly 1,000 of its employees residing therein and significant planned non-labor spending. This is followed by Baltimore City, Anne Arundel County, Howard County, and Harford County, each of which see over $1 billion in projected economic impact across the three-year span.

Among non-Service Area counties, Queen Anne's County saw the largest economic impact from BGE's planned 2021-2023 activities. While BGE reports no expected non-labor spending in its non-Service Area counties, Queen Anne's and other counties see significant impact from wages of BGE employees residing in their jurisdiction. The economic impacts of BGE's distribution network in Service Area and non-Service Area jurisdictions are detailed in figures 8 and 9, respectively.

Figure 8: Economic Impact in BGE Service Area, by County

Total Economic Impact of BGE Planned Investments & Activities, 2021-2023				
Study Area & Impact	**Direct**	**Indirect**	**Induced**	**Total**
Anne Arundel County				
Employment*	1,153	1,376	770	**3,299**
Labor Income	$188,100,833	$133,102,148	$38,850,632	**$360,053,614**
Output	$1,883,657,239	$577,834,341	$120,583,440	**$2,582,075,020**
Baltimore County				
Employment*	2,949	1,753	1,302	**6,004**
Labor Income	$481,275,448	$110,476,880	$66,915,146	**$658,667,475**
Output	$2,875,889,182	$297,796,518	$202,868,845	**$3,376,554,545**
Baltimore City				
Employment*	1,147	2,183	534	**3,864**
Labor Income	$187,162,674	$192,015,252	$32,232,652	**$411,410,578**
Output	$2,453,543,869	$626,249,291	$91,520,666	**$3,171,313,826**
Calvert County				
Employment*	20	18	14	**52**
Labor Income	$3,283,556	$2,802,459	$534,358	**$6,620,372**
Output	$40,691,175	$13,783,573	$2,003,617	**$56,478,365**
Carroll County				
Employment*	673	139	294	**1,106**
Labor Income	$109,764,576	$7,269,260	$11,610,715	**$128,644,551**
Output	$451,726,026	$19,864,260	$39,800,106	**$511,390,392**
Cecil County				
Employment*	72	5	25	**103**
Labor Income	$11,726,985	$195,600	$970,445	**$12,893,029**
Output	$15,306,717	$579,137	$3,462,299	**$19,348,152**
Frederick County				
Employment*	66	23	34	**123**
Labor Income	$10,788,826	$1,290,439	$1,440,146	**$13,519,411**
Output	$24,677,042	$3,848,043	$4,753,851	**$33,278,937**
Harford County				
Employment*	1,411	760	763	**2,934**
Labor Income	$230,317,978	$47,833,236	$32,184,996	**$310,336,210**
Output	$945,946,997	$215,917,963	$109,304,790	**$1,271,169,750**
Howard County				
Employment*	414	850	232	**1,495**
Labor Income	$67,547,431	$68,721,355	$12,665,321	**$148,934,107**
Output	$1,029,593,244	$334,273,403	$39,399,725	**$1,403,266,372**
Montgomery County				
Employment*	66	35	43	**144**
Labor Income	$10,788,826	$8,642,939	$2,780,323	**$22,212,088**
Output	$82,646,185	$27,432,635	$7,519,763	**$117,598,583**
Prince George's County				
Employment*	69	286	61	**416**
Labor Income	$11,257,905	$23,917,620	$2,584,086	**$37,759,611**
Output	$443,798,113	$165,670,414	$8,941,899	**$618,410,427**

Source: IMPLAN, 2020

*Total three-year employment in labor years. Divide by three for average yearly employment impact.

Figure 9: Economic Impact in BGE Employee Home Counties (Non-Service Area)

Total Economic Impact of BGE Planned Investments & Activities, 2021-2023				
Study Area & Impact	**Direct**	**Indirect**	**Induced**	**Total**
Caroline County				
Employment*	9	-	2	**11**
Labor Income	$1,407,238	-	$78,486	**$1,485,724**
Output	$1,407,238	-	$319,362	**$1,726,601**
Charles County				
Employment*	3	-	1	**4**
Labor Income	$469,079	-	$37,250	**$506,329**
Output	$469,079	-	$143,460	**$612,539**
Queen Anne's County				
Employment*	80	-	26	**106**
Labor Income	$13,134,223	-	$958,395	**$14,092,618**
Output	$13,134,223	-	$3,462,045	**$16,596,267**
St. Mary's County				
Employment*	6	-	2	**8**
Labor Income	$938,159	-	$85,688	**$1,023,847**
Output	$938,159	-	$308,732	**$1,246,891**
Talbot County				
Employment*	11	-	5	**17**
Labor Income	$1,876,318	-	$236,096	**$2,112,414**
Output	$1,876,318	-	$740,802	**$2,617,119**
Washington County				
Employment*	3	-	1	**4**
Labor Income	$469,079	-	$52,368	**$521,447**
Output	$469,079	-	$165,020	**$634,100**
Worcester County				
Employment*	6	-	2	**8**
Labor Income	$938,159	-	$94,247	**$1,032,405**
Output	$938,159	-	$317,371	**$1,255,530**

Source: IMPLAN, 2020

*Total three-year employment in labor years. Divide by three for average yearly employment impact.

Conclusion

The Economic Alliance of Greater Baltimore (EAGB) analyzed the economic impact of BGE's planned distribution investments and activities in the gas and electric distribution sector for the years 2021 through 2023. EAGB determined that BGE's economic impact will exceed $15.3 billion in output and create nearly 27,000 jobs across the three-year period, directly affecting eighteen jurisdictions in the State of Maryland. These investments will spur the creation of 2.31 non-BGE jobs for every BGE job created, and have a total economic multiplier of atleast 1.5 times the initial output across the State of Maryland. BGE's planned investments and business activities will infuse billions of dollars and thousands of jobs into the Maryland economy. All the while, BGE will continue to provide the critical gas and electric distribution services which power the Central Maryland economy and positively impact many other industries.

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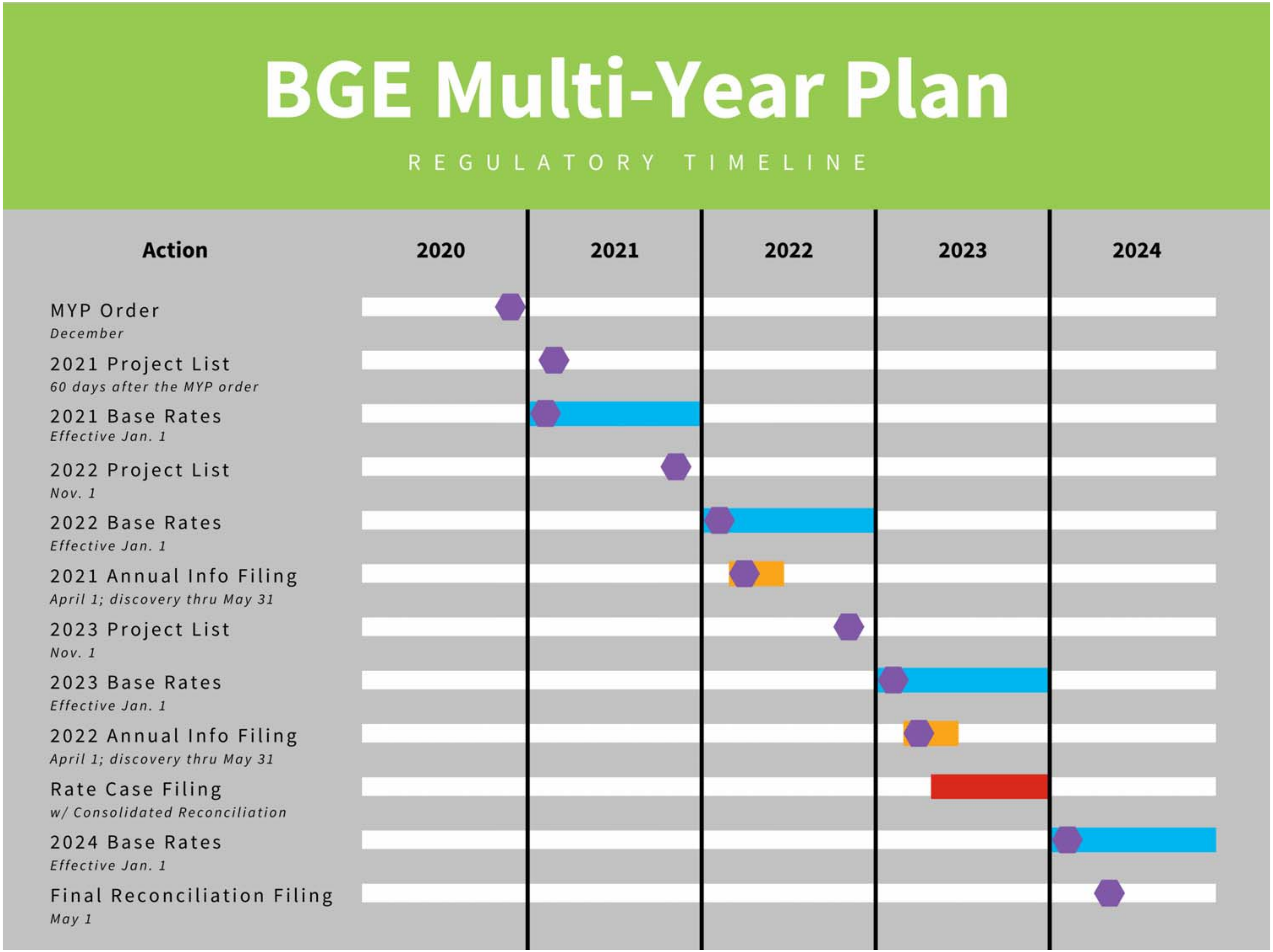
BGE Multi-Year Plan
REGULATORY TIMELINE
Action
2020
2021
2022
2023
2024
MYP Order
December
2021 Project List
60 days after the MYP order
2021 Base Rates
Effective Jan. 1
2022 Project List
Nov. 1
2022 Base Rates
Effective Jan. 1
2021 Annual Info Filing
April 1; discovery thru May 31
2023 Project List
Nov. 1
2023 Base Rates
Effective Jan. 1
2022 Annual Info Filing
April 1; discovery thru May 31
Rate Case Filing
w/ Consolidated Reconciliation
2024 Base Rates
Effective Jan. 1
Final Reconciliation Filing
May 1

Before the Maryland Public Service Commission

Case No.________

Prepared Direct Testimony of

David M. Vahos – Part 1

On Behalf of

Baltimore Gas and Electric Company

March 2, 2020

List of Issues and Major Conclusions

- In its letter to the Commission dated February 5, 2020, BGE expressed its willingness and desire to serve as the Pilot Utility consistent with the Commission's Order No. 89482 in Case No. 9618 supporting the use of multi-year plans ("MYP") in Maryland as an alternative to traditional ratemaking to benefit the public interest. BGE is therefore voluntarily making available, prior to the submission of its full MYP application, Part 1 of my Direct Testimony and Exhibits related to the 2019 Historic Test Year ("HTY"), which is to be used as the basis for comparison to the MYP years. Part 2 of my Direct Testimony and Exhibits, related to the Bridge Year and MYP years, will be provided when BGE files its full MYP application.

- The 10.25% return on equity requested in the Company's MYP is based on the 9.9% return on equity recommended by Company Witness McKenzie, adjusted upwards for a performance adder of 35 basis points to align with the midpoint of the upper half of Company Witness McKenzie's recommended cost of equity range. BGE believes that when a utility shows consistent excellent performance and customer satisfaction, that historical performance should positively impact the return on equity authorized by the Commission.

TABLE OF CONTENTS

I. QUALIFICATIONS

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. My name is David M. Vahos. My business address is 2 Center Plaza, 110 West Fayette Street, Baltimore, Maryland 21201.

Q. WHAT IS YOUR POSITION WITH BALTIMORE GAS AND ELECTRIC COMPANY?

A. I am Senior Vice President, Chief Financial Officer and Treasurer of Baltimore Gas and Electric Company ("BGE" or the "Company"). My current responsibilities include managing the financial condition of BGE and employing financial policies that maintain the financial health and stability of the utility, enabling the Company to obtain the capital necessary to provide safe and reliable service, and maintaining an appropriate capital structure. In my capacity as Chief Financial Officer, I have oversight of BGE's accounting, financial reporting, financial planning, tax and budgeting functions as well as BGE's internal financial control structure. As Treasurer, I am responsible for managing BGE's relationship with the financial community as well as the credit rating agencies.

Q. PLEASE DESCRIBE YOUR BUSINESS EXPERIENCE AND EDUCATIONAL BACKGROUND.

A. I have been employed by the Company since 1998, serving in various capacities in Finance and Accounting at BGE and Constellation Energy. Before coming to BGE, I was employed as an auditor at KPMG, one of the "Big 4" accounting firms. I am a Certified Public Accountant, and I hold a Bachelor's Degree in the Science of Accountancy from Villanova University in Pennsylvania and a Master of Business

Administration from Johns Hopkins University School of Continuing Studies. I am a member of the American Institute of Certified Public Accountants. I am also a Vice President of the Towson University Foundation Board, a member of the Towson University College of Business and Economics Advisory Board, a founding member of the Baltimore Chapter Board of Directors for the Association of Latino Professionals for America, a member of the YMCA of Central Maryland Board, a member of the University System of Maryland Foundation Board, and an active supporter of the United Way of Central Maryland.

Q. HAVE YOU PREVIOUSLY SUBMITTED WRITTEN TESTIMONY TO THIS COMMISSION?

A. Yes. See Company Exhibit DMV-1 for a summary of my testimony experience.

II. PURPOSE OF TESTIMONY

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY?

A. In its letter to the Commission dated February 5, 2020, BGE expressed its willingness and desire to serve as the Pilot Utility consistent with the Commission's Order No. 89482 in Case No. 9618 supporting the use of multi-year plans ("MYP") in Maryland as an alternative to traditional ratemaking to benefit the public interest. In an effort to help reduce the burden on Staff and other Intervenors, BGE is voluntarily making available certain testimony and information prior to the submission of its full MYP application.

The purpose of my testimony, which I have named as my Direct Testimony - Part 1, is to provide support for the Company's MYP application related to the 2019 Historic Test Year ("HTY") to be used as the basis for comparison to the MYP years. The attached exhibits provide actual 2019 amounts representing the HTY, adjusted for

Commission precedent and the impact of Case No. 9610, which I discuss in more detail later in my testimony. I am making available Part 1 of my Direct Testimony and will file this testimony with Part 2 of my Direct Testimony, which will discuss the 2020 Bridge Period and MYP years, when the Company files its MYP application.

In this testimony I will discuss the hypothetical calculation of a revenue requirement for the HTY that will serve only as a point of comparison for the revenue requirement for each of the MYP years. As part of that discussion, I will address the capital structure and rate of return for the HTY and will describe the exhibits setting forth the calculation of the HTY revenue requirement, including certain pro forma adjustments.

III. CAPITAL STRUCTURE AND RATE OF RETURN

Q. WHAT CAPITAL STRUCTURE AND RATES OF RETURN ARE REFLECTED IN THE 2019 HTY REVENUE REQUIREMENT CALCULATION THAT IS BEING PROVIDED FOR COMPARATIVE PURPOSES?

A. I have prepared a chart below that shows the Company's actual capital structure, on a permanent basis, as of December 31, 2019, as well as the calculation of the rate of return for this period, for both electric and gas. The capital structure is considered permanent in that it excludes short-term debt, a form of temporary financing. BGE is presenting a 7.28% overall rate of return for both electric and gas operations for the 2019 HTY based on the Company's actual embedded cost of debt as supported in Supplemental Information Item IV. 2.A. (a-n), as well as a 10.25% return on equity ("ROE") for both electric and gas.

Chart 1 –Capital Structure and Electric and Gas Rates of Return

	Capital Structure	Embedded Cost Rates	Weighted Cost
	----------	----------	----------
Long-term debt	47.2%	3.96%	1.87%
Common equity	52.8%	10.25%	5.41%
	----------		----------
	100.0%		7.28%

Q. WHAT IS THE BASIS OF THE 10.25% RETURN ON EQUITY?

A. The 10.25% ROE requested is based on the 9.9% ROE recommended by Company Witness McKenzie, adjusted upwards for a performance adder of 35 basis points that aligns with the midpoint of the upper half of Company Witness McKenzie's recommended cost of equity range. The 9.9% ROE recommended by Company Witness McKenzie represents the midpoint of his range. I am proposing that BGE's authorized ROE be set at the midpoint of the upper half of his range in recognition of BGE's outstanding performance and customer satisfaction results. Since 2014, BGE has delivered first quartile 2.5 Beta CAIDI results and in 2019 BGE delivered first quartile 2.5 Beta SAIFI results as well.[1] On the gas side of the business, BGE is deeply committed to operating safely for customers, employees and the general public and has consistently delivered first decile gas emergency response times, responding to 99.97% of emergencies within less than an hour. In fact, in 2019 BGE delivered its best ever gas emergency average response time, responding to gas emergencies within less than 22 minutes on average. Over the last several years, BGE has also replaced more than

[1] CAIDI is the Customer Average Interruption Duration Index and SAIFI is the System Average Interruption Frequency Index.

100 miles of outmoded cast iron and bare steel mains and more than 20,000 metallic gas services. These exceptional operating results have translated into superior customer satisfaction scores as well. For the past three years, J.D. Power has ranked BGE first among electric utilities in its East Large Segment, and first among gas utilities in the East Region for the past two years, for business customer satisfaction. Further, BGE's 2019 customer satisfaction scores from Escalent were the best ever on record. In addition, BGE has significantly improved in residential customer satisfaction surveys in recent years, moving to top decile rankings and the highest satisfaction levels measured to date. BGE believes that consistent excellent performance and customer satisfaction should positively impact the ROE authorized by the Commission.

Q. HOW DID BGE DETERMINE THE APPROPRIATE LEVEL OF PERFORMANCE ADDER TO REFLECT BGE'S HISTORICAL PERFORMANCE IN THE REQUESTED ROE?

A. Ultimately, the determination of the appropriate size of the performance adder is a matter of judgment and reason. As stated in Company Witness McKenzie's testimony, the fair ROE range for BGE's proxy group of peer utilities is from 9.2% to 10.6% with a midpoint of 9.9%. The 35 basis point adder above the midpoint of the range raises BGE's ROE to 10.25%, which is at the bottom of the top quartile of Company Witness McKenzie's fair ROE range for BGE. Given that BGE's recent historical operational performance and customer satisfaction results also fall within the top quartile of industry performance, a top quartile ROE award is appropriate.

Q. DOES THE TRANSITION TO A MYP MODEL CHANGE YOUR VIEW REGARDING THE APPROPRIATE RETURN ON EQUITY?

A. No. While the process of cost recovery is changing in Maryland, BGE still continues to be responsible for justifying that its rates are just and reasonable. I believe that regardless of whether historical test years or alternative rate recovery models are utilized, higher performance should be reflected in higher authorized ROEs, with the understanding that the authorized ROE should remain within the range of reasonableness.

IV. SUMMARY OF COMPANY HTY REVENUE REQUIREMENT EXHIBITS

Q. HAVE YOU PREPARED ANY OTHER EXHIBITS AND SUPPORTING SCHEDULES, MR. VAHOS?

A. Yes. In addition to Company Exhibit DMV-1 noted above, I have prepared five exhibits numbered as Company Exhibits DMV-3 through DMV-7 (with an "E" to indicate electric and a "G" to indicate gas).[2] Please note that Company Exhibit DMV-2 is not included in the pre-filing exhibits as it will provide a summary of the electric and gas base rate relief requested by the Company for each MYP year. The exhibits included in this filing described below, along with Company Exhibit DMV-2, will be updated with amounts and additional proforma adjustments for 2020 (the Bridge Period) and the MYP years (2021-2023) when the Company files its MYP application. The exhibits provided in this filing include:

Company Exhibit DMV-3 shows the derivation of electric and gas distribution rate base and operating income on an unadjusted and an adjusted basis for the HTY. This schedule also includes the actual capital structure and targeted rate of return, the unadjusted and adjusted electric and gas distribution returns actually earned using the foregoing amounts, and a revenue requirement summary for the 2019 HTY.

[2] Exhibits were prepared in a manner consistent with the formats agreed to by the Case No. 9618 Working Group.

Company Exhibit DMV-4 presents a reconciliation from unadjusted electric and gas distribution rate base, operating income and revenue requirement to the adjusted electric and gas distribution rate base, operating income and revenue requirement for the 2019 HTY. This schedule includes a listing of the Company's adjustments to electric and gas distribution operating income and rate base for the 2019 HTY, as well as the revenue requirement effect of each. Proforma adjustments are being presented to reflect Commission precedent and the impact of Case No. 9610.[3] Separate schedules detailing the computation of each proforma adjustment are also provided. Additional proforma adjustments not applicable to the HTY, but applicable to the MYP years, will be provided with my testimony in the full MYP application.

Company Exhibit DMV-5 presents the calculation of cash working capital included in electric and gas distribution unadjusted rate base for the 2019 HTY based on the current lag days.[4]

Company Exhibit DMV-6 quantifies the impact of the updated net lag days resulting from the 2019 lag study on cash working capital included in electric and gas distribution rate base for the 2019 HTY.

Company Exhibit DMV-7 presents a summary of the updated net lag days based on the 2019 lag study.

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[3] In the December 2019 in Order No. 89400 in Case No. 9610, the Commission granted the Joint Motion of parties in that proceeding for approval of a settlement agreement providing for new base rates and associated increases in electric and gas base distribution revenues, among other things. The 2019 HTY revenues have been adjusted to reflect the approximate level of distribution revenues that would have been recognized by BGE if the new base rates from Case No. 9610 had been effective for all of 2019. The Company is also therefore making certain adjustments to the 2019 HTY in order to approximate the level of expenses and rate base which would have been reflected if base rates from Case No. 9610 had been in effect the entirety of 2019 as well.

[4] The cash working capital schedule to reflect the effect of cash working capital on each individual adjustment has been eliminated due to the immaterial impact of the adjustment coupled with both an effort to simplify our filing.

Q. CAN YOU PLEASE TESTIFY TO THE ACCURACY OF THE FINANCIAL STATEMENTS UPON WHICH YOUR CASE IS BASED?

A. The 2019 HTY financial statement results that serve as the basis for these pre-filing exhibits as presented on Company Exhibits DMV-3 through DMV-7 are complete and accurate. PricewaterhouseCoopers ("PwC"), the Company's independent external auditor, issued a clean, unqualified opinion for the Company's 2019 financial statements for reporting to the U.S. Securities and Exchange Commission.

A. <u>COMPANY EXHIBIT DMV-3</u>

Q. PLEASE DESCRIBE COMPANY EXHIBIT DMV-3 – RATE BASE AND OPERATING INCOME SUMMARY.

A. Company Exhibit DMV-3, entitled "Rate Base and Operating Income Summary", shows the Company's electric and gas distribution average rate base, operating income, and electric and gas returns for the 2019 HTY. These schedules also include the actual permanent capital structure as of December 31, 2019, and rate of return calculation, as well as a revenue requirement summary for the 2019 HTY. As I have mentioned previously, the calculation of a revenue requirement for the 2019 HTY is entirely hypothetical and solely for the purpose of comparison to the 2021-2023 MYP years.

The first section, Rate Base (Average Basis), shows each major component of distribution rate base (lines 2 through 11) consistent with the Commission's previous findings. Rate base represents the amount of investment financed by investors that is used and useful in providing utility service to customers. All of the components of unadjusted rate base shown are 13-month average balances, with the exception of cash working capital which is computed using 2019 HTY operating expense levels. The unadjusted cash working capital calculation is presented in Company Exhibit DMV-5.

Column 1 presents rate base on an unadjusted basis. Column 2 reflects the impact of the various rate base ratemaking adjustments, and Column 3 presents rate base on an adjusted basis, which is computed by applying the ratemaking adjustments to the unadjusted balances.

In the operating income section, the Company's operating expenses for each period (lines 17 through 25) are deducted from distribution operating revenue (line 16), computed in accordance with the FERC Uniform System of Accounts. The allowance for funds used during construction ("AFC", line 26) is then added to this amount, and interest on customer deposits (line 27) is deducted. These two items are included because their corresponding balance sheet accounts (i.e., Construction Work In Progress ("CWIP") and customer deposits liability) are included in the calculation of rate base. Line 28 provides the operating income. Consistent with the rate base section above, columns are shown for unadjusted amounts, ratemaking adjustments, and adjusted amounts.

Lines 29 through 32 present the 2019 HTY actual permanent capital structure as of December 31, 2019, and weighted cost of debt, and proposed return on equity being requested in this proceeding.

Lines 33 through 38 provide the unadjusted and adjusted rates of return[5] and returns on equity.[6]

The final section of Company Exhibit DMV-3 summarizes a hypothetical revenue requirement for the 2019 HTY, which is presented for informational purposes

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5 The rate of return is calculated by dividing the operating income on line 31 by the average rate base on line 14.

6 The return on equity is the rate of return (line 37) less the weighted cost of debt (line 38) divided by the common equity ratio (line 40).

only. The Company's required operating income is calculated by multiplying the adjusted rate base by the rate of return supported by the capital structure section (lines 29-32) discussed above. The required operating income amount is then compared to the adjusted operating income or proforma operating income, which results in an operating income deficiency. This deficiency is "grossed up" for the additional taxes that will be paid as a result of the increased revenues and an uncollectible factor, a practice consistent with Commission precedent (line 45), arriving at a Revenue Requirement Deficiency amount.[7] As I mentioned earlier, this summary is for informational purposes only, and is presented to provide a point of comparison to the MYP years' revenue requirements to be included in the MYP application.

Q. WHAT IS THE BASIS OF THE AMOUNTS COMPRISING THE RATE BASE AND OPERATING INCOME INCLUDED ON EXHIBITS DMV-3?

A. The amounts comprising the operating income and rate base for the 2019 HTY reflect distribution revenues, expenses, and assets per the general ledger of BGE.

Q. ARE THERE ANY AMOUNTS THAT ARE NOT REFLECTED IN ADJUSTED RATE BASE AND OPERATING INCOME AS PRESENTED IN THIS FILING?

A. Yes. Electric transmission revenues, expenses, and rate base are appropriately excluded from this filing as they are FERC jurisdictional. Additionally, revenues and expenses associated with electric commodity revenues and expenses recovered through the Standard Offer Service ("SOS") charges, including SOS bad debt costs, are excluded from this filing. Furthermore, the portion of electric distribution bad debt expense associated with changes in the Accounts Receivable reserve is excluded from this filing.

[7] Case Nos. 9036, 9230, 9299, 9326, 9406 and 9484.

The majority of gas commodity revenues and expenses are also appropriately excluded from this filing as these revenues and expenses are recovered through the gas commodity cost recovery mechanism set forth in Rider 2 of BGE's Retail Gas Service Tariff. However, certain other gas commodity costs, namely bad debt, credit & collection costs, the return on gas storage, and the return on commodity-related cash working capital, are included in this filing, but are ultimately recovered through Rider 12, the Gas Administrative Charge ("GAC"), with a corresponding reduction to gas base rates via Rider 8. Regarding both gas distribution and gas commodity-related bad debt expense, the portion associated with changes in the Accounts Receivable reserve is excluded from this filing.

B. COMPANY EXHIBIT DMV-4

Q. PLEASE DESCRIBE COMPANY EXHIBIT DMV-4 – MYP REVENUE REQUIREMENT (UNADJUSTED AND ADJUSTED) SUMMARY BY YEAR.

A. Company Exhibit DMV-4, entitled "MYP Revenue Requirement (Unadjusted and Adjusted) Summary by Year", reconciles the unadjusted rate base, operating income (net of tax) and revenue requirement amounts for the 2019 HTY carried forward from Company Exhibit DMV-3 - to the adjusted amount as per Company Exhibit DMV-3. This exhibit lists the various operating income and rate base adjustments applied to unadjusted operating income and rate base to arrive at the respective adjusted amounts and revenue requirement amounts for the 2019 HTY. Each of the adjustments is shown net of income tax effects, where appropriate, at the prevailing 27.5175% statutory tax rate, and a revenue requirement impact for each adjustment is also shown. Each of these adjustments to operating income and rate base is appropriate in order to reflect Commission precedent, and the impact of Case No. 9610. I have also included supporting schedules (numbered to correspond to the schedule reference noted on this exhibit) showing the computation for each adjustment listed on Company Exhibit DMV-4.

Q. CAN YOU PLEASE WALK THROUGH THE RATEMAKING ADJUSTMENTS INCLUDED ON COMPANY EXHIBIT DMV-4 BEGINNING WITH OPERATING INCOME ADJUSTMENT 1?

A. In Case No. 9610, Order No. 89400, the Commission accepted a settlement that resulted in an increase of $25.0 million in electric base rates and $54.0 million in gas base rates. This rate change became effective with service rendered on or after December 17, 2019. Operating Income Adjustment 1 reflects the annual effect on operating income of this rate change not reflected in the 2019 HTY.

Q. CAN YOU PLEASE DISCUSS OPERATING INCOME ADJUSTMENT 2 IN COMPANY EXHIBIT DMV-4?

A. Operating Income Adjustment 2 annualizes unadjusted electric and gas AFC accrued during 2019 to reflect the 6.94% and 6.97% rates of return agreed to in the settlement agreement reached in Case No. 9610 for the purpose of calculating AFC, which were accepted by the Commission in Order No. 89400 for electric and gas, respectively. Operating Income Adjustment 2 reflects the annual impact on AFC of the Case No. 9610 settlement which is not reflected in the 2019 HTY.

Q. CAN YOU PLEASE DISCUSS OPERATING INCOME ADJUSTMENTS 3 THROUGH 19 AND RATE BASE ADJUSTMENTS 1 THROUGH 8 IN COMPANY EXHIBIT DMV-4?

A. Operating Income Adjustments 3 through 19 and the related Rate Base Adjustments 1 through 8 include the specific adjustments resulting from the application of the Case No. 9610 settlement agreement, which was accepted by the Commission in Order No. 89400, as well as certain other uncontested adjustments proposed in Case No. 9610. In addition to adjusting the 2019 HTY revenues to reflect the approximate level of distribution revenues that would have been recognized by BGE if the new base rates from Case No. 9610 had been in effect for all of 2019 in Operating Income Adjustment 1, the Company is also therefore making certain adjustments to the 2019 HTY in order to approximate the level of expenses and rate base which would have been reflected if base rates from Case No. 9610 had been in effect the entirety of 2019 as well. These adjustments include:

- the annualization of amortization of rate case expenses;
- the recovery of STRIDE audit fees;
- the annualization of Smart Grid regulatory asset costs incurred subsequent to November 2015 (the end of the test year in Case No. 9406) and the related rate base impact;
- the annualization of the amortization of conservation voltage reduction costs and the related rate base impact;
- the amortization of Maryland Additional Subtraction Modification tax regulatory liability;
- the annualization of the amortization of Riverside environmental mitigation costs and the related rate base impact;
- the annualization of depreciation expense and the related rate base impact;
- the impact of the Collective Bargaining Agreement ("CBA");

- the impact of the 10 additional sick days resulting from the CBA;
- the annualization of the customer operations wage adjustment;
- the annualization of the 2019 general wage increase;
- the annualization of the known increases to other taxes in 2019;
- the elimination of expiring regulatory asset amortizations and the related rate base impact;
- the normalization of gains on sale of real estate and the related rate base impact;
- the inclusion of safety and reliability investments on a terminal basis and related annualization of depreciation expense;
- the inclusion of STRIDE investments on a terminal basis and related annualization of depreciation expense; and
- the impact of general inflation on non-labor operations and maintenance costs.

Q. CAN YOU PLEASE DISCUSS <u>OPERATING INCOME ADJUSTMENT 20</u> IN COMPANY EXHIBIT DMV-4.

A. Operating Income Adjustment 20 normalizes the level of major outage event restoration expense (or major storm costs) recorded in the 2019 HTY consistent with ratemaking treatment authorized in prior cases. This adjustment reflects the five-year average level of incremental major outage event restoration expense experienced between January 2015 and December 2019. Consistent with BGE's adjustments in recent cases, the historical restoration costs have been adjusted to today's dollars based on the Consumer Price Index ("CPI") per the U.S. Department of Labor, Bureau of Labor Statistics.[8]

[8] Case Nos. 9299, 9326, 9355, 9406, and 9610.

Q. CAN YOU PLEASE DISCUSS <u>OPERATING INCOME ADJUSTMENT 21</u> IN COMPANY EXHIBIT DMV-4?

A. Operating Income Adjustment 21 reduces gas operating income by eliminating the one-time credit recorded in the 2019 HTY to establish a regulatory asset for the Riverside environmental costs as authorized in Case No. 9484, Order No. 88975.[9] This credit is being eliminated since it is a one-time non-recurring event.

Q. CAN YOU PLEASE DISCUSS <u>OPERATING INCOME ADJUSTMENT 22</u> IN COMPANY EXHIBIT DMV-4?

A. Operating Income Adjustment 22 removes all of the revenues associated with Rider 31 (ERI) which ended in December 2019 but are reflected in the 2019 HTY operating income. This adjustment is included in order to normalize the 2019 HTY for comparison purposes to the MYP years.

Q. CAN YOU PLEASE DISCUSS <u>OPERATING INCOME ADJUSTMENT 23</u> IN COMPANY EXHIBIT DMV-4?

A. Operating Income Adjustment 23 removes the STRIDE Rider 16 revenues, net, that are reflected in the 2019 HTY.[10] This adjustment is necessary to reflect the transfer of the STRIDE investments to base rates in Case No. 9610, in accordance with the settlement which was accepted by the Commission in Order No. 89400. Since the recovery of the Case No. 9610 STRIDE investments is reflected in the base rate increase provided in Operating Income Adjustment 1, it is appropriate to remove these revenues from the 2019 HTY.

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[9] Case No. 9484, Order No. 88975 at 37.

[10] STRIDE revenues, net, represents both STRIDE revenues per Rider 16 and the related STRIDE imbalance (i.e. difference between STRIDE revenues and STRIDE costs).

Q. CAN YOU PLEASE DISCUSS <u>OPERATING INCOME ADJUSTMENT 24</u>?

A. Operating Income Adjustment 24 eliminates from the 2019 HTY electric and gas operating income certain advertising expenses recorded as operating expenses, in accordance with the FERC Uniform System of Accounts, that BGE is not allowed to recover pursuant to COMAR 20.07.04.08. These expenses represent institutional and promotional advertising expenses. All charitable contributions, penalties, and lobbying costs, including the lobbying expense portion of the Edison Electric Institute dues and the American Gas Association dues, are recorded below the line and are not reflected in operating income. Therefore, it is not necessary to include these costs in this operating income adjustment.

Q. CAN YOU PLEASE DISCUSS <u>OPERATING INCOME ADJUSTMENT 25</u> IN COMPANY EXHIBIT DMV-4?

A. Operating Income Adjustment 25 eliminates from the 2019 HTY certain employee activity costs as directed by the Commission in Case No. 9299, Order No. 85374.

Q. CAN YOU PLEASE DISCUSS <u>OPERATING INCOME ADJUSTMENT 26</u> IN COMPANY EXHIBIT DMV-4?

A. Operating Income Adjustment 26 eliminates 100% of the 2019 HTY costs of the Supplemental Executive Retirement Program as required in Case No. 9484, Order No. 88975.

Q. CAN YOU PLEASE DISCUSS <u>OPERATING INCOME ADJUSTMENT 27</u> IN COMPANY EXHIBIT DMV-4?

A. Operating Income Adjustment 27 removes the non-recoverable amount of incentive compensation in the 2019 HTY consistent with Case No. 9326, Order No. 86060.

Q. CAN YOU PLEASE DISCUSS <u>OPERATING INCOME ADJUSTMENT 28</u> IN COMPANY EXHIBIT DMV-4?

A. Operating Income Adjustment 28 adjusts operating income for the known annualized amount of AFC included in unadjusted operating income at the electric 6.94% and gas 6.97% rates of return agreed to in the Case No. 9610 settlement and accepted by the Commission in Order No. 89400, to reflect a level that is consistent with the 7.28% rate of return calculated for the 2019 HTY.

Q. PLEASE DESCRIBE <u>OPERATING INCOME ADJUSTMENT 29</u> IN COMPANY EXHIBIT DMV-4?

A. In accordance with prior Commission orders, Operating Income Adjustment 29 increases operating income to reflect the income tax effect of pro-forma interest.[11] This adjustment was developed to provide for the fact that, under the Commission's well-established regulatory practice, interest expense is treated as a "below the line" item for purposes of setting distribution base rates. At the same time, the income tax benefit associated with interest expense, which reduces cost of service, is appropriately treated as an "above the line" item and as such is legitimately included in the determination of cost of service. To the extent that the Company's interest expense and the implicit amount of interest expense approved by the Commission in establishing the Company's authorized rate of return is different, the Commission has required the Company to "synchronize" the tax savings associated with this difference by adjusting the Company's tax expense in the manner reflected by this adjustment.

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[11] *Re Baltimore Gas and Electric Co.,* 78 Md. PSC 129 (1987); *Re Baltimore Gas and Electric Co.,* 80 Md. PSC 380 (1989); *Re Baltimore Gas and Electric Co.,* 80 Md. PSC 496 (1989); *Re Baltimore Gas and Electric Co.,* 96 Md. PSC 334 (2005); and *Re Baltimore Gas and Electric Co.,* 102 Md. PSC 74 (2011).

Q. PLEASE DISCUSS <u>RATE BASE ADJUSTMENT 9</u> IN COMPANY EXHIBIT DMV-4.

A. Rate Base Adjustment 9 reduces electric distribution and gas distribution rate base to remove the Rulemaking 54 ("RM54") capital software costs. Although an operating income adjustment to remove RM54 amortization is not necessary since it was not recorded as a gas distribution expense following the Commission's decision in Case No. 9484 or as an electric distribution expense reflected in Case No. 9610, RM54 capital is reflected in rate base as common plant and is allocated to electric and gas distribution. Since these investments are being recovered through the Purchase of Receivables mechanism, it is necessary to reflect both the gas and electric portions of RM54 capital in Rate Base Adjustment 9 which reduces electric and gas rate base.

C. <u>CASH WORKING CAPITAL</u>

Q. MR. VAHOS, WILL YOU PLEASE EXPLAIN CASH WORKING CAPITAL ("CWC")?

A. Certainly. In the regulated energy business, CWC is a component of rate base that represents the amount of cash a firm must obtain from its investors in order to provide the funds necessary to operate the business on a day-to-day basis. Investor funds are required in order to pay bills before cash from the sale of utility service actually begins to flow back to the Company.

By including CWC in rate base, the Commission is appropriately providing the Company an opportunity to recover the cost of this permanent financing need.

Q. HOW DOES THE COMMISSION DETERMINE THE AMOUNT OF CWC THAT IS APPROPRIATE FOR INCLUSION IN RATE BASE?

A. The method for determining CWC that is widely used throughout the regulated energy industry is known as a "Lead/Lag" Study.

Q. WILL YOU PLEASE EXPLAIN WHAT IS INVOLVED WITH CONDUCTING A "LEAD/LAG" STUDY?

A. Yes. A "Lead/Lag" Study involves a great deal of effort and analysis on the part of the Company's regulatory personnel. Essentially, for most of the major sources of expense, including labor, fringe benefits, taxes, and gas fuel, an analysis of payments is conducted. The process involves both analyzing payroll data and reviewing invoices in order to determine the exact date or mid-point of the period that the goods or service were provided. Each transaction is then traced to the actual disbursement date when payment was made in order to determine the number of days from the receipt of the goods or service to the outflow of cash related to each transaction. In addition, for other operations and maintenance expenses that are characterized by a high volume of relatively low dollar value transactions, large random samples of these transactions are selected, the invoices are reviewed, and the transactions are traced from the date of the receipt of the goods and service to the date of cash outflow. The lag days are determined for each item of expense based on the process described above. I will refer to the number of days for cash outflow as the "expense lag".

Offsetting the expense lag is the number of lag days associated with the cash inflow. This is determined by a careful analysis and study of the billing cycle. The revenue lag is a measure of how many days it takes from the rendition of service until the cash is received from the customer. I will refer to the number of days for cash inflow as the "revenue lag".

The expense lag is then netted against the revenue lag to determine the net lag for each item of expense. If the revenue lag is greater than the expense lag, then the item of expense creates a need for investor funds. Correspondingly, if the expense lag is greater than the revenue lag, the need for investor funds is mitigated. For example, if labor is determined to have a 41.0 day expense lag and the revenue lag is determined to be 47.1 days, the net lag for labor is 6.1 days (47.1 days minus 41.0 days). In order to determine the amount of CWC associated with labor, the net lag of 6.1 days would be multiplied by the average daily labor costs (total annual labor costs divided by 365) to determine the amount of investor funds that are required to support the payroll. This is calculated for each expense item and the sum of these calculations equals the required CWC which is included as a component of rate base.

Q. HAS THE COMPANY PREPARED AN UPDATED LEAD/LAG STUDY?

A. Yes. The Company updated its lead/lag study based on calendar year 2019 revenues and expenses. The updated lags based on 2019 payments resulted in higher expense lags in several categories. This resulted in an $28 million decrease ($19 million and $9 million for electric and gas, respectively) to rate base as calculated on Company Exhibit DMV-6, Line 19 and carried forward to Company Exhibit DMV-4, Line 31.

Q. COULD YOU NOW PLEASE DISCUSS YOUR EXHIBIT WHICH SETS FORTH THE DETAILS OF THE CASH WORKING CAPITAL ADJUSTMENT CALCULATIONS?

A. Company Exhibits DMV-5 through DMV-7 develop the total amount of CWC applicable for the 2019 HTY reflected in this pre-filing. As I discussed earlier, this represents the amount of investor supplied cash needed to operate the business on a day-to-day basis. The necessity for cash working capital results primarily from the fact that the lag in the

Company's collection of revenues after service has been rendered is greater than the lag in the Company's payment of expenses after the expenses have been incurred. In other words, a company must normally pay its bills before revenues for its service are received from customers.

Company Exhibits DMV-5 through DMV-7, are organized as follows:

- Company Exhibit DMV-5 summarizes the calculation of the CWC requirement reflected in unadjusted rate base for the 2019 HTY. This calculation is based on the current lag days as determined by the 2014 lead lag study.
- Company Exhibit DMV-6 calculates the impact of the change in the lag days on cash working capital. This exhibit summarizes the calculation of the CWC requirement for the 2019 HTY based on the updated lead lag days as reflected in the 2019 lead lag study.
- Company Exhibit DMV-7 summarizes the lag days for revenue and the various expense categories based on the 2019 lead lag study.

D. COMPANY EXHIBIT DMV-5

Q. COULD YOU PLEASE REVIEW COMPANY EXHIBIT DMV-5 WHICH SUMMARIZES THE CWC CALCULATION INCLUDED IN RATE BASE?

A. As I just mentioned, Company Exhibit DMV-5 summarizes the calculation of the cash working capital requirement which is included in unadjusted rate base based on the current lag days per the 2014 lag study. The Description column shows the various classes of operating expenses incurred by the Company. The Net Lag Days column represents the difference between the average days lag in the collection of revenue from customers and the appropriate lag for the particular item of expense based on the currently approved 2014 study.

The unadjusted dollar amounts of the various expenses for the 2019 HTY are shown in the CWC Expense column. The Cash Advanced column is calculated by converting the expense amounts to daily averages and then multiplying the average daily expense amounts by the net lag days. The cash advanced amount represents the dollar amount of working capital required as a result of the lag in the collection of revenues exceeding the lag in the payment of expenses. This exhibit supports the Company's overall unadjusted cash working capital included in rate base on line 6 of Company Exhibit DMV-3.

E. COMPANY EXHIBIT DMV-6

Q. COULD YOU PLEASE REVIEW COMPANY EXHIBIT DMV-6 WHICH SUMMARIZES THE IMPACT ON CWC OF THE UPDATED LAG DAYS?

A. Company Exhibit DMV-6 calculates the decrease of $28 million on cash working capital ($19 million for electric and $9 million for gas) based on the change in lag days as a result of reflecting the 2019 lag study. This exhibit summarizes the calculation of the cash working capital requirement similar to Company Exhibit DMV-5 - however this calculation is based on the updated lag days from the 2019 lag study which are summarized on Company Exhibit DMV-7. Company Exhibit DMV-6 is essentially the same as Company Exhibit DMV-5 with the exception of utilizing the new lag days based on the 2019 lag day study in the calculation. The difference between the cash working capital amounts based on the 2014 lag days (as calculated on Company Exhibit DMV-5) compared to the 2019 lag days on this exhibit is presented at the bottom of the schedule, and then is carried forward as a proforma adjustment to rate base to Company Exhibit DMV-4 (line 31).

F. COMPANY EXHIBIT DMV-7

Q. PLEASE DISCUSS THE REMAINING COMPANY EXHIBIT DMV-7.

A. Company Exhibit DMV-7 summarizes the results of the 2019 Lead/Lag Study. As I mentioned earlier in my testimony, the Company's most recently completed Lead/Lag Study is based primarily on 2019 actual payments and revenue collections. The lag days summarized on this exhibit support the lag days utilized for purposes of Company Exhibit DMV-6.

Q. MR. VAHOS, PLEASE BEGIN WITH THE CALCULATION OF THE REVENUE LAG. WHAT ELEMENTS MAKE UP THE AVERAGE LAG IN THE COLLECTION OF REVENUES FROM CUSTOMERS?

A. Company Exhibit DMV-7 starts out by setting forth the revenue lag calculation. There are four elements to the revenue lag as illustrated on this exhibit. First, there is the 14.7 average number of days during which service has been supplied to all customers before the meter is read. The second element is the 3.8 average number of days between the date the meter is read and the bill is delivered, determined by analyzing the meter reading schedules. The third element is the 28.4 average number of days between bill delivery and payment, determined by analyzing accounts receivable cash collections over a normal billing cycle for 21 consecutive cash dates. The final element is the 0.2 average number of days from the date payment is received from the customer to the date those funds are accessible by the Company. These four elements of the revenue lag total 47.1

days and represent the lag the Company experiences between the rendition of service to customers and the collection of the corresponding revenue.

Q. WHAT ELEMENTS MAKE UP THE AVERAGE LAG IN THE PAYMENT OF OPERATING EXPENSES?

A. Company Exhibit DMV-7 also shows the lag days for each operating expense component of the cash working capital calculation as well as the net lag days utilized for purposes of the cash working capital calculation computed on Company Exhibit DMV-6. For example, the 6.1 net lag days for salaries and wages is carried forward to Company Exhibit DMV-6 and represents the difference between the 47.1 day revenue lag and an average lag of 41.0 days in the payment of salaries and wages.

V. CONCLUSION

Q. DOES THIS CONCLUDE PART 1 OF YOUR DIRECT TESTIMONY?

A. Yes.

SUMMARY OF PREPARED TESTIMONY

DAVID M. VAHOS

Baltimore Gas and Electric – Chief Financial Officer and Treasurer

Case Number	**Nature of Proceeding**	**Nature of Testimony**
RATE CASES:		
Case No. 9299	Maryland Base Rate Case	Electric and Gas Revenue Requirement Witness
Case No. 9326	Maryland Base Rate Case	Electric and Gas Revenue Requirement Witness
Case No. 9355	Maryland Base Rate Case	Electric and Gas Revenue Requirement Witness
Case No. 9406	Maryland Base Rate Case	Electric and Gas Revenue Requirement Witness
Case No. 9610	Maryland Base Rate Case	Electric and Gas Revenue Requirement Witness
OTHER CASES:		
Case No. 9089	Qualified Rate Stabilization Charge	Support of BGE's Rate Stabilization Plan Cost Recovery
Case No. 9208	Advanced Meter Infrastructure (AMI)	Support of BGE's deployment of a Smart Grid Initiative
Case No. 9331	Gas System Strategic Infrastructure Development and Enhancement Plan (STRIDE)	Support of the BGE STRIDE cost recovery mechanism
Case Nos. 9226 / 9232	Pepco & Delmarva Standard Offer Service (SOS) Cash Working Capital (CWC)	Support of the February 4, 2014 settlement filed by Pepco and Delmarva and supported by Commission Staff and the Retail Energy Supply Association (RESA) that provided for recovery of SOS CWC, incremental costs, and a return
Case No. 9221	BGE Standard Offer Service (SOS) Cash Working Capital (CWC)	Support of BGE SOS CWC cost recovery

Baltimore Gas and Electric Company
Electric Distribution Rate Base and Electric Distribution Operating Income Summary
Multi-Year Plan
(Thousands of Dollars)

Line No.	Description	Historic Test Year (HTY) 2019 Unadjusted (1)	Ratemaking Adjustments (2)	Adjusted (3) = (1) + (2)
1	**Rate Base (Average Basis)**			
2	Electric Plant	$ 6,968,400	$ 131,151	$ 7,099,551
3	Accumulated Depreciation and Amortization	(2,590,058)	(1,631)	(2,591,689)
4	Materials and Supplies	24,912	-	24,912
5	Cash Working Capital	30,444	(19,266)	11,178
6	Accumulated Deferred Income Taxes	(624,683)	(16,641)	(641,324)
7	Prepaid Pension/OPEB Liab.	41,396	-	41,396
8	Customer Advances & Deposits	(85,417)	-	(85,417)
9	Regulatory Assets & Liabilities	(282,842)	(3,842)	(286,684)
10	Other	-	-	-
11	Total Rate Base	$ 3,482,152	$ 89,772	$ 3,571,924
12	**Operating Income**			
13	Operating Revenues			
14	Sale of Electricity	$ 1,152,987	$ 16,471	$ 1,169,457
15	Other Revenues	46,120	-	46,120
16	Operating Revenues	$ 1,199,107	$ 16,471	$ 1,215,577
17	Operating Expenses			
18	Net Metering Costs	$1,491	-	$ 1,491
19	Operation and Maintenance	433,864	$ 11,851	$ 445,715
20	Depreciation and Amortization	325,439	9,838	335,277
21	Other Taxes	168,253	3,470	171,722
22	Current Income Taxes	(4,481)	(447)	(4,928)
23	Deferred Income Taxes	37,364	(4,705)	32,659
24	Investment Tax Credit Adjustments	(40)	-	(40)
25	Total Operating Expenses	$ 961,889	$ 20,008	$ 981,897
26	Allowance for Funds Used During Construction	12,398	49	12,447
27	Interest on Customer Deposits	(2,081)	-	(2,081)
28	Operating Income	$ 247,534	$ (3,488)	$ 244,046
29	**Capital Structure**	Ratio	Cost	Wtd. Cost
30	Long-Term Debt	47.2%	3.96%	1.87%
31	Common Equity	52.8%	10.25%	5.41%
32	Total	100.0%		7.28%
33	**Rate of Return Summary**			
34	**Rate of Return**	**7.11%**		**6.83%**
35	Less Weighted Cost of Long-Term Debt	1.87%		1.87%
36	Net amount available for common equity	5.24%		4.96%
37	Common Equity ratio	52.80%		52.80%
38	**Return on Equity**	**9.92%**		**9.40%**
39	**Revenue Requirement Summary**		For Informational Purposes Only	
40	Rate Base			*$ 3,571,924*
41	Rate of Return			*7.28%*
42	Required Operating Income			*260,036*
43	Proforma Operating Income			*$ 244,046*
44	Operating Income Deficiency			*15,990*
45	Revenue Conversion Factor			*1.41636*
46	Rev. Rqmt. Deficiency (Excess)			*22,648*
47	Total Adjusted Distribution Revenue Requirement			
48	Rev. Rqmt. Deficiency (Excess) - MRP Incremental $ by Year			
49	Total Distribution Revenues, Adjusted			

Bridge 2020 Unadjusted (4)	Ratemaking Adjustments (5)	Adjusted (6) = (4) + (5)	Adjusted Variance vs. Prior Year (7)	MYP 2021 Unadjusted (8)	Ratemaking Adjustments (9)	Adjusted (10) = (8) + (9)	Adjusted Variance vs. Prior Year (11)	MYP 2022 Unadjusted (12)	Ratemaking Adjustments (13)	Adjusted (14) = (12) + (13)	Adjusted Variance vs. Prior Year (15)	MYP 2023 Unadjusted (16)	Ratemaking Adjustments (17)	Adjusted (18) = (16) + (17)	Adjusted Variance vs. Prior Year (19)
[redacted]				[redacted]				[redacted]				[redacted]			

Baltimore Gas and Electric Company
Electric MYP Revenue Requirement (Unadjusted and Adjusted) Summary By Year
For the Twelve Months Ended December 31,
(Thousands of Dollars)

Line No.	Description	Schedule Reference	HTY - 2019			Bridge Year - 2020			MYP 1 - 2021			MYP 2 - 2022			MYP 3 - 2023		
			Rate Base	Operating Income (Net of Tax)	Revenue Requirement	Rate Base	Operating Income (Net of Tax)	Revenue Requirement	Rate Base	Operating Income (Net of Tax)	Revenue Requirement	Rate Base	Operating Income (Net of Tax)	Revenue Requirement	Rate Base	Operating Income (Net of Tax)	Revenue Requirement
	Unadjusted Amounts	DMV-3E	3,482,152	247,534	8,451	[redacted]			[redacted]			[redacted]			[redacted]		
	Ratemaking Adjustments:																
1	Annualize Case No. 9610 Base Rate Revenues	OIA-1		16,187	(22,927)												
2	Annualize AFC to Reflect Case No. 9610 ROR	OIA-2		(492)	697												
3	Annualize Case No. 9610 Rate Case Expenses	OIA-3		(65)	92												
4	Annualize Case No. 9610 STRIDE Audit Fees	OIA-4	-	-	-												
5	Annualize Case No. 9610 Smart Grid Amortization	OIA-5/RBA-1	(2,027)	(4,054)	5,533												
6	Annualize Case No. 9610 CVR Amortization	OIA-6/RBA-2	(757)	(3,312)	4,613												
7	Annualize Maryland Additional Subtraction Modification Tax Benefit	OIA-7		1,848	(2,617)												
8	Annualize Case No. 9610 Riverside Amortization	OIA-8/RBA-3	-	-	-												
9	Annualize Case No. 9610 Depreciation Expense	OIA-9/RBA-4	463	926	(1,264)												
10	Annualize Collective Bargaining Agreement (CBA) Impact	OIA-10		(66)	93												
11	Annualize Additional Sick Days Resulting from CBA	OIA-11		(114)	161												
12	Annualize Customer Operation Wages	OIA-12		(297)	421												
13	Annualize 2019 General Wage Increase	OIA-13		(350)	496												
14	Annualize Other Tax Known Increases	OIA-14		(2,242)	3,175												
15	Eliminate Expiring Regulatory Asset Amortizations	OIA-15/RBA-5		16	(23)												
16	Amortize Gain on Sale of Real Estate	OIA-16/RBA-6		-	-												
17	Case 9610 Safety & Reliability Net Depreciation Expense Annualization'	OIA-17/RBA-7	111,781	(2,091)	14,487												
18	Case 9610 STRIDE Net Depreciation Expense Annualization	OIA-18/RBA-8		-	-												
19	General Inflation on Non-Labor O&M	OIA-19		(3,233)	4,579												
20	Normalize Major Outage Event Restoration Expense	OIA-20		(7,405)	10,488												
21	Eliminate One-Time Credit to Establish Riverside Environmental Regulatory Asset	OIA-21		-	-												
22	Eliminate ERI Rider 31 Revenues	OIA-22		(4,522)	6,405												
23	Eliminate STRIDE Revenues, Net	OIA-23		-	-												
24	Eliminate Advertising	OIA-24		916	(1,297)												
25	Eliminate Employee Activity Costs	OIA-25		251	(356)												
26	Eliminate SERP Costs	OIA-26		1,388	(1,966)												
27	Eliminate Certain Incentive Compensation	OIA-27		1,770	(2,507)												
28	Normalize AFC at Proposed ROR	OIA-28		540	(765)												
29	Interest Synchronization	OIA-29		913	(1,290)												
30	Eliminate RM54 Capital Software Costs	RBA-9	(422)	-	(44)												
					-												
31	Cash Working Capital Adjusted for Updated Lag Days	DMV-6E, Line 19	(19,266)	-	(1,987)												
32	Total Adjustments		89,772	(3,488)	14,197												
33	Total Revenue Requirement	DMV-3E	3,571,924	244,046	22,648												
	Rate of Return (Company Exhibit DMV-3E, line 35)		7.28%														
	Conversion Factor																
	Maryland State Income Tax		8.2500%														
	Federal Income Tax		21.0000%														
	Combined Income Tax Rate (SIT+(FITx(1-SIT))		27.5175%														
	Gross Receipts Tax		2.0000%														
	PSC Assessment Rate		0.2124%														
	Uncollectible Factor		0.3800%														
	Conversion Factor (1 /(1-Comb Tax)x(1-(GR+PSC+Uncoll))		1.41636														
	Conversion Factor % ((1-Comb Tax)x(1-(GR+PSC+Uncoll))		70.603%														

In Case No. 9610, Order No. 89400, the Commission accepted a settlement that resulted in an increase of $25 million in electric base rates. This rate change became effective with service rendered on or after December 17, 2019. Operating Income Adjustment 1 reflects the annual effect on operating income of this rate change not reflected in the 2019 HTY.

Description	**HTY 2019**	**Bridge Period 2020**	**MYP 1 2021**	**MYP 2 2022**	**MYP 3 2023**
Total increase in base rate revenues awarded	$25,000,000	[redacted]			
Case No. 9610 increase in base rate revenues reflected in the 2019 HTY	(2,161,822)				
Increase in base rate revenues to be realized	22,838,178				
Franchise Tax	(456,764)				
PSC Assessment	(48,508)				
Income Tax Effect at 27.5175%	(6,145,458)				
Adjustment to operating income	$16,187,449				
Amount Presented on Company Exhibit DMV-4E	$16,187,000				

Baltimore Gas and Electric Company
Case No. 9610 AFC Annualization - Electric
Multi-Year Plan

Operating Income
Adjustment 2

This adjustment annualizes unadjusted electric AFC accrued during the HTY 2019 to reflect the 6.94% rate of return for electric agreed to in the settlement agreement reached in Case No. 9610 for the purpose of calculating AFC, which was accepted by the Commission in Order No. 89400.

Description	HTY 2019	Bridge Period 2020	MYP 1 2021	MYP 2 2022	MYP 3 2023
Actual AFC for the 2019 HTY per Company Exhibit DMV-3E	$ 12,398	[redacted]			
Actual AFC for the 2019 HTY	12,397,545				
AFC accrued under the Case 9610 6.94% rate for the month of December 2019	(1,006,925)				
AFC to be subject to the new rate of 6.94%	11,390,620				
Conversion Factor to 6.94% AFC rates	6.94%/7.28%				
AFC for the period January - November 2019 restated to reflect a 6.94% AFC rate	10,858,640				
AFC to be subject to new rates	(11,390,620)				
Change in AFC	(531,979)				
Income Tax Effect of borrowed funds portion of AFC at 27.5175%	40,077				
Adjustment to Operating Income	$ (491,902)				
Amount presented on Company Exhibit DMV-4E	$ (492,000)				
Calculation of Income Tax Effect of Borrowed Funds Portion of AFC					
Increase (Decrease) in AFC	$ (531,979)				
Borrowed funds portion of AFC - %	27.4%				
Borrowed funds portion of AFC - $	(145,643)				
Income tax rate	27.5175%				
Income tax effect of borrowed funds portion of AFC	$ (40,077)				
Borrowed fund funds %					
Total Return	6.94%				
Weighted cost of Long-Term Debt	1.90%				
Borrowed Funds Portion of AFC %	27.4%				

Baltimore Gas and Electric Company
Case 9610 Electric Rate Case Expenses
Multi-Year Plan

Operating Income
Adjustment 3

This adjustment annualizes the amortization of deferred rate case expenses included in Case No. 9610, but not fully reflected in the HTY 2019.

Description	HTY 2019	Bridge Period 2020	MYP 1 2021	MYP 2 2022	MYP 3 2023
Annual amortization of deferred rate case expenses included in Case No. 9610	$ 97,280	[redacted]			
1 Month (December) reflected in HTY	(8,107)				
Amortization of deferred rate case expenses not reflected in the 2019 HTY	89,173				
Income tax effect at 27.5175%	(24,538)				
Adjustment to operating income	$ 64,635				
Amount Presented on Company Exhibit DMV-4E	$ (65,000)				

This adjustment annualizes the amortization of the electric Smart Grid regulatory asset incremental costs incurred since November 2015 (i.e. the end of the test year in Case No. 9406). This regulatory asset is being amortized through May 2026 years in accordance with the Case No. 9610 settlement which was accepted by the Commission in Order No. 89400. This adjustment reflects the portion of amortization which is not reflected in the HTY 2019. The companion adjustment is Rate Base Adjustment 1.

Description	HTY 2019	Bridge Period 2020	MYP 1 2021	MYP 2 2022	MYP 3 2023
Annual amortization of the 9406 post test year electric Smart Grid regulatory asset agreed to in the settlement in Case No. 9610	$ 6,102,176	[redacted]			
1 Month (December)	(508,515)				
Amortization of Case No. 9610 Smart Grid costs not reflected in the 2019 HTY	5,593,662				
Income tax effect at 27.5175%	(1,539,236)				
Adjustment to operating income	$4,054,426				
Amount Presented on Company Exhibit DMV-4E	($4,054,000)				

Baltimore Gas and Electric Company
Case No. 9610 Electric CVR Regulatory Asset Amort
Multi-Year Plan

Operating Income
Adjustment 6

This adjustment annualizes the CVR amortization as a result of the Case No. 9610 settlement which was accepted by the Commission in Order No. 89400, but not fully reflected in the 2019 HTY. The CVR 9610 Tranche is being amortized over 5 years in accordance with the Case No. 9610 settlement . In addition, this adjustment provides for the reversal of the 2019 HTY amounts deferred into the regulatory asset for CVR (i.e. depreciation, property taxes, and returns) so that the 2019 HTY reflects ongoing expenses and return based on the Case No. 9610 filing. The companion adjustment is Rate Base Adjustment 2.

Description	HTY 2019	Bridge Period 2020	MYP 1 2021	MYP 2 2022	MYP 3 2023
Annual amortization of the CVR regulatory asset 9610 tranche based on a 5 year period	$2,279,405	[redacted]			
1 Month (December)	(189,950)				
Amortization of Case No. 9610 CVR costs not reflected in the 2019 HTY	2,089,455				
Reversal of deferrals included in Case No. 9610	2,479,604				
Income tax effect at 27.5175%	(1,257,291)				
Adjustment to operating income	$3,311,768				
Amount Presented on Company Exhibit DMV-4E	($3,312,000)				

Baltimore Gas and Electric Company
Case 9610 Electric MD Additional Subtraction Modification Amortization
Multi-Year Plan

This adjustment provides customers with the state income tax benefit attributable to the recognition of an incremental increase to the Maryland "Statutory Subtraction" modification over the average remaining book lives of Maryland assets, approximately 32 years for electric, but which is not fully reflected in the 2019 HTY.

Description	HTY 2019	Bridge Period 2020	MYP 1 2021	MYP 2 2022	MYP 3 2023
Annual amortization of Maryland Additional Subraction Modification regulatory liability reflected in Case No. 9610	$2,780,900	[redacted]			
1 Month (December) reflected in HTY	(231,742)	[redacted]			
Amortization of Maryland Additional Subraction Modification regulatory liability not reflected in the 2019 HTY	2,549,158	[redacted]			
Income tax effect at 27.5175%	(701,465)	[redacted]			
Annual Maryland Additional Subraction Modification to be provided to customers	$1,847,694	[redacted]			
Adjustment to operating income	$1,847,694	[redacted]			
Amount Presented on Company Exhibit DMV-4E	$1,848,000	[redacted]			

Baltimore Gas and Electric Company
Case No. 9610 Electric Depreciation Rates
Multi-Year Plan

Operating Income
Adjustment 9

This adjustment annualizes the level of electric depreciation expense as a result of the new depreciation rates included in Exhibit 5 of the Case No. 9610 settlement agreement, which was accepted by the Commission in Order No. 89400. This adjustment is necessary since the new depreciation rates are not fully reflected in the 2019 HTY. The companion adjustment is Rate Base Adjustment 4.

Description	HTY 2019	Bridge Period 2020	MYP 1 2021	MYP 2 2022	MYP 3 2023
Direct	$ 3,141,484	[redacted]	[redacted]	[redacted]	[redacted]
Common	(4,535,217)	[redacted]	[redacted]	[redacted]	[redacted]
Annual Change in depreciation expense due to new depreciation rates agreed upon in Case No. 9610	(1,393,733)	[redacted]	[redacted]	[redacted]	[redacted]
1 Month (December) reflected in HTY	116,144	[redacted]	[redacted]	[redacted]	[redacted]
Change in depreciation expense not reflected in the 2019 HTY .	(1,277,589)	[redacted]	[redacted]	[redacted]	[redacted]
Income tax effect at 27.5175%	351,561	[redacted]	[redacted]	[redacted]	[redacted]
Adjustment to operating income	$ (926,028)	[redacted]	[redacted]	[redacted]	[redacted]
Amount Presented on Company Exhibit DMV-4E	$ 926,000	[redacted]	[redacted]	[redacted]	[redacted]

Baltimore Gas and Electric Company
Collective Bargaining Agreement - Electric
Multi-Year Plan

Operating Income
Adjustment 10

This adjustment reflects the impacts of the Collective Bargaining Agreement ("CBA") which are not fully reflected in the 2019 HTY.

Description	HTY 2019	Bridge Period 2020	MYP 1 2021	MYP 2 2022	MYP 3 2023
Specific Wage and Stipend Adjustments:		[redacted]			
Specific market wage adjustments	$ 244,605	[redacted]			
Premium and allowance adjustments	172,157	[redacted]			
Total specific wage and stipend adjustments	416,762	[redacted]			
General wage increase	1,444,685	[redacted]			
AIP reduction	(911,283)	[redacted]			
Elimination of 5 day sick pay accrual recorded in the HTY 2019	(858,827)	[redacted]			
Additional expenses resulting from the CBA not reflected in the 2019 HTY	91,337	[redacted]			
Income Tax Effect at 27.5175%	(25,134)	[redacted]			
Adjustment to Operating Income	$ 66,204	[redacted]			
Amount presented on Company Exhibit DMV-4E	$ (66,000)	[redacted]			

Baltimore Gas and Electric Company
CBA - 10 Add'l Sick Days - Electric
Multi-Year Plan

Operating Income
Adjustment 11

This adjustment annualizes the amortization of the union sick day regulatory asset established as a result of the Collective Bargaining Agreement ("CBA"), and then amortized over a 10 year period consistent with the Case No. 9610 settlement agreement which was accepted by the Commission in Order No. 89400.

Description	HTY 2019	Bridge Period 2020	MYP 1 2021	MYP 2 2022	MYP 3 2023
Additional 10 Days of Sick Pay	$ 1,717,045	[redacted]			
Amortization Period (years)	10				
Annual Amortization	171,705				
1 Month (December) reflected in HTY	(14,309)				
Amortization of sick pay expenses not reflected in the 2019 HTY	$157,396				
Income Tax Effect at 27.5175%	(43,311)				
Adjustment to Operating Income	$ 114,084				
Amount presented on Company Exhibit DMV-4E	$ (114,000)				

Baltimore Gas and Electric Company
2019 Customer Operations Market Adjustment - Electric
Multi-Year Plan

This adjustment reduces electric operating income by providing for the effect on labor costs of the July 2019 market wage adjustment for certain BGE Customer Operations positions, which is not fully reflected in the 2019 HTY.

Description	HTY 2019	Bridge Period 2020	MYP 1 2021	MYP 2 2022	MYP 3 2023
Effect of the July 2019 Customer Operations market adjustment not reflected in HTY	$ 410,142	[redacted]			
Income tax effect at 27.5175%	(112,861)				
Adjustment to operating income	$ 297,281				
Amount Presented on Company Exhibit DMV-4E	$ (297,000)				

Baltimore Gas and Electric Company
2019 Wage Increase - Electric
Multi-Year Plan

Operating Income
Adjustment 13

This adjustment reduces electric operating income by providing for the effect on labor costs of the March 2019 general wage increase for BGE employees as included in Case No. 9610, which is not fully reflected in 2019 HTY.

Description	HTY 2019	Bridge Period 2020	MYP 1 2021	MYP 2 2022	MYP 3 2023
Effect of the 2019 wage increase	$482,316	[redacted]			
Income tax effect at 27.5175%	(132,721)				
Adjustment to operating income	$349,595				
Amount Presented on Company Exhibit DMV-4E	($350,000)				

This adjustment reduces electric operating income for the annualized known increases in various taxes other than income taxes including the increase in real and personal property taxes effective with the July 1, 2019 property assessments and the Maryland Public Service Commission assessment rate effective July 2019 as included in Case No. 9610. Both of these are not fully reflected in the 2019 HTY without this adjustment.

Description	HTY 2019	Bridge Period 2020	MYP 1 2021	MYP 2 2022	MYP 3 2023
Real Estate and Property Taxes					
Projected July 2019 - June 2020 Assessment Amounts	$89,748,569	[redacted]			
Amounts recorded in the 2019 HTY	87,097,956				
Increase/(Decrease)	2,650,612				
PSC Assessment Rate					
Projected July 2019 - June 2020 Assessment Amounts	3,451,568				
Amounts recorded in the 2019 HTY	3,008,725				
Increase/(Decrease)	442,843				
Total					
Total Increase/(Decrease in taxes other than income taxes	3,093,455				
Income tax effect at 27.5175%	(851,242)				
Adjustment to operating income	$ 2,242,214				
Amount Presented on Company Exhibit DMV-4E	$ (2,242,000)				

Baltimore Gas and Electric Company
Fully Amortized Electric Regulatory Assets
Multi-Year Plan

Operating Income
Adjustment 15

This adjustment increases electric operating income by eliminating the amortization expense associated with the Case No. 9406 tranche of rate case expenses which was fully amortized in May 2019. Since this regulatory asset was fully amortized before the end of the 2019 HTY, the related amortization has been eliminated from operating income.

Description	HTY 2019	Bridge Period 2020	MYP 1 2021	MYP 2 2022	MYP 3 2023
Case No. 9406 Rate Case Expenses Regulatory Asset Amortization	$ 22,479	[redacted]			
Total amortization to be eliminated	22,479	[redacted]			
Income tax effect at 27.5175%	(6,186)	[redacted]			
Adjustment to operating income	$ 16,293	[redacted]			
Amount Presented on Company Exhibit DMV-4E	$ 16,000	[redacted]			

Baltimore Gas and Electric Company
Electric Safety Reliab. Depreciation
Multi-Year Plan

Operating Income
Adjustment 17

This adjustment annualizes the level of depreciation expense, net of depreciation savings, of non-revenue producing safety and reliability plant included in Case No. 9610, and as provided for in Rate Base Adjustment 7. This adjustment reflects the amounts included in the Case No. 9610 filing. Rate Base Adjustment 7 adjusts accumulated depreciation and accumulated deferred income taxes related to the additional net depreciation expense provided in this adjustment.

Description	HTY 2019	Bridge Period 2020	MYP 1 2021	MYP 2 2022	MYP 3 2023
Annual Depreciation associated with safety and reliability projects	$ 5,670,392	[redacted]			
Less - Safety and reliability depreciation included in the 2019 HTY	2,558,948				
Increase in depreciation associated with safety and reliability projects	3,111,444				
Depreciation Savings: Safety and reliability annual depreciation savings	412,377				
Less - Safety and reliability depreciation savings included in the 2019 HTY	186,098				
Depreciation savings related to safety and reliability retirements	226,278				
Net depreciation associated with safety and reliability projects	2,885,165				
Income Tax Effect at 27.5175%	(793,925)				
Adjustment to Operating Income	$ 2,091,240				
Amount presented on Company Exhibit DMV-4E	$ (2,091,000)				

Baltimore Gas and Electric Company
General Inflation - Electric
Multi-Year Plan

Operating Income
Adjustment 19

This adjustment, which was included in Case No. 9610, reduces electric operating income to provide for the effect of general inflation on non-labor O&M costs during the rate-effective period. This adjustment reflects a 1.420% inflation factor based on a five-year average of the Consumer Price Index ("CPI") per the U.S. Department of Labor, Bureau of Labor Statistics, as authorized by the Commission in Case No. 9484, Order No. 88975.

Description	HTY 2019	Bridge Period 2020	MYP 1 2021	MYP 2 2022	MYP 3 2023
O&M Expense included in DMV-3E	$ 433,864,441	[redacted]	[redacted]	[redacted]	[redacted]
Less:		[redacted]	[redacted]	[redacted]	[redacted]
Advertising Costs (OIA-24)	(1,263,874)	[redacted]	[redacted]	[redacted]	[redacted]
Employee Activity Costs (OIA-25)	(346,133)	[redacted]	[redacted]	[redacted]	[redacted]
SERP Costs (OIA-26)	(1,914,680)	[redacted]	[redacted]	[redacted]	[redacted]
Certain Incentives (OIA-27)	(2,441,422)	[redacted]	[redacted]	[redacted]	[redacted]
	427,898,331	[redacted]	[redacted]	[redacted]	[redacted]
Less labor included in O&M	113,786,361	[redacted]	[redacted]	[redacted]	[redacted]
Non-Labor O&M expense included in the 2019 HTY	314,111,971	[redacted]	[redacted]	[redacted]	[redacted]
Inflation factor	1.420%	[redacted]	[redacted]	[redacted]	[redacted]
Additional O&M due to inflation	4,460,390	[redacted]	[redacted]	[redacted]	[redacted]
Income tax effect at 27.5175%	(1,227,388)	[redacted]	[redacted]	[redacted]	[redacted]
Adjustment to operating income	$ 3,233,002	[redacted]	[redacted]	[redacted]	[redacted]
Amount Presented on Company Exhibit DMV-4E	$ (3,233,000)	[redacted]	[redacted]	[redacted]	[redacted]

Baltimore Gas and Electric Company
Electric Major Outage Restoration Expense
Multi-Year Plan

Operating Income
Adjustment 20

This adjustment normalizes the level of major outage event restoration expense recorded in the 2019 HTY. This adjustment reflects the five-year average level of incremental major outage event restoration expense experienced between January 2015 and December 2019. Consistent with Case Nos. 9299, 9326, 9355, and 9406, the historical restoration costs have been adjusted to today’s dollars based on the Consumer Price Index per the U.S. Department of Labor, Bureau of Labor Statistics.

Description	HTY 2019	Bridge Period 2020	MYP 1 2021	MYP 2 2022	MYP 3 2023
Calculation of Five-Year Average:		[redacted]			
Twelve months ended:					
12/31/2015	$ -				
12/31/2016	17,023,075				
12/31/2017	2,653,802				
12/31/2018	31,406,727				
12/31/2019	-				
Total expense for the five years	51,083,604				
Number of years	5				
Five-year average	10,216,721				
Actual major outage event restoration expense	-				
Actual less five-year average	(10,216,721)				
Income Tax Effect at 27.5175%	2,811,386				
Adjustment to Operating Income	$ (7,405,335)				
Amount presented on Company Exhibit DMV-4E	$ (7,405,000)				

Baltimore Gas and Electric Company
Eliminate Electric ERI Revenues, Net
Multi-Year Plan

Operating Income
Adjustment 22

This adjustment removes the revenues associated with Rider 31 (ERI) that are reflected in the 2019 HTY operating income. The ERI surcharge ended in December 2019.

Description	HTY 2019	Bridge Period 2020	MYP 1 2021	MYP 2 2022	MYP 3 2023
ERI revenues reflected in the 2019 HTY	$ 6,367,458	[redacted]			
Franchise Tax and PSC Assessment	(128,883)				
Income tax effect at 27.5175%	(1,716,700)				
Adjustment to operating income	$4,521,875				
Amount Presented on Company Exhibit DMV-4E	($4,522,000)				

Baltimore Gas and Electric Company
Eliminate Certain Electric Advertising Expenses
Multi-Year Plan

This adjustment eliminates from electric operating income for the 2019 HTY certain advertising expenses recorded as operating expenses in accordance with the FERC Uniform System of Accounts that BGE is not allowed to recover pursuant to COMAR 20.07.04.08. These expenses represent institutional and promotional advertising expenses. All charitable contributions, penalties, and lobbying costs, including the lobbying expense portion of the Edison Electric Institute dues, have been recorded below the line and are not reflected in operating income. Therefore, it is not necessary to include these costs in this operating income adjustment.

Description	HTY 2019	Bridge Period 2020	MYP 1 2021	MYP 2 2022	MYP 3 2023
Institutional and Promotional Advertising	$ 1,263,874	[redacted]			
Income Tax Effect at 27.5175%	(347,787)				
Adjustment to operating income	$ 916,088				
Amount Presented on Company Exhibit DMV-4E	$ 916,000				

Baltimore Gas and Electric Company
Eliminate Certain Electric Employee Activity Costs
Multi-Year Plan

Operating Income
Adjustment 25

This adjustment eliminates from electric operating income certain employee activity costs as directed by the Commission in Case No. 9299, Order No. 85374.

Description	HTY 2019	Bridge Period 2020	MYP 1 2021	MYP 2 2022	MYP 3 2023
100% of Company's skybox costs	$ 172,067	[redacted]			
Remaining employee activity costs	348,132				
50% factor	50%				
Subtotal - 50% of Remaining employee activity costs	174,066				
Total excluded employee activity costs for the twelve month period	346,133				
Income Tax Effect at 27.5175%	(95,247)				
Adjustment to operating income	$ 250,886				
Amount Presented on Company Exhibit DMV-4E	$ 251,000				

Baltimore Gas and Electric Company
Eliminate Certain Electric SERP Costs
Multi-Year Plan

Operating Income
Adjustment 26

This adjustment eliminates from electric operating income 100% of Supplemental Executive Retirement Program ("SERP") costs as required in Case No. 9484, Order No. 88975.

Description	HTY 2019	Bridge Period 2020	MYP 1 2021	MYP 2 2022	MYP 3 2023
SERP costs to be eliminated	$ 1,914,680	[redacted]			
Income tax effect at 27.5175%	(526,872)				
Adjustment to operating income	$ 1,387,808				
Amount Presented on Company Exhibit DMV-4E	$ 1,388,000				

Baltimore Gas and Electric Company
Reduce Certain Electric Long-Term Compensation
Multi-Year Plan

Operating Income
Adjustment 27

This adjustment removes the non- recoverable amount of incentive compensation from electric operating income consistent with Case No. 9326, Order No. 86060.

Description	HTY 2019	Bridge Period 2020	MYP 1 2021	MYP 2 2022	MYP 3 2023
Removal of certain incentive compensation	$ 2,441,422	[redacted]			
Income Tax Effect at 27.5175%	(671,818)				
Adjustment to operating income	$ 1,769,603				
Amount Presented on Company Exhibit DMV-4E	$ 1,770,000				

Baltimore Gas and Electric Company
Electric AFC Annualization Based on Proposed ROR
Multi-Year Plan

Operating Income
Adjustment 28

This adjustment adjusts electric operating income for the known annualized amount of AFC included in unadjusted operating income at the electric 6.94% rate of return included in the Case No. 9610 settlement agreement for the purpose of calculating AFC, which was accepted by the Commission in Order No. 89400, to reflect a level that is consistent with the rate of return for electric as supported by the Company for the 2019 HTY.

Description	HTY 2019	Bridge Period 2020	MYP 1 2021	MYP 2 2022	MYP 3 2023
Actual AFC for the twelve months per Company Exhibit DMV-3E	$ 12,398	[redacted]			
Actual AFC for each period	12,397,545	[redacted]			
Reduction in AFC to annualize to Case 9610 6.94% electric rate of return per Operating Income Adjustment No. 2	(531,979)	[redacted]			
Actual AFC for each period to be subject to new rate of return calculated	11,865,565	[redacted]			
Conversion Factor to ROR Requested	1.0490	[redacted]			
AFC for the twelve months restated to reflect the new AFC rate	12,446,875	[redacted]			
Actual AFC for each period to be subject to new rate of return calculated	11,865,565	[redacted]			
Change in AFC	581,310	[redacted]			
Income Tax effect of borrowed funds portion of AFC at 27.5175%	(41,089)	[redacted]			
Adjustment to operating income	$ 540,221	[redacted]			
Amount Presented on Company Exhibit DMV-4E	$ 540,000	[redacted]			
Calculation of Income Tax Effect of Borrowed Funds Portion of AFC		[redacted]			
Increase (Decrease) in AFC	$ 581,310	[redacted]			
Borrowed funds portion of AFC %	0.257	[redacted]			
Borrowed funds portion of AFC $	149,320	[redacted]			
Income tax rate	27.5175%	[redacted]			
Income tax effect of borrowed funds portion of AFC	$ 41,089	[redacted]			

Borrowed fund funds %	
Total Return	7.28%
Weighted cost of Long-Term Debt	1.87%
Borrowed Funds Portion of AFC %	25.7%

Baltimore Gas and Electric Company
Adjustment to Reflect the Electric Income Tax Effect of Pro Forma Interest
Multi-Year Plan

Operating Income
Adjustment 29

This adjustment synchronizes interest expense utilized in the income tax calculation with adjusted rate base and the weighted cost of debt implicit in the electric rate of return supported by the Company for the 2019 HTY.

Description	HTY 2019	Bridge Period 2020	MYP 1 2021	MYP 2 2022	MYP 3 2023
Unadjusted rate base - Company Exhibit DMV-3E, line 11	$ 3,482,151,901	[redacted]			
Rate base adjustments - Company Exhibit DMV-3E, line 11	89,771,676	[redacted]			
Rate Base adjusted for calculation of pro forma interest	$ 3,571,923,577	[redacted]			
Weighted cost of debt:		[redacted]			
Long-term debt	1.87%	[redacted]			
Long-term debt proforma interest	$ 66,794,971	[redacted]			
Long-term debt actual interest charges	63,473,619	[redacted]			
Adjustment to interest expense:	3,321,352	[redacted]			
Income tax rate	27.5175%	[redacted]			
Tax effect of pro forma interest	$ (913,953)	[redacted]			
Amount Presented on Company Exhibit DMV-4E	$ 914,000	[redacted]			

Baltimore Gas and Electric Company
Case 9610 Electric Smart Grid Regulatory Asset
Multi-Year Plan

Rate Base
Adjustment 1

This adjustment reduces electric rate base to reflect the impact of the accumulated amortization associated with the amortization of the electric Smart Grid cost regulatory asset through May 2026 as included in the Case No. 9610 settlement which was accepted by the Commission in Order No. 89400. It is the companion adjustment to Operating Income Adjustment No. 5.

Description	HTY 2019	Bridge Period 2020	MYP 1 2021	MYP 2 2022	MYP 3 2023
Change in Smart Grid Accumulated Amortization included in Case No. 9610 per Operating Income Adjustment 5	$5,593,662	[redacted]			
Adjustment to reflect average rate base	50%				
Increased accumulated amortization	2,796,831				
Income tax effect at 27.5175%	(769,618)				
Adjustment to rate base	$2,027,213				
Amount Presented on Company Exhibit DMV-4E	($2,027,000)				

Baltimore Gas and Electric Company
Impact of Case 9610 CVR Amortization
Multi-Year Plan

Rate Base
Adjustment 2

This adjustment reflects the impact on the CVR regulatory asset of the amortization included in the Case No. 9610 settlement. This is the companion adjustment to Operating Income Adjustment 6.

Description	HTY 2019	Bridge Period 2020	MYP 1 2021	MYP 2 2022	MYP 3 2023
Increase in amortization resulting from Operating Income Adjustment 6	$ 2,089,455	[redacted]			
Income tax effect at 27.5175%	(574,966)				
Increased accumulated amortization, net of tax	1,514,489				
Adjustment to reflect average rate base	50.0%				
Adjustment to rate base	$ 757,245				
Amount Presented on Company Exhibit DMV-4E	$ (757,000)				

Baltimore Gas and Electric Company
Case No. 9610 Impact of New Depreciation Rates
Multi-Year Plan

Rate Base
Adjustment 4

This adjustment reflects the impact on the accumulated depreciation reserve of the new depreciation rates resulting from the Case No. 9610 settlement. This is the companion adjustment to Operating Income Adjustment 9.

Description	HTY 2019	Bridge Period 2020	MYP 1 2021	MYP 2 2022	MYP 3 2023
Change in accumulated depreciation resulting from Operating Income Adjustment 9	$ (1,277,589)	[redacted]			
Deferred income taxes on normalized depreciation expense at 27.5175%	351,561				
Increased accumulated depreciation, net of tax	(926,028)				
Adjustment to reflect average rate base	50.0%				
Adjustment to rate base	$ (463,014)				
Amount Presented on Company Exhibit DMV-4E	$ 463,000				

Baltimore Gas and Electric Company
Electric Safety and Reliability Investments
Multi-Year Plan

Rate Base
Adjustment 7

This adjustment reflects the terminal impact of the known and measurable non-revenue producing safety and reliability investments as included in Case No. 9610. This adjustment includes the impact on plant in service, accumulated depreciation reserve, depreciation savings, and related accumulated deferred income taxes. It is a companion adjustment to Operating Income Adjustment 17, which adjusts the level of depreciation for these investments.

Description	HTY 2019	Bridge Period 2020	MYP 1 2021	MYP 2 2022	MYP 3 2023
Electric safety and reliability project investment included in Case No. 9610 filing	$ 258,779,185	[redacted]			
Electric safety and reliability project investment reflected in the Case No. 9610 average rate base	126,430,536				
Additional electric safety and reliability investment - Increase in plant in service	132,348,650				
Less:					
Additional accumulated depreciation, net of savings, per OIA Adj. No. 17	2,885,165				
Plus:					
Accumulated Deferred Income Taxes on the additional investment above	(17,682,354)				
Adjustment to Rate Base	$ 111,781,130				
Amount presented on Company Exhibit DMV-4E	$ 111,781,000				

Baltimore Gas and Electric Company
Eliminate Electric RM54 Software
Multi-Year Plan

Rate Base
Adjustment 9

This adjustment reduces electric rate base to remove the RM54 capital software costs. Although an operating income adjustment is not necessary for the RM54 amortization since it was not recorded as a distribution expense following the settlement agreement in Case No. 9610, the RM54 capital is recorded as common plant, and therefore was allocated to electric and gas distribution. Accordingly, since these costs will be recovered through the Purchase of Receivables discount rate, it is necessary to remove the electric portion of RM54 capital in Rate Base Adjustment 9.

Description	HTY 2019	Bridge Period 2020	MYP 1 2021	MYP 2 2022	MYP 3 2023
RM54 Plant in Service	$ 1,197,357				
RM54 Accumulative Amortization	(615,068)				
RM54 Software to be excluded from rate base	582,290	[redacted]			
Income Tax Effect at 27.5175%	(160,232)	[redacted]			
Adjustment to rate base	$ 422,058	[redacted]			
Amount Presented on Company Exhibit DMV-4E	$ (422,000)	[redacted]			

Baltimore Gas and Electric Company
Electric Cash Working Capital Reflected in Unadjusted Rate Base
Multi-Year Plan

Company Exhibit DMV-5E

2019 Actual HTY - Unadjusted Rate Base - Based on 2014 Lag Study Net Lag Days

Line No.	Description	Line of Business	CWC Expense	Net Lag Days	Cash Advanced
1	Net Metering Costs	Electric	1,490,726	(59.5)	(243,009)
2	Salaries and Wages	Electric	113,786,361	10.9	3,398,004
3	Fringe Benefits	Electric	38,548,735	31.6	3,337,370
4	Other Oper & Maint Expense	Electric	260,552,175	(1.5)	(1,070,762)
5	Property Taxes	Electric	87,097,956	133.6	31,880,238
6	Payroll Taxes	Electric	9,406,375	10.3	265,440
7	PSC Assessment	Electric	3,008,724	77.3	637,190
8	Electric Environmental Surcharge	Electric	4,176,638	4.2	48,060
9	Universal Service Fund	Electric	18,982,633	10.4	540,875
10	GRT Taxes	Electric	41,979,319	(5.6)	(644,066)
11	Other Taxes	Electric	3,600,903	14.0	138,117
12	Federal Income Taxes - Current	Electric	(11,667,242)	(4.5)	143,843
13	State Income Taxes - Current	Electric	7,186,121	(11.5)	(226,412)
14	Interest Expense	Electric	63,044,857	(41.6)	(7,185,386)
15	Short Term Interest	Electric	1,355,418	53.7	199,414
16	Interest on Customer Deposits	Electric	2,080,846	(136.0)	(775,329)
17	Total Electric Cash Working Capital		$644,630,547		$30,443,585
18	Total Electric Cash Working Capital ($000) carried forward to Unadjusted Rate Base Company Exhibit DMV-3E, line 6				$30,444

Baltimore Gas and Electric Company **Company Exhibit DMV-6E**
Electric Cash Working Capital Based on Updated Net Lag Days
Multi-Year Plan

2019 Lag Study Net Lag Days

Line No.	Description	Line of Business	CWC Expense	Net Lag Days per 2019 Lag Study	Updated Cash Advanced
1	Net Metering Costs	Electric	1,490,726	(140.3)	($573,011)
2	Salaries and Wages	Electric	113,786,361	6.1	1,901,635
3	Fringe Benefits	Electric	38,548,735	7.7	813,220
4	Other Oper & Maint Expense	Electric	260,552,175	(5.3)	(3,783,360)
5	Property Taxes	Electric	87,097,956	92.8	22,144,357
6	Payroll Taxes	Electric	9,406,375	6.1	157,202
7	PSC Assessment	Electric	3,008,724	77.5	638,839
8	Electric Environmental Surcharge	Electric	4,176,638	5.6	64,080
9	Universal Service Fund	Electric	18,982,633	11.2	582,481
10	GRT Taxes	Electric	41,979,319	(8.4)	(966,099)
11	Other Taxes	Electric	3,600,903	32.9	324,575
12	Federal Income Taxes - Current	Electric	(11,667,242)	(4.4)	140,646
13	State Income Taxes - Current	Electric	7,186,121	(11.5)	(226,412)
14	Interest Expense	Electric	63,044,857	(54.7)	(9,448,092)
15	Short Term Interest	Electric	1,355,418	49.1	182,332
16	Interest on Customer Deposits	Electric	2,080,846	(135.9)	(774,759)
17	Total Electric Cash Working Capital Based on New Lag Days - 2019 Lag Study		$644,630,547		$11,177,633
18	CWC Based on 2014 Lag Study included in Unadjusted Rate Base - Company Exhibit DMV-5E, line 17				$30,443,585
19	Impact of Change in Net Lag Days carried forward to Company Exhibit DMV-4E, line 31				$ (19,265,953)

Baltimore Gas and Electric Company
2019 Lag Study - Electric Lag Components

Line No.	Description	Lag Days	Revenue Lag	Net Lag Days
1	Revenue Lag:			
2	Rendition of service to meter reading date		14.7	
3	Meter reading date to bill delivery		3.8	
4	Bill delivery to payment		28.4	
5	Receipt of payment to date funds are accessible		0.2	
6	Total days lag in collection of revenue		47.1	
7	Expense Lag:			
8	Net Metering Costs	187.4	47.1	(140.3)
9	Salaries and Wages	41.0	47.1	6.1
10	Fringe Benefits	39.4	47.1	7.7
11	Other Oper & Maint Expense	52.4	47.1	(5.3)
12	Property Taxes	(45.7)	47.1	92.8
13	Payroll Taxes	41.0	47.1	6.1
14	PSC Assessment	(30.4)	47.1	77.5
15	Electric Environmental Surcharge	41.5	47.1	5.6
16	Universal Service Fund	35.9	47.1	11.2
17	GRT Taxes	55.5	47.1	(8.4)
18	Other Taxes	14.2	47.1	32.9
19	Federal Income Taxes	51.5	47.1	(4.4)
20	State Income Taxes	58.6	47.1	(11.5)
21	Interest Expense	101.8	47.1	(54.7)
22	Short Term Interest	(2.0)	47.1	49.1
23	Interest on Customer Deposits	183.0	47.1	(135.9)

Company Exhibit DMV-3G

Baltimore Gas and Electric Company

Gas Distribution Rate Base and Gas Distribution Operating Income Summary

Multi-Year Plan

(Thousands of Dollars)

Line No.	Description	Historic Test Year (HTY) 2019 Unadjusted (1)	Ratemaking Adjustments (2)	Adjusted (3) = (1) + (2)
1	**Rate Base (Average Basis)**			
2	Gas Plant	$3,229,265	$ 190,006	$ 3,419,271
3	Accumulated Depreciation and Amortization	(717,636)	(5,673)	(723,309)
4	Materials and Supplies	42,663	-	42,663
5	Cash Working Capital	19,798	(9,079)	10,719
6	Accumulated Deferred Income Taxes	(452,587)	(39,063)	(491,650)
7	Prepaid Pension/OPEB Liab.	21,662	-	21,662
8	Customer Advances & Deposits	(41,631)	-	(41,631)
9	Regulatory Assets & Liabilities	(225,473)	(895)	(226,368)
10	Other	-	-	-
11	Total Rate Base	$ 1,876,062	$ 135,296	$ 2,011,358
12	**Operating Income**			
13	Operating Revenues			
14	Sale of Gas	$ 523,989	$ 40,456	$ 564,446
15	Other Revenues	10,493	-	10,493
16	Operating Revenues	$ 534,482	$ 40,456	$ 574,939
17	Operating Expenses			
18	Gas Choice and Reliability Costs	$ 958	-	$ 958
19	Operation and Maintenance	240,139	4,215	244,354
20	Depreciation and Amortization	111,746	4,618	116,364
21	Other Taxes	60,389	2,491	62,880
22	Current Income Taxes	(73,278)	5,915	(67,363)
23	Deferred Income Taxes	88,475	726	89,201
24	Investment Tax Credit Adjustments	(348)	-	(348)
25	Total Operating Expenses	$ 428,082	$ 17,964	$ 446,046
26	Allowance for Funds Used During Construction	6,194	171	6,365
27	Interest on Customer Deposits	(1,091)	-	(1,091)
28	Operating Income	$ 111,503	$ 22,664	$ 134,167
29	**Capital Structure**	Ratio	Cost	Wtd. Cost
30	Long-Term Debt	47.2%	3.96%	1.87%
31	Common Equity	52.8%	10.25%	5.41%
32	Total	100.0%		7.28%
33	**Rate of Return Summary**			
34	**Rate of Return**	**5.94%**		**6.67%**
35	Less Weighted Cost of Long-Term Debt	1.87%		1.87%
36	Net amount available for common equity	4.07%		4.80%
37	Common Equity ratio	52.80%		52.80%
38	**Return on Equity**	**7.71%**		**9.09%**
39	**Revenue Requirement Summary**		For Informational Purposes Only	
40	Rate Base			*$ 2,011,358*
41	Rate of Return			*7.28%*
42	Required Operating Income			*146,427*
43	Proforma Operating Income			*$ 134,167*
44	Operating Income Deficiency			*12,260*
45	Revenue Conversion Factor			*1.41941*
46	Rev. Rqmt. Deficiency (Excess)			*17,402*
47	Total Adjusted Distribution Revenue Requirement			
48	Rev. Rqmt. Deficiency (Excess) - MRP Incremental $ by Year			
49	Total Distribution Revenues, Adjusted			

Bridge 2020 Unadjusted (4)	Ratemaking Adjustments (5)	Adjusted (6) = (4) + (5)	Adjusted Variance vs. Prior Year (7)	MYP 1 - 2021 Unadjusted (8)	Ratemaking Adjustments (9)	Adjusted (10) = (8) + (9)	Adjusted Variance vs. Prior Year (11)	MYP 2 - 2022 Unadjusted (12)	Ratemaking Adjustments (13)	Adjusted (14) = (12) + (13)	Adjusted Variance vs. Prior Year (15)	MYP 3 - 2023 Unadjusted (16)	Ratemaking Adjustments (17)	Adjusted (18) = (16) + (17)	Adjusted Variance vs. Prior Year (19)
[redacted]				[redacted]				[redacted]				[redacted]			

Company Exhibit DMV-4G

Baltimore Gas and Electric Company
Gas Distribution MYP Revenue Requirement (Unadjusted and Adjusted) Summary By Year
For the Twelve Months Ended December 31,
(Thousands of Dollars)

Line No.	Description	Schedule Reference	HTY - 2019			Bridge Year - 2020			MYP 1 - 2021			MYP 2 - 2022			MYP 3 - 2023		
			Rate Base	Operating Income (Net of Tax)	Revenue Requirement	Rate Base	Operating Income (Net of Tax)	Revenue Requirement	Rate Base	Operating Income (Net of Tax)	Revenue Requirement	Rate Base	Operating Income (Net of Tax)	Revenue Requirement	Rate Base	Operating Income (Net of Tax)	Revenue Requirement
	Unadjusted Amounts	DMV-3G	1,876,062	111,503	35,590	[redacted]			[redacted]			[redacted]			[redacted]		
	Ratemaking Adjustments:																
1	Annualize Case No. 9610 Base Rate Revenues	OIA-1		35,472	(50,349)												
2	Annualize AFC to Reflect Case No. 9610 ROR	OIA-2		(92)	131												
3	Annualize Case No. 9610 Rate Case Expenses	OIA-3		(26)	37												
4	Annualize Case No. 9610 STRIDE Audit Fees	OIA-4		(47)	67												
5	Annualize Case No. 9610 Smart Grid Amortization	OIA-5/RBA-1		2,411	(3,422)												
6	Annualize Case No. 9610 CVR Amortization	OIA-6/RBA-2	-	-	-												
7	Annualize Maryland Additional Subtraction Modification Tax Benefit	OIA-7		427	(606)												
8	Annualize Case No. 9610 Riverside Amortization	OIA-8/RBA-3	(30)	(60)	82												
9	Annualize Case No. 9610 Depreciation Expense	OIA-9/RBA-4	(1,887)	(3,773)	5,160												
10	Annualize Collective Bargaining Agreement (CBA) Impact	OIA-10		(33)	47												
11	Annualize Additional Sick Days Resulting from CBA	OIA-11		(60)	85												
12	Annualize Customer Operation Wages	OIA-12		(156)	221												
13	Annualize 2019 General Wage Increase	OIA-13		(183)	260												
14	Annualize Other Tax Known Increases	OIA-14		(1,151)	1,634												
15	Eliminate Expiring Regulatory Asset Amortizations	OIA-15/RBA-5	(105)	275	(401)												
16	Amortize Gain on Sale of Real Estate	OIA-16/RBA-6	(513)	513	(781)												
17	Case 9610 Safety & Reliability Net Depreciation Expense Annualization'	OIA-17/RBA-7	62,560	(1,340)	8,367												
18	Case 9610 STRIDE Net Depreciation Expense Annualization	OIA-18/RBA-8	84,577	(1,114)	10,321												
19	General Inflation on Non-Labor O&M	OIA-19		(1,767)	2,508												
20	Normalize Major Outage Event Restoration Expense	OIA-20		-	-												
21	Eliminate One-Time Credit to Establish Riverside Environmental Regulatory Asset	OIA-21		(3,323)	4,717												
22	Eliminate ERI Rider 31 Revenues	OIA-22		-	-												
23	Eliminate STRIDE Revenues, Net	OIA-23		(6,802)	9,655												
24	Eliminate Advertising	OIA-24		480	(681)												
25	Eliminate Employee Activity Costs	OIA-25		144	(204)												
26	Eliminate SERP Costs	OIA-26		728	(1,033)												
27	Eliminate Certain Incentive Compensation	OIA-27		929	(1,319)												
28	Normalize AFC at Proposed ROR	OIA-28		252	(358)												
29	Interest Synchronization	OIA-29		960	(1,365)												
30	Eliminate RM54 Capital Software Costs	RBA-9	(227)	-	(23)												
31	Cash Working Capital Adjusted for Updated Lag Days	DMV-6G, Line 18	(9,079)	-	(938)												
32	Total Adjustments		135,296	22,664	(18,188)												
33	Total Revenue Requirement	DMV-3G	2,011,358	134,167	17,402												
	Rate of Return		7.28%														
	Conversion Factor																
	Maryland State Income Tax		8.2500%														
	Federal Income Tax		21.0000%														
	Combined Income Tax Rate (SIT+(FITx(1-SIT))		27.5175%														
	Gross Receipts Tax		2.0000%														
	PSC Assessment Rate		0.2124%														
	Uncollectible Factor		0.5890%														
	Conversion Factor (1 /(1-Comb Tax)x(1-(GR+PSC+Uncoll))		1.41941														
	Conversion Factor % ((1-Comb Tax)x(1-(GR+PSC+Uncoll))		70.452%														

Baltimore Gas and Electric Company
Case No. 9610 Gas Base Rate Revenue Increase
Multi-Year Plan

Operating Income
Adjustment 1

In Case No. 9610, Order No. 89400, the Commission accepted a settlement that resulted in an increase of $54 million in gas base rates. This rate change became effective with service rendered on or after December 17, 2019. Operating Income Adjustment 1 reflects the annual effect on operating income of this rate change not reflected in the 2019 HTY.

Description	HTY 2019	Bridge Period 2020	MYP 1 2021	MYP 2 2022	MYP 3 2023
Total increase in base rate revenues awarded	$54,000,000	[redacted]			
Case No. 9610 increase in base rate revenues reflected in the 2019 HTY	(3,954,590)				
Increase in base rate revenues to be realized	50,045,410				
Franchise Tax	(1,000,908)				
PSC Assessment	(106,296)				
Income Tax Effect at 27.5175%	(13,466,571)				
Adjustment to operating income	$35,471,634				
Amount Presented on Company Exhibit DMV-4G	$35,472,000				

Baltimore Gas and Electric Company
Case 9610 Gas AFC Annualization
Multi-Year Plan

Operating Income
Adjustment 2

This adjustment annualizes unadjusted gas AFC accrued during the HTY 2019 to reflect the 6.97% rate of return agreed to in the settlement agreement reached in Case No. 9610 for the purpose of calculating AFC, which was accepted by the Commission in Order No. 89400.

Description	HTY 2019	Bridge Period 2020	MYP 1 2021	MYP 2 2022	MYP 3 2023
Actual AFC for the twelve months per Company Exhibit DMV-3E	6,194	[redacted]			
Actual AFC for 2019 HTY	6,194,022				
AFC accrued under the Case 9610 6.97% rate for the month of December 2019	(297,969)				
AFC to be subject to the new rate of 6.97%	5,896,053				
Conversion Factor to 6.97%	0.9831				
AFC for the period January - November 2019 restated to reflect a 6.97% AFC rates	5,796,261				
AFC to be subject to new rates	5,896,053				
Change in AFC	(99,792)				
Income Tax effect of borrowed funds portion of AFC at 27.5175%	7,486				
Adjustment to operating income	(92,307)				
Amount Presented on Company Exhibit DMV-4G	(92,000)				
Calculation of Income Tax Effect of Borrowed Funds Portion of AFC					
Increase (Decrease) in AFC	(99,792)				
Borrowed funds portion of AFC %	0.273				
Borrowed funds portion of AFC $	(27,203)				
Income tax rate	27.5175%				
Income tax effect of borrowed funds portion of AFC	($7,486)				
Borrowed fund funds %					
Total Return	6.97%				
Weighted cost of Long-Term Debt	1.90%				
Borrowed Funds Portion of AFC %	27.3%				

Baltimore Gas and Electric Company
Case 9610 Gas Rate Case Expenses
Multi-Year Plan

Operating Income
Adjustment 3

This adjustment annualizes the amortization of deferred rate case expenses included in Case No. 9610.

Description	HTY 2019	Bridge Period 2020	MYP 1 2021	MYP 2 2022	MYP 3 2023
Annual amortization of deferred rate case expenses included in Case No. 9610	$39,188	[redacted]			
1 Month (December) reflected in 2019 HTY	(3,266)				
Amortization of deferred rate case expenses not reflected in the 2019 HTY	35,922				
Income tax effect at 27.5175%	(9,885)				
Adjustment to operating income	$26,037				
Amount Presented on Company Exhibit DMV-4G	($26,000)				

Baltimore Gas and Electric Company
Case 9610 Gas STRIDE Audit Fee Amortization
Multi-Year Plan

Operating Income
Adjustment 4

This adjustment annualizes the amortization of the STRIDE audit fee reflected in Case No. 9610.

Description	HTY 2019	Bridge Period 2020	MYP 1 2021	MYP 2 2022	MYP 3 2023
Annual amortization of the deferred STRIDE audit fee included in Case No. 9610	$70,650	[redacted]			
1 Month (December) reflected in HTY	(5,888)				
Amortization of the deferred STRIDE audit fee not reflected in the 2019 HTY	64,763				
Income tax effect at 27.5175%	(17,821)				
Adjustment to operating income	$46,941				
Amount Presented on Company Exhibit DMV-4G	($47,000)				

This adjustment annualizes the amortization of the gas Smart Grid regulatory asset incremental costs incurred since November 2015 (i.e. the end of the test year in Case No. 9406). This regulatory asset is being amortized through May 2026 in accordance with the Case No. 9610 settlement which was accepted by the Commission in Order No. 89400. Previously, this regulatory asset was being amortized over 3 years as approved in Case No. 9484. This adjustment reflects the portion of the lower amortization which is not reflected in the HTY 2019.

Description	HTY 2019	Bridge Period 2020	MYP 1 2021	MYP 2 2022	MYP 3 2023
Lower amortization of the 9406 post test year gas Smart Grid regulatory asset agreed to in the settlement in Case No. 9610	$ (3,629,156)	[redacted]	[redacted]	[redacted]	[redacted]
1 Month (December) reflected in HTY	302,430	[redacted]	[redacted]	[redacted]	[redacted]
Amortization of Case No. 9610 Smart Grid costs not reflected in the 2019 HTY	(3,326,726)	[redacted]	[redacted]	[redacted]	[redacted]
Income tax effect at 27.5175%	915,432	[redacted]	[redacted]	[redacted]	[redacted]
Adjustment to operating income	$ (2,411,294)	[redacted]	[redacted]	[redacted]	[redacted]
Amount Presented on Company Exhibit DMV-4G	$ 2,411,000	[redacted]	[redacted]	[redacted]	[redacted]

Baltimore Gas and Electric Company
Case 9610 Gas MD Addtl Subtraction Modification Amortization
Multi-Year Plan

Operating Income
Adjustment 7

This adjustment provides customers with the state income tax benefit attributable to the recognition of an incremental increase to the Maryland "Statutory Subtraction" modification over the average remaining book lives of Maryland assets, approximately 39 years for gas, but which is not fully reflected in the 2019 HTY.

Description	HTY 2019	Bridge Period 2020	MYP 1 2021	MYP 2 2022	MYP 3 2023
Annual amortization of Maryland Additional Subraction Modification regulatory liability reflected in Case No. 9610	643,150	[redacted]			
1 Month (December) reflected in HTY	(53,596)				
Amortization of Maryland Additional Subraction Modification regulatory liability not reflected in the 2019 HTY	589,554				
Income tax effect at 27.5175%	(162,231)				
Annual Maryland Additional Subraction Modification to be provided to customers	$427,324				
Adjustment to operating income	$427,324				
Amount Presented on Company Exhibit DMV-4G	$427,000				

This adjustment annualizes the amortization of the Riverside environmental costs reflected in Case No. 9610.

Description	HTY 2019	Bridge Period 2020	MYP 1 2021	MYP 2 2022	MYP 3 2023
Annual amortization of Riverside environmental amortization reflected in Case No. 9610	$91,035	[redacted]			
1 Month (December) reflected in HTY	(7,586)				
Amortization of Case No. 9610 Riverside costs not reflected in the 2019 HTY	83,449				
Income tax effect at 27.5175%	(22,963)				
Adjustment to operating income	$60,486				
Amount Presented on Company Exhibit DMV-4G	($60,000)				

Baltimore Gas and Electric Company
Case No. 9610 Gas Depreciation Rates
Multi-Year Plan

This adjustment annualizes the level of gas depreciation expense as a result of the new depreciation rates included in Exhibit 5 of the Case No. 9610 settlement agreement, which was accepted by the Commission in Order No. 89400. This adjustment is necessary since the new depreciation rates are not fully reflected in the 2019 HTY. The companion adjustment is Rate Base Adjustment 4.

Description	HTY 2019	Bridge Period 2020	MYP 1 2021	MYP 2 2022	MYP 3 2023
Direct	$ 8,059,047	[redacted]			
Common	(2,380,329)				
Annual Change in depreciation expense due to new depreciation rates agreed upon in Case No. 9610	5,678,719				
1 Month (December) reflected in HTY	(473,227)				
Change in depreciation expense not reflected in the 2019 HTY	5,205,492				
Income tax effect at 27.5175%	(1,432,421)				
Adjustment to operating income	$ 3,773,071				
Amount Presented on Company Exhibit DMV-4G	$ (3,773,000)				

Baltimore Gas and Electric Company
Collective Bargaining Agreement - Gas
Multi-Year Plan

Operating Income
Adjustment 10

This adjustment reflects the impacts of the Collective Bargaining Agreement ("CBA") which are not fully reflected in the 2019 HTY.

Description	HTY 2019	Bridge Period 2020	MYP 1 2021	MYP 2 2022	MYP 3 2023
Specific Wage and Stipend Adjustments:		[redacted]			
Specific market wage adjustments	$ 126,039				
Premium and allowance adjustments	90,088				
Total specific wage and stipend adjustments	216,126				
General wage increase	755,984				
AIP reduction	(476,862)				
Elimination of 5 day sick pay accrual recorded in the 2019 HTY	(449,413)				
Additional expenses resulting from the CBA not reflected in the 2019 HTY	45,836				
Income Tax Effect at 27.5175%	(12,613)				
Adjustment to operating income	$ 33,223				
Amount Presented on Company Exhibit DMV-4G	$ (33,000)				

Baltimore Gas and Electric Company
CBA - 10 Add'l Sick Days - Gas
Multi-Year Plan

Operating Income
Adjustment 11

This adjustment annualizes the amortization of the union sick day regulatory asset established as a result of the CBA, and then amortized over a 10 year period consistent with the Case No. 9610 settlement agreement which was accepted by the Commission in Order No. 89400.

Description	HTY 2019	Bridge Period 2020	MYP 1 2021	MYP 2 2022	MYP 3 2023
Additional 10 Days of Sick Pay	$ 898,462	[redacted]			
Amortization Period (years)	10				
Annual Amortization	89,846				
1 Month (December) reflected in HTY	(7,487)				
Amortization of sick pay expenses not reflected in the 2019 HTY	82,369				
Income Tax Effect at 27.5175%	(22,666)				
Adjustment to operating income	$ 59,703				
Amount Presented on Company Exhibit DMV-4G	$ (60,000)				

Baltimore Gas and Electric Company
2019 Customer Operations Market Adjustment - Gas
Multi-Year Plan

Operating Income
Adjustment 12

This adjustment reduces gas operating income by providing for the effect on labor costs of the July 2019 market wage adjustment for certain BGE Customer Operations positions, which is not fully reflected in the 2019 HTY.

Description	HTY 2019	Bridge Period 2020	MYP 1 2021	MYP 2 2022	MYP 3 2023
Effect of the July 2019 Customer Operations market adjustment not reflected in HTY	215,074	[redacted]			
Income tax effect at 27.5175%	(59,183)				
Adjustment to operating income	$155,891				
Amount Presented on Company Exhibit DMV-4G	($156,000)				

Baltimore Gas and Electric Company
2019 Wage Increase - Gas
Multi-Year Plan

Operating Income
Adjustment 13

This adjustment reduces gas operating income by providing for the effect on labor costs of the March 2019 general wage increase for BGE employees as included in Case No. 9610, which is not fully reflected in 2019 HTY.

Description	HTY 2019	Bridge Period 2020	MYP 1 2021	MYP 2 2022	MYP 3 2023
Effect of the 2019 wage increase	253,146	[redacted]			
Income tax effect at 27.5175%	(69,659)				
Adjustment to operating income	$183,486				
Amount Presented on Company Exhibit DMV-4G	($183,000)				

Baltimore Gas and Electric Company
Changes in Other Taxes - Gas
Multi-Year Plan

Operating Income
Adjustment 14

This adjustment reduces gas operating income for the annualized known increases in various taxes other than income taxes including the increase in real and personal property taxes effective with the July 1, 2019 property assessments and the Maryland Public Service Commission assessment rate effective July 2019 as included in Case No. 9610. Both of these are not fully reflected in the 2019 HTY without this adjustment.

Description	HTY 2019	Bridge Period 2020	MYP 1 2021	MYP 2 2022	MYP 3 2023
Real Estate and Property Taxes					
Projected July 2019 - June 2020 Assessment Amounts	$41,365,305	[redacted]			
Amounts recorded in the 2019 HTY	39,882,644				
Increase/(Decrease)	1,482,661				
PSC Assessment Rate					
Projected July 2019 - June 2020 Assessment Amounts	1,519,733				
Amounts recorded in the 2019 HTY	1,414,492				
Increase/(Decrease)	$105,241				
Total					
Total Increase/(Decrease) in taxes other than income taxes	1,587,902				
Income tax effect at 27.5175%	(436,951)				
Adjustment to operating income	$1,150,951				
Amount Presented on Company Exhibit DMV-4G	($1,151,000)				

Baltimore Gas and Electric Company
Fully Amortized Gas Regulatory Assets
Multi-Year Plan

Operating Income
Adjustment 15

This adjustment increases gas operating income by eliminating the amortization expense associated with certain regulatory assets that will be fully amortized before the end of calendar year 2020. These regulatory assets include the Case No. 9406 tranche of rate case expenses which was fully amortized in May 2019; the Case No. 9484 tranche of STRIDE audit fees which was fully amortized in December 2019; and the tranche of Spring Gardens environmental costs from Case No. 9230 which will be fully amortized in November 2020. Since these regulatory assets were (or will be, as the case may be) fully amortized before the end of calendar year 2020, the related amortization has been eliminated from operating income. The associated regulatory assets have also been removed from rate base in the companion Rate Base Adjustment 5, as applicable.

Description	HTY 2019	Bridge Period 2020	MYP 1 2021	MYP 2 2022	MYP 3 2023
Case No. 9406 Rate Case Expenses	$ 8,438	[redacted]			
STRIDE Audit Fees	268,186				
Spring Gardens Environmental Case No. 9230 tranche	102,615				
Total amortization to be eliminated	379,239				
Income tax effect at 27.5175%	(104,357)				
Adjustment to operating income	$ 274,882				
Amount Presented on Company Exhibit DMV-4G	$ 275,000				

Baltimore Gas and Electric Company
Real Estate Gains and Losses
Multi-Year Plan

Operating Income
Adjustment 16

This adjustment reflects the deferral of the June 2018 gas net gain on the sale of real estate, which was recorded in accordance with the FERC Uniform System of Accounts. This adjustment amortizes net gains for ratemaking purposes over a two-year period as specified by the Commission in Case Nos. 7695, 9406, and 9484. It is the companion adjustment to Rate Base Adjustment 6.

Description	HTY 2019	Bridge Period 2020	MYP 1 2021	MYP 2 2022	MYP 3 2023
Amortization of gain on the sale of real estate applicable to HTY 2019	$708,183	[redacted]			
Income Tax Effect at 27.5175%	(194,874)				
Adjustment to Operating Income	$513,309				
Amount presented on Company Exhibit DMV-4G	$513,000				
Sale Recorded	Jun 2018				
Gain (Loss) Pre-Tax	1,416,366				
Monthly Amortization	59,015				
Months Amortized in last 12 Months	12				
Amortization for last 12 Months	708,183				
Remaining Months Unamortized	6				
Unamortized Balance at 12/31/19	354,092				

Baltimore Gas and Electric Company
Gas Safety Reliab. Depreciation
Multi-Year Plan

Operating Income
Adjustment 17

This adjustment annualizes the level of depreciation expense, net of depreciation savings, of non-revenue producing gas safety and reliability plant included in Case No. 9610, and as provided for in Rate Base Adjustment 7. This adjustment reflects the amounts included in the Case No. 9610 filing. Rate Base Adjustment 7 adjusts accumulated depreciation and accumulated deferred income taxes related to the additional net depreciation expense provided in this adjustment.

Description	HTY 2019	Bridge Period 2020	MYP 1 2021	MYP 2 2022	MYP 3 2023
Annual Depreciation associated with safety and reliability projects	$ 3,570,983	[redacted]			
Less - Safety and reliability depreciation included in the twelve months	1,649,517				
Increase in depreciation associated with safety and reliability projects	1,921,466				
Depreciation Savings:					
Safety and reliability annual depreciation savings	136,442				
Less - Safety and reliability depreciation savings included in the twelve months	63,026				
Depreciation savings related to safety and reliability retirements	73,416				
Net depreciation associated with safety and reliability projects	1,848,050				
Income Tax Effect at 27.5175%	(508,537)				
Adjustment to Operating Income	$ 1,339,513				
Amount presented on Company Exhibit DMV-4G	$ (1,340,000)				

Baltimore Gas and Electric Company
Gas STRIDE Net Depreciation
Multi-Year Plan

Operating Income
Adjustment 18

This adjustment annualizes the level of depreciation expense, net of depreciation savings, of STRIDE net investment included in Case No. 9610, and as provided in Rate Base Adjustment 8. This adjustment reflects the amounts included in the Case No. 9610 filing. Rate Base Adjustment 8 adjusts accumulated depreciation and accumulated deferred income taxes related to the additional net depreciation expense provided in this adjustment.

Description	HTY 2019	Bridge Period 2020	MYP 1 2021	MYP 2 2022	MYP 3 2023
Depreciation Expense:					
Annual Depreciation associated with STRIDE projects	$ 2,783,879	[redacted]	[redacted]	[redacted]	[redacted]
Less - Depreciation included in twelve months assoicated with STRIDE projects	1,186,434	[redacted]	[redacted]	[redacted]	[redacted]
Increase in depreciation associated with STRIDE projects	1,597,446	[redacted]	[redacted]	[redacted]	[redacted]
Depreciation Savings:					
Annual Depreciation savings associated with STRIDE retirements	106,368	[redacted]	[redacted]	[redacted]	[redacted]
Less - Deprec. savings included in the twelve mos. assoc with STRIDE retirements	45,332	[redacted]	[redacted]	[redacted]	[redacted]
Depreciation savings related to STRIDE retirements	61,036	[redacted]	[redacted]	[redacted]	[redacted]
Net depreciation associated with STRIDE projects	1,536,409	[redacted]	[redacted]	[redacted]	[redacted]
Income Tax Effect at 27.5175%	(422,781)	[redacted]	[redacted]	[redacted]	[redacted]
Adjustment to Operating Income	$ 1,113,628	[redacted]	[redacted]	[redacted]	[redacted]
Amount presented on Company Exhibit DMV-4G	$ (1,114,000)	[redacted]	[redacted]	[redacted]	[redacted]

Baltimore Gas and Electric Company
General Inflation - Gas
Multi-Year Plan

Operating Income
Adjustment 19

This adjustment, which was included in Case No. 9610, reduces gas operating income to provide for the effect of general inflation on non-labor O&M costs during the rate-effective period. This adjustment reflects a 1.420% inflation factor based on a five-year average of the Consumer Price Index ("CPI") per the U.S. Department of Labor, Bureau of Labor Statistics, as authorized by the Commission in Case No. 9484, Order No. 88975

Description	**HTY 2019**	**Bridge Period 2020**	**MYP 1 2021**	**MYP 2 2022**	**MYP 3 2023**
O&M Expense included in DMV-3G	$ 240,138,940	[redacted]			
Less:		[redacted]			
Advertising Costs (OIA-24)	(661,715)	[redacted]			
Employee Activity Costs (OIA-25)	(198,173)	[redacted]			
SERP Costs (OIA-26)	(1,003,916)	[redacted]			
Certain Incentives (OIA-27)	(1,281,391)	[redacted]			
Riverside Costs (OIA-21)	4,584,637	[redacted]			
O&M Expense included in the 2019 HTY	241,578,383	[redacted]			
Less labor included in O&M	69,926,687	[redacted]			
Non-Labor O&M expense included in the 2019 HTY	171,651,696	[redacted]			
Inflation factor	1.420%	[redacted]			
Additional O&M due to inflation	2,437,454	[redacted]			
Income tax effect at 27.5175%	(670,726)	[redacted]			
Adjustment to operating income	$ 1,766,728	[redacted]			
Amount Presented on Company Exhibit DMV-4G	$ (1,767,000)	[redacted]			

Baltimore Gas and Electric Company
Remove Credit to Establish Gas Riverside Regulatory Asset
Multi-Year Plan

This adjustment decreases operating income by eliminating the one-time credit recorded in the 2019 HTY to establish a regulatory asset for the Riverside environmental costs as authorized in Case No. 9484, Order No. 88975. This one-time credit is being eliminated since it is non-recurring.

Description	HTY 2019	Bridge Period 2020	MYP 1 2021	MYP 2 2022	MYP 3 2023
Riverside environmental costs established in a regulatory asset during the 2019 HTY	$4,584,637	[redacted]			
Income tax effect at 27.5175%	(1,261,577)				
Adjustment to operating income	$3,323,060				
Amount Presented on Company Exhibit DMV-4G	($3,323,000)				

Baltimore Gas and Electric Company
Eliminate Gas STRIDE Revenues, Net
Multi-Year Plan

Operating Income
Adjustment 23

This adjustment removes the STRIDE Rider 16 revenues, net, that are reflected in gas operating income in the 2019 HTY.

Description	**HTY 2019**	**Bridge Period 2020**	**MYP 1 2021**	**MYP 2 2022**	**MYP 3 2023**
STRIDE Rider revenues, net, reflected in the 2019 HTY	$ 9,589,008	[redacted]			
Franchise Tax and PSC Assessment	(204,504)				
Income Tax Effect at 27.5175%	(2,582,381)				
Adjustment to Operating Income	$ 6,802,124				
Amount presented on Company Exhibit DMV-4G	$ (6,802,000)				

Baltimore Gas and Electric Company
Eliminate Certain Gas Advertising Expenses
Multi-Year Plan

This adjustment eliminates from gas operating income for the 2019 HTY certain advertising expenses recorded as operating expenses in accordance with the FERC Uniform System of Accounts that BGE is not allowed to recover pursuant to COMAR 20.07.04.08. These expenses represent institutional and promotional advertising expenses. All charitable contributions, penalties, and lobbying costs, including the lobbying expense portion of the American Gas Association dues, have been recorded below the line and are not reflected in operating income. Therefore, it is not necessary to include these costs in this operating income adjustment.

Description	HTY 2019	Bridge Period 2020	MYP 1 2021	MYP 2 2022	MYP 3 2023
Institutional and Promotional Advertising	$ 661,715	[redacted]			
Income Tax Effect at 27.5175%	(182,087)				
Adjustment to operating income	$ 479,627				
Amount Presented on Company Exhibit DMV-4G	$ 480,000				

Baltimore Gas and Electric Company
Eliminate Certain Gas Employee Activity Costs
Multi-Year Plan

Operating Income
Adjustment 25

This adjustment eliminates from gas operating income certain employee activity costs as directed by the Commission in Case No. 9299, Order No. 85374.

Description	HTY 2019	Bridge Period 2020	MYP 1 2021	MYP 2 2022	MYP 3 2023
100% of Company's skybox costs	$ 89,025	[redacted]			
Remaining employee activity costs	218,295				
50% factor	50%				
Subtotal - 50% of Remaining employee activity costs	109,147				
Total excluded employee activity costs for the twelve month period	198,173				
Income Tax Effect at 27.5175%	(54,532)				
Adjustment to operating income	$ 143,641				
Amount Presented on Company Exhibit DMV-4G	$ 144,000				

Baltimore Gas and Electric Company
Eliminate Certain Gas SERP Costs
Multi-Year Plan

Operating Income
Adjustment 26

This adjustment eliminates from gas operating income 100% of Supplemental Executive Retirement Program ("SERP") costs as required in Case No. 9484, Order No. 88975.

Description	HTY 2019	Bridge Period 2020	MYP 1 2021	MYP 2 2022	MYP 3 2023
SERP costs to be eliminated	$1,003,916	[redacted]			
Income tax effect at 27.5175%	(276,253)				
Adjustment to operating income	$727,663				
Amount Presented on Company Exhibit DMV-4G	$728,000				

Baltimore Gas and Electric Company
Reduce Certain Gas Long-Term Compensation
Multi-Year Plan

Operating Income
Adjustment 27

This adjustment removes the non- recoverable amount of incentive compensation from gas operating income consistent with Case No. 9326, Order No. 86060.

Description	HTY 2019	Bridge Period 2020	MYP 1 2021	MYP 2 2022	MYP 3 2023
Removal of certain incentive compensation	$1,281,391	[redacted]			
Income Tax Effect at 27.5175%	(352,607)				
Adjustment to operating income	$928,784				
Amount Presented on Company Exhibit DMV-4G	$929,000				

Operating Income
Adjustment 28

Baltimore Gas and Electric Company
Gas AFC Annualization Based on Proposed ROR
Multi-Year Plan

This adjustment adjusts gas operating income for the known annualized amount of AFC included in unadjusted operating income at the gas 6.94% rate of return included in the Case No. 9610 settlement agreement for the purpose of calculating AFC, which was accepted by the Commission in Order No. 89400, to reflect a level that is consistent with the rate of return for electric as supported by the Company for the 2019 HTY.

Description	HTY 2019	Bridge Period 2020	MYP 1 2021	MYP 2 2022	MYP 3 2023
Actual AFC for the twelve months per Company Exhibit DMV-3G	$ 6,194	[redacted]	[redacted]	[redacted]	[redacted]
Actual AFC for each period	6,194,022	[redacted]	[redacted]	[redacted]	[redacted]
Reduction in AFC to annualize to Case 9610 6.97% gas rate of return per Operating Income Adjustment 2	(99,792)	[redacted]	[redacted]	[redacted]	[redacted]
Actual AFC for each period to be subject to new rate of return calculated	6,094,230	[redacted]	[redacted]	[redacted]	[redacted]
Conversion Factor to ROR Requested	1.0445	[redacted]	[redacted]	[redacted]	[redacted]
AFC for the twelve months restated to reflect 7.28% AFC rate	6,365,279	[redacted]	[redacted]	[redacted]	[redacted]
Actual AFC for twelve months	6,094,230	[redacted]	[redacted]	[redacted]	[redacted]
Change in AFC	271,049	[redacted]	[redacted]	[redacted]	[redacted]
Income Tax effect of borrowed funds portion of AFC at 27.5175%	(19,159)	[redacted]	[redacted]	[redacted]	[redacted]
Adjustment to operating income	$ 251,890	[redacted]	[redacted]	[redacted]	[redacted]
Amount Presented on Company Exhibit DMV-4G	$ 252,000	[redacted]	[redacted]	[redacted]	[redacted]
Calculation of Income Tax Effect of Borrowed Funds Portion of AFC		[redacted]	[redacted]	[redacted]	[redacted]
Increase (Decrease) in AFC	$ 271,049	[redacted]	[redacted]	[redacted]	[redacted]
Borrowed funds portion of AFC %	0.257	[redacted]	[redacted]	[redacted]	[redacted]
Borrowed funds portion of AFC $	69,624	[redacted]	[redacted]	[redacted]	[redacted]
Income tax rate	27.5175%	[redacted]	[redacted]	[redacted]	[redacted]
Income tax effect of borrowed funds portion of AFC	$ 19,159	[redacted]	[redacted]	[redacted]	[redacted]
Borrowed fund funds %		[redacted]	[redacted]	[redacted]	[redacted]
Total Return	7.28%	[redacted]	[redacted]	[redacted]	[redacted]
Weighted cost of Long-Term Debt	1.87%	[redacted]	[redacted]	[redacted]	[redacted]
Borrowed Funds Portion of AFC %	25.7%	[redacted]	[redacted]	[redacted]	[redacted]

Baltimore Gas and Electric Company
Adjustment to Reflect the Income Tax Effect of Pro Forma Interest - Gas
Multi-Year Plan

Operating Income
Adjustment 29

This adjustment synchronizes interest expense utilized in the income tax calculation with adjusted rate base and the weighted cost of debt implicit in the gas rates of return supported by the Company for the 2019 HTY.

Description	HTY 2019	Bridge Period 2020	MYP 1 2021	MYP 2 2022	MYP 3 2023
Unadjusted rate base - Company Exhibit DMV-3G	$1,876,062,242	[redacted]			
Rate base adjustments - Company Exhibit DMV-3G, line 11	135,295,716				
Rate Base adjusted for calculation of pro forma interest	$2,011,357,958				
Weighted cost of debt: Long-term debt	1.87%				
Long-term debt pro forma interest	$37,612,394				
Long-term debt actual interest charges	34,121,406				
Total adjustment to interest expense	3,490,988				
Income tax rate	27.5175%				
Tax effect of pro forma interest	($960,633)				
Amount Presented on Company Exhibit DMV-4G	$961,000				

Baltimore Gas and Electric Company
Gas Riverside Environmental Regulatory Asset
Multi-Year Plan

Rate Base
Adjustment 3

This adjustment reduces gas rate base to reflect the impact of the accumulated amortization associated with the Riverside regulatory asset reflected in Case No. 9610. It is the companion adjustment to Operating Income Adjustment No. 8.

Description		HTY 2019	Bridge Period 2020	MYP 1 2021	MYP 2 2022	MYP 3 2023
Change in the Riverside amortization reflected in Case No. 9610 per Operating Income Adjustment 8	$	83,449	[redacted]			
Adjustment to reflect average rate base		50.0%	[redacted]			
Increased accumulated amortization		41,724	[redacted]			
Income tax effect at 27.5175%		(11,482)	[redacted]			
Adjustment to rate base	$	30,243	[redacted]			
Amount Presented on Company Exhibit DMV-4G	$	(30,000)	[redacted]			

Baltimore Gas and Electric Company
Case No. 9610 Impact of New Depreciation Rates - Gas
Multi-Year Plan

Rate Base
Adjustment 4

This adjustment reflects the impact on the accumulated depreciation reserve of the new depreciation rates resulting from Case No. 9610. This is the companion adjustment to Operating Income Adjustment 9.

Description	HTY 2019	Bridge Period 2020	MYP 1 2021	MYP 2 2022	MYP 3 2023
Increase in accumulated depreciation resulting from Operating Income Adjustment 9	$ 5,205,492	[redacted]			
Deferred income taxes on normalized depreciation expense at 27.5175%	(1,432,421)				
Increased accumulated depreciation, net of tax	3,773,071				
Adjustment to reflect average rate base	50.0%				
Adjustment to rate base	$ 1,886,535				
Amount Presented on Company Exhibit DMV-4G	$ (1,887,000)				

This adjustment eliminates the tranche of Spring Gardens environmental costs from Case No. 9230 which will be fully amortized in November 2020 . Since this regulatory asset will be fully amortized prior to the end of calendar year 2020, it should not be included in rate base. This is the companion adjustment to Operating Income Adjustment 15.

Description	HTY 2019	Bridge Period 2020	MYP 1 2021	MYP 2 2022	MYP 3 2023
Regulatory Asset included in average rate base:					
Spring Gardens Environmental - Case No. 9230	$ 145,372	[redacted]			
Total regulatory asset to be eliminated	145,372				
Income tax effect at 27.5175%	(40,003)				
Adjustment to rate base	$ 105,369				
Amount Presented on Company Exhibit DMV-4G	$ (105,000)				

Baltimore Gas and Electric Company
Unamortized Gas Real Estate Gains and Losses
Multi-Year Plan

Rate Base
Adjustment 6

This adjustment reflects the unamortized gas gains on real estate which are being amortized into gas operating income for ratemaking purposes over a two year period as specified by the Commission in Case Nos. 7695, 9406, and 9484. This adjustment is a companion adjustment to Operating Income Adjustment 16.

Description		HTY 2019	Bridge Period 2020	MYP 1 2021	MYP 2 2022	MYP 3 2023
Unamortized gains on the sale of real estate:						
Unamortized balance @ 12/31/18	$	1,062,275	[redacted]			
Unamortized balance @ 12/31/19 per Operating Income Adjustment 16		354,092	[redacted]			
Average balance unamortized gains on sale of real estate		708,183	[redacted]			
Income Tax Effect at 27.5175%		(194,874)	[redacted]			
Adjustment to Rate Base	$	513,309	[redacted]			
Amount presented on Company Exhibit DMV-4G	$	(513,000)	[redacted]			

Baltimore Gas and Electric Company
Gas Safety and Reliability Investments
Multi-Year Plan

Rate Base
Adjustment 7

This adjustment reflects the terminal impact of the known and measurable non-revenue producing gas safety and reliability investments as filed in Case No. 9610. This adjustment includes the impact on plant in service, accumulated depreciation reserve, depreciation savings, and related accumulated deferred income taxes. It is a companion adjustment to Operating Income Adjustment 17, which adjusts the level of depreciation for these projects.

Description	HTY 2019	Bridge Period 2020	MYP 1 2021	MYP 2 2022	MYP 3 2023
Gas safety and reliability project investment included in Case No. 9610 filing	$ 157,845,262	[redacted]			
Gas safety and reliability project investment reflected in average rate base	77,362,013	[redacted]			
Additional gas safety and reliability investment - Increase in plant in service	80,483,249	[redacted]			
Less: Additional accumulated depreciation, net of savings, per Operating Income Adjustment 17	1,848,050	[redacted]			
Plus: Accumulated Deferred Income Taxes on the additional investment above	(16,075,384)	[redacted]			
Adjustment to Rate Base	$ 62,559,815	[redacted]			
Amount presented on Company Exhibit DMV-4G	$ 62,560,000	[redacted]			

Baltimore Gas and Electric Company
Gas Terminal STRIDE Net Investments
Multi-Year Plan

Rate Base
Adjustment 8

This adjustment reflects the terminal impact of the known and measurable STRIDE investments as filed in Case No. 9610. This adjustment includes the impact on plant in service, accumulated depreciation reserve, depreciation savings, and related accumulated deferred income taxes. It is a companion adjustment to Operating Income Adjustment 18, which adjusts the level of depreciation for these projects.

Description	HTY 2019	Bridge Period 2020	MYP 1 2021	MYP 2 2022	MYP 3 2023
STRIDE project investment as reflected in the Case No. 9610 filing	$ 203,439,164	[redacted]			
STRIDE project investment reflected in the Case No. 9610 average rate base	93,289,478				
Additional STRIDE investment - Increase in plant in service	110,149,686				
Less: Additional accumulated depreciation due to increased depreciation expense, net of depreciation savings, per Operating Income Adjustment 18	1,536,409				
Plus: Additional accumulated deferred income taxes related to the additional STRIDE project investment above	(24,036,179)				
Adjustment to Rate Base	$ 84,577,098				
Amount presented on Company Exhibit DMV-4G	$ 84,577,000				

Baltimore Gas and Electric Company
Eliminate Gas RM54 Software
Multi-Year Plan

Rate Base
Adjustment 9

This adjustment reduces gas rate base to remove the RM54 capital software costs. Although an operating income adjustment is not necessary for the gas RM54 amortization since it was not recorded as a distribution expense following the Commission's decision in Case No. 9484, the RM54 capital is recorded as common plant, and therefore was allocated to electric and gas distribution. Accordingly, it is necessary to remove the gas portion of RM54 capital in Rate Base Adjustment 9.

Description	HTY 2019	Bridge Period 2020	MYP 1 2021	MYP 2 2022	MYP 3 2023
RM54 Plant in Service	$ 626,999				
RM54 Accumulative Amortization	(314,133)				
RM54 Software to be excluded from rate base	312,865	[redacted]			
Income Tax Effect at 27.5175%	(86,093)	[redacted]			
Adjustment to rate base	$ 226,773	[redacted]			
Amount Presented on Company Exhibit DMV-4G	$ (227,000)	[redacted]			

Baltimore Gas and Electric Company
Cash Working Capital Reflected in Rate Base - Gas
Multi-Year Plan

Company Exhibit DMV-5G

2019 Actual HTY - Unadjusted Rate Base - Based on 2014 Lag Study Net Lag Days

Line No.	Description	Line of Business	CWC Expense	Net Lag Days	Cash Advanced
1	Purchased Fuel and Energy Expens	Gas	$181,305,130	8.6	$4,271,847
2	Gas Choice and Reliability Costs	Gas	$957,757	8.6	$22,566
3	Salaries and Wages	Gas	69,926,687	10.9	2,088,222
4	Fringe Benefits	Gas	23,535,740	31.6	2,037,615
5	Other Oper & Maint Expense	Gas	130,261,805	(1.5)	(535,322)
6	Property Taxes	Gas	39,882,644	133.6	14,598,140
7	Payroll Taxes	Gas	5,738,004	10.3	161,922
8	PSC Assessment	Gas	1,414,493	77.3	299,562
9	GRT Taxes	Gas	13,359,079	(5.6)	(204,961)
10	Other Taxes	Gas	(5,298)	14.0	(203)
11	Federal Income Taxes - Current	Gas	(56,790,001)	(4.5)	700,151
12	State Income Taxes - Current	Gas	(16,487,605)	(11.5)	519,472
13	Interest Expense	Gas	33,890,983	(41.6)	(3,862,643)
14	Short Term Interest	Gas	733,236	53.7	107,876
15	Interest on Customer Deposits	Gas	1,091,176	(136.0)	(406,575)
16	Total Gas Cash Working Capital		$428,813,832		$19,797,668
17	Total Electric Cash Working Capital ($000) carried forward to Unadjusted Rate Base Company Exhibit DMV-3G, line 6				$19,798

Company Exhibit DMV-6G

Baltimore Gas and Electric Company
Gas Cash Working Capital Based on Updated Net Lag Days
Multi-Year Plan

2019 Lag Study Net Lag Days

Line No.	Description	Line of Business	CWC Expense	Net Lag Days per 2019 Lag Study	Updated Cash Advanced
1	Purchased Fuel and Energy Expense	Gas	$181,305,130	9.8	$4,867,919
2	Gas Choice and Reliability Costs	Gas	$957,757	9.8	$25,715
3	Salaries and Wages	Gas	69,926,687	6.1	1,168,638
4	Fringe Benefits	Gas	23,535,740	7.7	496,507
5	Other Oper & Maint Expense	Gas	130,261,805	(5.3)	(1,891,473)
6	Property Taxes	Gas	39,882,644	92.8	10,140,026
7	Payroll Taxes	Gas	5,661,004	6.1	94,609
8	PSC Assessment	Gas	1,414,493	77.5	300,338
9	GRT Taxes	Gas	13,359,079	(8.4)	(307,442)
10	Other Taxes	Gas	71,509	32.9	6,446
11	Federal Income Taxes - Current	Gas	(56,790,001)	(4.4)	684,592
12	State Income Taxes - Current	Gas	(16,487,605)	(11.5)	519,472
13	Interest Expense	Gas	33,890,983	(54.7)	(5,079,005)
14	Short Term Interest	Gas	733,236	49.1	98,635
15	Interest on Customer Deposits	Gas	1,091,176	(135.9)	(406,276)
16	Total Gas Cash Working Capital Based on New Lag Days - 2019 Lag Study		$428,813,638		$10,718,700
17	CWC Based on 2014 Lag Study included in Unadjusted Rate Base - Company Exhibit DMV-5G, line 16				$19,797,668
18	Impact of Change in Net Lag Days carried forward to Company Exhibit DMV-4G, line 31				($9,078,968)

Baltimore Gas and Electric Company **Company Exhibit DMV-7G**

2019 Lag Study - Gas Lag Components

Line No.	Description	Lag Days	Revenue Lag	Net Lag Days
1	Revenue Lag:			
2	Rendition of service to meter reading date		14.7	
3	Meter reading date to bill delivery		3.8	
4	Bill delivery to payment		28.4	
5	Receipt of payment to date funds are accessible		0.2	
6	Total days lag in collection of revenue		47.1	
7	Expense Lag:			
8	Gas PFE	37.3	47.1	9.8
9	Salaries and Wages	41.0	47.1	6.1
10	Fringe Benefits	39.4	47.1	7.7
11	Other Oper & Maint Expense	52.4	47.1	(5.3)
12	Property Taxes	(45.7)	47.1	92.8
13	Payroll Taxes	41.0	47.1	6.1
14	PSC Assessment	(30.4)	47.1	77.5
15	Electric Environmental Surcharge	41.5	47.1	5.6
16	Universal Service Fund	35.9	47.1	11.2
17	GRT Taxes	55.5	47.1	(8.4)
18	Other Taxes	14.2	47.1	32.9
19	Federal Income Taxes	51.5	47.1	(4.4)
20	State Income Taxes	58.6	47.1	(11.5)
21	Interest Expense	101.8	47.1	(54.7)
22	Short Term Interest	(2.0)	47.1	49.1
23	Interest on Customer Deposits	183.0	47.1	(135.9)

Before the Maryland Public Service Commission

Case No.________

Prepared Direct Testimony of

David M. Vahos – Part 2

On Behalf of

Baltimore Gas and Electric Company

May 15, 2020

List of Issues and Major Conclusions

- BGE is proposing a Multi-Year Plan ("MYP") to set rates for the calendar years 2021-2023. In the MYP, the Company is not proposing an increase to electric and gas base distribution revenues in 2021 or 2022 and is proposing to increase revenues in 2023 by $235.3 million, of which $140.4 million is an increase in electric distribution rates and $94.9 million is an increase in gas distribution rates. Overall, the Company's electric and gas work plans include capital expenditures in each of the MYP years that are lower than the 2019 capital expenditure levels, and the ongoing O&M costs reflect a nominal 0.5% annual growth rate compared to 2019.

- In order to avoid base distribution revenue increases until 2023 and in light of the current economic situation in which Maryland finds itself as a result of the COVID-19 pandemic, BGE is decreasing the performance adder component of its recommended return on equity ("ROE") and proposing a series of proforma adjustments to remove major outage event restoration expenses included in base rates, accelerate certain tax benefits, suspend regulatory asset amortization in 2021, and extend the amortization periods of certain existing regulatory assets.

- In accordance with Order No. 89542 in Case No. 9639, BGE has established a regulatory asset to record any incremental impacts related to COVID-19. For purposes of this filing, BGE has included the framework for recovery of incremental COVID-19 costs. The Company's intent is to continue to track all COVID-19 related incremental costs and will update the applicable adjustments at the time of the hearings once the Company gains a better understanding of the level and timing of COVID-19 incremental costs.

- BGE is seeking to recover its Electric Vehicle ("EV") program costs over a five-year period in accordance with Commission Order No. 88997. At this time, the Company has implemented a cost-effective EV program, as demonstrated by Company Witnesses Warner and Case in their Direct Testimonies.

- BGE is seeking the recovery of certain Gas Meter Relocation and Protection Program costs that were deferred in a regulatory asset pursuant to Order No. 88975 issued in Case No. 9484 as the program is now substantially complete.

- The Company is proposing the termination of regulatory asset treatment for CVR costs effective with 2021 spending. With the adoption of an MYP filing, a two-year amortization no longer serves the originally intended purpose. As the filing provides for the amortization of CVR spending through calendar year 2020, the Company is proposing that the CVR spending no longer be deferred in a regulatory asset but flowed through to operating expense, similar to other expenses, effective in calendar year 2021.

Non-Operational Capital and O&M Spending Summary

The amounts set forth below represent the MYP capital and O&M budgeted amounts which are necessary to continue providing outstanding, safe and reliable electric and gas service to customers.

Capital

Category	Multi-Year Plan Period		
	2021	2022	2023
IT BU Projects	$83,629,401	$82,308,402	$81,814,318
BSC	$2,326,728	$2,274,076	$2,334,554
Fleet	$21,915,000	$20,615,000	$17,785,000
Real Estate and Facilities	$46,193,736	$42,736,611	$36,611,546
Training	$1,496,463	$1,496,770	$1,496,559
Other	$47,904,579	$63,309,048	$34,580,463
TOTAL	$203,465,907	$212,739,907	$174,622,440

O&M

Category	Multi-Year Plan Period		
	2021	2022	2023
IT BU Projects	$19,657,021	$19,535,399	$18,694,625
BSC	$172,165,403	$173,707,095	$176,089,299
Fleet	$707,000	$707,000	$707,000
Real Estate and Facilities	$21,716,349	$22,272,300	$22,903,681
Training	$26,650,959	$25,988,677	$25,386,069
Other	$111,538,238	$111,483,646	$111,692,952
TOTAL	$352,434,970	$353,694,117	$355,473,626

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I. QUALIFICATIONS

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. My name is David M. Vahos. My business address is 2 Center Plaza, 110 West Fayette Street, Baltimore, Maryland 21201.

Q. ARE YOU THE DAVID M. VAHOS WHO ALSO PREPARED PART 1 OF DIRECT TESTIMONY AND EXHIBITS IN THIS PROCEEDING, WHICH WAS PROVIDED TO ALL PARTIES ON MARCH 2, 2020, AND IS ALSO BEING FILED WITH THE COMMISSION WITH PART 2 OF YOUR DIRECT TESTIMONY?

A. Yes. I am.

II. PURPOSE OF TESTIMONY

Q. WHAT IS THE PURPOSE OF PART 2 OF YOUR DIRECT TESTIMONY?

A. As discussed in the Direct Testimony of Company Witness Case and as indicated in Part 1 of my Direct Testimony, BGE expressed its willingness and desire to serve as the Pilot Utility as the Commission examines multi-year rate plans as a form of alternative ratemaking in Maryland. Therefore, with the application, testimony and exhibits being submitted to the Commission, BGE is proposing a Multi-Year Plan ("MYP") filing consistent with Order Nos. 89226 and 89482 in Public Conference 51 and Case No. 9618. The purpose of Part 2 of my Direct Testimony is to support the Company's MYP base revenue requirement request to set rates for the calendar years 2021-2023.

Q. PLEASE SUMMARIZE THE REVENUE REQUIREMENT REQUEST FOR THE MYP YEARS IN THIS PROCEEDING.

A. Chart 1 below provides a summary of BGE's electric and gas requested revenue requirement for the three-year MYP period for the calendar years of 2021-2023:

Chart 1 – Revenue Requirement Summary

MYP Revenue Requirement Summary
($ in Millions)

	MYP 2021	MYP 2022	MYP 2023
Electric:			
Cumulative Electric Incremental Revenue Requirement Before Benefits and Adjustments	$ 109.0	$ 156.1	$ 203.8
Total Benefits and Adjustments	(109.0)	(156.1)	(63.4)
Annual Electric Incremental Revenue Requirement Including Benefits and Adjustments	**$ -**	**$ -**	**$ 140.4**
Gas:			
Cumulative Gas Incremental Revenue Requirement Before Benefits and Adjustments	$ 65.9	$ 76.2	$ 109.7
Total Benefits and Adjustments	(65.9)	(76.2)	(14.8)
Annual Gas Incremental Revenue Requirement Including Benefits and Adjustments	**$ -**	**$ -**	**$ 94.9**
Total Revenue Impact on Customers Bills	**$ -**	**$ -**	**$ 235.3**

As noted in Chart 1 above, the Company is not proposing to increase electric and gas base distribution revenues in 2021 or 2022 and is proposing to increase revenues in 2023 by $235.3 million. The Company's ongoing investments in its system and ongoing costs to serve customers safely and reliably warrant the requested increase in revenues in 2023.

The overall revenue requirement amounts above are based upon the budget developed by BGE for the MYP years of 2021-2023, as supported by Part 2 of my Direct Testimony and exhibits and as discussed in more detail later in my testimony. As discussed in the Direct Testimony of Company Witness Fiery, the requested 2021 and 2022 revenue requirements result in no increase to the base distribution portion of customer bills. In 2023, the requested revenue requirement increase results in a 4.8% increase on total electric bills and a 9.5% increase on total gas bills. An average residential customer receiving both electric and gas service from BGE will see an 8.3% increase to their 2023 bills, for an average annual increase of 2.8% over the MYP period, as supported in the Direct Testimony of Company Witness Fiery.

Q. HOW DOES THE COMPANY INTEND TO AVOID A REVENUE INCREASE UNTIL 2023?

A. In light of the public health impacts of the COVID-19 pandemic and the related executive orders closing many businesses, resulting in many businesses and individuals being without a steady source of income, the Company believes it beneficial to allow its customers time before being faced with an increase in electric and gas base distribution bills. However, BGE will continue to invest in its system and operations, thus supporting Central Maryland from an economic, employment, and diverse supplier perspective. In light of the above, the Company is decreasing the performance adder component of its recommended return on equity ("ROE") from Part 1 of my Direct Testimony and is proposing a series of proforma adjustments to remove major outage event restoration expenses recovered through base rates during the MYP period, accelerate certain tax benefits, suspend regulatory asset amortization in 2021, and extend the amortization periods of certain existing regulatory assets. In effect, through these recommendations, the Company is proposing to fund its ongoing capital and operations and maintenance ("O&M") expenditures while keeping base distribution revenues flat for customers through 2022. As can be seen in Chart 2 below, the proposed adjustments serve to keep base distribution revenues significantly lower than they otherwise would have been for customers in 2021 and 2022.

Chart 2 – Revenue Requirement Impact of COVID-19 Pandemic Benefits and Adjustments

Revenue Requirement Impact of Adjustments to Address COVID-19 Pandemic
($ in Millions)

	MYP 2021	MYP 2022	MYP 2023
Electric:			
Reduction in ROE Performance Adder	$ (4.5)	(4.9)	(5.3)
Accelerated Tax Benefits	(63.0)	(128.7)	(36.3)
Removal of major outage event outage restoration expenses	(10.5)	(10.5)	(10.5)
Reg Asset Amortization Adjustments	(31.0)	(12.0)	(11.3)
	$ (109.0)	$ (156.1)	$ (63.4)
Gas:			
Reduction in ROE Performance Adder	$ (2.7)	(3.0)	(3.3)
Accelerated Tax Benefits	(54.2)	(69.7)	(8.3)
Reg Asset Amortization Adjustments	(9.0)	(3.5)	(3.2)
	$ (65.9)	$ (76.2)	$ (14.8)
Total	$ (174.9)	$ (232.3)	$ (78.2)

Q. WHAT IS DRIVING THE NEED FOR THE REVENUE INCREASE IN 2023?

A. As discussed in the Direct Testimonies of the operational Company Witnesses Apte, Biagiotti, Burton and Olivier, as well as later within my testimony, capital investments and ongoing costs are necessary to maintain and modernize the electric and gas distribution systems so that the Company can continue providing safe and reliable electric and gas distribution service to our customers. And while the Company needs to continue making these investments and incurring the ongoing costs, the total capital expenditures in each of the MYP years are lower than the 2019 capital levels, and the $2.1 billion of ongoing O&M costs reflect a nominal 0.5% annual growth rate since 2019.

Q. WHAT AREAS WILL THE REMAINDER OF YOUR TESTIMONY ADDRESS?

A. My remainder of my testimony is organized as follows:

III. Proposed Adjustments to Address the COVID-19 Pandemic

IV. COVID-19 Pandemic Impacts on BGE's MYP

V. Budgeting Process

VI. Capital Structure and Rate of Return

VII. Proposed Major Outage Event Restoration Expense Regulatory Asset Treatment

VIII. Summary of Company Revenue Requirement Exhibits

IX. MYP Reconciliation

X. Non-Operational Capital and O&M Spending

XI. Conclusion

III. PROPOSED ADJUSTMENTS TO ADDRESS THE COVID-19 PANDEMIC

Q. HAS THE COMPANY CONSIDERED THE RECENT EVENTS ASSOCIATED WITH THE COVID-19 PANDEMIC IN THIS MYP FILING?

A. Yes. The Company realizes and appreciates the economic and public health challenges associated with Maryland's response to the COVID-19 pandemic that its customers are facing, including the closing of certain businesses per executive orders and the resulting loss of jobs by many people. As I mentioned above, in order to address the economic impact of the COVID-19 pandemic, BGE is decreasing the performance adder component of its recommended ROE and is proposing proforma revenue requirement adjustments to help mitigate the distribution rate impacts while BGE continues to invest in its systems and operations and support Central Maryland from an economic, employment, and diverse supplier perspective:

1) In Part 1 of my Direct Testimony at pages 4-5, I proposed a 10.25% return on equity for all MYP years based on the 9.9% return on equity recommended by Company Witness McKenzie, adjusted upwards for a performance adder of 35 basis points, which aligns with the midpoint of the upper end of Company Witness McKenzie's recommended ROE cost of equity range. However, in light of the COVID-19 pandemic impact on the Company's customers, I am now lowering the performance adder to 20 basis points, and thus the proposed ROE to 10.1%, which is still within Company Witness McKenzie's recommended ROE cost of equity range. Although BGE still believes it is appropriate that the Company's excellent performance and customer satisfaction results should positively impact the return on equity authorized by the Commission, the Company is lowering its recommended ROE to 10.1%.

2) Operating Income Adjustment 38 and Rate Base Adjustment 14 provide for the acceleration of certain tax benefits totaling $287.3 million over the three MYP years, which are discussed in further detail below.

3) Operating Income Adjustment 37 removes $30.6 million of projected incremental major outage event restoration expense from the electric revenue requirement and BGE is requesting regulatory asset treatment for major outage event restoration expenses. BGE's proposal is discussed further below and in Section VII.

4) Operating Income Adjustment 39 and Rate Base Adjustment 15 reflect the suspension of the amortization of existing base distribution regulatory assets in 2021, resulting in lower expenses being included in the revenue requirement in that year. These adjustments are discussed in further detail below.

5) Operating Income Adjustment 40 and Rate Base Adjustment 16 provide for a five-year extension of the amortization periods of the Smart Grid-related regulatory assets, resulting in lower annual amortization expense as discussed in further detail below.

Q. WITH RESPECT TO YOUR ACCELERATED TAX BENEFIT PROPOSAL, HOW ARE YOU PROPOSING TO PROVIDE THE $287.3 MILLION IN TAX BENEFITS TO CUSTOMERS?

A. As I mentioned above, the Company has included Operating Income Adjustment 38 and Rate Base Adjustment 14, which provide customers with an acceleration of tax benefits attributable to the amortization of the Tax Cuts and Jobs Act of 2017 ("TCJA") unprotected property and non-property excess deferred regulatory liabilities and the Maryland Additional Subtraction Modification ("MASM") tax benefit. BGE is proposing to give these tax benefits to customers over the MYP period, starting when the new rates become effective in January 2021, for each of the calendar years 2021 through 2023.

Q. WHAT IS THE TCJA UNPROTECTED PROPERTY AND UNPROTECTED NON-PROPERTY?

A. The TCJA tax benefits associated with the unprotected property and non-property relate to the annual amortization of the regulatory liability arising from changes in BGE's accumulated deferred income tax ("ADIT") balances that were approved by the Commission in its Letter Order issued on January 31, 2018.[1] The ADIT balances were previously recorded at the higher 35% federal income tax rate and are now reflected at the lower 21% tax rate, as a result of the TCJA. The difference between the ADIT balances at the 35% rate and the 21% rate is referred to as the "excess deferred income tax" regulatory liability. The Company includes this regulatory liability as a reduction to rate base and amortizes the property-related portion in accordance with the average rate assumption method and the non-property related portion over ten years, consistent with the Company's January 2018 TCJA filing, which was approved by the Commission.[2]

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[1] ADITs are produced when an item of income or expense is recognized by the Company in a different period for financial reporting than for income tax purposes. Most often, the difference results in a deferral of when taxes are paid. In effect, ADITs represent a significant source of interest free funds for BGE and customers. As such, ADITs are appropriately included as a reduction to rate base which in turn lowers customers' rates.

[2] Mail Log # 218429 filed January 5, 2018; and as amended by Mail Log # 218500 filed January 11, 2018.

Q. WHAT IS THE MASM TAX BENEFIT?

A. Prior to January 1, 2000, Maryland public utilities were subject to the Public Service Company Franchise Tax ("Franchise Tax") and generally were not subject to the Maryland Corporation Income Tax ("Income Tax"). Beginning January 1, 2000, in conjunction with deregulation of the electric utility industry, Maryland public service companies were no longer subject to the Franchise Tax and became only subject to the corporate income tax as defined above.[3]

The change in taxing mechanism would have resulted in public utilities effectively forgoing the benefit of tax depreciation recognized prior to January 1, 2000. As an accommodation, for assets that were owned by a public utility on January 1, 2000 ("pre-2000 assets"), Maryland tax law provides for a deduction from taxable income equal to the excess of net "book" value over net tax value as of January 1, 2000 (the "Statutory Subtraction Modification").[4] This deduction is "triggered" when the asset is sold, retired, or otherwise disposed.

Q. WHAT LED TO THIS CHANGE TO THE MASM?

A. Previously, BGE's deduction for tax depreciation was based upon the excess of net "book" value over net tax value as of January 1, 2000. BGE proposed to the State of Maryland an alternative methodology for calculating the Statutory Subtraction Modification that results in an additional deduction for tax purposes by basing the deduction on book cost, instead of net book cost, over net tax value.

In the fourth quarter of 2018, the Company received a favorable declaratory ruling from the Office of the Maryland Comptroller approving the alternative

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[3] Maryland House Bill 366, Chapter 6 of the Laws of Maryland of 1999

[4] *Md. Code Ann.*, Tax-Gen. § 10-309

methodology for calculating the Statutory Subtraction Modification. The receipt of the favorable declaratory ruling permitted BGE to record the MASM tax benefit for financial accounting purposes. Accordingly, BGE recorded an income tax benefit of $114.6 million, approximately $89.8 million related to electric distribution and $24.8 million related to gas distribution, for the MASM tax benefit in the fourth quarter of 2018. In Case No. 9610, BGE proposed to provide this tax benefit to customers over the average remaining book lives of Maryland assets, approximately 32 and 39 years for electric and gas, respectively, based on the depreciation study filed in that case.[5]

Q. OVER WHAT TIME PERIOD DOES BGE RECOMMEND THAT THESE TAX BENEFITS BE PROVIDED TO CUSTOMERS IN THE MYP PROCEEDING?

A. BGE proposes to use both outstanding regulatory liabilities as of December 31, 2019 over the three-year MYP period, but only to the extent needed to avoid any rate increases in 2021 and 2022. Currently both the TCJA and MASM regulatory liabilities are being amortized over a much longer period as noted above. BGE believes now is an appropriate time to give these benefits to customers on an accelerated basis. Therefore, in Operating Income Adjustment 38, the Company is proposing to flow these tax benefits to customers much sooner than the more than 30-year periods proposed and authorized previously.

Q. MR. VAHOS, YOU SAY ABOVE THAT YOU ARE PROPOSING TO USE THE TCJA AND MASM REGULATORY LIABILITIES OVER THE THREE MYP

[5] The Stipulation and Settlement Agreement approved by the Commission in Case No. 9610 did not address the period over which these tax benefits would be provided to customers.

YEARS, BUT ONLY TO THE EXTENT NEEDED TO AVOID ANY REVENUE INCREASES IN 2021 AND 2022. WHAT DO YOU MEAN BY THAT?

A. As I have explained in my testimony, the Company's proposed spending in the MYP period justifies the revenue increases otherwise calculated in my exhibits. However, the Company acknowledges the significant financial difficulties being experienced by its customers. Therefore, BGE is proposing that there be no revenue increases in 2021 and 2022 through, among other things, the use of the accelerated tax benefits. To the extent that the Commission agrees that it is appropriate for there to be no revenue increases in 2021 and 2022, the Commission can accept the Company's proposal to accelerate tax benefits to achieve this result.

Q. CAN YOU PLEASE EXPLAIN YOUR MAJOR OUTAGE EVENT RESTORATION EXPENSE PROPOSAL IN OPERATING INCOME ADJUSTMENT 37?

A. As I indicated above, I am proposing to remove $30.6 million of incremental major outage event restoration expenses from the MYP filing. The budgeted unadjusted operating income for the MYP years of 2021-2023, as reflected in my exhibits, includes $10.2 million of incremental major outage event restoration expense in each MYP year based on the current five-year average. I have included Operating Income Adjustment 37 which removes the $10.2 million included in the budget in each year. The removal of these costs will help keep base distribution revenues lower than they otherwise would have been for customers.[6]

[6] In Section VII below, BGE is proposing that it be authorized to create a regulatory asset for tracking major outage event restoration expense instead of including the five-year average in the revenue requirement calculation for each year of the MYP period.

Q. PLEASE ELABORATE ON YOUR PROPOSAL TO SUSPEND THE AMORTIZATION OF EXISTING BASE DISTRIBUTION REGULATORY ASSETS IN 2021 IN OPERATING INCOME ADJUSTMENT 39 AND RATE BASE ADJUSTMENT 15.

A. As mentioned above, I am also proposing Operating Income Adjustment 39 and Rate Base Adjustment 15, which reflect the suspension in 2021 of the amortization of existing base distribution regulatory assets.[7] The elimination of 2021 amortization amounts will keep base distribution revenues lower than they otherwise would have been for customers.

Q. HOW DO YOU PROPOSE TO HANDLE AMORTIZATION IN 2021 FOR ANY NEW REGULATORY ASSETS OR TRANCHES FOR WHICH YOU ARE REQUESTING RECOVERY FOR THE FIRST TIME IN THIS PROCEEDING?

A. Any new tranches reflected in this MYP, which ordinarily would commence amortization in 2021, are proposed to not commence amortizing until 2022, consistent with the treatment described above for existing base distribution regulatory assets.[8]

Q. PLEASE ELABORATE ON YOUR PROPOSAL TO EXTEND THE LIVES OF THE SMART GRID REGULATORY ASSETS AS PROPOSED IN OPERATING INCOME ADJUSTMENT 40 AND RATE BASE ADJUSTMENT 16.

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[7] Operating Income Adjustment 39 and Rate Base Adjustment 15 exclude amortization of existing regulatory assets associated with other non-base distribution mechanisms such as EmPOWER, SOS, etc.

[8] The new tranches in this case are for rate case expenses, STRIDE audit fees, CVR costs, Riverside environmental costs, gas meter mitigation costs, and EV program costs. However, this does not include the new COVID-19 regulatory asset for which the Company is requesting a different treatment.

A. Operating Income Adjustment 40 and Rate Base Adjustment 16 reflect the extension of the Smart Grid Regulatory Asset amortization period through 2031, an additional five years. Previously, the Commission approved Smart Grid-related regulatory asset lives so that they would be fully amortized as of May 2026. In this proceeding, the Company is proposing to extend the lives of these assets to December 2031, thereby resulting in lower annual amortization expense.

IV. COVID-19 PANDEMIC IMPACTS ON BGE'S MYP

Q. WILL THE COVID-19 PANDEMIC IMPACT THE COMPANY'S BUDGET REFLECTED IN THIS MYP FILING?

A. The COVID-19 pandemic will have impacts on the 2020 Bridge Period of the MYP, and potentially have impacts beyond 2020. Impacts on the 2020 Bridge Period will be seen in some areas of revenues, operating expenses, capital investments and financing costs.[9] Given the uncertainties related to the pandemic's impact on the Company's budget, it may be appropriate to update the January 1, 2021, rate base as it is the starting point for the calculation of the revenue requirement for the MYP period. BGE will continue to monitor this situation during the pendency of this proceeding and will make any changes ultimately determined necessary before the evidentiary hearings.

With respect to the MYP years beyond 2020, it is not currently clear what the impacts, if any, will be given the uncertainty regarding how and when Maryland's recovery from the pandemic will occur. It is important to note, though, that in the event the actual annual revenue requirement for the MYP period turns out to be significantly

[9] On April 9, 2020, the Commission issued Order No. 89542 in Case No. 9639 authorizing Maryland utilities to track incremental COVID-19 costs, as well as any assistance or benefits received that would offset COVID-19 related expenses, in a regulatory asset. Therefore, COVID-19 impacts will be tracked and recorded in the regulatory asset.

lower than what is approved in rates as a result of this proceeding, customers are protected by the MYP model the Commission has created as put forth in Order No. 89482 and discussed in the testimony of Company Witness Case.

Q. HAS THE COMPANY INCURRED ANY INCREMENTAL COSTS ASSOCIATED WITH THE COVID-19 PANDEMIC?

A. In accordance with Order No. 89542 in Case No. 9639, the Company has established a regulatory asset to record any incremental impacts related to the COVID-19 pandemic. Pursuant to the Commission's order, the Company will track and record all incremental costs associated with ensuring the safety of our employees, contractors, vendors, and the public. Examples of costs that will be recorded in the regulatory asset include enhanced cleaning services and supplies, masks and other protective equipment, screening and testing of employees, contractors, and vendors, as well as late payment fees and reconnection fees being waived. Through March 2020, the Company has incurred approximately $1.5 million of incremental impacts related to the COVID-19 pandemic, including $0.6 million for protective equipment, cleaning services, etc., to ensure the safety of our employees, $0.7 million for avoided late payment fees, and $0.2 million for avoided service application charges and reconnection fees. This amount is expected to grow over the course of 2020 and possibly into the MYP period depending on the duration of the pandemic. We expect the Company will also incur higher uncollectible costs given the suspension of terminations of service for nonpayment and reconnection of previously terminated accounts. However, these costs are at this time difficult to estimate.

Q. WHY ARE INCREMENTAL UNCOLLECTIBLES DIFFICULT TO ESTIMATE AT THIS TIME?

A. As noted above, the total amount of these costs is difficult to estimate simply because we do not know the duration of the pandemic and the related economic ramifications. Other costs, such as the incremental uncollectible expense, are even more difficult to estimate due to the time it will take for the write-offs to be incurred once normal collection practices can resume. BGE's policy is that customer accounts generally move to an "uncollectible" status seven months after the account is closed through the voluntary or involuntary stoppage of distribution service.[10] When an account is deemed uncollectible, the outstanding balance is written off. At the time of this filing, the Company has announced that it will not terminate service for non-payment through at least July 1, 2020, for residential and qualifying business customers. Once normal collection activities resume, the Company will be in a better position to begin estimating the level and timing of uncollectible write-offs. Once the pandemic-related uncollectible write-offs begin, the Company proposes to calculate the level of incremental pandemic-related write-offs by comparing the level of monthly write-offs at that point in time to the monthly uncollectible write-offs included in the historic test year from BGE's last rate case, Case No. 9610.

Q. ARE THERE ANY OTHER INCREMENTAL COVID-19 COSTS THE COMPANY IS PROPOSING TO ESTIMATE?

A. Yes. The Company is proposing to estimate the level of avoided late payment fees and service application and reconnection fees in the same manner as incremental uncollectible expense. As the Company is not assessing these fees in its billing system, these amounts are not known in the system of record. Thus, I propose to calculate these

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[10] The accounts will not become uncollectible at this time, however, if there are any pending service orders, the account has a credit or deposit available, or a payment has been made on the account within the prior two months.

avoided fees based on the monthly level of these items that were included in the historic test year of the Company's last rate case, Case No. 9610.

Q. IS THE COMPANY REQUESTING RECOVERY OF ANY INCREMENTAL IMPACTS ASSOCIATED WITH THE COVID-19 PANDEMIC IN THIS MYP?

A. For purposes of this filing, I have included Operating Income Adjustment 41 and Rate Base Adjustment 17 to provide the framework for recovery of incremental COVID-19 costs in this proceeding. At the time of this filing, since the extent of the impacts resulting from the pandemic is unclear, the amount included in these adjustments is zero. The Company's intent is to continue to track all of its COVID-19 related incremental costs and it will update the adjustments at the time of the evidentiary hearings once the Company gains a better understanding of the level and timing of COVID-19 incremental costs. BGE respectfully requests that the Commission find the methodology for calculating incremental impacts described above as appropriate and eligible for inclusion in the COVID-19 regulatory asset. Operating Income Adjustment 41 provides for recovery of COVID-19 incremental costs over a five-year period beginning in 2023. The COVID-19 incremental costs will be updated at the time of the evidentiary hearings.

V. BUDGETING PROCESS

Q. HOW IS BGE'S BUDGET DEVELOPED?

A. The budget includes forward-looking financial data for five years to meet the Company's operational plans for providing safe and reliable service and achieving high levels of customer satisfaction, in the most cost-effective manner possible. O&M costs as well as capital expenditures are developed to achieve both operational and compliance objectives. The budgets for 2021, 2022, and 2023 are outlined and supported within the Direct Testimonies of Company Witnesses Apte, Biagiotti, Burton and Olivier, as well as later in my testimony. As detailed in these testimonies and accompanying exhibits, the Company's expenditures are budgeted at a project level. Project expenditures are comprised of budgeted amounts in various states of maturity – ranging from projects that will begin construction in the near term to initial budgets for projects that do not yet have a detailed design and will not begin field construction until later in the five-year budget. The more than 300 projects shown in the exhibits of the Company witnesses mentioned above are aggregated into categories that span across the organization, which are assigned to category managers and executive ownership ensuring appropriate rigor and governance. [11]

Q. WHAT IS A CATEGORY IN RELATION TO CAPITAL AND O&M BUDGETS AND SPENDING?

A. A category is a grouping of similar projects that is managed by a Category Manager to ensure work and spending targets are met and that the work is executed efficiently and effectively. The Category Manager is responsible for identifying the needed work and funding needs, approving the projects that make up the category and ensuring that the projects are executed as planned. For example, I am an Executive Category Owner (as are Company Witnesses Apte, Biagiotti, Burton, and Olivier) and in this role, Executive Category Owners ensure that the Category Managers are executing the category spend as expected.

[11] Category view includes both direct and indirect costs to support the work being done within each category. Examples of indirect costs include supervision, workload management, dispatch, fleet, etc. that support the enterprise.

Q. CAN YOU PROVIDE MORE HIGH-LEVEL DETAILS ABOUT HOW THE PROCESS WORKS?

A. Certainly. Electric distribution, as sponsored by Company Witness Biagiotti, and gas distribution, as sponsored by Company Witness Burton, both have Corrective Maintenance and Preventative Maintenance O&M categories as detailed in their respective testimonies. These categories provide valuable insights into the BGE planning process.

For example, electric distribution personnel will develop the work plan to perform required system inspections as part of the Preventative Maintenance category, e.g. pole inspections. In the case of distribution pole inspections, distribution personnel know the yearly volume of required inspections, resources and costs associated with the inspections. This work and cost, along with all the other preventative maintenance activities in the budget, are reviewed and eventually approved by the Executive Category Owner. Furthermore, preventative maintenance efforts will generate Corrective Maintenance Category activities based on the defects identified during their inspections. Using distribution pole inspections again, distribution personnel can reasonably estimate the level of corrective work, resources, and cost associated with remediating identified issues using historical trends. This corrective work and cost, along with all the other corrective maintenance activities in the budget, are reviewed and eventually approved by the Executive Category Owner. Lastly, capital investments will also influence Preventative and Corrective Maintenance Categories as aging and obsolete system assets are replaced with modern assets.

BGE's gas distribution personnel would follow a similar process in relation to their Preventative and Corrective Maintenance work plans. For example, the process for determining the Preventative and Corrective Maintenance budgets for leak surveys would be nearly identical for the process described above for pole inspections.

These are just some examples of how the planning process works across the Company. In general, the planning process is not an isolated activity by category but rather a complex interrelated activity that reflects the impacts of inspections, repairs, and asset replacements. Ultimately, the Company relies on Category Managers and Executive Category Managers to review and approve these plans.

Q. WHAT ABOUT NON-CAPITAL AND NON-O&M BUDGETS SUCH AS FOR REVENUES, TAXES, AND OTHER OPERATING INCOME AND RATE BASE ITEMS?

A. In addition to the details in the Direct Testimonies of Company Witnesses Apte, Biagiotti, Burton and Olivier, BGE is providing detailed support and descriptions of budget information for other operating income and rate base line items that can be found in the various filing requirements, as well as later in my testimony, as I walk through the revenue requirement exhibits and each line item of operating income and rate base. This includes both an explanation of the approach utilized to budget the items as well as the final output from the budgeting process.

Q. AT A HIGH LEVEL, WHO HAS GOVERNANCE OVER THE BUDGET?

A. The budget is constructed and reviewed by both BGE and Exelon executive leadership members, who provide final oversight prior to being presented to the company boards. The final budget is reviewed and approved by both the BGE Board of Directors as well as the Exelon Board of Directors.

VI. CAPITAL STRUCTURE AND RATE OF RETURN

Q. WHAT CAPITAL STRUCTURE AND RATES OF RETURN DOES BGE RECOMMEND BE UTILIZED IN THIS PROCEEDING?

A. I have prepared a chart below that shows the Company's proposed capital structure for each MYP year, as well as the calculation of the rate of return for each period. BGE requests overall rates of return for both electric and gas operations of 7.12% for the MYP periods of 2021, 2022, and 2023, based on the Company's projected embedded cost of debt for each year as well as a 10.1% return on equity for both electric and gas. Although the Company is proposing a rate of return based on the budgeted embedded cost of debt, the projected cost of debt in the budget did not change enough year to year to impact the overall rate of return. The capital structure and return on equity are the same for each of projected rates of return.

Chart 3 – Proposed Capital Structures and Electric and Gas Rates of Return

MYP-2021	Capital Structure	Embedded Cost Rates	Weighted Cost
Long-term debt	48.0%	3.89%	1.87%
Common equity	52.0%	10.10%	5.25%
	100.0%		7.12%
MYP-2022			
Long-term debt	48.0%	3.90%	1.87%
Common equity	52.0%	10.10%	5.25%
	100.0%		7.12%
MYP-2023			
Long-term debt	48.0%	3.89%	1.87%
Common equity	52.0%	10.10%	5.25%
	100.0%		7.12%

Q. WHAT IS THE BASIS OF THE CAPITAL STRUCTURES REFLECTED IN THE CHART ABOVE?

A. As I explained in Part 1 of my Direct Testimony, the proposed equity percentage of 52% for the Bridge Period and MYP years is consistent with the capital structure underlying rates of return approved in prior proceedings, and also aligns with other utilities in the Company's peer group as noted in the Direct Testimony of Company Witness McKenzie. Furthermore, the 52% proposed equity percentage is consistent with the 2019 Historic Test Year ("HTY") provided in Part 1 of my Direct Testimony, which was 52.8%. The BGE MYP equity percentage budget for each of the MYP years is developed to target a year-end equity percentage of 52%.[12]

Q. DOES THE CAPITAL STRUCTURE REFLECT ANY NEW DEBT ISSUANCES?

A. Yes. Chart 4 below provides the debt issuances in the budget during the MYP period including the year of issuance, rate, and amounts for each new issuance.

Chart 4 – Projected Debt Issuances[13]

Month	Rate		Amount
Projected 2020 Issuance	3.450%	$	300,000,000
Projected 2021 Issuance	3.450%	$	500,000,000
Projected 2022 Issuance	3.500%	$	500,000,000
Projected 2023 Issuance	3.550%	$	600,000,000

Q. HOW DO YOU EVALUATE THE NEED FOR NEW DEBT ISSUANCES IN THE BUDGET?

A. In the Company's budget, long-term debt is issued when BGE's budgeted temporary short-term debt balances, inclusive of impacts from long-term debt retirements, begin to approach two-thirds of BGE's existing credit facility. The projected balance of BGE's long-term debt is net of debt retirements that have reached their maturity date.[14]

Q. WHAT IS THE BASIS OF THE COST OF LONG-TERM DEBT?

A. The projected embedded cost of debt for each of the MYP years as well as the Bridge Period represents the overall cost for all debt projected to be outstanding at the end of

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12 Equity infusions are also expected to allow the Company to maintain the equity percentage of 52%.
13 The Company is currently contemplating changes to the 2020 debt financings and will update the parties once any transactions are final.
14 The embedded cost of debt calculation also reflects the maturity of $850 million in long-term debt during 2021 through 2023.

each period, including any new debt issuances planned for each of those periods. The interest rates that are applied to the debt issuance balances are projected based on the 2019 year-end 30-year Treasury forward curve, plus an adder of 99 basis points based on indicative pricing for companies rated comparably to BGE obtained from multiple banks at the time the budget was prepared.

Q. WHAT IS THE BASIS OF THE ROE?

A. As I mentioned earlier, in Part 1 of my Direct Testimony, I proposed a 10.25% return on equity for each of the MYP years based on the 9.9% return on equity recommended by Company Witness McKenzie, adjusted upwards for a performance adder of 35 basis points to align with the midpoint of the upper end of Company Witness McKenzie's recommended ROE cost of equity range to reflect BGE's excellent performance and customer satisfaction results. However, in light of the COVID-19 pandemic, I am now lowering the performance adder to 20 basis points, and thus the proposed ROE to 10.1%, which is still within Company Witness McKenzie's recommended cost of equity range. Although BGE still believes it is appropriate that historical performance should positively impact the return on equity authorized by the Commission, the Company is lowering its recommended ROE to 10.1% in recognition of the COVID-19 pandemic.

Q. WILL THE COMPANY UPDATE THE CAPITAL STRUCTURE AND RATE OF RETURN DURING THE COURSE OF THE PROCEEDING?

A. No. The Commission's Order No. 89482 in Case No. 9618 requires that the ROE and capital structure be set for the duration of the MYP period. Therefore, the Company is not proposing to update the ROE, rate of return or capital structure in this proceeding including in the Annual Informational Filings or during the Reconciliation process.

VII. PROPOSED MAJOR OUTAGE EVENT RESTORATION EXPENSE REGULATORY ASSET TREATMENT

Q. HOW DOES THE COMPANY CURRENTLY RECOVER INCREMENTAL MAJOR OUTAGE EVENT RESTORATION EXPENSES?

A. Current Commission-authorized treatment for BGE's restoration expense related to major outage events, as defined by COMAR 20.50.01.03, provides for a five-year average of major outage event restoration expense to be built into rates to serve as a proxy for major outage event restoration expense in the rate-effective period.

Q. WHAT SPECIFIC REGULATORY TREATMENT IS THE COMPANY REQUESTING FOR INCREMENTAL MAJOR OUTAGE EVENT RESTORATION EXPENSES IN THIS PROCEEDING?

A. The Company is requesting that it be allowed to establish a regulatory asset for actual incremental major outage event restoration expenses incurred in the future, with recovery over a five-year period. In this way, customers would not pay for actual incremental major outage event restoration expenses until after they are incurred, reviewed in a proceeding, and approved to be included in rates by the Commission.

Q. WHAT LEVEL OF INCREMENTAL MAJOR OUTAGE EVENT RESTORATION EXPENSES ARE INCLUDED IN THIS MYP FILING?

A. As I mentioned earlier in my testimony, the budgeted unadjusted operating income for the MYP years of 2021-2023, as reflected in my exhibits, includes $10.2 million of incremental major outage event restoration expense in each MYP year based on the current five-year average. I have included Operating Income Adjustment 37 which removes the annual $10.2 million included in the budget to mitigate the impact of the COVID-19 pandemic.

Q. WHY ARE YOU REQUESTING THIS CHANGE IN RATEMAKING TREATMENT?

A. As I mentioned above, one reason we are requesting this change is due to the impacts of the pandemic and our objective to avoid an increase in base distribution revenues until 2023 in an effort to support the Central Maryland economy. The other reason is that major outage event restoration expenses can be significant and unpredictable, in both amount and timing. Under the current methodology, the five-year average amount is inadequate to cover significant major outage event restoration expense resulting from a storm such as a hurricane. This change in ratemaking treatment would more appropriately align recovery of incremental costs related to major outage events with the actual incremental costs to restore service to customers as a result of those storms. In addition, this change would more closely align with the regulatory treatment for major outage event restoration expense authorized for two other Maryland utilities.[15]

VIII. <u>SUMMARY OF COMPANY REVENUE REQUIREMENT EXHIBITS</u>

Q. HAVE YOU PREPARED ANY REVENUE REQUIREMENT EXHIBITS AND SUPPORTING SCHEDULES, MR. VAHOS?

A. Yes. I have prepared six exhibits numbered as Company Exhibit DMV-2 and Company Exhibits DMV-3-Updated through DMV-7-Updated. In the exhibits filed with

[15] *Re Potomac Electric Power Co.*, Case No. 9311, Order No. 85724 at 38 (Md. PSC, July 12, 2013); *Re Potomac Electric Power Co.*, Case No. 9336, Order No. 86441 at 33 and 37 (Md. PSC, July 2, 2014); *Re Potomac Electric Power Co.*, Case No. 9418, Order No. 87884 at 57-58 (Md. PSC, Nov. 16, 2016); and *Re Delmarva Power & Light Co.*, Case No. 9455, Order No. 88567 at 11 (Md. PSC, Feb. 9, 2018).

testimony in previous base rate cases, the information for BGE's electric and gas requests was shown in the same exhibit. In this proceeding, the information for electric and gas is shown separately and the exhibits and proforma adjustments are titled with an "E" to indicate electric and a "G" to indicate gas.[16] As I mentioned in Part 1 of my Direct Testimony, the exhibits included in this Part 2 of my Direct Testimony are now being updated with budgeted amounts as well as additional proforma adjustments for 2020 (the Bridge Period), and the MYP years (2021-2023). The exhibits provided in this filing include:

Company Exhibit DMV-2 presents the calculations of the electric and gas distribution base rate relief sought by the Company in this proceeding for each MYP year.

Company Exhibit DMV-3-Updated shows the derivation of electric and gas distribution rate base and operating income on an unadjusted and adjusted basis for the HTY, the Bridge Period and each MYP year. This schedule also includes the capital structure and targeted rate of return, the unadjusted and adjusted electric and gas distribution returns based on the foregoing amounts, and a revenue requirement summary for each period.

Company Exhibit DMV-3-1 supports the total unadjusted O&M amounts included in Exhibit DMV-3 described above. It provides a reconciliation from the exhibits supported in the Direct Testimonies of Company Witnesses Apte, Biagiotti, Burton and Olivier, as well as Company Exhibit DMV-8 discussed later within my

[16] Exhibits were prepared in a manner consistent with the formats agreed to by the Case No. 9618 Working Group.

testimony, to the total O&M included in unadjusted operating income on Company Exhibit DMV-3-Updated, line 19, for each of the years.

Company Exhibit DMV-4-Updated presents a reconciliation from unadjusted electric and gas distribution rate base, operating income and revenue requirement to the adjusted electric and gas distribution rate base, operating income and the revenue requirement for the HTY, the Bridge Period, and each MYP year. This schedule includes a listing of the Company's adjustments to electric and gas distribution operating income and rate base for each period, as well as the revenue requirement effect of each. Proforma adjustments are being presented to reflect Commission precedent for all periods as well as the impact of Case No. 9610 for the 2019 HTY as discussed in Part 1 of my Direct Testimony.[17] Separate schedules detailing the computation of proforma adjustments are also provided.

Company Exhibit DMV-5-Updated presents the calculation of cash working capital included in electric and gas distribution unadjusted rate base for the HTY, the Bridge Period, and the MYP years based on the current lag days.

Company Exhibit DMV-6-Updated quantifies the impact of the updated net lag days resulting from the 2019 lag study on cash working capital included in electric and gas distribution rate base for the HTY, the Bridge Period, and the MYP years.

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[17] In December 2019 in Order No. 89400 in Case No. 9610, the Commission granted the Joint Motion of parties in that proceeding for approval of a Stipulation and Settlement Agreement providing for new base rates and associated increases in electric and gas base distribution revenues, among other things. The 2019 HTY revenues have been adjusted to reflect the level of distribution revenues that would have been recognized by BGE if the new base rates from Case No. 9610 had been effective for all of 2019. Therefore, the Company is also making certain adjustments to the 2019 HTY in order to approximate the level of expenses and rate base which would have been reflected if the base rates from Case No. 9610 had been in effect for the entirety of 2019 as well.

Company Exhibit DMV-7-Updated presents a summary of the updated net lag days based on the 2019 lag study which was previously presented in Part 1 of my Direct Testimony.[18]

Q. WHAT PERIOD IS THE MYP COVERING, MR. VAHOS?

A. The Company's request for rate relief in this MYP is based on adjusted budgeted electric and gas distribution operating income and adjusted budgeted electric and gas distribution rate base for each of the MYP years 2021, 2022, and 2023. In addition, I have included columns and related amounts on each of my exhibits for the actual 2019 HTY as well as 2020, the Bridge Period.

Q. PLEASE EXPLAIN WHY THE HTY OF 2019 AND THE BRIDGE PERIOD OF 2020 ARE BEING PROVIDED AS PART OF THE MYP FILING.

A. As required by the Commission's Order 89428 in Case No. 9618, the HTY based on 2019 results (the most recently available actual information) and the Bridge Period of 2020, which have been adjusted pursuant to known Commission-approved adjustments, are being provided for comparison purposes only. The HTY serves as the basis to begin evaluating the Company's budgets and projections upon which the revenue requirements requested are based. The Bridge Period is designed to provide linkage between the HTY and the first year of budgeted rates (2021 in our case). These periods help provide more transparency with respect to the Company's planning process.

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[18] Company Exhibit DMV-7-Updated was revised to include an additional line for Combined Income Tax lag for both federal and state income taxes.

A. COMPANY EXHIBIT DMV-2

Q. PLEASE DESCRIBE COMPANY EXHIBIT DMV-2 –MULTI-YEARPLAN REVENUE REQUIREMENT.

A. Company Exhibit DMV-2, entitled "Multi-Year Plan Revenue Requirement," shows the step-by-step determination of the base rate revenues the Company is requesting in this proceeding for each of the MYP years 2021 – 2023.

I will now take the opportunity to describe the step-by-step calculation. First, the Company's required income (line 3) is calculated by multiplying the adjusted rate base (line 1) for each of the MYP years by the rate of return (line 2) supported in the Direct Testimony of Company Witness McKenzie and in Parts 1 and 2 of my Direct Testimony. Second, I compare the amount on line 3 to the adjusted operating income for each period (line 4), which results in an operating income deficiency (line 5).[19] Third, this deficiency is "grossed up" for the additional taxes that will be paid as a result of the increased revenues and uncollectible factor, a practice consistent with Commission precedent (line 6).[20] Line 7 reflects the cumulative additional revenues needed to provide the Company an opportunity to earn the proposed rate of return for each period on the Company's adjusted average distribution rate base after recovering all prudently incurred costs and all applicable taxes. Line 8 presents the additional revenues needed for each year of the MYP.

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[19] Adjusted Rate Base as presented on line 1 of Company Exhibits DMV-2E and DMV-2G is calculated on Company Exhibits DMV-3E and DMV-3G (line 11). Adjusted Operating Income as presented on line 4 of Company Exhibits DMV-2E and DMV-2G is calculated on Company Exhibits DMV-3E and DMV-3G (line 28).

[20] Case Nos. 9036, 9230, 9299, 9326, 9406 and 9484.

B. <u>COMPANY EXHIBIT DMV-3-UPDATED</u>

Q. PLEASE DESCRIBE COMPANY EXHIBIT DMV-3-UPDATED – RATE BASE AND OPERATING INCOME SUMMARY.

A. Company Exhibit DMV-3-Updated, entitled "Rate Base and Operating Income Summary" shows the Company's electric and gas average rate base, operating income, and returns for each of the periods – 2019 HTY, the 2020 Bridge Period, and the MYP years of 2021–2023. These schedules also include the budgeted capital structure, as well as a revenue requirement summary for each period. As explained earlier in my testimony, the revenue requirement provided for the 2019 HTY and the 2020 Bridge Period represents a revenue requirement that is being presented for informational purposes in order to provide a point of comparison to the MYP years' revenue requirements. Please refer to Part 1 of my Direct Testimony at pages 8-11 for a detailed description for Company Exhibit DMV-3.

Q. WHAT IS THE BASIS FOR EACH BUDGETED RATE BASE LINE – BEGINNING WITH EXHIBIT DMV-3-UPDATED, LINE 2 - ELECTRIC AND GAS PLANT?

A. Plant includes plant in service, construction work in progress and property held for future use. Plant in Service represents historical capital projects actually in service at the beginning of the MYP year, increased by budgeted capital spend for investments projected to go into service during the budget period, net of projected asset retirements. Construction work in progress ("CWIP") consists of costs accumulated in projects that have yet to be placed into service. In other words, the beginning CWIP balance plus budgeted capital spend less the transfer of accumulated CWIP to plant in service for assets that are projected to be placed in service comprises the CWIP budget. The total capital spend for each period is supported by the Direct Testimonies of Company Witnesses Apte, Biagiotti, Burton and Olivier as well as in Section X of Part 2 of my Direct Testimony. Property held for future use ("PHFU") includes certain investments, generally land, that are not expected to be used and useful for a number of years but for which the Company has an implementation plan, consistent with Federal Energy Regulatory Commission ("FERC") accounting rules. The projection of PHFU is based on the 2019 HTY balance and is held flat over the Bridge Period and three MYP years.

Q. WHAT IS THE BASIS FOR THE BUDGETED RATE BASE AMOUNTS FOR EXHIBIT DMV-3-UPDATED, LINE 3 - ACCUMULATED DEPRECIATION AND AMORTIZATION?

A. Accumulated Depreciation represents the cumulative amount of depreciation, retirements, gross salvage value and cost of removal. In this case, the beginning balance is based on December 2019 actual results and future estimates reflected increases for additional projects placed into service, including cost of removal, net of retirements.

Q. WHAT IS THE BASIS FOR THE BUDGETED RATE BASE AMOUNTS FOR EXHIBIT DMV-3-UPDATED, LINE 4 - MATERIALS AND SUPPLIES?

A. The materials and supplies category consists of fuel stock inventory and equipment, such as transformers cables, etc. A growth rate of 2.5% is applied to the historical materials and supplies amount to build the budget.

Q. WHAT IS THE BASIS FOR THE BUDGETED RATE BASE AMOUNTS FOR EXHIBIT DMV-3-UPDATED, LINE 5 - CASH WORKING CAPITAL?

A. As discussed in Part 1 of my Direct Testimony, at pages 18 – 19, and later in this Part 2, cash working capital is the average amount of funds required to bridge the gap between the time expenditures are made to provide services and the time revenues are received for those services. In setting rates for public utilities, an allowance for cash working capital is an element of rate base. This line item is supported by Company Exhibit DMV-5-Updated.

Q. WHAT IS THE BASIS FOR THE BUDGETED RATE BASE AMOUNTS FOR EXHIBIT DMV-3-UPDATED, LINE 6 - ACCUMULATED DEFERRED INCOME TAXES?

A. Accumulated Deferred Income Taxes ("ADIT") represents the cumulative deferred income taxes resulting from temporary income tax differences between income tax reporting and Generally Accepted Accounting Principles ("GAAP") reporting. The projected ADIT is based on the historical ADIT balance plus the budgeted deferred income taxes.

Q. WHAT IS THE BASIS FOR THE BUDGETED RATE BASE AMOUNTS FOR EXHIBIT DMV-3-UPDATED, LINE 7 - PREPAID PENSION/OPEB LIABILITY?

A. The pension and OPEB balance included in rate base represents the cumulative difference between cash funding and actuarially determined cost.[21] The projected level of this balance during the MYP period is determined by updating the most recent actual balance with anticipated levels of funding and actuarially determined cost.

[21] OPEB stands for Other Post-Employment Benefits.

Q. WHAT IS THE BASIS FOR THE BUDGETED RATE BASE AMOUNTS FOR EXHIBIT DMV-3-UPDATED, LINE 8 - CUSTOMER ADVANCES AND DEPOSITS?

A. Customer advances represent the funds the Company has received in advance of providing a service to the customer. Customer deposits represent the amount of collateral required from a customer based on their credit worthiness. The customer deposits included in the budget period are based on historical accounts receivable and historical deposits with customer advances in the budget period held flat to historical amounts.

Q. WHAT IS THE BASIS FOR THE BUDGETED RATE BASE AMOUNTS FOR EXHIBIT DMV-3-UPDATED, LINE 9 - REGULATORY ASSETS AND LIABILITIES?

A. Regulatory assets and regulatory liabilities refer to specific amounts that the Commission has permitted BGE to defer to its balance sheet and subsequently amortize over a set period of time. BGE budgets regulatory assets and liability deferrals to the extent the deferrals are authorized based on Commission precedent and applies the existing approved amortization periods for budget purposes.

Q. WHAT IS THE BASIS FOR EACH BUDGETED OPERATING INCOME LINE FOR THE PROJECTED PERIODS – BEGINNING WITH EXHIBIT DMV-3-UPDATED, LINE 14 - OPERATING REVENUES FROM SALE OF ELECTRICITY AND SALE OF GAS?

A. The electricity and gas operating revenues included within the budget are categorized as follows:

- Decoupled Base Distribution Revenues – Decoupled base distribution revenues are budgeted and calculated by using budgeted customer counts based on econometric modeling multiplied by the currently authorized distribution customer tariff rates for each applicable rate class. Within these decoupled distribution revenues, customer growth is the only driver of the changes in revenue. Decoupled base distribution revenues represent about 80% of the total electric and gas distribution revenues.
- Non-Decoupled Base Distribution Revenues – Non-Decoupled base distribution revenues are budgeted and calculated using budgeted billing determinants based on econometric modeling multiplied by currently authorized distribution customer tariff rates for each applicable rate class. Energy sales budgets are weather normalized and adjusted for the estimated impacts of energy efficiency, solar and electric vehicle adoption. Non-Decoupled base distribution revenues represent about 5% of the total electric and gas distribution revenues.

Q. DO THE BUDGETED REVENUES FROM THE SALE OF GAS INCLUDE STRIDE REVENUES?

A. Yes. STRIDE surcharge revenues and capital investments are reflected in a manner similar to prior base rate cases, in that the Company includes the surcharge revenues and the capital investments in operating income and rate base, respectively. In this MYP, the 2021-2023 budget underlying the MYP revenue requirement calculations includes budgeted STRIDE surcharge revenues, rate base, and related expenses such as depreciation and property taxes. Given the direction regarding the STRIDE surcharge in Order No. 89482, the budgeted STRIDE surcharge revenues included in the MYP revenue requirement calculations reflect the expectation that the STRIDE surcharge will be at the statutory cap starting in 2022 and will remain at the cap until the Company's next base rate case is adjudicated and new base rates from that future base rate case are effective. As described in the Direct Testimony of Company Witness Fiery, the Company is proposing that the STRIDE surcharge be reset concurrent with new base rates becoming effective in January 2021. Therefore, the 2021 MYP year revenue requirement reflects STRIDE surcharge revenues assuming a one-time reset for STRIDE investments for the period October 2019 through December 2020, consistent with §4-210 of the Public Utilities Article of the Maryland Annotated Code and prior Commission decisions in Case Nos. 9355, 9406, 9484 and 9610, where the Commission authorized the transfer and recovery of actual STRIDE investments into base rates.

Q. WHAT IS THE BASIS FOR THE BUDGETED AMOUNTS FOR EXHIBIT DMV-3-UPDATED, LINE 15 - OTHER REVENUES?

A. Other revenues are budgeted using historical revenue amounts. Other revenues include late payment revenues, service application fees, etc., and represent about 15% of the total electric and gas distribution revenues.

Q. WHAT IS THE BASIS FOR THE BUDGETED AMOUNTS FOR EXHIBIT DMV-3E-UPDATED, LINE 18 - ELECTRIC NET METERING COSTS?

A. Net Metering costs represent the annual settlement amount for net metering customers who have generated an amount of energy for the year over and above their actual consumption. Net Metering costs are budgeted based on historical net metering credit amounts provided to customers for energy generation plus a growth rate that is based on net metering customer applications and the subsequent completion rate of these applications.

Q. WHAT IS THE BASIS FOR THE BUDGETED AMOUNTS FOR EXHIBIT DMV-3G-UPDATED, LINE 18 - GAS CHOICE AND RELIABILITY COSTS?

A. The Gas Choice and Reliability Cost ("GCRC") Rider provides a cost recovery mechanism for capacity costs associated with gas system load growth and Provider of Last Resort obligations. GCRC revenues are budgeted by multiplying currently approved GCRC rates by budgeted customer sales volumes. GCRC costs are budgeted to match associated revenues so that there is no impact on gas distribution service operating income.

Q. WHAT IS THE BASIS FOR THE BUDGETED AMOUNTS FOR EXHIBIT DMV-3-UPDATED, LINE 19 - OPERATIONS AND MAINTENANCE COSTS?

A. As I described above in Section V about the Budgeting Process, the Company's O&M expenses are budgeted at the category level and are supported partially by my testimony in Section X about spending in the Non-Operational Category and by Company Witnesses Apte, Biagiotti, Burton, and Olivier in their Direct Testimonies. Company Exhibit DMV-3-1 provides a reconciliation from all witnesses' Direct Testimonies to the total unadjusted O&M included in Company Exhibit DMV-3-Updated, line 19. I discuss Exhibit DMV-3-1 in more detail later in my testimony.

Q. WHAT IS THE BASIS FOR THE BUDGETED AMOUNTS FOR EXHIBIT DMV-3-UPDATED, LINE 20 - DEPRECIATION AND AMORTIZATION?

A. BGE depreciation and amortization expense ("D&A") includes the depreciation and amortization of plant in service as well as regulatory assets and liabilities.[22] The budgeted depreciation is based on Commission-approved depreciation rates applied to all assets that have already been placed in service, new assets that are budgeted to be placed into service, as well as budgeted asset retirements.[23] D&A for existing plant in service at the beginning of the MYP period represents approximately 70% of the total D&A expense.

Q. WHAT IS THE BASIS FOR THE BUDGETED AMOUNTS FOR EXHIBIT DMV-3-UPDATED, LINE 21 - OTHER TAXES?

A. Other Taxes include property taxes, payroll taxes, revenue taxes and various other jurisdictional specific taxes. The budget for these taxes is calculated using actual historical trends as well as by applying the current authorized tax rates to the budgeted basis (i.e. property taxes apply an 8% growth rate based on average historical growth to property tax assessment amounts). Property taxes represent about 60% of the total other tax expense.

Q. WHAT IS THE BASIS FOR THE BUDGETED AMOUNTS FOR EXHIBIT DMV-3-UPDATED, LINE 22 – CURRENT INCOME TAXES?

A. This line represents total projected income taxes – including both current and deferred income taxes – for purposes of the projected periods.[24] For budget purposes, a simplified method is used to calculate income tax expense for income statement

[22] Amortization is calculated by taking the value of the intangible asset, regulatory asset or liability and dividing it by the amortization period.
[23] Depreciation expense reflects updated depreciation rates in accordance with the Case No. 9610 Stipulation and Settlement Agreement. It is not anticipated that these rates will change during the MYP period.
[24] In the HTY and the Company's accounting records, current and deferred income taxes are tracked and reported separately.

purposes by multiplying pretax income by the combined statutory income tax rate of 27.5175%. This initial income tax subtotal is reduced for excess deferred tax amortization and amortization of the MASM.

Q. WHAT IS THE BASIS FOR THE BUDGETED AMOUNTS FOR EXHIBIT DMV-3-UPDATED, LINE 26 – ALLOWANCE FOR FUNDS USED DURING CONSTRUCTION?

A. Allowance for Funds Used During Construction ("AFC") is a Maryland regulated utility accounting practice whereby the costs of debt and equity funds used to finance plant construction are credited on the income statement and charged to applicable construction in progress on the balance sheet. The rates utilized in the AFC calculation included in unadjusted operating income are based on the authorized rates of return available at the time of the budget process.[25] These rates are applied to budgeted capital spend eligible for AFC.

Q. WHAT IS THE BASIS FOR THE BUDGETED AMOUNTS FOR EXHIBIT DMV-3-UPDATED, LINE 27 – INTEREST ON CUSTOMER DEPOSITS?

A. The budgeted interest on customer deposits is calculated using the annual Commission determined rate (1.66% in 2020) and applied to the budgeted average customer deposits in each future year.

Q. ARE THERE ANY NOTEWORTHY AMOUNTS THAT ARE NOT REFLECTED IN ADJUSTED OPERATING INCOME AND RATE BASE AS PRESENTED IN THIS FILING?

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[25] During the MYP period, BGE will accrue AFC using the authorized rate of return from this proceeding, consistent with prior practice.

A. Yes. Consistent with the 2019 HTY amounts as discussed in Part 1 of my Direct Testimony at page 10, electric transmission revenues, expenses, and rate base are appropriately excluded from this filing, including the projected periods, as they are FERC jurisdictional. Additionally, revenues and expenses associated with electric commodity revenues and expenses recovered through the Standard Offer Service ("SOS") charges, including SOS bad debt costs, are excluded from this filing. Furthermore, the portion of electric distribution bad debt expense associated with changes in the Accounts Receivable reserve is excluded from this filing.

Likewise, the majority of gas commodity revenues and expenses are also appropriately excluded from this filing as these revenues and expenses are recovered through the gas commodity cost recovery mechanism set forth in Rider 2 of BGE's Retail Gas Service Tariff. However, similar to what was described for the 2019 HTY in Part 1 of my Direct Testimony at page 11, certain other gas commodity costs, namely bad debt, credit & collection costs, the return on gas storage, and the return on commodity-related cash working capital, are included in this filing, but are ultimately recovered through Rider 12, the Gas Administrative Charge ("GAC"), with a corresponding reduction to gas base rates via Rider 8.[26] Regarding both gas distribution and gas commodity-related bad debt expense, the portion associated with changes in the Accounts Receivable reserve is excluded from this filing for all periods.

Q. ARE THERE ANY AMOUNTS FROM THE COMPANY'S BUDGETS THAT ARE NOT REFLECTED IN THE MYP?

[26] *See* the Direct Testimony of Company Witness Fiery for how the GAC will work in the context of an MYP.

A. Yes. The Company's budgets are designed to reflect how actual performance will be reported for external financial reporting purposes (i.e. investor view). Consequently, some items that are required to be recorded for GAAP purposes as O&M (i.e. charitable giving, industry association dues, etc.) that are treated as below the line for ratemaking are reflected in BGE's budgets that support the Company's MYP. Therefore, the Company is excluding these costs for ratemaking purposes in the MYP, as explained in Section VIII.C below which addresses Company Exhibit DMV-3-1. Over the MYP period, when actual results are reported in the Annual Informational Filings and during the Reconciliation process, no exclusion will be needed as these costs are appropriately recorded in below the line FERC accounts when they occur.[27]

C. <u>COMPANY EXHIBIT DMV-3-1</u>

Q. PLEASE DESCRIBE COMPANY EXHIBIT DMV-3-1 – RECONCILIATION OF WITNESS-SPONSORED O&M TO UNADJUSTED O&M PER EXHIBIT DMV-3 BY MYP YEAR.

A. Company Exhibit DMV-3-1 provides a reconciliation of the O&M spend sponsored by Company Witnesses Apte, Biagiotti, Burton, and Olivier in their Direct Testimonies and by my testimony about Non-Operational Category spending in Section X below, to the total unadjusted distribution O&M included in cost of service as reflected on Company Exhibit DMV-3-Updated, line 19. The first section presents the total O&M spend sponsored by Company Witnesses Apte, Biagiotti, Burton, and Olivier. This

[27] Items that are recorded for GAAP purposes as O&M, but are treated as below the line for ratemaking, are reflected in the 2020-2023 Plan Documentation exhibits provided with the Direct Testimony of Company Witnesses Apte, Biagiotti, Burton and Olivier, as well as Part 2 of my Direct Testimony, and then adjusted out for ratemaking purposes in Exhibit DMV-3-1 in the Below the line/Other row.

amount consists of the direct electric distribution, direct gas distribution, and total common spending.[28] These amounts exclude direct transmission O&M, electric commodity O&M, and the portion of distribution uncollectible expense associated with changes in the Accounts Receivable reserve. The second section shows a line of business view of the sponsored spend (i.e. direct electric distribution, direct gas distribution, total common, and below the line/other). As I mentioned earlier in my testimony, the below the line items reflect amounts that are required to be recorded for GAAP purposes as O&M (i.e. charitable contributions) but are excluded or treated as below the line for ratemaking purposes. The last section, the reconciliation to Exhibit DMV-3, shows the adjustments necessary to arrive at the O&M amounts reflected on Company Exhibit DMV-3-Updated. These include the removal of the transmission portion of the total common O&M amounts sponsored by the various witnesses which has been excluded from both electric and gas distribution, as well as the GAAP O&M amounts that are excluded for ratemaking purposes.

D. <u>COMPANY EXHIBIT DMV-4-UPDATED</u>

Q. PLEASE DESCRIBE COMPANY EXHIBIT DMV-4-UPDATED – MYP REVENUE REQUIREMENT (UNADJUSTED AND ADJUSTED) SUMMARY BY YEAR.

A. Company Exhibit DMV-4-Updated, entitled "MYP Revenue Requirement (Unadjusted and Adjusted) Summary by Year," reconciles the unadjusted rate base, operating income (net of tax) and revenue requirement amounts for the HTY, the Bridge Period,

[28] Common costs support the business as a whole and, therefore, benefit all lines of businesses indirectly. Common costs are generally allocated to the various lines of businesses based on the A&G and T&D Allocation factors.

and MYP periods, carried forward from Company Exhibit DMV-3-Updated, to the adjusted amounts as per Company Exhibit DMV-3-Updated. As I mentioned in Part 1 of my Direct Testimony, this exhibit lists the various operating income and rate base adjustments applied to unadjusted operating income and rate base to arrive at the respective adjusted amounts and revenue requirement amounts for each period. Each of the adjustments is shown net of income tax effects, where appropriate, at the prevailing 27.5175% statutory tax rate, and a revenue requirement impact for each adjustment is also shown. I have also included supporting schedules (numbered to correspond to the schedule reference noted on this exhibit) showing the computation for each adjustment listed on Company Exhibit DMV-4-Updated.

Q. PLEASE WALK THROUGH THE RATEMAKING ADJUSTMENTS INCLUDED ON COMPANY EXHIBIT DMV-4-UPDATED.

A. The first group of adjustments (Operating Income Adjustments 1 - 23 and Rate Base Adjustments 1 - 8) relate exclusively to the 2019 HTY period and are discussed in detail in Part 1 of my Direct Testimony at pages 12-15. The second group (Operating Income Adjustments 24-42 and Rate Base Adjustments 9-17) impact the projected MYP periods and may also impact the HTY period as well. I will now walk through this second set of adjustments – the adjustments impacting the MYP years.

Q. PLEASE DESCRIBE <u>OPERATING INCOME ADJUSTMENT 24-UPDATED</u> IN COMPANY EXHIBIT DMV-4-UPDATED.

A. As noted in Part 1 of my Direct Testimony, Operating Income Adjustment 24-Updated eliminates from electric and gas operating income for each period certain advertising expenses recorded as operating expenses, in accordance with the FERC Uniform System of Accounts, that BGE is not allowed to recover pursuant to COMAR

20.07.04.08. These expenses represent institutional and promotional advertising expenses. All charitable contributions, penalties, and lobbying costs, including the lobbying expense portion of the Edison Electric Institute and American Gas Association dues, are treated as below the line for ratemaking purposes and are removed from the revenue requirement in Company Exhibit DMV-3-1.[29] Therefore, it is not necessary to include these costs in this operating income adjustment. This schedule, which was provided in Part 1 of my Direct Testimony, has been updated to reflect amounts for the Bridge Period and MYP years.

Q. CAN YOU PLEASE DISCUSS <u>OPERATING INCOME ADJUSTMENT 25-UPDATED</u> IN COMPANY EXHIBIT DMV-4-UPDATED?

A. Operating Income Adjustment 25-Updated eliminates certain employee activity costs as directed by the Commission in Case No. 9299, Order No. 85374. This schedule, which was provided in Part 1 of my Direct Testimony, has been updated to reflect amounts for the Bridge Period and MYP years.

Q. CAN YOU PLEASE DISCUSS <u>OPERATING INCOME ADJUSTMENT 26-UPDATED</u> IN COMPANY EXHIBIT DMV-4-UPDATED?

A. Operating Income Adjustment 26-Updated eliminates 100% of the costs of the Supplemental Executive Retirement Program as required in Case No. 9484, Order No. 88975. This schedule, which was provided in Part 1 of my Direct Testimony, has been updated to reflect amounts for the Bridge Period and MYP years.

Q. CAN YOU PLEASE DISCUSS <u>OPERATING INCOME ADJUSTMENT 27-UPDATED</u> IN COMPANY EXHIBIT DMV-4-UPDATED?

[29] Reflected in Company Exhibit DMV-3-1 in the line described as Below the line/Other.

A. Operating Income Adjustment 27-Updated removes the non-recoverable amount of incentive compensation consistent with Case No. 9326, Order No. 86060. This schedule, which was provided in Part 1 of my Direct Testimony, has been updated to reflect amounts for the Bridge Period and MYP years.

Q. CAN YOU PLEASE DISCUSS <u>OPERATING INCOME ADJUSTMENT 28-UPDATED</u> IN COMPANY EXHIBIT DMV-4-UPDATED?

A. Operating Income Adjustment 28-Updated adjusts operating income for the annualized amount of AFC included in unadjusted operating income to reflect a level that is consistent with the rates of return calculated for each period. This schedule, which was provided in Part 1 of my Direct Testimony, has been updated to reflect amounts for the Bridge Period and MYP years.

Q. CAN YOU PLEASE DISCUSS <u>OPERATING INCOME ADJUSTMENT 29-UPDATED</u> AND <u>RATE BASE ADJUSTMENT 9-UPDATED</u> IN COMPANY EXHIBIT DMV-4-UPDATED?

A. Operating Income Adjustment 29-Updated and Rate Base Adjustment 9-Updated relate to the costs incurred by the Company associated with capitalized software changes to BGE's billing system that are necessary to allow for accelerated customer switching between third-party suppliers and BGE commodity service, as required by the COMAR revisions adopted in Rulemaking 54 ("RM54"). In Case No. 9484, Order No. 88975, the Commission accepted the Company's proposal to recover the gas RM54 costs through the supplier liability fund consistent with Order No. 88432.[30] With respect to operating income, BGE in this proceeding is removing RM54 costs in the Bridge Period

[30] Case No. 9484, Order No. 88975 at 90.

and the first year of the MYP (2021) since these expenses are budgeted as distribution expenses in these years but will ultimately be recovered through the supplier liability fund. MYP years 2022 and 2023 do not include an adjustment since the RM54 software will be fully amortized at the end of 2021. In addition, as I explained in Part 1 of my Direct Testimony, these costs are not being recorded as distribution expenses in the HTY, so there is no need for a related operating income adjustment for the 2019 HTY.

With respect to rate base for the RM54 spend, Rate Base Adjustment 9, the companion adjustment to Operating Income Adjustment 29, reduces electric distribution and gas distribution rate base to remove the RM54 capital software costs in the HTY, the Bridge Period, and each of the MYP years. RM54 capital is reflected in rate base as common plant and is allocated to electric and gas distribution in each period. Since this software is currently being recovered through the supplier liability fund, it is necessary to eliminate RM54 capital from rate base.

Q. CAN YOU PLEASE DISCUSS <u>OPERATING INCOME ADJUSTMENT 30</u> IN COMPANY EXHIBIT DMV-4-UPDATED?

A. Operating Income Adjustment 30 reduces operating income to reflect the amortization of rate case expenses associated with Case No. 9610, but incurred after the test year in that proceeding, as well as rate case expenses associated with the current proceeding. BGE proposes to amortize these rate case expenses over a three-year period, consistent with Commission precedent allowing for recovery of rate case expenses over a three-year period[31] and beginning with 2022, the second MYP rate-effective year as discussed earlier in my testimony.

[31] Case Nos. 9326, 9406, 9484, and 9610.

Q. IF THE COMPANY INCURS ADDITIONAL RATE CASE EXPENSES DURING THE MYP YEARS OF 2021-2023, HOW WILL THESE COSTS BE ACCOUNTED FOR?

A. While no additional recovery of rate case expenses is included in the MYP years of 2021-2023, the Company may certainly incur such costs. If these costs are incurred, they will be recorded as O&M expense and included in the Annual Informational Filings and during the Reconciliation process for the 2021-2023 MYP years as I discuss later in my testimony.

Q. CAN YOU PLEASE DISCUSS <u>OPERATING INCOME ADJUSTMENT 31</u> IN COMPANY EXHIBIT DMV-4-UPDATED?

A. Operating Income Adjustment 31 reduces gas operating income for recovery of the STRIDE audit fees for the 2020-2023 audit years. These STRIDE audit fees are not included in the projected gas operating income as they are budgeted in a regulatory asset in accordance with Commission Order No. 86147 in Case No. 9331. In light of the decision to defer 2021 amortization as discussed in Section III above, the Company is now seeking recovery of the 2020, 2021, and 2022 fees in the MYP 2022 period and the 2023 fees in the MYP 2023 period in this proceeding through gas base rates.[32]

Q. CAN YOU PLEASE DISCUSS <u>OPERATING INCOME ADJUSTMENT 32</u> AND <u>RATE BASE ADJUSTMENT 10</u> IN COMPANY EXHIBIT DMV-4-UPDATED?

A. Operating Income Adjustment 32 provides for the amortization of electric distribution Conservation Voltage Reduction ("CVR") program costs consistent with adjustments authorized in Case Nos. 9299, 9326, 9406, and 9610. This adjustment recovers the

[32] Case No. 9331, Order No. 86147 at 36, fn. 123.

amortization of the CVR costs incurred subsequent to July 2019 (the end of the test year in Case No. 9610) through December 2020 over a two-year period beginning in 2022 in light of the decision to defer 2021 amortization as discussed in Section III above. The Company is not seeking amortization of CVR spending subsequent to 2020 as will be discussed in Operating Income Adjustment 33. The adjustment in MYP years 2022 and 2023 only reflects amortization of deferred amounts through December 2020. Rate Base Adjustment 10 is the companion adjustment and reflects the impact on the CVR regulatory asset, and therefore on rate base, of the additional amortization provided in this proceeding.

Q. CAN YOU PLEASE DISCUSS <u>OPERATING INCOME ADJUSTMENT 33</u> AND <u>RATE BASE ADJUSTMENT 11</u> IN COMPANY EXHIBIT DMV-4-UPDATED?

A. Operating Income Adjustment 33 reduces electric operating income to reflect the Company's proposed termination of regulatory asset treatment for CVR costs effective with 2021 spending. As I just mentioned above, Operating Income Adjustment 32 provides for the amortization of CVR spending through calendar year 2020. With the adoption of an MYP, a two-year amortization no longer serves the originally intended purpose. Therefore, effective in 2021, the Company is proposing that CVR spending no longer be deferred in a regulatory asset but instead be flowed through to operating expense similar to other expenses. For purposes of the budget, CVR spending is reflected in a regulatory asset and not as an operating expense. Therefore, in order to reflect the termination of regulatory asset treatment for CVR costs effective with calendar year 2021, Operating Income Adjustment 33 adds the budgeted CVR spending to O&M expenses, with a corresponding reduction to rate base proposed in Rate Base Adjustment 11 for all three MYP years (2021–2023).

Q. CAN YOU PLEASE DISCUSS <u>OPERATING INCOME ADJUSTMENT 34</u> AND <u>RATE BASE ADJUSTMENT 12</u> IN COMPANY EXHIBIT DMV-4-UPDATED?

A. Operating Income Adjustment 34 reduces gas operating income to reflect the amortization of a new tranche of Riverside environmental costs consistent with Case No. 9484, Order No. 88975. In Case No. 9484, the Commission authorized the Company to amortize its actual costs over ten years.[33] This adjustment recovers the amortization of the third tranche of Riverside environmental costs incurred subsequent to July 2019 (the end of the test year in Case No. 9610) through December 2020 over a ten-year period beginning in MYP 2022. There are no new Riverside environmental costs reflected in the MYP years. In the event that there is any additional spend related to Riverside environmental costs, it will be deferred in a regulatory asset and included in the Annual Informational Filings and during the Reconciliation process for the 2021-2023 MYP years. Rate Base Adjustment 12 is the companion adjustment and reflects the rate base impact of the additional Riverside amortization provided in this proceeding.

Q. PLEASE DESCRIBE <u>OPERATING INCOME ADJUSTMENT 35</u> IN COMPANY EXHIBIT DMV-4-UPDATED.

A. Operating Income Adjustment 35 provides for the recovery of certain Gas Meter Relocation and Protection Program costs that were deferred in a regulatory asset pursuant to Order No. 88975 issued in Case No. 9484.[34] Consistent with Order No. 88975, BGE seeks to move those costs into rates. This adjustment seeks recovery for

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[33] Case No. 9484, Order No. 88975 at 37.
[34] *Id.* at 45. BGE created the regulatory asset and has included program costs incurred subsequent to July 2018 for O&M and subsequent to October 2018 for depreciation.

the prudently incurred but deferred program costs through December 2020, at which time the program will be substantially complete.

The Commission noted in Order No. 88975 that the Gas Meter Relocation and Protection Program is a safety program that the Commission's Engineering Division agrees is appropriate.[35] Therefore, the Commission allowed recovery of all program costs that had been incurred by the Company at that time.[36] Since the Commission's decision allowing full cost recovery for costs incurred, the Company has effectively completed the program. Customers have benefited from the relocation and protection of gas meters in that meters are now less susceptible to damaging vehicle strikes, are more accessible to first responders or Company personnel in emergency situations when the gas supply must be turned off quickly, and are placed in a completely ventilated area (outside) so that in the event of a gas leak, natural gas will dissipate fully into the atmosphere. BGE customers and the public in general are now safer thanks to the work completed within the Gas Meter Relocation and Protection Program. For all of these reasons, the Company is seeking recovery of all deferred program costs in MYP Year 2022.

Q. PLEASE DESCRIBE <u>OPERATING INCOME ADJUSTMENT 36</u> AND <u>RATE BASE ADJUSTMENT 13</u> IN COMPANY EXHIBIT DMV-4-UPDATED.

A. Operating Income Adjustment 36 and Rate Base Adjustment 13 provide for the recovery of Electric Vehicle ("EV") costs. In Order No. 88997 in Case No. 9478, the Commission directed utilities to seek cost recovery of EV program costs in a future rate

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[35] *Id.* at 44.
[36] *Id.*

case proceeding.[37] In its order, the Commission also directed the utilities to provide a cost-effectiveness assessment.[38] At this time, the Company is implementing a cost-effective EV program, as demonstrated by Company Witness Warner in his Direct Testimony and also discussed by Company Witness Case. Operating Income Adjustment 36 provides for the amortization of the EV regulatory asset as of the end of each MYP year beginning in 2022 over a five-year period as approved by the Commission in Order No. 88997. Rate Base Adjustment 13 is the companion adjustment.

Q. PLEASE DESCRIBE <u>OPERATING INCOME ADJUSTMENT 37</u> IN COMPANY EXHIBIT DMV-4-UPDATED.

A. As discussed earlier in my testimony, Operating Income Adjustment 37 removes the $10.2 million of major outage event restoration expense included in the budget in each MYP year in an effort to mitigate the impact of the COVID-19 pandemic. The removal of these costs will help keep base distribution revenues lower than they otherwise would have been for customers.

Q. PLEASE DESCRIBE <u>OPERATING INCOME ADJUSTMENT 38</u> AND <u>RATE BASE ADJUSTMENT 14</u> IN COMPANY EXHIBIT DMV-4-UPDATED.

A. Operating Income Adjustment 38 provides customers with certain accelerated tax benefits associated with the TCJA excess deferred regulatory liability and the MASM regulatory liability over the MYP period, faster than the periods approved in prior proceedings, as discussed earlier in my testimony. Rate Base Adjustment 14 is the companion adjustment.

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37 Case No. 9478, Order No. 88997 at 77.
38 *Id.* at 44, fn. 170.

Q. PLEASE DESCRIBE <u>OPERATING INCOME ADJUSTMENT 39</u> AND <u>RATE BASE ADJUSTMENT 15</u> IN COMPANY EXHIBIT DMV-4-UPDATED.

A. As discussed in Section III earlier in my testimony, Operating Income Adjustment 39 reflects the suspension of the amortization in 2021 of all existing base distribution regulatory assets. The elimination of 2021 amortization amounts will keep base distribution revenues in this MYP lower than they otherwise would have been for customers. Rate Base Adjustment 15 is the companion adjustment.

Q. PLEASE DESCRIBE <u>OPERATING INCOME ADJUSTMENT 40</u> AND <u>RATE BASE ADJUSTMENT 16</u> IN COMPANY EXHIBIT DMV-4-UPDATED.

A. As discussed in Section III earlier in my testimony, Operating Income Adjustment 40 reflects the extension of the Smart Grid Regulatory Asset amortization period through 2031, an additional five years. Rate Base Adjustment 16 is the companion adjustment.

Q. PLEASE DESCRIBE <u>OPERATING INCOME ADJUSTMENT 41</u> AND <u>RATE BASE ADJUSTMENT 17</u> IN COMPANY EXHIBIT DMV-4-UPDATED.

A. As discussed in Section IV earlier in my testimony, Operating Income Adjustment 41 and Rate Base Adjustment 17 provide the framework for the recovery of incremental COVID-19 costs over a five-year period beginning in 2023. While I have not included any costs in this Direct Testimony filing, these adjustments will be updated at the time of the evidentiary hearings.

Q. PLEASE DESCRIBE <u>OPERATING INCOME ADJUSTMENT 42</u> IN COMPANY EXHIBIT DMV-4-UPDATED.

A. In accordance with prior Commission orders, Operating Income Adjustment 39 (which was formerly numbered as Operating Income Adjustment 29 in Part 1 of my Direct

Testimony) increases operating income (and decreases the revenue requirement) to reflect the income tax effect of proforma interest.[39] This adjustment was developed to provide for the fact that, under the Commission's well-established regulatory practice, interest expense is treated as a "below the line" item for purposes of setting distribution base rates. At the same time, the income tax benefit associated with interest expense, which reduces cost of service, is appropriately treated as an "above the line" item and as such is legitimately included in the determination of cost of service. To the extent that the Company's budgeted interest expense and the implicit amount of interest expense approved by the Commission in establishing the Company's authorized rate of return is different, the Commission has required the Company to "synchronize" the tax savings associated with this difference by adjusting the Company's tax expense in the manner reflected by this adjustment. This adjustment is included for all MYP years, as well as the HTY and the Bridge Period for comparison purposes.

Q. PLEASE EXPLAIN THE BASIS OF THE BUDGETED INTEREST EXPENSE.

A. The budgeted interest expense for the projected periods (i.e. the Bridge Period and MYP years) is based on the existing amount of long-term debt that BGE currently has outstanding and any projected new issuances and the application of each issuance's budgeted interest rate.

E. <u>CASH WORKING CAPITAL</u>

Q. MR. VAHOS, WILL YOU PLEASE EXPLAIN CASH WORKING CAPITAL ("CWC")?

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[39] *Re Baltimore Gas and Electric Co.,* 78 Md. PSC 129 (1987); *Re Baltimore Gas and Electric Co.,* 80 Md. PSC 380 (1989); *Re Baltimore Gas and Electric Co.,* 80 Md. PSC 496 (1989); *Re Baltimore Gas and Electric Co.,* 96 Md. PSC 334 (2005); and *Re Baltimore Gas and Electric Co.,* 102 Md. PSC 74 (2011).

A. Certainly. As I explained in Part 1 of my Direct Testimony at page 18, in the regulated energy business, CWC is a component of rate base that represents the amount of cash a firm must obtain from its investors in order to provide the funds necessary to operate the business on a day-to-day basis. The method for determining CWC that is widely used throughout the regulated energy industry is known as a "Lead/Lag" Study. Please refer to Part 1 of my Direct Testimony at pages 19–20 for detailed explanation of what is involved with conducting a Lead/Lag Study.

Q. WHICH LEAD/LAG STUDY IS BEING USED FOR THE MYP YEARS?

A. As I mentioned in Part 1 of my Direct Testimony at page 20, the Company updated its lead/lag study based on calendar year 2019 revenues and expenses, which is reflected in the projected Bridge Period and MYP years cash working capital calculations. This resulted in an approximately $30 million decrease ($20 million and $10 million for electric and gas, respectively, for each year) to rate base as calculated on Company Exhibit DMV-6-Updated, line 18, for each period and carried forward to Company Exhibit DMV-4-Updated, line 43.

Q. COULD YOU NOW PLEASE DISCUSS YOUR EXHIBIT WHICH SETS FORTH THE DETAILS OF THE CASH WORKING CAPITAL ADJUSTMENT CALCULATIONS?

A. Similar to the exhibits described in Part 1 of my Direct Testimony at pages 20-21, Company Exhibits DMV-5-Updated through DMV-7-Updated develop the total amount of CWC applicable for the HTY, the Bridge Period and the MYP years. Company Exhibits DMV-5-Updated through DMV-7-Updated have been updated for the Bridge Period and MYP years.

Company Exhibits DMV-5-Updated through DMV-7-Updated, are organized as follows:

- Company Exhibit DMV-5-Updated summarizes the calculation of the CWC requirement reflected in unadjusted rate base for each period. This calculation is based on the current lag days as determined by the 2014 lead lag study.
- Company Exhibit DMV-6-Updated calculates the impact of the change in the lag days on cash working capital. This exhibit summarizes the calculation of the CWC requirement for each period based on the updated lead lag days as reflected in the 2019 lead lag study.
- Company Exhibit DMV-7-Updated summarizes the lag days for revenue and the various expense categories based on the 2019 lead lag study.

F. COMPANY EXHIBIT DMV-5-UPDATED

Q. COULD YOU PLEASE REVIEW COMPANY EXHIBIT DMV-5-UPDATED WHICH SUMMARIZES THE CWC CALCULATION INCLUDED IN RATE BASE?

A. As I just mentioned, Company Exhibits DMV-5-Updated summarizes the calculation of the cash working capital requirement which is included in unadjusted rate base based on the current lag days per the 2014 lag study. Please refer to Part 1 of my Direct Testimony at pages 21-22 for a detailed explanation of this schedule.[40] This exhibit supports the Company's overall unadjusted cash working capital included in rate base on line 5 of Company Exhibit DMV-3-Updated for the HTY, the Bridge Period and each MYP year.

[40] For purposes of the cash working capital calculation for current taxes, a five-year historical average of current income taxes for the period 2015-2019 serves as a proxy for budgeted current income taxes for each projected period. This amount will be trued up for actual current taxes in the Annual Information Filings and during the Reconciliation process.

G. COMPANY EXHIBIT DMV-6-UPDATED

Q. COULD YOU PLEASE REVIEW COMPANY EXHIBIT DMV-6-UPDATED WHICH SUMMARIZES THE IMPACT ON CWC OF THE UPDATED LAG DAYS?

A. As discussed in Part 1 of my Direct Testimony, Company Exhibit DMV-6-Updated calculates the decrease on cash working capital (approximately $20 million for electric and $10 million for gas for each period) based on the change in lag days as a result of reflecting the 2019 lag study. Please refer to Part 1 of my Direct Testimony at pages 22-23 for a detailed explanation of this schedule.

H. COMPANY EXHIBIT DMV-7-UPDATED

Q. PLEASE DISCUSS THE REMAINING COMPANY EXHIBIT DMV-7-UPDATED.

A. Company Exhibit DMV-7 summarizes the results of the 2019 Lead/Lag Study, the most recently completed study. Please refer to Part 1 of my Direct Testimony at pages 23–24 for a detailed explanation of this schedule. The lag days summarized on this exhibit support the lag days utilized for purposes of Company Exhibit DMV-6-Updated.

IX. MYP RECONCILIATION

Q. HOW DO YOU PLAN TO COMPLY WITH THE ORDER NO. 89482 AS IT RELATES TO THE RECONCILIATION, MR. VAHOS?

A. In accordance with Commission's Order No. 89482, the reconciliation will be conducted in a three-step process as follows:

1) an annual informational filing;

2) a consolidated reconciliation review in a subsequent rate case; and

3) a final reconciliation review after the conclusion of the MYP period.

Q. PLEASE EXPLAIN THE FIRST STEP – THE ANNUAL INFORMATION FILING.

A. Within 90 days following the end of the first and second MYP years (2021 and 2022), the Company will provide an informational filing to compare actual adjusted calendar-year results to the budgeted adjusted calendar-year data included in the MYP (an "Annual Informational Filing"). In each Annual Informational Filing, the imbalance for the period would be calculated consistent with the MYP revenue requirement approved by the Commission in an order in this MYP proceeding. Rate base and operating income would use actual results from the applicable MYP period in calculating the actual revenue requirement to determine the imbalance. The specifics of each Annual Informational Filing will be open for discovery and review, and if a significant disparity between revenues and costs to the detriment of ratepayers is demonstrated, the Commission may determine that an adjustment would be appropriately included in the Riders proposed by Company Witness Fiery.[41] Extraordinary costs may also be considered by the Commission during the MYP and also in the context of the Annual Informational Filings, for instance in the case of any significant tax changes.

Q. PLEASE CONTINUE WITH THE NEXT STEP – THE CONSOLIDATED RECONCILIATION REVIEW.

[41] *See* electric Rider 16 and gas Rider 15 proposed in the Direct Testimony of Company Witness Fiery.

A. As required by Order No. 89482, BGE will file a new rate case at least 210 days prior to the end of the MYP period for rates effective immediately following this MYP (i.e. January 2024). This next rate case will include a review of investments and spending during 2021 and 2022. In addition, the new rate case filing will include a consolidated reconciliation of the actual data for calendar years 2021 and 2022.

Q. PLEASE CONTINUE WITH THE LAST STEP – THE FINAL RECONCILIATION REVIEW.

A. Within 120 days following the end of the MYP period, the Company will file a final reconciliation for any investments and costs in the last MYP year (calendar year 2023) not previously reviewed and reconciled. The Commission will then approve any adjustments and reconciliations. Once approved, all adjustments and reconciliations will be recovered through the Riders discussed in the Direct Testimony of Company Witness Fiery.

X. NON-OPERATIONAL CAPITAL AND O&M SPENDING

Q. WHAT IS THE PURPOSE OF THIS SECTION OF YOUR TESTIMONY?

A. As described earlier in my testimony, BGE develops its budget by investment category. I am supporting the levels of capital and O&M costs that BGE is requesting as part of its MYP for the non-operational categories of Information Technology ("IT"), Exelon Business Services Company ("BSC"), Fleet, Training, Real Estate and Facilities, and Other. My testimony discusses how these areas support BGE's electric and gas operations and provide overall benefits to customers.

Q. ARE YOU SPONSORING ANY EXHIBITS IN THIS SECTION OF YOUR TESTIMONY?

A. Yes. I am sponsoring Exhibit DMV-8. This exhibit provides details regarding the capital and O&M plans which this section of my testimony supports.

A. NON-OPERATIONAL CATEGORY OVERVIEW

Q. PLEASE PROVIDE A DESCRIPTION OF THE CATEGORIES YOU ARE SUPPORTING IN YOUR TESTIMONY.

A. The categories I am supporting are the non-operational departments in the Company as well as back-office support for BGE operations. I will be covering the capital and O&M costs included in the Company's MYP for the years 2021-2023 for the IT, BSC, Fleet, Training, Real Estate and Facilities, and Other responsibility areas. I have also included actual and projected capital and O&M costs for 2019 and 2020 for these categories for informational purposes only. In my testimony below, I will describe each of these areas in more detail:

- IT, which is a part of the BSC, delivers technological solutions to BGE that align with the company's overall business and strategic objectives and enhance the customer experience.
- BSC costs refer to the services provided to BGE by BSC, including functions where the BSC employees providing services to BGE are embedded within the utility. BSC costs include, but are not limited to, the following functions: Finance, Human Resources, Legal, Internal Audit, Treasury, Tax, Accounts Payable, Employee Benefits, and Information Security. Appendix H of BGE's Cost Allocation Manual ("CAM"), which was filed with the Commission on March 4, 2020, describes the various services provided by BSC to BGE as well

as the methodologies used to assign the costs of these services across the Exelon companies.[42]

- Fleet, Training, and Real Estate and Facilities are responsible for providing overall support to BGE related to vehicle maintenance, employee training, and the renovation and maintenance of workspaces.
- The Other category includes administrative costs that support the Company's operations, such as Safety and Wellness, Emergency Preparedness, and Environmental services. The category also includes non-operational departments including the CEO's Office, Marketing, Security, Strategy and Regulatory Affairs and Governmental and External Affairs.

B. CATEGORY DETAILS

Q. WHAT ARE THE PROJECTED CAPITAL COSTS FOR THESE AREAS FOR THE MYP PERIOD OF 2021-2023?

A. Total annual capital costs for these categories for the period 2021-2023 range from $174.6 million to $212.7 million. Table 1 below provides the capital details by year and Category.

Table 1

Category	Historical	Bridge	Multi-Year Plan Period		
	2019A	2020	2021	2022	2023
IT BU Projects	$135,945,141	$138,187,074	$83,629,401	$82,308,402	$81,814,318
BSC	$5,954,529	$3,292,470	$2,326,728	$2,274,076	$2,334,554
Fleet	$21,074,820	$29,075,000	$21,915,000	$20,615,000	$17,785,000
Real Estate and Facilities	$43,531,919	$81,052,489	$46,193,736	$42,736,611	$36,611,546
Training	$611,445	$1,496,900	$1,496,463	$1,496,770	$1,496,559
Other	$17,156,805	$51,346,897	$47,904,579	$63,309,048	$34,580,463
TOTAL	$224,274,659	$304,450,830	$203,465,907	$212,739,907	$174,622,440

[42] Mail Log #228935.

Q. WHAT IS DRIVING THE CAPITAL COST TRENDS IN THESE CATEGORIES OVER THE MYP PERIOD?

A. On average, budgeted total capital spending in the 2021-2023 time period is approximately 12% less than total spending in 2019, and 35% less than projected total spending in 2020. The overall trend within the MYP period is driven by decreases across the period in IT Business Unit ("BU") Projects, Real Estate and Facilities, and Fleet. The decrease in IT BU Projects and Real Estate and Facilities is primarily driven by the expected completion of certain large projects while the reduction in Fleet is driven by Fleet asset replacement rates.

Q. WHAT ARE THE PROJECTED O&M COSTS FOR THESE AREAS FOR 2021-2023?

A. Total O&M costs for these categories for the period 2021-2023 range from $352.4 million to $355.5 million. Table 2 below provides the O&M details by year and Category.

Table 2

Category	Historical	Bridge	Multi-Year Plan Period		
	2019A	2020	2021	2022	2023
IT BU Projects	$25,515,691	$36,207,710	$19,657,021	$19,535,399	$18,694,625
BSC	$159,888,955	$172,882,739	$172,165,403	$173,707,095	$176,089,299
Fleet	$591,838	$707,000	$707,000	$707,000	$707,000
Real Estate and Facilities	$20,548,383	$21,698,483	$21,716,349	$22,272,300	$22,903,681
Training	$26,034,421	$27,929,523	$26,650,959	$25,988,677	$25,386,069
Other	$98,716,948	$109,758,681	$111,538,238	$111,483,646	$111,692,952
TOTAL	$331,296,236	$369,184,136	$352,434,970	$353,694,117	$355,473,626

Q. WHAT IS DRIVING THE OVERALL O&M TRENDS IN THESE CATEGORIES?

A. Overall, O&M is increasing slightly across the non-operational categories for the 2021-2023 MYP period. The increase is driven by BSC, which is due to an increase in ongoing maintenance costs for IT systems.

Q. PLEASE DESCRIBE THE IT BU PROJECTS CATEGORY, INCLUDING THE TYPES OF PROJECTS IN THIS CATEGORY AND ANY KEY DRIVERS.

A. IT BU capital projects are investments the BGE organization identifies as a strategic or operational need. These investments enable business strategies including keeping existing platforms operational and secured and optimizing efficiency with common platforms across Exelon.

Examples of the BU Projects include projects to: replace or refresh aging assets; improve the customer experience; support the interconnection of Distributed Energy Resources assets; improve communications during storm events; and support regulatory initiatives.

IT BU Project O&M costs are the costs related to the IT O&M components of IT BU projects that are not eligible for capitalization.

Q. WHAT IS THE 2021-2023 PROJECTED SPEND FOR THE IT BU PROJECT CATEGORY?

A.

Category	Historical	Bridge	Multi-Year Plan Period		
	2019A	2020	2021	2022	2023
IT BU Project – Capital	$135,945,141	$138,187,074	$83,629,401	$82,308,402	$81,814,318
IT BU Project – O&M	$25,515,691	$36,207,710	$19,657,021	$19,535,399	$18,694,625

Q. WHAT ARE THE KEY CAPITAL IT BU PROJECTS IN THE 2021-2023 TIME PERIOD?

A. The Land Mobile Radio, the Core Geographic Information System program, the Mobile Mapping Solution for Mobile Dispatch (OneMDS), and the Advanced Distribution Management System Implementation project are all key projects needed to keep existing platforms operational and secured and optimize efficiency with common platforms across Exelon Utilities.

IT BU Project capital is at its peak in 2020 and is expected to return to a normalized level in the MYP period.

Q. DESCRIBE THE IT BU PROJECT O&M COSTS IN THE 2021-2023 TIME PERIOD.

A. IT BU Projects O&M costs are the costs related to the IT O&M components of specific utility projects that are not capitalized. The reduction in O&M costs for IT BU Projects from the Bridge Period to the MYP period is due a reduction from a peak level of investments during the Bridge Period.

Q. PLEASE DESCRIBE THE FLEET CATEGORY, INCLUDING THE TYPES OF PROJECTS IN THIS CATEGORY AND ANY KEY DRIVERS.

A. The fleet organization is responsible for the design, purchase, maintenance, repair, and preparation for disposal of fleet vehicles through sale or salvage. The capital expenditure portion of that work is primarily for purchase activities.

As of December 2019, the BGE fleet consists of approximately 870 light vehicles, 420 heavy vehicles and 550 units of equipment (tractors, trailers, others).

The Fleet O&M category funds a service using all electric buses from the BGE Spring Gardens campus to the BGE headquarters related to an employee shuttle program. Support costs for fleet vehicles, including maintenance and fuel costs, are allocated across the capital and O&M portfolio to the departments operating the vehicles.

Q. WHAT IS THE 2021-2023 PROJECTED SPEND FOR THE FLEET CATEGORY?

A.

Category	Historical	Bridge	Multi-Year Plan Period		
	2019A	2020	2021	2022	2023
Fleet – Capital	$21,074,820	$29,075,000	$21,915,000	$20,615,000	$17,785,000
Fleet – O&M	$591,838	$707,000	$707,000	$707,000	$707,000

Q. DESCRIBE THE FLEET CAPITAL COSTS IN THE 2021-2023 TIME PERIOD.

A. The scheduled life cycle for most fleet assets is approximately nine to ten years. Year-to-year asset replacements are based on asset age and condition. The trend in Fleet capital spending over the 2021-2023 time period reflects this refresh cycle. In addition, as demands in the electric and gas businesses change year to year, additional fleet assets may need to be purchased to support business needs. Lastly, BGE is planning to purchase electric vehicles for our fleet over the MYP period as current vehicles reach the end of their useful lives.

Q. DESCRIBE THE FLEET O&M COSTS IN THE 2021-2023 TIME PERIOD?

A. The Fleet O&M spend in 2021-2023 is flat over the MYP period.

Q. PLEASE DESCRIBE THE REAL ESTATE AND FACILITIES CATEGORY, INCLUDING THE TYPES OF PROJECTS IN THIS CATEGORY AND ANY KEY DRIVERS.

A. Real Estate and Facilities capital is primarily for construction activity on BGE facilities. These projects may be complete renovations or infrastructure upgrades.

Real Estate and Facilities O&M includes routine costs for day to day maintenance, repair and the administration of all of BGE's building facilities.

Q. WHAT IS THE 2021-2023 PROJECTED SPEND FOR THE REAL ESTATE AND FACILITIES CATEGORY?

A.

Category	Historical	Bridge	Multi-Year Plan Period		
	2019A	2020	2021	2022	2023
Real Estate and Facilities – Capital	$43,531,919	$81,052,489	$46,193,736	$42,736,611	$36,611,546
Real Estate and Facilities – O&M	$20,548,383	$21,698,483	$21,716,349	$22,272,300	$22,903,681

Q. DESCRIBE THE REAL ESTATE AND FACILITIES CAPITAL COSTS IN THE 2021-2023 TIME PERIOD?

A. The Facilities group performs two types of capital projects:

- Renovations of existing BGE buildings - In older BGE buildings, some refurbishment may be required to meet current building codes. In addition, employee workspaces need to be updated to increase productivity and make more efficient use of space. These projects include furniture, infrastructure, workspace improvements, IT and audiovisual facilities and other workplace improvements.
- Infrastructure projects – mechanical, electrical, plumbing, structural, and HVAC systems must be replaced and/or modernized to improve reliability and energy efficiency.

From 2021-2023 the completion of the Howard Service Center Rebuild in 2021 and a decrease in the renovation budget result in a steady decline in the Real Estate and Facilities capital expenditures over the period.

Q. DESCRIBE THE REAL ESTATE AND FACILITIES O&M COSTS IN THE 2021-2023 TIME PERIOD.

A. The largest spend in this category is routine and non-routine facilities repairs and maintenance. The workload for Real Estate and Facilities is expected to remain constant over the 2021-2023 time period, also consistent with the Bridge Period, so the budget is essentially flat with minor adjustments for inflation.

Q. PLEASE DESCRIBE THE TRAINING CATEGORY, INCLUDING THE TYPES OF PROJECTS IN THIS CATEGORY AND ANY KEY DRIVERS.

A. Utility training by the Training department ensures that the BGE workforce is qualified to safely perform the tasks needed to construct and maintain an efficient and reliable energy delivery distribution system by:

- Developing, delivering and administering craft and technical training for our gas and electric businesses.
- Providing standardized training, and qualification and re-qualification programs for our diverse and inclusive workforce which includes both employees and contractors.

Training for BGE craft organizations, electric and gas design personnel, and customer field personnel is performed or managed by the Training department. This training ensures that employees are trained to safely and effectively operate and maintain the gas and electric systems in accordance with BGE standards as well as standards established by the Occupational Safety and Health Administration, the Department of Transportation (DOT) including the Pipeline and Hazardous Materials Safety Administration, and the North American Electric Reliability Council.

In addition to this upfront craft training, the Training department also performs evaluations to verify performance in accordance with DOT and Commission standards (operator qualifications) of both BGE employees and contractors.

Q. WHAT IS THE 2021-2023 PROJECTED SPEND FOR THE TRAINING CATEGORY?

A.

Category	Historical	Bridge	Multi-Year Plan Period		
	2019A	2020	2021	2022	2023
Training – Capital	$611,445	$1,496,900	$1,496,463	$1,496,770	$1,496,559
Training – O&M	$26,034,421	$27,929,523	$26,650,959	$25,988,677	$25,386,069

Q. DESCRIBE THE CAPITAL TRAINING COSTS IN THE 2021-2023 TIME PERIOD.

A. Training is developing a library of technology-based virtual reality and augmented reality (VR and AR) training courses which is driving the capital training costs.

Q. DESCRIBE THE O&M TRAINING COSTS IN THE 2021-2023 TIME PERIOD.

A. The O&M cost trends in Training are primarily driven by Training department staffing and the volume of trainees each year (as employees charge their time during training to the Training category). Trainee volumes also vary year to year, and the overall reduction in spending is largely driven by reduced volume from training due to the expected staffing requirements over this period.

Q. PLEASE DESCRIBE THE OTHER CATEGORY, INCLUDING THE TYPES OF PROJECTS IN THIS CATEGORY AND ANY KEY DRIVERS.

A. The Other category includes administrative costs that support the Company's operations, such as Safety and Wellness, Emergency Preparedness, and Environmental services. Non-operational department costs also reside in this category, including the Chief Executive Officer's Office, Marketing, Strategy and Regulatory Affairs and Governmental/External Affairs. The Security budget is in this category as well, which is primarily responsible for keeping employees safe throughout the BGE territory. This includes on-site security as well as off-site, off-duty police personnel in the field.

Q. WHAT IS THE 2021-2023 PROJECTED SPEND FOR THE OTHER CATEGORY?

A.

Category	Historical	Bridge	Multi-Year Plan Period		
	2019A	2020	2021	2022	2023
Other – Capital	$17,156,805	$51,346,897	$47,904,579	$63,309,048	$34,580,463
Other – O&M	$98,716,948	$109,758,681	$111,538,238	$111,483,646	$111,692,952

Q. DESCRIBE THE OTHER CAPITAL COSTS IN THE 2021-2023 TIME PERIOD.

A. One of the largest projects in this category is for an Exelon Utilities Analytics Smart Energy Services ("SES") software upgrade. This $21 million project in 2022 is a continuation of the Smart Energy Services program that started in 2012. The program will continue to deliver the same benefits as the existing SES program.

The EV public charging infrastructure program described in the Direct Testimonies of Company Witnesses Case and Warner also resides in this category. The costs cover the purchase and installation of public charging stations across the BGE territory. The program began in 2019 and is projected to be completed in 2021.

Peak Rewards capital covers the purchase and installation of smart thermostats and is estimated at $13 million per year.[43]

Q. DESCRIBE THE OTHER O&M COSTS IN THE 2021-2023 TIME PERIOD.

A. Baltimore City Conduit Rental charges are the largest single cost within the O&M Other category at approximately $27 million per year. These costs cover BGE's portion of maintenance costs for Baltimore City's underground municipal conduit cable infrastructure system in order for BGE to utilize the system to provide safe, reliable and efficient electric service to customers. Total costs for Security are $7 million to $8 million per year and includes the contracted guard service as well as off-site, off-duty police personnel in the field. The marketing costs for 2021-2023 are primarily for educational communications.[44] Educational marketing includes advertising for BGE services and programs such as safety, budget billing, seasonal readiness and other BGE offerings. Channels that are used include direct mail, social media and email marketing. This spend is $6 million to $7 million per year. BGE's new Infrastructure Academy program is funded in this category, where BGE partners with contractors and various non-profit organizations to train "work ready" adults in the BGE territory and enable them to pursue construction careers locally. This spend is approximately $3 million per year. These expenses are treated as below the line for ratemaking purposes and are removed from the revenue requirement in Company Exhibit DMV-3-1.[45] The remaining dollars are primarily the labor for the remaining non-operational

[43] The budget underlying the MYP was finalized prior to the Commission's approval of BGE's Bring Your Own Device program at the end of 2019. These costs will be addressed in the EmPOWER Maryland surcharge and therefore do not impact distribution base rates.
[44] Through Operating Income Adjustment 24, institutional and promotional advertising expenses are removed as required under COMAR 20.07.04.08.
[45] Reflected in Company Exhibit DMV-3-1 in the line described as Below the line/Other.

departments, such as Strategy and Regulatory Affairs and Governmental and External Affairs.

Q. PLEASE DESCRIBE THE BSC CATEGORY, TYPES OF PROJECTS AND KEY DRIVERS.

A. BSC provides services to BGE pursuant to the General Services Agreement, which is provided as Appendix G of the Company's CAM. Certain BSC costs reside directly at BGE and are not allocated from BSC (BSC embedded). Examples of BSC embedded employees include embedded Finance, Controller, and Human Resource employees.

Q. WHAT IS THE 2021-2023 PROJECTED SPEND FOR THE BSC CATEGORY?

A.

Category	Historical	Bridge	Multi-Year Plan Period		
	2019A	2020	2021	2022	2023
BSC – Capital	$5,954,529	$3,292,470	$2,326,728	$2,274,076	$2,334,554
BSC – O&M	$159,888,955	$172,882,739	$172,165,403	$173,707,095	$176,089,299

Q. DESCRIBE THE CAPITAL BSC COSTS IN THE 2021-2023 TIME PERIOD.

A. BSC capital costs include Corporate projects, such as BSC Enterprise Wide IT projects.

Q. DESCRIBE THE O&M BSC COSTS IN THE 2021-2023 TIME PERIOD.

A. BSC O&M costs can be segregated into two main components – IT and Non-IT:

- IT provides standard IT baseline services to support Exelon's businesses. These services include End-User Support Services, IT Systems Operations Services, and IT Service Delivery.
- Non-IT functions include primarily Corporate and Information Security Services, Corporate Affairs, Corporate Development, Executive Services, Exelon Utilities, Human Resources, Legal, Real Estate, Risk, and Supply.

As noted earlier in my testimony, Appendix H of BGE's CAM describes the various services provided by BSC to BGE as well as the methodologies used to assign the costs of these services across Exelon.

XI. CONCLUSION

Q. DO YOU HAVE ANY CONCLUDING REMARKS, MR. VAHOS?

A. Yes. As supported in my testimony above, the Company is asking that the Commission grant BGE's request as shown earlier in Chart 1 on page 2 and repeated below for ease of reference, which results in no base distribution revenue increase in 2021 or 2022 in order to help customers. In 2023, the Company is requesting an increase of $235.3 million to reflect ongoing BGE investments and costs to serve customers safely and reliability. In order to avoid base distribution revenue increases until 2023 and in light of the current economic situation in which Maryland finds itself as a result of the COVID-19 pandemic, the Company is decreasing the performance adder component of its recommended ROE from Part 1 of my Direct Testimony and is proposing a series of proforma adjustments to remove major outage event restoration expenses included in base rates, accelerate certain tax benefits, suspend regulatory asset amortization in 2021, and extend the amortization periods of certain existing regulatory assets.

Chart 1 – Revenue Requirement Summary

MYP Revenue Requirement Summary
($ in Millions)

	MYP 2021	MYP 2022	MYP 2023
Electric:			
Cumulative Electric Incremental Revenue Requirement Before Benefits and Adjustments	$ 109.0	$ 156.1	$ 203.8
Total Benefits and Adjustments	(109.0)	(156.1)	(63.4)
Annual Electric Incremental Revenue Requirement Including Benefits and Adjustments	**$ -**	**$ -**	**$ 140.4**
Gas:			
Cumulative Gas Incremental Revenue Requirement Before Benefits and Adjustments	$ 65.9	$ 76.2	$ 109.7
Total Benefits and Adjustments	(65.9)	(76.2)	(14.8)
Annual Gas Incremental Revenue Requirement Including Benefits and Adjustments	**$ -**	**$ -**	**$ 94.9**
Total Revenue Impact on Customers Bills	**$ -**	**$ -**	**$ 235.3**

Q. ARE THERE ANY OTHER EXPLICIT APPROVALS WITH RESPECT TO THE REVENUE REQUIREMENT THAT YOU ARE REQUESTING THE COMMISSION PROVIDE TO THE COMPANY?

A. Yes. The Company respectfully requests the Commission's approval for the following:

1) A ROE of 10.1%, inclusive of the 20-basis point performance adder;

2) Acceleration of tax benefits associated with the 2017 TCJA excess deferred regulatory liability and the MASM regulatory liability, as provided in Operating Income Adjustment 38 and Rate Base Adjustment 14;

3) Regulatory asset treatment for incremental major outage event restoration expenses (i.e. major storm costs) to be recovered over a five-year period in order to address the impacts of the pandemic, as requested in Operating Income Adjustment 37;

4) Suspension or deferral of 2021 amortization associated with all base distribution regulatory assets as requested in Operating Income Adjustment 39 and Rate Base Adjustment 15;

5) Five-year extension for all Smart-Grid related regulatory assets as requested in Operating Income Adjustment 40 and Rate Base Adjustment 16;

6) Recovery of Electric Vehicle program costs over a five-year period as provided in Operating Income Adjustment 36 and Rate Base Adjustment 13;

7) Termination of CVR regulatory asset treatment effective 2021 as provided in Operating Income Adjustment 33 and Rate Base Adjustment 11;

8) Recovery of Gas Meter Relocation and Protection Program costs over a one-year period in MYP 2021 as provided in Operating Income Adjustment 35, and

9) Inclusion in a regulatory asset of the incremental impacts of COVID-19 such as enhanced cleaning services and supplies, masks and other protective equipment, screening and testing of employees, contractors, and vendors, as well as the waiver of late payment fees and service applications costs, and uncollectible write-offs, determined in the manner described in my testimony above, and recovery of such costs over a five-year period beginning in 2023.

Q. DOES THIS CONCLUDE YOUR DIRECT TESTIMONY?

A. Yes.

Company Exhibit DMV-2E

Baltimore Gas and Electric Company
Electric Distribution Multi-Year Plan (MYP) Revenue Requirement
For the Twelve Months Ended December 31,
(Thousands of Dollars)

Line	Description	Schedule Reference	MYP 1 2021	MYP 2 2022	MYP 3 2023
1	Rate Base	DMV-3E	$ 4,112,800	$ 4,434,657	$ 4,710,328
2	Rate of Return	DMV-3E	7.12%	7.12%	7.12%
3	Required Income		$ 292,831	$ 315,748	$ 335,375
4	Adjusted Operating Income	DMV-3E	$ 292,831	$ 315,748	$ 236,271
5	Operating Income Deficiency (Excess)		$ -	$ -	$ 99,104
6	Conversion Factor	See Below	1.41636	1.41636	1.41636
7	Revenue Requirement Deficiency (Excess) - Cumulative		$ -	$ -	$ 140,367
8	Revenue Requirement Deficiency (Excess) - Annual		$ -	$ -	$ 140,367

9	**Conversion Factor**	
10	Maryland State Income Tax	8.2500%
11	Federal Income Tax	21.0000%
12	Combined Income Tax Rate (SIT+(FITx(1-SIT))	27.5175%
13	Gross Receipts Tax	2.0000%
14	PSC Assessment Rate	0.2124%
15	Uncollectible Factor	0.3800%
16	Conversion Factor (1 /(1-Comb Tax)x(1-(GR+PSC+Uncoll))	1.41636
17	Conversion Factor % ((1-Comb Tax)x(1-(GR+PSC+Uncoll))	70.603%

Baltimore Gas and Electric Company

Electric Distribution Rate Base and Electric Distribution Operating Income Summary

Multi-Year Plan

(Thousands of Dollars)

Line No.	Description	HTY 2019 Unadjusted (1)	HTY 2019 Ratemaking Adjustments (2)	HTY 2019 Adjusted (3) = (1) + (2)	Bridge 2020 Unadjusted (4)	Bridge 2020 Ratemaking Adjustments (5)	Bridge 2020 Adjusted (6) = (4) + (5)	Bridge 2020 Adjusted Variance vs. Prior Year (7) = (6) - (3)
1	**Rate Base (Average Basis)**							
2	Electric Plant	$ 6,968,400	$ 131,151	$ 7,099,551	$ 7,424,318	$ (1,175)	$ 7,423,144	$ 323,593
3	Accumulated Depreciation and Amortization	(2,590,058)	(1,631)	(2,591,689)	(2,708,780)	853	(2,707,927)	(116,238)
4	Materials and Supplies	24,912	-	24,912	26,257	-	26,257	1,345
5	Cash Working Capital	30,444	(19,266)	11,178	30,148	(20,008)	10,140	(1,038)
6	Accumulated Deferred Income Taxes	(624,683)	(16,641)	(641,324)	(672,809)	89	(672,721)	(31,397)
7	Prepaid Pension/OPEB Liab.	41,396	-	41,396	41,406	-	41,406	10
8	Customer Advances & Deposits	(85,417)	-	(85,417)	(87,213)	-	(87,213)	(1,796)
9	Regulatory Assets & Liabilities	(282,842)	(3,842)	(286,684)	(255,495)	-	(255,495)	31,189
10	Other[1]	-	-	-	-	-	-	-
11	Total Rate Base	$ 3,482,152	$ 89,772	$ 3,571,924	$ 3,797,832	$ (20,241)	$ 3,777,590	$ 205,667
12	**Operating Income**							
13	Operating Revenues							
14	Sale of Electricity	$ 1,152,987	$ 16,471	$ 1,169,457	$ 1,185,952	$ -	$ 1,185,952	$ 16,495
15	Other Revenues	46,120	-	46,120	37,342	-	37,342	(8,778)
16	Operating Revenues	$ 1,199,107	$ 16,471	$ 1,215,577	$ 1,223,294	$ -	$ 1,223,294	$ 7,717
17	Operating Expenses							
18	Net Metering Costs	$ 1,491	$ -	$ 1,491	$ 1,517	$ -	$ 1,517	$ 26
19	Operation and Maintenance	433,864	11,851	445,715	459,332	(6,951)	452,381	6,666
20	Depreciation and Amortization	325,439	9,838	335,277	359,125	(235)	358,891	23,614
21	Other Taxes	168,253	3,470	171,722	168,606	-	168,606	(3,116)
22	Current Income Taxes	(4,481)	(447)	(4,928)	22,420	1,691	24,111	29,039
23	Deferred Income Taxes	37,364	(4,705)	32,659	-	-	-	(32,659)
24	Investment Tax Credit Adjustments	(40)	-	(40)	-	-	-	40
25	Total Operating Expenses	$ 961,889	$ 20,008	$ 981,897	$ 1,011,001	$ (5,495)	$ 1,005,506	$ 23,609
26	Allowance for Funds Used During Construction	12,398	49	12,447	12,989	241	13,231	784
27	Interest on Customer Deposits	(2,081)	-	(2,081)	(1,330)	-	(1,330)	751
28	Operating Income	$ 247,534	$ (3,488)	$ 244,046	$ 223,953	$ 5,736	$ 229,688	$ (14,358)
29	**Capital Structure**	Ratio	Cost	Wtd. Cost	Ratio	Cost	Wtd. Cost	
30	Long-Term Debt	47.2%	3.96%	1.87%	48.0%	3.91%	1.88%	
31	Common Equity	52.8%	10.25%	5.41%	52.0%	10.10%	5.25%	
32	Total	100.0%		7.28%	100.0%		7.13%	
33	**Rate of Return Summary**							
34	**Rate of Return**	**7.11%**		**6.83%**	**5.90%**		**6.08%**	
35	Less Weighted Cost of Long-Term Debt	1.87%		1.87%	1.88%		1.88%	
36	Net amount available for common equity	5.24%		4.96%	4.02%		4.20%	
37	Common Equity ratio	52.80%		52.80%	52.0%		52.0%	
38	**Return on Equity**	**9.92%**		**9.40%**	**7.72%**		**8.08%**	
39	**Revenue Requirement Summary**		For Informational Purposes Only			For Informational Purposes Only		
40	Rate Base			$ 3,571,924			$ 3,777,590	
41	Rate of Return			7.28%			7.13%	
42	Required Operating Income			260,036			269,342	
43	Proforma Operating Income			$ 244,046			$ 229,688	
44	Operating Income Deficiency			15,990			39,654	
45	Revenue Conversion Factor			1.41636			1.41636	
46	Rev. Rqmt. Deficiency (Excess)			22,648			56,164	
47	Total Adjusted Distribution Revenue Requirement							
48	Rev. Rqmt. Deficiency (Excess) - MRP Incremental $ by Year							
49	Total Distribution Revenues, Adjusted							

Line No.	Description	MYP 2021 Unadjusted (8)	MYP 2021 Ratemaking Adjustments (9)	MYP 2021 Adjusted (10) = (8) + (9)	MYP 2021 Adjusted Variance vs. Prior Year (11) = (10) - (6)	MYP 2022 Unadjusted (12)	MYP 2022 Ratemaking Adjustments (13)	MYP 2022 Adjusted (14) = (12) + (13)	MYP 2022 Adjusted Variance vs. Prior Year (15) = (14) - (10)
1	**Rate Base (Average Basis)**								
2	Electric Plant	$ 7,861,965	$ (1,170)	$ 7,860,794	$ 437,651	$ 8,281,844	$ -	$ 8,281,844	$ 421,050
3	Accumulated Depreciation and Amortization	(2,850,917)	1,084	(2,849,833)	(141,906)	(3,016,471)	-	(3,016,471)	(166,638)
4	Materials and Supplies	26,935	-	26,935	679	27,631	-	27,631	696
5	Cash Working Capital	32,100	(20,922)	11,178	1,038	34,457	(21,905)	12,552	1,373
6	Accumulated Deferred Income Taxes	(693,685)	(2,889)	(696,574)	(23,854)	(728,360)	(6,456)	(734,817)	(38,242)
7	Prepaid Pension/OPEB Liab.	50,753	-	50,753	9,347	52,965	-	52,965	2,212
8	Customer Advances & Deposits	(89,984)	-	(89,984)	(2,771)	(92,854)	-	(92,854)	(2,870)
9	Regulatory Assets & Liabilities	(234,128)	33,658	(200,470)	55,025	(214,608)	118,416	(96,192)	104,278
10	Other[1]	-	-	-	-	-	-	-	-
11	Total Rate Base	$ 4,103,039	$ 9,761	$ 4,112,800	$ 335,209	$ 4,344,603	$ 90,054	$ 4,434,657	$ 321,858
12	**Operating Income**								
13	Operating Revenues								
14	Sale of Electricity	$ 1,194,154	$ -	$ 1,194,154	$ 8,202	$ 1,203,547	$ -	$ 1,203,547	$ 9,393
15	Other Revenues	36,908	-	36,908	(434)	36,870	-	36,870	(38)
16	Operating Revenues	$ 1,231,062	$ -	$ 1,231,062	$ 7,768	$ 1,240,417	$ -	$ 1,240,417	$ 9,355
17	Operating Expenses								
18	Net Metering Costs	$ 1,668	$ -	$ 1,668	$ 151	$ 1,820	$ -	$ 1,820	$ 151
19	Operation and Maintenance	452,566	(17,768)	434,799	(17,582)	455,139	(13,101)	442,038	7,239
20	Depreciation and Amortization	380,617	(28,436)	352,181	(6,710)	398,767	(12,577)	386,190	34,010
21	Other Taxes	175,981	-	175,981	7,374	183,901	-	183,901	7,920
22	Current Income Taxes	16,981	(33,698)	(16,717)	(40,828)	10,357	(91,531)	(81,175)	(64,457)
23	Deferred Income Taxes	-	-	-	-	-	-	-	-
24	Investment Tax Credit Adjustments	-	-	-	-	-	-	-	-
25	Total Operating Expenses	$ 1,027,814	$ (79,902)	$ 947,911	$ (57,595)	$ 1,049,984	$ (117,209)	$ 932,775	$ (15,137)
26	Allowance for Funds Used During Construction	10,870	186	11,056	(2,174)	9,368	161	9,529	(1,527)
27	Interest on Customer Deposits	(1,376)		(1,376)	(46)	(1,424)		(1,424)	(48)
28	Operating Income	$ 212,743	$ 80,088	$ 292,831	$ 63,143	$ 198,378	$ 117,370	$ 315,748	$ 22,917
29	**Capital Structure**	Ratio	Cost	Wtd. Cost		Ratio	Cost	Wtd. Cost	
30	Long-Term Debt	48.0%	3.89%	1.87%		48.0%	3.90%	1.87%	
31	Common Equity	52.0%	10.10%	5.25%		52.0%	10.10%	5.25%	
32	Total	100.0%		7.12%		100.0%		7.12%	
33	**Rate of Return Summary**								
34	**Rate of Return**	**5.19%**		**7.12%**		**4.57%**		**7.12%**	
35	Less Weighted Cost of Long-Term Debt	1.87%		1.87%		1.87%		1.87%	
36	Net amount available for common equity	3.32%		5.25%		2.70%		5.25%	
37	Common Equity ratio	52.0%		52.0%		52.0%		52.0%	
38	**Return on Equity**	**6.38%**		**10.10%**		**5.18%**		**10.10%**	
39	**Revenue Requirement Summary**								
40	Rate Base			$ 4,112,800				$ 4,434,657	
41	Rate of Return			7.12%				7.12%	
42	Required Operating Income			292,831				315,748	
43	Proforma Operating Income			$ 292,831				$ 315,748	
44	Operating Income Deficiency			0				(0)	
45	Revenue Conversion Factor			1.41636				1.41636	
46	Rev. Rqmt. Deficiency (Excess)			0				0	
47	Total Adjusted Distribution Revenue Requirement								
48	Rev. Rqmt. Deficiency (Excess) - MRP Incremental $ by Year			**$ 0**				**$ (0)**	
49	Total Distribution Revenues, Adjusted			1,231,063				1,240,417	

Line No.	Description	MYP 2023 Unadjusted (16)	MYP 2023 Ratemaking Adjustments (17)	MYP 2023 Adjusted (18) = (16) + (17)	MYP 2023 Adjusted Variance vs. Prior Year (19) = (18) - (14)
1	**Rate Base (Average Basis)**				
2	Electric Plant	$ 8,687,504	$ -	$ 8,687,504	$ 405,660
3	Accumulated Depreciation and Amortization	(3,199,513)	-	(3,199,513)	(183,042)
4	Materials and Supplies	28,344	-	28,344	713
5	Cash Working Capital	36,809	(23,182)	13,627	1,075
6	Accumulated Deferred Income Taxes	(760,018)	(7,662)	(767,680)	(32,863)
7	Prepaid Pension/OPEB Liab.	52,758	-	52,758	(207)
8	Customer Advances & Deposits	(95,695)	-	(95,695)	(2,841)
9	Regulatory Assets & Liabilities	(199,236)	190,219	(9,017)	87,175
10	Other[1]	-	-	-	-
11	Total Rate Base	$ 4,550,952	$ 159,375	$ 4,710,328	$ 275,670
12	**Operating Income**				
13	Operating Revenues				
14	Sale of Electricity	$ 1,211,689	$ -	$ 1,211,689	$ 8,142
15	Other Revenues	36,977	-	36,977	106
16	Operating Revenues	$ 1,248,665	$ -	$ 1,248,665	$ 8,248
17	Operating Expenses				
18	Net Metering Costs	$ 1,971	$ -	$ 1,971	$ 151
19	Operation and Maintenance	460,804	(13,102)	447,701	5,663
20	Depreciation and Amortization	418,898	(12,224)	406,675	20,484
21	Other Taxes	192,704	-	192,704	8,804
22	Current Income Taxes	2,080	(30,809)	(28,729)	52,446
23	Deferred Income Taxes	-	-	-	-
24	Investment Tax Credit Adjustments	-	-	-	-
25	Total Operating Expenses	$ 1,076,458	$ (56,136)	$ 1,020,322	$ 87,548
26	Allowance for Funds Used During Construction	9,241	158	9,399	(130)
27	Interest on Customer Deposits	(1,471)		(1,471)	(47)
28	Operating Income	$ 179,977	$ 56,294	$ 236,271	$ (79,477)
29	**Capital Structure**	Ratio	Cost	Wtd. Cost	
30	Long-Term Debt	48.0%	3.89%	1.87%	
31	Common Equity	52.0%	10.10%	5.25%	
32	Total	100.0%		7.12%	
33	**Rate of Return Summary**				
34	**Rate of Return**	**3.95%**		**5.02%**	
35	Less Weighted Cost of Long-Term Debt	1.87%		1.87%	
36	Net amount available for common equity	2.08%		3.15%	
37	Common Equity ratio	52.0%		52.0%	
38	**Return on Equity**	**4.01%**		**6.05%**	
39	**Revenue Requirement Summary**				
40	Rate Base			$ 4,710,328	
41	Rate of Return			7.12%	
42	Required Operating Income			335,375	
43	Proforma Operating Income			$ 236,271	
44	Operating Income Deficiency			99,104	
45	Revenue Conversion Factor			1.41636	
46	Rev. Rqmt. Deficiency (Excess)			140,367	
47	Total Adjusted Distribution Revenue Requirement				
48	Rev. Rqmt. Deficiency (Excess) - MRP Incremental $ by Year			**$ 140,367**	
49	Total Distribution Revenues, Adjusted			1,389,032	

[1] Other line consistent with Case 9618 Working Group exhibit template. Included in case if needed in future update.

Company Exhibit DMV-3E-1

Reconciliation of Witness Sponsored O&M to Unadjusted O&M Included in Company Exhibit DMV-3E

	2019	2020	2021	2022	2023	Total MYP 21-23
O&M Per VP Sponsored Testimony						
Apte	$ 32,056,814	$ 36,070,875	$ 38,999,435	$ 39,569,612	$ 40,767,593	$ 119,336,640
Biagiotti	132,550,423	130,175,907	133,130,108	136,865,064	139,501,018	409,496,190
Burton	99,775,087	92,180,056	91,553,991	88,210,783	86,535,682	266,300,456
Olivier	110,130,330	110,155,039	111,456,230	110,877,626	110,782,016	333,115,872
Vahos	331,296,236	369,184,136	352,434,970	353,694,117	355,473,626	1,061,602,713
Total O&M(A)	$ 705,808,890	$ 737,766,013	$ 727,574,734	$ 729,217,202	$ 733,059,935	$ 2,189,851,871
Total VP Sponsored O&M by Line of Business						
Direct Electric Distribution		188,616,355	189,643,596	191,313,473	195,608,411	576,565,480
Direct Gas Distribution		113,518,933	112,868,564	109,405,414	107,099,333	329,373,311
Common(B)		428,830,782	415,423,059	416,487,378	417,584,813	1,249,495,249
Below the line/Other		6,799,943	9,639,515	12,010,937	12,767,379	34,417,831
Total	$ 705,808,890	737,766,013	727,574,734	729,217,202	733,059,935	2,189,851,871
Reconciliation to Company Exhibit DMV-3E						
Remove Transmission Allocation of Common/Other	(22,218,153)	(32,315,798)	(31,559,950)	(32,093,496)	(32,357,351)	(96,010,797)
Remove Below the Line	(9,587,356)	(6,799,943)	(9,639,515)	(12,010,937)	(12,767,379)	(34,417,831)
Total Distribution O&M	$ 674,003,381	$ 698,650,272	$ 686,375,269	$ 685,112,768	$ 687,935,205	$ 2,059,423,243
Electric Distribution Unadjusted O&M (Exhibit DMV-3E, Line 19)	433,864,441	459,332,444	452,566,453	455,138,826	460,803,749	1,368,509,028
Gas Distribution Unadjusted O&M (Exhibit DMV-3G, Line 19)	240,138,940	239,317,828	233,808,816	229,973,942	227,131,456	690,914,215
Total Unadjusted O&M Included on Exhibit DMV-3	$ 674,003,381	$ 698,650,272	$ 686,375,269	$ 685,112,768	$ 687,935,205	$ 2,059,423,243

(A) Total excludes direct assigned transmission spend, Political Action Committee spend, commodity spend, and uncollectible reserve activity.

(B) Common is allocated across Electric Distribution, Gas Distribution, and Transmission

Baltimore Gas and Electric Company
Electric MYP Revenue Requirement (Unadjusted and Adjusted) Summary By Year
For the Twelve Months Ended December 31,
(Thousands of Dollars)

Line No.	Description	Schedule Reference	HTY - 2019			Bridge Year - 2020			MYP 1 - 2021			MYP 2 - 2022			MYP 3 - 2023		
			Rate Base	Operating Income (Net of Tax)	Revenue Requirement	Rate Base	Operating Income (Net of Tax)	Revenue Requirement	Rate Base	Operating Income (Net of Tax)	Revenue Requirement	Rate Base	Operating Income (Net of Tax)	Revenue Requirement	Rate Base	Operating Income (Net of Tax)	Revenue Requirement
	Unadjusted Amounts	DMV-3E	3,482,152	247,534	8,451	3,797,832	223,953	66,332	4,103,039	212,743	112,450	4,344,603	198,378	157,156	4,550,952	179,977	204,028
	Ratemaking Adjustments:																
1	Annualize Case No. 9610 Base Rate Revenues	OIA-1	-	16,187	(22,927)	-	-	-	-	-	-	-	-	-	-	-	-
2	Annualize AFC to Reflect Case No. 9610 ROR	OIA-2	-	(492)	697	-	-	-	-	-	-	-	-	-	-	-	-
3	Annualize Case No. 9610 Rate Case Expenses	OIA-3	-	(65)	92	-	-	-	-	-	-	-	-	-	-	-	-
4	Annualize Case No. 9610 STRIDE Audit Fees	OIA-4	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
5	Annualize Case No. 9610 Smart Grid Amortization	OIA-5/RBA-1	(2,027)	(4,054)	5,533	-	-	-	-	-	-	-	-	-	-	-	-
6	Annualize Case No. 9610 CVR Amortization	OIA-6/RBA-2	(757)	(3,312)	4,613	-	-	-	-	-	-	-	-	-	-	-	-
7	Annualize Maryland Additional Subtraction Modification Tax Benefit	OIA-7	-	1,848	(2,617)	-	-	-	-	-	-	-	-	-	-	-	-
8	Annualize Case No. 9610 Riverside Amortization	OIA-8/RBA-3	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
9	Annualize Case No. 9610 Depreciation Expense	OIA-9/RBA-4	463	926	(1,264)	-	-	-	-	-	-	-	-	-	-	-	-
10	Annualize Collective Bargaining Agreement (CBA) Impact	OIA-10	-	(66)	93	-	-	-	-	-	-	-	-	-	-	-	-
11	Annualize Additional Sick Days Resulting from CBA	OIA-11	-	(114)	161	-	-	-	-	-	-	-	-	-	-	-	-
12	Annualize Customer Operation Wages	OIA-12	-	(297)	421	-	-	-	-	-	-	-	-	-	-	-	-
13	Annualize 2019 General Wage Increase	OIA-13	-	(350)	496	-	-	-	-	-	-	-	-	-	-	-	-
14	Annualize Other Tax Known Increases	OIA-14	-	(2,242)	3,175	-	-	-	-	-	-	-	-	-	-	-	-
15	Eliminate Expiring Regulatory Asset Amortizations	OIA-15/RBA-5	-	16	(23)	-	-	-	-	-	-	-	-	-	-	-	-
16	Amortize Gain on Sale of Real Estate	OIA-16/RBA-6	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
17	Case 9610 Safety & Reliability Net Depreciation Expense Annualization	OIA-17/RBA-7	111,781	(2,091)	14,487	-	-	-	-	-	-	-	-	-	-	-	-
18	Case 9610 STRIDE Net Depreciation Expense Annualization	OIA-18/RBA-8	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
19	General Inflation on Non-Labor O&M	OIA-19	-	(3,233)	4,579	-	-	-	-	-	-	-	-	-	-	-	-
20	Normalize Major Outage Event Restoration Expense	OIA-20	-	(7,405)	10,488	-	-	-	-	-	-	-	-	-	-	-	-
21	Eliminate One-Time Credit to Establish Riverside Environmental Regulatory Asset	OIA-21	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
22	Eliminate ERI Rider 31 Revenues	OIA-22	-	(4,522)	6,405	-	-	-	-	-	-	-	-	-	-	-	-
23	Eliminate STRIDE Revenues, Net	OIA-23	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
24	Eliminate Advertising	OIA-24	-	916	(1,297)	-	360	(510)	-	360	(510)	-	366	(518)	-	372	(527)
25	Eliminate Employee Activity Costs	OIA-25	-	251	(356)	-	426	(603)	-	429	(608)	-	431	(610)	-	438	(620)
26	Eliminate SERP Costs	OIA-26	-	1,388	(1,966)	-	1,291	(1,829)	-	1,326	(1,878)	-	1,278	(1,810)	-	1,224	(1,734)
27	Eliminate Certain Incentive Compensation	OIA-27	-	1,770	(2,507)	-	2,961	(4,194)	-	2,751	(3,896)	-	2,868	(4,062)	-	2,939	(4,163)
28	Normalize AFC at Proposed ROR	OIA-28	-	540	(765)	-	224	(317)	-	173	(245)	-	149	(211)	-	147	(208)
29	Eliminate RM54 Capital Software Costs	OIA-29/RBA-9	(422)	-	(44)	(234)	170	(264)	(62)	145	(212)	-	-	-	-	-	-
30	Amortize Rate Case Expenses	OIA-30	-	-	-	-	-	-	-	-	-	-	(69)	98	-	(69)	98
31	Amortize STRIDE Audit Fees	OIA-31	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
32	Amortize CVR Program Costs	OIA-32/RBA-10	-	-	-	-	-	-	-	-	-	(1,017)	(2,033)	2,777	(3,050)	(2,033)	2,572
33	Reversal of CVR Program Cost Deferral	OIA-33/RBA-11	-	-	-	-	-	-	(682)	(1,363)	1,862	(1,733)	(739)	872	(2,485)	(767)	836
34	Amortize Riverside Environmental Costs	OIA-34/RBA-12	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
35	Amortize the Gas Meter Mitigation Regulatory Asset	OIA-35	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
36	Amortize Electric Vehicle Program Costs	OIA-36/RBA-13	-	-	-	-	-	-	-	-	-	(397)	(795)	1,086	(1,320)	(1,051)	1,355
37	Reversal of Major Outage Event Restoration Expense	OIA-37	-	-	-	-	-	-	-	7,393	(10,471)	-	7,393	(10,471)	-	7,393	(10,471)
38	Accelerated Tax Benefits	OIA-38/RBA-14	-	-	-	-	-	-	23,071	46,143	(63,029)	94,953	97,622	(128,692)	162,374	37,220	(36,342)
39	2021 Regulatory Asset Amortization Suspension	OIA-39/RBA-15	-	-	-	-	-	-	8,355	22,449	(30,953)	16,710	-	1,685	16,710	-	1,685
40	Smart Grid Regulatory Asset Life Extension	OIA-40/RBA-16	-	-	-	-	-	-	-	-	-	3,443	9,911	(13,690)	10,328	9,911	(12,996)
41	COVID-19 Regulatory Asset amortization	OIA-41/RBA-17	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
42	Interest Synchronization	OIA-42	-	913	(1,290)	-	304	(430)	-	283	(400)	-	987	(1,401)	-	570	(808)
43	Cash Working Capital Adjusted for Updated Lag Days	DMV-6E, Line 19	(19,266)	-	(1,987)	(20,008)		(2,021)	(20,922)		(2,110)	(21,905)		(2,209)	(23,182)		(2,338)
44	Total Adjustments		89,772	(3,488)	14,197	(20,242)	5,736	(10,168)	9,760	80,089	(112,450)	90,054	117,369	(157,156)	159,375	56,294	(63,661)
45	Total Revenue Requirement	DMV-3E	3,571,924	244,046	22,648	3,777,590	229,689	56,164	4,112,799	1,286 292,832	-	4,434,657	315,747	-	4,710,328	236,271	140,367
	Rate of Return (Company Exhibit DMV-3E, line 32)		7.28%			7.13%			7.12%			7.12%			7.12%		
	Conversion Factor																
	Maryland State Income Tax		8.2500%			8.2500%			8.2500%			8.2500%			8.2500%		
	Federal Income Tax		21.0000%			21.0000%			21.0000%			21.0000%			21.0000%		
	Combined Income Tax Rate (SIT+(FITx(1-SIT))		27.5175%			27.5175%			27.5175%			27.5175%			27.5175%		
	Gross Receipts Tax		2.0000%			2.0000%			2.0000%			2.0000%			2.0000%		
	PSC Assessment Rate		0.2124%			0.2124%			0.2124%			0.2124%			0.2124%		
	Uncollectible Factor		0.3800%			0.3800%			0.3800%			0.3800%			0.3800%		
	Conversion Factor (1 /(1-Comb Tax)x(1-(GR+PSC+Uncoll))		1.41636			1.41636			1.41636			1.41636			1.41636		
	Conversion Factor % ((1-Comb Tax)x(1-(GR+PSC+Uncoll))		70.603%			70.603%			70.603%			70.603%			70.603%		

Baltimore Gas and Electric Company
Case No. 9610 Electric Base Rate Revenue Increase
Multi-Year Plan

In Case No. 9610, Order No. 89400, the Commission accepted a settlement that resulted in an increase of $25 million in electric base rates. This rate change became effective with service rendered on or after December 17, 2019. Operating Income Adjustment 1E reflects the annual effect on electric operating income of this rate change not reflected in the 2019 HTY.

Description	HTY 2019	Bridge Period 2020	MYP 1 2021	MYP 2 2022	MYP 3 2023
Total increase in base rate revenues awarded	$ 25,000,000	$ -	$ -	$ -	$ -
Case No. 9610 increase in base rate revenues reflected in the 2019 HTY	(2,161,822)	-	-	-	-
Increase in base rate revenues to be realized	22,838,178	-	-	-	-
Franchise Tax	(456,764)	-	-	-	-
PSC Assessment	(48,508)	-	-	-	-
Income Tax Effect at 27.5175%	(6,145,458)	-	-	-	-
Adjustment to operating income	$ 16,187,449				
Amount Presented on Company Exhibit DMV-4E	$ 16,187,000	$ -	$ -	$ -	$ -

Mapping to Exhibit DMV-3E Ratemaking Adjustments:

Sale of Electricity (Line 14)	$ 22,838,178	$ -	$ -	$ -	$ -
Other Taxes (Line 21)	505,272	-	-	-	-
Current Income Taxes (Line 22)	6,145,458	-	-	-	-

Baltimore Gas and Electric Company
Case No. 9610 AFC Annualization - Electric
Multi-Year Plan

Operating Income
Adjustment 2E

This adjustment annualizes unadjusted electric AFC accrued during the HTY 2019 to reflect the 6.94% rate of return for electric agreed to in the settlement agreement reached in Case No. 9610 for the purpose of calculating AFC, which was accepted by the Commission in Order No. 89400.

Description	HTY 2019	Bridge Period 2020	MYP 1 2021	MYP 2 2022	MYP 3 2023
Actual AFC for the 2019 HTY per Company Exhibit DMV-3E	$ 12,398	$ -	$ -	$ -	$ -
Actual AFC for the 2019 HTY	12,397,545				
AFC accrued under the Case 9610 6.94% rate for the month of December 2019	(1,006,925)				
AFC to be subject to the new rate of 6.94%	11,390,620				
Conversion Factor to 6.94% AFC rates	6.94%/7.28%				
AFC for the period January - November 2019 restated to reflect a 6.94% AFC rate	10,858,640	-	-	-	-
AFC to be subject to new rates	(11,390,620)	-	-	-	-
Change in AFC	(531,979)	-	-	-	-
Income Tax Effect of borrowed funds portion of AFC at 27.5175%	40,077				
Adjustment to Operating Income	$ (491,902)	$ -	$ -	$ -	$ -
Amount presented on Company Exhibit DMV-4E	$ (492,000)	$ -	$ -	$ -	$ -

Calculation of Income Tax Effect of Borrowed Funds Portion of AFC	
Increase (Decrease) in AFC	$ (531,979)
Borrowed funds portion of AFC - %	27.4%
Borrowed funds portion of AFC - $	(145,643)
Income tax rate	27.5175%
Income tax effect of borrowed funds portion of AFC	$ (40,077)

Borrowed fund funds %	
Total Return	6.94%
Weighted cost of Long-Term Debt	1.90%
Borrowed Funds Portion of AFC %	27.4%

Mapping to Exhibit DMV-3E Ratemaking Adjustments:

Allowance for Funds Used During Construction (Line 26)	$ (531,979)	$ -	$ -	$ -	$ -
Deferred Income Taxes (Line 23)	(40,077)	-	-	-	-

Baltimore Gas and Electric Company
Case 9610 Electric Rate Case Expenses
Multi-Year Plan

Operating Income
Adjustment 3E

This adjustment annualizes the amortization of deferred rate case expenses included in Case No. 9610, but not fully reflected in the HTY 2019.

Description	HTY 2019	Bridge Period 2020	MYP 1 2021	MYP 2 2022	MYP 3 2023
Annual amortization of deferred rate case expenses included in Case No. 9610	$ 97,280	$ -	$ -	$ -	$ -
1 Month (December) reflected in HTY	(8,107)	-	-	-	-
Amortization of deferred rate case expenses not reflected in the 2019 HTY	89,173	-	-	-	-
Income tax effect at 27.5175%	(24,538)	-	-	-	-
Adjustment to operating income	$ 64,635	$ -	$ -	$ -	$ -
Amount Presented on Company Exhibit DMV-4E	$ (65,000)	$ -	$ -	$ -	$ -

Mapping to Exhibit DMV-3E Ratemaking Adjustments:

Operation and Maintenance (Line 19)	$ 89,173	$ -	$ -	$ -	$ -
Deferred Income Taxes (Line 23)	(24,538)				
	$ 64,635	$ -	$ -	$ -	$ -

Baltimore Gas and Electric Company
Case No. 9610 Electric Smart Grid Regulatory Asset Amort
Multi-Year Plan

Operating Income
Adjustment 5E

This adjustment annualizes the amortization of the electric Smart Grid regulatory asset incremental costs incurred since November 2015 (i.e. the end of the test year in Case No. 9406). This regulatory asset is being amortized through May 2026 years in accordance with the Case No. 9610 settlement which was accepted by the Commission in Order No. 89400. This adjustment reflects the portion of amortization which is not reflected in the HTY 2019. The companion adjustment is Rate Base Adjustment 1E.

Description	HTY 2019	Bridge Period 2020	MYP 1 2021	MYP 2 2022	MYP 3 2023
Annual amortization of the 9406 post test year electric Smart Grid regulatory asset agreed to in the settlement in Case No. 9610	$ 6,102,176	$ -	$ -	$ -	$ -
1 Month (December)	(508,515)	-	-	-	-
Amortization of Case No. 9610 Smart Grid costs not reflected in the 2019 HTY	5,593,662	-	-	-	-
Income tax effect at 27.5175%	(1,539,236)	-	-	-	-
Adjustment to operating income	$4,054,426	$ -	$ -	$ -	$ -
Amount Presented on Company Exhibit DMV-4E	($4,054,000)	$ -	$ -	$ -	$ -

Mapping to Exhibit DMV-3E Ratemaking Adjustments:

Depreciation and Amortization (Line 20)	$ 5,593,662	$ -	$ -	$ -	$ -
Deferred Income Taxes (Line 23)	(1,539,236)				
	$ 4,054,426	$ -	$ -	$ -	$ -

This adjustment annualizes the CVR amortization as a result of the Case No. 9610 settlement which was accepted by the Commission in Order No. 89400, but not fully reflected in the 2019 HTY. The CVR 9610 Tranche is being amortized over 5 years in accordance with the Case No. 9610 settlement . In addition, this adjustment provides for the reversal of the 2019 HTY amounts deferred into the regulatory asset for CVR (i.e. depreciation, property taxes, and returns) so that the 2019 HTY reflects ongoing expenses and return based on the Case No. 9610 filing. The companion adjustment is Rate Base Adjustment 2E.

Description	HTY 2019	Bridge Period 2020	MYP 1 2021	MYP 2 2022	MYP 3 2023
Annual amortization of the CVR regulatory asset 9610 tranche based on a 5 year period	$2,279,405	$ -	$ -	$ -	$ -
1 Month (December)	(189,950)	-	-	-	-
Amortization of Case No. 9610 CVR costs not reflected in the 2019 HTY	2,089,455	-	-	-	-
Reversal of deferrals included in Case No. 9610	2,479,604				
Income tax effect at 27.5175%	(1,257,291)	-	-	-	-
Adjustment to operating income	$3,311,768	$ -	$ -	$ -	$ -
Amount Presented on Company Exhibit DMV-4E	($3,312,000)	$ -	$ -	$ -	$ -

Mapping to Exhibit DMV-3E Ratemaking Adjustments:

Operation and Maintenance (Line 19)	$ 2,089,455	$ -	$ -	$ -	$ -
Depreciation and Amortization (Line 20)	2,479,604	-	-	-	-
Deferred Income Taxes (Line 23)	(1,257,291)	-	-	-	-
	$ 3,311,768	$ -	$ -	$ -	$ -

This adjustment provides customers with the state income tax benefit attributable to the recognition of an incremental increase to the Maryland “Statutory Subtraction” modification over the average remaining book lives of Maryland assets, approximately 32 years for electric, but which is not fully reflected in the 2019 HTY.

Description	HTY 2019	Bridge Period 2020	MYP 1 2021	MYP 2 2022	MYP 3 2023
Annual amortization of Maryland Additional Subraction Modification regulatory liability reflected in Case No. 9610	$2,780,900	$ -	$ -	$ -	$ -
1 Month (December) reflected in HTY	(231,742)	-	-	-	-
Amortization of Maryland Additional Subraction Modification regulatory liability not reflected in the 2019 HTY	2,549,158	-	-	-	-
Income tax effect at 27.5175%	(701,465)	-	-	-	-
Annual Maryland Additional Subraction Modification to be provided to customers	$1,847,694	$ -	$ -	$ -	$ -
Adjustment to operating income	$1,847,694	$ -	$ -	$ -	$ -
Amount Presented on Company Exhibit DMV-4E	$1,848,000	$ -	$ -	$ -	$ -

Mapping to Exhibit DMV-3E Ratemaking Adjustments:

Deferred Income Taxes (Line 23)	$ (1,847,694)	$ -	$ -	$ -	$ -
	$ (1,847,694)	$ -	$ -	$ -	$ -

Baltimore Gas and Electric Company
Case No. 9610 Electric Depreciation Rates
Multi-Year Plan

Operating Income
Adjustment 9E

This adjustment annualizes the level of electric depreciation expense as a result of the new depreciation rates included in Exhibit 5 of the Case No. 9610 settlement agreement, which was accepted by the Commission in Order No. 89400. This adjustment is necessary since the new depreciation rates are not fully reflected in the 2019 HTY. The companion adjustment is Rate Base Adjustment 4E.

Description	**HTY 2019**	**Bridge Period 2020**	**MYP 1 2021**	**MYP 2 2022**	**MYP 3 2023**
Direct	$ 3,141,484	$ -	$ -	$ -	$ -
		-	-	-	-
Common	(4,535,217)	-	-	-	-
Annual Change in depreciation expense due to new depreciation rates agreed upon in Case No. 9610	(1,393,733)	-	-	-	-
1 Month (December) reflected in HTY	116,144	-	-	-	-
Change in depreciation expense not reflected in the 2019 HTY	(1,277,589)	-	-	-	-
.					
Income tax effect at 27.5175%	351,561	-	-	-	-
Adjustment to operating income	$ (926,028)	$ -	$ -	$ -	$ -
Amount Presented on Company Exhibit DMV-4E	$ 926,000	$ -	$ -	$ -	$ -

Mapping to Exhibit DMV-3E Ratemaking Adjustments:

Depreciation and Amortization (Line 20)	$ (1,277,589)	$ -	$ -	$ -	$ -
Current Income Taxes (Line 22)	351,561				
	$ (926,028)	$ -	$ -	$ -	$ -

Baltimore Gas and Electric Company
Collective Bargaining Agreement - Electric
Multi-Year Plan

Operating Income
Adjustment 10E

This adjustment reflects the impacts of the Collective Bargaining Agreement ("CBA") which are not fully reflected in the 2019 HTY.

Description	HTY 2019	Bridge Period 2020	MYP 1 2021	MYP 2 2022	MYP 3 2023
Specific Wage and Stipend Adjustments:					
Specific market wage adjustments	$ 244,605	$ -	$ -	$ -	$ -
Premium and allowance adjustments	172,157	-	-	-	-
Total specific wage and stipend adjustments	416,762	-	-	-	-
General wage increase	1,444,685	-	-	-	-
AIP reduction	(911,283)	-	-	-	-
Elimination of 5 day sick pay accrual recorded in the HTY 2019	(858,827)	-	-	-	-
Additional expenses resulting from the CBA not reflected in the 2019 HTY	91,337	-	-	-	-
Income Tax Effect at 27.5175%	(25,134)	-	-	-	-
Adjustment to Operating Income	$ 66,204	$ -	$ -	$ -	$ -
Amount presented on Company Exhibit DMV-4E	$ (66,000)	$ -	$ -	$ -	$ -

Mapping to Exhibit DMV-3E Ratemaking Adjustments:

Operation and Maintenance (Line 19)	$ 91,337	$ -	$ -	$ -	$ -
Current Income Taxes (Line 22)	(25,134)				
	$ 66,204	$ -	$ -	$ -	$ -

Baltimore Gas and Electric Company
CBA - 10 Add'l Sick Days - Electric
Multi-Year Plan

Operating Income
Adjustment 11E

This adjustment annualizes the amortization of the union sick day regulatory asset established as a result of the Collective Bargaining Agreement ("CBA"), and then amortized over a 10 year period consistent with the Case No. 9610 settlement agreement which was accepted by the Commission in Order No. 89400.

Description	HTY 2019	Bridge Period 2020	MYP 1 2021	MYP 2 2022	MYP 3 2023
Additional 10 Days of Sick Pay	$ 1,717,045	$ -	$ -	$ -	$ -
Amortization Period (years)	10	-	-	-	-
Annual Amortization	171,705	-	-	-	-
1 Month (December) reflected in HTY	(14,309)	-	-	-	-
Amortization of sick pay expenses not reflected in the 2019 HTY	$157,396	-	-	-	-
Income Tax Effect at 27.5175%	(43,311)	-	-	-	-
Adjustment to Operating Income	$ 114,084	$ -	$ -	$ -	$ -
Amount presented on Company Exhibit DMV-4E	$ (114,000)	$ -	$ -	$ -	$ -

Mapping to Exhibit DMV-3E Ratemaking Adjustments:

Depreciation and Amortization (Line 20)	$ 157,396	$ -	$ -	$ -	$ -
Deferred Income Taxes (Line 23)	(43,311)				
	$ 114,084	$ -	$ -	$ -	$ -

Baltimore Gas and Electric Company
2019 Customer Operations Market Adjustment - Electric
Multi-Year Plan

Operating Income
Adjustment 12E

This adjustment reduces electric operating income by providing for the effect on labor costs of the July 2019 market wage adjustment for certain BGE Customer Operations positions, which is not fully reflected in the 2019 HTY.

Description	HTY 2019	Bridge Period 2020	MYP 1 2021	MYP 2 2022	MYP 3 2023
Effect of the July 2019 Customer Operations market adjustment not reflected in HTY	$ 410,142	$ -	$ -	$ -	$ -
Income tax effect at 27.5175%	(112,861)	-	-	-	-
Adjustment to operating income	$ 297,281	$ -	$ -	$ -	$ -
Amount Presented on Company Exhibit DMV-4E	$ (297,000)	-	-	-	-

Mapping to Exhibit DMV-3E Ratemaking Adjustments:

	HTY 2019	Bridge Period 2020	MYP 1 2021	MYP 2 2022	MYP 3 2023
Operation and Maintenance (Line 19)	$ 410,142	$ -	$ -	$ -	$ -
Current Income Taxes (Line 22)	(112,861)				
	$ 297,281	$ -	$ -	$ -	$ -

Baltimore Gas and Electric Company
2019 Wage Increase - Electric
Multi-Year Plan

Operating Income
Adjustment 13E

This adjustment reduces electric operating income by providing for the effect on labor costs of the March 2019 general wage increase for BGE employees as included in Case No. 9610, which is not fully reflected in 2019 HTY.

Description	HTY 2019	Bridge Period 2020	MYP 1 2021	MYP 2 2022	MYP 3 2023
Effect of the 2019 wage increase	$ 482,316	$ -	$ -	$ -	$ -
Income tax effect at 27.5175%	(132,721)	-	-	-	-
Adjustment to operating income	$ 349,595	$ -	$ -	$ -	$ -
Amount Presented on Company Exhibit DMV-4E	$ (350,000)	$ -	$ -	$ -	$ -

Mapping to Exhibit DMV-3E Ratemaking Adjustments:

Operation and Maintenance (Line 19)	$ 482,316	$ -	$ -	$ -	$ -
Current Income Taxes (Line 22)	(132,721)				
	$ 349,595	$ -	$ -	$ -	$ -

Baltimore Gas and Electric Company
Changes in Other Taxes - Electric
Multi-Year Plan

Operating Income
Adjustment 14E

This adjustment reduces electric operating income for the annualized known increases in various taxes other than income taxes including the increase in real and personal property taxes effective with the July 1, 2019 property assessments and the Maryland Public Service Commission assessment rate effective July 2019 as included in Case No. 9610. Both of these are not fully reflected in the 2019 HTY without this adjustment.

Description	HTY 2019	Bridge Period 2020	MYP 1 2021	MYP 2 2022	MYP 3 2023
Real Estate and Property Taxes					
Projected July 2019 - June 2020 Assessment Amounts	$89,748,569	$ -	$ -	$ -	$ -
Amounts recorded in the 2019 HTY	87,097,956	-	-	-	-
Increase/(Decrease)	2,650,612	-	-	-	-
PSC Assessment Rate					
Projected July 2019 - June 2020 Assessment Amounts	3,451,568	-	-	-	-
Amounts recorded in the 2019 HTY	3,008,725	-	-	-	-
Increase/(Decrease)	442,843	-	-	-	-
Total					
Total Increase/(Decrease in taxes other than income taxes	3,093,455	-	-	-	-
		-			
Income tax effect at 27.5175%	(851,242)	-	-	-	-
Adjustment to operating income	$ 2,242,214	$ -	$ -	$ -	$ -
Amount Presented on Company Exhibit DMV-4E	$ (2,242,000)	$ -	$ -	$ -	$ -

Mapping to Exhibit DMV-3E Ratemaking Adjustments:

Other Taxes (Line 21)	$ 3,093,455	$ -	$ -	$ -	$ -
Current Income Taxes (Line 22)	(851,242)				
	$ 2,242,214	$ -	$ -	$ -	$ -

Baltimore Gas and Electric Company
Fully Amortized Electric Regulatory Assets
Multi-Year Plan

This adjustment increases electric operating income by eliminating the amortization expense associated with the Case No. 9406 tranche of rate case expenses which was fully amortized in May 2019. Since this regulatory asset was fully amortized before the end of the 2019 HTY, the related amortization has been eliminated from operating income.

Description	HTY 2019	Bridge Period 2020	MYP 1 2021	MYP 2 2022	MYP 3 2023
Case No. 9406 Rate Case Expenses Regulatory Asset Amortization	$ 22,479	$ -	$ -	$ -	$ -
		-	-	-	-
Total amortization to be eliminated	22,479	-	-	-	-
Income tax effect at 27.5175%	(6,186)	-	-	-	-
Adjustment to operating income	$ 16,293	$ -	$ -	$ -	$ -
Amount Presented on Company Exhibit DMV-4E	$ 16,000	$ -	$ -	$ -	$ -

Mapping to Exhibit DMV-3E Ratemaking Adjustments:

	HTY 2019	Bridge Period 2020	MYP 1 2021	MYP 2 2022	MYP 3 2023
Operation and Maintenance (Line 19)	$ (22,479)	$ -	$ -	$ -	$ -
Deferred Income Taxes (Line 23)	6,186				
	$ (16,293)	$ -	$ -	$ -	$ -

This adjustment annualizes the level of depreciation expense, net of depreciation savings, of non-revenue producing safety and reliability plant included in Case No. 9610, and as provided for in Rate Base Adjustment 7E. This adjustment reflects the amounts included in the Case No. 9610 filing. Rate Base Adjustment 7E adjusts accumulated depreciation and accumulated deferred income taxes related to the additional net depreciation expense provided in this adjustment.

Description	HTY 2019	Bridge Period 2020	MYP 1 2021	MYP 2 2022	MYP 3 2023
Annual Depreciation associated with safety and reliability projects	$ 5,670,392	$ -	$ -	$ -	$ -
Less - Safety and reliability depreciation included in the 2019 HTY	2,558,948	-	-	-	-
Increase in depreciation associated with safety and reliability projects	3,111,444	-	-	-	-
Depreciation Savings: Safety and reliability annual depreciation savings	412,377	-	-	-	-
Less - Safety and reliability depreciation savings included in the 2019 HTY	186,098	-	-	-	-
Depreciation savings related to safety and reliability retirements	226,278	-	-	-	-
Net depreciation associated with safety and reliability projects	2,885,165				
Income Tax Effect at 27.5175%	(793,925)	-	-	-	-
Adjustment to Operating Income	$ 2,091,240	$ -	$ -	$ -	$ -
Amount presented on Company Exhibit DMV-4E	$ (2,091,000)	$ -	$ -	$ -	$ -

Baltimore Gas and Electric Company
General Inflation - Electric
Multi-Year Plan

Operating Income
Adjustment 19E

This adjustment, which was included in Case No. 9610, reduces electric operating income to provide for the effect of general inflation on non-labor O&M costs during the rate-effective period. This adjustment reflects a 1.420% inflation factor based on a five-year average of the Consumer Price Index ("CPI") per the U.S. Department of Labor, Bureau of Labor Statistics, as authorized by the Commission in Case No. 9484, Order No. 88975.

Description	HTY 2019	Bridge Period 2020	MYP 1 2021	MYP 2 2022	MYP 3 2023
O&M Expense included in DMV-3E	$ 433,864,441	$ -	$ -	$ -	$ -
Less:					
Advertising Costs (OIA-24E-Updated)	(1,263,874)	-	-	-	-
Employee Activity Costs (OIA-25E-Updated)	(346,133)	-	-	-	-
SERP Costs (OIA-26E-Updated)	(1,914,680)	-	-	-	-
Certain Incentives (OIA-27E-Updated)	(2,441,422)	-	-	-	-
	427,898,331	-	-	-	-
Less labor included in O&M	113,786,361	-	-	-	-
Non-Labor O&M expense included in the 2019 HTY	314,111,971	-	-	-	-
Inflation factor	1.420%				
Additional O&M due to inflation	4,460,390	-	-	-	-
Income tax effect at 27.5175%	(1,227,388)	-	-	-	-
Adjustment to operating income	$ 3,233,002	$ -	$ -	$ -	$ -
Amount Presented on Company Exhibit DMV-4E	$ (3,233,000)	$ -	$ -	$ -	$ -

Mapping to Exhibit DMV-3E Ratemaking Adjustments:

Operation and Maintenance (Line 19)	$ 4,460,390	$ -	$ -	$ -	$ -
Current Income Taxes (Line 22)	(1,227,388)				
	$ 3,233,002	$ -	$ -	$ -	$ -

Baltimore Gas and Electric Company
Electric Major Outage Restoration Expense
Multi-Year Plan

Operating Income
Adjustment 20E

This adjustment normalizes the level of major outage event restoration expense recorded in the 2019 HTY. This adjustment reflects the five-year average level of incremental major outage event restoration expense experienced between January 2015 and December 2019. Consistent with Case Nos. 9299, 9326, 9355, and 9406, the historical restoration costs have been adjusted to today's dollars based on the Consumer Price Index per the U.S. Department of Labor, Bureau of Labor Statistics.

Description	HTY 2019	Bridge Period 2020	MYP 1 2021	MYP 2 2022	MYP 3 2023
Calculation of Five-Year Average:					
Twelve months ended:					
12/31/2015	$ -	$ -	$ -	$ -	$ -
12/31/2016	17,023,075				
12/31/2017	2,653,802				
12/31/2018	31,406,727				
12/31/2019	-				
Total expense for the five years	51,083,604	-	-	-	-
Number of years	5				
Five-year average	10,216,721	-	-	-	-
Actual major outage event restoration expense	-	-	-	-	-
Actual less five-year average	(10,216,721)	-	-	-	-
Income Tax Effect at 27.5175%	2,811,386				
Adjustment to Operating Income	$ (7,405,335)	$ -	$ -	$ -	$ -
Amount presented on Company Exhibit DMV-4E	$ (7,405,000)	$ -	$ -	$ -	$ -

Mapping to Exhibit DMV-3E Ratemaking Adjustments:

Operation and Maintenance (Line 19)	$ 10,216,721	$ -	$ -	$ -	$ -
Current Income Taxes (Line 22)	(2,811,386)				
	$ 7,405,335	$ -	$ -	$ -	$ -

Baltimore Gas and Electric Company
Eliminate Electric ERI Revenues, Net
Multi-Year Plan

Operating Income
Adjustment 22E

This adjustment removes the revenues associated with Rider 31 (ERI) that are reflected in the 2019 HTY operating income. The ERI surcharge ended in December 2019.

Description	HTY 2019	Bridge Period 2020	MYP 1 2021	MYP 2 2022	MYP 3 2023
ERI revenues reflected in the 2019 HTY	$ 6,367,458	$ -	$ -	$ -	$ -
Franchise Tax and PSC Assessment	(128,883)	-	-	-	-
Income tax effect at 27.5175%	(1,716,700)	-	-	-	-
Adjustment to operating income	$4,521,875	$ -	$ -	$ -	$ -
Amount Presented on Company Exhibit DMV-4E	($4,522,000)	$ -	$ -	$ -	$ -

Mapping to Exhibit DMV-3E Ratemaking Adjustments:

Sale of Electricity (Line 14)	$ (6,367,458)	$ -	$ -	$ -	$ -
Other Taxes (Line 21)	(128,883)	-	-	-	-
Current Income Taxes (Line 22)	(1,716,700)	-	-	-	-

This adjustment eliminates from electric operating income for each period certain advertising expenses recorded as operating expenses, in accordance with the FERC Uniform System of Accounts, that BGE is not allowed to recover pursuant to COMAR 20.07.04.08. These expenses represent institutional and promotional advertising expenses. All charitable contributions, penalties, and lobbying costs, including the lobbying expense portion of the Edison Electric Institute dues and the American Gas Association dues, are treated as below the line for ratemaking purposes and are removed from the revenue requirement in Company Exhibit DMV-3E-1. Therefore, it is not necessary to include these costs in this operating income adjustment. This schedule, which was provided in Part 1 of my Direct Testimony, has been updated to reflect amounts for the Bridge Period and MYP years.

Description	HTY 2019	Bridge Period 2020	MYP 1 2021	MYP 2 2022	MYP 3 2023
Institutional and Promotional Advertising	$ 1,263,874	$ 496,645	$ 496,645	$ 505,117	$ 513,820
Income Tax Effect at 27.5175%	(347,787)	(136,664)	(136,664)	(138,996)	(141,390)
Adjustment to operating income	$ 916,088	$ 359,981	$ 359,981	$ 366,121	$ 372,430
Amount Presented on Company Exhibit DMV-4E	$ 916,000	$ 360,000	$ 360,000	$ 366,000	$ 372,000

Mapping to Exhibit DMV-3E Ratemaking Adjustments:

Operation and Maintenance (Line 19)	$ (1,263,874)	$ (496,645)	$ (496,645)	$ (505,117)	$ (513,820)
Current Income Taxes (Line 22)	347,787	136,664	136,664	138,996	141,390
	$ (916,088)	$ (359,981)	$ (359,981)	$ (366,121)	$ (372,430)

Baltimore Gas and Electric Company
Eliminate Certain Electric Employee Activity Costs
Multi-Year Plan

Operating Income
Adjustment 25E-Updated

This adjustment eliminates from electric operating income certain employee activity costs as directed by the Commission in Case No. 9299, Order No. 85374. This schedule, which was provided in Part 1 of my testimony, has been updated to reflect amounts for the Bridge Period and MYP years.

Description	HTY 2019	Bridge Period 2020	MYP 1 2021	MYP 2 2022	MYP 3 2023
100% of Company's skybox costs	$ 172,067	$ 183,210	$ 183,210	$ 183,210	$ 183,210
Remaining employee activity costs	348,132	810,259	817,807	824,192	841,412
50% factor	50%	50%	50%	50%	50%
Subtotal - 50% of Remaining employee activity costs	174,066	405,130	408,903	412,096	420,706
Total excluded employee activity costs for the twelve month period	346,133	588,340	592,113	595,306	603,916
Income Tax Effect at 27.5175%	(95,247)	(161,896)	(162,935)	(163,813)	(166,183)
Adjustment to operating income	$ 250,886	$ 426,443	$ 429,179	$ 431,493	$ 437,733
Amount Presented on Company Exhibit DMV-4E	$ 251,000	$ 426,000	$ 429,000	$ 431,000	$ 438,000

Mapping to Exhibit DMV-3E Ratemaking Adjustments:

Operation and Maintenance (Line 19)	$ (346,133)	$ (588,340)	$ (592,113)	$(595,306)	$(603,916)
Current Income Taxes (Line 22)	95,247	161,896	162,935	163,813	166,183
	$ (250,886)	$ (426,443)	$ (429,179)	$(431,493)	$(437,733)

Baltimore Gas and Electric Company
Eliminate Certain Electric SERP Costs
Multi-Year Plan

Operating Income
Adjustment 26E-Updated

This adjustment eliminates from electric operating income 100% of Supplemental Executive Retirement Program ("SERP") costs as required in Case No. 9484, Order No. 88975. This schedule, which was provided in Part 1 of my Direct Testimony, has been updated to reflect amounts for the Bridge Period and MYP years.

Description	HTY 2019	Bridge Period 2020	MYP 1 2021	MYP 2 2022	MYP 3 2023
SERP costs to be eliminated	$ 1,914,680	$ 1,781,081	$ 1,828,763	$ 1,763,469	$ 1,688,305
Income tax effect at 27.5175%	(526,872)	(490,109)	(503,230)	(485,263)	(464,579)
Adjustment to operating income	$ 1,387,808	$ 1,290,972	$ 1,325,533	$ 1,278,206	$ 1,223,726
Amount Presented on Company Exhibit DMV-4E	$ 1,388,000	$ 1,291,000	$ 1,326,000	$ 1,278,000	$ 1,224,000

Mapping to Exhibit DMV-3E Ratemaking Adjustments:

Operation and Maintenance (Line 19)	$ (1,914,680)	$(1,781,081)	$(1,828,763)	$ (1,763,469)	$ (1,688,305)
Current Income Taxes (Line 22)	526,872	490,109	503,230	485,263	464,579
	$ (1,387,808)	$(1,290,972)	$(1,325,533)	$ (1,278,206)	$ (1,223,726)

This adjustment removes the non-recoverable amount of incentive compensation from electric operating income consistent with Case No. 9326, Order No. 86060. This schedule, which was provided in Part 1 of my Direct Testimony, has been updated to reflect amounts for the Bridge Period and MYP years.

Description	HTY 2019	Bridge Period 2020	MYP 1 2021	MYP 2 2022	MYP 3 2023
Removal of certain incentive compensation	$ 2,441,422	$ 4,085,424	$ 3,795,654	$ 3,956,429	$ 4,054,823
Income Tax Effect at 27.5175%	(671,818)	(1,124,207)	(1,044,469)	(1,088,710)	(1,115,786)
Adjustment to operating income	$ 1,769,603	$ 2,961,217	$ 2,751,185	$ 2,867,719	$ 2,939,037
Amount Presented on Company Exhibit DMV-4E	$ 1,770,000	$ 2,961,000	$ 2,751,000	$ 2,868,000	$ 2,939,000

Mapping to Exhibit DMV-3E Ratemaking Adjustments:

Operation and Maintenance (Line 19)	$ (2,441,422)	$ (4,085,424)	$ (3,795,654)	$ (3,956,429)	$ (4,054,823)
Current Income Taxes (Line 22)	671,818	1,124,207	1,044,469	1,088,710	1,115,786
	$ (1,769,603)	$ (2,961,217)	$ (2,751,185)	$ (2,867,719)	$ (2,939,037)

Baltimore Gas and Electric Company
Electric AFC Annualization Based on Proposed ROR
Multi-Year Plan

Operating Income
Adjustment 28E-Updated

This adjustment adjusts electric operating income for the known annualized amount of AFC included in unadjusted operating income to reflect a level that is consistent with the rate of return for electric as supported by the Company for each period. This schedule, which was provided in Part 1 of my Direct Testimony, has been updated to reflect amounts for the Bridge Period and MYP years.

Description	HTY 2019	Bridge Period 2020	MYP 1 2021	MYP 2 2022	MYP 3 2023
Actual AFC for the twelve months per Company Exhibit DMV-3E	$ 12,398	$ 12,989	$ 10,870	$ 9,368	$ 9,241
Actual AFC for each period	12,397,545	12,989,304	10,869,980	9,368,319	9,240,651
Reduction in AFC to annualize to Case 9610 6.94% electric rate of return per Operating Income Adjustment No. 2E	(531,979)	-	-	-	-
Actual AFC for each period to be subject to new rate of return calculated	11,865,565	12,989,304	10,869,980	9,368,319	9,240,651
Conversion Factor to ROR Requested	1.0490	1.0186	1.0171	1.0171	1.0171
AFC for the twelve months restated to reflect the new AFC rate	12,446,875	13,230,534	11,056,322	9,528,918	9,399,062
Actual AFC for each period to be subject to new rate of return calculated	11,865,565	12,989,304	10,869,980	9,368,319	9,240,651
Change in AFC	581,310	241,230	186,343	160,600	158,411
Income Tax effect of borrowed funds portion of AFC at 27.5175%	(41,089)	(17,503)	(13,467)	(11,607)	(11,449)
Adjustment to operating income	$ 540,221	$ 223,727	$ 172,875	$ 148,993	$146,962
Amount Presented on Company Exhibit DMV-4E	$ 540,000	$ 224,000	$ 173,000	$ 149,000	$147,000
Calculation of Income Tax Effect of Borrowed Funds Portion of AFC					
Increase (Decrease) in AFC	$ 581,310	$241,230	$186,343	$160,600	$158,411
Borrowed funds portion of AFC %	0.257	0.264	0.263	0.263	0.263
Borrowed funds portion of AFC $	149,320	63,606	48,941	42,180	41,605
Income tax rate	27.5175%	27.5175%	27.5175%	27.5175%	27.5175%
Income tax effect of borrowed funds portion of AFC	$ 41,089	$17,503	$13,467	$11,607	$11,449
Borrowed fund funds %					
Total Return	7.28%	7.13%	7.12%	7.12%	7.12%
Weighted cost of Long-Term Debt	1.87%	1.88%	1.87%	1.87%	1.87%
Borrowed Funds Portion of AFC %	25.7%	26.4%	26.3%	26.3%	26.3%
Mapping to Exhibit DMV-3E Ratemaking Adjustments:					
Allowance for Funds Used During Construction (Line 26)	$ 581,310	$ 241,230	$ 186,343	$ 160,600	$ 158,411
Deferred Income Taxes (Line 23)	41,089	-	-	-	-
Current Income Taxes (Line 22)	-	17,503	13,467	11,607	11,449

Baltimore Gas and Electric Company
Eliminate Electric RM54 Amortization
Multi-Year Plan

Operating Income
Adjustment 29E-Updated

This adjustment relate to the costs incurred by the Company associated with capitalized software changes to BGE's billing system that are necessary to allow for customer accelerated switching between third party suppliers and BGE commodity service, as required by the COMAR revisions adopted in Rulemaking 54 ("RM54"). In Case No. 9484, Order No. 88975, the Commission accepted the Company's proposal to recover the gas RM54 costs through the supplier liability fund consistent with Order No. 88432. With respect to operating income, BGE in this proceeding is removing RM54 costs in the projected Bridge Period and the first year of the MYP (2021) since these expenses are budgeted as distribution expenses in these years but will ultimately be recovered through the supplier liability fund. MYP years 2022 and 2023 do not include an adjustment since the RM54 software will be fully amortized at the end of 2021. In addition, these costs are not being recorded as distribution expenses in the HTY, so there is no need for a related operating income adjustment for the 2019 HTY. The companion adjustment is Rate Base Adjustment 9E.

Description	HTY 2019	Bridge Period 2020	MYP 1 2021	MYP 2 2022	MYP 3 2023
RM54 Amortization included in each period	$ -	$ 234,542	$ 200,646	$ -	$ -
Income Tax Effect at 27.5175%		(64,540)	(55,213)		
Adjustment to operating income	$ -	$ 170,002	$ 145,433	$ -	$ -
Amount Presented on Company Exhibit DMV-4E	$ -	$ 170,000	$ 145,000	$ -	$ -

Mapping to Exhibit DMV-3E Ratemaking Adjustments:

Depreciation and Amortization (Line 20)	$ -	$ (234,542)	$ (200,646)	$ -	$ -
Current Income Taxes (Line 22)		64,540	55,213		
	$ -	$ (170,002)	$ (145,433)	$ -	$ -

Baltimore Gas and Electric Company
Electric Rate Case Expenses
Multi-Year Plan

Operating Income
Adjustment 30E

This adjustment reduces operating income to to reflect the amortization of rate case expenses associated with Case No. 9610, but incurred after the test year in that proceeding, as well as rate case expenses associated with the current proceeding. BGE proposes to amortize these rate case expenses over a three-year period, consistent with Case Nos. 9326, 9406, 9484, and 9610 Commission precedent allowing for recovery of rate case expenses over a three-year period and beginning with 2022, the second MYP rate-effective year.

Description	HTY 2019	Bridge Period 2020	MYP 1 2021	MYP 2 2022	MYP 3 2023
Rate case expenses assoc with Case 9610 incurred after hearings	$ -	$ -	$ -	$ 85,492	$ 85,492
Rate case expenses assoc with the current MYP proceeding	-	-	-	201,069	201,069
Total rate case expenses to be amortized	-	-	-	286,561	286,561
3-year amortization	-	-	-	3	3
Amortization of deferred rate case expenses	-	-	-	95,520	95,520
Income Tax effect at 27.5175%	-	-	-	(26,285)	(26,285)
Adjustment to operating income	$ -	$ -	$ -	$ 69,235	$ 69,235
Amount Presented on Company Exhibit DMV-4E	$ -	$ -	$ -	$ (69,000)	$ (69,000)

Mapping to Exhibit DMV-3E Ratemaking Adjustments:

Operation and Maintenance (Line 19)	$ -	$ -	$ -	$ 95,520	$ 95,520
Current Income Taxes (Line 22)				(26,285)	(26,285)
	$ -	$ -	$ -	$ 69,235	$ 69,235

This adjustment provides for the amortization of electric distribution Conservation Voltage Reduction ("CVR") program costs consistent with adjustments authorized in Case Nos. 9299, 9326, 9406, and 9610. This adjustment recovers the amortization of the CVR costs incurred subsequent to July 2019 (the end of the test year in Case No. 9610) through December 2020 over a two-year period beginning in 2022 in light of the decision to defer 2021 amortization. The Company is not seeking amortization of CVR spending subsequent to 2020 as will be discussed in Operating Income Adjustment 33. The adjustment in MYP years 2022 and 2023 only reflects amortization of deferred amounts through December 2020. Rate Base Adjustment 10 is the companion adjustment and reflects the impact on the CVR regulatory asset, and therefore on rate base, of the additional amortization provided in this proceeding.

Description	HTY 2019	Bridge Period 2020	MYP 1 2021	MYP 2 2022	MYP 3 2023
CVR costs deferred August 2019 - December 2020	$ -	$ -	$ -	$ 5,609,693	$5,609,693
2-Year Amortization	-	-	-	2	2
CVR costs to be recovered in the twelve months	-	-	-	2,804,846	2,804,846
Income tax effect at 27.5175%	-	-	-	(771,824)	(771,824)
Adjustment to operating income	$ -	$ -	$ -	$ 2,033,023	$2,033,023
Amount Presented on Company Exhibit DMV-4E	-	-	-	(2,033,000)	(2,033,000)

Mapping to Exhibit DMV-3E Ratemaking Adjustments:

Operation and Maintenance (Line 19)	$ -	$ -	$ -	$ 2,804,846	$ 2,804,846
Current Income Taxes (Line 22)	-	-	-	(771,824)	(771,824)
	$ -	$ -	$ -	$ 2,033,023	$ 2,033,023

Baltimore Gas and Electric Company
Reversal of Electric CVR Program Deferrals
Multi-Year Plan

Operating Income
Adjustment 33E

This adjustment reduces electric operating income to reflect the Company's proposed termination of regulatory asset treatment for CVR costs effective with 2021 spending. Operating Income Adjustment 32 provides for the amortization of CVR spending through calendar year 2020. With adoption of a MYP, a two-year amortization no longer serves the originally intended purpose. Therefore, effective in 2021, the Company is proposing that CVR spending no longer be deferred in a regulatory asset but instead be flowed through to operating expense similar to other expenses. For purposes of the budget, CVR spending is reflected in a regulatory asset and not as an operating expense. Therefore, in order to reflect the termination of regulatory asset treatment for CVR costs effective with calendar year 2021, Operating Income Adjustment 33 adds the budgeted CVR spending to O&M expenses, with a corresponding reduction to rate base proposed in Rate Base Adjustment 11 for all three MYP years (2021 – 2023).

Description	HTY 2019	Bridge Period 2020	MYP 1 2021	MYP 2 2022	MYP 3 2023
CVR spending deferred during MYP years	$ -	$ -	$ 1,880,661	$ 1,019,163	$ 1,058,064
Income Tax Effect at 27.5175%	-	-	(517,511)	(280,448)	(291,153)
Adjustment to operating income	$ -	$ -	$ 1,363,150	$ 738,715	$ 766,911
Amount Presented on Company Exhibit DMV-4E	$ -	$ -	$ (1,363,000)	$ (739,000)	$ (767,000)

Mapping to Exhibit DMV-3E Ratemaking Adjustments:

Operation and Maintenance (Line 19)	$ -	$ -	$ 1,880,661	$ 1,019,163	$ 1,058,064
Current Income Taxes (Line 22)	-	-	(517,511)	(280,448)	(291,153)
	$ -	$ -	$ 1,363,150	$ 738,715	$ 766,911

Baltimore Gas and Electric Company
Electric Vehicle Amortization
Multi-Year Plan

Operating Income
Adjustment 36E

This adjustment provides for the recovery of Electric Vehicle ("EV") costs. In Case No. 9478, Order No. 88997, the Commission directed utilities to seek cost recovery of EV program costs in a future rate case proceeding. In its order, the Commission also directed the utilities to provide a cost-effectiveness assessment. At this time, the Company is implementing a cost-effective EV program, as demonstrated by Company Witness Warner in his Direct Testimony. This adjustment provides for the amortization of the EV regulatory asset as of the end of each MYP year beginning in 2022 over a five-year period as approved by the Commission in Order No. 88997. Rate Base Adjustment 13E is the companion adjustment.

Description	HTY 2019	Bridge Period 2020	MYP 1 2021	MYP 2 2022	MYP 3 2023
EV costs deferred through the end of each previous year	$ -	$ -	$ -	$ 5,483,148	$ 7,247,786
5-Year Amortization	-	-	-	5	5
EV costs to be recovered in the twelve months	-	-	-	1,096,630	1,449,557
Income tax effect at 27.5175%	-	-	-	(301,765)	(398,882)
Adjustment to operating income	$ -	$ -	$ -	$ 794,865	$ 1,050,675
Amount Presented on Company Exhibit DMV-4E	$ -	$ -	$ -	$ (795,000)	$(1,051,000)

Mapping to Exhibit DMV-3E Ratemaking Adjustments:

Operation and Maintenance (Line 19)	$ -	$ -	$ -	$ 1,096,630	$ 1,449,557
Current Income Taxes (Line 22)	-	-	-	(301,765)	(398,882)
	$ -	$ -	$ -	$ 794,865	$ 1,050,675

Baltimore Gas and Electric Company
Reversal of Major Outage Event Restoration Expense
Multi-Year Plan

Operating Income
Adjustment 37E

This adjustment removes the $10.2 million of major outage event restoration expense included in the budget in each period in an effort to mitigate the impact of the COVID-19 pandemic. The removal of these costs will help keep base distribution revenues lower in this MYP than they otherwise would have been for customers.

Description	HTY 2019	Bridge Period 2020	MYP 1 2021	MYP 2 2022	MYP 3 2023
Major Outage Event Restoration Expense included in budgeted O&M	$ -	$ -	$ 10,200,000	$ 10,200,000	$ 10,200,000
Income tax effect at 27.5175%	-		(2,806,785)	(2,806,785)	(2,806,785)
Adjustment to operating income	$ -	$ -	$ 7,393,215	$ 7,393,215	$ 7,393,215
Amount Presented on Company Exhibit DMV-4E	$ -	$ -	$ 7,393,000	$ 7,393,000	$ 7,393,000

Mapping to Exhibit DMV-3E Ratemaking Adjustments:

Operation and Maintenance (Line 19)	$ -	$ -	$ (10,200,000)	$(10,200,000)	$ (10,200,000)
Current Income Taxes (Line 22)	-	-	2,806,785	2,806,785	2,806,785
	$ -	$ -	$ (7,393,215)	$ (7,393,215)	$ (7,393,215)

This adjustment provides customers with an acceleration of tax benefits attributable to the amortization of the Tax Cuts and Jobs Act of 2017 (“TCJA”) unprotected property and non-property excess deferred regulatory liabilities and the Maryland Additional Subtraction Modification (“MASM”) tax benefit. BGE is proposing to give these tax benefits to customers over the MYP period, starting when the new rates become effective in January 2021, for each of the calendar years 2021 through 2023 in an effort to help with the economic recovery and mitigate the financial impacts of the pandemic. The companion adjustment is Rate Base Adjustment 14E.

Description	HTY 2019	Bridge Period 2020	MYP 1 2021	MYP 2 2022	MYP 3 2023
Accelerated Amortization of Tax Benefits:					
TCJA - Unprotected Property	$ -	$ -	$ (2,172,260)	$ 76,172,117	$ 24,465,740
TCJA - Unprotected Non-Property	-	-	589,170	16,589,170	8,464,979
Maryland Subtraction Modification	-	-	47,725,705	4,860,334	4,289,334
Adjustment to operating income	$ -	$ -	$ 46,142,616	$ 97,621,622	$ 37,220,054
Amount Presented on Company Exhibit DMV-4E	$ -	$ -	$ 46,143,000	$ 97,622,000	$ 37,220,000

Mapping to Exhibit DMV-3E Ratemaking Adjustments:

Current Income Taxes (Line 22)	$ -	$ -	$ (46,142,616)	$ (97,621,622)	$ (37,220,054)
	$ -	$ -	$ (46,142,616)	$ (97,621,622)	$ (37,220,054)

Baltimore Gas and Electric Company
2021 Electric Regulatory Asset Amortization Suspension
Multi-Year Plan

Operating Income Adjustment 39E

This adjustment increases electric operating income by reflecting the suspension in 2021 of the amortization of existing base distribution regulatory assets in an effort to help with the economic recovery and mitigate the financial impacts of the pandemic. The elimination of 2021 amortization amounts will keep base distribution revenues lower in this MYP than they otherwise would have been for customers. The companion adjustment is Rate Base Adjustment 15E.

Description	HTY 2019	Bridge Period 2020	MYP 1 2021	MYP 2 2022	MYP 3 2023
Deferred Costs to Achieve - Case 9406 tranche	$ -	$ -	$ 358,570	$ -	$ -
Case No. 9406 Rate Case Expenses (Case No. 9610 tranche)	-	-	49,524	-	-
Case No. 9610 Rate Case Expenses (Case No. 9610 tranche)	-	-	47,757	-	-
Union 10-Day Sick Bank	-	-	171,705	-	-
CVR Case No. 9610 tranche	-	-	2,279,405	-	-
Smart Grid	-	-	28,064,038	-	-
Total regulatory asset amortization to be eliminated		-	30,970,998	-	-
Income tax effect at 27.5175%		-	(8,522,444)	-	-
Adjustment to operating income	$ -	$ -	$ 22,448,554	$ -	$ -
Amount Presented on Company Exhibit DMV-4E	$ -	$ -	$ 22,449,000	$ -	$ -

Mapping to Exhibit DMV-3E Ratemaking Adjustments:

Operation and Maintenance (Line 19)	$ -	$ -	$ (2,735,255)	$ -	$ -
Depreciation and Amortization (Line 20)			(28,235,743)		
Current Income Taxes (Line 22)			8,522,444		
	$ -	$ -	$ (22,448,554)	$ -	$ -

Baltimore Gas and Electric Company
Electric Smart Grid Regulatory Asset Life Extension
Multi-Year Plan

Operating Income
Adjustment 40E

This adjustment increases electric operating income by reflecting the extension of the Smart Grid Regulatory Asset amortization period through 2031, an additional five years, in an effort to help with the economic recovery and mitigate the financial impacts of the pandemic. Previously, the Commission approved Smart Grid-related regulatory asset lives so that they would be fully amortized as of May 2026. In this proceeding, the Company is proposing to extend the lives of these assets to December 2031, thereby resulting in lower annual amortization expense. The companion adjustment is Rate Base Adjustment 16E.

Description	HTY 2019	Bridge Period 2020	MYP 1 2021	MYP 2 2022	MYP 3 2023
Current Annual Amortization (based on amortization throuigh May 2026)	$ -	$ -	$ -	$ 28,064,038	$ 28,064,038
Proposed Annual Amortization (based on amortization throuigh December 2031)	-	-	-	14,390,626	14,390,626
Total regulatory asset amortization to be eliminated		-	-	13,673,412	13,673,412
Income tax effect at 27.5175%		-	-	(3,762,581)	(3,762,581)
Adjustment to operating income	$ -	$ -	$ -	$ 9,910,831	$ 9,910,831
Amount Presented on Company Exhibit DMV-4E	$ -	$ -	$ -	$ 9,911,000	$ 9,911,000

Mapping to Exhibit DMV-3E Ratemaking Adjustments:

	HTY 2019	Bridge Period 2020	MYP 1 2021	MYP 2 2022	MYP 3 2023
Depreciation and Amortization (Line 20)	$ -	$ -	$ -	$ (13,673,412)	$ (13,673,412)
Current Income Taxes (Line 22)	-	-	-	3,762,581	3,762,581
	$ -	$ -	$ -	$ (9,910,831)	$ (9,910,831)

Baltimore Gas and Electric Company
Electric COVID-19 Expenses
Multi-Year Plan

Operating Income
Adjustment 41E

This adjustment provides the framework for the electric recovery of COVID-19 incremental costs over a five-year period beginning in 2023. The COVID-19 incremental costs will be updated at the time of the hearings. The companion adjustment is Rate Base Adjustment 17E.

Description	HTY 2019	Bridge Period 2020	MYP 1 2021	MYP 2 2022	MYP 3 2023
COVID-19 Expenses	$ -	$ -	$ -	$ -	$ -
Total COVID-19 expenses to be amortized	-	-	-		
5-year amortization	-	-	-	5	5
Amortization of deferred COVID-19 expenses	-	-	-	-	-
Income Tax effect at 27.5175%	-	-	-		
Adjustment to operating income	$ -	$ -	$ -	$ -	$ -
Amount Presented on Company Exhibit DMV-4E	$ -	$ -	$ -	$ -	$ -

Mapping to Exhibit DMV-3E Ratemaking Adjustments:

Operation and Maintenance (Line 19)	$ -	$ -	$ -	$ -	$ -
Current Income Taxes (Line 22)					
	$ -	$ -	$ -	$ -	$ -

Baltimore Gas and Electric Company
Adjustment to Reflect the Electric Income Tax Effect of Pro Forma Interest
Multi-Year Plan

Operating Income
Adjustment 42E

This adjustment synchronizes interest expense utilized in the income tax calculation with adjusted rate base and the weighted cost of debt implicit in the electric rate of return supported by the Company for each period.

Description	HTY 2019	Bridge Period 2020	MYP 1 2021	MYP 2 2022	MYP 3 2023
Unadjusted rate base - Company Exhibit DMV-3E, line 11	$ 3,482,151,901	$3,797,831,719	$4,103,039,088	$4,344,602,921	$4,550,952,491
Rate base adjustments - Company Exhibit DMV-3E, line 11	89,771,676	(20,241,492)	9,760,513	90,054,353	159,375,265
Rate Base adjusted for calculation of pro forma interest	$ 3,571,923,577	$3,777,590,227	$4,112,799,601	$4,434,657,275	$4,710,327,756
Weighted cost of debt:					
Long-term debt	1.87%	1.88%	1.87%	1.87%	1.87%
Long-term debt proforma interest	$ 66,794,971	$ 71,018,696	$ 76,909,353	$ 82,928,091	$ 88,083,129
Long-term debt actual interest charges	63,473,619	69,915,572	75,880,783	79,340,403	86,012,059
Adjustment to interest expense:	3,321,352	1,103,124	1,028,569	3,587,688	2,071,070
Income tax rate	27.5175%	27.5175%	27.5175%	27.5175%	27.5175%
Tax effect of pro forma interest	$ (913,953)	$ (303,552)	$ (283,037)	$ (987,242)	$ (569,907)
Amount Presented on Company Exhibit DMV-4E	$ 914,000	$ 304,000	$ 283,000	$ 987,000	$ 570,000

Mapping to Exhibit DMV-3E Ratemaking Adjustments:

Current Income Taxes (Line 22)	$ (913,953)	$ (303,552)	$ (283,037)	$ (987,242)	$ (569,907)
	$ (913,953)	$ (303,552)	$ (283,037)	$ (987,242)	$ (569,907)

Baltimore Gas and Electric Company
Case 9610 Electric Smart Grid Regulatory Asset
Multi-Year Plan

Rate Base
Adjustment 1E

This adjustment reduces electric rate base to reflect the impact of the accumulated amortization associated with the amortization of the electric Smart Grid cost regulatory asset through May 2026 as included in the Case No. 9610 settlement which was accepted by the Commission in Order No. 89400. It is the companion adjustment to Operating Income Adjustment No. 5E.

Description	HTY 2019	Bridge Period 2020	MYP 1 2021	MYP 2 2022	MYP 3 2023
Change in Smart Grid Accumulated Amortization included in Case No. 9610 per Operating Income Adjustment 5E	$ 5,593,662	$ -	$ -	$ -	$ -
Adjustment to reflect average rate base	50%	-	-	-	-
Increased accumulated amortization	2,796,831	-	-	-	-
Income tax effect at 27.5175%	(769,618)	-	-	-	-
Adjustment to rate base	$ 2,027,213	$ -	$ -	$ -	$ -
Amount Presented on Company Exhibit DMV-4E	$ (2,027,000)	$ -	$ -	$ -	$ -

Mapping to Exhibit DMV-3E Ratemaking Adjustments:

Regulatory Assets & Liabilities (Line 9)	$ (2,796,831)	$ -	$ -	$ -	$ -
Accumulated Deferred Income Taxes (Line 6)	769,618	-	-	-	-
	$ (2,027,213)	$ -	$ -	$ -	$ -

This adjustment reflects the impact on the CVR regulatory asset of the amortization included in the Case No. 9610 settlement. This is the companion adjustment to Operating Income Adjustment 6E.

Description	HTY 2019	Bridge Period 2020	MYP 1 2021	MYP 2 2022	MYP 3 2023
Increase in amortization resulting from Operating Income Adjustment 6E	$ 2,089,455	$ -	$ -	$ -	$ -
Income tax effect at 27.5175%	(574,966)	-	-	-	-
Increased accumulated amortization, net of tax	1,514,489	-	-	-	-
Adjustment to reflect average rate base	50.0%	-	-	-	-
Adjustment to rate base	$ 757,245	$ -	$ -	$ -	$ -
Amount Presented on Company Exhibit DMV-4E	$ (757,000)	$ -	$ -	$ -	$ -

Mapping to Exhibit DMV-3E Ratemaking Adjustments:

Regulatory Assets & Liabilities (Line 9)	$ (1,044,727)	$ -	$ -	$ -	$ -
Accumulated Deferred Income Taxes (Line 6)	287,483	-	-	-	-
	$ (757,245)	$ -	$ -	$ -	$ -

Baltimore Gas and Electric Company
Case No. 9610 Impact of New Depreciation Rates
Multi-Year Plan

Rate Base
Adjustment 4E

This adjustment reflects the impact on the accumulated depreciation reserve of the new depreciation rates resulting from the Case No. 9610 settlement. This is the companion adjustment to Operating Income Adjustment 9E.

Description	HTY 2019	Bridge Period 2020	MYP 1 2021	MYP 2 2022	MYP 3 2023
Change in accumulated depreciation resulting from Operating Income Adjustment 9E	$ (1,277,589)	$ -	$ -	$ -	$ -
Deferred income taxes on normalized depreciation expense at 27.5175%	351,561	-	-	-	-
Increased accumulated depreciation, net of tax	(926,028)	-	-	-	-
Adjustment to reflect average rate base	50.0%	-	-	-	-
Adjustment to rate base	$ (463,014)	$ -	$ -	$ -	$ -
Amount Presented on Company Exhibit DMV-4E	$ 463,000	$ -	$ -	$ -	$ -

Mapping to Exhibit DMV-3E Ratemaking Adjustments:

Accumulated Depreciation and Amortization (Line 3)	$ 638,794	$ -	$ -	$ -	$ -
Accumulated Deferred Income Taxes (Line 6)	(175,780)	-	-	-	-
	$ 463,014	$ -	$ -	$ -	$ -

Baltimore Gas and Electric Company
Electric Safety and Reliability Investments
Multi-Year Plan

Rate Base
Adjustment 7E

This adjustment reflects the terminal impact of the known and measurable non-revenue producing safety and reliability investments as included in Case No. 9610. This adjustment includes the impact on plant in service, accumulated depreciation reserve, depreciation savings, and related accumulated deferred income taxes. It is a companion adjustment to Operating Income Adjustment 17E, which adjusts the level of depreciation for these investments.

Description	HTY 2019	Bridge Period 2020	MYP 1 2021	MYP 2 2022	MYP 3 2023
Electric safety and reliability project investment included in Case No. 9610 filing	$ 258,779,185	$ -	$ -	$ -	$ -
Electric safety and reliability project investment reflected in the Case No. 9610 average rate base	126,430,536	-	-	-	-
Additional electric safety and reliability investment - Increase in plant in service	132,348,650	-	-	-	-
Less:					
Additional accumulated depreciation, net of savings, per OIA Adj. No. 17E	2,885,165	-	-	-	-
Plus:					
Accumulated Deferred Income Taxes on the additional investment above	(17,682,354)	-	-	-	-
Adjustment to Rate Base	$ 111,781,130	$ -	$ -	$ -	$ -
Amount presented on Company Exhibit DMV-4E	$ 111,781,000	$ -	$ -	$ -	$ -

Mapping to Exhibit DMV-3E Ratemaking Adjustments:

Electric Plant (Line 2)	$ 132,348,650	$ -	$ -	$ -	$ -
Accumulated Depreciation and Amortization (Line 3)	(2,885,165)				
Accumulated Deferred Income Taxes (Line 6)	(17,682,354)	-	-	-	-
	$ 111,781,130	$ -	$ -	$ -	$ -

Baltimore Gas and Electric Company
Eliminate Electric RM54 Software
Multi-Year Plan

Rate Base
Adjustment 9E-Updated

This adjustment reduces electric rate base to remove the RM54 capital software costs. The RM54 capital is recorded as common plant, and therefore is allocated to electric and gas distribution. Accordingly, since these costs will be recovered through the Purchase of Receivables discount rate, it is necessary to remove the electric portion of RM54 capital in Rate Base Adjustment 9E. The companion adjustment is Operating Income Adjustment 29E-Updated.

Description	HTY 2019	Bridge Period 2020	MYP 1 2021	MYP 2 2022	MYP 3 2023
RM54 Plant in Service	$ 1,197,357	$ 1,174,807	$ 1,170,231	$ -	$ -
RM54 Accumulated Amortization	(615,068)	(852,524)	(1,084,039)	-	-
RM54 Software to be excluded from rate base	582,290	322,283	86,192	-	-
Income Tax Effect at 27.5175%	(160,232)	(88,684)	(23,718)	-	-
Adjustment to rate base	$ 422,058	$233,599	$62,474	$ -	$ -
Amount Presented on Company Exhibit DMV-4E	$ (422,000)	($234,000)	($62,000)	$ -	$ -

Mapping to Exhibit DMV-3E Ratemaking Adjustments:

Electric Plant (Line 2)	$ (1,197,357)	$ (1,174,807)	$ (1,170,231)	$ -	$ -
Accumulated Depreciation and Amortization (Line 3)	615,068	852,524	1,084,039	-	-
Accumulated Deferred Income Taxes (Line 6)	160,232	88,684	23,718	-	-
	$ (422,058)	$ (233,599)	$ (62,474)	$ -	$ -

Baltimore Gas and Electric Company
Impact of Electric CVR Amortization
Multi-Year Plan

This adjustment reflects the impact on the CVR regulatory asset of the additional amortization provided. This is the companion adjustment to Operating Income Adjustment 32E.

Description	HTY 2019	Bridge Period 2020	MYP 1 2021	MYP 2 2022	MYP 3 2023
Increase in amortization resulting from Operating Income Adjustment 32E	$ -	$ -	$ -	$ 2,804,846	$ 2,804,846
Adjustment to reflect average rate base	50%	50%	50%	50%	50%
Average Rate Base impact of current period amortization	-	-	-	1,402,423	1,402,423
Accumulated Amortization as of end of prior period	-	-			2,804,846
Total CVR accumulated amortization impact	-	-		1,402,423	4,207,269
Income tax effect at 27.5175%	-	-	-	(385,912)	(1,157,735)
Adjustment to rate base	$ -	$ -	$ -	$ 1,016,511	$ 3,049,534
Amount Presented on Company Exhibit DMV-4E	$ -	$ -	$ -	$(1,017,000)	$ (3,050,000)

Mapping to Exhibit DMV-3E Ratemaking Adjustments:

Regulatory Assets & Liabilities (Line 9)	$ -	$ -	$ -	$(1,402,423)	$ (4,207,269)
Accumulated Deferred Income Taxes (Line 6)	-	-	-	385,912	1,157,735
	$ -	$ -	$ -	$(1,016,511)	$ (3,049,534)

Baltimore Gas and Electric Company
Impact of Reversal of Electric CVR Deferrals
Multi-Year Plan

Rate Base
Adjustment 11E

This adjustment reflects the impact on rate base of terminating regulatory asset treatment for CVR. It is the companion adjustment to Operating Income Adjustment 33E.

Description	HTY 2019	Bridge Period 2020	MYP 1 2021	MYP 2 2022	MYP 3 2023
CVR expenditures deferred in regulatory asset during each MYP year from Operating Income Adjustment 33E	$ -	$ -	$ 1,880,661	$ 1,019,163	$ 1,058,064
Adjustment to reflect average rate base	-	-	50%	50%	50%
Average Rate Base impact of current period spend			940,331	509,582	529,032
Total additional CVR spend to be reflected in O&M as of end of prior period	-	-	-	1,880,661	2,899,824
Total reduction in rate base of currently deferred CVR spend	-	-	940,331	2,390,243	3,428,856
Income tax effect at 27.5175%	-	-	(258,755)	(657,735)	(943,535)
Adjustment to rate base	$ -	$ -	$ 681,575	$ 1,732,508	$ 2,485,321
Amount Presented on Company Exhibit DMV-4E	$ -	$ -	$ (682,000)	$(1,733,000)	$ (2,485,000)

Mapping to Exhibit DMV-3E Ratemaking Adjustments:

Regulatory Assets & Liabilities (Line 9)	$ -	$ -	$ (940,331)	$(2,390,243)	$ (3,428,856)
Accumulated Deferred Income Taxes (Line 6)	-	-	258,755	657,735	943,535
	$ -	$ -	$ (681,575)	$(1,732,508)	$ (2,485,321)

Baltimore Gas and Electric Company
Impact of Electric Vehicle Pgm Amortization
Multi-Year Plan

Rate Base
Adjustment 13E

This adjustment reflects the impact on the Electric Vehicle (“EV”) regulatory asset of the additional amortization provided. This is the companion adjustment to Operating Income Adjustment 36E.

Description	HTY 2019	Bridge Period 2020	MYP 1 2021	MYP 2 2022	MYP 3 2023
Increase in amortization resulting from Operating Income Adjustment 36E	$ -	$ -	$ -	$ 1,096,630	$ 1,449,557
Adjustment to reflect average rate base	-	-	50%	50%	50%
Average Rate Base impact of current period amortization				548,315	724,779
Accumulated Amortization as of end of prior period	-	-	-		1,096,630
Total EV accumulated amortization impact	-	-		548,315	1,821,408
Income tax effect at 27.5175%	-	-	-	(150,883)	(501,206)
Increased accumulated amortization, net of tax	$ -	$ -	$ -	$ 397,432	$ 1,320,202
Adjustment to rate base	$ -	$ -	$ -	$ 397,432	$ 1,320,202
Amount Presented on Company Exhibit DMV-4E	$ -	$ -	$ -	$ (397,000)	$ (1,320,000)
Mapping to Exhibit DMV-3E Ratemaking Adjustments:					
Regulatory Assets & Liabilities (Line 9)	$ -	$ -	$ -	$ (548,315)	$ (1,821,408)
Accumulated Deferred Income Taxes (Line 6)	-	-	-	150,883	501,206
	$ -	$ -	$ -	$ (397,432)	$ (1,320,202)

Baltimore Gas and Electric Company
Electric Accelerated Tax Benefits Regulatory Liability Impact
Multi-Year Plan

Rate Base
Adjustment 14E

This adjustment reflects the rate base impact of the accelerated tax benefits. This is the companion adjustment to Operating Income Adjustment 38E.

Description	HTY 2019	Bridge Period 2020	MYP 1 2021	MYP 2 2022	MYP 3 2023
Accelerated tax benefits resulting from Operating Income Adjustment 38E	$ -	$ -	$ 46,142,616	$ 97,621,622	$ 37,220,054
Adjustment to reflect average rate base	-	-	50%	50%	50%
Average Rate Base impact of current period amortization			23,071,308	48,810,811	18,610,027
Accumulated Accelerated tax benefits as of end of prior period	-	-	-	46,142,616	143,764,237
Adjustment to rate base	$ -	$ -	$ 23,071,308	$ 94,953,426	$ 162,374,264
Amount Presented on Company Exhibit DMV-4E	$ -	$ -	$ 23,071,000	$ 94,953,000	$ 162,374,000

Mapping to Exhibit DMV-3E Ratemaking Adjustments:

Regulatory Assets & Liabilities (Line 9)	$ -	$ -	$ 23,071,308	$ 94,953,426	$ 162,374,264

Baltimore Gas and Electric Company
2021 Electric Regulatory Asset Amortization Suspension
Multi-Year Plan

Rate Base
Adjustment 15E

This adjustment reflects the rate base impact of eliminating the 2021 amortization expense associated with certain regulatory assets in light of the current economic situation as a result of the COVID-19 pandemic. The companion adjustment is Operating Income Adjustment 39E.

Description	HTY 2019	Bridge Period 2020	MYP 1 2021	MYP 2 2022	MYP 3 2023
Deferred Costs to Achieve - Case 9406 tranche	$ -	$ -	$ 358,570	$ -	$ -
CVR Case No. 9610 tranche	-	-	2,279,405	-	-
Smart Grid	-	-	20,415,997	-	-
Total rate base impact of regulatory asset amortization eliminated in 2021		-	23,053,971	-	-
Adjustment to reflect average rate base	-	-	50%	50%	50%
Average Rate Base impact of current period amortization			11,526,986		
Accumulated Amortization as of end of prior period	-	-	-	23,053,971	23,053,971
Total 2021 regulatory asset accumulated amortization impact	-	-	11,526,986	23,053,971	23,053,971
Income tax effect at 27.5175%		-	(3,171,938)	(6,343,877)	(6,343,877)
Adjustment to operating income	$ -	$ -	$ 8,355,047	$16,710,095	$16,710,095
Amount Presented on Company Exhibit DMV-4E	$ -	$ -	$ 8,355,000	$16,710,000	$16,710,000

Mapping to Exhibit DMV-3E Ratemaking Adjustments:

Regulatory Assets & Liabilities (Line 9)			$ 11,526,986	$ 23,053,971	$ 23,053,971
Accumulated Deferred Income Taxes (Line 6)			(3,171,938)	(6,343,877)	(6,343,877)
	$ -	$ -	$ 8,355,047	$ 16,710,095	$ 16,710,095

Baltimore Gas and Electric Company
Electric Smart Grid Regulatory Asset Life Extension
Multi-Year Plan

Rate Base
Adjustment 16E

This adjustment reflects the rate base impact of extending the Smart Grid regulatory asset recovery period through December 2031 from May 2026 in light of the current economic situation as a result of the COVID-19 pandemic. The companion adjustment is Operating Income Adjustment 40E.

Description	HTY 2019	Bridge Period 2020	MYP 1 2021	MYP 2 2022	MYP 3 2023
Total rate base impact of Operating Income Adjustment 40	-	-	-	$ 9,499,110	9,499,110
Adjustment to reflect average rate base	-	-	-	50%	50%
Average Rate Base impact of current period amortization				4,749,555	4,749,555
Accumulated Amortization as of end of prior period	-	-	-	-	9,499,110
Total Smart Grid regulatory asset accumulated amortization impact	-	-		4,749,555	14,248,664
Income tax effect at 27.5175%		-	-	(1,306,959)	(3,920,876)
Adjustment to operating income	$ -	$ -	$ -	$ 3,442,596	$10,327,788
Amount Presented on Company Exhibit DMV-4E	$ -	$ -	$ -	$ 3,443,000	$10,328,000

Mapping to Exhibit DMV-3E Ratemaking Adjustments:

Regulatory Assets & Liabilities (Line 9)			$ -	$ 4,749,555	$ 14,248,664
Accumulated Deferred Income Taxes (Line 6)				(1,306,959)	(3,920,876)
	$ -	$ -	$ -	$ 3,442,596	$ 10,327,788

Baltimore Gas and Electric Company
COVID-19 Regulatory Asset
Multi-Year Plan

Rate Base
Adjustment 17E

This adjustment reflects the inclusion of the COVID-19 regulatory asset in Rate base. This is the companion adjustment to Operating Income Adjustment 41E.

Description	HTY 2019	Bridge Period 2020	MYP 1 2021	MYP 2 2022	MYP 3 2023
Total COVID-19 Regulatory Asset	$ -	$ -	$ -	$ -	$ -
Increase in amortization resulting from Operating Income Adjustment 41E	-	-	-	-	-
Adjustment to reflect average rate base	-	-	50%	50%	50%
Average Rate Base impact of current period amortization					
Accumulated Amortization as of end of prior period	-	-	-	-	-
Total COVID-19 accumulated amortization impact	-	-			
Total COVID-19 regulatory asset, net of amortization					
Income tax effect at 27.5175%	-	-	-	-	-
COVID-19 regulatory asset rate base impact, net of tax	$ -	$ -	$ -	$ -	$ -
Adjustment to rate base	$ -	$ -	$ -	$ -	$ -
Amount Presented on Company Exhibit DMV-4E	$ -	$ -	$ -	$ -	$ -

Mapping to Exhibit DMV-3E Ratemaking Adjustments:

Regulatory Assets & Liabilities (Line 9)	$ -	$ -	$ -	$ -	$ -
Accumulated Deferred Income Taxes (Line 6)	-	-	-	-	-
	$ -	$ -	$ -	$ -	$ -

Baltimore Gas and Electric Company **Company Exhibit DMV-5E-Updated**

Electric Cash Working Capital Reflected in Unadjusted Rate Base

Multi-Year Plan

2019 Actual HTY - Unadjusted Rate Base - Based on 2014 Lag Study Net Lag Days

Line No.	Description	Line of Business	CWC Expense	Net Lag Days	Cash Advanced
1	Net Metering Costs	Electric	1,490,726	(59.5)	(243,009)
2	Salaries and Wages	Electric	113,786,361	10.9	3,398,004
3	Fringe Benefits	Electric	38,548,735	31.6	3,337,370
4	Other Oper & Maint Expense	Electric	260,552,175	(1.5)	(1,070,762)
5	Property Taxes	Electric	87,097,956	133.6	31,880,238
6	Payroll Taxes	Electric	9,406,375	10.3	265,440
7	PSC Assessment	Electric	3,008,724	77.3	637,190
8	Electric Environmental Surcharge	Electric	4,176,638	4.2	48,060
9	Universal Service Fund	Electric	18,982,633	10.4	540,875
10	GRT Taxes	Electric	41,979,319	(5.6)	(644,066)
11	Other Taxes	Electric	3,600,903	14.0	138,117
12	Federal Income Taxes - Current	Electric	(11,667,242)	(4.5)	143,843
13	State Income Taxes - Current	Electric	7,186,121	(11.5)	(226,412)
14	Interest Expense	Electric	63,044,857	(41.6)	(7,185,386)
15	Short Term Interest	Electric	1,355,418	53.7	199,414
16	Interest on Customer Deposits	Electric	2,080,846	(136.0)	(775,329)
17	Total Electric Cash Working Capital		$644,630,547		$30,443,585
18	Total Electric Cash Working Capital ($000) carried forward to Unadjusted Rate Base Company Exhibit DMV-3E, line 5				$30,444

Baltimore Gas and Electric Company **Company Exhibit DMV-5E-Updated**

Electric Cash Working Capital Reflected in Unadjusted Rate Base

Multi-Year Plan

2020 Bridge Period - Unadjusted Rate Base - Based on 2014 Lag Study Net Lag Days

Line No.	Description	Line of Business	CWC Expense	Net Lag Days	Cash Advanced
1	Net Metering Costs	Electric	1,516,864	(59.5)	(247,270)
2	Salaries and Wages	Electric	121,276,502	10.9	3,621,682
3	Fringe Benefits	Electric	37,225,108	31.6	3,222,776
4	Other Oper & Maint Expense	Electric	290,946,335	(1.5)	(1,195,670)
5	Property Taxes	Electric	88,983,031	133.6	32,570,227
6	Payroll Taxes	Electric	10,575,995	10.3	298,446
7	PSC Assessment	Electric	3,346,336	77.3	708,690
8	Electric Environmental Surcharge	Electric	4,185,977	4.2	48,167
9	Universal Service Fund	Electric	16,224,448	10.4	462,286
10	GRT Taxes	Electric	41,662,572	(5.6)	(639,207)
11	Other Taxes	Electric	3,628,138	14.0	139,161
12	Current Taxes	Electric	23,353,038	(5.9)	(377,487)
13	State Income Taxes - Current	Electric	-	(11.5)	-
14	Interest Expense	Electric	69,915,572	(41.6)	(7,968,460)
15	Short Term Interest	Electric	-	53.7	-
16	Interest on Customer Deposits	Electric	1,329,794	(136.0)	(495,485)
17	Total Electric Cash Working Capital		$714,169,710		$30,147,857
18	Total Electric Cash Working Capital ($000) carried forward to Unadjusted Rate Base Company Exhibit DMV-3E, line 5				$30,148

Baltimore Gas and Electric Company **Company Exhibit DMV-5E-Updated**

Electric Cash Working Capital Reflected in Unadjusted Rate Base

Multi-Year Plan

2021 MYP Period - Unadjusted Rate Base - Based on 2014 Lag Study Net Lag Days

Line No.	Description	Line of Business	CWC Expense	Net Lag Days	Cash Advanced
1	Net Metering Costs	Electric	1,668,285	(59.5)	(271,953)
2	Salaries and Wages	Electric	124,989,190	10.9	3,732,554
3	Fringe Benefits	Electric	35,903,916	31.6	3,108,394
4	Other Oper & Maint Expense	Electric	281,996,975	(1.5)	(1,158,892)
5	Property Taxes	Electric	96,101,673	133.6	35,175,845
6	Payroll Taxes	Electric	10,739,893	10.3	303,071
7	PSC Assessment	Electric	3,480,189	77.3	737,037
8	Electric Environmental Surcharge	Electric	4,153,443	4.2	47,793
9	Universal Service Fund	Electric	16,268,626	10.4	463,544
10	GRT Taxes	Electric	41,608,955	(5.6)	(638,384)
11	Other Taxes	Electric	3,628,138	14.0	139,161
12	Current Taxes	Electric	23,353,038	(5.9)	(377,487)
13	State Income Taxes - Current	Electric	-	(11.5)	-
14	Interest Expense	Electric	75,880,783	(41.6)	(8,648,330)
15	Short Term Interest	Electric	-	53.7	-
16	Interest on Customer Deposits	Electric	1,376,152	(136.0)	(512,758)
17	Total Electric Cash Working Capital		$721,149,255		$32,099,595
18	Total Electric Cash Working Capital ($000) carried forward to Unadjusted Rate Base Company Exhibit DMV-3E, line 5				$32,100

Baltimore Gas and Electric Company **Company Exhibit DMV-5E-Updated**

Electric Cash Working Capital Reflected in Unadjusted Rate Base

Multi-Year Plan

2022 MYP Period - Unadjusted Rate Base - Based on 2014 Lag Study Net Lag Days

Line No.	Description	Line of Business	CWC Expense	Net Lag Days	Cash Advanced
1	Net Metering Costs	Electric	1,819,705	(59.5)	(296,637)
2	Salaries and Wages	Electric	127,275,003	10.9	3,800,815
3	Fringe Benefits	Electric	34,626,302	31.6	2,997,784
4	Other Oper & Maint Expense	Electric	283,909,231	(1.5)	(1,166,750)
5	Property Taxes	Electric	103,789,807	133.6	37,989,913
6	Payroll Taxes	Electric	10,746,589	10.3	303,260
7	PSC Assessment	Electric	3,619,397	77.3	766,519
8	Electric Environmental Surcharge	Electric	4,153,239	4.2	47,791
9	Universal Service Fund	Electric	16,320,688	10.4	465,028
10	GRT Taxes	Electric	41,643,008	(5.6)	(638,906)
11	Other Taxes	Electric	3,628,138	14.0	139,161
12	Current Tax	Electric	23,353,038	(5.9)	(377,487)
13	State Income Taxes - Current	Electric	-	(11.5)	-
14	Interest Expense	Electric	79,340,403	(41.6)	(9,042,632)
15	Short Term Interest	Electric	-	53.7	-
16	Interest on Customer Deposits	Electric	1,423,790	(136.0)	(530,508)
17	Total Electric Cash Working Capital		$735,648,337		$34,457,349
18	Total Electric Cash Working Capital ($000) carried forward to Unadjusted Rate Base Company Exhibit DMV-3E, line 5				$34,457

Baltimore Gas and Electric Company
Electric Cash Working Capital Reflected in Unadjusted Rate Base
Multi-Year Plan

2023 MYP Period - Unadjusted Rate Base - Based on 2014 Lag Study Net Lag Days

Line No.	Description	Line of Business	CWC Expense	Net Lag Days	Cash Advanced
1	Net Metering Costs	Electric	1,971,126	(59.5)	(321,320)
2	Salaries and Wages	Electric	130,191,127	10.9	3,887,899
3	Fringe Benefits	Electric	34,722,445	31.6	3,006,108
4	Other Oper & Maint Expense	Electric	286,664,731	(1.5)	(1,178,074)
5	Property Taxes	Electric	112,092,991	133.6	41,029,106
6	Payroll Taxes	Electric	10,796,748	10.3	304,675
7	PSC Assessment	Electric	3,764,172	77.3	797,180
8	Electric Environmental Surcharge	Electric	4,161,581	4.2	47,887
9	Universal Service Fund	Electric	16,387,210	10.4	466,923
10	GRT Taxes	Electric	41,873,573	(5.6)	(642,444)
11	Other Taxes	Electric	3,628,138	14.0	139,161
12	Current Taxes	Electric	23,353,038	(5.9)	(377,487)
13	State Income Taxes - Current	Electric	-	(11.5)	-
14	Interest Expense	Electric	86,012,059	(41.6)	(9,803,018)
15	Short Term Interest	Electric	-	53.7	-
16	Interest on Customer Deposits	Electric	1,470,917	(136.0)	(548,068)
17	Total Electric Cash Working Capital		$757,089,855		$36,808,527
18	Total Electric Cash Working Capital ($000) carried forward to Unadjusted Rate Base Company Exhibit DMV-3E, line 5				$36,809

Baltimore Gas and Electric Company **Company Exhibit DMV-6E-Updated**
Electric Cash Working Capital Based on Updated Net Lag Days
Multi-Year Plan

2019 Cash Working Capital Based on 2019 Lag Study Net Lag Days

Line No.	Description	Line of Business	CWC Expense	Net Lag Days per 2019 Lag Study	Updated Cash Advanced
1	Net Metering Costs	Electric	1,490,726	(140.3)	($573,011)
2	Salaries and Wages	Electric	113,786,361	6.1	1,901,635
3	Fringe Benefits	Electric	38,548,735	7.7	813,220
4	Other Oper & Maint Expense	Electric	260,552,175	(5.3)	(3,783,360)
5	Property Taxes	Electric	87,097,956	92.8	22,144,357
6	Payroll Taxes	Electric	9,406,375	6.1	157,202
7	PSC Assessment	Electric	3,008,724	77.5	638,839
8	Electric Environmental Surcharge	Electric	4,176,638	5.6	64,080
9	Universal Service Fund	Electric	18,982,633	11.2	582,481
10	GRT Taxes	Electric	41,979,319	(8.4)	(966,099)
11	Other Taxes	Electric	3,600,903	32.9	324,575
12	Federal Income Taxes - Current	Electric	(11,667,242)	(4.4)	140,646
13	State Income Taxes - Current	Electric	7,186,121	(11.5)	(226,412)
14	Interest Expense	Electric	63,044,857	(54.7)	(9,448,092)
15	Short Term Interest	Electric	1,355,418	49.1	182,332
16	Interest on Customer Deposits	Electric	2,080,846	(135.9)	(774,759)
17	Total Electric Cash Working Capital Based on New Lag Days - 2019 Lag Study		$644,630,547		$11,177,633
18	CWC Based on 2014 Lag Study included in Unadjusted Rate Base - Company Exhibit DMV-5E, line 17				$30,443,585
19	Impact of Change in Net Lag Days carried forward to Company Exhibit DMV-4E, line 43				$ (19,265,953)

Baltimore Gas and Electric Company
Electric Cash Working Capital Based on Updated Net Lag Days
Multi-Year Plan

2020 Cash Working Capital Based on 2019 Lag Study Net Lag Days

Line No.	Description	Line of Business	CWC Expense	Net Lag Days per 2019 Lag Study	Updated Cash Advanced
1	Net Metering Costs	Electric	1,516,864	(140.3)	($583,058)
2	Salaries and Wages	Electric	121,276,502	6.1	2,026,813
3	Fringe Benefits	Electric	37,225,108	7.7	785,297
4	Other Oper & Maint Expense	Electric	290,946,335	(5.3)	(4,224,700)
5	Property Taxes	Electric	88,983,031	92.8	22,623,631
6	Payroll Taxes	Electric	10,575,995	6.1	176,749
7	PSC Assessment	Electric	3,346,336	77.5	710,523
8	Electric Environmental Surcharge	Electric	4,185,977	5.6	64,223
9	Universal Service Fund	Electric	16,224,448	11.2	497,846
10	GRT Taxes	Electric	41,662,572	(8.4)	(958,810)
11	Other Taxes	Electric	3,628,138	32.9	327,029
12	Current Taxes	Electric	23,353,038	(5.2)	(332,701)
13	State Income Taxes - Current	Electric	-	(11.5)	-
14	Interest Expense	Electric	69,915,572	(54.7)	(10,477,758)
15	Short Term Interest	Electric	-	49.1	-
16	Interest on Customer Deposits	Electric	1,329,794	(135.9)	(495,121)
17	Total Electric Cash Working Capital Based on New Lag Days - 2019 Lag Study		$714,169,710		$10,139,964
18	CWC Based on 2014 Lag Study included in Unadjusted Rate Base - Company Exhibit DMV-5E, line 17				30,147,857
19	Impact of Change in Net Lag Days carried forward to Company Exhibit DMV-4E, line 43				$ (20,007,893)

Baltimore Gas and Electric Company
Electric Cash Working Capital Based on Updated Net Lag Days
Multi-Year Plan

2021 Cash Working Capital Based on 2019 Lag Study Net Lag Days

Line No.	Description	Line of Business	CWC Expense	Net Lag Days per 2019 Lag Study	Updated Cash Advanced
1	Net Metering Costs	Electric	1,668,285	(140.3)	($641,261)
2	Salaries and Wages	Electric	124,989,190	6.1	2,088,860
3	Fringe Benefits	Electric	35,903,916	7.7	757,425
4	Other Oper & Maint Expense	Electric	281,996,975	(5.3)	(4,094,751)
5	Property Taxes	Electric	96,101,673	92.8	24,433,521
6	Payroll Taxes	Electric	10,739,893	6.1	179,489
7	PSC Assessment	Electric	3,480,189	77.5	738,944
8	Electric Environmental Surcharge	Electric	4,153,443	5.6	63,724
9	Universal Service Fund	Electric	16,268,626	11.2	499,202
10	GRT Taxes	Electric	41,608,955	(8.4)	(957,576)
11	Other Taxes	Electric	3,628,138	32.9	327,029
12	Current Taxes	Electric	23,353,038	(5.2)	(332,701)
13	State Income Taxes - Current	Electric	-	(11.5)	-
14	Interest Expense	Electric	75,880,783	(54.7)	(11,371,723)
15	Short Term Interest	Electric	-	49.1	-
16	Interest on Customer Deposits	Electric	1,376,152	(135.9)	(512,381)
17	Total Electric Cash Working Capital Based on New Lag Days - 2019 Lag Study		$721,149,255		$11,177,802
18	CWC Based on 2014 Lag Study included in Unadjusted Rate Base - Company Exhibit DMV-5E, line 17				32,099,595
19	Impact of Change in Net Lag Days carried forward to Company Exhibit DMV-4E, line 43				$ (20,921,793)

Baltimore Gas and Electric Company **Company Exhibit DMV-6E-Updated**

Electric Cash Working Capital Based on Updated Net Lag Days

Multi-Year Plan

2022 Cash Working Capital Based on 2019 Lag Study Net Lag Days

Line No.	Description	Line of Business	CWC Expense	Net Lag Days per 2019 Lag Study	Updated Cash Advanced
1	Net Metering Costs	Electric	1,819,705	(140.3)	($699,465)
2	Salaries and Wages	Electric	127,275,003	6.1	2,127,062
3	Fringe Benefits	Electric	34,626,302	7.7	730,473
4	Other Oper & Maint Expense	Electric	283,909,231	(5.3)	(4,122,518)
5	Property Taxes	Electric	103,789,807	92.8	26,388,203
6	Payroll Taxes	Electric	10,746,589	6.1	179,601
7	PSC Assessment	Electric	3,619,397	77.5	768,502
8	Electric Environmental Surcharge	Electric	4,153,239	5.6	63,721
9	Universal Service Fund	Electric	16,320,688	11.2	500,799
10	GRT Taxes	Electric	41,643,008	(8.4)	(958,360)
11	Other Taxes	Electric	3,628,138	32.9	327,029
12	Current Taxes	Electric	23,353,038	(5.2)	(332,701)
13	State Income Taxes - Current	Electric	-	(11.5)	-
14	Interest Expense	Electric	79,340,403	(54.7)	(11,890,192)
15	Short Term Interest	Electric	-	49.1	-
16	Interest on Customer Deposits	Electric	1,423,790	(135.9)	(530,118)
17	Total Electric Cash Working Capital Based on New Lag Days - 2019 Lag Study		$735,648,337		$12,552,037
18	CWC Based on 2014 Lag Study included in Unadjusted Rate Base - Company Exhibit DMV-5E, line 17				34,457,349
19	Impact of Change in Net Lag Days carried forward to Company Exhibit DMV-4E, line 43				$ (21,905,313)

Baltimore Gas and Electric Company **Company Exhibit DMV-6E-Updated**

Electric Cash Working Capital Based on Updated Net Lag Days

Multi-Year Plan

2023 Cash Working Capital Based on 2019 Lag Study Net Lag Days

Line No.	Description	Line of Business	CWC Expense	Net Lag Days per 2019 Lag Study	Updated Cash Advanced
1	Net Metering Costs	Electric	1,971,126	(140.3)	($757,668)
2	Salaries and Wages	Electric	130,191,127	6.1	2,175,797
3	Fringe Benefits	Electric	34,722,445	7.7	732,501
4	Other Oper & Maint Expense	Electric	286,664,731	(5.3)	(4,162,529)
5	Property Taxes	Electric	112,092,991	92.8	28,499,259
6	Payroll Taxes	Electric	10,796,748	6.1	180,439
7	PSC Assessment	Electric	3,764,172	77.5	799,242
8	Electric Environmental Surcharge	Electric	4,161,581	5.6	63,849
9	Universal Service Fund	Electric	16,387,210	11.2	502,840
10	GRT Taxes	Electric	41,873,573	(8.4)	(963,666)
11	Other Taxes	Electric	3,628,138	32.9	327,029
12	Current Taxes	Electric	23,353,038	(5.2)	(332,701)
13	State Income Taxes - Current	Electric	-	(11.5)	-
13	Interest Expense	Electric	86,012,059	(54.7)	(12,890,026)
14	Short Term Interest	Electric	-	49.1	-
15	Interest on Customer Deposits	Electric	1,470,917	(135.9)	(547,665)
16	Total Electric Cash Working Capital Based on New Lag Days - 2019 Lag Study		$757,089,855		$13,626,702
17	CWC Based on 2014 Lag Study included in Unadjusted Rate Base - Company Exhibit DMV-5E, line 17				36,808,527
18	Impact of Change in Net Lag Days carried forward to Company Exhibit DMV-4E, line 43				$ (23,181,825)

2019 Lag Study - Electric Lag Components

Line No.	Description	Lag Days	Revenue Lag	Net Lag Days
1	Revenue Lag:			
2	Rendition of service to meter reading date		14.7	
3	Meter reading date to bill delivery		3.8	
4	Bill delivery to payment		28.4	
5	Receipt of payment to date funds are accessible		0.2	
6	Total days lag in collection of revenue		47.1	
7	Expense Lag:			
8	Net Metering Costs	187.4	47.1	(140.3)
9	Salaries and Wages	41.0	47.1	6.1
10	Fringe Benefits	39.4	47.1	7.7
11	Other Oper & Maint Expense	52.4	47.1	(5.3)
12	Property Taxes	(45.7)	47.1	92.8
13	Payroll Taxes	41.0	47.1	6.1
14	PSC Assessment	(30.4)	47.1	77.5
15	Electric Environmental Surcharge	41.5	47.1	5.6
16	Universal Service Fund	35.9	47.1	11.2
17	GRT Taxes	55.5	47.1	(8.4)
18	Other Taxes	14.2	47.1	32.9
19	Federal Income Taxes	51.5	47.1	(4.4)
20	State Income Taxes	58.6	47.1	(11.5)
21	Combined Income Taxes	52.3	47.1	(5.2)
22	Interest Expense	101.8	47.1	(54.7)
23	Short Term Interest	(2.0)	47.1	49.1
24	Interest on Customer Deposits	183.0	47.1	(135.9)

Baltimore Gas and Electric Company
Gas Distribution Multi-Year Plan (MYP) Revenue Requirement
For the Twelve Months Ended December 31,
(Thousands of Dollars)

Line	Description	Schedule Reference	MYP 1 2021	MYP 2 2022	MYP 3 2023
1	Rate Base	DMV-3G	$ 2,415,423	$ 2,706,591	$ 2,974,594
2	Rate of Return	DMV-3G	7.12%	7.12%	7.12%
3	Required Income		$ 171,978	$ 192,709	$ 211,791
4	Adjusted Operating Income	DMV-3G	$ 171,978	$ 192,709	$ 144,943
5	Operating Income Deficiency (Excess)		$ -	$ -	$ 66,848
6	Conversion Factor	See Below	1.41941	1.41941	1.41941
7	Revenue Requirement Deficiency (Excess) - Cumulative		$ -	$ -	$ 94,885
8	Revenue Requirement Deficiency (Excess) - Annual		$ -	$ -	$ 94,885
9	**Conversion Factor**				
10	Maryland State Income Tax		8.2500%		
11	Federal Income Tax		21.0000%		
12	Combined Income Tax Rate (SIT+(FITx(1-SIT))		27.5175%		
13	Gross Receipts Tax		2.0000%		
14	PSC Assessment Rate		0.2124%		
15	Uncollectible Factor		0.5890%		
16	Conversion Factor (1 /(1-Comb Tax)x(1-(GR+PSC+Uncoll))		1.41941		
17	Conversion Factor % ((1-Comb Tax)x(1-(GR+PSC+Uncoll))		70.452%		

Baltimore Gas and Electric Company
Gas Distribution Rate Base and Gas Distribution Operating Income Summary
Multi-Year Plan
(Thousands of Dollars)

Line No.	Description	Historic Test Year (HTY) 2019 Unadjusted (1)	Ratemaking Adjustments (2)	Adjusted (3) = (1) + (2)	Bridge 2020 Unadjusted (4)	Ratemaking Adjustments (5)	Adjusted (6) = (4) + (5)	Adjusted Variance vs. Prior Year (7) = (6) - (3)
1	**Rate Base (Average Basis)**							
2	Gas Plant	$ 3,229,265	$ 190,006	$ 3,419,271	$ 3,631,905	$ (652)	$ 3,631,253	$ 211,981
3	Accumulated Depreciation and Amortization	(717,636)	(5,673)	(723,309)	(757,993)	442	(757,551)	(34,242)
4	Materials and Supplies	42,663	-	42,663	40,611	-	40,611	(2,052)
5	Cash Working Capital	19,798	(9,079)	10,719	19,504	(9,642)	9,862	(857)
6	Accumulated Deferred Income Taxes	(452,587)	(39,063)	(491,650)	(545,113)	58	(545,055)	(53,406)
7	Prepaid Pension/OPEB Liab.	21,662	-	21,662	21,724	-	21,724	61
8	Customer Advances & Deposits	(41,631)	-	(41,631)	(42,083)	-	(42,083)	(452)
9	Regulatory Assets & Liabilities	(225,473)	(895)	(226,368)	(223,219)	-	(223,219)	3,150
10	Other[1]	-	-	-	-	-	-	-
11	Total Rate Base	$ 1,876,062	$ 135,296	$ 2,011,358	$ 2,145,335	$ (9,794)	$ 2,135,542	$ 124,184
12	**Operating Income**							
13	Operating Revenues							
14	Sale of Gas	$ 523,989	$ 40,456	$ 564,446	$ 580,750	$ -	$ 580,750	$ 16,304
15	Other Revenues	10,493	-	10,493	9,795	-	9,795	(698)
16	Operating Revenues	$ 534,482	$ 40,456	$ 574,939	$ 590,545	$ -	$ 590,545	$ 15,607
17	Operating Expenses							
18	Gas Choice and Reliability Costs	$ 958	-	$ 958	$ 2,079		$ 2,079	$ 1,121
19	Operation and Maintenance	240,139	4,215	244,354	239,318	(3,595)	235,723	(8,631)
20	Depreciation and Amortization	111,746	4,618	116,364	135,360	(131)	135,230	18,865
21	Other Taxes	60,389	2,491	62,880	65,275	-	65,275	2,395
22	Current Income Taxes	(73,278)	5,915	(67,363)	22,888	415	23,304	1,813
23	Deferred Income Taxes	88,475	726	89,201	-	-	-	-
24	Investment Tax Credit Adjustments	(348)	-	(348)	-		-	-
25	Total Operating Expenses	$ 428,082	$ 17,964	$ 446,046	$ 464,920	$ (3,310)	$ 461,610	$ 15,564
26	Allowance for Funds Used During Construction	6,194	171	6,365	5,678	105	5,783	(582)
27	Interest on Customer Deposits	(1,091)	-	(1,091)	(697)		(697)	394
28	Operating Income	$ 111,503	$ 22,664	$ 134,167	$ 130,606	$ 3,416	$ 134,021	$ (146)
29	**Capital Structure**	Ratio	Cost	Wtd. Cost	Ratio	Cost	Wtd. Cost	
30	Long-Term Debt	47.2%	3.96%	1.87%	48.0%	3.91%	1.88%	
31	Common Equity	52.8%	10.25%	5.41%	52.0%	10.10%	5.25%	
32	Total	100.0%		7.28%	100.0%		7.13%	
33	**Rate of Return Summary**							
34	**Rate of Return**	**5.94%**		**6.67%**	**6.09%**		**6.28%**	
35	Less Weighted Cost of Long-Term Debt	1.87%		1.87%	1.88%		1.88%	
36	Net amount available for common equity	4.07%		4.80%	4.21%		4.40%	
37	Common Equity ratio	52.80%		52.80%	52.0%		52.0%	
38	**Return on Equity**	**7.71%**		**9.09%**	**8.09%**		**8.45%**	
39	**Revenue Requirement Summary**		For Informational Purposes Only			For Informational Purposes Only		
40	Rate Base			*$ 2,011,358*			*$ 2,135,542*	
41	Rate of Return			*7.28%*			*7.13%*	
42	Required Operating Income			*146,427*			*152,264*	
43	Proforma Operating Income			*$ 134,167*			*$ 134,021*	
44	Operating Income Deficiency			*12,260*			*18,243*	
45	Revenue Conversion Factor			*1.41941*			*1.41941*	
46	Rev. Rqmt. Deficiency (Excess)			*17,402*			*25,893*	
47	Total Adjusted Distribution Revenue Requirement							
48	Rev. Rqmt. Deficiency (Excess) - MRP Incremental $ by Year							
49	Total Distribution Revenues, Adjusted							

Line No.	Description	MYP 1 - 2021 Unadjusted (8)	Ratemaking Adjustments (9)	Adjusted (10) = (8) + (9)	Adjusted Variance vs. Prior Year (11) = (10) - (6)	MYP 2 - 2022 Unadjusted (12)	Ratemaking Adjustments (13)	Adjusted (14) = (12) + (13)	Adjusted Variance vs. Prior Year (15) = (14) - (10)
1	**Rate Base (Average Basis)**								
2	Gas Plant	$ 4,020,899	$ (656)	$ 4,020,243	$ 388,990	$ 4,405,983	$ (656)	$ 4,405,326	$ 385,084
3	Accumulated Depreciation and Amortization	(821,748)	574	(821,174)	(63,623)	(902,857)	654	(902,202)	(81,028)
4	Materials and Supplies	41,748	-	41,748	1,136	42,427	-	42,427	679
5	Cash Working Capital	20,471	(10,063)	10,408	546	21,636	(10,473)	11,163	755
6	Accumulated Deferred Income Taxes	(621,621)	(1,021)	(622,642)	(77,587)	(691,704)	(2,516)	(694,221)	(71,579)
7	Prepaid Pension/OPEB Liab.	26,630	-	26,630	4,906	27,790	-	27,790	1,161
8	Customer Advances & Deposits	(43,536)	-	(43,536)	(1,453)	(45,041)	-	(45,041)	(1,505)
9	Regulatory Assets & Liabilities	(219,842)	23,589	(196,253)	26,966	(214,298)	75,646	(138,652)	57,601
10	Other[1]	-	-	-	-	-	-	-	-
11	Total Rate Base	$ 2,403,000	$ 12,422	$ 2,415,423	$ 279,881	$ 2,643,936	$ 62,655	$ 2,706,591	$ 291,168
12	**Operating Income**								
13	Operating Revenues								
14	Sale of Gas	$ 579,999	$ -	$ 579,999	$ (751)	$ 599,474	$ -	$ 599,474	$ 19,474
15	Other Revenues	9,862	-	9,862	67	9,866	-	9,866	4
16	Operating Revenues	$ 589,861	$ -	$ 589,861	$ (684)	$ 609,339	$ -	$ 609,339	$ 19,478
17	Operating Expenses								
18	Gas Choice and Reliability Costs	$ 2,413	-	$ 2,413	$ 334	$ 2,418	-	$ 2,418	$ 5
19	Operation and Maintenance	233,809	(3,705)	230,104	(5,619)	229,974	(3,250)	226,724	(3,380)
20	Depreciation and Amortization	148,147	(8,877)	139,269	4,040	158,867	(2,697)	156,169	16,900
21	Other Taxes	68,947	-	68,947	3,672	73,116	-	73,116	4,169
22	Current Income Taxes	18,331	(37,232)	(18,901)	(42,205)	19,377	(54,263)	(34,886)	(15,985)
23	Deferred Income Taxes	-	-	-	-	-	-	-	-
24	Investment Tax Credit Adjustments	-	-	-	-	-	-	-	-
25	Total Operating Expenses	$ 471,645	$ (49,814)	$ 421,832	$ (39,778)	$ 483,752	$ (60,210)	$ 423,541	$ 1,710
26	Allowance for Funds Used During Construction	4,591	79	4,670	(1,113)	7,529	129	7,658	2,988
27	Interest on Customer Deposits	(722)		(722)	(24)	(747)		(747)	(25)
28	Operating Income	$ 122,086	$ 49,892	$ 171,978	$ 37,957	$ 132,370	$ 60,340	$ 192,709	$ 20,731
29	**Capital Structure**	Ratio	Cost	Wtd. Cost		Ratio	Cost	Wtd. Cost	
30	Long-Term Debt	48.0%	3.89%	1.87%		48.0%	3.90%	1.87%	
31	Common Equity	52.0%	10.10%	5.25%		52.0%	10.10%	5.25%	
32	Total	100.0%		7.12%		100.0%		7.12%	
33	**Rate of Return Summary**								
34	**Rate of Return**	**5.08%**		**7.12%**		**5.01%**		**7.12%**	
35	Less Weighted Cost of Long-Term Debt	1.87%		1.87%		1.87%		1.87%	
36	Net amount available for common equity	3.21%		5.25%		3.14%		5.25%	
37	Common Equity ratio	52.0%		52.0%		52.0%		52.0%	
38	**Return on Equity**	**6.17%**		**10.10%**		**6.03%**		**10.10%**	
39	**Revenue Requirement Summary**								
40	Rate Base			*$ 2,415,423*				*$ 2,706,591*	
41	Rate of Return			*7.12%*				*7.12%*	
42	Required Operating Income			*171,978*				*192,709*	
43	Proforma Operating Income			*$ 171,978*				*$ 192,709*	
44	Operating Income Deficiency			*(0)*				*(0)*	
45	Revenue Conversion Factor			*1.41941*				*1.41941*	
46	Rev. Rqmt. Deficiency (Excess)			*(0)*				*(0)*	
47	Total Adjusted Distribution Revenue Requirement								
48	Rev. Rqmt. Deficiency (Excess) - MRP Incremental $ by Year			**$ (0)**				**$ 0**	
49	Total Distribution Revenues, Adjusted			589,861				609,339	

Line No.	Description	MYP 3 - 2023 Unadjusted (16)	Ratemaking Adjustments (17)	Adjusted (18) = (16) + (17)	Adjusted Variance vs. Prior Year (19) = (18) - (14)
1	**Rate Base (Average Basis)**				
2	Gas Plant	$ 4,797,575	$ -	$ 4,797,575	$ 392,248
3	Accumulated Depreciation and Amortization	(998,774)	-	(998,774)	(96,572)
4	Materials and Supplies	42,667	-	42,667	240
5	Cash Working Capital	22,796	(11,008)	11,788	625
6	Accumulated Deferred Income Taxes	(758,177)	(3,375)	(761,552)	(67,331)
7	Prepaid Pension/OPEB Liab.	27,682	-	27,682	(109)
8	Customer Advances & Deposits	(46,531)	-	(46,531)	(1,490)
9	Regulatory Assets & Liabilities	(210,403)	112,142	(98,262)	40,390
10	Other[1]	-	-	-	-
11	Total Rate Base	$ 2,876,834	$ 97,759	$ 2,974,594	$ 268,003
12	**Operating Income**				
13	Operating Revenues				
14	Sale of Gas	$ 603,379	$ -	$ 603,379	$ 3,906
15	Other Revenues	9,866	-	9,866	0
16	Operating Revenues	$ 613,245	$ -	$ 613,245	$ 3,906
17	Operating Expenses				
18	Gas Choice and Reliability Costs	$ 2,432	-	$ 2,432	$ 14
19	Operation and Maintenance	227,131	(3,416)	223,715	(3,008)
20	Depreciation and Amortization	172,338	(3,798)	168,540	12,370
21	Other Taxes	77,247	-	77,247	4,131
22	Current Income Taxes	15,229	(13,421)	1,808	36,694
23	Deferred Income Taxes	-	-	-	-
24	Investment Tax Credit Adjustments	-	-	-	-
25	Total Operating Expenses	$ 494,377	$ (20,634)	$ 473,742	$ 50,201
26	Allowance for Funds Used During Construction	6,107	105	6,212	(1,446)
27	Interest on Customer Deposits	(771)		(771)	(25)
28	Operating Income	$ 124,204	$ 20,739	$ 144,943	$ (47,766)
29	**Capital Structure**	Ratio	Cost	Wtd. Cost	
30	Long-Term Debt	48.0%	3.89%	1.87%	
31	Common Equity	52.0%	10.10%	5.25%	
32	Total	100.0%		7.12%	
33	**Rate of Return Summary**				
34	**Rate of Return**	**4.32%**		**4.87%**	
35	Less Weighted Cost of Long-Term Debt	1.87%		1.87%	
36	Net amount available for common equity	2.45%		3.00%	
37	Common Equity ratio	52.0%		52.0%	
38	**Return on Equity**	**4.71%**		**5.77%**	
39	**Revenue Requirement Summary**				
40	Rate Base			*$ 2,974,594*	
41	Rate of Return			*7.12%*	
42	Required Operating Income			*211,791*	
43	Proforma Operating Income			*$ 144,943*	
44	Operating Income Deficiency			*66,848*	
45	Revenue Conversion Factor			*1.41941*	
46	Rev. Rqmt. Deficiency (Excess)			*94,885*	
47	Total Adjusted Distribution Revenue Requirement				
48	Rev. Rqmt. Deficiency (Excess) - MRP Incremental $ by Year			**$ 94,885**	
49	Total Distribution Revenues, Adjusted			708,130	

[1] Other line consistent with Case 9618 Working Group exhibit template. Included in case if needed in future update.

Reconciliation of Witness Sponsored O&M to Unadjusted O&M Included in Company Exhibit DMV-3G

	2019	2020	2021	2022	2023	Total MYP 21-23
O&M Per VP Sponsored Testimony						
Apte	$ 32,056,814	$ 36,070,875	$ 38,999,435	$ 39,569,612	$ 40,767,593	$ 119,336,640
Biagiotti	132,550,423	130,175,907	133,130,108	136,865,064	139,501,018	409,496,190
Burton	99,775,087	92,180,056	91,553,991	88,210,783	86,535,682	266,300,456
Olivier	110,130,330	110,155,039	111,456,230	110,877,626	110,782,016	333,115,872
Vahos	331,296,236	369,184,136	352,434,970	353,694,117	355,473,626	1,061,602,713
Total O&M[A]	$ 705,808,890	$ 737,766,013	$ 727,574,734	$ 729,217,202	$ 733,059,935	$ 2,189,851,871
Total VP Sponsored O&M by Line of Business						
Direct Electric Distribution		188,616,355	189,643,596	191,313,473	195,608,411	576,565,480
Direct Gas Distribution		113,518,933	112,868,564	109,405,414	107,099,333	329,373,311
Common[B]		428,830,782	415,423,059	416,487,378	417,584,813	1,249,495,249
Below the line/Other		6,799,943	9,639,515	12,010,937	12,767,379	34,417,831
Total	$ 705,808,890	737,766,013	727,574,734	729,217,202	733,059,935	2,189,851,871
Reconciliation to Company Exhibit DMV-3G						
Remove Transmission Allocation of Common/Other	(22,218,153)	(32,315,798)	(31,559,950)	(32,093,496)	(32,357,351)	(96,010,797)
Remove Below the Line	(9,587,356)	(6,799,943)	(9,639,515)	(12,010,937)	(12,767,379)	(34,417,831)
Total Distribution O&M	$ 674,003,381	$ 698,650,272	$ 686,375,269	$ 685,112,768	$ 687,935,205	$ 2,059,423,243
Electric Distribution Unadjusted O&M (Exhibit DMV-3E, Line 19)	433,864,441	459,332,444	452,566,453	455,138,826	460,803,749	1,368,509,028
Gas Distribution Unadjusted O&M (Exhibit DMV-3G, Line 19)	240,138,940	239,317,828	233,808,816	229,973,942	227,131,456	690,914,215
Total Unadjusted O&M Included on Exhibit DMV-3	$ 674,003,381	$ 698,650,272	$ 686,375,269	$ 685,112,768	$ 687,935,205	$ 2,059,423,243

(A) Total excludes direct assigned transmission spend, Political Action Committee spend, commodity spend, and uncollectible reserve activity.

(B) Common is allocated across Electric Distribution, Gas Distribution, and Transmission

Company Exhibit DMV-4G-Updated

Baltimore Gas and Electric Company
Gas Distribution MYP Revenue Requirement (Unadjusted and Adjusted) Summary By Year
For the Twelve Months Ended December 31,
(Thousands of Dollars)

Line No.	Description	Schedule Reference	HTY - 2019 Rate Base	HTY - 2019 Operating Income (Net of Tax)	HTY - 2019 Revenue Requirement	Bridge Year - 2020 Rate Base	Bridge Year - 2020 Operating Income (Net of Tax)	Bridge Year - 2020 Revenue Requirement	MYP 1 - 2021 Rate Base	MYP 1 - 2021 Operating Income (Net of Tax)	MYP 1 - 2021 Revenue Requirement	MYP 2 - 2022 Rate Base	MYP 2 - 2022 Operating Income (Net of Tax)	MYP 2 - 2022 Revenue Requirement	MYP 3 - 2023 Rate Base	MYP 3 - 2023 Operating Income (Net of Tax)	MYP 3 - 2023 Revenue Requirement
	Unadjusted Amounts	DMV-3G	1,876,062	111,503	35,590	2,145,335	130,606	31,733	2,403,000	122,086	69,562	2,643,936	132,370	79,314	2,876,834	124,204	114,442
	Ratemaking Adjustments:																
1	Annualize Case No. 9610 Base Rate Revenues	OIA-1	-	35,472	(50,349)	-	-	-	-	-	-	-	-	-	-	-	-
2	Annualize AFC to Reflect Case No. 9610 ROR	OIA-2	-	(92)	131	-	-	-	-	-	-	-	-	-	-	-	-
3	Annualize Case No. 9610 Rate Case Expenses	OIA-3	-	(26)	37	-	-	-	-	-	-	-	-	-	-	-	-
4	Annualize Case No. 9610 STRIDE Audit Fees	OIA-4	-	(47)	67	-	-	-	-	-	-	-	-	-	-	-	-
5	Annualize Case No. 9610 Smart Grid Amortization	OIA-5/RBA-1	-	2,411	(3,422)	-	-	-	-	-	-	-	-	-	-	-	-
6	Annualize Case No. 9610 CVR Amortization	OIA-6/RBA-2	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
7	Annualize Maryland Additional Subtraction Modification Tax Benefit	OIA-7	-	427	(606)	-	-	-	-	-	-	-	-	-	-	-	-
8	Annualize Case No. 9610 Riverside Amortization	OIA-8/RBA-3	(30)	(60)	82	-	-	-	-	-	-	-	-	-	-	-	-
9	Annualize Case No. 9610 Depreciation Expense	OIA-9/RBA-4	(1,887)	(3,773)	5,160	-	-	-	-	-	-	-	-	-	-	-	-
10	Annualize Collective Bargaining Agreement (CBA) Impact	OIA-10	-	(33)	47	-	-	-	-	-	-	-	-	-	-	-	-
11	Annualize Additional Sick Days Resulting from CBA	OIA-11	-	(60)	85	-	-	-	-	-	-	-	-	-	-	-	-
12	Annualize Customer Operation Wages	OIA-12	-	(156)	221	-	-	-	-	-	-	-	-	-	-	-	-
13	Annualize 2019 General Wage Increase	OIA-13	-	(183)	260	-	-	-	-	-	-	-	-	-	-	-	-
14	Annualize Other Tax Known Increases	OIA-14	-	(1,151)	1,634	-	-	-	-	-	-	-	-	-	-	-	-
15	Eliminate Expiring Regulatory Asset Amortizations	OIA-15/RBA-5	(105)	275	(401)	-	-	-	-	-	-	-	-	-	-	-	-
16	Amortize Gain on Sale of Real Estate	OIA-16/RBA-6	(513)	513	(781)	-	-	-	-	-	-	-	-	-	-	-	-
17	Case 9610 Safety & Reliability Net Depreciation Expense Annualization	OIA-17/RBA-7	62,560	(1,340)	8,367	-	-	-	-	-	-	-	-	-	-	-	-
18	Case 9610 STRIDE Net Depreciation Expense Annualization	OIA-18/RBA-8	84,577	(1,114)	10,321	-	-	-	-	-	-	-	-	-	-	-	-
19	General Inflation on Non-Labor O&M	OIA-19	-	(1,767)	2,508	-	-	-	-	-	-	-	-	-	-	-	-
20	Normalize Major Outage Event Restoration Expense	OIA-20	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
21	Eliminate One-Time Credit to Establish Riverside Environmental Regulatory Asset	OIA-21	-	(3,323)	4,717	-	-	-	-	-	-	-	-	-	-	-	-
22	Eliminate ERI Rider 31 Revenues	OIA-22	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
23	Eliminate STRIDE Revenues, Net	OIA-23	-	(6,802)	9,655	-	-	-	-	-	-	-	-	-	-	-	-
24	Eliminate Advertising	OIA-24	-	480	(681)	-	189	(268)	-	189	(268)	-	192	(273)	-	195	(277)
25	Eliminate Employee Activity Costs	OIA-25	-	144	(204)	-	186	(264)	-	186	(264)	-	186	(264)	-	187	(265)
26	Eliminate SERP Costs	OIA-26	-	728	(1,033)	-	678	(962)	-	696	(988)	-	671	(952)	-	642	(911)
27	Eliminate Certain Incentive Compensation	OIA-27	-	929	(1,319)	-	1,553	(2,204)	-	1,443	(2,048)	-	1,504	(2,135)	-	1,542	(2,189)
28	Normalize AFC at Proposed ROR	OIA-28	-	252	(358)	-	98	(139)	-	73	(104)	-	120	(170)	-	97	(138)
29	Eliminate RM54 Capital Software Costs	OIA-29/RBA-9	(227)	-	(23)	(152)	95	(150)	(60)	95	(141)	(1)	12	(17)	-	-	-
30	Amortize Rate Case Expenses	OIA-30	-	-	-	-	-	-	-	-	-	-	(32)	45	-	(32)	45
31	Amortize STRIDE Audit Fees	OIA-31	-	-	-	-	-	-	-	-	-	-	(165)	234	-	(58)	82
32	Amortize CVR Program Costs	OIA-32/RBA-10	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
33	Reversal of CVR Program Cost Deferral	OIA-33/RBA-11	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
34	Amortize Riverside Environmental Costs	OIA-34/RBA-12	-	-	-	-	-	-	-	-	-	(98)	(196)	268	(294)	(196)	248
35	Amortize the Gas Meter Mitigation Regulatory Asset	OIA-35	-	-	-	-	-	-	-	-	-	-	(810)	1,150	-	-	-
36	Amortize Electric Vehicle Program Costs	OIA-36/RBA-13	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
37	Reversal of Storm Costs	OIA-37	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
38	Accelerated Tax Benefits	OIA-38/RBA-14	-	-	-	-	-	-	19,795	39,591	(54,195)	66,499	53,818	(69,669)	99,877	12,938	(8,271)
39	2021 Regulatory Asset Amortization Suspension	OIA-39/RBA-15	-	-	-	-	-	-	2,750	6,511	(8,964)	5,500	-	556	5,500	-	556
40	Smart Grid Regulatory Asset Life Extension	OIA-40/RBA-16	-	-	-	-	-	-	-	-	-	1,228	2,949	(4,062)	3,683	2,949	(3,814)
41	COVID-19 Regulatory Asset amortization	OIA-41/RBA-17	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
42	Interest Synchronization	OIA-42	-	960	(1,365)	-	618	(877)	-	1,109	(1,573)	-	2,091	(2,967)	-	2,475	(3,511)
43	Cash Working Capital Adjusted for Updated Lag Days	DMV-6G, Line 19	(9,079)	-	(938)	(9,642)	-	(976)	(10,063)	-	(1,017)	(10,473)	-	(1,058)	(11,008)		(1,112)
44	Total Adjustments		135,296	22,664	(18,188)	(9,794)	3,417	(5,840)	12,422	49,893	(69,562)	62,655	60,340	(79,314)	97,758	20,739	(19,557)
45	Total Revenue Requirement	DMV-3G	2,011,358	134,167	17,402	2,135,542	134,023	25,893	2,415,422	171,979	-	2,706,591	192,710	-	2,974,593	144,943	94,885
	Rate of Return (Company Exhibit DMV-3G, line 32)		7.28%			7.13%			7.12%			7.12%			7.12%		
	Conversion Factor																
	Maryland State Income Tax		8.2500%			8.2500%			8.2500%			8.2500%			8.2500%		
	Federal Income Tax		21.0000%			21.0000%			21.0000%			21.0000%			21.0000%		
	Combined Income Tax Rate (SIT+(FITx(1-SIT))		27.5175%			27.5175%			27.5175%			27.5175%			27.5175%		
	Gross Receipts Tax		2.0000%			2.0000%			2.0000%			2.0000%			2.0000%		
	PSC Assessment Rate		0.2124%			0.2124%			0.2124%			0.2124%			0.2124%		
	Uncollectible Factor		0.5890%			0.5890%			0.5890%			0.5890%			0.5890%		
	Conversion Factor (1 /(1-Comb Tax)x(1-(GR+PSC+Uncoll))		1.41941			1.41941			1.41941			1.41941			1.41941		
	Conversion Factor % ((1-Comb Tax)x(1-(GR+PSC+Uncoll))		70.452%			70.4520%			70.4520%			70.4520%			70.4520%		

Baltimore Gas and Electric Company
Case No. 9610 Gas Base Rate Revenue Increase
Multi-Year Plan

Operating Income
Adjustment 1G

In Case No. 9610, Order No. 89400, the Commission accepted a settlement that resulted in an increase of $54 million in gas base rates. This rate change became effective with service rendered on or after December 17, 2019. Operating Income Adjustment 1G reflects the annual effect on gas operating income of this rate change not reflected in the 2019 HTY.

Description	HTY 2019	Bridge Period 2020	MYP 1 2021	MYP 2 2022	MYP 3 2023
Total increase in base rate revenues awarded	$ 54,000,000	$ -	$ -	$ -	$ -
Case No. 9610 increase in base rate revenues reflected in the 2019 HTY	(3,954,590)	-	-	-	-
Increase in base rate revenues to be realized	50,045,410	-	-	-	-
Franchise Tax	(1,000,908)	-	-	-	-
PSC Assessment	(106,296)	-	-	-	-
Income Tax Effect at 27.5175%	(13,466,571)	-	-	-	-
Adjustment to operating income	$ 35,471,634	$ -	$ -	$ -	$ -
Amount Presented on Company Exhibit DMV-4G	$ 35,472,000	$ -	$ -	$ -	$ -

Mapping to Exhibit DMV-3G Ratemaking Adjustments:

Sale of Gas (Line 14)	$ 50,045,410	$ -	$ -	$ -	$ -
Other Taxes (Line 21)	1,107,205	-	-	-	-
Current Income Taxes (Line 22)	13,466,571	-	-	-	-

This adjustment annualizes unadjusted gas AFC accrued during the HTY 2019 to reflect the 6.97% rate of return agreed to in the settlement agreement reached in Case No. 9610 for the purpose of calculating AFC, which was accepted by the Commission in Order No. 89400.

Description	HTY 2019	Bridge Period 2020	MYP 1 2021	MYP 2 2022	MYP 3 2023
Actual AFC for the twelve months per Company Exhibit DMV-3E	$ 6,194	$ -	$ -	$ -	$ -
Actual AFC for 2019 HTY	6,194,022	-	-	-	-
AFC accrued under the Case 9610 6.97% rate for the month of December 2019	(297,969)				
AFC to be subject to the new rate of 6.97%	5,896,053				
Conversion Factor to 6.97%	0.9831	-	-	-	-
AFC for the period January - November 2019 restated to reflect a 6.97% AFC rates	5,796,261				
AFC to be subject to new rates	5,896,053	-	-	-	-
Change in AFC	(99,792)	-	-	-	-
Income Tax effect of borrowed funds portion of AFC at 27.5175%	7,486	-	-	-	-
Adjustment to operating income	$ (92,307)	$ -	$ -	$ -	$ -
Amount Presented on Company Exhibit DMV-4G	$ (92,000)	$ -	$ -	$ -	$ -
Calculation of Income Tax Effect of Borrowed Funds Portion of AFC					
Increase (Decrease) in AFC	(99,792)	-	-	-	-
Borrowed funds portion of AFC %	0.273	-	-	-	-
Borrowed funds portion of AFC $	(27,203)	-	-	-	-
Income tax rate	27.5175%				
Income tax effect of borrowed funds portion of AFC	$ (7,486)	$ -	$ -	$ -	$ -
Borrowed fund funds %					
Total Return	6.97%				
Weighted cost of Long-Term Debt	1.90%				
Borrowed Funds Portion of AFC %	27.3%				

Mapping to Exhibit DMV-3G Ratemaking Adjustments:

Description	HTY 2019	Bridge Period 2020	MYP 1 2021	MYP 2 2022	MYP 3 2023
Allowance for Funds Used During Construction (Line 26)	$ (99,792)	$ -	$ -	$ -	$ -
Deferred Income Taxes (Line 23)	(7,486)	-	-	-	-

Baltimore Gas and Electric Company
Case 9610 Gas Rate Case Expenses
Multi-Year Plan

Operating Income
Adjustment 3G

This adjustment annualizes the amortization of deferred rate case expenses included in Case No. 9610.

Description	HTY 2019	Bridge Period 2020	MYP 1 2021	MYP 2 2022	MYP 3 2023
Annual amortization of deferred rate case expenses included in Case No. 9610	$ 39,188	$ -	$ -	$ -	$ -
		-	-	-	-
1 Month (December) reflected in 2019 HTY	(3,266)	-	-	-	-
		-	-	-	-
Amortization of deferred rate case expenses not reflected in the 2019 HTY	35,922	-	-	-	-
Income tax effect at 27.5175%	(9,885)	-	-	-	-
Adjustment to operating income	$ 26,037	$ -	$ -	$ -	$ -
Amount Presented on Company Exhibit DMV-4G	$ (26,000)	$ -	$ -	$ -	$ -

Mapping to Exhibit DMV-3G Ratemaking Adjustments:

	HTY 2019	Bridge Period 2020	MYP 1 2021	MYP 2 2022	MYP 3 2023
Operation and Maintenance (Line 19)	$ 35,922	$ -	$ -	$ -	$ -
Deferred Income Taxes (Line 23)	(9,885)				
	$ 26,037	$ -	$ -	$ -	$ -

Baltimore Gas and Electric Company
Case 9610 Gas STRIDE Audit Fee Amortization
Multi-Year Plan

Operating Income
Adjustment 4G

This adjustment annualizes the amortization of the STRIDE audit fee reflected in Case No. 9610.

Description	HTY 2019	Bridge Period 2020	MYP 1 2021	MYP 2 2022	MYP 3 2023
Annual amortization of the deferred STRIDE audit fee included in Case No. 9610	$ 70,650	$ -	$ -	$ -	$ -
1 Month (December) reflected in HTY	(5,888)	-	-	-	-
Amortization of the deferred STRIDE audit fee not reflected in the 2019 HTY	64,763	-	-	-	-
Income tax effect at 27.5175%	(17,821)	-	-	-	-
Adjustment to operating income	$ 46,941	$ -	$ -	$ -	$ -
Amount Presented on Company Exhibit DMV-4G	$ (47,000)	$ -	$ -	$ -	$ -

Mapping to Exhibit DMV-3G Ratemaking Adjustments:

Operation and Maintenance (Line 19)	$ 64,763	$ -	$ -	$ -	$ -
Deferred Income Taxes (Line 23)	(17,821)				
	$ 46,941	$ -	$ -	$ -	$ -

This adjustment annualizes the amortization of the gas Smart Grid regulatory asset incremental costs incurred since November 2015 (i.e. the end of the test year in Case No. 9406). This regulatory asset is being amortized through May 2026 in accordance with the Case No. 9610 settlement which was accepted by the Commission in Order No. 89400. Previously, this regulatory asset was being amortized over 3 years as approved in Case No. 9484. This adjustment reflects the portion of the lower amortization which is not reflected in the HTY 2019.

Description	HTY 2019	Bridge Period 2020	MYP 1 2021	MYP 2 2022	MYP 3 2023
Lower amortization of the 9406 post test year gas Smart Grid regulatory asset agreed to in the settlement in Case No. 9610	$ (3,629,156)	$ -	$ -	$ -	$ -
1 Month (December) reflected in HTY	302,430	-	-	-	-
Amortization of Case No. 9610 Smart Grid costs not reflected in the 2019 HTY	(3,326,726)	-	-	-	-
Income tax effect at 27.5175%	915,432	-	-	-	-
Adjustment to operating income	$ (2,411,294)	$ -	$ -	$ -	$ -
Amount Presented on Company Exhibit DMV-4G	$ 2,411,000	$ -	$ -	$ -	$ -

Mapping to Exhibit DMV-3G Ratemaking Adjustments:

Depreciation and Amortization (Line 20)	$ (3,326,726)	$ -	$ -	$ -	$ -
Deferred Income Taxes (Line 23)	915,432				
	$ (2,411,294)	$ -	$ -	$ -	$ -

This adjustment provides customers with the state income tax benefit attributable to the recognition of an incremental increase to the Maryland "Statutory Subtraction" modification over the average remaining book lives of Maryland assets, approximately 39 years for gas, but which is not fully reflected in the 2019 HTY.

Description	HTY 2019	Bridge Period 2020	MYP 1 2021	MYP 2 2022	MYP 3 2023
Annual amortization of Maryland Additional Subraction Modification regulatory liability reflected in Case No. 9610	$ 643,150	$ -	$ -	$ -	$ -
1 Month (December) reflected in HTY	(53,596)	-	-	-	-
Amortization of Maryland Additional Subraction Modification regulatory liability not reflected in the 2019 HTY	589,554	-	-	-	-
Income tax effect at 27.5175%	(162,231)	-	-	-	-
Annual Maryland Additional Subraction Modification to be provided to customers	$ 427,324	$ -	$ -	$ -	$ -
Adjustment to operating income	$ 427,324	$ -	$ -	$ -	$ -
Amount Presented on Company Exhibit DMV-4G	$427,000	-	-	-	-

Mapping to Exhibit DMV-3G Ratemaking Adjustments:

Deferred Income Taxes (Line 23)	$ (427,324)	$ -	$ -	$ -	$ -
	$ (427,324)	$ -	$ -	$ -	$ -

Baltimore Gas and Electric Company
Case 9610 Gas Riverside Amortization
Multi-Year Plan

Operating Income
Adjustment 8G

This adjustment annualizes the amortization of the Riverside environmental costs reflected in Case No. 9610. The companion adjustment is Rate Base Adjustment 3G.

Description	HTY 2019	Bridge Period 2020	MYP 1 2021	MYP 2 2022	MYP 3 2023
Annual amortization of Riverside environmental amortization reflected in Case No. 9610	$ 91,035	$ -	$ -	$ -	$ -
1 Month (December) reflected in HTY	(7,586)	-	-	-	-
		-	-	-	-
Amortization of Case No. 9610 Riverside costs not reflected in the 2019 HTY	83,449	-	-	-	-
Income tax effect at 27.5175%	(22,963)	-	-	-	-
Adjustment to operating income	$ 60,486	$ -	$ -	$ -	$ -
Amount Presented on Company Exhibit DMV-4G	$ (60,000)	$ -	$ -	$ -	$ -

Mapping to Exhibit DMV-3G Ratemaking Adjustments:

Description	HTY 2019	Bridge Period 2020	MYP 1 2021	MYP 2 2022	MYP 3 2023
Depreciation and Amortization (Line 20)	$ 83,449	$ -	$ -	$ -	$ -
Deferred Income Taxes (Line 23)	(22,963)				
	$ 60,486	$ -	$ -	$ -	$ -

Baltimore Gas and Electric Company
Case No. 9610 Gas Depreciation Rates
Multi-Year Plan

Operating Income
Adjustment 9G

This adjustment annualizes the level of gas depreciation expense as a result of the new depreciation rates included in Exhibit 5 of the Case No. 9610 settlement agreement, which was accepted by the Commission in Order No. 89400. This adjustment is necessary since the new depreciation rates are not fully reflected in the 2019 HTY. The companion adjustment is Rate Base Adjustment 4G.

Description	HTY 2019	Bridge Period 2020	MYP 1 2021	MYP 2 2022	MYP 3 2023
Direct	$ 8,059,047	$ -	$ -	$ -	$ -
Common	(2,380,329)	-	-	-	-
		-	-	-	-
Annual Change in depreciation expense due to new depreciation rates agreed upon in Case No. 9610	5,678,719	-	-	-	-
1 Month (December) reflected in HTY	(473,227)	-	-	-	-
Change in depreciation expense not reflected in the 2019 HTY	5,205,492	-	-	-	-
Income tax effect at 27.5175%	(1,432,421)	-	-	-	-
Adjustment to operating income	$ 3,773,071	$ -	$ -	$ -	$ -
Amount Presented on Company Exhibit DMV-4G	$ (3,773,000)	$ -	$ -	$ -	$ -

Mapping to Exhibit DMV-3G Ratemaking Adjustments:

Depreciation and Amortization (Line 20)	$ 5,205,492	$ -	$ -	$ -	$ -
Current Income Taxes (Line 22)	(1,432,421)				
	$ 3,773,071	$ -	$ -	$ -	$ -

Baltimore Gas and Electric Company
Collective Bargaining Agreement - Gas
Multi-Year Plan

Operating Income
Adjustment 10G

This adjustment reflects the impacts of the Collective Bargaining Agreement ("CBA") which are not fully reflected in the 2019 HTY.

Description	HTY 2019	Bridge Period 2020	MYP 1 2021	MYP 2 2022	MYP 3 2023
Specific Wage and Stipend Adjustments:					
Specific market wage adjustments	$ 126,039	$ -	$ -	$ -	$ -
Premium and allowance adjustments	90,088	-	-	-	-
Total specific wage and stipend adjustments	216,126	-	-	-	-
General wage increase	755,984	-	-	-	-
AIP reduction	(476,862)	-	-	-	-
Elimination of 5 day sick pay accrual recorded in the 2019 HTY	(449,413)	-	-	-	-
Additional expenses resulting from the CBA not reflected in the 2019 HTY	45,836	-	-	-	-
Income Tax Effect at 27.5175%	(12,613)	-	-	-	-
Adjustment to operating income	$ 33,223	$ -	$ -	$ -	$ -
Amount Presented on Company Exhibit DMV-4G	$ (33,000)	$ -	$ -	$ -	$ -

Mapping to Exhibit DMV-3G Ratemaking Adjustments:

Operation and Maintenance (Line 19)	$ 45,836	$ -	$ -	$ -	$ -
Current Income Taxes (Line 22)	(12,613)				
	$ 33,223	$ -	$ -	$ -	$ -

Baltimore Gas and Electric Company
CBA - 10 Add'l Sick Days - Gas
Multi-Year Plan

Operating Income
Adjustment 11G

This adjustment annualizes the amortization of the union sick day regulatory asset established as a result of the CBA, and then amortized over a 10 year period consistent with the Case No. 9610 settlement agreement which was accepted by the Commission in Order No. 89400.

Description	HTY 2019	Bridge Period 2020	MYP 1 2021	MYP 2 2022	MYP 3 2023
Additional 10 Days of Sick Pay	$ 898,462	$ -	$ -	$ -	$ -
Amortization Period (years)	10	-	-	-	-
Annual Amortization	89,846	-	-	-	-
1 Month (December) reflected in HTY	(7,487)	-	-	-	-
Amortization of sick pay expenses not reflected in the 2019 HTY	82,369	-	-	-	-
Income Tax Effect at 27.5175%	(22,666)	-	-	-	-
Adjustment to operating income	$ 59,703	$ -	$ -	$ -	$ -
Amount Presented on Company Exhibit DMV-4G	$ (60,000)	$ -	$ -	$ -	$ -

Mapping to Exhibit DMV-3G Ratemaking Adjustments:

Depreciation and Amortization (Line 20)	$ 82,369	$ -	$ -	$ -	$ -
Deferred Income Taxes (Line 23)	(22,666)				
	$ 59,703	$ -	$ -	$ -	$ -

This adjustment reduces gas operating income by providing for the effect on labor costs of the July 2019 market wage adjustment for certain BGE Customer Operations positions, which is not fully reflected in the 2019 HTY.

Description	HTY 2019	Bridge Period 2020	MYP 1 2021	MYP 2 2022	MYP 3 2023
Effect of the July 2019 Customer Operations market adjustment not reflected in HTY	$ 215,074	$ -	$ -	$ -	$ -
Income tax effect at 27.5175%	(59,183)	-	-	-	-
Adjustment to operating income	$ 155,891	$ -	$ -	$ -	$ -
Amount Presented on Company Exhibit DMV-4G	$(156,000)	$ -	$ -	$ -	$ -

Mapping to Exhibit DMV-3G Ratemaking Adjustments:

Operation and Maintenance (Line 19)	$ 215,074	$ -	$ -	$ -	$ -
Current Income Taxes (Line 22)	(59,183)				
	$ 155,891	$ -	$ -	$ -	$ -

Baltimore Gas and Electric Company
2019 Wage Increase - Gas
Multi-Year Plan

Operating Income
Adjustment 13G

This adjustment reduces gas operating income by providing for the effect on labor costs of the March 2019 general wage increase for BGE employees as included in Case No. 9610, which is not fully reflected in 2019 HTY.

Description	HTY 2019	Bridge Period 2020	MYP 1 2021	MYP 2 2022	MYP 3 2023
Effect of the 2019 wage increase	$ 253,146	$ -	$ -	$ -	$ -
Income tax effect at 27.5175%	(69,659)	-	-	-	-
Adjustment to operating income	$ 183,486	$ -	$ -	$ -	$ -
Amount Presented on Company Exhibit DMV-4G	$ (183,000)	$ -	$ -	$ -	$ -

Mapping to Exhibit DMV-3G Ratemaking Adjustments:

Operation and Maintenance (Line 19)	$ 253,146	$ -	$ -	$ -	$ -
Current Income Taxes (Line 22)	(69,659)				
	$ 183,486	$ -	$ -	$ -	$ -

Baltimore Gas and Electric Company
Changes in Other Taxes - Gas
Multi-Year Plan

Operating Income
Adjustment 14G

This adjustment reduces gas operating income for the annualized known increases in various taxes other than income taxes including the increase in real and personal property taxes effective with the July 1, 2019 property assessments and the Maryland Public Service Commission assessment rate effective July 2019 as included in Case No. 9610. Both of these are not fully reflected in the 2019 HTY without this adjustment.

Description	**HTY 2019**	**Bridge Period 2020**	**MYP 1 2021**	**MYP 2 2022**	**MYP 3 2023**
Real Estate and Property Taxes					
Projected July 2019 - June 2020 Assessment Amounts	$ 41,365,305	$ -	$ -	$ -	$ -
Amounts recorded in the 2019 HTY	39,882,644	-	-	-	-
Increase/(Decrease)	1,482,661	-	-	-	-
PSC Assessment Rate					
Projected July 2019 - June 2020 Assessment Amounts	1,519,733	-	-	-	-
Amounts recorded in the 2019 HTY	1,414,492	-	-	-	-
Increase/(Decrease)	105,241	-	-	-	-
Total					
Total Increase/(Decrease) in taxes other than income taxes	1,587,902				
		-			
Income tax effect at 27.5175%	(436,951)	-	-	-	-
Adjustment to operating income	$ 1,150,951	$ -	$ -	$ -	$ -
Amount Presented on Company Exhibit DMV-4G	$ (1,151,000)	$ -	$ -	$ -	$ -

Mapping to Exhibit DMV-3G Ratemaking Adjustments:

Other Taxes (Line 21)	$ 1,587,902	$ -	$ -	$ -	$ -
Current Income Taxes (Line 22)	(436,951)				
	$ 1,150,951	$ -	$ -	$ -	$ -

Baltimore Gas and Electric Company
Fully Amortized Gas Regulatory Assets
Multi-Year Plan

Operating Income
Adjustment 15G

This adjustment increases gas operating income by eliminating the amortization expense associated with certain regulatory assets that will be fully amortized before the end of calendar year 2020. These regulatory assets include the Case No. 9406 tranche of rate case expenses which was fully amortized in May 2019; the Case No. 9484 tranche of STRIDE audit fees which was fully amortized in December 2019; and the tranche of Spring Gardens environmental costs from Case No. 9230 which will be fully amortized in November 2020. Since these regulatory assets were (or will be, as the case may be) fully amortized before the end of calendar year 2020, the related amortization has been eliminated from operating income. The associated regulatory assets have also been removed from rate base in the companion Rate Base Adjustment 5G, as applicable.

Description	HTY 2019	Bridge Period 2020	MYP 1 2021	MYP 2 2022	MYP 3 2023
Case No. 9406 Rate Case Expenses	$ 8,438	$ -	$ -	$ -	$ -
STRIDE Audit Fees	268,186	-	-	-	-
Spring Gardens Environmental Case No. 9230 tranche	102,615	-	-	-	-
Total amortization to be eliminated	379,239	-	-	-	-
Income tax effect at 27.5175%	(104,357)	-	-	-	-
Adjustment to operating income	$ 274,882	$ -	$ -	$ -	$ -
Amount Presented on Company Exhibit DMV-4G	$ 275,000	$ -	$ -	$ -	$ -

Mapping to Exhibit DMV-3G Ratemaking Adjustments:

Operation and Maintenance (Line 19)	$ (276,624)	$ -	$ -	$ -	$ -
Depreciation and Amortization (Line 20)	$ (102,615)				
Deferred Income Taxes (Line 23)	104,357				
	$ (274,882)	$ -	$ -	$ -	$ -

Baltimore Gas and Electric Company
Real Estate Gains and Losses
Multi-Year Plan

This adjustment reflects the deferral of the June 2018 gas net gain on the sale of real estate, which was recorded in accordance with the FERC Uniform System of Accounts. This adjustment amortizes net gains for ratemaking purposes over a two-year period as specified by the Commission in Case Nos. 7695, 9406, and 9484. It is the companion adjustment to Rate Base Adjustment 6G.

Description	HTY 2019	Bridge Period 2020	MYP 1 2021	MYP 2 2022	MYP 3 2023
Amortization of gain on the sale of real estate applicable to HTY 2019	$ 708,183	$ -	$ -	$ -	$ -
Income Tax Effect at 27.5175%	(194,874)	-	-	-	-
Adjustment to Operating Income	$ 513,309	$ -	$ -	$ -	$ -
Amount presented on Company Exhibit DMV-4G	$ 513,000	$ -	$ -	$ -	$ -

Sale Recorded	Jun 2018
Gain (Loss) Pre-Tax	1,416,366
Monthly Amortization	59,015
Months Amortized in last 12 Months	12
Amortization for last 12 Months	708,183
Remaining Months Unamortized	6
Unamortized Balance at 12/31/19	354,092

Mapping to Exhibit DMV-3G Ratemaking Adjustments:

	HTY 2019	Bridge Period 2020	MYP 1 2021	MYP 2 2022	MYP 3 2023
Depreciation and Amortization (Line 20)	$ (708,183)	$ -	$ -	$ -	$ -
Deferred Income Taxes (Line 23)	194,874	-	-	-	-
	$ (513,309)	$ -	$ -	$ -	$ -

Baltimore Gas and Electric Company
Gas Safety Reliab. Depreciation
Multi-Year Plan

Operating Income
Adjustment 17G

This adjustment annualizes the level of depreciation expense, net of depreciation savings, of non-revenue producing gas safety and reliability plant included in Case No. 9610, and as provided for in Rate Base Adjustment 7G. This adjustment reflects the amounts included in the Case No. 9610 filing. Rate Base Adjustment 7G adjusts accumulated depreciation and accumulated deferred income taxes related to the additional net depreciation expense provided in this adjustment.

Description	HTY 2019	Bridge Period 2020	MYP 1 2021	MYP 2 2022	MYP 3 2023
Annual Depreciation associated with safety and reliability projects	$ 3,570,983	$ -	$ -	$ -	$ -
Less - Safety and reliability depreciation included in the twelve months	1,649,517	-	-	-	-
Increase in depreciation associated with safety and reliability projects	1,921,466	-	-	-	-
Depreciation Savings:					
Safety and reliability annual depreciation savings	136,442	-	-	-	-
Less - Safety and reliability depreciation savings included in the twelve months	63,026	-	-	-	-
Depreciation savings related to safety and reliability retirements	73,416	-	-	-	-
Net depreciation associated with safety and reliability projects	1,848,050	-	-	-	-
Income Tax Effect at 27.5175%	(508,537)	-	-	-	-
Adjustment to Operating Income	$ 1,339,513	$ -	$ -	$ -	$ -
Amount presented on Company Exhibit DMV-4G	$ (1,340,000)	$ -	$ -	$ -	$ -

Mapping to Exhibit DMV-3G Ratemaking Adjustments:

Depreciation and Amortization (Line 20)	$ 1,848,050	$ -	$ -	$ -	$ -
Current Income Taxes (Line 22)	(508,537)				
	$ 1,339,513	$ -	$ -	$ -	$ -

Baltimore Gas and Electric Company
Gas STRIDE Net Depreciation
Multi-Year Plan

Operating Income
Adjustment 18G

This adjustment annualizes the level of depreciation expense, net of depreciation savings, of STRIDE net investment included in Case No. 9610, and as provided in Rate Base Adjustment 8G. This adjustment reflects the amounts included in the Case No. 9610 filing. Rate Base Adjustment 8G adjusts accumulated depreciation and accumulated deferred income taxes related to the additional net depreciation expense provided in this adjustment.

Description	HTY 2019	Bridge Period 2020	MYP 1 2021	MYP 2 2022	MYP 3 2023
Depreciation Expense:					
Annual Depreciation associated with STRIDE projects	$ 2,783,879	$ -	$ -	$ -	$ -
Less - Depreciation included in twelve months assoicated with STRIDE projects	1,186,434	-	-	-	-
Increase in depreciation associated with STRIDE projects	1,597,446	-	-	-	-
Depreciation Savings: Annual Depreciation savings associated with STRIDE retirements	106,368	-	-	-	-
Less - Deprec. savings included in the twelve mos. assoc with STRIDE retirements	45,332	-	-	-	-
Depreciation savings related to STRIDE retirements	61,036	-	-	-	-
Net depreciation associated with STRIDE projects	1,536,409	-	-	-	-
Income Tax Effect at 27.5175%	(422,781)	-	-	-	-
Adjustment to Operating Income	$ 1,113,628	$ -	$ -	$ -	$ -
Amount presented on Company Exhibit DMV-4G	$ (1,114,000)	$ -	$ -	$ -	$ -

Mapping to Exhibit DMV-3G Ratemaking Adjustments:

Description	HTY 2019	Bridge Period 2020	MYP 1 2021	MYP 2 2022	MYP 3 2023
Depreciation and Amortization (Line 20)	$ 1,536,409	$ -	$ -	$ -	$ -
Current Income Taxes (Line 22)	(422,781)				
	$ 1,113,628	$ -	$ -	$ -	$ -

Baltimore Gas and Electric Company
General Inflation - Gas
Multi-Year Plan

Operating Income
Adjustment 19G

This adjustment, which was included in Case No. 9610, reduces gas operating income to provide for the effect of general inflation on non-labor O&M costs during the rate-effective period. This adjustment reflects a 1.420% inflation factor based on a five-year average of the Consumer Price Index ("CPI") per the U.S. Department of Labor, Bureau of Labor Statistics, as authorized by the Commission in Case No. 9484, Order No. 88975

Description	HTY 2019	Bridge Period 2020	MYP 1 2021	MYP 2 2022	MYP 3 2023
O&M Expense included in DMV-3G	$ 240,138,940	$ -	$ -	$ -	$ -
Less:					
Advertising Costs (OIA-24G-Updated)	(661,715)	-	-	-	-
Employee Activity Costs (OIA-25G-Updated)	(198,173)	-	-	-	-
SERP Costs (OIA-26G-Updated)	(1,003,916)	-	-	-	-
Certain Incentives (OIA-27G-Updated)	(1,281,391)	-	-	-	-
Riverside Costs (OIA-21G-Updated)	4,584,637	-	-	-	-
O&M Expense included in the 2019 HTY	241,578,383	-	-	-	-
Less labor included in O&M	69,926,687	-	-	-	-
Non-Labor O&M expense included in the 2019 HTY	171,651,696	-	-	-	-
Inflation factor	1.420%				
Additional O&M due to inflation	2,437,454	-	-	-	-
Income tax effect at 27.5175%	(670,726)	-	-	-	-
Adjustment to operating income	$ 1,766,728	$ -	$ -	$ -	$ -
Amount Presented on Company Exhibit DMV-4G	$ (1,767,000)	$ -	$ -	$ -	$ -

Mapping to Exhibit DMV-3G Ratemaking Adjustments:

	HTY 2019	Bridge Period 2020	MYP 1 2021	MYP 2 2022	MYP 3 2023
Operation and Maintenance (Line 19)	$ 2,437,454	$ -	$ -	$ -	$ -
Current Income Taxes (Line 22)	(670,726)				
	$ 1,766,728	$ -	$ -	$ -	$ -

Baltimore Gas and Electric Company
Remove Credit to Establish Gas Riverside Regulatory Asset
Multi-Year Plan

Operating Income
Adjustment 21G

This adjustment decreases operating income by eliminating the one-time credit recorded in the 2019 HTY to establish a regulatory asset for the Riverside environmental costs as authorized in Case No. 9484, Order No. 88975. This one-time credit is being eliminated since it is non-recurring.

Description	HTY 2019	Bridge Period 2020	MYP 1 2021	MYP 2 2022	MYP 3 2023
Riverside environmental costs established in a regulatory asset during the 2019 HTY	$ 4,584,637	$ -	$ -	$ -	$ -
Income tax effect at 27.5175%	(1,261,577)	-	-	-	-
Adjustment to operating income	$ 3,323,060	$ -	$ -	$ -	$ -
Amount Presented on Company Exhibit DMV-4G	$(3,323,000)	$ -	$ -	$ -	$ -

Mapping to Exhibit DMV-3G Ratemaking Adjustments:

Operation and Maintenance (Line 19)	$ 4,584,637	$ -	$ -	$ -	$ -
Current Income Taxes (Line 22)	(1,261,577)	-	-	-	-
	$ 3,323,060	$ -	$ -	$ -	$ -

Baltimore Gas and Electric Company
Eliminate Gas STRIDE Revenues, Net
Multi-Year Plan

Operating Income
Adjustment 23G

This adjustment removes the STRIDE Rider 16 revenues, net, that are reflected in gas operating income in the 2019 HTY.

Description	HTY 2019	Bridge Period 2020	MYP 1 2021	MYP 2 2022	MYP 3 2023
STRIDE Rider revenues, net, reflected in the 2019 HTY	$ 9,589,008	$ -	$ -	$ -	$ -
Franchise Tax and PSC Assessment	(204,504)	-	-	-	-
Income Tax Effect at 27.5175%	(2,582,381)	-	-	-	-
Adjustment to Operating Income	$ 6,802,124	$ -	$ -	$ -	$ -
Amount presented on Company Exhibit DMV-4G	$ (6,802,000)	$ -	$ -	$ -	$ -

Mapping to Exhibit DMV-3G Ratemaking Adjustments:

Sale of Gas (Line 14)	$ (9,589,008)	$ -	$ -	$ -	$ -
Other Taxes (Line 21)	(204,504)	-	-	-	-
Current Income Taxes (Line 22)	(2,582,381)	-	-	-	-

Baltimore Gas and Electric Company
Eliminate Certain Gas Advertising Expenses
Multi-Year Plan

Operating Income
Adjustment 24G-Updated

This adjustment eliminates from gas operating income for each period certain advertising expenses recorded as operating expenses, in accordance with the FERC Uniform System of Accounts, that BGE is not allowed to recover pursuant to COMAR 20.07.04.08. These expenses represent institutional and promotional advertising expenses. All charitable contributions, penalties, and lobbying costs, including the lobbying expense portion of the Edison Electric Institute dues and the American Gas Association dues, are treated as below the line for ratemaking purposes and are removed from the revenue requirement in Company Exhibit DMV-3G-1. Therefore, it is not necessary to include these costs in this operating income adjustment. This schedule, which was provided in Part 1 of my Direct Testimony, has been updated to reflect amounts for the Bridge Period and MYP years.

Description	HTY 2019	Bridge Period 2020	MYP 1 2021	MYP 2 2022	MYP 3 2023
Institutional and Promotional Advertising	$ 661,715	$260,436	$260,436	$264,878	$269,442
Income Tax Effect at 27.5175%	(182,087)	(71,665)	(71,665)	(72,888)	(74,144)
Adjustment to operating income	$ 479,627	$188,771	$188,771	$191,990	$195,298
Amount Presented on Company Exhibit DMV-4G	$ 480,000	$189,000	$189,000	$192,000	$195,000

Mapping to Exhibit DMV-3G Ratemaking Adjustments:

Operation and Maintenance (Line 19)	$ (661,715)	$ (260,436)	$ (260,436)	$ (264,878)	$ (269,442)
Current Income Taxes (Line 22)	182,087	71,665	71,665	72,888	74,144
	$ (479,627)	$ (188,771)	$ (188,771)	$ (191,990)	$ (195,298)

Baltimore Gas and Electric Company
Eliminate Certain Gas Employee Activity Costs
Multi-Year Plan

Operating Income
Adjustment 25G-Updated

This adjustment eliminates from gas operating income certain employee activity costs as directed by the Commission in Case No. 9299, Order No. 85374. This schedule, which was provided in Part 1 of my testimony, has been updated to reflect amounts for the Bridge Period and MYP years.

Description	HTY 2019	Bridge Period 2020	MYP 1 2021	MYP 2 2022	MYP 3 2023
100% of Company's skybox costs	$ 89,025	$ 96,100	$ 96,100	$ 96,100	$ 96,100
Remaining employee activity costs	218,295	320,695	320,519	321,167	323,771
50% factor	50%	50%	50%	50%	50%
Subtotal - 50% of Remaining employee activity costs	109,147	160,348	160,260	160,584	161,886
Total excluded employee activity costs for the twelve month period	198,173	256,448	256,360	256,684	257,986
Income Tax Effect at 27.5175%	(54,532)	(70,568)	(70,544)	(70,633)	(70,991)
Adjustment to operating income	$ 143,641	$ 185,880	$ 185,816	$ 186,051	$ 186,994
Amount Presented on Company Exhibit DMV-4G	$ 144,000	$ 186,000	$ 186,000	$ 186,000	$ 187,000

Mapping to Exhibit DMV-3G Ratemaking Adjustments:

Operation and Maintenance (Line 19)	$ (198,173)	$ (256,448)	$ (256,360)	$ (256,684)	$ (257,986)
Current Income Taxes (Line 22)	54,532	70,568	70,544	70,633	70,991
	$ (143,641)	$ (185,880)	$ (185,816)	$ (186,051)	$ (186,994)

Baltimore Gas and Electric Company
Eliminate Certain Gas SERP Costs
Multi-Year Plan

Operating Income
Adjustment 26G-Updated

This adjustment eliminates from gas operating income 100% of Supplemental Executive Retirement Program ("SERP") costs as required in Case No. 9484, Order No. 88975. This schedule, which was provided in Part 1 of my Direct Testimony, has been updated to reflect amounts for the Bridge Period and MYP years.

Description	HTY 2019	Bridge Period 2020	MYP 1 2021	MYP 2 2022	MYP 3 2023
SERP costs to be eliminated	$ 1,003,916	$ 934,810	$ 959,835	$ 925,565	$ 886,114
Income tax effect at 27.5175%	(276,253)	(257,236)	(264,123)	(254,692)	(243,836)
Adjustment to operating income	$ 727,663	$ 677,574	$ 695,712	$ 670,873	$ 642,278
Amount Presented on Company Exhibit DMV-4G	$ 728,000	$ 678,000	$ 696,000	$ 671,000	$ 642,000

Mapping to Exhibit DMV-3G Ratemaking Adjustments:

Operation and Maintenance (Line 19)	$ (1,003,916)	$ (934,810)	$ (959,835)	$ (925,565)	$ (886,114)
Current Income Taxes (Line 22)	276,253	257,236	264,123	254,692	243,836
	$ (727,663)	$ (677,574)	$ (695,712)	$ (670,873)	$ (642,278)

Baltimore Gas and Electric Company
Reduce Certain Gas Long-Term Compensation
Multi-Year Plan

Operating Income
Adjustment 27G-Updated

This adjustment removes the non-recoverable amount of incentive compensation from gas operating income consistent with Case No. 9326, Order No. 86060. This schedule, which was provided in Part 1 of my Direct Testimony, has been updated to reflect amounts for the Bridge Period and MYP years.

Description	HTY 2019	Bridge Period 2020	MYP 1 2021	MYP 2 2022	MYP 3 2023
Removal of certain incentive compensation	$ 1,281,391	$ 2,142,947	$ 1,990,952	$ 2,075,284	$ 2,126,895
Income Tax Effect at 27.5175%	(352,607)	(589,685)	(547,860)	(571,066)	(585,268)
Adjustment to operating income	$ 928,784	$ 1,553,261	$ 1,443,092	$ 1,504,218	$ 1,541,627
Amount Presented on Company Exhibit DMV-4G	$ 929,000	$ 1,553,000	$ 1,443,000	$ 1,504,000	$ 1,542,000

Mapping to Exhibit DMV-3G Ratemaking Adjustments:

Operation and Maintenance (Line 19)	$ (1,281,391)	$ (2,142,947)	$ (1,990,952)	$ (2,075,284)	$ (2,126,895)
Current Income Taxes (Line 22)	352,607	589,685	547,860	571,066	585,268
	$ (928,784)	$ (1,553,261)	$ (1,443,092)	$ (1,504,218)	$ (1,541,627)

Baltimore Gas and Electric Company
Gas AFC Annualization Based on Proposed ROR
Multi-Year Plan

Operating Income
Adjustment 28G-Updated

This adjustment adjusts gas operating income for the known annualized amount of AFC included in unadjusted operating income to reflect a level that is consistent with the rate of return for gas as supported by the Company for each period. This schedule, which was provided in Part 1 of my Direct Testimony, has been updated to reflect amounts for the Bridge Period and MYP years.

Description	HTY 2019	Bridge Period 2020	MYP 1 2021	MYP 2 2022	MYP 3 2023
Actual AFC for the twelve months per Company Exhibit DMV-3G	$ 6,194	$ 5,678	$ 4,591	$ 7,529	$ 6,107
Actual AFC for each period	6,194,022	5,677,849	4,591,288	7,529,012	6,107,138
Reduction in AFC to annualize to Case 9610 6.97% gas rate of return per Operating Income Adjustment 2G	(99,792)	-	-	-	-
Actual AFC for each period to be subject to new rate of return calculated	6,094,230	5,677,849	4,591,288	7,529,012	6,107,138
Conversion Factor to ROR Requested	1.0445	1.0186	1.0171	1.0171	1.0171
AFC for the twelve months restated to reflect 7.28% AFC rate	6,365,279	5,783,294	4,669,996	7,658,081	6,211,832
Actual AFC for twelve months	6,094,230	5,677,849	4,591,288	7,529,012	6,107,138
Change in AFC	271,049	105,446	78,708	129,069	104,694
Income Tax effect of borrowed funds portion of AFC at 27.5175%	(19,159)	(7,651)	(5,688)	(9,328)	(7,566)
Adjustment to operating income	$ 251,890	$ 97,795	$ 73,019	$119,741	$ 97,127
Amount Presented on Company Exhibit DMV-4G	$ 252,000	$ 98,000	$ 73,000	$120,000	$ 97,000
Calculation of Income Tax Effect of Borrowed Funds Portion of AFC					
Increase (Decrease) in AFC	$ 271,049	$ 105,446	$ 78,708	$129,069	$104,694
Borrowed funds portion of AFC %	0.257	0.264	0.263	0.263	0.263
Borrowed funds portion of AFC $	69,624	27,803	20,672	33,899	27,497
Income tax rate	27.5175%	27.5175%	27.5175%	27.5175%	27.5175%
Income tax effect of borrowed funds portion of AFC	$ 19,159	$ 7,651	$ 5,688	$ 9,328	$ 7,566
Borrowed fund funds %					
Total Return	7.28%	7.13%	7.12%	7.12%	7.12%
Weighted cost of Long-Term Debt	1.87%	1.88%	1.87%	1.87%	1.87%
Borrowed Funds Portion of AFC %	25.7%	26.4%	26.3%	26.3%	26.3%

Mapping to Exhibit DMV-3G Ratemaking Adjustments:

Allowance for Funds Used During Construction (Line 26)	$ 271,049	$ 105,446	$ 78,708	$ 129,069	$ 104,694
Deferred Income Taxes (Line 23)	19,159	-	-	-	-
Current Income Taxes (Line 22)	-	7,651	5,688	9,328	7,566

Baltimore Gas and Electric Company
Eliminate Gas RM54 Amortization
Multi-Year Plan

Operating Income
Adjustment 29G-Updated

This adjustment relate to the costs incurred by the Company associated with capitalized software changes to BGE's billing system that are necessary to allow for customer accelerated switching between third party suppliers and BGE commodity service, as required by the COMAR revisions adopted in Rulemaking 54 ("RM54"). In Case No. 9484, Order No. 88975, the Commission accepted the Company's proposal to recover the gas RM54 costs through the supplier liability fund consistent with Order No. 88432. With respect to operating income, BGE in this proceeding is removing RM54 costs in the projected Bridge Period through the second year of the MYP (2022) since these expenses are budgeted as distribution expenses in these years but will ultimately be recovered through the supplier liability fund. MYP year 2023 do not include an adjustment since the RM54 software will be fully amortized in early 2022. In addition, these costs are not being recorded as distribution expenses in the HTY, so there is no need for a related operating income adjustment for the 2019 HTY. The companion adjustment is Rate Base Adjustment 9G-Updated.

Description	HTY 2019	Bridge Period 2020	MYP 1 2021	MYP 2 2022	MYP 3 2023
RM54 Amortization included in each period	$ -	$ 130,804	$ 131,245	$ 17,083	$ -
Income Tax Effect at 27.5175%	-	(35,994)	(36,115)	(4,701)	-
Adjustment to operating income	$ -	$ 94,810	$ 95,129	$ 12,382	$ -
Amount Presented on Company Exhibit DMV-4G	$ -	$ 95,000	$ 95,000	$ 12,000	$ -

Mapping to Exhibit DMV-3G Ratemaking Adjustments:

Depreciation and Amortization (Line 20)	$ -	$ (130,804)	$ (131,245)	$ (17,083)	$ -
Current Income Taxes (Line 22)		35,994	36,115	4,701	
	$ -	$ (94,810)	$ (95,129)	$ (12,382)	$ -

Baltimore Gas and Electric Company
Gas Rate Case Expenses
Multi-Year Plan

Operating Income
Adjustment 30G

This adjustment reduces operating income to to reflect the amortization of rate case expenses associated with Case No. 9610, but incurred after the test year in that proceeding, as well as rate case expenses associated with the current proceeding. BGE proposes to amortize these rate case expenses over a three-year period, consistent with Case Nos. 9326, 9406, 9484, and 9610 Commission precedent allowing for recovery of rate case expenses over a three-year period and beginning with 2022, the second MYP rate-effective year as discussed earlier in my testimony.

Description	HTY 2019	Bridge Period 2020	MYP 1 2021	MYP 2 2022	MYP 3 2023
Rate case expenses assoc with Case 9610 incurred after hearings	$ -	$ -	$ -	$ 38,409	$ 38,409
Rate case expenses assoc with the current MYP proceeding	-	-	-	95,931	95,931
Total rate case expenses to be amortized	-	-	-	134,340	134,340
3-year amortization	-	-	-	3	3
Amortization of deferred rate case expenses	-	-	-	44,780	44,780
Income Tax effect at 27.5175%	-	-	-	(12,322)	(12,322)
Adjustment to operating income	$ -	$ -	$ -	$ 32,458	$ 32,458
Amount Presented on Company Exhibit DMV-4G	$ -	$ -	$ -	$ (32,000)	$ (32,000)

Mapping to Exhibit DMV-3G Ratemaking Adjustments:

Operation and Maintenance (Line 19)	$ -	$ -	$ -	$ 44,780	$ 44,780
Current Income Taxes (Line 22)	-	-	-	(12,322)	(12,322)
	$ -	$ -	$ -	$ 32,458	$ 32,458

Baltimore Gas and Electric Company
Recover the Gas Deferred STRIDE Audit Fee
Multi-Year Plan

Operating Income
Adjustment 31G

This adjustment reduces gas operating income for recovery of the STRIDE audit fees for the 2020 - 2023 audit years. These STRIDE audit fees are not included in the projected gas operating income as they are budgeted in a regulatory asset in accordance with Commission Order No. 86147 in Case No. 9331. In light of the decision to defer 2021 amortization, the Company is now seeking recovery of the 2020, 2021, and 2022 fees in the MYP 2022 period and the 2023 fees in the MYP 2023 period in this proceeding through gas base rates.

Description	HTY 2019	Bridge Period 2020	MYP 1 2021	MYP 2 2022	MYP 3 2023
Total STRIDE audit fee deferred	$ -	$ -	$ -	$ 227,596	$ 79,690
Income tax effect at 27.5175%	-	-	-	(62,629)	(21,929)
Adjustment to operating income	$ -	$ -	$ -	$ 164,967	$ 57,761
Amount Presented on Company Exhibit DMV-4G	$ -	$ -	$ -	$(165,000)	$(58,000)

Mapping to Exhibit DMV-3G Ratemaking Adjustments:

Operation and Maintenance (Line 19)	$ -	$ -	$ -	$ 227,596	$ 79,690
Current Income Taxes (Line 22)				(62,629)	(21,929)
	$ -	$ -	$ -	$ 164,967	$ 57,761

Baltimore Gas and Electric Company
Gas Riverside Environmental Costs
Multi-Year Plan

Operating Income
Adjustment 34G

This adjustment reduces gas operating income to reflect the amortization of a new tranche of Riverside environmental costs consistent with Case No. 9484, Order No. 88975. In Case No. 9484, the Commission authorized the Company to amortize its actual costs over ten years. This adjustment recovers the amortization of the third tranche of Riverside environmental costs incurred subsequent to July 2019 (the end of the test year in Case No. 9610) through December 2020 over a ten-year period beginning in MYP 2022. There are no new Riverside environmental costs reflected in the MYP years. In the event that there is any additional spend related to Riverside environmental costs, it will be deferred in a regulatory asset and included in the Annual Informational Filings and Reconciliation for the 2021-2023 MYP years. Rate Base Adjustment 12G is the companion adjustment.

Description	HTY 2019	Bridge Period 2020	MYP 1 2021	MYP 2 2022	MYP 3 2023
Actual Environmental Costs associated with Riverside site spent to date since July 2019 (i.e. subsequent to the Case No. 9610 test year)	$ -	$ -	$ -	$2,701,735	$2,701,735
10-Year Amortization	-	-	-	10	10
	-				
Amortization of Riverside environmental costs not reflected in the test year	-	-	-	270,173	270,173
Income tax effect at 27.5175%	-	-	-	(74,345)	(74,345)
Adjustment to operating income	$ -	$ -	$ -	$ 195,828	$ 195,828
Amount Presented on Company Exhibit DMV-4G	$ -	$ -	$ -	$ (196,000)	$ (196,000)

Mapping to Exhibit DMV-3G Ratemaking Adjustments:

Depreciation and Amortization (Line 20)	$ -	$ -	$ -	$ 270,173	$ 270,173
Deferred Income Taxes (Line 23)				(74,345)	(74,345)
	$ -	$ -	$ -	$ 195,828	$ 195,828

Baltimore Gas and Electric Company
Gas Meter Mitigation Program Regulatory Asset Amortization
Multi-Year Plan

Operating Income
Adjustment 35G

This adjustment provides for the recovery of certain Gas Meter Relocation and Protection Program costs that were deferred in a regulatory asset pursuant to Order No. 88975 issued in Case No. 9484. Consistent with Order No. 88975, BGE seeks to move those costs into rates. This adjustment seeks recovery for the prudently incurred but deferred program costs through December 2020, at which time the program will be substantially complete.

Description	HTY 2019	Bridge Period 2020	MYP 1 2021	MYP 2 2022	MYP 3 2023
Gas Meter Mitigation Regulatory Asset as of December 31, 2020	$ -	$ -	$ -	$ 1,117,640	$ -
Income tax effect at 27.5175%	-	-		(307,547)	-
Adjustment to operating income	$ -	$ -	$ -	$ 810,093	$ -
Amount Presented on Company Exhibit DMV-4G	$ -	$ -	$ -	$ (810,000)	$ -

Mapping to Exhibit DMV-3G Ratemaking Adjustments:

Depreciation and Amortization (Line 20)	$ -	$ -	$ -	$ 1,117,640	$ -
Current Income Taxes (Line 22)				(307,547)	
	$ -	$ -	$ -	$ 810,093	$ -

This adjustment provides customers with an acceleration of tax benefits attributable to the amortization of the Tax Cuts and Jobs Act of 2017 ("TCJA") unprotected property and non-property excess deferred regulatory liabilities and the Maryland Additional Subtraction Modification ("MASM") tax benefit. BGE is proposing to give these tax benefits to customers over the MYP period, starting when the new rates become effective in January 2021, for each of the calendar years 2021 through 2023 in an effort to help with the economic recovery and mitigate the financial impacts of the pandemic. The companion adjustment is Rate Base Adjustment 14G.

Description	HTY 2019	Bridge Period 2020	MYP 1 2021	MYP 2 2022	MYP 3 2023
Accelerated Amortization of Tax Benefits:					
TCJA - Unprotected Property	$ -	$ -	$ 32,884,389	$ 40,363,563	$ 12,062,829
TCJA - Unprotected Non-Property	-	-	(1,236,217)	7,417,300	(1,236,217)
Maryland Subtraction Modification	-	-	7,942,329	6,036,829	2,111,526
Adjustment to operating income	$ -	$ -	$ 39,590,501	$ 53,817,692	$ 12,938,138
Amount Presented on Company Exhibit DMV-4G	$ -	$ -	$ 39,591,000	$ 53,818,000	$ 12,938,000

Mapping to Exhibit DMV-3G Ratemaking Adjustments:

Current Income Taxes (Line 22)	$ -	$ -	$ (39,590,501)	$ (53,817,692)	$ (12,938,138)
	$ -	$ -	$ (39,590,501)	$ (53,817,692)	$ (12,938,138)

Baltimore Gas and Electric Company
2021 Gas Regulatory Asset Amortization Suspension
Multi-Year Plan

Operating Income
Adjustment 39G

This adjustment increases gas operating income by reflecting the suspension in 2021 of the amortization of existing base distribution regulatory assets in an effort to help with the economic recovery and mitigate the financial impacts of the pandemic. The elimination of 2021 amortization amounts will keep base distribution revenues in this MYP lower than they otherwise would have been for customers. The companion adjustment is Rate Base Adjustment 15G.

Description	HTY 2019	Bridge Period 2020	MYP 1 2021	MYP 2 2022	MYP 3 2023
Deferred Costs to Achieve - Case 9406 tranche	$ -	$ -	$ 153,757	$ -	$ -
Case No. 9406 Rate Case Expenses (Case No. 9484 tranche)	-	-	20,723	-	-
Case No. 9484 Rate Case Expenses (Case No. 9484 tranche)	-	-	23,688	-	-
Case No. 9484 Rate Case Expenses (Case No. 9610 tranche)	-	-	17,732	-	-
Case No. 9610 Rate Case Expenses (Case No. 9610 tranche)	-	-	21,456	-	-
Riverside Environmental (Case No. 9484 tranche)	-	-	62,222	-	-
Riverside Environmental (Case No. 9610 tranche)	-	-	91,035	-	-
Union 10-Day Sick Bank	-	-	89,846	-	-
Smart Grid	-	-	8,502,904	-	-
Total regulatory asset amortization to be eliminated		-	8,983,363	-	-
Income tax effect at 27.5175%		-	(2,471,997)	-	-
Adjustment to operating income	$ -	$ -	$ 6,511,366	$ -	$ -
Amount Presented on Company Exhibit DMV-4G	$ -	$ -	$ 6,511,000	$ -	$ -

Mapping to Exhibit DMV-3G Ratemaking Adjustments:

Operation and Maintenance (Line 19)	$ -	$ -	$ (237,355)	$ -	$ -
Depreciation and Amortization (Line 20)			(8,746,008)		
Current Income Taxes (Line 22)			2,471,997		
	$ -	$ -	$ (6,511,366)	$ -	$ -

Baltimore Gas and Electric Company
Gas Smart Grid Regulatory Asset Life Extension
Multi-Year Plan

Operating Income
Adjustment 40G

This adjustment increases gas operating income by reflecting the extension of the Smart Grid Regulatory Asset amortization period through 2031, an additional five years, in an effort to help with the economic recovery and mitigate the financial impacts of the pandemic. Previously, the Commission approved Smart Grid-related regulatory asset lives so that they would be fully amortized as of May 2026. In this proceeding, the Company is proposing to extend the lives of these assets to December 2031, thereby resulting in lower annual amortization expense. The companion adjustment is Rate Base Adjustment 16G.

Description	HTY 2019	Bridge Period 2020	MYP 1 2021	MYP 2 2022	MYP 3 2023
Current Annual Amortization (based on amortization throuigh May 2026)	$ -	$ -	$ -	$ 8,502,904	$ 8,502,904
Proposed Annual Amortization (based on amortization throuigh December 2031)	-	-	-	4,434,765	4,434,765
Total regulatory asset amortization to be eliminated		-	-	4,068,139	4,068,139
Income tax effect at 27.5175%		-	-	(1,119,450)	(1,119,450)
Adjustment to operating income	$ -	$ -	$ -	$ 2,948,689	$ 2,948,689
Amount Presented on Company Exhibit DMV-4G	$ -	$ -	$ -	$ 2,949,000	$ 2,949,000

Mapping to Exhibit DMV-3G Ratemaking Adjustments:

Depreciation and Amortization (Line 20)	$ -	$ -	$ -	$ (4,068,139)	$ (4,068,139)
Current Income Taxes (Line 22)	-	-	-	1,119,450	1,119,450
	$ -	$ -	$ -	$ (2,948,689)	$ (2,948,689)

Baltimore Gas and Electric Company
Gas COVID-19 Expenses
Multi-Year Plan

Operating Income
Adjustment 41G

This adjustment provides the framework for the gasrecovery of COVID-19 incremental costs over a five-year period beginning in 2023. The COVID-19 incremental costs will be updated at the time of the hearings. The companion adjustment is Rate Base Adjustment 17G.

Description	HTY 2019	Bridge Period 2020	MYP 1 2021	MYP 2 2022	MYP 3 2023
COVID-19 Expenses	$ -	$ -	$ -	$ -	$ -
Total COVID-19 expenses to be amortized	-	-	-		
5-year amortization	-	-	-	5	5
Amortization of deferred COVID-19 expenses	-	-	-	-	-
Income Tax effect at 27.5175%	-	-	-		
Adjustment to operating income	$ -	$ -	$ -	$ -	$ -
Amount Presented on Company Exhibit DMV-4G	$ -	$ -	$ -	$ -	$ -

Mapping to Exhibit DMV-3G Ratemaking Adjustments:

Operation and Maintenance (Line 19)	$ -	$ -	$ -	$ -	$ -
Current Income Taxes (Line 22)					
	$ -	$ -	$ -	$ -	$ -

Baltimore Gas and Electric Company
Adjustment to Reflect the Income Tax Effect of Pro Forma Interest - Gas
Multi-Year Plan

Operating Income
Adjustment 42G

This adjustment synchronizes interest expense utilized in the income tax calculation with adjusted rate base and the weighted cost of debt implicit in the gas rates of return supported by the Company for each period.

Description	HTY 2019	Bridge Period 2020	MYP 1 2021	MYP 2 2022	MYP 3 2023
Unadjusted rate base - Company Exhibit DMV-3G, line 11	$1,876,062,242	$2,145,335,496	$2,403,000,293	$2,643,936,257	$2,876,834,429
Rate base adjustments - Company Exhibit DMV-3G, line 11	135,295,716	(9,793,837)	12,422,459	62,654,935	97,759,283
Rate Base adjusted for calculation of pro forma interest	$2,011,357,958	$2,135,541,659	$2,415,422,752	$2,706,591,192	$2,974,593,711
Weighted cost of debt: Long-term debt	1.87%	1.88%	1.87%	1.87%	1.87%
Long-term debt pro forma interest	$ 37,612,394	$ 40,148,183	$ 45,168,405	$ 50,613,255	$ 55,624,902
Long-term debt actual interest charges	34,121,406	37,903,944	41,137,917	43,013,511	46,630,474
Total adjustment to interest expense	3,490,988	2,244,239	4,030,489	7,599,745	8,994,428
Income tax rate	27.5175%	27.5175%	27.5175%	27.5175%	27.5175%
Tax effect of pro forma interest	($960,633)	($617,558)	($1,109,090)	($2,091,260)	($2,475,042)
Amount Presented on Company Exhibit DMV-4G	$961,000	$618,000	$1,109,000	$2,091,000	$2,475,000

Mapping to Exhibit DMV-3G Ratemaking Adjustments:

Current Income Taxes (Line 22)	$ (960,633)	$ (617,558)	$ (1,109,090)	$ (2,091,260)	$ (2,475,042)
	$ (960,633)	$ (617,558)	$ (1,109,090)	$ (2,091,260)	$ (2,475,042)

Baltimore Gas and Electric Company
Gas Riverside Environmental Regulatory Asset
Multi-Year Plan

Rate Base
Adjustment 3G

This adjustment reduces gas rate base to reflect the impact of the accumulated amortization associated with the Riverside regulatory asset reflected in Case No. 9610. It is the companion adjustment to Operating Income Adjustment No. 8G.

Description	HTY 2019	Bridge Period 2020	MYP 1 2021	MYP 2 2022	MYP 3 2023
Change in the Riverside amortization reflected in Case No. 9610 per Operating Income Adjustment 8G	$ 83,449	$ -	$ -	$ -	$ -
Adjustment to reflect average rate base	50.0%				
Increased accumulated amortization	41,724				
Income tax effect at 27.5175%	(11,482)				
Adjustment to rate base	$ 30,243	$ -	$ -	$ -	$ -
Amount Presented on Company Exhibit DMV-4G	$ (30,000)	$ -	$ -	$ -	$ -

Mapping to Exhibit DMV-3G Ratemaking Adjustments:

Regulatory Assets & Liabilities (Line 9)	$ (41,724)	$ -	$ -	$ -	$ -
Accumulated Deferred Income Taxes (Line 6)	11,482	-	-	-	-
	$ (30,243)	$ -	$ -	$ -	$ -

Baltimore Gas and Electric Company
Case No. 9610 Impact of New Depreciation Rates - Gas
Multi-Year Plan

Rate Base
Adjustment 4G

This adjustment reflects the impact on the accumulated depreciation reserve of the new depreciation rates resulting from Case No. 9610. This is the companion adjustment to Operating Income Adjustment 9G.

Description	HTY 2019	Bridge Period 2020	MYP 1 2021	MYP 2 2022	MYP 3 2023
Increase in accumulated depreciation resulting from Operating Income Adjustment 9G	$ 5,205,492	$ -	$ -	$ -	$ -
Deferred income taxes on normalized depreciation expense at 27.5175%	(1,432,421)	-	-	-	-
Increased accumulated depreciation, net of tax	3,773,071	-	-	-	-
Adjustment to reflect average rate base	50.0%				
Adjustment to rate base	$ 1,886,535	$ -	$ -	$ -	$ -
Amount Presented on Company Exhibit DMV-4G	$ (1,887,000)	-	-	-	-

Mapping to Exhibit DMV-3G Ratemaking Adjustments:

	HTY 2019	Bridge Period 2020	MYP 1 2021	MYP 2 2022	MYP 3 2023
Accumulated Depreciation and Amortization (Line 3)	$ (2,602,746)	$ -	$ -	$ -	$ -
Accumulated Deferred Income Taxes (Line 6)	716,211	-	-	-	-
	$ (1,886,535)	$ -	$ -	$ -	$ -

Baltimore Gas and Electric Company
Remove Fully Amortized Gas Regulatory Assets
Multi-Year Plan

Rate Base
Adjustment 5G

This adjustment eliminates the tranche of Spring Gardens environmental costs from Case No. 9230 which will be fully amortized in November 2020 . Since this regulatory asset will be fully amortized prior to the end of calendar year 2020, it should not be included in rate base. This is the companion adjustment to Operating Income Adjustment 15G.

Description	HTY 2019	Bridge Period 2020	MYP 1 2021	MYP 2 2022	MYP 3 2023
Regulatory Asset included in average rate base:					
Spring Gardens Environmental - Case No. 9230	$ 145,372	$ -	$ -	$ -	$ -
		-	-	-	-
Total regulatory asset to be eliminated	145,372				
Income tax effect at 27.5175%	(40,003)	-	-	-	-
Adjustment to rate base	$ 105,369	-	-	-	-
Amount Presented on Company Exhibit DMV-4G	$ (105,000)	-	-	-	-

Mapping to Exhibit DMV-3G Ratemaking Adjustments:

Regulatory Assets & Liabilities (Line 9)	$ (145,372)	$ -	$ -	$ -	$ -
Accumulated Deferred Income Taxes (Line 6)	40,003	-	-	-	-
	$ (105,369)	$ -	$ -	$ -	$ -

Baltimore Gas and Electric Company
Unamortized Gas Real Estate Gains and Losses
Multi-Year Plan

Rate Base
Adjustment 6G

This adjustment reflects the unamortized gas gains on real estate which are being amortized into gas operating income for ratemaking purposes over a two year period as specified by the Commission in Case Nos. 7695, 9406, and 9484. This adjustment is a companion adjustment to Operating Income Adjustment 16G.

Description	HTY 2019	Bridge Period 2020	MYP 1 2021	MYP 2 2022	MYP 3 2023
Unamortized gains on the sale of real estate:					
Unamortized balance @ 12/31/18	$ 1,062,275	$ -	$ -	$ -	$ -
Unamortized balance @ 12/31/19 per Operating Income Adjustment 16G	354,092	-	-	-	-
Average balance unamortized gains on sale of real estate	708,183	-	-	-	-
Income Tax Effect at 27.5175%	(194,874)	-	-	-	-
Adjustment to Rate Base	$ 513,309	$ -	$ -	$ -	$ -
Amount presented on Company Exhibit DMV-4G	$ (513,000)	$ -	$ -	$ -	$ -

Mapping to Exhibit DMV-3G Ratemaking Adjustments:

	HTY 2019	Bridge Period 2020	MYP 1 2021	MYP 2 2022	MYP 3 2023
Regulatory Assets & Liabilities (Line 9)	$ (708,183)	$ -	$ -	$ -	$ -
Accumulated Deferred Income Taxes (Line 6)	194,874	-	-	-	-
	$ (513,309)	$ -	$ -	$ -	$ -

This adjustment reflects the terminal impact of the known and measurable non-revenue producing gas safety and reliability investments as filed in Case No. 9610. This adjustment includes the impact on plant in service, accumulated depreciation reserve, depreciation savings, and related accumulated deferred income taxes. It is a companion adjustment to Operating Income Adjustment 17G, which adjusts the level of depreciation for these projects.

Description	HTY 2019	Bridge Period 2020	MYP 1 2021	MYP 2 2022	MYP 3 2023
Gas safety and reliability project investment included in Case No. 9610 filing	$ 157,845,262	$ -	$ -	$ -	$ -
Gas safety and reliability project investment reflected in average rate base	77,362,013	-	-	-	-
Additional gas safety and reliability investment - Increase in plant in service	80,483,249	-	-	-	-
Less:					
Additional accumulated depreciation, net of savings, per Operating Income Adjustment 17G	1,848,050	-	-	-	-
Plus:					
Accumulated Deferred Income Taxes on the additional investment above	(16,075,384)	-	-	-	-
Adjustment to Rate Base	$ 62,559,815	$ -	$ -	$ -	$ -
Amount presented on Company Exhibit DMV-4G	$ 62,560,000	$ -	$ -	$ -	$ -

Mapping to Exhibit DMV-3G Ratemaking Adjustments:

Description	HTY 2019	Bridge Period 2020	MYP 1 2021	MYP 2 2022	MYP 3 2023
Gas Plant (Line 2)	$ 80,483,249	$ -	$ -	$ -	$ -
Accumulated Depreciation and Amortization (Line 3)	(1,848,050)				
Accumulated Deferred Income Taxes (Line 6)	(16,075,384)	-	-	-	-
	$ 62,559,815	$ -	$ -	$ -	$ -

Baltimore Gas and Electric Company
Gas Terminal STRIDE Net Investments
Multi-Year Plan

Rate Base
Adjustment 8G

This adjustment reflects the terminal impact of the known and measurable STRIDE investments as filed in Case No. 9610. This adjustment includes the impact on plant in service, accumulated depreciation reserve, depreciation savings, and related accumulated deferred income taxes. It is a companion adjustment to Operating Income Adjustment 18G, which adjusts the level of depreciation for these projects.

Description	HTY 2019	Bridge Period 2020	MYP 1 2021	MYP 2 2022	MYP 3 2023
STRIDE project investment as reflected in the Case No. 9610 filing	$ 203,439,164	$ -	$ -	$ -	$ -
STRIDE project investment reflected in the Case No. 9610 average rate base	93,289,478	-	-	-	-
Additional STRIDE investment - Increase in plant in service	110,149,686	-	-	-	-
Less: Additional accumulated depreciation due to increased depreciation expense, net of depreciation savings, per Operating Income Adjustment 18G	1,536,409	-	-	-	-
Plus: Additional accumulated deferred income taxes related to the additional STRIDE project investment above	(24,036,179)	-	-	-	-
Adjustment to Rate Base	$ 84,577,098	$ -	$ -	$ -	$ -
Amount presented on Company Exhibit DMV-4G	$ 84,577,000	$ -	$ -	$ -	$ -

Mapping to Exhibit DMV-3G Ratemaking Adjustments:

Gas Plant (Line 2)	$ 110,149,686	$ -	$ -	$ -	$ -
Accumulated Depreciation and Amortization (Line 3)	(1,536,409)				
Accumulated Deferred Income Taxes (Line 6)	(24,036,179)	-	-	-	-
	$ 84,577,098	$ -	$ -	$ -	$ -

Baltimore Gas and Electric Company
Eliminate Gas RM54 Software
Multi-Year Plan

Rate Base
Adjustment 9G-Updated

This adjustment reduces gas rate base to remove the RM54 capital software costs. The RM54 capital is recorded as common plant, and therefore is allocated to electric and gas distribution. Accordingly, since these costs will be recovered through the Purchase of Receivables discount rate, it is necessary to remove the gas portion of RM54 capital in Rate Base Adjustment 9G. The companion adjustment is Operating Income Adjustment 29G-Updated.

Description	**HTY 2019**	**Bridge Period 2020**	**MYP 1 2021**	**MYP 2 2022**	**MYP 3 2023**
RM54 Plant in Service	$ 626,999	$ 652,160	$ 656,223	$ 656,223	$ -
RM54 Accumulated Amortization	(314,133)	(442,307)	(573,518)	(654,436)	-
RM54 Software to be excluded from rate base	312,865	209,853	82,705	1,787	-
Income Tax Effect at 27.5175%	(86,093)	(57,746)	(22,758)	(492)	
Adjustment to rate base	$ 226,773	$ 152,107	$ 59,947	$ 1,295	$ -
Amount Presented on Company Exhibit DMV-4G	$ (227,000)	$ (152,000)	$ (60,000)	$ (1,000)	$ -

Mapping to Exhibit DMV-3G Ratemaking Adjustments:

Gas Plant (Line 2)	$ (626,999)	$ (652,160)	$ (656,223)	$ (656,223)	$ -
Accumulated Depreciation and Amortization (Line 3)	314,133	442,307	573,518	654,436	-
Accumulated Deferred Income Taxes (Line 6)	86,093	57,746	22,758	492	-
	$ (226,773)	$ (152,107)	$ (59,947)	$ (1,295)	$ -

Baltimore Gas and Electric Company
Impact of Gas Riverside Environmental Amortization
Multi-Year Plan

Rate Base
Adjustment 12G

This adjustment reflects the impact on the Riverside environmental regulatory asset of the additional amortization provided. This is the companion adjustment to Operating Income Adjustment 34G.

Description	HTY 2019	Bridge Period 2020	MYP 1 2021	MYP 2 2022	MYP 3 2023
Increase in amortization resulting from Operating Income Adjustment 34G	$ -	$ -	$ -	$ 270,173	$ 270,173
Adjustment to reflect average rate base	50%	50%	50%	50%	50%
Average Rate Base impact of current period amortization				135,087	135,087
Accumulated Amortization as of end of prior period	-	-	-		270,173
Total Riverside accumulated amortization impact	-	-		135,087	405,260
Income tax effect at 27.5175%	-	-	-	(37,172)	(111,517)
Increased accumulated amortization, net of tax	$ -	$ -	$ -	$ 97,914	$ 293,743
Adjustment to rate base	$ -	$ -	$ -	$ 97,914	$ 293,743
Amount Presented on Company Exhibit DMV-4G	$ -	$ -	$ -	$ (98,000)	$ (294,000)

Mapping to Exhibit DMV-3G Ratemaking Adjustments:

Regulatory Assets & Liabilities (Line 9)	$ -	$ -	$ -	$ (135,087)	$ (405,260)
Accumulated Deferred Income Taxes (Line 6)	-	-	-	37,172	111,517
	$ -	$ -	$ -	$ (97,914)	$ (293,743)

Baltimore Gas and Electric Company
Gas Accelerated Tax Benefits Regulatory Liability Impact
Multi-Year Plan

Rate Base
Adjustment 14G

This adjustment reflects the rate base impact of the accelerated tax benefits. This is the companion adjustment to Operating Income Adjustment 38G.

Description	HTY 2019	Bridge Period 2020	MYP 1 2021	MYP 2 2022	MYP 3 2023
Accelerated tax benefits resulting from Operating Income Adjustment 38G	$ -	$ -	$ 39,590,501	$ 53,817,692	$ 12,938,138
Adjustment to reflect average rate base	-	-	50%	50%	50%
Average Rate Base impact of current period amortization			19,795,251	26,908,846	6,469,069
Accumulated Accelerated tax benefits as of end of prior period	-	-	-	39,590,501	93,408,193
Adjustment to rate base	$ -	$ -	$ 19,795,251	$ 66,499,347	$ 99,877,263
Amount Presented on Company Exhibit DMV-4G	$ -	$ -	$ 19,795,000	$ 66,499,000	$ 99,877,000

Mapping to Exhibit DMV-3G Ratemaking Adjustments:

Regulatory Assets & Liabilities (Line 9)	$ -	$ -	$ 19,795,251	$ 66,499,347	$ 99,877,263

Baltimore Gas and Electric Company
2021 Gas Regulatory Asset Amortization Suspension
Multi-Year Plan

Rate Base
Adjustment 15G

This adjustment reflects the rate base impact of eliminating the 2021 amortization expense associated with all regulatory assets in light of the current economic situation as a result of the COVID-19 pandemic. The companion adjustment is Operating Income Adjustment 39G.

Description	HTY 2019	Bridge Period 2020	MYP 1 2021	MYP 2 2022	MYP 3 2023
Deferred Costs to Achieve - Case 9406 tranche	$ -	$ -	$ 153,757	$ -	$ -
Riverside Environmental (Case No. 9484 tranche)	-	-	62,222	-	-
Riverside Environmental (Case No. 9610 tranche)			91,035		
Smart Grid Full Program	-	-	7,281,068	-	-
Total rate base impact of regulatory asset amortization eliminated in 2021		-	7,588,082	-	-
Adjustment to reflect average rate base	-	-	50%	50%	50%
Average Rate Base impact of current period amortization			3,794,041		
Accumulated Amortization as of end of prior period	-	-	-	7,588,082	7,588,082
Total 2021 regulatory asset accumulated amortization impact	-	-	3,794,041	7,588,082	7,588,082
Income tax effect at 27.5175%		-	(1,044,025)	(2,088,050)	(2,088,050)
Adjustment to operating income	$ -	$ -	$ 2,750,016	$ 5,500,031	$ 5,500,031
Amount Presented on Company Exhibit DMV-4G	$ -	$ -	$ 2,750,000	$ 5,500,000	$ 5,500,000

Mapping to Exhibit DMV-3G Ratemaking Adjustments:

Description	HTY 2019	Bridge Period 2020	MYP 1 2021	MYP 2 2022	MYP 3 2023
Regulatory Assets & Liabilities (Line 9)			$ 3,794,041	$ 7,588,082	$ 7,588,082
Accumulated Deferred Income Taxes (Line 6)			(1,044,025)	(2,088,050)	(2,088,050)
	$ -	$ -	$ 2,750,016	$ 5,500,031	$ 5,500,031

Baltimore Gas and Electric Company
Gas Smart Grid Regulatory Asset Life Extension
Multi-Year Plan

Rate Base
Adjustment 16G

This adjustment reflects the rate base impact of extending the Smart Grid regulatory asset recovery period through December 2031 from May 2026 in light of the current economic situation as a result of the COVID-19 pandemic. The companion adjustment is Operating Income Adjustment 40G.

Description	HTY 2019	Bridge Period 2020	MYP 1 2021	MYP 2 2022	MYP 3 2023
Total rate base impact of Operating Income Adjustment 40		-	-	$ 3,387,719	$ 3,387,719
Adjustment to reflect average rate base	-	-	-	50%	50%
Average Rate Base impact of current period amortization				1,693,860	1,693,860
Accumulated Amortization as of end of prior period	-	-	-	-	3,387,719
Total Smart Grid regulatory asset accumulated amortization impact	-	-		1,693,860	5,081,579
Income tax effect at 27.5175%		-	-	(466,108)	(1,398,323)
Adjustment to operating income	$ -	$ -	$ -	$ 1,227,752	$ 3,683,255
Amount Presented on Company Exhibit DMV-4G	$ -	$ -	$ -	$ 1,228,000	$ 3,683,000

Mapping to Exhibit DMV-3G Ratemaking Adjustments:

Regulatory Assets & Liabilities (Line 9)			$ -	$ 1,693,860	$ 5,081,579
Accumulated Deferred Income Taxes (Line 6)				(466,108)	(1,398,323)
	$ -	$ -	$ -	$ 1,227,752	$ 3,683,255

Baltimore Gas and Electric Company
COVID-19 Regulatory Asset
Multi-Year Plan

Rate Base
Adjustment 17G

This adjustment reflects the inclusion of the COVID-19 regulatory asset in Rate base. This is the companion adjustment to Operating Income Adjustment 41G.

Description	HTY 2019	Bridge Period 2020	MYP 1 2021	MYP 2 2022	MYP 3 2023
Total COVID-19 Regulatory Asset	$ -	$ -	$ -	$ -	$ -
Increase in amortization resulting from Operating Income Adjustment 41G	-	-	-	-	-
Adjustment to reflect average rate base	-	-	50%	50%	50%
Average Rate Base impact of current period amortization	-	-	-	-	-
Accumulated Amortization as of end of prior period	-	-	-	-	-
Total COVID-19 accumulated amortization impact	-	-	-	-	-
Total COVID-19 regulatory asset, net of amortization	-	-	-	-	-
Income tax effect at 27.5175%	-	-	-	-	-
COVID-19 regulatory asset rate base impact, net of tax	$ -	$ -	$ -	$ -	$ -
Adjustment to rate base	$ -	$ -	$ -	$ -	$ -
Amount Presented on Company Exhibit DMV-4G	$ -	$ -	$ -	$ -	$ -

Mapping to Exhibit DMV-3G Ratemaking Adjustments:

Regulatory Assets & Liabilities (Line 9)	$ -	$ -	$ -	$ -	$ -
Accumulated Deferred Income Taxes (Line 6)	-	-	-	-	-
	$ -	$ -	$ -	$ -	$ -

Baltimore Gas and Electric Company
Cash Working Capital Reflected in Rate Base - Gas
Multi-Year Plan

Company Exhibit DMV-5G-Updated

2019 Actual HTY - Unadjusted Rate Base - Based on 2014 Lag Study Net Lag Days

Line No.	Description	Line of Business	CWC Expense	Net Lag Days	Cash Advanced
1	Purchased Fuel and Energy Expense	Gas	$181,305,130	8.6	$4,271,847
2	Gas Choice and Reliability Costs	Gas	$957,757	8.6	$22,566
3	Salaries and Wages	Gas	69,926,687	10.9	2,088,222
4	Fringe Benefits	Gas	23,535,740	31.6	2,037,615
5	Other Oper & Maint Expense	Gas	130,261,805	(1.5)	(535,322)
6	Property Taxes	Gas	39,882,644	133.6	14,598,140
7	Payroll Taxes	Gas	5,738,004	10.3	161,922
8	PSC Assessment	Gas	1,414,493	77.3	299,562
9	GRT Taxes	Gas	13,359,079	(5.6)	(204,961)
10	Other Taxes	Gas	(5,298)	14.0	(203)
11	Federal Income Taxes - Current	Gas	(56,790,001)	(4.5)	700,151
12	State Income Taxes - Current	Gas	(16,487,605)	(11.5)	519,472
13	Interest Expense	Gas	33,890,983	(41.6)	(3,862,643)
14	Short Term Interest	Gas	733,236	53.7	107,876
15	Interest on Customer Deposits	Gas	1,091,176	(136.0)	(406,575)
16	Total Gas Cash Working Capital		$428,813,832		$19,797,668
17	Total Gas Cash Working Capital ($000) carried forward to Unadjusted Rate Base Company Exhibit DMV-3G, line 5				$19,798

Baltimore Gas and Electric Company | Company Exhibit DMV-5G-Updated

Cash Working Capital Reflected in Rate Base - Gas
Multi-Year Plan

2020 Bridge Period - Unadjusted Rate Base - Based on 2014 Lag Study Net Lag Days

Line No.	Description	Line of Business	CWC Expense	Net Lag Days	Cash Advanced
1	Purchased Fuel and Energy Expense	Gas	$168,171,867	8.6	$3,962,406
2	Gas Choice and Reliability Costs	Gas	2,078,579	8.6	$48,975
3	Salaries and Wages	Gas	73,209,255	10.9	2,186,249
4	Fringe Benefits	Gas	20,897,805	31.6	1,809,235
5	Other Oper & Maint Expense	Gas	139,360,007	(1.5)	(572,712)
6	Property Taxes	Gas	42,926,687	133.6	15,712,344
7	Payroll Taxes	Gas	5,941,727	10.3	167,671
8	PSC Assessment	Gas	1,550,128	77.3	328,287
9	GRT Taxes	Gas	14,856,449	(5.6)	(227,935)
10	Other Taxes	Gas	-	14.0	-
11	Income Taxes - Current	Gas	(41,397,058)	(5.9)	669,158
12	State Income Taxes - Current	Gas	-	-	-
13	Interest Expense	Gas	37,903,944	(41.6)	(4,320,011)
14	Short Term Interest	Gas	-	-	-
15	Interest on Customer Deposits	Gas	697,331	(136.0)	(259,827)
16	Total Gas Cash Working Capital		$466,196,720		$19,503,838
17	Total Gas Cash Working Capital ($000) carried forward to Unadjusted Rate Base Company Exhibit DMV-3G, line 5				$19,504

Baltimore Gas and Electric Company **Company Exhibit DMV-5G-Updated**
Cash Working Capital Reflected in Rate Base - Gas
Multi-Year Plan

2021 MYP Period - Unadjusted Rate Base - Based on 2014 Lag Study Net Lag Days

Line No.	Description	Line of Business	CWC Expense	Net Lag Days	Cash Advanced
1	Purchased Fuel and Energy Expense	Gas	$167,987,425	8.6	$3,958,060
2	Gas Choice and Reliability Costs	Gas	2,412,682	8.6	$56,847
3	Salaries and Wages	Gas	76,064,212	10.9	2,271,507
4	Fringe Benefits	Gas	20,355,156	31.6	1,762,255
5	Other Oper & Maint Expense	Gas	131,538,398	(1.5)	(540,569)
6	Property Taxes	Gas	46,353,734	133.6	16,966,737
7	Payroll Taxes	Gas	6,081,083	10.3	171,603
8	PSC Assessment	Gas	1,612,133	77.3	341,419
9	GRT Taxes	Gas	14,899,615	(5.6)	(228,597)
10	Other Taxes	Gas	-	14.0	-
11	Income Taxes - Current	Gas	(41,397,058)	(5.9)	669,158
12	State Income Taxes - Current	Gas	-	-	-
13	Interest Expense	Gas	41,137,917	(41.6)	(4,688,595)
14	Short Term Interest	Gas	-	-	-
15	Interest on Customer Deposits	Gas	721,641	(136.0)	(268,885)
16	Total Gas Cash Working Capital		$467,766,937		$20,470,938
17	Total Gas Cash Working Capital ($000) carried forward to Unadjusted Rate Base Company Exhibit DMV-3G, line 5				$20,471

Baltimore Gas and Electric Company **Company Exhibit DMV-5G-Updated**
Cash Working Capital Reflected in Rate Base - Gas
Multi-Year Plan

2022 MYP Period - Unadjusted Rate Base - Based on 2014 Lag Study Net Lag Days

Line No.	Description	Line of Business	CWC Expense	Net Lag Days	Cash Advanced
1	Purchased Fuel and Energy Expense	Gas	$168,940,602	8.6	$3,980,518
2	Gas Choice and Reliability Costs	Gas	2,417,919	8.6	$56,970
3	Salaries and Wages	Gas	77,528,841	10.9	2,315,245
4	Fringe Benefits	Gas	19,675,941	31.6	1,703,451
5	Other Oper & Maint Expense	Gas	127,158,775	(1.5)	(522,570)
6	Property Taxes	Gas	50,054,732	133.6	18,321,403
7	Payroll Taxes	Gas	6,084,803	10.3	171,708
8	PSC Assessment	Gas	1,676,618	77.3	355,076
9	GRT Taxes	Gas	15,299,686	(5.6)	(234,735)
10	Other Taxes	Gas	-	14.0	-
11	Income Taxes - Current	Gas	(41,397,058)	(5.9)	669,158
12	State Income Taxes - Current	Gas	-	-	-
13	Interest Expense	Gas	43,013,511	(41.6)	(4,902,362)
14	Short Term Interest	Gas	-	-	-
15	Interest on Customer Deposits	Gas	746,622	(136.0)	(278,193)
16	Total Gas Cash Working Capital		$471,200,992		$21,635,669
17	Total Gas Cash Working Capital ($000) carried forward to Unadjusted Rate Base Company Exhibit DMV-3G, line 5				$21,636

Baltimore Gas and Electric Company
Cash Working Capital Reflected in Rate Base - Gas
Multi-Year Plan

Company Exhibit DMV-5G-Updated

2023 MYP Period - Unadjusted Rate Base - Based on 2014 Lag Study Net Lag Days

Line No.	Description	Line of Business	CWC Expense	Net Lag Days	Cash Advanced
1	Purchased Fuel and Energy Expense	Gas	$171,885,539	8.6	$4,049,906
2	Gas Choice and Reliability Costs	Gas	2,432,339	8.6	$57,310
3	Salaries and Wages	Gas	78,598,624	10.9	2,347,192
4	Fringe Benefits	Gas	19,558,002	31.6	1,693,241
5	Other Oper & Maint Expense	Gas	123,411,501	(1.5)	(507,171)
6	Property Taxes	Gas	54,051,591	133.6	19,784,363
7	Payroll Taxes	Gas	6,052,529	10.3	170,797
8	PSC Assessment	Gas	1,743,683	77.3	369,279
9	GRT Taxes	Gas	15,399,128	(5.6)	(236,261)
10	Other Taxes	Gas	-	14.0	-
11	Income Taxes - Current	Gas	(41,397,058)	(5.9)	669,158
12	State Income Taxes - Current	Gas	-	-	-
13	Interest Expense	Gas	46,630,474	(41.6)	(5,314,597)
14	Short Term Interest	Gas	-	-	-
15	Interest on Customer Deposits	Gas	771,334	(136.0)	(287,401)
16	Total Gas Cash Working Capital		$479,137,686		$22,795,816
17	Total Gas Cash Working Capital ($000) carried forward to Unadjusted Rate Base Company Exhibit DMV-3G, line 5				$22,796

Baltimore Gas and Electric Company **Company Exhibit DMV-6G-Updated**
Gas Cash Working Capital Based on Updated Net Lag Days
Multi-Year Plan

2019 Cash Working Capital Based on 2019 Lag Study Net Lag Days

Line No.	Description	Line of Business	CWC Expense	Net Lag Days per 2019 Lag Study	Updated Cash Advanced
1	Purchased Fuel and Energy Expense	Gas	$181,305,130	9.8	$4,867,919
2	Gas Choice and Reliability Costs	Gas	957,757	9.8	$25,715
3	Salaries and Wages	Gas	69,926,687	6.1	1,168,638
4	Fringe Benefits	Gas	23,535,740	7.7	496,507
5	Other Oper & Maint Expense	Gas	130,261,805	(5.3)	(1,891,473)
6	Property Taxes	Gas	39,882,644	92.8	10,140,026
7	Payroll Taxes	Gas	5,661,004	6.1	94,609
8	PSC Assessment	Gas	1,414,493	77.5	300,338
9	GRT Taxes	Gas	13,359,079	(8.4)	(307,442)
10	Other Taxes	Gas	71,509	32.9	6,446
11	Federal Income Taxes - Current	Gas	(56,790,001)	(4.4)	684,592
12	State Income Taxes - Current	Gas	(16,487,605)	(11.5)	519,472
13	Interest Expense	Gas	33,890,983	(54.7)	(5,079,005)
14	Short Term Interest	Gas	733,236	49.1	98,635
15	Interest on Customer Deposits	Gas	1,091,176	(135.9)	(406,276)
16	Total Gas Cash Working Capital Based on New Lag Days - 2019 Lag Study		$428,813,638		$10,718,700
17	CWC Based on 2014 Lag Study included in Unadjusted Rate Base - Company Exhibit DMV-5G, line 16				$19,797,668
18	Impact of Change in Net Lag Days carried forward to Company Exhibit DMV-4G, line 43				($9,078,968)

Baltimore Gas and Electric Company
Gas Cash Working Capital Based on Updated Net Lag Days
Multi-Year Plan

2020 Cash Working Capital Based on 2019 Lag Study Net Lag Days

Line No.	Description	Line of Business	CWC Expense	Net Lag Days per 2019 Lag Study	Updated Cash Advanced
1	Purchased Fuel and Energy Expense	Gas	$168,171,867	9.8	$4,515,299
2	Gas Choice and Reliability Costs	Gas	2,078,579	9.8	$55,808
3	Salaries and Wages	Gas	73,209,255	6.1	1,223,497
4	Fringe Benefits	Gas	20,897,805	7.7	440,858
5	Other Oper & Maint Expense	Gas	139,360,007	(5.3)	(2,023,584)
6	Property Taxes	Gas	42,926,687	92.8	10,913,963
7	Payroll Taxes	Gas	5,941,727	6.1	99,300
8	PSC Assessment	Gas	1,550,128	77.5	329,137
9	GRT Taxes	Gas	14,856,449	(8.4)	(341,902)
10	Other Taxes	Gas	-	32.9	-
11	Income Taxes - Current	Gas	(41,397,058)	(5.2)	589,766
12	State Income Taxes - Current	Gas	-	-	-
13	Interest Expense	Gas	37,903,944	(54.7)	(5,680,399)
14	Short Term Interest	Gas	-	-	-
15	Interest on Customer Deposits	Gas	697,331	(135.9)	(259,636)
16	Total Gas Cash Working Capital Based on New Lag Days - 2019 Lag Study		$466,196,720		$9,862,108
17	CWC Based on 2014 Lag Study included in Unadjusted Rate Base - Company Exhibit DMV-5G, line 16				$19,503,838
18	Impact of Change in Net Lag Days carried forward to Company Exhibit DMV-4G, line 43				($9,641,730)

Baltimore Gas and Electric Company **Company Exhibit DMV-6G-Updated**
Gas Cash Working Capital Based on Updated Net Lag Days
Multi-Year Plan

2021 Cash Working Capital Based on 2019 Lag Study Net Lag Days

Line No.	Description	Line of Business	CWC Expense	Net Lag Days per 2019 Lag Study	Updated Cash Advanced
1	Purchased Fuel and Energy Expense	Gas	$167,987,425	9.8	$4,510,347
2	Gas Choice and Reliability Costs	Gas	2,412,682	9.8	$64,779
3	Salaries and Wages	Gas	76,064,212	6.1	1,271,210
4	Fringe Benefits	Gas	20,355,156	7.7	429,410
5	Other Oper & Maint Expense	Gas	131,538,398	(5.3)	(1,910,010)
6	Property Taxes	Gas	46,353,734	92.8	11,785,278
7	Payroll Taxes	Gas	6,081,083	6.1	101,629
8	PSC Assessment	Gas	1,612,133	77.5	342,302
9	GRT Taxes	Gas	14,899,615	(8.4)	(342,895)
10	Other Taxes	Gas	-	32.9	-
11	Income Taxes - Current	Gas	(41,397,058)	(5.2)	589,766
12	State Income Taxes - Current	Gas	-	-	-
13	Interest Expense	Gas	41,137,917	(54.7)	(6,165,052)
14	Short Term Interest	Gas	-	-	-
15	Interest on Customer Deposits	Gas	721,641	(135.9)	(268,688)
16	Total Gas Cash Working Capital Based on New Lag Days - 2019 Lag Study		$467,766,937		$10,408,077
17	CWC Based on 2014 Lag Study included in Unadjusted Rate Base - Company Exhibit DMV-5G, line 16				$20,470,938
18	Impact of Change in Net Lag Days carried forward to Company Exhibit DMV-4G, line 43				($10,062,861)

Baltimore Gas and Electric Company
Gas Cash Working Capital Based on Updated Net Lag Days
Multi-Year Plan

2022 Cash Working Capital Based on 2019 Lag Study Net Lag Days

Line No.	Description	Line of Business	CWC Expense	Net Lag Days per 2019 Lag Study	Updated Cash Advanced
1	Purchased Fuel and Energy Expense	Gas	$168,940,602	9.8	$4,535,939
2	Gas Choice and Reliability Costs	Gas	$2,417,919	9.8	$64,919
3	Salaries and Wages	Gas	77,528,841	6.1	1,295,687
4	Fringe Benefits	Gas	19,675,941	7.7	415,081
5	Other Oper & Maint Expense	Gas	127,158,775	(5.3)	(1,846,415)
6	Property Taxes	Gas	50,054,732	92.8	12,726,244
7	Payroll Taxes	Gas	6,084,803	6.1	101,691
8	PSC Assessment	Gas	1,676,618	77.5	355,994
9	GRT Taxes	Gas	15,299,686	(8.4)	(352,102)
10	Other Taxes	Gas	-	32.9	-
11	Income Taxes - Current	Gas	(41,397,058)	(5.2)	589,766
12	State Income Taxes - Current	Gas	-	-	-
13	Interest Expense	Gas	43,013,511	(54.7)	(6,446,134)
14	Short Term Interest	Gas	-	-	-
15	Interest on Customer Deposits	Gas	746,622	(135.9)	(277,989)
16	Total Gas Cash Working Capital Based on New Lag Days - 2019 Lag Study		$471,200,992		$11,162,683
17	CWC Based on 2014 Lag Study included in Unadjusted Rate Base - Company Exhibit DMV-5G, line 16				$21,635,669
18	Impact of Change in Net Lag Days carried forward to Company Exhibit DMV-4G, line 43				($10,472,986)

Baltimore Gas and Electric Company **Company Exhibit DMV-6G-Updated**
Gas Cash Working Capital Based on Updated Net Lag Days
Multi-Year Plan

2023 Cash Working Capital Based on 2019 Lag Study Net Lag Days

Line No.	Description	Line of Business	CWC Expense	Net Lag Days per 2019 Lag Study	Updated Cash Advanced
1	Purchased Fuel and Energy Expense	Gas	$171,885,539	9.8	$4,615,009
2	Gas Choice and Reliability Costs	Gas	2,432,339	9.8	$65,307
3	Salaries and Wages	Gas	78,598,624	6.1	1,313,566
4	Fringe Benefits	Gas	19,558,002	7.7	412,593
5	Other Oper & Maint Expense	Gas	123,411,501	(5.3)	(1,792,003)
6	Property Taxes	Gas	54,051,591	92.8	13,742,432
7	Payroll Taxes	Gas	6,052,529	6.1	101,152
8	PSC Assessment	Gas	1,743,683	77.5	370,234
9	GRT Taxes	Gas	15,399,128	(8.4)	(354,391)
10	Other Taxes	Gas	-	32.9	-
11	Income Taxes - Current	Gas	(41,397,058)	(5.2)	589,766
12	State Income Taxes - Current	Gas	-	-	-
13	Interest Expense	Gas	46,630,474	(54.7)	(6,988,183)
14	Short Term Interest	Gas	-	-	-
15	Interest on Customer Deposits	Gas	771,334	(135.9)	(287,190)
16	Total Gas Cash Working Capital Based on New Lag Days - 2019 Lag Study		$479,137,686		$11,788,292
17	CWC Based on 2014 Lag Study included in Unadjusted Rate Base - Company Exhibit DMV-5G, line 16				$22,795,816
18	Impact of Change in Net Lag Days carried forward to Company Exhibit DMV-4G, line 43				($11,007,524)

Baltimore Gas and Electric Company
2019 Lag Study - Gas Lag Components

Company Exhibit DMV-7G-Updated

Line No.	Description	Lag Days	Revenue Lag	Net Lag Days
1	Revenue Lag:			
2	Rendition of service to meter reading date		14.7	
3	Meter reading date to bill delivery		3.8	
4	Bill delivery to payment		28.4	
5	Receipt of payment to date funds are accessible		0.2	
6	Total days lag in collection of revenue		47.1	
7	Expense Lag:			
8	Gas PFE	37.3	47.1	9.8
9	Salaries and Wages	41.0	47.1	6.1
10	Fringe Benefits	39.4	47.1	7.7
11	Other Oper & Maint Expense	52.4	47.1	(5.3)
12	Property Taxes	(45.7)	47.1	92.8
13	Payroll Taxes	41.0	47.1	6.1
14	PSC Assessment	(30.4)	47.1	77.5
15	Electric Environmental Surcharge	41.5	47.1	5.6
16	Universal Service Fund	35.9	47.1	11.2
17	GRT Taxes	55.5	47.1	(8.4)
18	Other Taxes	14.2	47.1	32.9
19	Federal Income Taxes	51.5	47.1	(4.4)
20	State Income Taxes	58.6	47.1	(11.5)
21	Combined Income Taxes	52.3	47.1	(5.2)
22	Interest Expense	101.8	47.1	(54.7)
23	Short Term Interest	(2.0)	47.1	49.1
24	Interest on Customer Deposits	183.0	47.1	(135.9)

An Exelon Company

2020-2023 Plan Documentation – Capital and O&M

Executive Category Owner: David M. Vahos

Title: Senior Vice President, CFO & Treasurer

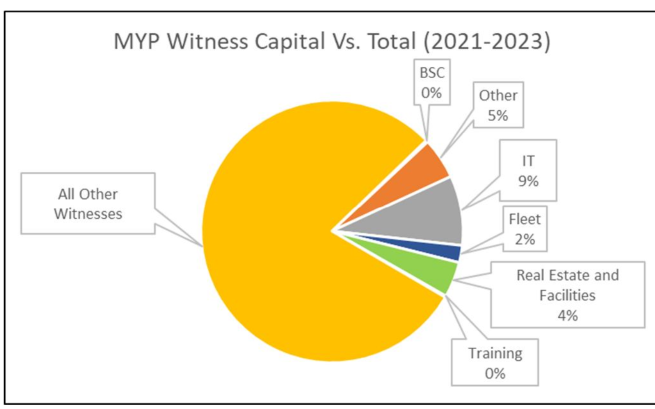
I. Financial Summary

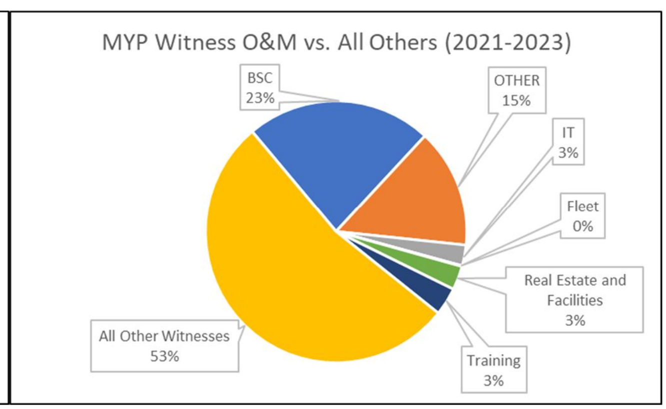
A. Capital

CATEGORY	2019A	2020F	2021F	2022F	2023F
INFORMATION TECHNOLOGY	$135,945,141	$138,187,074	$83,629,401	$82,308,402	$81,814,318
BUSINESS SERVICES COMPANY	$5,954,529	$3,292,470	$2,326,728	$2,274,076	$2,334,554
FLEET	$21,074,820	$29,075,000	$21,915,000	$20,615,000	$17,785,000
REAL ESTATE AND FACILITIES	$43,531,919	$81,052,489	$46,193,736	$42,736,611	$36,611,546
TRAINING	$611,445	$1,496,900	$1,496,463	$1,496,770	$1,496,559
OTHER	$17,156,805	$51,346,897	$47,904,579	$63,309,048	$34,580,463
ANNUAL TOTALS FOR CAPITAL	**$224,274,659**	**$304,450,830**	**$203,465,907**	**$212,739,907**	**$174,622,440**

B. O&M

CATEGORY	2019A	2020F	2021F	2022F	2023F
INFORMATION TECHNOLOGY	$25,515,691	$36,207,710	$19,657,021	$19,535,399	$18,694,625
BUSINESS SERVICES COMPANY	$159,888,955	$172,882,739	$172,165,403	$173,707,095	$176,089,299
FLEET	$591,838	$707,000	$707,000	$707,000	$707,000
REAL ESTATE AND FACILITIES	$20,548,383	$21,698,483	$21,716,349	$22,272,300	$22,903,681
TRAINING	$26,034,421	$27,929,523	$26,650,959	$25,988,677	$25,386,069
OTHER	$98,716,948	$109,758,681	$111,538,238	$111,483,646	$111,692,952
ANNUAL TOTALS FOR O&M	**$331,296,236**	**$369,184,136**	**$352,434,970**	**$353,694,117**	**$355,473,626**





II. Capital Category Cashflows and Functions

A. Information Technology

Category	2019A	2020F	2021F	2022F	2023F
Information Technology	$135,945,141	$138,187,074	$83,629,401	$82,308,402	$81,814,318

- The overall trend in Information Technology (IT) capital expenditures over the 2020-2023 time period reflects completion of the following projects by 2020:
  - Customer Care and Billing (CC&B)
  - Leased Line Optimization (LLO)
  - BGE Distribution Supervisory Control and Data Acquisition (D-SCADA) Lifecycle Upgrade
  - Energy Management System (EMS) Consolidation
  - Exelon Utilities (EU) Customer Journey – I Sign Up and Move.

  The final 3 years of spending reflects an ongoing baseload level of IT projects, without as many concurrent large projects.

- Some examples of planned IT projects over the 2020-2023 timeframe include the following:
  - Lifecycle projects – Replace or refresh aging components in smart grid infrastructure, communication networks, communication tower infrastructure, call center telephony, servers, storage, and personal computers/laptops.
  - Operational platform projects – Integrate common Exelon utility platforms including Advance Distribution Management Systems, Mobile Dispatch for Field Workers, and Geographic Information Systems.
  - Customer experience projects – Improve the ease-of-use of various interactive channels (telephone, web, and mobile) and create tools to provide customers with data and analytics to manage their energy usage.
  - Grid interconnect projects – Support grid interconnections for Distributed Energy Resource (DER) assets and adapt distribution operating systems to the growing number of DER connected assets.
  - Outage restoration projects – Improve communications during storm events, and leverage analytics to improve IT system performance during high-volume transaction events such as storms. For example: BGE's customers can view outage maps and monitor outage information through apps on their mobile devices and the BGE website.
  - Regulatory projects – Support the implementation of mandatory projects, such as the 2020 Demand Response Enhancement program, to meet EmPOWER MD goals and PJM requirements.

B. Business Services Company

Category	2019A	2020F	2021F	2022F	2023F
Business Services Company	$5,954,529	$3,292,470	$2,326,728	$2,274,076	$2,334,554

- The Business Services Company (BSC) capital costs billed to BGE are primarily planning, design, and implementation of various enterprise-wide corporate IT projects.

C. Fleet

Category	2019A	2020F	2021F	2022F	2023F
Fleet	$21,074,820	$29,075,000	$21,915,000	$20,615,000	$17,785,000

- The scheduled life cycle for most fleet assets is approximately 9 or 10 years, with year-to-year asset replacements based on asset age and condition. The trend in Fleet capital spending over the 2020-2023 time period reflects this replacement cycle, with the bulk of replacements occurring from 2020 to 2022, with a peak in 2020.
- BGE is also in the process of converting its existing internal combustion engine assets to electric vehicles where the technology supports and meets business needs. Along with converting fleet assets, BGE will install infrastructure across its facilities to support the charging requirements of electric vehicles.
- As of December 2019, the BGE fleet consists of approximately:
  - 870 light vehicles.
  - 420 heavy vehicles.
  - 550 units of equipment (tractors, trailers, others).
- The fleet organization is responsible for design, purchase, maintenance, repair, and preparation for disposal of fleet vehicles through sale or salvage. The capital expenditure portion of that work is primarily for purchase activities.

D. Real Estate and Facilities

Category	2019A	2020F	2021F	2022F	2023F
Real Estate and Facilities	$43,531,919	$81,052,489	$46,193,736	$42,736,611	$36,611,546

- During 2020, the electric system operations center rebuild, Howard Service Center rebuild, interior and exterior renovations at BGE's headquarters building and significant infrastructure replacements drive the increased capital expenditures. From 2021 through 2023 the completion of the Howard Service Center Rebuild in 2021 and a reduction in the renovation budget in 2023 result in a steady decline in the Real Estate and Facilities capital expenditures over that period...
- The facilities group performs:
  - Renovations and rebuilds of existing BGE buildings – in older BGE buildings, some refurbishment may be required to meet current building codes. In addition, employee workspaces are outdated and in need of updating to make more efficient use of space and improve the workplace environment. These projects include furniture, infrastructure, workspace improvements, IT and audiovisual facilities, and other workplace improvements.
  - Infrastructure projects – mechanical, electrical, plumbing, structural, and HVAC systems must be replaced and/or modernized to maintain reliability and improve energy efficiency. In addition, outdoor facilities (e.g., walkways, parking facilities and lighting) must be replaced.

E. Training

Category	2019A	2020F	2021F	2022F	2023F
Training	$611,445	$1,496,900	$1,496,463	$1,496,770	$1,496,559

- Over the 2020 through 2023 time horizon, training will be developing a library of technology-based virtual reality and augmented reality (VR and AR) training courses. Increasing the use of VR and AR is expected to improve the quality of instructor-led training by increasing consistency and quality.

F. Other

Category	2019A	2020F	2021F	2022F	2023F
Other	$17,156,805	$51,346,897	$47,904,579	$63,309,048	$34,580,463

- Other investments include BGE's General & Administrative (G&A) costs for back-office activities across the entire organization that support field activities.
    - The G&A allocation accumulates support costs for field work, such as design, engineering and project management, which are then distributed as an overhead to field projects.
    - Common costs attributable to electric transmission that have no impact on distribution rate base or MYP distribution rates account for 90% of the back office allocation spend over the MYP period. This is consistent with how common spend is captured throughout the Capital and O&M templates. Directly assigned transmission costs have been removed from the templates; however, those common costs that are not directly assigned to electric transmission (but are allocated to transmission) are included in these templates for consistency purposes. These costs are removed in the calculation of the MYP distribution revenue requirement.
    - The remainder of the G&A value is the result of limitations within the budgeting tool related to differences between cost pool inflation and the rate of inflation applied to allocations (this limitation does not impact actuals), as well as minor adjustments associated with how the budgeting tool accounts for vacancies.
- This category also includes:
    - In 2022, there is a Smart Energy Services (SES) software upgrade. This $21 million project is a continuation of the Smart Energy Services program that started in 2012. The program will continue to deliver the same benefits as the existing SES program.
    - The electric vehicle (EV) public charging infrastructure program, which covers the purchase and installation of public charging stations across the BGE service territory. The program began in 2019 and is projected to be completed in 2021.
    - The Peak Rewards Capital category which covers the purchase and installation of smart thermostats and is estimated at $13 million per year.
    - Meter infrastructure projects to enable enhanced communication on the AMI network.
    - BGE's Innovation budget, which invests capital into projects to increase the efficiency, effectiveness, safety, reliability and/or resiliency of BGE Operations and BGE customers.

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III. Capital Details

This Section provides additional details for capital projects with spending greater than $1 million in any year within the 2019-2023 time period for each of the categories below.

A. IT – Customer Experience

Project Name	58584: EU Analytics Customer Project Two			
2019A	**2020F**	**2021F**	**2022F**	**2023F**
$2,197,109	$2,803,214			
Problem Statement		**Solution Statement**		**Estimated / In-Service Date**
BGE has a need to develop enhanced analytical tools.		This project will implement a solution for customer-related analytics that falls generally into the categories of customer strategy, customer operations, revenue cycle and marketing.		December 2020

Project Name	59039: Customer Care and Billing Implementation			
2019A	**2020F**	**2021F**	**2022F**	**2023F**
$34,413,430	$53,394,130	$8,379	$551	
Problem Statement		**Solution Statement**		**Estimated / In-Service Date**
BGE Customer Care and Billing (CC&B) has not been updated since it went live in 2012.		This project will deliver the Oracle CC&B platform which will be deployed as an upgrade for BGE.		September 2020

Project Name	64713: EU Digital Program - 2020			
2019A	**2020F**	**2021F**	**2022F**	**2023F**
	$1,947,912	$2,546,254	$2,643,807	$4,29055
Problem Statement		**Solution Statement**		**Estimated / In-Service Date**
Customer expectations continue to grow as other organizations and service providers shape their experiences.		On-going enhancements are expected to grow self-service options, improve proactive outbound communications, and use technology and innovation to reduce customer barriers and meet customers where they are in their daily lives.		Beyond 2023

Project Name	64715: EU Customer Journey - I Sign Up And Move			
2019A	**2020F**	**2021F**	**2022F**	**2023F**
$304,071	$3,440,995			
Problem Statement		**Solution Statement**		**Estimated / In-Service Date**
BGE needs to improve the sign up and move experience for its customers.		Improve Customer experience for I Sign Up and Move Journey - Basic Sign Up and Move - Preference Center setting - Concierge/Unified Home Services - Quick verification of credit / identity - Onboarding Assessment - 3rd party log-in, Establishing my Account.		December 2020

Project Name	64847: EU Digital System Hardening			
2019A	**2020F**	**2021F**	**2022F**	**2023F**
$223,194	$1,043,821	$1,181,277		
Problem Statement		**Solution Statement**		**Estimated / In-Service Date**
Customers expect access to our digital channels no matter the time of day/day of week and no matter the circumstances. In a time of need, especially in an outage/storm situation, the impact to instability in these channels deeply impacts a customer's experience.		This work will foundationally ensure our digital systems support our customer volumes and anticipated experiences as these channels expand in terms of both feature depth and increased customer interactions.		December 2021

Project Name	57144: Digital Strategy Epay			
2019A	**2020F**	**2021F**	**2022F**	**2023F**
$1,093,229				
Problem Statement		**Solution Statement**		**Estimated / In-Service Date**
The Exelon Utilities use different payment processing vendors. BGE is currently using 2 solutions; one is an in-house solution on an end-of-life Oracle ePayment solution (for ACH payments); for credit cards BGE uses Speedpay.		EU Digital Payment updated ePayment vendors to a more aligned digital payment processing solution.		December 2019

Project Name	57271: Digital Solar Toolkit			
2019A	**2020F**	**2021F**	**2022F**	**2023F**
$1,062,258				
Problem Statement		**Solution Statement**		**Estimated / In-Service Date**
Solar is growing, however, some customers and developers have limited access to information about the process and products.		BGE's toolkit will provide additional information to make the process a more streamlined experience for customers and developers.		December 2019

Project Name	60929: Prepaid Energy Pilot Impementation			
2019A	**2020F**	**2021F**	**2022F**	**2023F**
$2,800,716				
Problem Statement		**Solution Statement**		**Estimated / In-Service Date**
Customers are looking for additional and alternative payment options. BGE sought regulatory approval to proceed with its prepaid pilot, and on September 14, 2018 the MD PSC provided its approval. The order directs BGE to implement its 12-month prepaid pilot program.		This project developed and implemented a solution for the prepaid pilot.		September 2019

Project Name	60912: Common Meter Data Management Software

2019A	**2020F**	**2021F**	**2022F**	**2023F**
$22,338,591				

Problem Statement	**Solution Statement**	**Estimated / In-Service Date**
Each operating company, BGE, PECO, and ComEd, has their own Meter Data Management System (MDMS). The MDMS are key to collecting and processing meter reads, calculating billing determinants, and forwarding them to billing in support of the meter-to-cash process. BGE and PECO are on older Oracle (LODESTAR) products while ComEd has upgraded to the latest Oracle product. The LODESTAR product line is reaching its end of support period and there are lifecycle reasons to upgrade.	This project facilitates an upgrade to a common MDMS between BGE, PECO, and ComEd. The amount shown is BGE's portion only.	October 2019

A. IT – Lifecycle

Project Name	63386: BGE Distribution System Operations / Transmission System Operations Turret Platform Replacement and NICE Integrations			
2019A	**2020F**	**2021F**	**2022F**	**2023F**
$1,030,522				
Problem Statement		**Solution Statement**		**Estimated / In-Service Date**
This project mitigates end of life concerns with the present turret telephony systems.		The proposed solution would replace the current application environment with an IP Solution that is server based with high availability, session initiation protocol (SIP) trunk integration, Cisco integration and distributive deployment while supporting our legacy connectivity.		January 2020

Project Name	57345: Leased Line Optimization (LLO)			
2019A	**2020F**	**2021F**	**2022F**	**2023F**
$3,100,575	$3,199,404		$8,259,944	
Problem Statement		**Solution Statement**		**Estimated / In-Service Date**
The Gas and Electric divisions are using Verizon Wireless leased analog circuits.		Enhance the BGE private network for remote locations utilizing wireless and fiber technologies.		December 2022

Project Name	59709: Land Mobile Radio (LMR)			
2019A	**2020F**	**2021F**	**2022F**	**2023F**
$7,887,155	$3,050,881	$20,069,891	$12,469,933	$681,000
Problem Statement		**Solution Statement**		**Estimated / In-Service Date**
This project mitigates end of life concerns with the current BGE field radio system.		The project initiated in 2019 and completed console roll outs and tower infrastructure work. Additional phases include finishing base stations and antennas, begin on subscribers, deploy remainder of subscribers and go live.		June 2022

Project Name	59877: BGE Distribution-Supervisory Control And Data Acquisition Lifecycle Upgrade			
2019A	**2020F**	**2021F**	**2022F**	**2023F**
$2,533,453	$5,796,100			
Problem Statement		**Solution Statement**		**Estimated / In-Service Date**
The current version of the Supervisory Control and Data Acquisition (SCADA) system is considered end of life.		Upgrade the existing system.		September 2020

Project Name	60727: Pass Through - Capital IT			
2019A	**2020F**	**2021F**	**2022F**	**2023F**
$3,565,852	$4,900,000	$4,900,000	$4,900,000	$4,900,000
Problem Statement		**Solution Statement**		**Estimated / In-Service Date**
Each year, PCs, servers and network equipment is determined to be at end of sustainable life, expiration of warranty, or they experience frequent failures due to aged hardware and software and need to be replaced.		PCs, servers, and network equipment are refreshed.		Monthly / Various

Project Name	61589: Load Settlement & Forecasting Deployment			
2019A	**2020F**	**2021F**	**2022F**	**2023F**
$13,385	$1,352,570	$1,129,992		
Problem Statement		**Solution Statement**		**Estimated / In-Service Date**
Currently, each operating company, BGE, ComEd and PECO has their own retail operations application. Furthermore, BGE's application is at end of life.		Oracle has been selected as the systems solution.		December 2021

Project Name	61614: Distribution Automation Network Upgrade - Silver Spring Network			
2019A	**2020F**	**2021F**	**2022F**	**2023F**
$18,167,668	$14,100,835	$19,972,433	$6,330,000	
Problem Statement		**Solution Statement**		**Estimated / In-Service Date**
This project mitigates end of life concerns with the existing BGE distribution automation wireless platform.		Replace legacy radio platforms with SSN wireless infrastructure.		Monthly / Various

Project Name	66379: IT Projects			
2019A	**2020F**	**2021F**	**2022F**	**2023F**
	($273,675)	$3,643	$20,259,746	$54,748,006
Problem Statement		**Solution Statement**		**Estimated / In-Service Date**
There is a baseline level of IT investment needed to maintain BGE technology into the future.		This project holds the baseline funding for the yet to be designed IT projects.		Monthly / Various

A. IT – Operational Platform

Project Name	54732: BGE Field Enhancement Program			
2019A	**2020F**	**2021F**	**2022F**	**2023F**
$1,124,829	$1,078,880	$1,146,680	$1,358,580	$1,947,041
Problem Statement		**Solution Statement**		**Estimated / In-Service Date**
BGE is in the process of hardening physical security for substations and gas gates.		Configure the newly acquired hardware to support increased bandwidth needed to support video cameras.		December 2023

Project Name	57113: EU Analytics AMI Capital IT			
2019A	**2020F**	**2021F**	**2022F**	**2023F**
$4,554,104	$3,890,056	$1,513,311		
Problem Statement		**Solution Statement**		**Estimated / In-Service Date**
AMI data provides untapped potential to generate and analyze system information.		The AMI analytics platform will enable BGE to leverage smart grid data as an asset to generate actionable intelligence, drive innovation, and unlock new business insights.		December 2021

Project Name	61616: Mobile Mapping Solution for Mobile Dispatch Implementation			
2019A	**2020F**	**2021F**	**2022F**	**2023F**
$7,596,326	$13,541,255	$12,104,843	$7,354,599	$943,923
Problem Statement		**Solution Statement**		**Estimated / In-Service Date**
Currently the Exelon utilities have obsolete business processes including paper based forms that are run on disparate systems and don't enable the field worker to operate efficiently.		The implementation of oneMDS will transform the field worker experience across all of the Exelon utilities by moving them to more efficient converged business processes supported on a more modern, digital platform.		January 2023

Project Name	64601: Line Sensors Deployment			
2019A	**2020F**	**2021F**	**2022F**	**2023F**
$120,309	$1,367,032	$1,811,205	$2,000,814	$1,828,268
Problem Statement		**Solution Statement**		**Estimated / In-Service Date**
BGE wants to minimize outage duration times. Line sensors help pinpoint faults and decrease duration of outages.		The business will be installing approximately 4,000 line sensors on the BGE network.		Monthly / Various

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Project Name	64849: BGE-PHI Powerbase Implementation			
2019A	**2020F**	**2021F**	**2022F**	**2023F**
		$1,671,993	$736,121	
Problem Statement		**Solution Statement**		**Estimated / In-Service Date**
Configurations, settings, test results and specifications for devices throughout distribution substations such as relays, switches, breakers, current transformers, (CTs), potential transformers (PTs) and others must be stored, accessed, imported, exported and managed. BGEs current solution does not support leading practice data management in these areas.		This project will enable BGE to take advantage of additional functionality and best practices of the other Exelon utilities who are using PowerBase. The costs shown are BGE's portion of the project.		April 2022

Project Name	54600: Business Intelligence & Data Analytics - Grid Domain IT			
2019A	**2020F**	**2021F**	**2022F**	**2023F**
$3,865,503	$2,636,693	$1,405	$92	
Problem Statement		**Solution Statement**		**Estimated / In-Service Date**
Smart grid data provides untapped potential to generate and analyze system information.		This project will implement a solution for grid related analytics that fall generally into the categories of asset management, grid operations, and extended system.		December 2020

Project Name	57111: EU Analytics Customer Experience Capital			
2019A	**2020F**	**2021F**	**2022F**	**2023F**
$2,014,420				
Problem Statement		**Solution Statement**		**Estimated / In-Service Date**
Smart grid data provides untapped potential to generate and analyze information.		This project will implement a new solution for customer-related analytics that falls generally into the categories of customer strategy, customer operations, revenue cycle and marketing.		April 2019

A. IT– Outage Restoration

Project Name	61401: Advanced Distribution Management System Implementation			
2019A	**2020F**	**2021F**	**2022F**	**2023F**
$1,551,406	$6,074,263	$6,040,562	$6,914,992	$6,068,591
Problem Statement		**Solution Statement**		**Estimated / In-Service Date**
Current distribution management systems lack the flexibility and interoperability to meet expected future customer requirements for a modernized grid and enterprise requirements for efficient operations.		The implementation of an ADMS platform enables the distribution system to adapt and transform in support of changing customer needs and the market shifts anticipated by grid modernization. The ADMS program drives standardization of business processes and the convergence of multiple, utility-specific systems onto a common platform for distribution operations.		After 2023

Project Name	61601: Single Connectivity Model			
2019A	**2020F**	**2021F**	**2022F**	**2023F**
$3,630,588	$2,371,719			
Problem Statement		**Solution Statement**		**Estimated / In-Service Date**
Currently, BG&E uses two systems to define and to store its electric distribution network connectivity model: the Atlas Geographic Information System (GIS) system; and the Distribution Management Information System (DMIS). Having two systems for the connectivity model creates complexities and inefficiencies and data integrity issues.		This project will utilize the upgraded GE Smallworld GIS to house a single connectivity model that will feed the outage management system and other systems. This approach is required for ADMS implementation, will improve data integrity and will provide for additional future capabilities.		December 2020

Project Name	64741: EU Core Geographic Information System Implementation (Electric/Gas)			
2019A	**2020F**	**2021F**	**2022F**	**2023F**
	$1,760,097	$2,757,037	$7,064,989	$5,486,703
Problem Statement		**Solution Statement**		**Estimated / In-Service Date**
Exelon Utilities, including BGE, currently utilize disparate Core Geographic Information System (GIS) applications, interfaces and primarily manual business processes.		The Core GIS project implements the updated GE Smallworld application, for both Electric and Gas, while also developing and deploying standardized asset design, as-built and data maintenance processes, and develops a common data model to increase mutual assistance efficiency, interface reusability and operational effectiveness. The GIS Program, including Core GIS Implementation and GIS Data Quality projects, is foundational to ADMS implementation.		After 2023

A. IT – Regulatory

Project Name	64690: BGE PC 44 Rate Pilots			
2019A	**2020F**	**2021F**	**2022F**	**2023F**
	$1,017,159	$1,000,000		
Problem Statement		**Solution Statement**		**Estimated / In-Service Date**
Maryland PSC established a Rate Design workgroup under Public Conference 44 (PC44) that has been tasked with assessing future rate offerings and options in Maryland, including rate pilots. MD PSC issued an order for a 3rd party supplier load shaping rate pilot to start in 2020.		This project is to develop and implement the third party supplier load shaping pilot and any other potential rate pilots that the MD PSC orders in PC44. The requirements to execute the third party supplier load shaping pilot are unknown at this early stage as BGE and the selected third party supplier have just begun the process to execute a contract.		October 2021

Project Name	64692: Supplier Consolidated Billing - Case # 9461			
2019A	**2020F**	**2021F**	**2022F**	**2023F**
	$475,940	$2,943,233	$508,600	
Problem Statement		**Solution Statement**		**Estimated / In-Service Date**
The MD PSC has issued an order approving Supplier Consolidated Billing (SCB) for retail electric and gas supply customers in Maryland.		Third Party Suppliers will handle billing of customers for not only electric and gas but also the distribution and transmission charges of the utility. The full requirements are not yet fully realized so the PSC has created a working group to address implementation details.		September 2022

B. Business Services Company (BSC)

Project Name	61453: IT BSC - Capital			
2019A	**2020F**	**2021F**	**2022F**	**2023F**
$2,548,740	$2,482,491	$2,213,440	$2,157,567	$2,214,583
Problem Statement		**Solution Statement**		**Estimated / In-Service Date**
There is a need for initial development and lifecycle upgrades of corporate systems and security that support BGE.		Develop and upgrade corporate systems and facilities such as Exelon Now (employee IT self help and help desk ticket development), middleware systems, encryption system upgrades and the backup security operations center build.		Monthly / Various

Project Name	58436: Cost To Optimize – Master Data Management - Fusion Capital			
2019A	**2020F**	**2021F**	**2022F**	**2023F**
$2,617,335				
Problem Statement		**Solution Statement**		**Estimated / In-Service Date**
BGE, along with other EU companies, currently utilizes a variety of master data management (MDM) and non-MDM integrations.		Replace Master Data Management (MDM) integrations at BGE with Oracle Fusion, allowing for reductions in middleware support and licensing costs. Costs shown are BGE's portion.		October 2019

C. Fleet

Project Name	59820: Lease Buyout - Balloon Pymt			
2019A	**2020F**	**2021F**	**2022F**	**2023F**
$164,202	$1,000,000	$700,000	$400,000	$100,000
Problem Statement		**Solution Statement**		**Estimated / In-Service Date**
To maintain the fleet, BGE will purchase assets at the end of their lease.		Capital is used to procure leased assets when the lease has matured.		Monthly / Various

Project Name	60088: Fleet Projects			
2019A	**2020F**	**2021F**	**2022F**	**2023F**
$582,243	$1,275,000	$1,115,000	$1,415,000	$585,000
Problem Statement		**Solution Statement**		**Estimated / In-Service Date**
Purchase shop equipment and mechanic tools.		Evaluate and select shop equipment and tools that meet the safety needs of the shop/personnel, as well as continue to keep up with new technology and maintain vehicles in a timely manner.		Monthly / Various

Project Name	60089: Fleet Capital Procurement			
2019A	**2020F**	**2021F**	**2022F**	**2023F**
$20,328,375	$26,800,000	$20,100,000	$18,800,000	$17,100,000
Problem Statement		**Solution Statement**		**Estimated / In-Service Date**
BGE needs to replace fleet assets that reach their end of life.		BGE fleet evaluates asset performance to identify the appropriate replacement schedule and purchases assets, including those required for the beginning of fleet electrification.		Monthly / Various

D. Real Estate and Facilities

Project Name	55266: G&E Building - 5th Floor			
2019A	**2020F**	**2021F**	**2022F**	**2023F**
$2,752,571	$2,382,844			
Problem Statement		**Solution Statement**		**Estimated / In-Service Date**
The facility is outdated and infrastructure needs to be replaced.		This project will include the replacement of existing infrastructure, including HVAC, lighting, fire systems, and windows.		January 2020

Project Name	55267: G&E Building - 6th Floor			
2019A	**2020F**	**2021F**	**2022F**	**2023F**
$3,758,040	$683,172			
Problem Statement		**Solution Statement**		**Estimated / In-Service Date**
The facility is outdated and infrastructure needs to be replaced.		This project will include the replacement of existing infrastructure, including HVAC, lighting, fire systems, and windows.		January 2020

Project Name	55270: Front Street - 3rd Floor			
2019A	**2020F**	**2021F**	**2022F**	**2023F**
$4,025,389				
Problem Statement		**Solution Statement**		**Estimated / In-Service Date**
The facility is outdated and infrastructure needs to be replaced.		This project will include the replacement of existing infrastructure, including HVAC, lighting, fire systems, and windows.		December 2019

Project Name	57948: G&E Building - 7th Floor			
2019A	**2020F**	**2021F**	**2022F**	**2023F**
$3,505,027	$716,249			
Problem Statement		**Solution Statement**		**Estimated / In-Service Date**
The facility is outdated and infrastructure needs to be replaced.		This project will include the replacement of existing infrastructure, including HVAC, lighting, fire systems, and windows.		January 2020

Project Name	58006: Front Street and Monument Street Warehouse Elevators			
2019A	**2020F**	**2021F**	**2022F**	**2023**
$615,152	$4,141,585	$87,878		
Problem Statement		**Solution Statement**		**Estimated / In-Service Date**
The project is to ensure building infrastructure systems meet current building codes.		The elevators will get new cabs and new mechanical drives.		April 2021

Project Name	58341: RBC South			
2019A	**2020F**	**2021F**	**2022F**	**2023F**
$1,177,731				
Problem Statement		**Solution Statement**		**Estimated / In-Service Date**
The facility is outdated and infrastructure needs to be replaced.		This project will include new furniture, carpet, paint, and ceiling tiles.		April 2019

Project Name	58528: Spring Gardens (SPG) Parking Lot			
2019A	**2020F**	**2021F**	**2022F**	**2023F**
$5,301,305				
Problem Statement		**Solution Statement**		**Estimated / In-Service Date**
There is insufficient parking for company and personal vehicles on the SPG campus, and comingling of company and personal vehicles creates traffic flow and safety-related concerns.		New parking lot built for service vehicles to aid in flow of parking and to create a more efficient traffic flow for the campus.		August 2019

Project Name	58529: Riverside Fence			
2019A	**2020F**	**2021F**	**2022F**	**2023F**
$1,538,785				
Problem Statement		**Solution Statement**		**Estimated / In-Service Date**
The existing footprint of the substation interferes with the area scheduled for remediation and further development.		Rebuild the substation fence to support the remediation work.		May 2019

Project Name	59384: Front Street Boilers			
2019A	**2020F**	**2021F**	**2022F**	**2023F**
$65,558	$3,148,912	$114,298		
Problem Statement		**Solution Statement**		**Estimated / In-Service Date**
The current boilers are at end of life and no longer meet the capacity needs of the building.		This project replaces the steam boilers with new, energy efficient boilers that can meet the capacity needs of the facility.		June 2021

Project Name	59740: Facilities Building Purchase			
2019A	**2020F**	**2021F**	**2022F**	**2023F**
$22,570	$5,767,250			
Problem Statement		**Solution Statement**		**Estimated / In-Service Date**
BGE has been comingling office and field personnel resulting in potential traffic and safety related concerns.		BGE has an agreement in place to purchase One Center Plaza, a multi-story building co-located with the G&E Building, at the beginning of 2020. This project funds the purchase of the building.		January 2020

Project Name	60820: Infrastructure - Capital Infrastructure Management Projects			
2019A	**2020F**	**2021F**	**2022F**	**2023F**
$3,477,901	$10,387,208	$9,277,431	$9,237,931	$7,878,630
Problem Statement		**Solution Statement**		**Estimated / In-Service Date**
Required planned and emergent capital maintenance work (i.e., replacements, removal, capital improvements to existing equipment, etc.).		To address planned and emergent infrastructure needs through capital improvement or replacement of such things as HVAC, elevators, controller systems (alarms), motors, chillers, boilers and paving.		Monthly / Various

Project Name	60832: Renovations - Capital Lifecycle Projects			
2019A	**2020F**	**2021F**	**2022F**	**2023F**
$79,637	$20,838,341	$20,157,312	$24,706,532	$19,696,842
Problem Statement		**Solution Statement**		**Estimated / In-Service Date**
Other BGE facilities are outdated and infrastructure needs to be renovated or removed and replaced.		This project will include the removal and replacement of existing infrastructure, including HVAC, lighting, fire systems, windows and other improvements.		Monthly / Various

Project Name	60838: Howard Service Center			
2019A	**2020F**	**2021F**	**2022F**	**2023F**
$1,120,857	$20,219,264	$6,135,364		
Problem Statement		**Solution Statement**		**Estimated / In-Service Date**
The facility is outdated and infrastructure needs to be replaced.		BGE is renovating the Howard Service Center. This project will include the replacement of existing infrastructure, including HVAC, lighting, fire systems, and windows.		July 2021

Project Name	60886: G&E Building - 4th floor			
2019A	**2020F**	**2021F**	**2022F**	**2023F**
$9,868,364	$5,583,522			
Problem Statement		**Solution Statement**		**Estimated / In-Service Date**
The facility is outdated and infrastructure needs to be replaced.		This project will include the replacement of existing infrastructure, including HVAC, lighting, fire systems, and windows.		March 2020

Project Name	62566: Exelon Utilities Transmission System Operations (TSO) Mid Atlantic South Energy Operations Building			
2019A	**2020F**	**2021F**	**2022F**	**2023F**
$610,031	$4,498,455	$3,423,583		
Problem Statement		**Solution Statement**		**Estimated / In-Service Date**
There is a need to enhance facility security, improve operator situational awareness and visualization, and establish continuity of electric system control to be more resilient for disaster recovery scenarios. The TSO is in a common building that houses other distribution functions.		Modernize the TSO control room environment to align with industry standards.		September 2021

Project Name	66523: Perry Hall Fiber Construction			
2019A	**2020F**	**2021F**	**2022F**	**2023F**
$1,116,512				
Problem Statement		**Solution Statement**		**Estimated / In-Service Date**
The Perry Hall Service Center and Substation is currently connected to the enterprise network over an unlicensed microwave radio link which provides a connection speed up to 100 megabits per second (Mbps). The connection is subject to interference from cellular providers and suffers a noticeable reduction in network speed as a result.		Construct new fiber optic cable from Windy Edge Substation to Perry Hall. This fiber connection will add significant resiliency.		Monthly / Various

Project Name	66622: Office and Support Facilities Program			
2019A	**2020F**	**2021F**	**2022F**	**2023F**
	$861,529	$5,730,312	$7,569,079	$7,797,407
Problem Statement		**Solution Statement**		**Estimated / In-Service Date**
Current levels of office building and support facility security are dated and require replacement to ensure the security of the sites as well as the safety of the personnel that work at those locations.		The Office and Support Facilities (OSF) project is to increase the security and safety at company office buildings and support facilities (i.e., service centers). The required work will span the next 8 years and will start in 2020 with a scoping analysis.		Monthly / Various

E. Training

Project Name	60127: Budget Utility Training Capital			
2019A	**2020F**	**2021F**	**2022F**	**2023F**
$611,445	$1,496,900	$1,496,463	$1,496,770	$1,496,559
Problem Statement		**Solution Statement**		**Estimated / In-Service Date**
Traditional instructor-led training is a cost intensive way to train employees.		BGE is developing training simulations using virtual reality technologies in several of our lines of business.		Monthly / Various

F. Other

Project Name	55789: PC44 Program - Capital			
2019A	**2020F**	**2021F**	**2022F**	**2023F**
	$2,250,000	$2,589,332	$1,067,042	
Problem Statement		**Solution Statement**		**Estimated / In-Service Date**
BGE needs to explore ways to improve the BGE electric grid to support EVs, solar, and energy storage.		Invest in equipment or technology for PC44 topics – EVs, solar, and energy storage.		Monthly / Various

Project Name	60971: Supplier Consolidated Billing Capex			
2019A	**2020F**	**2021F**	**2022F**	**2023F**
		$972,078	$3,307,431	$318,499
Problem Statement		**Solution Statement**		**Estimated / In-Service Date**
MD PSC issued an order for Supplier Consolidated Billing (SCB) implementation by Sept 2022.		Build/modify IT systems to support SCB by Sept 2022.		December 2023

Project Name	60975: Peak Rewards Capital			
2019A	**2020F**	**2021F**	**2022F**	**2023F**
$6,908,788	$13,426,844	$13,176,233	$13,209,247	$13,204,287
Problem Statement		**Solution Statement**		**Estimated / In-Service Date**
In 2017, the MD General Assembly amended the Energy Efficiency Act of 2008. This amendment now requires MD utilities to achieve a targeted average annual incremental gross energy savings of 2% for years 2018-2023. The 2% targeted savings is based on each utility's 2016 weather-normalized gross retail sales and line losses.		In order to achieve this goal, BGE continues to deploy its PeakRewards program, which is a direct load control demand response system. PeakRewards helps ease the burden on BGE's existing electricity delivery system and reduce the need for additional power plants in Maryland. *Note: The Budget was finalized prior to the MD PSC approval of the Bring Your Own Device (BYOD) program at the end of 2019. These costs will be addressed in the EmPower MD surcharge and therefore do not impact distribution base rates.*		Monthly / Various

Project Name	60996: Corporate Items Logistics - Topside			
2019A	**2020F**	**2021F**	**2022F**	**2023F**
$1,604,079	$(696,805)	$(1,721,478)	$(2,795,586)	$(3,742,137)
Problem Statement		**Solution Statement**		**Estimated / In-Service Date**
The final pension update occurs after the budget details are developed causing a difference.		This project captures the pension topside amount based on the difference between the final pension cost and the original budgeted amount.		Monthly / Various

Project Name	61072: Smart Energy Rewards Smart Energy Manager Smart Energy Services Capital			
2019A	**2020F**	**2021F**	**2022F**	**2023F**
$34,326	$878,267	$1,051,311	$1,153,759	$1,264,493
Problem Statement		**Solution Statement**		**Estimated / In-Service Date**
In 2017, the MD General Assembly amended the Energy Efficiency Act of 2008. This amendment now requires MD utilities to achieve a targeted average annual incremental gross energy savings of 2% for years 2018-2023. The 2% targeted savings is based on each utility's 2016 weather-normalized gross retail sales and line losses.		BGE continues to deploy its Smart Energy Manager (SEM) Program, which allows customers to view their energy usage online and proactively messages customers, based on their notification preferences, on ways to save energy and money. BGE also continues to deploy its Smart Energy Rewards Program.		After 2023

Project Name	61568: Innovation Initiative - Capital			
2019A	**2020F**	**2021F**	**2022F**	**2023F**
$888,271	$2,000,000	$2,000,000	$1,999,953	$2,050,018
Problem Statement		**Solution Statement**		**Estimated / In-Service Date**
BGE needs to support innovation.		Certain small investments need to be made before investing for full-scale deployment. BGE invests capital into projects that may have the ability to increase the efficiency, effectiveness, safety, reliability and/or resiliency of BGE Operations and BGE customers.		Monthly / Various

Project Name	62791: Electric Vehicle Station Equipment Program Capital - BGE Public			
2019A	**2020F**	**2021F**	**2022F**	**2023F**
$2,369,180	$5,286,000	$6,237,125		
Problem Statement		**Solution Statement**		**Estimated / In-Service Date**
BGE needs to respond to the PSC Electric Vehicle Portfolio order to expand Electric Vehicle Station Equipment infrastructure.		Purchase electric vehicle charging equipment and install within BGE's service territory for public use.		Monthly / Various

Project Name	64789: EU Analytics – Smart Energy Services 4			
2019A	**2020F**	**2021F**	**2022F**	**2023F**
			$20,500,000	
Problem Statement		**Solution Statement**		**Estimated / In-Service Date**
Meet EmPOWER MD Energy Efficiency and Behavioral Demand Response goals.		Perform EU Analytics Smart Energy Services software upgrade. This project is a continuation of the Smart Energy Services program that started in 2012.		June 2022

Project Name	53369: Back Office Allocation			
2019A	**2020F**	**2021F**	**2022F**	**2023F**
$508,732	$22,364,311	$17,924,631	$17,521,552	$16,864,424
Problem Statement		**Solution Statement**		**Estimated / In-Service Date**
The residual amount of back office allocation that remains in the budget primarily reflects common costs attributable to transmission plus minor amounts associated with budgeting tool limitations and associated adjustments.		The residual amount of back office allocation that remains in the budget primarily reflects common costs attributable to transmission plus minor amounts associated with budgeting tool limitations and associated adjustments.		Monthly / Various

Project Name	58663: Netgear Replacement			
2019A	**2020F**	**2021F**	**2022F**	**2023F**
$1,085,573				
Problem Statement		**Solution Statement**		**Estimated / In-Service Date**
Verizon Wireless has communicated that 3G cellular service will be discontinued at the end of 2019. Itron Gen 4.5 APs communicate over the 3G cellular service and will lose connectivity when 3G service is discontinued.		This project will ensure the AMI network will continue to function as required followign the elimination of Verizon 3G service. Itron Gen 4.5 Access Points (APs) will be replaced with Itron Gen 5 APs.		Monthly / Various

Project Name	60940: Distribution Transformer Purchases			
2019A	**2020F**	**2021F**	**2022F**	**2023F**
$1,294,768				
Problem Statement		**Solution Statement**		**Estimated / In-Service Date**
Distribution transformers are purchased in bulk and not for specific projects.		This project was established to act as a clearing account for distribution transformers. Costs accumulate in this account as transformers are purchased and placed into inventory and those costs are subsequently transferred out to jobs when the transformers are pulled from inventory and used on a job. The ending balance in any given period reflects the current supply versus demand. For budget purposes, it is assumed the supply and demand are equally offsetting and therefore net to zero in this project.		Monthly / Various

Project Name	61076: Meter Engineering & Standards Capital			
2019A	**2020F**	**2021F**	**2022F**	**2023F**
$1,373,231	$1,341,839	$1,299,246	$973,653	$996,768
Problem Statement		**Solution Statement**		**Estimated / In-Service Date**
As originally planned, the rollout of the AMI network infrastructure covered 95% of the territory, leaving some areas uncovered by the RF canopy, resulting in some meters requiring manual efforts to collect billing information.		This project will ensure that the RF canopy provides the maximum practical coverage for the AMI network.		Monthly / Various

Project Name	61587: Capital Portion of Compensation			
2019A	**2020F**	**2021F**	**2022F**	**2023F**
	$1,705,626	$1,705,626	$1,705,626	$1,705,626
Problem Statement		**Solution Statement**		**Estimated / In-Service Date**
Capitalized portion of certain BGE executive compensation. Actual amounts are allocated to various projects but the budget resides in this project.		Capitalized portion of certain BGE executive compensation. Actual amounts are allocated to various projects but the budget resides in this project.		Monthly / Various

Project Name	63252: AMI 4.5 Relay Replacement			
2019A	**2020F**	**2021F**	**2022F**	**2023F**
			$2,696,711	
Problem Statement		**Solution Statement**		**Estimated / In-Service Date**
The current AMI relays will be outdated by 2022 and in need of a lifecycle upgrade.		This project provides more current AMI relays to enable installation of more advanced equipment and features on the AMI network.		Monthly / Various

IV. O&M Category Cashflows and Functions

A. Information Technology

Category	2019A	2020F	2021F	2022F	2023F
Information Technology	$25,515,691	$36,207,710	$19,657,021	$19,535,399	$18,694,625

- The overall trend in Information Technology (IT) O&M spending is related to several large projects ending in 2020, with baseload IT O&M spend in the remaining years of the plan relatively flat.
- IT BU project O&M costs are the costs related to the IT O&M components of specific utility projects that are not capitalized. These costs support initiation activities, planning and implementing, and post implementation activities.
- IT BU O&M costs may also include portions of project management office (PMO) support, specific to the O&M activities mentioned above.
- These IT O&M costs help BGE's customers by maintaining existing IT systems that serve BGE operations.
- IT also maintains internal communication networks and real-time systems to deliver reliable power to customers through secure power grid operations.

B. Business Services Company

Category	2019A	2020F	2021F	2022F	2023F
Business Services Company	$159,888,955	$172,882,739	$172,165,403	$173,707,095	$176,089,299

- Pursuant to the General Services Agreement, which is provided as Appendix G to BGE's Cost Allocation Manual, Exelon Business Services Company (EBSC) establishes a Service Level Arrangement (SLA) document with each client company to which they provide services. Each EBSC SLA between EBSC and the client company documents the specific list of EBSC services by practice area provided to each client company as well as any additional affiliate-specific services that may be uniquely requested by or provided to that client company. There are also BSC costs incurred directly at BGE ("BSC embedded costs") that are not governed by the SLA process as they are not allocated from BSC. Examples include embedded Finance, Controller, and Human Resource employees.
- BSC O&M costs can be segregated into two main components – IT and Non-IT:
  - IT provides standard IT baseline services to support Exelon's businesses. These services include End-User Support Services, IT Systems Operations Services, and IT Service Delivery. These IT services are provided by a combination of Business Unit Application Delivery and Support Departments, Cloud and Infrastructure Services Department, and Office of the CIO. Service descriptions can be found in Appendix H to BGE's Cost Allocation Manual.
  - Non-IT functions include Corporate and Information Security Services (CISS), Corporate Affairs, Corporate Development, Executive Services (primarily CEO and Board of Directors office), Exelon Utilities, Human Resources, Legal, Real Estate, and Supply, among others.
- BSC costs are relatively flat over the plan period. The increase from 2019 to 2020 relates primarily to increases in IT baseline services, transfers of certain groups of employees from BGE to BSC and one-time 2019 savings not expected to continue.

C. Fleet

Category	2019A	2020F	2021F	2022F	2023F
Fleet: Employee Shuttle	$591,838	$707,000	$707,000	$707,000	$707,000

- The Fleet O&M category funds an employee shuttle service, using all-electric buses. The costs of operation include contracted drivers, satellite parking site rental, security guard services and bus maintenance costs.

D. Real Estate and Facilities

Category	2019A	2020F	2021F	2022F	2023F
Real Estate and Facilities	$20,548,383	$21,698,483	$21,716,349	$22,272,300	$22,903,681

- Facilities O&M includes routine costs for day-to-day maintenance, repair and the administration of all of BGE's building facilities. The costs include internal and contract labor. Examples include:
    - Electric usage, water usage and sewage, other utility usage (chilled water, steam, gas)
    - Cleaning services (cleaning, trash removal and extermination services)
    - Infrastructure routine and non-routine repairs and maintenance
    - Snow removal and roads and grounds maintenance
    - Mailing services
    - Lease costs
- Real Estate O&M includes
    - Right of way rental fees.
    - Administration of third-party pole attachments in FCC-regulated distribution asset attachment projects
    - Lease fees paid for non-BGE communications tower rent.
    - Real estate property administration and acquisition work including research to confirm existing property rights required for gas and electric projects.
- The workload for Real Estate and Facilities is expected to remain constant over the 2020-2023 time period, so the budget is essentially flat with minor adjustments for inflation. The budget is split approximately 60% for facilities and 40% for real estate expenses.

E. Training

Category	2019A	2020F	2021F	2022F	2023F
Training	$26,034,421	$27,929,523	$26,650,959	$25,988,677	$25,386,069

- Utility employee training by the training department ensures that the BGE workforce is qualified to safely perform the tasks needed to construct and maintain an efficient and reliable energy delivery distribution system by:
    - Developing, delivering and administering craft and technical training for our gas and electric businesses

- o Providing standardized training, and qualification and re-qualification programs for our diverse and inclusive workplace which includes employees and contractors.

- Training for BGE craft organizations, electric and gas design personnel, customer call representatives and customer field personnel is performed or managed by the Training department. This training ensures that employees are trained to safely and effectively operate and maintain the Gas and Electric systems in accordance with BGE standards, Occupational Safety and Health Administration (OSHA), Department of Transportation (DOT), and Pipeline and Hazardous Materials Safety Administration (PHMSA) requirements, and operator qualifications (OQ).
- The O&M cost trends in Training are primarily driven by Training department staffing and the volume of trainees in a given year. Training department O&M expense is increasing slightly to address inflation. Trainee volumes vary year to year, and the overall reduction in spending is largely driven by reduced volume of trainees. Gas Service training costs vary as new hires are brought on in non-consecutive years.
- The Training department performs on-going progression development and evaluations, and also provides initial and annual technical refresher training for employees.
- About one third of the total O&M expense covers training department labor and the remainder covers the salaries and benefits of employees that are in classroom training.

F. Other

Category	2019A	2020F	2021F	2022F	2023F
Other	$98,716,948	$109,758,681	$111,538,238	$111,483,646	$111,692,952

- The Other category includes BGE's General & Administrative (G&A) costs, which capture back-office activities across the entire organization that support field activities.
  - o The G&A allocation accumulates support costs for field work, such as design, engineering and project management, which are then distributed as overhead to O&M field projects.
  - o Common costs attributable to transmission that have no impact on distribution rate base or MYP distribution rates account for the majority of the back office allocation project spend over the MYP period. This is consistent with how common spend is captured throughout the Capital and O&M templates. Directly assigned transmission costs have been removed from the templates; however, those costs that are not directly assigned to the transmission line of business are included in these templates for consistency purposes. These costs are removed in the calculation of the MYP distribution revenue requirement (see Exhibit DMV-3-1).
  - o Because of varying rates of inflation in pool costs, and differences between cost pool inflation and the rate of inflation applied to allocations, a residual amount could remain in the budget. This is a limitation within the budgeting tool and is the primary driver for the amount that remains after accounting for the electric transmission business.
- There are also other administrative costs that support system operations. Examples of these include Operations Support, Safety and Wellness, Locating Services, Distribution Integrity Management Program, Emergency Preparedness and Support Services – Environmental. Several BGE-embedded non-operational department costs also reside in this category, including Human Resources, Legal, CEO's Office, CFO's Office, Strategy and Regulatory Affairs and Governmental/External Affairs.
- Baltimore City Conduit Rental charges for conduit maintenance are the largest single cost within the Other category and are relatively flat over the 2019 to 2023 period.

- The Security budget resides in this category, which is primarily responsible for keeping employees safe throughout the BGE territory. This includes onsite security as well as off-site, off-duty police personnel in the field.
- BGE's new Infrastructure Academy program is funded in this category, where BGE partners with contractors and various non-profit organizations to train "work ready" adults in the BGE territory and enable them to pursue construction careers locally. Infrastructure Academy costs are below the line and do not affect the revenue requirements for the MYP.
- BGE's Innovation budget is also part of "Other" and includes projects that may have the ability to increase the efficiency, effectiveness, safety, reliability and/or resiliency of BGE operations and BGE customers.
- This category also includes marketing expense and internal and external BGE communications expenses other than labor.

V. O&M Project Details

Information Technology
Major Cost Drivers by Project

Instructions:

List actual O&M expenses by project for 2019; provide a high-level description of the types of costs within the project, and discuss the key drivers of each type. Also list forecasted O&M expenses for 2020-2023.

#	Project	Description and Key Drivers	2019 Actuals	2020 Forecast	2021 Forecast	2022 Forecast	2023 Forecast
1	59040: Customer Care and Billing (CC&B) Systems Implementation	BGE Customer Care and Billing (CC&B) has not been updated since it went live in 2012. This project will deliver the Oracle CC&B platform which will be deployed as an upgrade for BGE. This project funds the O&M activities associated with that upgrade.	5,943,403	15,665,264			
2	59781: EU Geographic Information System (GIS) Data Quality	The data quality improvement project starts with the establishment of robust EU GIS Governance and data quality standards.	512,076	1,580,112	2,082,803	1,190,673	1,627,574
3	60874: Pass Through O&M IT	IT Pass-Through costs are IT components billed to BGE that are directly associated with BGE. These costs include telecom circuits, printer services, mobile phone usage, and leased IT equipment.	5,562,793	5,662,917	5,662,917	5,662,917	5,662,917
4	60919: Common Meter Data Management (MDM) O&M - MDM Integrations	Meter Data Services - Upgrade the Oracle Meter Data Management System to version 2.2 for BGE.	2,796,642				
5	61423: Advanced Distribution Management System Implementation	The implementation of ADMS platform enables the distribution system to adapt and transform in support of changing customer needs and the market shifts anticipated by grid modernization. The ADMS Program drives standardization of business processes and the convergence of multiple, utility-specific systems onto a common platform for distribution operations. Technologies include Distribution SCADA, Outage Management, and Advanced applications. The project has completed the Phase 1 Planning & Analysis and is currently in Phase 2 Design. The project is forecasted to run through 2026, with elaboration of system design, product selection, release planning and business benefits to occur in Phase 2 Design.	1,755,840	1,765,651	826,647	895,789	2,351,182
6	61602: Single Connectivity Model	Retire the BGE Distribution Management Information System (DMIS) used for Distribution Electric Models in the outage management system (OMS). House the connectivity model in GIS and use that to feed OMS. This project represents the O&M portion of the single connectivity project described in capital project 61601: Single Connectivity Model.	699,904	1,585,684			
7	61617: Mobile Mapping Solution for Mobile Dispatch Implementation - OM	This O&M project includes the planning, analysis and design, development, implementation, close project activities and organizational change management (training and communications) for the oneMDS capital project.	400,412	1,178,261	2,890,442	2,598,097	(1)
8	64686: Storm Critical Systems - IT Hardening and Remediation	The purpose of this project is to implement recommendations to harden Storm Critical Systems and their related infrastructure and processes.		1,132,854	1,196,870	988,987	
9	64699: BGE Powerbase Implementation	Implement relay database PowerBase (Doble) for BGE.		552,430	1,864,988	1,026,481	
10	64714: EU Digital Program - 2020	Support self-service and improve transactional success. Likely worked by various workstreams including Payment Enhancements, Innovation & Pilot Expansion, Solar Toolkit Enhancements, Call Reduction Initiative, etc.		458,664	749,566	767,836	1,380,302
11	64742: EU Core Geographic Information System (GIS) Implementation (Electric / Gas)	Core GIS program is intended to develop and deploy Electric and Gas standardized asset design, as-built and data maintenance processes, as well as develop a common data model to increase mutual assistance efficiency, interface reusability and operational effectiveness for the electric and gas utilities as they also deploy the core GIS application.	1,816,340	2,262,239	905,417	1,047,129	801,374

Information Technology
Major Cost Drivers by Project

Instructions:

List actual O&M expenses by project for 2019; provide a high-level description of the types of costs within the project, and discuss the key drivers of each type. Also list forecasted O&M expenses for 2020-2023.

#	Project	Description and Key Drivers	2019 Actuals	2020 Forecast	2021 Forecast	2022 Forecast	2023 Forecast
12	66377: IT O&M Projects	There is a baseline level of IT O&M spend needed to maintain BGE technology into the future. This project holds the baseline funding for the yet to be designed IT O&M projects.		132,485	2,437,503	4,853,903	6,746,855
13	57 Projects with no year >= $1 million		6,028,281	4,231,149	1,039,868	503,587	124,422
14	**Total**		**$ 25,515,691**	**$ 36,207,710**	**$ 19,657,021**	**$ 19,535,399**	**$ 18,694,625**

Business Services Company (BSC)
Major Cost Drivers by Project

Instructions:

List actual O&M expenses by project for 2019; provide a high-level description of the types of costs within the project, and discuss the key drivers of each type. Also list forecasted O&M expenses for 2020-2023.

#	Project	Description and Key Drivers	2019 Actuals	2020 Forecast	2021 Forecast	2022 Forecast	2023 Forecast
1	60003: Entrepreneurial Growth Board	Exelon's Exelorate projects identify strategic technology opportunity areas for the utility. Exelon is investigating new technologies such as wearables, augmented reality glasses, smart vests, smart helmets and digital assistants. Exelon is also exploring how blockchain will play a role in enabling distributed energy resources to enhance the value of the grid. Projects under drones and robotics include use cases in aerial and underground operations.	916,446	1,111,188	1,129,752	1,172,184	1,196,052
2	60111: IT BSC - O&M	BSC IT provides standard IT services to support Exelon's businesses. These Services include End-User Support Services, IT Systems Operations Services, and IT Service Delivery.	3,666,773	1,292,074	433,962	438,244	444,578
3	60113: BSC Originally Contracted Work	Functions include Corporate and Information Security Services (CISS), Corporate Affairs, Human Resources, Corporate Development, Corporate Strategy, Executive Services (primarily CEO and Board of Directors office), Exelon Utilities, Finance, Government and Regulatory Affairs & Public Policy, Human Resources, Legal, Real Estate, and Supply.	55,245,404	62,704,115	62,143,611	62,287,197	63,488,512
4	60715: BGE - IT Customer Baseline	Costs include infrastructure, labor, licenses, maintenance, support, management, project work, compliance and technical services.	35,859,929	37,029,579	41,282,686	40,866,816	40,684,795
5	60719: BGE - IT Work Asset Management (WAM) Baseline	Costs associated primarily with the End User Services service is provided to support and maintain application services, which includes costs of all the infrastructure, labor, licenses, maintenance, support, management, project work, compliance and technical services necessary to maintain the end user services.	22,290,704	25,848,813	26,410,452	26,550,213	26,764,604
6	60721: BGE - IT Real Time Baseline	This service is provided to support and maintain application services, which includes costs of infrastructure, labor, licenses, maintenance, support, management, project work, compliance and technical services.	9,032,476	10,217,341	10,482,194	10,764,647	10,715,480
7	60822: IT Optimization Costs - O&M - BSC Billed	A few of the major projects include Service Now (integrated service management tool suite) and the BSC Robotics project to complete repetitive, structured, rule-based tasks.	3,797,373	3,674,681	21,300	7,735	
8	60943: Bank Fees	Includes costs associated with maintaining Bank Accounts.	1,046,002	686,789	185,363	185,363	185,363
9	60944: CFO Office	Includes Labor and Non-Labor costs for the BGE Financial Operations, FP&A, and Controllership departments.	4,878,716	4,799,911	4,194,760	4,255,234	4,423,871
10	60956: Legal	Includes Labor and Non-Labor costs for BGE legal services as well as costs associated with outside legal counsel support.	3,379,457	3,447,431	3,493,461	3,452,622	3,535,551
11	60961: Human Resources	Includes Labor and Non-Labor costs for the BGE HR department.	5,284,400	4,972,959	3,551,944	3,618,143	3,714,845
12	61531: Strategic Communications	The Communications Practice Area enables the company to successfully pursue business goals and objectives by developing and providing strategic direction, management and communications support.	1,526,518	1,418,877	1,445,734	1,478,691	1,527,068
13	61626: BGE - IT Digital Grid Baseline	IT costs associated with support of Smart Meters.	11,181,500	12,739,070	13,232,144	13,528,822	13,626,190
14	61719: Enterprise Wide Systems (EWS) O&M Projects	Planning, design, and implementation of IT projects related to licensing, upgrade and expansion of technology platforms including Oracle database, SQL Server database, SharePoint, and others. This also includes application and technical and service delivery to support and maintain application services, which includes costs of all the infrastructure, labor, licenses, maintenance, support, management, compliance and technical services necessary to maintain the applications for Finance, HR, Corporate Applications, Security, and Legal.	58,674	2,000,244	2,279,100	2,535,842	2,532,598

Business Services Company (BSC)
Major Cost Drivers by Project

Instructions:

List actual O&M expenses by project for 2019; provide a high-level description of the types of costs within the project, and discuss the key drivers of each type. Also list forecasted O&M expenses for 2020-2023.

#	Project	Description and Key Drivers	2019 Actuals	2020 Forecast	2021 Forecast	2022 Forecast	2023 Forecast
15	66907: BGE - BSC IT Project Tails	Costs associated with ongoing maintenance costs in support of Capital Projects.	-		1,141,287	1,837,945	2,517,895
16	10 Projects with no year >= $1 million		1,724,583	939,667	737,653	727,397	731,897
17	**Total**		**$ 159,888,955**	**$ 172,882,739**	**$ 172,165,403**	**$ 173,707,095**	**$ 176,089,299**

Fleet
Major Cost Drivers by Project

Instructions:

List actual O&M expenses by project for 2019; provide a high-level description of the types of costs within the project, and discuss the key drivers of each type. Also list forecasted O&M expenses for 2020-2023.

#	Project	Description and Key Drivers	2019 Actuals	2020 Forecast	2021 Forecast	2022 Forecast	2023 Forecast
1	1 Project with no year >=$1 million		591,838	707,000	707,000	707,000	707,000
2	**Total**		**$ 591,838**	**$ 707,000**	**$ 707,000**	**$ 707,000**	**$ 707,000**

Real Estate and Facilities
Major Cost Drivers by Project

Instructions:

List actual O&M expenses by project for 2019; provide a high-level description of the types of costs within the project, and discuss the key drivers of each type. Also list forecasted O&M expenses for 2020-2023.

#	Project	Description and Key Drivers	2019 Actuals	2020 Forecast	2021 Forecast	2022 Forecast	2023 Forecast
1	53714: Tower Rent Payments	Tower rent payments for BGE communication equipment on non-BGE towers.	1,427,535	1,467,313	1,503,996	1,541,559	1,580,149
2	57775: Pole Attachment - Fiber Split	Fiber installation for third party pole attachments which is FCC regulated.	2,125,189	150,858	158,493	166,518	174,950
3	60809: Utility Usage	BGE requires the use of chilled water, steam and gas services in order to operate its buildings and provide cooling and heat to employees.	783,451	937,186	960,616	984,608	1,009,255
7	60813: Cleaning Services	Cleaning, Trash Removal and Extermination services at company office buildings and service centers.	2,509,364	2,822,205	2,892,755	2,965,004	3,039,236
8	60817: Snow Removal Costs	Expeditious and safe removal of snow and ice to support continued operations.	1,326,624	1,200,000	1,230,000	1,260,720	1,292,280
9	60819: Routine Repairs and Maintenance	Pole prep and replacement expenses for third party pole attachments which is FCC regulated.	4,648,766	5,625,256	5,718,531	5,825,985	5,971,569
10	60849: Real Estate	Real Estate labor expenses for property and acquisition research that cannot otherwise be capitalized and small non-labor expenses such as travel expenses.	665,030	1,167,836	1,134,987	1,154,954	1,184,655
11	61420: Non-Routine Repairs and Maintenance	Non-routine repairs that the Facilities Department performs to major systems, buildings and areas not covered by capital work and renovations.	1,815,917	2,936,475	2,745,296	2,807,944	2,879,232
12	61581: Water Sewage	Water fees for Sewage equipment primarily located on railroad properties.	770,136	997,737	1,083,417	1,169,199	1,269,484
13	61582: Electric Utility Usage	Electric fees for Usage equipment primarily located on railroad properties.	1,648,240	1,985,863	2,035,510	2,086,348	2,138,576
14	10 Projects with no year >= $1 million		2,828,131	2,407,754	2,252,748	2,309,461	2,364,295
15	**Total**		**$ 20,548,383**	**$ 21,698,483**	**$ 21,716,349**	**$ 22,272,300**	**$ 22,903,681**

Training
Major Cost Drivers by Project

Instructions:

List actual O&M expenses by project for 2019; provide a high-level description of the types of costs within the project, and discuss the key drivers of each type. Also list forecasted O&M expenses for 2020-2023.

#	Project	Description and Key Drivers	2019 Actuals	2020 Forecast	2021 Forecast	2022 Forecast	2023 Forecast
1	60121: Electric Distribution Training	This project covers the initial multi-year skills education in various disciplines of BGE electric distribution. Examples including operating distribution equipment, electrical theory, pole climbing as well as required regulatory training such as pole top rescue, bucket rescue, manhole rescue etc. This project is priimarily labor.	9,349,055	11,273,222	9,966,299	8,084,669	7,739,195
2	60122: Gas Service Training	This training for the Gas Emergency First Responders includes compliance, corporate, operator qualification and refresher training. Pursuant to DOT Code of Federal Regulations Part 192.805, BGE is required to have a written plan of the operator qualifications required for individuals performing covered tasks on a pipeline facility. This project is primarily labor.	1,383,745	1,032,588	344,272	1,106,067	349,627
3	60123: BOO Training Gas Operator Qualification Training	This training for the Gas Construction & Maintenance Department includes compliance, corporate, operator qualification and refresher training. Pursuant to DOT Code of Federal Regulations Part 192.805, BGE is required to have a written plan of the operator qualifications required for individuals performing covered tasks on a pipeline facility. This project is primarily labor.	3,140,786	3,693,201	4,326,941	4,611,181	4,819,938
4	60124: BGE Training Dept.	This project includes the labor and other expenses for the BGE Utility Training Department. Utility training supports the new hire programs, progression training and compliance for all BGE employees and a qualification program for gas contractors.	11,473,479	10,894,660	11,023,591	11,181,118	11,435,537
5	4 Projects with no year >= $1 million		687,356	1,035,852	989,856	1,005,642	1,041,772
6	**Total**		**$ 26,034,421**	**$ 27,929,523**	**$ 26,650,959**	**$ 25,988,677**	**$ 25,386,069**

Other
Major Cost Drivers by Project

Instructions:

List actual O&M expenses by project for 2019; provide a high-level description of the types of costs within the project, and discuss the key drivers of each type. Also list forecasted O&M expenses for 2020-2023.

#	Project	Description and Key Drivers	2019 Actuals	2020 Forecast	2021 Forecast	2022 Forecast	2023 Forecast
1	53369: Back Office General and Administrative Cost Allocation	The amount of back office allocation remaining in the budget is a combination of common costs attributable to transmission and residual amounts resulting from limitations on how the budgeting tool handles inflation. The transmission amounts do not impact MYP rates.	6,526,518	3,111,656	2,494,682	2,072,952	1,573,328
2	55552: Pricing & Tariffs	The Pricing & Tariffs department is responsible for the ratemaking activities at MD-PSC and FERC, the administration of BGE's gas and electric rates and tariffs, and coordination of regulatory filings and compliance.	2,233,152	2,222,289	2,251,615	2,288,607	2,349,509
3	58449: Distribution Integrity Management Plan (DIMP) O&M	Funding for qualified personnel to provide oversight, organization, and analysis of operational data to proactively address risks related to gas distribution assets included in the Distribution Integrity Management Plan (DIMP.)	630,587	1,121,782	1,168,654	1,195,175	1,237,317
4	58579: Large Project Outreach	These costs relate to certain community outreach activities for Large Centrally Managed Projects. Work done by consulting firms that provide an on-site Outreach Specialist to aid the project team with proactive education of the residential and business stakeholders nearest to the project construction activities.	44,606	988,960	1,010,254	1,026,391	1,034,353
5	60017: Emergency Preparedness	Administrative costs to support BGE Electric Distribution emergency preparedness. Costs include drills, training as well as safety equipment purchases for storm role functions.	1,260,851	1,508,406	1,577,981	1,710,141	1,972,216
6	60020: Operations Support	100% O&M account for the daily operations of DSO Support (87393). Department work includes: support of a 24x7 control room, identifying procedures and safety best practices. This group has technical experts that work with complex voltage issues or investigations of automation schemes. They also perform training of system operators that operate the distribution system for reliability and safety of field resources.	2,171,122	3,190,672	3,317,265	3,435,845	3,553,007
7	60021: Operations Computer Support	Daily back office administrative maintenance support of the operational software systems utilized by the OCC. Supports BGE operations preparedness with various IT systems utilized by the OCC including OMS, D-SCADA, DA, ESC, etc. They will at times collaborate with BSC IT if issues are experienced on a server, etc., but their main role is to support the OCC.	1,174,278	1,745,299	1,808,550	1,866,116	1,925,761
8	60025: Investment Management	This project is associated with the Labor costs of the Investment Management team. The Investment Management team is responsible for governance and oversight of the Long Range 5-year Plan development and execution. The team also oversees and provides strategy for prompt year execution of the plan.	1,300,342	800,505	811,892	819,579	829,353
9	60041: Equipment Diagnostic and Repair Unit Labor	EDRU (Equipment Diagnostic and Repair Unit) employees labor. This covers instrument repair lab labor, Rubber Goods lab labor, office labor/unit support and the Senior Electrical testers labor. Also includes waste facility labor for testing oil samples.	1,444,856	1,158,094	1,217,583	1,263,887	1,425,877
10	60042: Baltimore City Conduit Rental	These rental costs support maintenance of Baltimore City's underground municipal conduit cable infrastructure system in order for BGE to provide safe, reliable and efficient electric service to customers.	26,694,050	27,147,231	27,147,231	27,294,236	27,441,884
11	60043: Substation Distribution Field Switching	Various distribution switching operations, within the substation, are required to make the equipment safe for either routine preventive maintenance or emergent corrective action.	1,749,249	810,946	836,919	863,864	891,076

Other
Major Cost Drivers by Project

Instructions:

List actual O&M expenses by project for 2019; provide a high-level description of the types of costs within the project, and discuss the key drivers of each type. Also list forecasted O&M expenses for 2020-2023.

#	Project	Description and Key Drivers	2019 Actuals	2020 Forecast	2021 Forecast	2022 Forecast	2023 Forecast
12	60051: Gas Services - Emergency Response	Funding for Gas Services non-operational activities, including Labor for Gas Mechanics to attend meetings, materials for truck stock and miscellaneous supplies.	1,014,876	866,577	892,845	915,300	938,377
13	60639: BSC Capitalization	Capitalized portion of BSC IT costs that are billed to BGE.	(10,704,277)	(9,782,532)	(9,782,532)	(9,782,543)	(9,782,543)
14	60936: Miscellaneous Corporate Adjustment	This project is used to budget for company-wide items such as workers compensation, corporate owned life insurance, and corporate charitable contribution to Maryland charities. Charitable contributions are below the line and do not affect the revenue requirements for the MYP.	5,885,482	2,382,592	3,229,847	4,028,784	2,491,064
15	60948: Post Project Reassessment	Budget for historical spend that needs to be re-classified from capital to O&M based on capital project reviews.	1,832	999,989	999,996	1,024,310	1,049,951
16	60951: BGE Strategy	Labor resource and other costs to explore new technologies related to PC44 Initiative, Regulatory Policy, or other Exelon utility activities.	1,875,475	1,853,897	1,879,291	1,893,830	1,942,841
17	60960: CEO Office	CEO O&M costs including employee labor and non-labor expenses. Non-labor expenses typically include seminars and training, professional fees and travel.	3,140,502	3,265,530	3,268,060	3,305,477	3,386,351
18	60967: Gas Supply	This Gas Supply team is responsible for purchasing Natural Gas for BGE's customers.	1,509,074	1,703,323	1,760,614	1,806,134	1,867,253
19	60974: Peak Rewards O&M	MD utilities are required to achieve a targeted average annual incremental gross energy savings of 2% for years 2018 – 2023. BGE continues to deploy its PeakRewards program to achieve this goal. The program is a direct load control demand response system. This Project captures Thermostat Application Programming Interface (API) costs, labor (including Call Center costs), staff augmentation and training.	2,798,898	4,164,595	4,148,165	4,165,262	4,017,837
20	60982: BGE COO Office Expense	COO General & Administrative costs including employee labor and non-labor expenses.	1,229,509	1,674,901	1,690,353	1,719,736	1,759,929
21	60983: Safety and Wellness	Labor and contracting costs used to enhance the safety culture by implementing and managing safety programs. The program is responsible for the OSHA log, Safety KPIs, safety programs, safety culture development, and field support.	2,771,434	2,819,608	2,789,863	2,196,429	2,584,481
22	60984: Security Section Office	Labor and non-labor costs related to the operation of the BGE Security unit which performs investigative services, compliance support, physical security support and review of all BGE facilities.	4,929,541	4,791,606	4,953,418	5,199,535	5,329,306
23	60994: Intercompany Billing	Work performed by BGE employees on behalf of other affiliates.	5,126,779	2,989,372	2,991,570	2,991,570	2,991,570
24	60995: Corporate Items Logistics	Annual costs relating to employee tuition reimbursment program where BGE reimburses employees for taking courses for skill improvement.	810,659	935,796	963,628	992,573	1,022,676
25	61007: BGE Physical Security Maintenance	Servicing of electronic security equipment (e.g., surveillance cameras, motion detection sensors, routers and DVRs) deployed at all company facilities and field asset sites.	1,209,286	1,478,769	1,754,677	1,963,353	2,174,038
26	61493: Support Services - Environmental - O&M	Labor and non-labor costs for the operation of the Environmental unit which provides oversight to the BGE Environmental Management Program. 2019 reflects Rate Case No. 9484 authorization to create a Regulatory Asset for the Riverside environmental cost.	(3,107,479)	1,851,520	1,830,623	1,688,311	1,731,386
27	61529: O&M Portion of Compensation	O&M portion of certain BGE executive compensation. A portion of this compensation is excluded from the revenue requirements calculation via a pro forma adjustment.	-	5,632,565	5,525,075	5,388,052	5,315,058

Other
Major Cost Drivers by Project

Instructions:

List actual O&M expenses by project for 2019; provide a high-level description of the types of costs within the project, and discuss the key drivers of each type. Also list forecasted O&M expenses for 2020-2023.

#	Project	Description and Key Drivers	2019 Actuals	2020 Forecast	2021 Forecast	2022 Forecast	2023 Forecast
28	61533: Communications Educational	This project includes advertising and promotion for BGE services and programs such as safety, budget billing and seasonal readiness. Channels that are used include advertising (multiple media), direct mail, social media and email marketing. This project is all outside services.	3,016,435	2,837,529	2,311,755	2,591,943	2,659,068
29	61534: Communications General	Department Labor to project manage all marketing programs including working with internal program owners and outside agencies. The department also performs market research and analysis on marketing effectiveness.	1,721,120	1,741,949	1,766,995	1,763,530	1,808,504
30	61536: Communications Promotional	This project funds non-recoverable promotional brand and sponsorship marketing. An example is advertising that highlights BGE's volunteerism in the community. This project is adjusted out of revenue requirements through a proforma adjustment. Reference exhibits Operating Income Adjustment 24E-Updated and 24G-Updated.	1,200,527	757,081	757,081	769,995	783,263
31	61538: Governmental & External Affairs	Government & External Affairs VP and management level employee labor and non-labor.	1,151,531	1,644,928	1,665,979	1,439,277	1,476,198
32	61540: External Affairs	External Affairs employee labor and non labor in support of relationship building and legislative and policy strategic support to advance BGE's business.	1,654,841	1,796,051	1,825,023	1,858,548	1,906,530
33	61541: Government Affairs VP	Government & External Affairs VP level employee labor and non-labor in support of efforts to build coalitions with key stakeholders and fund activities to influence legislative and regulatory outcomes.	1,386,177	1,588,429	1,599,690	1,628,279	1,663,202
34	61542: Major Accounts	Employee labor and non-labor to support large customer accounts.	4,622,482	4,337,475	4,283,250	4,353,584	4,465,746
35	61556: Choice Programs - Gas O&M	Gas Choice Team Labor - Manage Gas Choice programs including all interactions with customers, suppliers and regulatory agencies.	945,926	730,484	997,047	1,013,312	1,040,298
36	61557: Choice Programs - Electric O&M	Electric Choice Labor - Manage Electric Choice programs including all interactions with customers, suppliers and regulatory agencies.	1,071,272	907,188	1,058,551	1,076,352	1,104,917
37	61558: Load Forecasting	Provide analytics support for rate cases, rate designs, unbilled estimation and SER bill impacts.	1,474,414	957,337	721,025	669,188	686,949
agg	61569: Innovation Initiative - O&M	This project houses the budget for innovation projects approved by BGE leadership to advance new technologies.	586,878	1,000,004	1,000,056	1,000,030	1,025,064
39	62245: BGE Infrastructure Academy	The BGE Infrastructure Academy is an initiative where BGE, contractors, and non-profit partners will collaborate to train "work ready" adults and connect them to construction careers. Infrastructure Academy costs are below the line and do not affect the revenue requirements for the MYP. Reference Company Exhibits DMV-3E-1 and DMV-3G-1.	464,321	2,207,571	2,734,780	2,738,611	2,745,092
40	84 Projects with no year >= $1 million		15,699,822	17,818,707	18,278,887	17,248,091	17,274,865
41	**Total**		**$ 98,716,948**	**$ 109,758,681**	**$ 111,538,238**	**$ 111,483,646**	**$ 111,692,952**

BEFORE THE

PUBLIC SERVICE COMMISSION OF MARYLAND

IN THE MATTER OF THE APPLICATION	**)**	
OF BALTIMORE GAS AND ELECTRIC	**)**	
COMPANY FOR AUTHORITY TO	**)**	**CASE NO. ______**
INCREASE EXISTING RATES AND	**)**	
CHARGES FOR ELECTRIC AND GAS	**)**	
SERVICE	**)**	

DIRECT TESTIMONY

OF

ADRIEN M. MCKENZIE, CFA

ON BEHALF OF

BALTIMORE GAS AND ELECTRIC COMPANY

March 2, 2020

TABLE OF CONTENTS

GLOSSARY

Algonquin	Algonquin Power & Utilities, Inc.
BGE or the Company	Baltimore Gas and Electric Company
CAISO	California Independent System Operator
CAPM	Capital Asset Pricing Model
DCF	discounted cash flow
DOE	United States Department of Energy
DPS	dividends per share
ECAPM	Empirical Capital Asset Pricing Model
EEI	Edison Electric Institute
EIA	Energy Information Administration
Empire District	Empire District Electric Company
ECAPM	Empirical Capital Asset Pricing Model
EPS	earnings per share
Exelon	Exelon Corporation
FERC	Federal Energy Regulatory Commission
FINCAP, Inc.	Financial Concepts and Applications, Inc.
IBES	Institutional Brokers' Estimate System
MDPSC	Maryland Public Service Commission
Moody's	Moody's Investors Service
MRP	multi-year rate plan
RCA	Regulatory Commission of Alaska
ROE	return on equity
RRA	S&P Global Market Intelligence, RRA Regulatory Focus (formerly Regulatory Research Associates, Inc.
S&P	S&P Global Ratings
STRIDE	Strategic Infrastructure Development and Enhancement surcharge
Value Line	The Value Line Investment Survey
VSCC	Virginia State Corporation Commission
Zacks	Zacks Investment Research

I. INTRODUCTION

Q. Please state your name and business address.

A. Adrien M. McKenzie, 3907 Red River, Austin, Texas, 78751.

Q. In what capacity are you employed?

A. I am President of FINCAP, Inc., a firm providing financial, economic, and policy consulting services to business and government.

Q. Please describe your educational background and qualifications.

A. A description of my background and qualifications, including a resume containing the details of my experience, is attached as Exhibit AMM-1.

A. Overview

Q. What is the purpose of your testimony in this case?

A. The purpose of my testimony is to present to the MDPSC my independent assessment of the just and reasonable ROE for the jurisdictional electric and gas utility operations of BGE during the period when rates established in this proceeding will be in effect. In addition, I also examine the reasonableness of BGE's common equity ratio, considering both the specific risks faced by the Company and other industry guidelines.

Q. Please summarize the information and materials you rely on to support the opinions and conclusions contained in your testimony.

A. To prepare my testimony, I use information from a variety of sources that would normally be relied upon by a person in my capacity. In connection with the present filing, I consider and rely upon discussions with corporate management, publicly available financial reports, and prior regulatory filings relating to BGE. I also review information relating generally to current capital market conditions and specifically to investor perceptions, requirements, and expectations for BGE's electric and gas utility operations. These sources, coupled with my experience in the fields of finance and utility regulation, have given me a working knowledge of the issues relevant to investors' required return for BGE, and they form the basis of my analyses and conclusions.

Q. How is your testimony organized?

A. I first briefly review BGE's operations and finances. I then explain the development of proxy groups of electric and natural gas utilities used as the basis for my quantitative analyses, including the implications of the Company's regulatory mechanisms and proposed pilot MRP. Next I discuss current conditions in the capital markets and their implications in evaluating a just and reasonable return for the Company, including expectations of increasing capital costs over the duration of the MRP. With this as a background, I discuss well-accepted quantitative analyses to estimate the current cost of equity for the proxy groups of electric and gas utilities. These include the DCF model, the CAPM, the ECAPM, an equity risk premium approach based on allowed equity returns, and reference to expected earned rates of return for electric and gas utilities, which are all methods that are commonly relied on in regulatory proceedings. In addition, I discuss the importance of considering the impact of projected bond yields over the horizon of the proposed pilot MRP.

Based on the results of my analyses, I determine a just and reasonable cost of equity for BGE. My evaluation takes into account the specific risks for the Company's electric and gas utility operations in Maryland and BGE's requirements for financial strength. Next, my testimony discusses the regulatory and economic principles supporting an ROE adder for exemplary performance. Finally, consistent with the fact that utilities must compete for capital with firms outside their own industry, I corroborate my utility quantitative analyses by applying the DCF model to a group of low risk non-utility firms.

B. Summary and Conclusions

Q. What is your recommended ROE for BGE?

A. I apply the DCF, CAPM, ECAPM, risk premium, and expected earnings analyses to separate proxy groups of electric and gas utilities, with the results being summarized on Exhibit AMM-2. As shown there, based on the results of my analysis, I recommend a cost of equity range for the Company's electric and gas operations of 9.2% to 10.6%. It is my conclusion that the 9.9% midpoint of this range represents a just and reasonable cost of equity that is adequate to compensate the Company's investors, while maintaining the Company's financial integrity and ability to attract capital on reasonable terms.

As my testimony documents, the electric and gas utilities in my proxy groups operate under a wide variety of regulatory mechanisms, including decoupling and infrastructure cost trackers. Similarly, the vast majority of these proxy firms operate in regulatory jurisdictions that allow for future test years, formula rates, and MRPs. As a result, there is no basis to distinguish BGE from the proxy groups used as the basis of my analyses.

The 9.9% midpoint of my recommended range does not explicitly incorporate any allowance for superior results. A performance adder to recognize and encourage exemplary operations, such as that documented in the Company's testimony, is consistent with sound regulatory policy and an appropriate consideration in establishing a fair rate of return. Incorporating the

35 basis-point ROE performance adder proposed by BGE to my 9.9% recommended cost of equity results in a fair ROE of 10.25%.

II. FUNDAMENTAL ANALYSES

Q. What is the purpose of this section?

A. My objective is to evaluate and opine as to a just and reasonable ROE for BGE. Much of my work is predicated on a comparison of BGE within the utility industry as a whole, and more specifically to proxy groups of publicly traded electric and natural gas utilities. As a foundation for my opinions and subsequent quantitative analyses, this section briefly reviews the operations and finances of BGE. In addition, I explain the basis for my proxy groups used to estimate the cost of equity and examine alternative objective indicators of investment risk applicable to these firms. I also evaluate the investment risks of BGE against those of my reference groups, as well as examining specific conditions impacting today's capital markets. An understanding of the fundamental factors driving the risks and prospects of electric and gas utilities is essential in developing an informed opinion of investors' expectations and requirements that are the basis of a just and reasonable rate of return.

A. Baltimore Gas and Electric Company

Q. Briefly describe BGE and its utility operations.

A. Incorporated in 1906 and based in Baltimore, Maryland, BGE is engaged in the purchase and regulated retail sale of electricity and natural gas and the provision of electricity distribution and transmission and gas distribution services in central Maryland, including the City of Baltimore. The Company serves more than 1.25 million business and residential electric customers and more than 675,000 gas customers. As a whole, BGE had total operating revenue of $3.1 billion in 2019 and total assets of $10.6 billion. The company has approximately 3,200 employees.

Q. Where does BGE obtain the capital used to finance its investment in utility plant?

A. BGE is a subsidiary of Exelon and obtains its equity capital solely from Exelon, whose common stock is publicly traded on the New York Stock Exchange under the symbol, EXC. BGE issues long-term debt in its own name and has been assigned a corporate credit rating of A by S&P and A3 by Moody's.

Q. Does BGE anticipate the need for capital going forward?

A. Yes. The Company must undertake investments to provide for necessary maintenance and replacements of its electric and natural gas utility systems as it continues to provide safe and reliable service to its customers. For 2020, it is estimating total capital expenditures of $1.3 billion, including $279 million for electric transmission, $563 million for electric distribution, and $471 for its gas utility.[1] This total projected spending level represents a significant increase when compared to average annual spending over the most recent three-year period (2017-2019) of $1 billion.[2] Continued support for BGE's financial integrity and flexibility will be instrumental in attracting the capital necessary to fund these projects in an effective manner.

[1] Exelon Corporation, SEC Form 10-K for the year ended December 31, 2018. Exelon's SEC Form 10-Q for the third quarter of 2019 noted that, "[a]s of September 30, 2019, there have been no material changes to the Registrants' projected capital expenditures as disclosed in Liquidity and Capital Resources of the Exelon 2018 Form 10-K."

[2] Id.

B. Determination of Proxy Groups

Q. How do you implement quantitative methods to estimate the cost of common equity for BGE?

A. Application of quantitative methods to estimate the cost of common equity requires observable capital market data, such as stock prices and beta values. Moreover, even for a firm with publicly traded stock, the cost of common equity can only be estimated. As a result, applying quantitative models using observable market data only produces an estimate that inherently includes some degree of observation error. Thus, the accepted approach to increase confidence in the results is to apply quantitative methods to a proxy group of publicly traded companies that investors regard as risk-comparable. The results of the analysis on the sample of companies are relied upon to establish a range of reasonableness for the cost of equity for the specific company at issue.

Q. How do you identify the proxy group of electric utilities relied on for your analyses?

A. In order to reflect the risks and prospects associated with BGE's jurisdictional electric operations, the first part of my analyses focuses on a reference group of other utilities composed of those companies included in Value Line's electric utility industry groups with: (1) a Value Line Safety Rank of "1" or "2", (2) a Value Line Financial Strength Rating of "B++" or higher, and (3) a Value Line beta of 0.75 or less.[3] These criteria result in a proxy group composed of thirty-two companies, which I will refer to as the "Electric Group."

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[3] In addition to the companies included in Value Line's electric utility industry groups, I also considered Algonquin Power & Utilities Company and Emera, Inc, which would both be regarded as comparable utility investment opportunities by investors. Neither of these companies met my required screening criteria.

While my analysis of a comparable risk proxy group would normally incorporate a review of credit ratings, I exclude this criterion in deference to the MDPSC's prior findings.[4] In my view, credit ratings do provide an important and objective guide to overall investment risks that is referenced by both fixed income and equity investors, and I have cited them elsewhere in my testimony. Credit ratings are also widely accepted by regulatory agencies as a guide to investment risk, with FERC finding that "corporate credit ratings are a reasonable measure to use to screen for investment risk," and concluding, "[c]redit ratings are a key consideration in developing a proxy group that is risk-comparable."[5]

Q. What proxy group of gas utilities did you consider in your analyses?

A. I examined quantitative estimates of investors' required ROE for a separate proxy group of natural gas utilities, which was determined based on the publicly traded firms included in Value Line's Natural Gas Utility industry. I excluded one of these firms—UGI Corporation—because it is primarily engaged in propane sales and marketing. I refer to the nine remaining utilities as the "Gas Group."

C. Relative Risks of the Proxy Groups and BGE

Q. Did you evaluate investors' risk perceptions for the Electric and Gas Groups?

A. Yes. The quality rankings published by Value Line provide an important and objective assessment of relative risks that are considered by investors in

[4] In Case No. 9299, the Commission concluded that, "We wholly reject the notion that companies with similar bond ratings deserve similar ROEs. Bond ratings measure risk of default, not equity values." Case No. 9299, Order No. 85374 (Feb. 22, 2013) at 65.
[5] *Potomac-Appalachian Transmission Highline*, 133 FERC ¶ 61,152 at P 63 (2010).

forming their expectations and measure the risks associated with common stocks. Value Line's primary risk indicator is its Safety Rank, which ranges from "1" (Safest) to "5" (Riskiest). This overall risk measure is intended to capture the total risk of a stock, and incorporates elements of stock price stability and financial strength. Given that Value Line is perhaps the most widely available source of investment advisory information, its Safety Rank provides useful guidance regarding the risk perceptions of investors.

The Financial Strength Rating is designed as a guide to overall financial strength and creditworthiness, with the key inputs including financial leverage, business volatility measures, and company size. Value Line's Financial Strength Ratings range from "A++" (strongest) down to "C" (weakest) in nine steps. These objective, published indicators incorporate consideration of a broad spectrum of risks, including financial and business position, relative size, and exposure to firm-specific factors.

Finally, beta measures a utility's stock price volatility relative to the market as a whole, and reflects the tendency of a stock's price to follow changes in the market. A stock that tends to respond less to market movements has a beta less than 1.00, while stocks that tend to move more than the market have betas greater than 1.00. Beta is the only relevant measure of investment risk under modern capital market theory, and is widely cited in academics and in the investment industry as a guide to investors' risk perceptions. Moreover, in my experience Value Line is the most widely referenced source for beta in regulatory proceedings. As noted in *New Regulatory Finance*:

> Value Line is the largest and most widely circulated independent investment advisory service, and influences the expectations of a large number of institutional and individual investors. … Value Line betas are computed on a theoretically sound basis using a broadly based market index, and they are adjusted for the regression tendency of betas to converge to 1.00.[6]

Q. How do the overall risks of your two proxy groups compare to BGE?

A. Table 1 compares the Electric Group and the Gas Group to the Company across the three Value Line risk measures discussed above, as well as S&P's corporate credit ratings and long-term issuer ratings from Moody's, which are also widely referenced by the investment community:

TABLE 1
COMPARISON OF RISK INDICATORS

	Credit Ratings		Value Line		
Proxy Group	**S&P**	**Moody's**	**Safety Rank**	**Financial Strength**	**Beta**
Electric Group	BBB+	Baa1	2	A	0.58
Gas Group	A-	A3	2	A	0.66
BGE	A	A3	2	B++	0.65

Note: BGE's Value Line data is for its parent, Exelon Corp.

The average Safety Rank and Financial Strength for the two utility groups is identical, while the lower beta of the Electric Group indicates somewhat less risk than for the group of gas utilities. Meanwhile the average credit rating of A-/A3 for the Gas Group indicates that investors may view these utilities as being slightly less risky than the Electric Group, which is rated BBB+/Baa1.

The credit ratings corresponding to the Electric and Gas Groups are similar to, or slightly weaker than BGE's ratings. On the other hand, the average Value Line risk indicators for the proxy groups, which incorporate a

[6] Morin, Roger A., *New Regulatory Finance*, *Pub. Util. Reports* (2006) at 71.

broad spectrum of risks, including financial and business position, regulatory recovery mechanisms, and exposure to company specific factors, are generally stronger than those associated with the Company. Considered together, a comparison of these objective measures indicates that investors would likely conclude that the overall investment risks for the firms in the Electric and Gas Group are comparable to BGE.

Q. Has the MDPSC approved various regulatory mechanisms applicable to BGE's electric and gas utility operations?

A. Yes. BGE operates under STRIDE and revenue decoupling. In addition, the Company is proposing to implement a pilot MRP in this proceeding, the first of its kind in Maryland.

Q. Did you consider the implications of these regulatory mechanisms in your evaluation?

A. Yes. Adjustment mechanisms, cost trackers, and future test years have been increasingly prevalent in the utility industry in recent years, along with alternatives to traditional ratemaking such as formula rates and MRPs. As shown on exhibits AMM-3 and AMM-4, reflective of this trend, the companies in my Electric and Gas Groups operate under a wide variety of cost adjustment mechanisms, which encompass revenue decoupling and adjustment clauses designed to address rising capital investment outside of a traditional rate case and increasing costs of environmental compliance measures, as well as riders to recover the cost of environmental compliance measures, bad debt expenses, certain taxes and fees, post-retirement employee benefit costs and transmission-related charges. *RRA Regulatory Focus* concluded in its recent review of adjustment clauses that:

> More recently and with greater frequency, commissions have approved mechanisms that permit the costs associated with the construction of new generation capacity or delivery infrastructure to be reflected in rates, effectively including these items in rate base without a full rate case. In some instances, these mechanisms may even provide the utilities a cash return on construction work in progress.
>
> . . . [C]ertain types of adjustment clauses are more prevalent than others. For example, those that address electric and fuel and gas commodity charges are in place in all jurisdictions. Also, about two-thirds of all utilities have riders in place to recover costs related to energy efficiency programs, and roughly half of the utilities utilize some type of decoupling mechanism.[7]

With respect to formula rates and MRPs, a report prepared for the DOE noted that "MRPs are used in many states today to regulate utilities," and observed that seventeen states currently have approved MRPs for electric and gas utilities, including California, Florida, Georgia, New York, and Washington.[8] Meanwhile, formula rates have been used at FERC as the basis to establish rates for interstate electric transmission service for decades, with EEI reporting their adoption in eight retail jurisdictions.[9] As documented on Exhibits AMM-3 and AMM-4, the majority of firms included in the Electric and Gas Groups operate in states that have approved formula rates or MRPs for utilities under their jurisdiction.

Thus, while investors would consider BGE's regulatory mechanisms—including its proposed pilot MRP—to be supportive of the Company's financial

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[7] S&P Global Market Intelligence, *Adjustment Clauses, A State-by-State Overview*, RRA Regulatory Focus (Nov. 12, 2019).

[8] U.S. Department of Energy, *State Performance-Based Regulation Using Multiyear Rate Plans for U.S. Electric Utilities*, GRID Modernization Laboratory Consortium (Jul. 2017) at 2.3. *See also,* ScottMadden, *Innovative Ratemaking – Multiyear Rate Plans* (Feb. 2014).

[9] Edison Electric Institute, *Alternative Regulation for Emerging Utility Challenges: 2015 Update* (Nov. 11, 2015).

integrity, this does not provide a basis to distinguish the risks of BGE from the utilities in my Electric and Gas Groups.

III. CAPITAL MARKET ESTIMATES AND ANALYSES

Q. What is the purpose of this section of your testimony?

A. This section presents capital market estimates of the cost of equity. First, I discuss the current outlook for capital costs, including investors' view that interest rates remain on an upward trend. I then address the concept of the cost of common equity, along with the risk-return tradeoff principle fundamental to capital markets. Next, I describe various quantitative analyses conducted to estimate the cost of common equity for the proxy groups of comparable risk utilities.

A. Outlook for Capital Costs

Q. Please summarize current economic and capital market conditions.

A. In the third quarter of 2019, U.S. real GDP growth continued to slow to 2.1% from its recent apex of 3.2% in the second quarter of 2018. The unemployment rate remained in the neighborhood of 3.5% toward the end of 2019, which is indicative of a strong labor market and an economy that remains at full employment. Inflation, as evidenced by the Consumer Price Index, remained steady at around 2.1% in November 2019. Investors continue to face volatility as capital markets respond to uncertainties regarding the implications of an expanding economy at or near full employment, and continued wage gains. These underlying risks have been exacerbated by concerns over the implications of the Trump Administration's tariff policies. A recent Federal Reserve study concluded that the 2018 tariffs reduced manufacturing employment in the U.S. and increased producer prices. While fears of an escalating international trade war with China have eased more recently as the U.S. and China have concluded the first phase of a trade agreement, uncertainty over trade policy remains elevated and investors continue to confront signs of global economic weakness. Economic activity has remained weak in many emerging market economies, including Brazil and Mexico, along with continued signs of softening in China. Finally, investors continue to confront the implications of heightened geopolitical tensions in the Middle East, which have led to ongoing concerns over possible disruptions in crude oil supplies and attendant price volatility, as well as more recent risks stemming from uncertainties associated with the coronavirus outbreak in China.

Q. What is the recent direction of Federal Reserve monetary policies?

A. In early 2019, the Federal Reserve indicated its intention to adopt a more patient and accommodative stance to future policy adjustments, while observing that the appropriate target range for the federal funds rate would depend on future data. In the second half of 2019, the Federal Reserve lowered the target range for its benchmark federal funds rate by 75 basis points, reversing their policy of steady rate increases in 2016 and 2017. At the December 2019 FOMC meeting, economic projections by Fed members and bank presidents indicated a strong expectation that the target federal funds rate will increase during the 2020–2022 time frame and beyond.

The Federal Reserve continues to exert considerable influence over capital market conditions through its massive holdings of Treasuries and mortgage-backed securities, which continue to exceed $3.7 trillion.[10] While beginning a gradual balance sheet normalization program in October 2017, the Federal Reserve ended the reduction in its holdings of Treasury securities in 2019 and indicated in October its intention to purchase Treasury bills at least into the second quarter of 2020 in order to maintain ample reserve balances.

Q. Is there evidence that investors continue to anticipate higher interest rates in the foreseeable future?

A. Yes. Despite the decline in bond yields during the latter part of 2019, recent forecasts continue to anticipate higher long-term rates over the near-term. Table 2 below compares current interest rates on 10-year and 30-year Treasury bonds, triple-A rated corporate bonds, and double-A rated utility bonds with the average of near-term projections from Value Line, IHS Global Insight, Blue Chip Financial Forecasts, and the EIA:

[10] *Factors Affecting Reserve Balances*, H.4.1 (Jan. 2, 2020). https://www.federalreserve.gov/releases/h41/current/. Prior to the initiation of the stimulus program in 2009, the Federal Reserve's holdings of U.S. Treasury bonds and notes amounted to approximately $400-$500 billion.

TABLE 2
INTEREST RATE TRENDS

	Dec. 2019	2020	2021	2022	2023
10-Yr. Treasury	1.9%	2.4%	2.7%	2.9%	3.1%
30-Yr. Treasury	2.3%	2.6%	3.0%	3.3%	3.4%
Aaa Corporate	3.0%	3.4%	3.7%	3.9%	4.1%
Aa Utility	3.2%	4.2%	4.4%	4.6%	4.7%

Sources:
Moody's Investors Service.
https://fred.stlouisfed.org/.
Value Line Investment Survey, Forecast for the U.S. Economy (Nov. 29, 2019).
IHS Global Insight, Long-Term Macro Forecast - Baseline (Oct. 15, 2019).
Energy Information Administration, Annual Energy Outlook 2020 (Jan. 29, 2020).
Wolters Kluwer, Blue Chip Financial Forecasts (Dec. 1, 2019).

As the table shows, investors continue to anticipate higher interest rates over the near-term.

Q. What do these forecasts imply in light of BGE's proposed pilot MRP?

A. These expectations for higher interest rates suggest that long-term capital costs—including the cost of equity—will increase over the time period covered by the proposed MRP. As a result, cost of equity estimates based on current data are likely to understate the return that will be required by investors over the term of the MRP, during which BGE's rates will remain fixed.

Q. Is it necessary that interest rate forecasts, like those shown above, be perfectly accurate in order to be relied on?

A. No. When estimating investors' required rate of return, what investors expect, not what actually happens, is what matters most. While the projections of various services may be proven optimistic or pessimistic in hindsight, this is irrelevant in assessing expected interest rates and how they might influence the Company's allowed ROE. Any difference in actual rates as compared to analysts' forecasts is beside the point. What is most important is that investors share analysts' views when the forecasts were made and incorporate those views into their decision-making process, not the actual rates that ultimately transpire.

B. Economic Standards

Q. What fundamental economic principle underlies the cost of equity concept?

A. The fundamental economic principle underlying the cost of equity concept is the notion that investors are risk averse. In capital markets where relatively risk-free assets are available (e.g., U.S. Treasury securities), investors can be induced to hold riskier assets only if they are offered a premium, or additional return, above the rate of return on a risk-free asset. Because all assets compete with each other for investor funds, riskier assets must yield a higher expected rate of return than safer assets to induce investors to invest and hold them.

Given this risk-return tradeoff, the required rate of return (k) from an asset (i) can generally be expressed as:

$$k_i = R_f + RP_i$$

where: R_f = Risk-free rate of return, and
RP_i = Risk premium required to hold riskier asset i.

Thus, the required rate of return for a particular asset at any time is a function of: (1) the yield on risk-free assets, and (2) the asset's relative risk, with investors demanding correspondingly larger risk premiums for bearing greater risk.

Q. Is there evidence that the risk-return tradeoff principle actually operates in the capital markets?

A. Yes. The risk-return tradeoff can be readily documented in segments of the capital markets where required rates of return can be directly inferred from market data and where generally accepted measures of risk exist. Bond yields, for example, reflect investors' expected rates of return, and bond ratings measure the risk of individual bond issues. Comparing the observed yields on government securities, which are considered free of default risk, to the yields on bonds of various rating categories demonstrates that the risk-return tradeoff does, in fact, exist.

Q. Does the risk-return tradeoff observed with fixed income securities extend to common stocks and other assets?

A. It is widely accepted that the risk-return tradeoff evidenced with long-term debt extends to all assets. Documenting the risk-return tradeoff for assets other than fixed income securities, however, is complicated by two factors. First, there is no standard measure of risk applicable to all assets. Second, for most assets – including common stock – required rates of return cannot be observed. Yet there is every reason to believe that investors exhibit risk aversion in deciding whether or not to hold common stocks and other assets, just as when choosing among fixed-income securities.

Q. Is this risk-return tradeoff limited to differences between firms?

A. No. The risk-return tradeoff principle applies not only to investments in different firms, but also to different securities issued by the same firm. The securities issued by a utility vary considerably in risk because they have different characteristics and priorities. As noted earlier, long-term debt is senior among all capital in its claim on a utility's net revenues and is, therefore, the least risky. The last investors in line are common shareholders: they receive only the net revenues, if any, remaining after all other claimants have been paid. As a result, the rate of return that investors require from a utility's common stock, the most junior and riskiest of its securities, must be considerably higher than the yield offered by the utility's senior, long-term debt.

Q. What are the challenges in determining a just and reasonable ROE for a regulated enterprise?

A. The actual return investors require is unobservable. Different methodologies have been developed to estimate investors' expected and required return on capital, but all such methodologies are merely theoretical tools and generally produce a range of estimates, based on different assumptions and inputs. The DCF method, which is frequently referenced and relied on by regulators, is only one theoretical approach to gain insight into the return investors require; there are numerous other methodologies for estimating the cost of capital and the ranges produced by the different approaches can vary widely.

Q. Is it customary to consider the results of multiple approaches when evaluating a just and reasonable ROE?

A. Yes. In my experience, financial analysts and regulators routinely consider the results of alternative approaches in determining allowed ROEs. It is widely recognized that no single method can be regarded as failsafe; with all approaches having advantages and shortcomings. As FERC has noted, "[t]he determination of rate of return on equity starts from the premise that there is no single approach or methodology for determining the correct rate of return."[11] More recently, FERC recognized the potential for any application of the DCF model to produce unreliable results.[12] Similarly, a publication of the Society of Utility and Regulatory Financial Analysts concluded that:

> Each model requires the exercise of judgment as to the reasonableness of the underlying assumptions of the methodology and on the reasonableness of the proxies used to validate the theory. Each model has its own way of examining investor behavior, its own premises, and its own set of simplifications of reality. Each method proceeds from different fundamental premises, most of which cannot be validated empirically. Investors clearly do not subscribe to any singular method, nor does the stock price reflect the application of any one single method by investors.[13]

As this treatise succinctly observed, "no single model is so inherently precise that it can be relied on solely to the exclusion of other theoretically sound models."[14] Similarly, *New Regulatory Finance* concluded that:

> There is no single model that conclusively determines or estimates the expected return for an individual firm. Each methodology possesses its own way of examining investor behavior, its own premises, and its own set of simplifications of reality. Each method proceeds from different fundamental premises that cannot be validated empirically. Investors do not necessarily subscribe to any one method, nor does the stock price reflect the application of any one single method by the price-setting investor. There is no monopoly as to which method is used by investors. In the absence of any hard evidence as to which method outdoes the other, all relevant evidence should be used and weighted equally, in order to minimize judgmental error, measurement error, and conceptual infirmities.[15]

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[11] *Northwest Pipeline Co.*, Opinion No. 396-C, 81 FERC ¶ 61,036 at 4 (1997).
[12] *Coakley v. Bangor Hydro-Elec. Co.*, Opinion No. 531, 147 FERC ¶ 61,234 at P 41 (2014).
[13] David C. Parcell, *The Cost of Capital – A Practitioner's Guide*, Society of Utility and Regulatory Financial Analysts (2010) at 84.
[14] Id.
[15] Roger A. Morin, *New Regulatory Finance*, Pub. Util. Reports, Inc. (2006) at 429.

Thus, while the DCF model is a recognized approach to estimating the ROE, it is not without shortcomings and does not otherwise eliminate the need to ensure that the "end result" is fair. The Indiana Utility Regulatory Commission has recognized this principle:

> There are three principal reasons for our unwillingness to place a great deal of weight on the results of any DCF analysis. One is. . . the failure of the DCF model to conform to reality. The second is the undeniable fact that rarely if ever do two expert witnesses agree on the terms of a DCF equation for the same utility – for example, as we shall see in more detail below, projections of future dividend cash flow and anticipated price appreciation of the stock can vary widely. And, the third reason is that the unadjusted DCF result is almost always well below what any informed financial analysis would regard as defensible, and therefore require an upward adjustment based largely on the expert witness's judgment. In these circumstances, we find it difficult to regard the results of a DCF computation as any more than suggestive.[16]

As this discussion indicates, consideration of the results of alternative approaches reduces the potential for error associated with any single quantitative method. Just as investors inform their decisions through the use of a variety of methodologies, my evaluation of a fair ROE for the Company considered the results of multiple financial models.

Q. Does the fact that BGE is a subsidiary of Exelon in any way alter these fundamental standards underlying a just and reasonable ROE?

A. No. While the Company has no publicly traded common stock and Exelon is BGE's only shareholder, this does not change the standards governing the determination of a just and reasonable ROE for the Company. Ultimately, the common equity that is required to support the utility operations of BGE must

[16] *Ind. Michigan Power Co.*, Cause No. 38728, 116 PUR4th, 1, 17-18 (IURC 8/24/1990).

be raised in the capital markets, where investors consider the Company's ability to offer a rate of return that is competitive with other risk-comparable alternatives. BGE must compete with other investment opportunities and unless there is a reasonable expectation that investors will have the opportunity to earn returns commensurate with the underlying risks, capital will be allocated elsewhere, the Company's financial integrity will be weakened, and investors will demand an even higher rate of return. BGE's ability to offer a reasonable return on investment is a necessary ingredient in ensuring that customers continue to enjoy economical rates and reliable service.

Q. What does the above discussion imply with respect to estimating the ROE for a utility?

A. Although the ROE is unobservable, it is a function of the returns available from other investment alternatives and the risks to which the equity capital is exposed. Because it is not readily observable, the ROE for a particular utility must be estimated by analyzing information about capital market conditions generally, assessing the relative risks of the company specifically, and employing various quantitative methods that focus on investors' required rates of return. These various quantitative methods typically attempt to infer investors' required rates of return from stock prices, interest rates, or other capital market data.

C. Discounted Cash Flow Analyses

Q. How is the DCF model used to estimate the cost of common equity?

A. DCF models are based on the assumption that the price of a share of common stock is equal to the present value of the expected cash flows (i.e., future dividends and stock price) that will be received while holding the stock, discounted at investors' required rate of return. Rather than developing annual estimates of cash flows into perpetuity, the DCF model can be simplified to a "constant growth" form:[17]

$$P_0 = \frac{D_1}{k_e - g}$$

where: P_0 = Current price per share;
D_1 = Expected dividend per share in the coming year;
k_e = Cost of equity; and,
g = Investors' long-term growth expectations.

The cost of common equity (k_e) can be isolated by rearranging terms within the equation:

$$k_e = \frac{D_1}{P_0} + g$$

This constant growth form of the DCF model recognizes that the rate of return to stockholders consists of two parts: 1) dividend yield (D_1/P_0); and 2) growth (g). In other words, investors expect to receive a portion of their total return in the form of current dividends and the remainder through price appreciation.

[17] The constant growth DCF model is dependent on a number of strict assumptions, which in practice are never met. These include a constant growth rate for both dividends and earnings; a stable dividend payout ratio; the discount rate exceeds the growth rate; a constant growth rate for book value and price; a constant earned rate of return on book value; no sales of stock at a price above or below book value; a constant price-earnings ratio; a constant discount rate (*i.e.*, no changes in risk or interest rate levels and a flat yield curve); and all of the above extend to infinity. Nevertheless, the DCF method provides a workable and practical approach to estimate investors' required return that is widely referenced in utility ratemaking.

Q. What steps are required to apply the constant growth DCF model?

A. The first step in implementing the constant growth DCF model is to determine the expected dividend yield (D_1/P_0) for the firm in question. This is usually calculated based on an estimate of dividends to be paid in the coming year divided by the current price of the stock. The second, and more controversial, step is to estimate investors' long-term growth expectations (g) for the firm. The final step is to add the firm's dividend yield and estimated growth rate to arrive at an estimate of its cost of common equity.

Q. How did you determine the dividend yields for the proxy groups?

A. Estimates of dividends to be paid by each of these utilities over the next twelve months, obtained from Value Line, served as D_1. This annual dividend was then divided by a 30-day average stock price for each utility to arrive at the expected dividend yield. The expected dividends, stock prices, and resulting dividend yields for the firms in the Electric and Gas Groups are presented on Exhibits AMM-5 and AMM-7, respectively. As shown on the first page of these exhibits, dividend yields for the firms in the Electric Group ranged from 1.5% to 4.8% and averaged 3.2%, while dividend yields for the Gas Group ranged from 1.8% to 4.0% and averaged 2.8%.

Q. What is the next step in applying the constant growth DCF model?

A. The next step is to evaluate long-term growth expectations, or "g", for the firm in question. In constant growth DCF theory, earnings, dividends, book value, and market price are all assumed to grow in lockstep, and the growth horizon of the DCF model is infinite. But implementation of the DCF model is more than just a theoretical exercise; it is an attempt to replicate the mechanism investors used to arrive at observable stock prices. A wide variety of techniques can be used to derive growth rates, but the only “g” that matters in applying the DCF model is the value that investors expect.

Q. What are investors most likely to consider in developing their long-term growth expectations?

A. Implementation of the DCF model is solely concerned with replicating the forward-looking evaluation of real-world investors. In the case of utilities, dividend growth rates are not likely to provide a meaningful guide to investors’ current growth expectations. Utility dividend policies reflect the need to accommodate business risks and investment requirements in the industry, as well as potential uncertainties in the capital markets. As a result, dividend growth in the utility industry has lagged growth in earnings as utilities conserve financial resources.

A measure that plays a pivotal role in determining investors’ long-term growth expectations is future trends in EPS, which provide the source for future dividends and ultimately support share prices. The importance of earnings in evaluating investors’ expectations and requirements is well accepted in the investment community, and surveys of analytical techniques relied on by professional analysts indicate that growth in earnings is far more influential than trends in DPS.

The availability of projected EPS growth rates also is key to investors relying on this measure as compared to future trends in DPS. Apart from Value Line, investment advisory services do not generally publish comprehensive DPS growth projections, and this scarcity of dividend growth rates relative to the abundance of earnings forecasts attests to their relative influence. The fact that securities analysts focus on EPS growth, and that DPS growth rates are not routinely published, indicates that projected EPS growth rates are likely to provide a superior indicator of the future long-term growth expected by investors.

Q. Do the growth rate projections of security analysts consider historical trends?

A. Yes. Professional security analysts study historical trends extensively in developing their projections of future earnings. Hence, to the extent there is any useful information in historical patterns, that information is incorporated into analysts' growth forecasts.

Q. Did Professor Myron J. Gordon, a pioneer of the DCF approach, recognize the pivotal role that earnings play in forming investors' expectations?

A. Yes. Dr. Gordon specifically recognized that "it is the growth that investors expect that should be used" in applying the DCF model and he concluded:

> A number of considerations suggest that investors may, in fact, use earnings growth as a measure of expected future growth.[18]

Q. Are analysts' assessments of growth rates appropriate for estimating investors' required return using the DCF model?

A. Yes. In applying the DCF model to estimate the cost of common equity, the only relevant growth rate is the forward-looking expectations of investors that are captured in current stock prices. Investors, just like securities analysts and others in the investment community, do not know how the future will actually turn out. They can only make investment decisions based on their best estimate of what the future holds in the way of long-term growth for a particular

[18] Myron J. Gordon, *The Cost of Capital to a Public Utility*, MSU Public Utilities Studies (1974) at 89.

stock, and securities prices are constantly adjusting to reflect their assessment of available information.

Any claims that analysts' estimates are not relied upon by investors are illogical given the reality of a competitive market for investment advice. If financial analysts' forecasts do not add value to investors' decision-making, then it is irrational for investors to pay for these estimates. Similarly, those financial analysts who fail to provide reliable forecasts will lose out in competitive markets relative to those analysts whose forecasts investors find more credible. The reality that analyst estimates are routinely referenced in the financial media and in investment advisory publications (e.g., Value Line) implies that investors use them as a basis for their expectations.

While the projections of securities analysts may be proven optimistic or pessimistic in hindsight, this is irrelevant in assessing the expected growth that investors have incorporated into current stock prices, and any bias in analysts' forecasts – whether pessimistic or optimistic – is irrelevant if investors share analysts' views. Earnings growth projections of security analysts provide the most frequently referenced guide to investors' views and are widely accepted in applying the DCF model. As explained in *New Regulatory Finance*:

> Because of the dominance of institutional investors and their influence on individual investors, analysts' forecasts of long-run growth rates provide a sound basis for estimating required returns. Financial analysts exert a strong influence on the expectations of many investors who do not possess the resources to make their own forecasts, that is, they are a cause of *g* [growth]. <u>The accuracy of these forecasts in the sense of whether they turn out to be correct is not an issue here, as long as they reflect widely held expectations</u>.[19]

[19] Roger A. Morin, *New Regulatory Finance*, Pub. Util. Reports, Inc. (2006) at 298 (emphasis added).

Q. The MDPSC has previously characterized projected growth estimates as "speculative" and suggested that historical growth rates may provide greater "certainty."[20] Do you agree?

A. No. While I agree that historical growth rates are dependent on data that is known with certainty, this does not support a finding that historical measures provide a more suitable basis on which to apply the DCF model. In fact, empirical research comes to the opposite conclusion. As summarized in *New Regulatory Finance*, "[p]ublished studies in the academic literature demonstrate that growth forecasts made by securities analysts represent an appropriate source of DCF growth rates, are reasonable indicators of investors' expectations and are more accurate than forecasts based on historical growth."[21]

Q. Have other regulators also recognized that analysts' growth rate estimates are an important and meaningful guide to investors' expectations?

A. Yes. The Kentucky Public Service Commission has indicated its preference for relying on analysts' projections in establishing investors' expectations:

> KU's argument concerning the appropriateness of using investors' expectations in performing a DCF analysis is more persuasive than the AG's argument that analysts' projections should be rejected in favor of historical results. The Commission agrees that analysts' projections of growth will be relatively more compelling in forming investors' forward-looking expectations than relying on historical performance . . .[22]

[20] Case No. 9484, Order No. 88975 (Jan. 4, 2019) at 62.
[21] Roger A Morin, *New Regulatory Finance*, Pub. Util. Reports, Inc. (2006) at 298.
[22] *Kentucky Utilities Co.*, Case No. 2009-00548 (Ky PSC Jul. 30, 2010) at 30-31.

Similarly, FERC has expressed a clear preference for projected EPS growth rates in applying the DCF model to estimate the cost of equity for both electric and natural gas pipeline utilities:

> Opinion No. 414-A held that the IBES five-year growth forecasts for each company in the proxy group are the best available evidence of the short-term growth rates expected by the investment community. It cited evidence that (1) those forecasts are provided to IBES by professional security analysts, (2) IBES reports the forecast for each firm as a service to investors, and (3) the IBES reports are well known in the investment community and used by investors. The Commission has also rejected the suggestion that the IBES analysts are biased and stated that "in fact the analysts have a significant incentive to make their analyses as accurate as possible to meet the needs of their clients since those investors will not utilize brokerage firms whose analysts repeatedly overstate the growth potential of companies."[23]

The Public Utility Regulatory Authority of Connecticut has also noted that "there is not growth in DPS without growth in EPS," and concluded that securities analysts' growth projections have a greater influence over investors' expectations and stock prices.[24] In addition, the RCA has previously determined that analysts' EPS growth rates provide a superior basis on which to estimate investors' expectations:

> We also find persuasive the testimony . . . that projected EPS returns are more indicative of investor expectations of dividend growth than historical growth data because persons making the forecasts already consider the historical numbers in their analyses.[25]

[23] *Kern River Gas Transmission Co.*, 126 FERC ¶ 61,034 at P 121 (2009) (footnote omitted).
[24] *Decision*, Docket No. 13-02-20 (Sept. 24, 2013).
[25] Regulatory Commission of Alaska, U-07-76(8) at 65, n. 258.

The RCA has concluded that arguments against exclusive reliance on analysts' EPS growth rates to apply the DCF model "are not convincing."[26]

Q. What are security analysts currently projecting in the way of growth for the firms in the proxy groups?

A. The earnings growth projections for each of the firms in the Electric and Gas Groups reported by Value Line, IBES,[27] and Zacks are displayed on page 2 of Exhibits AMM-5 and AMM-7.

Q. How else are investors' expectations of future long-term growth prospects often estimated when applying the constant growth DCF model?

A. In constant growth theory, growth in book equity will be equal to the product of the earnings retention ratio (one minus the dividend payout ratio) and the earned rate of return on book equity. Furthermore, if the earned rate of return and the payout ratio are constant over time, growth in earnings and dividends will be equal to growth in book value. Despite the fact that these conditions are never met in practice, this "sustainable growth" approach may provide a rough guide for evaluating a firm's growth prospects and is frequently proposed in regulatory proceedings.

The sustainable growth rate is calculated by the formula, $g = br+sv$, where "b" is the expected retention ratio, "r" is the expected earned return on equity, "s" is the percent of common equity expected to be issued annually as new common stock, and "v" is the equity accretion rate. Under DCF theory, the "sv" factor is a component of the growth rate designed to capture the

[26] Regulatory Commission of Alaska, U-08-157(10) at 36.

[27] Formerly I/B/E/S International, Inc., IBES growth rates are now compiled and published by Thomson Reuters.

impact of issuing new common stock at a price above, or below, book value. The sustainable, “br+sv” growth rates for each firm in the proxy groups are summarized on page 2 of Exhibits AMM-5 and AMM-7, with the underlying details being presented on Exhibits AMM-6 and AMM-8.

Q. What cost of common equity estimates were implied for the Electric and Gas Groups using the DCF model?

A. After combining the dividend yields and respective growth projections for each utility, the resulting cost of common equity estimates are shown on page 3 of Exhibits AMM-5 and AMM-7.

Q. In evaluating the results of the constant growth DCF model, is it appropriate to eliminate illogical estimates at the extreme low or high end of the range?

A. Yes. In applying quantitative methods to estimate the cost of equity, it is essential that the resulting values pass fundamental tests of reasonableness and economic logic. Accordingly, DCF estimates that are implausibly low or high should be eliminated when evaluating the results of this method.

Q. How did you evaluate DCF estimates at the low end of the range?

A. I based my evaluation of DCF estimates at the low end of the range on the fundamental risk-return tradeoff, which holds that investors will only take on more risk if they expect to earn a higher rate of return to compensate them for the greater uncertainly. Because common stocks lack the protections associated with an investment in long-term bonds, a utility’s common stock imposes far greater risks on investors. As a result, the rate of return that investors require from a utility’s common stock is considerably higher than the yield offered by senior, long-term debt. Consistent with this principle, DCF results that are not sufficiently higher than the yield available on less risky utility bonds must be eliminated.

Q. Have similar tests been applied by regulators?

A. Yes. FERC has noted that adjustments are justified where applications of the DCF approach produce illogical results. FERC evaluates DCF results against observable yields on long-term public utility debt and has recognized that it is appropriate to eliminate estimates that do not sufficiently exceed this threshold.[28] FERC affirmed that:

> The purpose of the low-end outlier test is to exclude from the proxy group those companies whose ROE estimates are below the average bond yield or are above the average bond yield but are sufficiently low that an investor would consider the stock to yield essentially the same return as debt. In public utility ROE cases, the Commission has used 100 basis points above the cost of debt as an approximation of this threshold, but has also considered the distribution of proxy group companies to inform its decision on which companies are outliers. As the Presiding Judge explained, this is a flexible test.[29]

Q. What interest rate benchmarks did you consider in evaluating the DCF results for BGE?

A. Utility bonds rated "Baa" represent the lowest ratings grade for which Moody's publishes index values, and the closest available approximation for the risks of common stock, which are significantly greater than those of long-term debt. Monthly yields on Baa utility bonds reported by Moody's averaged approximately 3.78% over the six months ended December 2019.[30] Moreover, as indicated earlier, it is generally expected that long-term interest rates will

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[28] *See, e.g.*, *Southern California Edison Co.*, 131 FERC ¶ 61,020 at P 55 (2010).
[29] Opinion No. 531, 147 FERC ¶ 61,234 at P 122 (2014).
[30] Moody's Investors Service, *CreditTrends.*

rise over the near-term. As shown in Table 3 below, forecasts of IHS Global Insight and the EIA imply an average Baa bond yield of approximately 4.9% over the period 2020-2023:

TABLE 3
IMPLIED BAA BOND YIELD

	Baa Yield 2020-23
Projected Aa Utility Yield	
IHS Global Insight (a)	4.38%
EIA (b)	4.49%
Average	4.43%
Current Baa - Aa Yield Spread (c)	0.50%
Implied Baa Utility Yield	**4.93%**

(a) IHS Global Insight, Long-Term Macro Forecast - Baseline (Oct. 15, 2019).
(b) Energy Information Administration, Annual Energy Outlook 2020 (Jan. 29, 2020).
(c) Based on monthly average bond yields from Moody's Investors Service for the six-month period Jul. - Dec. 2019.

Q. What else should be considered in evaluating DCF estimates at the low end of the range?

A. While a 100 basis point spread over public utility bond yields is a starting place in evaluating low-end values, reference to a static test ignores the implications of the inverse relationship between equity risk premiums and bond yields. Specifically, the premium that investors demand to bear the higher risks of common stock is not constant. As demonstrated empirically in the application of the risk premium method,[31] equity risk premiums expand when interest rates fall, and vice versa.

For example, FERC first referenced a 100 basis point risk premium over Moody's bond yield averages as a threshold to eliminate DCF results in SoCal Edison, citing prior decisions in Atlantic Path 15,[32] Startrans,[33] and Pioneer[34] in support of this policy.[35] Because bond yields declined significantly between the time of those findings and the study period in this case, the inverse relationship implies a significant increase in the equity risk premium that investors require to accept the higher uncertainties associated with an investment in utility common stocks versus bonds. As a result, using a fixed premium of 100 basis points over Baa public utility bond yields will vastly understate the threshold for investors' minimum required return on utility stocks. In fact, as shown on Exhibit AMM-9, recognizing the inverse relationship between equity risk premiums and bond yields would indicate a current low-end threshold in the range of approximately 6.0% to 6.7%. The impact of widening equity risk premiums should be considered in evaluating low-end cost of equity estimates.

Q. What do you conclude regarding the reasonableness of DCF values at the low end of the range of results?

A. As highlighted on page 3 of Exhibits AMM-5 and AMM-7, after considering these benchmarks and the distribution of individual estimates, I eliminate low-end DCF estimates ranging from -3.3% to 6.5%. Based on my professional

[31] Exhibit AMM-12 at 4; Exhibit AMM-13 at 5.
[32] *Atl. Path 15, LLC*, 122 FERC ¶ 61,135 (2008) ("*Atlantic Path 15*").
[33] *Startrans IO, LLC*, 122 FERC ¶ 61,306 (2008) ("*Startrans*").
[34] *Pioneer Transmission, LLC*, 126 FERC ¶ 61,281 (2009) ("*Pioneer*").
[35] *SoCal Edison* at P 54.

experience and the risk-return tradeoff principle that is fundamental to finance, it is inconceivable that investors are not requiring a substantially higher rate of return for holding common stock. As a result, these values provide little guidance as to the returns investors require from utility common stocks and should be excluded.

Q. Do you also recommend excluding estimates at the high end of the range of DCF results?

A. Yes. As highlighted on page 3 of Exhibit AMM-7, I exclude DCF estimates for Northwest Natural at 29.8% and NiSource Inc. at 15.5%. While it is just as important to evaluate DCF estimates at the upper end of the range, there is no objective benchmark analogous to the bond yield averages used to eliminate illogical low-end values. Compared with the balance of the remaining estimates, however, these values are unreasonably high and should be removed.

Beyond this, the upper end of the DCF results is set by cost of equity estimates of 13.8% (Electric Group) and 14.5% (Gas Group). While a 13.8% or 14.5% cost of equity estimate may exceed the majority of the remaining values, low-end DCF estimates in the 6.5% to 7.5% range are assuredly far below investors' required rate of return. Taken together and considered along with the balance of the results, the remaining values provide a reasonable basis on which to frame the range of plausible DCF estimates and evaluate investors' required rate of return.

Q. What ROE estimates are implied by your DCF results for the proxy groups?

A. As shown on page 3 of Exhibits AMM-5 and AMM-7 and summarized in Table 4, below, after eliminating illogical values, application of the constant growth DCF model resulted in the following ROE estimates:

TABLE 4
DCF RESULTS – PROXY GROUPS

	Electric		Gas	
Growth Rate	**Average**	**Midpoint**	**Average**	**Midpoint**
Value Line	9.3%	10.3%	11.0%	11.5%
IBES	8.7%	9.7%	8.4%	8.9%
Zacks	8.7%	8.9%	9.4%	10.1%
br + sv	8.4%	9.9%	11.0%	11.1%

D. Capital Asset Pricing Model

Q. Please describe the CAPM.

A. The CAPM is a theory of market equilibrium that measures risk using the beta coefficient. Assuming investors are fully diversified, the relevant risk of an individual asset (e.g., common stock) is its volatility relative to the market as a whole, with beta reflecting the tendency of a stock's price to follow changes in the market. A stock that tends to respond less to market movements has a beta less than 1.0, while stocks that tend to move more than the market have betas greater than 1.0. The CAPM is mathematically expressed as:

$$R_j = R_f + \beta_j(R_m - R_f)$$

where: R_j = required rate of return for stock j;
R_f = risk-free rate;
R_m = expected return on the market portfolio; and,
β_j = beta, or systematic risk, for stock j.

Under the CAPM formula above, a stock's required return is a function of the risk-free rate (R_f), plus a risk premium that is scaled to reflect the relative volatility of a firm's stock price, as measured by beta (β). Like the DCF model, the CAPM is an *ex-ante,* or forward-looking model based on expectations of the future. As a result, in order to produce a meaningful estimate of investors' required rate of return, the CAPM must be applied using estimates that reflect the expectations of actual investors in the market, not with backward-looking, historical data.

Q. Why is the CAPM approach a relevant component when evaluating the cost of equity for BGE?

A. The CAPM approach (which also forms the foundation of the ECAPM) generally is considered to be the most widely referenced method for estimating the cost of equity among academicians and professional practitioners, with the pioneering researchers of this method receiving the Nobel Prize in 1990. Because this is the dominant model for estimating the cost of equity outside the regulatory sphere, the CAPM (and ECAPM) provides important insight into investors' required rate of return for utility stocks, including the Company.

Q. How did you apply the CAPM to estimate the ROE?

A. Application of the CAPM to the proxy groups is based on a forward-looking estimate for investors' required rate of return from common stocks presented in Exhibit AMM-10. In order to capture the expectations of today's investors in current capital markets, the expected market rate of return was estimated by conducting a DCF analysis on the dividend paying firms in the S&P 500.

The dividend yield for each firm is obtained from Value Line, and the growth rate is equal to the average of the earnings growth projections for each firm published by IBES, Zacks, and Value Line, with each firm's dividend yield and growth rate being weighted by its proportionate share of total market value. Based on the weighted average of the projections for the individual firms, current estimates imply an average growth rate over the next five years of 9.3%. Combining this average growth rate with a year-ahead dividend yield of 2.3% results in a current cost of common equity estimate for the market as a whole (R_m) of 11.6%. Subtracting a 2.3% risk-free rate based on the average yield on 30-year Treasury bonds for the six-months ending December 2019 produced a market equity risk premium of 9.3%.

Q. What was the source of the beta values you used to apply the CAPM?

A. As indicated earlier in my discussion of risk measures for the proxy groups, I relied on the beta values reported by Value Line, which in my experience is the most widely referenced source for beta in regulatory proceedings.

Q. What else should be considered in applying the CAPM?

A. Financial research indicates that the CAPM does not fully account for observed differences in rates of return attributable to firm size. Accordingly, a modification is required to account for this size effect. As explained by Morningstar:

> One of the most remarkable discoveries of modern finance is the finding of a relationship between firm size and return. On average, small companies have higher returns than large ones. . . . The relationship between firm size and return cuts across the entire size spectrum; it is not restricted to the smallest stocks.[36]

According to the CAPM, the expected return on a security should consist of the riskless rate, plus a premium to compensate for the systematic risk of the particular security. The degree of systematic risk is represented by the beta coefficient. The need for the size adjustment arises because differences in investors' required rates of return that are related to firm size are not fully captured by beta. To account for this, researchers have developed size premiums that need to be added to account for the level of a firm's market capitalization in determining the CAPM cost of equity.[37] Accordingly, my CAPM analyses also incorporated an adjustment to recognize the impact of size distinctions, as measured by the market capitalization for the firms in the Electric and Gas Groups.

Q. Is this size adjustment related to the relative size of BGE as compared with the proxy group?

A. No. I am not proposing to apply a general size risk premium in evaluating a just and reasonable ROE for the Company and my recommendation does not include any adjustment related to the relative size of BGE. Rather, this size adjustment is specific to the CAPM and merely corrects for an observed inability of the beta measure to fully reflect the risks perceived by investors for

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[36] Morningstar, *2015 Ibbotson SBBI Classic Yearbook*, at 99.

[37] Originally compiled by Ibbotson Associates and published in their annual yearbook entitled, *Stocks, Bonds, Bills and Inflation*, these size premia are now developed by Duff & Phelps and presented in its *Valuation Handbook – Guide to Cost of Capital*.

the firms in the proxy groups. As FERC has recognized, "[t]his type of size adjustment is a generally accepted approach to CAPM analyses."[38]

Q. What is the implied ROE for the Electric and Gas Groups using the CAPM approach?

A. As shown on Exhibit AMM-10, after adjusting for the impact of firm size, the CAPM approach implies an average ROE for the Electric Group of 8.2% (page 1) and 9.8% for the Gas Group (page 3).[39]

Q, Did you also apply the CAPM using forecasted bond yields?

A. Yes. As discussed earlier, there is general consensus that interest rates will increase over the period when the rates established in this proceeding will be in effect. Accordingly, in addition to the use of current bond yields, I applied the CAPM based on the forecasted long-term Treasury bond yields developed based on projections published by Value Line, IHS Global Insight and Blue Chip for the years 2020-2023. As shown on Exhibit AMM-10, incorporating a forecasted Treasury bond yield implies an average cost of equity estimate of 8.5% for the Electric Group (page 2) and 10.1% for the Gas Group (page 4).[40]

E. Empirical Capital Asset Pricing Model

Q. How does the ECAPM approach differ from traditional applications of the CAPM?

A. Empirical tests of the CAPM have shown that low-beta securities earn returns somewhat higher than the CAPM would predict, and high-beta securities earn less than predicted. In other words, the CAPM tends to overstate the actual

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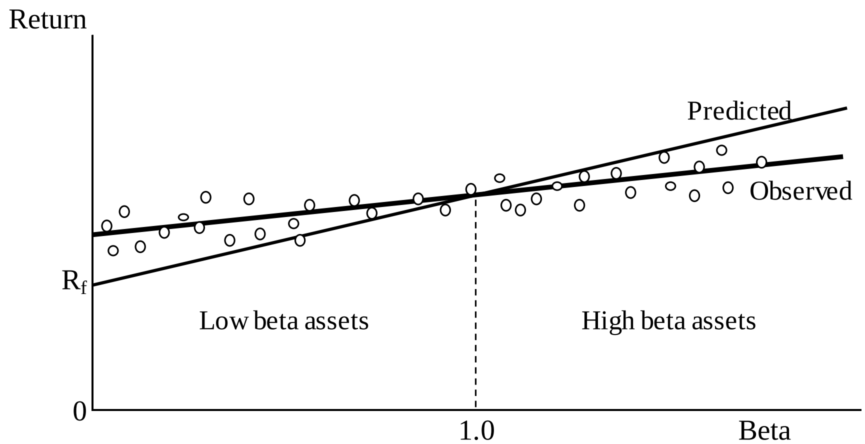
[38] Opinion No. 531-B, 150 FERC ¶ 61,165 at P 117 (2015).
[39] The midpoint results for the electric and gas groups were 8.4% and 9.8%, respectively.
[40] The midpoint results for the electric and gas groups were 8.8% and 10.0%, respectively.

sensitivity of the cost of capital to beta, with low-beta stocks tending to have higher returns and high-beta stocks tending to have lower risk returns than predicted by the CAPM. This is illustrated graphically in the figure below:

FIGURE 1
CAPM – PREDICTED VS. OBSERVED RETURNS



Because the betas of utility stocks, including those in the proxy groups, are generally less than 1.0, this implies that cost of equity estimates based on the traditional CAPM would understate the cost of equity. This empirical finding is widely reported in the finance literature, as summarized in *New Regulatory Finance*:

> As discussed in the previous section, several finance scholars have developed refined and expanded versions of the standard CAPM by relaxing the constraints imposed on the CAPM, such as dividend yield, size, and skewness effects. These enhanced CAPMs typically produce a risk-return relationship that is flatter than the CAPM prediction in keeping with the actual observed risk-return relationship. The ECAPM makes use of these empirical relationships.[41]

[41] Roger A. Morin, *New Regulatory Finance*, Pub. Util. Reports (2006) at 189.

As discussed in *New Regulatory Finance*, based on a review of the empirical evidence, the expected return on a security is related to its risk by the ECAPM, which is represented by the following formula:

$$R_j = R_f + 0.25(R_m - R_f) + 0.75[\beta_j(R_m - R_f)]$$

Like the CAPM formula presented earlier, the ECAPM represents a stock's required return as a function of the risk-free rate (R_f), plus a risk premium. In the formula above, this risk premium is composed of two parts: (1) the market risk premium (R_m - R_f) weighted by a factor of 25%, and (2) a company-specific risk premium based on the stock's relative volatility [$\beta_j(R_m - R_f)$] weighted by 75%. This ECAPM equation, and its associated weighting factors, recognizes the observed relationship between standard CAPM estimates and the cost of capital documented in the financial research, and corrects for the understated returns that would otherwise be produced for low beta stocks.

Q. Is the use of the ECAPM consistent with the use of Value Line betas?

A. Yes. Value Line beta values are adjusted for the observed tendency of beta to converge toward the mean value of 1.00 over time.[42] The purpose of this adjustment is to refine beta values determined using historical data to better match forward-looking estimates of beta, which are the relevant parameter in applying the CAPM or ECAPM models. Meanwhile, the ECAPM does not involve any adjustment to beta whatsoever. Rather, it represents a formal recognition of findings in the financial literature that the observed risk-return tradeoff illustrated in Figure 1 is flatter than predicted by the CAPM. In other

[42] *See, e.g.,* Marshall E. Blume, *Betas and Their Regression Tendencies*, Journal of Finance (Jun. 1975), pp. 785-795.

words, even if a firm's beta value were estimated with perfect precision, the CAPM would still understate the return for low-beta stocks and overstate the return for high-beta stocks. The ECAPM and the use of adjusted betas represent two separate and distinct issues in estimating returns.

Q. Have other regulators relied on the ECAPM?

A. Yes. The ECAPM approach has been relied on by the Staff of the MDPSC. For example, Staff Witness Julie McKenna noted that "the ECAPM model adjusts for the tendency of the CAPM model to underestimate returns for low Beta stocks," and concluded that, "I believe under current economic conditions that the ECAPM gives a more realistic measure of the ROE than the CAPM model does."[43] The staff of the Colorado commission has recognized that, "The ECAPM is an empirical method that attempts to enhance the CAPM analysis by flattening the risk-return relationship,"[44] and relied on the exact same standard ECAPM equation presented above.[45] The Regulatory Commission of Alaska has also relied on the ECAPM approach, noting that:

> Tesoro averaged the results it obtained from CAPM and ECAPM while at the same time providing empirical testimony that the ECAPM results are more accurate then [sic] traditional CAPM results. The reasonable investor would be aware of these empirical results. Therefore, we adjust Tesoro's recommendation to reflect only the ECAPM result.[46]

The Wyoming Office of Consumer Advocate, an independent division of the Wyoming Public Service Commission, has also relied on this same ECAPM formula in estimating the cost of equity for a natural gas utility, as

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[43] *Direct Testimony and Exhibits of Julie McKenna*, Maryland PSC Case No. 9299 (Oct. 12, 2012) at 9.
[44] Proceeding No. 13AL-0067G, *Answer Testimony and Schedules of Scott England* (July 31, 2013) at 47.
[45] *Id.* at 48.
[46] Regulatory Commission of Alaska, Order No. P-97-004(151) (Nov. 27, 2002) at 145.

have witnesses for the Office of Arkansas Attorney General.[47] More recently, the Montana Public Service Commission determined that "[t]he evidence in this proceeding has convinced the Commission that the [ECAPM] should be the primary method for estimating . . . the cost of equity" for a gas distribution utility under its jurisdiction.[48]

Q. What cost of equity estimates were indicated by the ECAPM?

A. My applications of the ECAPM were based on the same forward-looking market rate of return, risk-free rates, and beta values discussed earlier in connections with the CAPM. As shown on Exhibit AMM-11, applying the forward-looking ECAPM approach to the firms in the Electric (page 1) and Gas (page 3) Groups results in average cost of equity estimates of 9.2% and 10.6%, after incorporating the size adjustment corresponding to the market capitalization of the individual utilities.[49]

As shown on pages 2 and 4 of Exhibit AMM-11, applying the ECAPM using a forecasted Treasury bond yield for 2020-2023 implies average cost of equity estimates of 9.4% and 10.8% for the Electric and Gas Groups, respectively.[50]

F. Utility Risk Premium

Q. Briefly describe the risk premium method.

A. The risk premium method extends the risk-return tradeoff observed with bonds to estimate investors' required rate of return on common stocks. The cost of

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[47] Docket No. 30011-97-GR-17, *Pre-Filed Direct Testimony of Anthony J. Ornelas* (May 1, 2018) at 52-53; Docket No. 17-071-U, *Direct Testimony of Marlon F. Griffing, PH.D.* (May 29, 2018) at 33-35.
[48] Montana Public Service Commission, Docket No. D2017.9.80, Order No. 7575c (Sep. 26, 2018) at P 114.
[49] The midpoint results for the electric and gas groups were 9.4% and 10.5%, respectively.
[50] The midpoint results for the electric and gas groups were 9.7% and 10.7%, respectively.

equity is estimated by first determining the additional return investors require to forgo the relative safety of bonds and to bear the greater risks associated with common stock, and by then adding this equity risk premium to the current yield on bonds. Like the DCF model, the risk premium method is capital market oriented. However, unlike DCF models, which indirectly impute the cost of equity, risk premium methods directly estimate investors' required rate of return by adding an equity risk premium to observable bond yields.

Q. Is the risk premium approach a widely accepted method for estimating the cost of equity?

A. Yes. The risk premium approach is based on the fundamental risk-return principle that is central to finance, which holds that investors will require a premium in the form of a higher return in order to assume additional risk. This method is routinely referenced by the investment community and in academia and regulatory proceedings, and provides an important tool in estimating a just and reasonable ROE for BGE.

Q. How did you implement the risk premium method?

A. Estimates of equity risk premiums for utilities are based on surveys of previously authorized ROEs. Authorized ROEs presumably reflect regulatory commissions' best estimates of the cost of equity, however determined, at the time they issued their final order. Such ROEs should represent a balanced and impartial outcome that considers the need to maintain a utility's financial integrity and ability to attract capital. Moreover, allowed returns are an important consideration for investors and have the potential to influence other observable investment parameters, including credit ratings and borrowing costs. Thus, when considered in the context of a complete and rigorous analysis, this data provides a logical and frequently referenced basis for estimating equity risk premiums for regulated utilities.

Q. Is it circular to consider risk premiums based on authorized returns in assessing a just and reasonable ROE for BGE?

A. No. In establishing authorized returns, regulators typically consider the results of alternative market-based approaches, including the DCF model. Because allowed risk premiums consider objective market data (e.g., stock prices, dividends, beta, and interest rates), and are not based strictly on past actions of other regulators, this mitigates concerns over any potential for circularity.

Q. How did you calculate the equity risk premiums based on allowed returns?

A. The ROEs authorized for electric and gas utilities by regulatory commissions across the U.S. are compiled by S&P Global Market Intelligence and published in its *RRA Regulatory Focus* report. On page 3 of Exhibit AMM-12, the average yield on public utility bonds is subtracted from the average allowed ROE for electric utilities to calculate equity risk premiums for each year between 1974 and 2019.[51] As shown there, over this period these equity risk premiums for electric utilities average 3.79%, and the yields on public utility bonds average 8.10%.

With respect to gas utilities, in Exhibit AMM-13, the average yield on single-A public utility bonds is subtracted from the average allowed return for gas utilities to calculate equity risk premiums for each quarter between 1980 and 2019 Q3. As shown on page 4 of Exhibit AMM-13, over this period, these

[51] My analysis encompasses the entire period for which published data is available.

equity risk premiums for gas utilities averaged 3.61%, and the yields on single-A public utility bonds averaged 7.96%.

Q. Is there any capital market relationship that must be considered when implementing the risk premium method?

A. Yes. The magnitude of equity risk premiums is not constant and equity risk premiums tend to move inversely with interest rates. In other words, when interest rate levels are relatively high, equity risk premiums narrow, and when interest rates are relatively low, equity risk premiums widen. The implication of this inverse relationship is that the cost of equity does not move as much as, or in lockstep with, interest rates. Accordingly, for a 1% increase or decrease in interest rates, the cost of equity may only rise or fall some fraction of 1%. Therefore, when implementing the risk premium method, adjustments may be required to incorporate this inverse relationship if current interest rate levels have diverged from the average interest rate level represented in the data set.

Current bond yields are lower than those prevailing over the risk premium study periods. Given that equity risk premiums move inversely with interest rates, these lower bond yields also imply an increase in the equity risk premium that investors require to accept the higher uncertainties associated with an investment in utility common stocks versus bonds. In other words, higher required equity risk premiums offset the impact of declining interest rates on the ROE.

Q. Has this inverse relationship been documented in the financial research?

A. Yes. There is considerable empirical evidence that when interest rates are relatively high, equity risk premiums narrow, and when interest rates are relatively low, equity risk premiums are greater. This inverse relationship between equity risk premiums and interest rates has been widely reported in the financial literature. As summarized by *New Regulatory Finance*:

> Published studies by Brigham, Shome, and Vinson (1985), Harris (1986), Harris and Marston (1992, 1993), Carleton, Chambers, and Lakonishok (1983), Morin (2005), and McShane (2005), and others demonstrate that, beginning in 1980, risk premiums varied inversely with the level of interest rates – rising when rates fell and declining when rates rose.[52]

Other regulators have also recognized that, while the cost of equity trends in the same direction as interest rates, these variables do not move in lock-step.[53] This relationship is illustrated in the figures on page 4 of Exhibit AMM-12 and page 5 of Exhibit AMM-13.

Q. What ROE is implied by the risk premium method using surveys of allowed returns?

A. Based on the regression output between the interest rates and equity risk premiums displayed on page 4 of Exhibit AMM-12, the equity risk premium for electric utilities increases by approximately 43 basis points for each percentage point drop in the yield on average public utility bonds. For gas utilities (page 5 of Exhibit AMM-13), the increase is approximately 47 basis points. As illustrated on page 1 of Exhibit AMM-12 with an average yield on public utility bonds for the six-months ending December 2019 of 3.5%, this implies a current equity risk premium of 5.78% for electric utilities. Adding this equity risk premium to the average yield on triple-B utility bonds implies a

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[52] Roger A. Morin, *New Regulatory Finance*, Pub. Util. Reports (2006) at 128.

[53] *See, e.g.*, California Public Utilities Commission, Decision 08-05-035 (May 29, 2008); Entergy Mississippi Formula Rate Plan FRP-6, https://www.entergy-mississippi.com/userfiles/content/price/tariffs/eml_frp.pdf (last visited Apr. 15, 2019); *Martha Coakley et al.*, 147 FERC ¶ 61,234 at P 147 (2014).

current ROE of 9.56%. For gas utilities, as shown on page 1 of Exhibit AMM-13, the utility risk premium model implies a current ROE of 9.17%.

Q. What is the result of the risk premium approach after incorporating forecasted bond yields?

A. As shown on page 2 of Exhibits AMM-12 and AMM-13, incorporating a forecasted yield for 2020-2023 and adjusting for changes in interest rates since the study period implies an equity risk premium of 5.25% for electric utilities and 5.20% for gas utilities, which is less than current equity risk premiums. These lower equity risk premiums are consistent with the inverse relationship I described above. Adding this equity risk premium to the implied average yield on triple-B and single-A public utility bonds for 2020-2023 of 4.63% and 4.58%, respectively, results in an implied cost of equity of 10.23% (electric) and 9.78% (gas).

G. Expected Earnings Approach

Q. What other analyses do you conduct to estimate the ROE?

A. I also evaluate the ROE using the expected earnings method. Reference to rates of return available from alternative investments of comparable risk can provide an important benchmark in assessing the return necessary to assure confidence in the financial integrity of a firm and its ability to attract capital. This expected earnings approach is consistent with the economic underpinnings for a just and reasonable rate of return established by the U.S. Supreme Court in *Bluefield* and *Hope*.[54] Moreover, it avoids the complexities

[54] *Bluefield Water Works & Improvement Co. v. Pub. Serv. Comm'n*, 262 U.S. 679 (1923); *Fed. Power Comm'n v. Hope Natural Gas Co.*, 320 U.S. 591 (1944).

and limitations of capital market methods and instead focuses on the returns earned on book equity, which are readily available to investors.

Q. What economic premise underlies the expected earnings approach?

A. The simple, but powerful concept underlying the expected earnings approach is that investors compare each investment alternative with the next best opportunity. If the utility is unable to offer a return similar to that available from other opportunities of comparable risk, investors will become unwilling to supply the capital on reasonable terms. For existing investors, denying the utility an opportunity to earn what is available from other similar risk alternatives prevents them from earning their opportunity cost of capital. Such an outcome would violate the *Hope* and *Bluefield* standards and undermine the utility's access to capital on reasonable terms.

Q. How is the expected earnings approach typically implemented?

A. The traditional comparable earnings test identifies a group of companies that are believed to be comparable in risk to the utility. The actual earnings of those companies on the book value of their investment are then compared to the allowed return of the utility. While the traditional comparable earnings test is implemented using historical data taken from the accounting records, it is also common to use projections of returns on book investment, such as those published by recognized investment advisory publications (*e.g.*, Value Line). Because these returns on book value equity are analogous to the allowed return on a utility's rate base, this measure of opportunity costs results in a direct, "apples to apples" comparison.

Moreover, regulators do not set the returns that investors earn in the capital markets, which are a function of dividend payments and fluctuations in common stock prices - both of which are outside their control. Regulators can only establish the allowed ROE, which is applied to the book value of a utility's investment in rate base, as determined from its accounting records. This is analogous to the expected earnings approach, which measures the return that investors expect the utility to earn on book value. As a result, the expected earnings approach provides a meaningful guide to ensure that the allowed ROE is similar to what other utilities of comparable risk will earn on invested capital. This expected earnings test does not require theoretical models to indirectly infer investors' perceptions from stock prices or other market data. As long as the proxy companies are similar in risk, their expected earned returns on invested capital provide a direct benchmark for investors' opportunity costs that is independent of fluctuating stock prices, market-to-book ratios, debates over DCF growth rates, or the limitations inherent in any theoretical model of investor behavior.

Q. What ROEs are indicated for BGE based on the expected earnings approach?

A. For the firms in the proxy groups, the year-end returns on common equity projected by Value Line over its forecast horizon are shown on Exhibit AMM-14. As I explained earlier in my discussion of the br+sv growth rates used in applying the DCF model, Value Line's returns on common equity are calculated using year-end equity balances, which understates the average return earned over the year.[55] Accordingly, these year-end values were

[55] For example, to compute the annual return on a passbook savings account with a beginning balance of $1,000 and an ending balance of $5,000, the interest income would be divided by the average balance of $3,000. Using the $5,000 balance at the end of the year would understate the actual return.

converted to average returns using the same adjustment factor discussed earlier and developed on Exhibits AMM-6 and AMM-8. As shown on Exhibit AMM-14, Value Line's projections suggest an average ROE of 10.7% for both the Electric Group (page 1) and Gas Group (page 2).[56]

IV. NON-UTILITY BENCHMARK

Q. What is the purpose of this section of your testimony?

A. This section presents the results of my DCF analysis applied to a group of low-risk firms in the competitive sector, which I refer to as the "Non-Utility Group." This analysis was not relied on to arrive at my recommended ROE range of reasonableness; however, it is my opinion that this is a relevant consideration in evaluating just and reasonable ROEs for the Company's electric and gas utility operations.

Q. Do utilities have to compete with non-regulated firms for capital?

A. Yes. The cost of capital is an opportunity cost based on the returns that investors could realize by putting their money in other alternatives. Clearly, the total capital invested in utility stocks is only the tip of the iceberg of total common stock investment, and there is a plethora of other enterprises available to investors beyond those in the utility industry. Utilities must compete for capital, not just against firms in their own industry, but with other investment opportunities of comparable risk. Indeed, modern portfolio theory is built on the assumption that rational investors will hold a diverse portfolio of stocks, not just companies in a single industry.

[56] The midpoint results for the electric and gas groups were 10.4% and 11.1%, respectively.

Q. Is it consistent with the *Bluefield* and *Hope* cases to consider investors' required ROE for non-utility companies?

A. Yes. The cost of equity capital in the competitive sector of the economy form the very underpinning for utility ROEs because regulation purports to serve as a substitute for the actions of competitive markets. The Supreme Court has recognized that it is the degree of risk, not the nature of the business, which is relevant in evaluating an allowed ROE for a utility. The *Bluefield* case refers to "business undertakings attended with comparable risks and uncertainties." It does not restrict consideration to other utilities. Similarly, the *Hope* case states:

> By that standard the return to the equity owner should be commensurate with returns on investments in other enterprises having corresponding risks.[57]

As in the *Bluefield* decision, there is nothing to restrict "other enterprises" solely to the utility industry.

Q. Does consideration of the results for the Non-Utility Group improve the reliability of DCF results?

A. Yes. The estimates of growth from the DCF model depend on analysts' forecasts. It is possible for utility growth rates to be distorted by short-term trends in the industry, or by the industry falling into favor or disfavor by analysts. Such distortions could result in biased DCF estimates for utilities. Because the Non-Utility Group includes low risk companies from more than one industry, it helps to insulate against any possible distortion that may be present in results for a particular sector.

[57] *Federal Power Comm'n v. Hope Natural Gas Co*., 320 U.S. 391 (1944) ("*Hope*").

Q. What criteria did you apply to develop the Non-Utility Group?

A. My comparable risk proxy group was composed of those United States companies followed by Value Line that:

1) pay common dividends;
2) have a Safety Rank of "1" or "2";
3) have a Financial Strength Rating of "B++" or greater;
4) have a beta of 0.80 or less; and
5) have investment grade credit ratings from S&P and Moody's.

Q. How do the overall risks of this Non-Utility Group compare with the Electric and Gas Groups?

A. Table 7 compares the Non-Utility Group with the proxy groups across the measures of investment risk discussed earlier:

TABLE 7
COMPARISON OF RISK INDICATORS

	Credit Ratings		Value Line		
			Safety	Financial	
Proxy Group	**S&P**	**Moody's**	**Rank**	**Strength**	**Beta**
Non-Utility Group	A-	A3	1	A+	0.72
Electric Group	BBB+	Baa1	2	A	0.58
Gas Group	A-	A3	2	A	0.66
BGE	A-	A3	2	B++	0.65

Note: BGE's Value Line data is for its parent, Exelon Corp.

As shown above, considered together the risk indicators for the Non-Utility Group generally suggest comparable or less risk than for the proxy groups and BGE.

The companies that make up the Non-Utility Group are representative of the pinnacle of corporate America. These firms, which include household names such as Coca-Cola, Kellogg, Procter & Gamble, and Walmart, have long corporate histories, well-established track records, and conservative risk profiles. Many of these companies pay dividends on a par with utilities, with the average dividend yield for the group at 2.7%. Moreover, because of their significance and name recognition, these companies receive intense scrutiny by the investment community, which increases confidence that published growth estimates are representative of the consensus expectations reflected in common stock prices.

Q. What were the results of your DCF analysis for the Non-Utility Group?

A. I applied the DCF model to the Non-Utility Group using the same analysts' EPS growth projections described earlier for the proxy groups. The results of my DCF analysis for the Non-Utility Group are presented in Exhibit AMM-16. As summarized in Table 8, below, after eliminating illogical values, application of the constant growth DCF model resulted in the following cost of equity estimates:

TABLE 8
DCF RESULTS – NON-UTILITY GROUP

	Cost of Equity	
Growth Rate	**Average**	**Midpoint**
Value Line	10.7%	10.9%
IBES	9.4%	10.6%
Zacks	9.3%	10.2%

As discussed earlier, reference to the Non-Utility Group is consistent with established regulatory principles. Required returns for utilities should be in line with those of non-utility firms of comparable risk operating under the constraints of free competition. Because the actual cost of equity is unobservable, and DCF results inherently incorporate a degree of error, cost of equity estimates for the Non-Utility Group provide an important benchmark in evaluating a just and reasonable ROE for BGE.

Q. The MDPSC elected to give "little consideration" to your non-utility DCF results in Case No. 9484.[58] What is your response?

A. In Order No. 88975, the MDPSC referenced its disapproval of comparisons between regulated and non-regulated companies based on its findings in a 2011 order in Case No. 9230.[59] While the underlying conceptual principles are the same, there are significant differences between my DCF analysis for the Non-Utility Group and the study presented by BGE's witness in Case No. 9230, Dr. William Avera. Whereas Dr. Avera's group consisted of a broad sample of 69 companies,[60] the more stringent screening criteria used in my analysis limited the group to only 38 firms with conservative risk profiles.

Further, the MDPSC expressed concern that, based on the results of Dr. Avera's study, "there is about a 200 basis point difference between the Company's DCF utility and non-utility results."[61] As indicated in Table 8, this observation does not apply to my evidence. While the results for the Non-Utility Group suggest a cost of equity at the upper end of the DCF estimates for my Electric and Gas Groups, they fall within the range of DCF values for these proxy groups of utilities. Thus, while I do not rely on the Non-Utility Group to establish my ROE recommendations in this case, I believe it provides an important benchmark to ensure that the end-result of the MDPSC's deliberations meets the regulatory standards established by the United States Supreme Court in its *Bluefield* and *Hope* decisions.

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[58] Order No. 88975, Case No. 9484 (Jan. 4, 2019) at 63-64.
[59] *Id.* at 64 (citing Order No. 83907, Case No. 9230 (Mar. 9, 2011)).
[60] Order No. 83907, Case No. 9230 (Mar. 9, 2011) at 49.
[61] *Id.* at 64.

V. RETURN ON EQUITY FOR BGE

Q. What is the purpose of this section?

A. This section presents an overview of the relationship between ROE and preservation of a utility's financial integrity and the ability to attract capital under reasonable terms, and presents my conclusions regarding the just and reasonable ROE applicable to BGE's utility operations. Finally, I discuss the reasonableness of the Company's capital structure request in this case.

A. Importance of Financial Strength

Q. What is the role of the ROE in setting a utility's rates?

A. The ROE is the cost of attracting and retaining common equity investment in the utility's physical plant and assets. This investment is necessary to finance the asset base needed to provide utility service. Investors commit capital only if they expect to earn a return on their investment commensurate with returns available from alternative investments with comparable risks. Moreover, a just and reasonable ROE is integral in meeting sound regulatory economics and the standards set forth by the U.S. Supreme Court. The *Bluefield* case set the standard against which just and reasonable rates are measured:

> A public utility is entitled to such rates as will permit it to earn a return on the value of the property which it employs for the convenience of the public equal to that generally being made at the same time and in the same general part of the country on investments in other business undertakings which are attended by corresponding risks and uncertainties. . . . The return should be reasonable, sufficient to assure confidence in the financial soundness of the utility, and should be adequate, under efficient and economical management, to maintain and support its credit and enable it to raise money necessary for the proper discharge of its public duties.[62]

[62] *Bluefield Water Works & Improvement Co. v. Pub. Serv. Comm'n*, 262 U.S. 679 (1923).

The *Hope* case expanded on the guidelines as to a reasonable ROE, reemphasizing its findings in *Bluefield* and establishing that the rate-setting process must produce an end-result that allows the utility a reasonable opportunity to cover its capital costs. The Court stated:

> From the investor or company point of view it is important that there be enough revenue not only for operating expenses but also for the capital costs of the business. These include service on the debt and dividends on the stock. . . . By that standard, the return to the equity owner should be commensurate with returns on investments in other enterprises having corresponding risks. That return, moreover, should be sufficient to assure confidence in the financial integrity of the enterprise, so as to maintain credit and attract capital.[63]

In summary, the Supreme Court's findings in *Hope* and *Bluefield* established that a just and reasonable ROE must be sufficient to: 1) fairly compensate the utility's investors, 2) enable the utility to offer a return adequate to attract new capital on reasonable terms, and 3) maintain the utility's financial integrity. These standards should allow the utility to fulfill its obligation to provide reliable service while meeting the needs of customers through necessary system replacement and expansion, but the Supreme Court's requirements can only be met if the utility has a reasonable opportunity to actually earn its allowed ROE.

While the *Hope* and *Bluefield* decisions did not establish a particular method to be followed in fixing rates (or in determining the allowed ROE),[64] these and subsequent cases enshrined the importance of an end result that meets the opportunity cost standard of finance. Under this doctrine, the

[63] *Fed. Power Comm'n v. Hope Natural Gas Co.*, 320 U.S. 591 (1944).
[64] *Id.* at 602 (*finding,* "the Commission was not bound to the use of any single formula or combination of formulae in determining rates." and, "[I]t is not theory but the impact of the rate order which counts.")

required return is established by investors in the capital markets based on expected returns available from comparable risk investments. Coupled with modern financial theory, which has led to the development of formal risk-return models (e.g., DCF and CAPM), practical application of the *Bluefield* and *Hope* standards involves the independent, case-by-case consideration of capital market data in order to evaluate an ROE that will produce a balanced and fair end result for investors and customers.

Q. Throughout your testimony you refer repeatedly to the concepts of "financial strength," "financial integrity," and "financial flexibility." ~~w~~Would you briefly describe what you mean by these terms?

A. These terms are generally synonymous and refer to the utility's ability to attract and retain the capital that is necessary to provide service at reasonable cost, consistent with the Supreme Court standards. BGE's plans call for a continuation of capital investments to preserve and enhance service reliability for its customers. The Company must generate adequate cash flow from operations to fund these requirements and for repayment of maturing debt, together with access to capital from external sources under reasonable terms, on a sustainable basis.

Rating agencies and potential debt investors tend to place significant emphasis on maintaining strong financial metrics and credit ratings that support access to debt capital markets under reasonable terms. This emphasis on financial metrics and credit ratings is shared by equity investors who also focus on cash flows, capital structure and liquidity, much like debt investors. Investors understand the important role that a supportive regulatory environment plays in establishing a sound financial profile that will permit the utility access to debt and equity capital markets on reasonable terms in both favorable financial markets and during times of potential disruption and crisis.

Q. What part does regulation play in ensuring that BGE has access to capital under reasonable terms and on a sustainable basis?

A. Regulatory signals are a major driver of investors' risk assessment for utilities. Investors recognize that constructive regulation is a key ingredient in supporting utility credit ratings and financial integrity. Security analysts study commission orders and regulatory policy statements to advise investors about where to put their money. As Moody's noted, "the regulatory environment is the most important driver of our outlook because it sets the pace for cost recovery."[65] Similarly, S&P observed that, "Regulatory advantage is the most heavily weighted factor when S&P Global Ratings analyzes a regulated utility's business risk profile."[66] Value Line summarizes these sentiments:

> As we often point out, the most important factor in any utility's success, whether it provides electricity, gas, or water, is the regulatory climate in which it operates. Harsh regulatory conditions can make it nearly impossible for the best run utilities to earn a reasonable return on their investment.[67]

In addition, the ROE set by regulators impacts investor confidence in not only the jurisdictional utility, but also in the ultimate parent company that is the entity that actually issues common stock.

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[65] Moody's Investors Service, *Regulation Will Keep Cash Flow Stable As Major Tax Break Ends*, Industry Outlook (Feb. 19, 2014).

[66] S&P Global Ratings, *Assessing U.S. Investors-Owned Utility Regulatory Environments*, RatingsExpress (Aug. 10, 2016).

[67] Value Line Investment Survey, *Water Utility Industry* (Jan. 13, 2017) at p. 1780.

Q. Do customers benefit by enhancing the utility's financial flexibility?

A. Yes. Providing an ROE that is sufficient to maintain the Company's ability to attract capital under reasonable terms, even in times of financial and market stress, is not only consistent with the economic requirements embodied in the U.S. Supreme Court's *Hope* and *Bluefield* decisions, it is also in customers' best interests. Customers enjoy the benefits that come from ensuring that the utility has the financial wherewithal to take whatever actions are required to ensure safe and reliable service.

B. Conclusions and Recommendations

Q. What are your findings regarding the just and reasonable ROE for BGE?

A. Considering the economic requirements necessary to support continuous access to capital under reasonable terms and the results of my two separate analyses, I recommend the same 9.9% ROE for both BGE's electric and gas utility operations, which is consistent with the case-specific evidence presented in my testimony. The bases for my conclusion are summarized below:

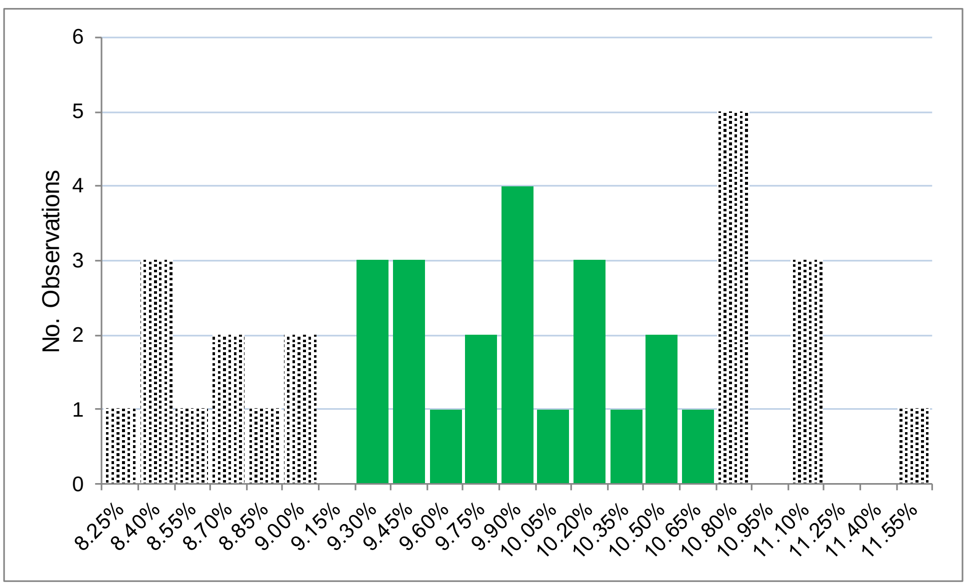
- In order to reflect the risks and prospects associated with BGE's utility business, I conducted separate analyses for a thirty-two company Electric Group and a nine firm Gas Group.
- Because investors' required return on equity is unobservable and no single method should be viewed in isolation, I applied the DCF, CAPM, ECAPM, and risk premium methods to estimate a just and reasonable ROE for BGE, as well as referencing the expected earnings approach.
- Based on the results of these analyses, and giving less weight to extremes at the high and low ends of the range, I conclude that the cost of equity for a regulated electric and gas utility is in the 9.2% to 10.6% range.
- My ROE recommendations for both BGE's electric and gas operations is the midpoint of this range, or 9.9%.

- The electric and gas utilities in my proxy groups operate under a wide variety of regulatory mechanisms, including decoupling and infrastructure cost trackers. Similarly, the vast majority of firms in my proxy groups operate in regulatory jurisdictions that allow for future test years, formula rates, and MRPs. As a result, the mitigation in risks associated with the Company's regulatory mechanisms—including the proposed pilot MRP—is already reflected in the results of my analyses and, as a result, no further adjustment is justified or warranted.

Q. How does your recommended ROE range compare to the distribution of cost of equity estimates resulting from your analyses?

A. The results of my analyses are presented on Schedule AMM-2, and summarized in the histogram shown in Figure 2, below:

FIGURE 2
DISTRIBUTION OF COST OF EQUITY ESTIMATES



As illustrated above, my recommended ROE range of 9.2% to 10.6% captures the bulk of the individual cost of equity estimates making up the middle of the distribution, with my 9.9% ROE recommendation being consistent with the center of the underlying frequency table.

Q. Based on the case-specific evidence developed in your testimony, is there a basis to differentiate between the ROE recommendations for BGE's electric and gas utility operations?

A. No. While the results of my analyses could arguably support a higher ROE for BGE's gas utility operations, with the ROE for electric utility operations being somewhat lower, I do not believe such an approach is warranted in this case. First, as indicated earlier, the actual return that investors require is not directly observable. Different methodologies have been developed to estimate investors' required return on capital, but all such methodologies are simply theoretical tools and generally produce a range of estimates based on different assumptions and inputs. In light of these considerations, distinctions between the results for the Electric and Gas Groups are more likely to reflect the "noise" inherent in applying imprecise models, rather than fundamental differences in investors' required rates of return.

This conclusion is supported by reference to authorized ROEs. Contradicting the current results produced by the methodologies presented in my testimony, ROEs allowed by state regulatory agencies have traditionally been higher for electric utilities than for gas utilities.[68] Moreover, the relative investment risks of my two proxy groups also contradict the notion that the allowed ROE for electric utilities would fall below that of their counterparts in the natural gas distribution industry. On balance, a comparison of the risk indicators discussed earlier and summarized in Table 1 suggests that investors would view the Electric Group as having somewhat greater risks than the Gas

[68] Based on data reported by S&P Global Market Intelligence, electric ROEs have exceeded those authorized for gas utilities by approximately 12 basis points since 1990. S&P Global Market Intelligence, *Major Rate Case Decisions — January-September 2019*, RRA Regulatory Focus (Oct. 17, 2019).

Group, which would support a higher (not a lower) ROE. Taken together, I conclude that this evidence supports a single ROE recommendation for BGE's electric and gas operations at this time.

Q. Does BGE's request for an MRP have implications in the evaluation of a fair ROE for the Company?

A. Yes. While bond yields decreased during 2019, as documented in my testimony, widely recognized independent forecasting services, along with the members of the Federal Open Market Committee, generally expect interest rates to rise over the period covered by the MRP. This indicates that long-term capital costs—including the cost of equity—will move higher over the duration of the MRP. Given that the ROE will be fixed for the duration of the MRP, these expectations for higher capital costs emphasize the need to consider the impact of projected bond yields in evaluating the results of the CAPM, ECAPM, and risk premium methods, and in establishing a fair ROE under the MRP.

Q. What did the DCF results for your select group of non-utility firms indicate with respect to your evaluation?

A. As shown on page 3 of Exhibit AMM-16, average DCF estimates for a low-risk group of firms in the competitive sector of the economy ranged from 9.3 to 10.7%. While I did not base my recommendations on these results, they confirm that an ROE of 9.9% falls in a reasonable range to maintain BGE's financial integrity, provide a return commensurate with investments of comparable risk, and support the Company's ability to attract capital.

Q. Does your 9.9% ROE recommendation provide for or recognize any increment of return for other factors?

A. No it does not. My 9.9% recommended ROE does not explicitly incorporate any allowance for exemplary performance or efficient and economic management, as discussed in the testimony of BGE's witness.[69] A performance adder to recognize such factors should be added to my fair rate of return on equity for BGE.

Q. In evaluating the fair rate of return for BGE, is it appropriate to consider a performance adder to recognize and encourage exemplary management?

A. Yes. As discussed in greater detail in the testimony of BGE Witness David M. Vahos, the Company has distinguished itself in numerous measures of operating efficiency and effectiveness while achieving outstanding customer satisfaction results. As a result, consumers and the service area economy have benefited from a climate of efficient operations and excellent customer service. Awarding an increment of return above the cost of equity, such as the 35 basis points proposed by Mr. Vahos, recognizes that BGE's superior management continues to be instrumental in achieving these results. Moreover, including a performance adder for exemplary management above the minimum fair rate of return required by investors is entirely consistent with fostering an environment in which customers are assured reliable service at reasonable rates and stockholders are fairly treated.

[69] Nor does it consider issuance costs associated with the sale of common stock. While such flotation costs are legitimate business expenses that would imply an upward adjustment to the cost of equity, in deference to the MDPSC’s prior findings on this issue, I did not include an adjustment to my recommended ROE to account for them. This treatment further supports the reasonableness of my ROE recommendation.

Q. Is a performance adder consistent with the economic rationale underlying traditional rate of return / rate base regulation?

A. Yes. The goal of regulation is to achieve the same result that would prevail in a competitive market, where the actions of buyers and sellers serve to effectively regulate price and quality of service. In competitive markets, high-performing companies that combine outstanding service with reasonable prices are able to benefit from efficient operations by realizing higher rates of return for their shareholders. However, traditional regulation departs from this competitive market ideal when the prices charged by well-managed, efficient utilities that improve operations and customer service through productivity and other programs are lowered during rate proceedings, thereby lessening the incentive for exceptional performance. Similarly, under the competitive market paradigm that serves as the foundation for regulation, the expected ROE is a key economic signal to management and investors. But establishing an ROE based on broad proxy groups of other utilities denies the utility the economic benefit of superior customer service that would accrue to unregulated firms.

Consistent with this logic, the MDPSC observed that "[i]n a competitive market, for which regulation is intended to be a substitute, [a utility's] continuing poor reliability would cause it to lose business and profits to its competitors," and that the allowed ROE should consider a utility's standard of reliability and service quality.[70] The MDPSC went on to conclude that it would not allow "a monopoly distribution company, to reap growing profits while it provides subpar service to customers."[71] The corollary to the MDPSC's logic also warrants consideration of an upward adjustment in this proceeding in

[70] Case No. 9286, Order No. 85028 (Jul. 20, 2012) at 108.
[71] *Id.* at 109.

order to recognize BGE's exemplary performance. As Mr. Vahos discusses, the Company has provided customer benefits in the form of efficient operations and superior customer satisfaction. In keeping with these results, it is consistent with sound regulatory policy to allow BGE the opportunity to earn an ROE from the upper end of my recommended range.

Q. What rate of return on equity is implied for BGE after incorporating an incentive for effective management?

A. Adding the 35 basis-point increment proposed by Mr. Vahos to my 9.9% recommendation results in a fair rate of return on equity of 10.25%. This fair ROE falls at the midpoint of the upper end of my recommended range of 9.2% to 10.6%.

C. Capital Structure

Q. Is an evaluation of the capital structure maintained by a utility relevant in assessing its return on equity?

A. Yes. Other things equal, a higher debt ratio and lower common equity ratio, translates into increased financial risk for all investors. A greater amount of debt means more investors have a senior claim on available cash flow, thereby reducing the certainty that each will receive their contractual payments. This increases the risks to which lenders are exposed, and they require correspondingly higher rates of interest. From common shareholders' standpoint, a higher debt ratio means that there are proportionately more investors ahead of them, thereby increasing the uncertainty as to the amount of cash flow that will remain.

Q. What common equity ratio is implicit in BGE's capital structure?

A. BGE's capital structure is presented in the testimony of BGE Witness David M. Vahos. As summarized in his testimony, the common equity ratio applicable to the historic test year is 52.8%, which is generally comparable with equity ratios implicit in the rates of return authorized by the MDPSC in prior BGE rate cases.

Q. How does this compare to the average equity ratios maintained by the utilities in the proxy groups?

A. Page 1 of Exhibit AMM-17 presents the sources of long-term capital (long-term debt and common equity) used by the publicly traded firms in the Electric Group, while page 2 displays similar data for the companies in the Gas Group. As shown on these pages, for the most recent historical period, common equity ratios for the Electric Group ranged between 26.9% and 72.8% and averaged 47.2%, or 47.0% after eliminating the highest and lowest values. For the Gas Group, common equity contributed 51.2% of total capital at fiscal year-end 2019, or 51.6% after excluding the highest and lowest values. Common equity ratios for the utilities in the Gas Group ranged between 37.5% and 62.0%.

Q. How do these historical capitalization ratios compare with investors' forward-looking expectations?

A. As shown on Exhibit AMM-17, Value Line expects an average common equity ratio of 48.0% for the Electric Group (page 1) and 56.3% for the Gas Group (page 2) over its three-to-five year forecast horizon. After excluding the highest and lowest values, projected equity ratios ranged from 33.0% to 58.5% (electric) and 47.0% to 62.0% (gas).[72]

Q. What other factors do investors consider in their assessment of a company's capital structure?

A. Utilities, including BGE, are facing significant capital investment plans. Coupled with the potential for turmoil in capital markets, this warrants a stronger balance sheet to deal with an uncertain environment. A conservative financial profile, in the form of a reasonable common equity ratio, is consistent with the need to accommodate these uncertainties and maintain the continuous access to capital under reasonable terms that is required to fund operations and necessary system investment, even during times of adverse capital market conditions.

Q. What does this evidence suggest with respect to BGE's proposed capital structure?

A. BGE's ratemaking capital structure is consistent with the range of industry benchmarks reflected in the average capital structure ratios maintained by the proxy groups. The capitalization employed by the Company reflects the need to address the funding of ongoing capital expenditures, and support BGE's financial integrity and access to capital on reasonable terms. This mix of external financing is reasonable in light of investors' future expectations for the Electric and Gas Groups over the period covered by the pilot MRP and the importance of maintaining the Company's financial strength. Based on this evidence, I conclude that the Company's ratemaking capital structure

[72] Excluding the highest and lowest values, Value Line's projections imply average equity ratios of 48.1% and 57.1% for the proxy groups of electric and gas utilities, respectively.

represents a reasonable mix of capital sources from which to calculate the BGE's overall rate of return.

Q. Does this conclude your direct testimony?

A. Yes, it does.

EXHIBIT AMM-1

QUALIFICATIONS OF ADRIEN M. MCKENZIE

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. My name is Adrien M. McKenzie. My business address is 3907 Red River St., Austin, Texas 78751.

Q. PLEASE STATE YOUR OCCUPATION.

A. I am a principal in FINCAP, Inc., a firm engaged primarily in financial, economic, and policy consulting in the field of public utility regulation.

Q. PLEASE DESCRIBE YOUR QUALIFICATIONS AND EXPERIENCE.

A. I received B.A. and M.B.A. degrees with a major in finance from The University of Texas at Austin, and hold the Chartered Financial Analyst (CFA®) designation. Since joining FINCAP in 1984, I have participated in consulting assignments involving a broad range of economic and financial issues, including cost of capital, cost of service, rate design, economic damages, and business valuation. I have extensive experience in economic and financial analysis for regulated industries, and in preparing and supporting expert witness testimony before courts, regulatory agencies, and legislative committees throughout the U.S. and Canada. I have personally sponsored direct and rebuttal testimony in over 130 proceedings filed with the Federal Energy Regulatory Commission ("FERC") and regulatory agencies in Alaska, Arkansas, Colorado, Hawaii, Idaho, Indiana, Iowa, Kansas, Kentucky, Maryland, Michigan, Montana, Nebraska, New Mexico, Ohio, Oklahoma, Oregon, South Dakota, Texas, Virginia, Washington, West Virginia, and Wyoming. My testimony addressed the establishment of risk-comparable proxy groups, the application of alternative quantitative methods, and the consideration of regulatory standards and policy objectives in establishing a fair rate of return on equity for regulated electric, gas, and water utility operations. In connection with these assignments, my responsibilities have included critically evaluating the positions of other parties and preparation of rebuttal testimony, representing clients in settlement negotiations and hearings, and assisting in the preparation of legal briefs.

FINCAP was formed in 1979 as an economic and financial consulting firm serving clients in both the regulated and competitive sectors. FINCAP conducts assignments ranging from broad qualitative analyses and policy consulting to technical analyses and research. The firm's experience is in the areas of public utilities, valuation of closely-held businesses, and economic evaluations (e.g., damage and cost/benefit analyses). Prior to joining FINCAP, I was employed by an oil and gas firm and was responsible for operations and accounting. I am a member of the CFA Institute, the CFA Society of Austin. A resume containing the details of my qualifications and experience is attached below.

ADRIEN M. McKENZIE

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Economic and Financial Counsel

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Summary of Qualifications

Adrien McKenzie has an MBA in finance from the University of Texas at Austin and holds the Chartered Financial Analyst (CFA®) designation. He has over 30 years of experience in economic and financial analysis for regulated industries, and in preparing and supporting expert witness testimony before courts, regulatory agencies, and legislative committees throughout the U.S. and Canada. Assignments have included a broad range of economic and financial issues, including cost of capital, cost of service, rate design, economic damages, and business valuation.

Employment

President FINCAP, Inc. (June 1984 to June 1987) (April 1988 to present)	Economic consulting firm specializing in regulated industries and valuation of closely-held businesses. Assignments have involved electric, gas, telecommunication, and water/sewer utilities, with clients including utilities, consumer groups, municipalities, regulatory agencies, and cogenerators. Areas of participation have included rate of return, revenue requirements, rate design, tariff analysis, avoided cost, forecasting, and negotiations. Develop cost of capital analyses using alternative market models for electric, gas, and telephone utilities. Prepare pre-filed direct and rebuttal testimony, participate in settlement negotiations, respond to interrogatories, evaluate opposition testimony, and assist in the areas of cross-examination and the preparations of legal briefs. Other assignments have involved preparation of technical reports, valuations, estimation of damages, industry studies, and various economic analyses in support of litigation.
Manager, McKenzie Energy Company (Jan. 1981 to May. 1984)	Responsible for operations and accounting for firm engaged in the management of working interests in oil and gas properties.

Education

M.B.A., Finance, University of Texas at Austin (Sep. 1982 to May. 1984)	Program included coursework in corporate finance, accounting, financial modeling, and statistics. Received Dean's Award for Academic Excellence and Good Neighbor Scholarship. Professional Report: *The Impact of Construction Expenditures on Investor-Owned Electric Utilities*
B.B.A., Finance, University of Texas at Austin (Jan. 1981 to May 1982)	Electives included capital market theory, portfolio management, and international economics and finance. Elected to Beta Gamma Sigma business honor society. Dean's List 1981-1982.
Simon Fraser University, Vancouver, Canada and University of Hawaii at Manoa, Honolulu, Hawaii (Jan. 1979 to Dec 1980)	Coursework in accounting, finance, economics, and liberal arts.

Professional Associations

Received Chartered Financial Analyst (CFA®) designation in 1990.

Member – CFA Institute.

Bibliography

“A Profile of State Regulatory Commissions,” A Special Report by the Electricity Consumers Resource Council (ELCON), Summer 1991.

“The Impact of Regulatory Climate on Utility Capital Costs: An Alternative Test,” with Bruce H. Fairchild, *Public Utilities Fortnightly* (May 25, 1989).

Presentations

“ROE at FERC: Issues and Methods,” *Expert Briefing on Parallels in ROE Issues between AER, ERA, and FERC*, Jones Day (Sydney, Melbourne, and Perth, Australia) (April 15, 2014).

Cost of Capital Working Group eforum, Edison Electric Institute (April 24, 2012).

“Cost-of-Service Studies and Rate Design,” General Management of Electric Utilities (A Training Program for Electric Utility Managers from Developing Countries), Austin, Texas (October 1989 and November 1990 and 1991).

Representative Assignments

Mr. McKenzie has prepared and supported prefiled testimony submitted in over 250 regulatory proceedings. In addition to filings before regulators in over thirty state jurisdictions, Mr. McKenzie has considerable expertise in preparing expert analyses and testimony before the Federal Energy Regulatory Commission ("FERC") on the issue of rate of return on equity ("ROE"), and has broad experience in applying and evaluating the results of quantitative methods to estimate a fair ROE, including discounted cash flow approaches, the Capital Asset Pricing Model, risk premium methods, and other quantitative benchmarks. Other representative assignments have included developing cost of service and cost allocation studies, the application of econometric models to analyze the impact of anti-competitive behavior and estimate lost profits; development of explanatory models for nuclear plant capital costs in connection with prudency reviews; and the analysis of avoided cost pricing for cogenerated power.

ROE ANALYSES **Exhibit AMM-2**

SUMMARY OF RESULTS

	Electric Group		Gas Group	
Method	**Average**	**Midpoint**	**Average**	**Midpoint**
DCF				
Value Line	9.3%	10.3%	11.0%	11.5%
IBES	8.7%	9.7%	8.4%	8.9%
Zacks	8.7%	8.9%	9.4%	10.1%
Internal br + sv	8.4%	9.9%	11.0%	11.1%
CAPM				
Current Bond Yield	8.2%	8.4%	9.8%	9.8%
Projected Bond Yield	8.5%	8.8%	10.1%	10.0%
Empirical CAPM				
Current Bond Yield	9.2%	9.4%	10.6%	10.5%
Projected Bond Yield	9.4%	9.7%	10.8%	10.7%
Utility Risk Premium				
Current Bond Yields	9.6%		9.2%	
Projected Bond Yield	10.2%		9.8%	
Expected Earnings	10.7%	10.4%	10.7%	10.7%

Recommended ROE

Cost of Equity Range	9.2% -- 10.6%
Midpoint	**9.9%**

	Type of adjustment clause (a)											
			Decoupling				New Capital				(b)	(c)
Company	**Fuel/PPA**	**Conserv. Program Expense**	**Full**	**Partial**	**Renewables Expense**	**Environ-mental Compliance**	**Generation Capacity**	**Generic Infrastructure**	**RTO-related Trans. Expense**	**Other**	**Future Test Year**	**Formula Rates / MRP**
ALLETE	✓	✓	--	--	✓	✓	--	--	✓	✓	C	✓
Alliant Energy	✓	✓	--	--	✓	✓	--	--	✓	✓	C	✓
Ameren Corp.	✓	✓	--	✓	✓	✓	--	✓	✓	✓	O,P	✓
American Elec Pwr	✓	✓	--	✓	✓	✓	✓	✓	✓	✓	C,O,P	✓
Avangrid, Inc.	D	✓	✓	--	✓	--	D	--	✓	✓	C	✓
Avista Corp.	✓	✓	✓	✓	✓	--	--	--	--	--	P	✓
Black Hills Corp.	✓	✓	--	✓	✓	✓	✓	✓	✓	✓	O	--
CMS Energy Corp.	✓	✓	--	--	✓	--	--	--	✓	--	C	✓
Consolidated Edison	D	✓	✓	--	✓	--	D	✓	--	✓	C,P	✓
Dominion Energy	✓	✓	--	--	✓	✓	✓	✓	✓	✓	--	✓
DTE Energy Co.	✓	✓	--	--	✓	--	--	--	✓	--	C	--
Duke Energy Corp.	✓	✓	--	✓	✓	✓	✓	✓	✓	✓	C,O	✓
Entergy Corp.	✓	✓	--	✓	✓	✓	✓	✓	✓	✓	O,P	✓
Eversource Energy	✓	✓	✓	✓	✓	--	--	✓	✓	✓	C	✓
Exelon Corp.	D	✓	✓	✓	✓	✓	D	✓	✓	✓	O,P	✓
FirstEnergy Corp.	✓	✓	--	✓	✓	✓	--	✓	✓	✓	O,P	✓
Fortis Inc.	✓	✓	✓	✓	✓	✓	--	--	✓	✓	C	✓
Hawaiian Elec.	✓	✓	✓	--	✓	--	✓	✓	--	✓	C	✓
IDACORP, Inc.	✓	✓	✓	--	✓	--	--	--	--	--	C,P	--
MGE Energy	✓	--	--	--	✓	--	--	--	--	✓	C	--
NextEra Energy, Inc.	✓	✓	--	--	--	✓	✓	✓	--	✓	C	✓
NorthWestern Corp.	✓	✓	--	--	✓	--	--	--	--	✓	--	--
OGE Energy Corp.	✓	✓	--	✓	✓	✓	✓	✓	✓	✓	P	✓
Otter Tail Corp.	✓	✓	--	--	✓	✓	✓	✓	✓	✓	C,O	✓
Pinnacle West Capital	✓	✓	--	✓	✓	✓	--	--	✓	✓	--	✓
Portland General Elec.	✓	✓	--	✓	✓	✓	✓	--	--	--	C	--
PPL Corp.	✓	✓	--	✓	✓	✓	--	✓	✓	✓	O	✓
Pub Sv Enterprise Grp.	D	✓	--	--	✓	--	D	✓	--	✓	P	--
Sempra Energy	✓	✓	✓	--	--	--	--	✓	✓	✓	C	✓
Southern Company	✓	✓	--	✓	✓	✓	✓	--	--	✓	C,O	✓
WEC Energy Group	✓	✓	--	--	✓	--	--	--	--	✓	C	--
Xcel Energy Inc.	✓	✓	--	✓	✓	✓	✓	✓	✓	✓	C,O	✓

(a) S&P Global Market Intelligence, *Adjustment Clauses* , RRA Regulatory Focus (Nov. 12, 2019).
(b) Edison Electric Institute, *Alternative Regulation for Emerging Utility Challenges: 2015 Update* (Nov. 11, 2015).
(c) Formula rates and Multiyear Rate plans approved in the state listed for this operating company. *See* , (b); U.S. Department of Energy, *State Performance-Based Regulation Using Multiyear Rate Plans for U.S. Electric Utilities,* GRID Modernization Laboratory Consortium (Jul. 2017); The Brattle Group, *Exploring the Use of Alternative Regulatory Mechanisms to Establish New Base Rates,* Joint Utilities of Maryland (Mar. 29, 2018).

Notes:
D - Delivery-only utility.
C - Fully-forecasted test years commonly used in the state listed for this operating company.
O - Fully-forecasted test years occasionally used in the state listed for this operating company.
P - Partially-forecasted test years commonly or occasionally used in the state listed for this operating company.
LIR - Limited issue reopeners.

ELECTRIC GROUP OPERATING COS.

		Type of adjustment clause (a)											
				Decoupling				New Capital				(b)	(c)
Company	State	Fuel/PPA	Conserv. Program Expense	Full	Partial	Renewables Expense	Environ-mental Compliance	Generation Capacity	Generic Infrastructure	RTO-related Trans. Expense	Other	Future Test Year	Formula Rates / MRP
ALLETE													
Minnesota Power	MN	✓	✓	--	--	✓	✓	--	--	✓	✓	C	✓
ALLIANT ENERGY CORP.													
Interstate Power & Light	IA	✓	✓	--	--	✓	✓	--	--	✓	✓	--	✓
Wisconsin Power & Light	WI	✓	--	--	--	--	--	--	--	--	✓	C	--
AMEREN CORP.													
Ameren Illinois Co.	IL	D	✓	--	--	✓	✓	D	--	✓	✓	O	✓
Union Electric Co.	MO	✓	✓	--	✓	✓	✓	--	✓	✓	✓	P	--
AMERICAN ELEC PWR													
Southwestern Electric Pwr Co.	AR	✓	✓	--	✓	--	✓	✓	--	✓	✓	P	--
Southwestern Electric Pwr Co.	TX	✓	✓	--	--	--	--	--	✓	✓	--	--	✓
Appalachian Power	VA	✓	✓	--	--	✓	--	✓	--	✓	✓	--	✓
Appalachian Power/Wheeling Power	WV	✓	✓	--	--	✓	--	--	--	--	✓	--	--
Indiana Michigan Power Co.	IN	✓	✓	--	✓	✓	✓	--	✓	✓	✓	--	✓
Kentucky Power Co.	KY	✓	✓	--	✓	✓	✓	--	--	--	✓	O	--
Southwestern Electric Pwr Co.	LA	✓	✓	--	✓	--	✓	--	--	--	✓	O	✓
Indiana Michigan Power Co.	MI	✓	✓	--	--	✓	--	--	--	--	✓	C	--
Ohio Power Co.	OH	D	✓	--	✓	✓	--	D	✓	✓	✓	P	✓
Public Service Co. of Oklahoma	OK	✓	✓	--	✓	✓	--	--	✓	✓	✓	--	--
Kingsport Power	TN	✓	--	--	--	--	--	--	--	--	--	C	✓
AEP Texas	TX	D	✓	--	--	--	--	D	✓	✓	--	--	✓
AVANGRID													
United Illuminating	CT	D	✓	✓	--	--	--	D	--	✓	--	C	✓
Central Maine Power	ME	D	--	✓	--	--	--	D	--	--	✓	C	✓
New York State Electric & Gas	NY	D	--	✓	--	✓	--	D	--	--	✓	C	✓
Rochester G&E	NY	D	--	✓	--	✓	--	D	--	--	✓	C	✓
AVISTA CORP.													
Alaska Electric Light & Power	AK	✓	--	--	--	--	--	--	--	--	--	--	--
Avista Corp.	ID	✓	✓	✓	--	--	--	--	--	--	--	P	--
Avista Corp.	WA	✓	✓	--	✓	✓	--	--	--	--	--	--	✓
BLACK HILLS CORP.													
Black Hills Colorado Electric	CO	✓	✓	--	--	✓	--	✓	✓	--	✓	--	✓
Black Hills Power	SD	✓	✓	--	✓	✓	✓	--	--	✓	✓	--	--
Cheyenne Light Fuel & Power	WY	✓	✓	--	✓	✓	--	--	--	--	✓	O	--
CMS ENERGY													
Consumers Energy Co.	MI	✓	✓	--	--	✓	--	--	--	✓	--	C	--

ELECTRIC GROUP OPERATING COS.

		Type of adjustment clause (a)											
				Decoupling				New Capital				(b)	(c)
Company	State	Fuel/PPA	Conserv. Program Expense	Full	Partial	Renewables Expense	Environ-mental Compliance	Generation Capacity	Generic Infrastructure	RTO-related Trans. Expense	Other	Future Test Year	Formula Rates / MRP
CONSOLIDATED EDISON													
Rockland Electric	NJ	D	✓	--	--	✓	--	D	✓	--	✓	P	--
Consolidated Edison of NY	NY	D	--	✓	--	✓	--	D	--	--	✓	C	✓
Orange & Rockland	NY	D	--	✓	--	✓	--	D	--	--	--	C	✓
DOMINION ENERGY													
Virginia Electric & Power	NC	✓	✓	--	--	✓	✓	--	--	--	--	--	--
Virginia Electric & Power	VA	✓	✓	--	--	✓	✓	✓	✓	✓	✓	--	✓
South Caroline Electric & Gas	SC	✓	✓	--	--	--	✓	✓	--	--	--	--	✓
DTE ENERGY CO.													
DTE Electric Co.	MI	✓	✓	--	--	✓	--	--	--	✓	--	C	--
DUKE ENERGY													
Duke Energy Florida	FL	✓	✓	--	--	--	✓	✓	--	--	✓	C	✓
Duke Energy Indiana	IN	✓	✓	--	✓	✓	✓	✓	✓	✓	✓	--	✓
Duke Energy Kentucky	KY	✓	✓	--	✓	✓	✓	--	--	--	✓	O	--
Duke Energy Carolinas	NC	✓	✓	--	--	✓	✓	--	--	--	--	--	--
Duke Energy Progress	NC	✓	✓	--	--	✓	✓	--	--	--	--	--	--
Duke Energy Ohio	OH	D	✓	--	✓	✓	--	D	✓	✓	✓	P	✓
Duke Energy Progress	SC	✓	✓	--	--	--	✓	--	--	--	--	--	✓
Duke Energy Carolinas	SC	✓	✓	--	--	--	✓	--	--	--	--	--	✓
ENTERGY CORP.													
Entergy Arkansas Inc.	AR	✓	✓	--	✓	✓	--	✓	✓	✓	✓	P	✓
Entergy New Orleans Inc.	LA	✓	✓	--	✓	--	✓	✓	--	✓	✓	O	✓
Entergy Louisiana	LA	✓	✓	--	✓	--	✓	✓	✓	✓	✓	O	✓
Entergy Mississippi	MS	✓	✓	--	✓	--	✓	--	--	✓	✓	O	✓
Entergy Texas Inc.	TX	✓	✓	--	--	--	--	--	✓	--	✓	--	✓
EVERSOURCE ENERGY													
Connecticut Light & Power	CT	D	✓	✓	--	--	--	D	✓	✓	--	C	✓
NSTAR Electric Co.	MA	D	✓	✓	--	✓	--	D	✓	✓	✓	--	--
Public Service Co. of New Hampshire	NH	✓	--	--	✓	--	--	--	✓	✓	--	--	✓
EXELON CORP.													
Delmarva Power and Light	DE	D	--	--	--	--	--	D	✓	✓	✓	P	--
Potomac Electric Power Co.	DC	D	--	--	✓	✓	--	D	✓	--	✓	P	--
Commonweath Edison Co.	IL	D	✓	--	--	✓	✓	D	✓	✓	✓	O	✓
Baltimore Gas & Electric	MD	D	✓	✓	--	--	--	D	--	--	✓	P	--
Delmarva Power and Light	MD	D	✓	✓	--	--	--	D	--	--	--	P	--
Potomac Electric Power Co.	MD	D	✓	✓	--	--	--	D	--	--	✓	P	--
Atlantic City Electric Co.	NJ	D	✓	--	--	✓	--	D	✓	--	✓	P	--
PECO Energy	PA	D	✓	--	--	--	--	D	✓	--	✓	O	--

ELECTRIC GROUP OPERATING COS.

		Type of adjustment clause (a)											
				Decoupling				New Capital				(b)	(c)
Company	State	Fuel/PPA	Conserv. Program Expense	Full	Partial	Renewables Expense	Environ-mental Compliance	Generation Capacity	Generic Infrastructure	RTO-related Trans. Expense	Other	Future Test Year	Formula Rates / MRP
FIRSTENERGY CORP.													
The Potomac Edison Co.	MD	D	✓	--	--	--	--	D	✓	--	✓	P	--
Jersey Central Power & Light Co.	NJ	D	✓	--	--	✓	✓	D	✓	--	✓	P	--
Cleve. Elec. Illum./Ohio Ed./Toledo Ed.	OH	D	✓	--	✓	✓	--	D	✓	✓	✓	P	✓
Metropolitan Edison Co.	PA	D	✓	--	--	--	--	D	✓	✓	✓	O	--
Pennsylvania Electric Co.	PA	D	✓	--	--	--	--	D	✓	✓	✓	O	--
Pennsylvania Power	PA	D	✓	--	--	--	--	D	✓	--	✓	O	--
West Penn Power Co.	PA	D	✓	--	--	--	--	D	✓	--	✓	O	--
Monongahela Power	WV	✓	✓	--	--	--	--	--	✓	--	✓	--	--
The Potomac Edison Co.	WV	✓	✓	--	--	--	--	--	✓	--	✓	--	--
FORTIS, INC.													
Tucson Electric Power	AZ	✓	✓	--	✓	✓	✓	--	--	--	✓	--	✓
UNS Electric	AZ	✓	✓	--	✓	✓	--	--	--	✓	✓	--	✓
Central Hudson Gas & Electric	NY	D	--	✓	--	✓	--	D	--	--	✓	C	✓
HAWAIIAN ELEC.													
Hawaiian Electric Co.	HI	✓	✓	✓	--	✓	--	✓	✓	--	✓	C	✓
Hawaiia Electric Light	HI	✓	✓	✓	--	✓	--	✓	✓	--	✓	C	✓
Maui Electric	HI	✓	✓	✓	--	✓	--	✓	✓	--	✓	C	✓
IDACORP													
Idaho Power Co.	ID	✓	✓	✓	--	--	--	--	--	--	--	P	--
Idaho Power Co.	OR	✓	✓	--	--	✓	--	--	--	--	--	C	--
MGE ENERGY													
Madison Gas & Electric Co.	WI	✓	--	--	--	✓	--	--	--	--	✓	C	--
NEXTERA ENERGY													
Florida Power & Light	FL	✓	✓	--	--	--	✓	✓	--	--	✓	C	✓
Lone Star Transmission	TX	D	--	--	--	--	--	D	✓	--	--	--	✓
Gulf Power Co.	FL	✓	✓	--	--	--	✓	✓	--	--	✓	C	✓
NORTHWESTERN CORP.													
NorthWestern Corporation	MT	✓	✓	--	--	✓	--	--	--	--	✓	--	--
NorthWestern Corporation	SD	✓	✓	--	--	--	--	--	--	--	--	--	--
OGE ENERGY CORP.													
Oklahoma G&E	AR	✓	✓	--	✓	✓	✓	✓	--	✓	✓	P	--
Oklahoma G&E	OK	✓	✓	--	✓	✓	✓	--	✓	✓	✓	--	✓
OTTER TAIL CORP.													
Otter Tail Power Co.	MN	✓	✓	--	--	✓	✓	--	--	✓	--	C	--
Otter Tail Power Co.	ND	✓	--	--	--	--	✓	✓	✓	--	✓	O	✓
Otter Tail Power Co.	SD	✓	✓	--	--	✓	✓	✓	✓	--	--	--	--

ELECTRIC GROUP OPERATING COS.

		Type of adjustment clause (a)											
				Decoupling				New Capital				(b)	(c)
Company	**State**	**Fuel/PPA**	**Conserv. Program Expense**	**Full**	**Partial**	**Renewables Expense**	**Environ-mental Compliance**	**Generation Capacity**	**Generic Infrastructure**	**RTO-related Trans. Expense**	**Other**	**Future Test Year**	**Formula Rates / MRP**
PINNACLE WEST CAPITAL													
Arizona Public Service Co.	AZ	✓	✓	--	✓	✓	✓	--	--	✓	✓	--	✓
PORTLAND GENERAL ELECTRIC													
Portland General Electric	OR	✓	✓	--	✓	✓	✓	✓	--	--	--	C	--
PPL CORP.													
Kentucky Utilities Co.	KY	✓	✓	--	✓	✓	✓	--	--	--	✓	O	--
Louisville Gas & Electric Co.	KY	✓	✓	--	✓	✓	✓	--	--	--	✓	O	--
PPL Electric Utilities Corp.	PA	D	✓	--	--	--	--	D	✓	✓	✓	O	--
Kentucky Utilities Co.	VA	✓	--	--	--	--	--	--	--	--	--	--	✓
PUB SV ENTERPRISE GRP													
Pub Service Electric & Gas Co.	NJ	D	✓	--	--	✓	--	D	✓	--	✓	P	--
SEMPRA ENERGY													
San Diego Gas & Electric	CA	✓	--	✓	--	--	--	--	--	--	✓	C	✓
Oncor Electric Delivery	TX	D	✓	--	--	--	--	D	✓	✓	--	--	✓
SOUTHERN CO.													
Alabama Power Co.	AL	✓	--	--	--	✓	✓	✓	--	--	✓	C	✓
Georgia Power Co.	GA	✓	--	--	--	--	--	✓	--	--	--	C	✓
Mississippi Power Co.	MS	✓	✓	--	✓	--	✓	--	--	--	✓	O	✓
WEC ENERGY GROUP													
Wisconsin Electric Power Co.	MI	✓	✓	--	--	✓	--	--	--	--	--	C	--
Wisconsin Electric Power Co.	WI	✓	--	--	--	✓	--	--	--	--	✓	C	--
Wisconsin Public Service Corp.	WI	✓	--	--	--	--	--	--	--	--	✓	C	--
XCEL ENERGY, INC.													
Public Service Co. of Colorado	CO	✓	✓	--	--	✓	✓	✓	✓	--	✓	--	✓
Northern States Power Co. (MN)	MN	✓	✓	--	✓	✓	✓	--	--	✓	--	C	✓
Southwestern Public Service Co.	NM	✓	✓	--	--	✓	--	--	--	--	✓	O	--
Northern States Power Co. (MN)	ND	✓	--	--	--	--	--	--	✓	--	✓	O	✓
Northern States Power Co. (MN)	SD	✓	✓	--	✓	--	✓	✓	✓	--	✓	--	--
Southwestern Public Service Co.	TX	✓	✓	--	--	--	--	--	✓	✓	✓	--	✓
Northern States Power Co. (WI)	WI	✓	--	--	--	--	--	--	--	--	✓	C	--

Sources:
(a) S&P Global Market Intelligence, *Adjustment Clauses* , RRA Regulatory Focus (Nov. 12, 2019).
(b) Edison Electric Institute, *Alternative Regulation for Emerging Utility Challenges: 2015 Update* (Nov. 11, 2015).
(c) Formula rates and Multiyear Rate plans approved in the state listed for this operating company. *See* , (b); U.S. Department of Energy, *State Performance-Based Regulation Using Multiyear Rate Plans for U.S. Electric Utilities,* GRID Modernization Laboratory Consortium (Jul. 2017); The Brattle Group, *Exploring the Use of Alternative Regulatory Mechanisms to Establish New Base Rates,* Joint Utilities of Maryland (Mar. 29, 2018).

Notes:
D - Delivery-only utility.
C - Fully-forecasted test years commonly used in the state listed for this operating company.
O - Fully-forecasted test years occasionally used in the state listed for this operating company.
P - Partially-forecasted test years commonly or occasionally used in the state listed for this operating company.
LIR - Limited issue reopeners.

GAS GROUP

Company	State	Type of adjustment clause								(c)
				Decoupling						Formula
		Purchased Gas Adjustment	Conserv. Program Expense	Full	Partial	Environ-mental Compliance	Infrastructure Tracker	Other	Future Test Year	Rates / MRP
ATMOS ENERGY										
Atmos Energy	KS	✓	--	--	✓	--	✓	✓	--	--
Atmos Energy	KY	✓	✓	--	✓	--	✓	✓	O	--
Atmos Energy	LA	✓	--	--	✓	--	✓	--	O	✓
Atmos Energy	MS	✓	✓	--	✓	--	✓	--	O	✓
Atmos Energy	TN	✓	--	--	✓	--	--	✓	C	✓
Atmos Energy	TX	✓	--	--	✓	--	✓	✓	--	✓
CHESAPEAKE UTILITES										
Chesapeake Utilities	DE	✓	--	--	--	✓	✓	✓	P	--
Florida Public Utilities	FL	✓	✓	--	--	✓	✓	✓	C	✓
NEW JERSEY RESOURCES										
New Jersey Natural Gas	NJ	✓	✓	✓	--	✓	✓	✓	P	--
NISOURCE INC.										
Northern Indiana Public Svc	IN	✓	✓	--	--	--	✓	✓	--	✓
Columbia Gas of Kentucky	KY	✓	✓	--	✓	--	✓	✓	O	--
Columbia Gas of Maryland	MD	✓	✓	--	✓	--	✓	✓	P	--
Columbia Gas of Massachusetts	MA	✓	✓	✓	--	✓	✓	✓	--	--
Columbia Gas of Ohio	OH	D	✓	--	--	--	✓	✓	P	✓
Columbia Gas of Pennsylvania	PA	✓	--	--	✓	--	✓	✓	O	--
Columbia Gas of Virginia	VA	✓	✓	--	✓	--	✓	✓	--	✓
NORTHWEST NATURAL										
Northwest Natural Gas	OR	✓	✓	--	✓	✓	--	--	C	--
Northwest Natural Gas	WA	✓	✓	--	--	--	--	--	--	✓
ONE GAS, INC.										
Kansas Gas Service	KS	✓	--	--	✓	--	✓	✓	--	--
Oklahoma Natural Gas	OK	✓	✓	--	✓	--	--	✓	--	✓
Texas Gas Service	TX	✓	--	--	✓	--	✓	--	--	✓
SOUTH JERSEY INDUSTRIES										
Elizabethtown Gas	NJ	✓	✓	--	✓	✓	✓	✓	P	--
South Jersey Gas	NJ	✓	✓	✓	--	✓	✓	✓	P	--
SOUTHWEST GAS										
Southwest Gas	AZ	✓	✓	✓	--	--	✓	✓	--	✓
Southwest Gas	CA	✓	--	✓	--	--	--	--	C	✓
Southwest Gas	NV	✓	--	✓	--	--	✓	✓	--	--
SPIRE INC.										
Spire Alabama	AL	✓	--	--	✓	--	--	✓	C	✓
Spire Gulf	AL	✓	--	--	✓	--	--	✓	C	✓
Laclede Gas	MO	✓	--	--	✓	--	✓	✓	P	--
Missouri Gas Energy	MO	✓	--	--	--	--	✓	✓	P	--

(a) S&P Global Market Intelligence, *Adjustment Clauses* , RRA Regulatory Focus (Nov. 12, 2019).
(b) Edison Electric Institute, *Alternative Regulation for Emerging Utility Challenges: 2015 Update* (Nov. 11, 2015).
(c) Formula rates and Multiyear Rate plans approved in the state listed for this operating company. *See* , (b); U.S. Department of Energy, *State Performance-Based Regulation Using Multiyear Rate Plans for U.S. Electric Utilities,* GRID Modernization Laboratory Consortium (Jul. 2017); The Brattle Group, *Exploring the Use of Alternative Regulatory Mechanisms to Establish New Base Rates,* Joint Utilities of Maryland (Mar. 29, 2018).

Notes:
D - Delivery-only utility.
C - Fully-forecasted test years commonly
O - Fully-forecasted test years occasionall
P - Partially-forecasted test years commor
LIR - Limited issue reopeners.

DCF MODEL - ELECTRIC GROUP **Exhibit AMM-5**

DIVIDEND YIELD

		(a)	(b)	
	Company	**Price**	**Dividends**	**Yield**
1	ALLETE	$ 80.15	$ 2.46	3.1%
2	Alliant Energy	$ 53.33	$ 1.42	2.7%
3	Ameren Corp.	$ 75.20	$ 2.01	2.7%
4	American Elec Pwr	$ 92.04	$ 2.84	3.1%
5	Avangrid, Inc.	$ 49.42	$ 1.78	3.6%
6	Avista Corp.	$ 47.47	$ 1.60	3.4%
7	Black Hills Corp.	$ 77.03	$ 2.14	2.8%
8	CMS Energy Corp.	$ 61.65	$ 1.63	2.6%
9	Consolidated Edison	$ 87.64	$ 3.06	3.5%
10	Dominion Energy	$ 81.89	$ 3.76	4.6%
11	DTE Energy Co.	$ 125.72	$ 4.05	3.2%
12	Duke Energy Corp.	$ 89.00	$ 3.82	4.3%
13	Entergy Corp.	$ 117.73	$ 3.74	3.2%
14	Eversource Energy	$ 82.42	$ 2.23	2.7%
15	Exelon Corp.	$ 44.75	$ 1.52	3.4%
16	FirstEnergy Corp.	$ 47.85	$ 1.60	3.3%
17	Fortis Inc.	$ 53.24	$ 1.94	3.6%
18	Hawaiian Elec.	$ 44.83	$ 1.31	2.9%
19	IDACORP, Inc.	$ 105.41	$ 2.68	2.5%
20	MGE Energy	$ 77.53	$ 1.45	1.9%
21	NextEra Energy, Inc.	$ 235.77	$ 5.49	2.3%
22	NorthWestern Corp.	$ 71.09	$ 2.38	3.3%
23	OGE Energy Corp.	$ 43.04	$ 1.58	3.7%
24	Otter Tail Corp.	$ 50.10	$ 1.46	2.9%
25	Pinnacle West Capital	$ 87.24	$ 3.13	3.6%
26	Portland General Elec.	$ 55.50	$ 1.59	2.9%
27	PPL Corp.	$ 34.55	$ 1.66	4.8%
28	Pub Sv Enterprise Grp.	$ 59.23	$ 1.94	3.3%
29	Sempra Energy	$ 148.27	$ 4.12	2.8%
30	Southern Company	$ 62.38	$ 2.54	4.1%
31	WEC Energy Group	$ 89.56	$ 2.53	2.8%
32	Xcel Energy Inc.	$ 62.07	$ 1.70	2.7%
	Average			**3.2%**

(a) Average of closing prices for 30 trading days ended Dec. 27, 2019.

(b) The Value Line Investment Survey, Summary & Index (Jan. 3, 2020).

DCF MODEL - ELECTRIC GROUP

GROWTH RATES

	Company	(a) V Line	(b) IBES	(c) Zacks	(d) br+sv Growth
		Earnings Growth			
1	ALLETE	5.0%	7.0%	7.2%	3.2%
2	Alliant Energy	6.5%	5.0%	5.5%	4.6%
3	Ameren Corp.	6.5%	4.7%	6.2%	5.3%
4	American Elec Pwr	4.0%	5.9%	5.7%	4.5%
5	Avangrid, Inc.	8.5%	6.2%	7.4%	1.7%
6	Avista Corp.	3.5%	3.5%	3.4%	3.0%
7	Black Hills Corp.	5.0%	3.7%	4.3%	4.3%
8	CMS Energy Corp.	7.0%	7.5%	6.4%	6.5%
9	Consolidated Edison	3.0%	2.8%	2.0%	3.4%
10	Dominion Energy	6.5%	4.4%	4.8%	8.6%
11	DTE Energy Co.	4.5%	4.8%	6.0%	5.4%
12	Duke Energy Corp.	6.0%	4.7%	4.8%	2.9%
13	Entergy Corp.	2.0%	-1.6%	7.0%	6.1%
14	Eversource Energy	5.5%	5.6%	5.6%	4.9%
15	Exelon Corp.	9.0%	0.5%	4.5%	5.0%
16	FirstEnergy Corp.	6.5%	-6.6%	6.0%	9.1%
17	Fortis Inc.	2.5%	4.7%	5.7%	2.0%
18	Hawaiian Elec.	2.5%	3.4%	4.2%	3.6%
19	IDACORP, Inc.	3.5%	2.5%	3.9%	3.4%
20	MGE Energy	6.0%	4.0%	n/a	5.3%
21	NextEra Energy, Inc.	10.5%	8.0%	8.0%	5.8%
22	NorthWestern Corp.	3.0%	3.2%	2.7%	3.1%
23	OGE Energy Corp.	6.5%	3.5%	4.5%	3.8%
24	Otter Tail Corp.	5.0%	9.0%	7.0%	4.9%
25	Pinnacle West Capital	5.0%	4.4%	4.9%	3.8%
26	Portland General Elec.	4.5%	4.1%	4.5%	3.4%
27	PPL Corp.	1.5%	0.5%	n/a	6.0%
28	Pub Sv Enterprise Grp.	6.0%	3.7%	3.7%	4.8%
29	Sempra Energy	11.0%	10.1%	7.7%	8.4%
30	Southern Company	3.5%	1.6%	4.5%	4.2%
31	WEC Energy Group	6.0%	6.2%	6.1%	4.2%
32	Xcel Energy Inc.	5.5%	5.2%	5.4%	4.6%

(a) The Value Line Investment Survey (Oct. 25, Nov. 15 & Dec. 13 2019).
(b) www.finance.yahoo.com (retreived Dec. 3, 2019).
(c) www.zacks.com (retrieved Dec. 3, 2019).
(d) See Exhibit AMM-6.

DCF COST OF EQUITY ESTIMATES

		(a)	(a)	(a)	(a)
		Earnings Growth			br+sv
	Company	**V Line**	**IBES**	**Zacks**	**Growth**
1	ALLETE	8.1%	10.1%	10.3%	6.3%
2	Alliant Energy	9.2%	7.7%	8.2%	7.2%
3	Ameren Corp.	9.2%	7.4%	8.8%	8.0%
4	American Elec Pwr	7.1%	9.0%	8.7%	7.6%
5	Avangrid, Inc.	12.1%	9.8%	11.0%	5.3%
6	Avista Corp.	6.9%	6.9%	6.7%	6.3%
7	Black Hills Corp.	7.8%	6.4%	7.0%	7.0%
8	CMS Energy Corp.	9.6%	10.1%	9.1%	9.2%
9	Consolidated Edison	6.5%	6.3%	5.5%	6.9%
10	Dominion Energy	11.1%	9.0%	9.4%	13.2%
11	DTE Energy Co.	7.7%	8.1%	9.2%	8.6%
12	Duke Energy Corp.	10.3%	8.9%	9.1%	7.2%
13	Entergy Corp.	5.2%	1.6%	10.2%	9.3%
14	Eversource Energy	8.2%	8.3%	8.3%	7.6%
15	Exelon Corp.	12.4%	3.9%	7.9%	8.4%
16	FirstEnergy Corp.	9.8%	-3.3%	9.3%	12.5%
17	Fortis Inc.	6.1%	8.3%	9.3%	5.7%
18	Hawaiian Elec.	5.4%	6.3%	7.1%	6.6%
19	IDACORP, Inc.	6.0%	5.0%	6.4%	6.0%
20	MGE Energy	7.9%	5.9%	n/a	7.1%
21	NextEra Energy, Inc.	12.8%	10.3%	10.3%	8.1%
22	NorthWestern Corp.	6.3%	6.5%	6.1%	6.5%
23	OGE Energy Corp.	10.2%	7.2%	8.2%	7.5%
24	Otter Tail Corp.	7.9%	11.9%	9.9%	7.8%
25	Pinnacle West Capital	8.6%	8.0%	8.5%	7.4%
26	Portland General Elec.	7.4%	7.0%	7.4%	6.2%
27	PPL Corp.	6.3%	5.3%	n/a	10.8%
28	Pub Sv Enterprise Grp.	9.3%	7.0%	7.0%	8.1%
29	Sempra Energy	13.8%	12.8%	10.5%	11.2%
30	Southern Company	7.6%	5.6%	8.6%	8.2%
31	WEC Energy Group	8.8%	9.0%	9.0%	7.0%
32	Xcel Energy Inc.	8.2%	7.9%	8.2%	7.4%
	Average (b)	**9.3%**	**8.7%**	**8.7%**	**8.4%**
	Midpoint (b) (c)	**10.3%**	**9.7%**	**8.9%**	**9.9%**

(a) Sum of dividend yield (Exhibit AMM-5, p. 1) and respective growth rate (Exhibit AMM-5, p. 2).
(b) Excludes highlighted figures.
(c) Average of low and high values.

DCF MODEL - ELECTRIC GROUP

SUSTAINABLE GROWTH RATE

		(a)	(a)	(a)			(b)	(c)		(d)	(e)		
			2023				Adjustment				"sv" Factor		
	Company	EPS	DPS	BVPS	b	r	Factor	Adjusted r	br	s	v	sv	br + sv
1	ALLETE	$4.25	$2.85	$48.25	32.9%	8.8%	1.0169	9.0%	3.0%	0.0075	0.3567	0.27%	3.2%
2	Alliant Energy	$2.80	$1.74	$27.55	37.9%	10.2%	1.0227	10.4%	3.9%	0.0178	0.3518	0.63%	4.6%
3	Ameren Corp.	$4.25	$2.35	$41.50	44.7%	10.2%	1.0337	10.6%	4.7%	0.0175	0.3360	0.59%	5.3%
4	American Elec Pwr	$5.00	$3.35	$48.50	33.0%	10.3%	1.0288	10.6%	3.5%	0.0227	0.4457	1.01%	4.5%
5	Avangrid, Inc.	$3.00	$2.10	$52.50	30.0%	5.7%	1.0076	5.8%	1.7%	(0.0000)	-	0.00%	1.7%
6	Avista Corp.	$2.50	$1.80	$32.35	28.0%	7.7%	1.0261	7.9%	2.2%	0.0230	0.3189	0.73%	3.0%
7	Black Hills Corp.	$4.25	$2.60	$45.50	38.8%	9.3%	1.0263	9.6%	3.7%	0.0135	0.3933	0.53%	4.3%
8	CMS Energy Corp.	$3.25	$2.00	$24.00	38.5%	13.5%	1.0391	14.1%	5.4%	0.0201	0.5636	1.13%	6.5%
9	Consolidated Edison	$5.00	$3.40	$60.50	32.0%	8.3%	1.0222	8.4%	2.7%	0.0207	0.3278	0.68%	3.4%
10	Dominion Energy	$5.00	$4.05	$39.75	19.0%	12.6%	1.0536	13.3%	2.5%	0.1094	0.5583	6.11%	8.6%
11	DTE Energy Co.	$7.25	$4.95	$75.75	31.7%	9.6%	1.0449	10.0%	3.2%	0.0533	0.4173	2.22%	5.4%
12	Duke Energy Corp.	$5.75	$4.05	$69.50	29.6%	8.3%	1.0201	8.4%	2.5%	0.0154	0.2486	0.38%	2.9%
13	Entergy Corp.	$6.75	$4.30	$58.25	36.3%	11.6%	1.0330	12.0%	4.3%	0.0392	0.4581	1.80%	6.1%
14	Eversource Energy	$4.25	$2.65	$46.25	37.6%	9.2%	1.0346	9.5%	3.6%	0.0336	0.4032	1.36%	4.9%
15	Exelon Corp.	$3.75	$1.80	$40.25	52.0%	9.3%	1.0255	9.6%	5.0%	0.0048	0.1526	0.07%	5.0%
16	FirstEnergy Corp.	$3.00	$1.90	$18.00	36.7%	16.7%	1.0387	17.3%	6.3%	0.0422	0.6571	2.77%	9.1%
17	Fortis Inc.	$2.75	$2.35	$43.75	14.5%	6.3%	1.0351	6.5%	0.9%	0.0358	0.3000	1.07%	2.0%
18	Hawaiian Elec.	$2.25	$1.50	$24.25	33.3%	9.3%	1.0233	9.5%	3.2%	0.0123	0.3938	0.48%	3.6%
19	IDACORP, Inc.	$5.25	$3.35	$56.25	36.2%	9.3%	1.0175	9.5%	3.4%	(0.0001)	0.4079	-0.01%	3.4%
20	MGE Energy	$3.25	$1.70	$30.25	47.7%	10.7%	1.0255	11.0%	5.3%	-	0.5519	0.00%	5.3%
21	NextEra Energy, Inc.	$11.50	$7.00	$93.25	39.1%	12.3%	1.0299	12.7%	5.0%	0.0154	0.5451	0.84%	5.8%
22	NorthWestern Corp.	$4.00	$2.70	$45.00	32.5%	8.9%	1.0163	9.0%	2.9%	0.0048	0.3571	0.17%	3.1%
23	OGE Energy Corp.	$2.75	$1.85	$24.00	32.7%	11.5%	1.0181	11.7%	3.8%	0.0006	0.4947	0.03%	3.8%
24	Otter Tail Corp.	$2.50	$1.65	$23.25	34.0%	10.8%	1.0293	11.1%	3.8%	0.0216	0.5105	1.10%	4.9%
25	Pinnacle West Capital	$5.75	$3.80	$55.75	33.9%	10.3%	1.0195	10.5%	3.6%	0.0060	0.4425	0.27%	3.8%
26	Portland General Elec.	$3.00	$1.95	$32.50	35.0%	9.2%	1.0152	9.4%	3.3%	0.0026	0.3810	0.10%	3.4%
27	PPL Corp.	$2.75	$1.80	$21.50	34.5%	12.8%	1.0371	13.3%	4.6%	0.0299	0.4625	1.38%	6.0%
28	Pub Sv Enterprise Grp.	$4.00	$2.30	$36.25	42.5%	11.0%	1.0239	11.3%	4.8%	0.0007	0.3958	0.03%	4.8%
29	Sempra Energy	$9.00	$5.25	$76.50	41.7%	11.8%	1.0500	12.4%	5.1%	0.0642	0.5065	3.25%	8.4%
30	Southern Company	$3.75	$2.78	$30.25	25.9%	12.4%	1.0283	12.7%	3.3%	0.0174	0.4958	0.86%	4.2%
31	WEC Energy Group	$4.50	$3.00	$36.75	33.3%	12.2%	1.0176	12.5%	4.2%	(0.0000)	0.5545	0.00%	4.2%
32	Xcel Energy Inc.	$3.25	$2.05	$30.25	36.9%	10.7%	1.0238	11.0%	4.1%	0.0117	0.4739	0.55%	4.6%

SUSTAINABLE GROWTH RATE

		(a)	(a)	(f)	(a)	(a)	(f)	(g)	(a)	(a)		(h)	(a)	(a)	(g)
		2018			2023			Chg	2023 Price				Common Shares		
	Company	Eq Ratio	Tot Cap	Com Eq	Eq Ratio	Tot Cap	Com Eq	Equity	High	Low	Avg.	M/B	2018	2023	Growth
1	ALLETE	60.1%	$3,584	$2,154	58.0%	$4,400	$2,552	3.4%	$85.0	$65.0	$75.0	1.554	51.50	52.75	0.48%
2	Alliant Energy	46.7%	$9,832	$4,592	48.0%	$12,000	$5,760	4.6%	$50.0	$35.0	$42.5	1.543	236.06	250.00	1.15%
3	Ameren Corp.	48.8%	$15,632	$7,628	49.5%	$21,600	$10,692	7.0%	$70.0	$55.0	$62.5	1.506	244.50	259.00	1.16%
4	American Elec Pwr	46.8%	$40,677	$19,037	46.5%	$54,600	$25,389	5.9%	$95.0	$80.0	$87.5	1.804	493.25	525.00	1.26%
5	Avangrid, Inc.	73.8%	$20,472	$15,108	62.0%	$26,300	$16,306	1.5%	$60.0	$45.0	$52.5	1.000	309.01	309.00	0.00%
6	Avista Corp.	49.5%	$3,580	$1,772	50.0%	$4,600	$2,300	5.4%	$55.0	$40.0	$47.5	1.468	65.69	71.00	1.57%
7	Black Hills Corp.	42.5%	$5,132	$2,181	44.5%	$6,375	$2,837	5.4%	$85.0	$65.0	$75.0	1.648	60.00	62.50	0.82%
8	CMS Energy Corp.	30.7%	$15,476	$4,751	33.0%	$21,300	$7,029	8.1%	$65.0	$45.0	$55.0	2.292	283.37	296.00	0.88%
9	Consolidated Edison	48.9%	$34,221	$16,734	49.5%	$42,200	$20,889	4.5%	$100.0	$80.0	$90.0	1.488	321.00	344.00	1.39%
10	Dominion Energy	39.2%	$51,251	$20,090	41.0%	$83,800	$34,358	11.3%	$105.0	$75.0	$90.0	2.264	680.90	862.00	4.83%
11	DTE Energy Co.	45.8%	$22,371	$10,246	46.0%	$34,900	$16,054	9.4%	$150.0	$110.0	$130.0	1.716	181.93	212.00	3.11%
12	Duke Energy Corp.	46.2%	$94,940	$43,862	44.5%	$120,500	$53,623	4.1%	$105.0	$80.0	$92.5	1.331	727.00	770.00	1.16%
13	Entergy Corp.	35.9%	$24,602	$8,832	39.0%	$31,500	$12,285	6.8%	$125.0	$90.0	$107.5	1.845	189.06	210.00	2.12%
14	Eversource Energy	46.9%	$24,474	$11,478	46.5%	$34,900	$16,229	7.2%	$85.0	$70.0	$77.5	1.676	316.89	350.00	2.01%
15	Exelon Corp.	47.2%	$65,229	$30,788	50.0%	$79,500	$39,750	5.2%	$55.0	$40.0	$47.5	1.180	968.19	988.00	0.41%
16	FirstEnergy Corp.	27.4%	$24,565	$6,731	30.5%	$32,500	$9,913	8.0%	$60.0	$45.0	$52.5	2.917	511.92	550.00	1.45%
17	Fortis Inc.	37.2%	$40,082	$14,911	44.5%	$47,600	$21,182	7.3%	$70.0	$55.0	$62.5	1.429	428.50	485.00	2.51%
18	Hawaiian Elec.	51.7%	$4,182	$2,162	52.0%	$5,250	$2,730	4.8%	$45.0	$35.0	$40.0	1.649	108.88	113.00	0.75%
19	IDACORP, Inc.	56.4%	$4,205	$2,372	56.5%	$5,000	$2,825	3.6%	$110.0	$80.0	$95.0	1.689	50.42	50.40	-0.01%
20	MGE Energy	62.3%	$1,310	$816	58.5%	$1,800	$1,053	5.2%	$75.0	$60.0	$67.5	2.231	34.67	34.67	0.00%
21	NextEra Energy, Inc.	56.0%	$60,926	$34,119	50.5%	$91,100	$46,006	6.2%	$225.0	$185.0	$205.0	2.198	478.00	495.00	0.70%
22	NorthWestern Corp.	47.8%	$4,065	$1,943	52.0%	$4,400	$2,288	3.3%	$80.0	$60.0	$70.0	1.556	50.32	51.10	0.31%
23	OGE Energy Corp.	58.0%	$6,902	$4,003	55.0%	$8,725	$4,799	3.7%	$55.0	$40.0	$47.5	1.979	199.70	200.00	0.03%
24	Otter Tail Corp.	55.3%	$1,319	$729	49.5%	$1,975	$978	6.0%	$55.0	$40.0	$47.5	2.043	39.66	41.80	1.06%
25	Pinnacle West Capital	53.0%	$9,861	$5,226	55.5%	$11,450	$6,355	4.0%	$110.0	$90.0	$100.0	1.794	112.10	114.00	0.34%
26	Portland General Elec.	53.5%	$4,684	$2,506	50.5%	$5,775	$2,916	3.1%	$60.0	$45.0	$52.5	1.615	89.27	90.00	0.16%
27	PPL Corp.	36.7%	$31,726	$11,643	45.0%	$37,500	$16,875	7.7%	$45.0	$35.0	$40.0	1.860	720.32	780.00	1.60%
28	Pub Sv Enterprise Grp.	52.2%	$27,545	$14,378	49.5%	$36,900	$18,266	4.9%	$65.0	$55.0	$60.0	1.655	504.00	505.00	0.04%
29	Sempra Energy	38.4%	$38,769	$14,887	46.0%	$53,400	$24,564	10.5%	$180.0	$130.0	$155.0	2.026	273.77	320.00	3.17%
30	Southern Company	37.6%	$65,750	$24,722	41.0%	$80,000	$32,800	5.8%	$70.0	$50.0	$60.0	1.983	1033.80	1080.00	0.88%
31	WEC Energy Group	49.4%	$19,813	$9,788	48.5%	$24,075	$11,676	3.6%	$90.0	$75.0	$82.5	2.245	315.52	315.50	0.00%
32	Xcel Energy Inc.	43.6%	$28,025	$12,219	42.0%	$36,900	$15,498	4.9%	$65.0	$50.0	$57.5	1.901	514.04	530.00	0.61%

(a) The Value Line Investment Survey (Oct. 25, Nov. 15 & Dec. 13 2019)..
(b) Computed using the formula 2*(1+5-Yr. Change in Equity)/(2+5 Yr. Change in Equity).
(c) Product of average year-end "r" for 2023 and Adjustment Factor.
(d) Product of change in common shares outstanding and M/B Ratio.
(e) Computed as 1 - B/M Ratio.
(f) Product of total capital and equity ratio.
(g) Five-year rate of change in common equity.
(h) Average of High and Low expected market prices divided by 2023 BVPS.

DIVIDEND YIELD

	Company	(a) Price	(b) Dividends	Yield
1	Atmos Energy Corp.	$ 108.23	$ 2.33	2.2%
2	Chesapeake Utilities	$ 93.05	$ 1.68	1.8%
3	New Jersey Resources	$ 43.21	$ 1.25	2.9%
4	NiSource Inc.	$ 26.78	$ 0.80	3.0%
5	Northwest Natural	$ 69.11	$ 1.91	2.8%
6	ONE Gas, Inc.	$ 90.13	$ 2.16	2.4%
7	South Jersey Industries	$ 31.22	$ 1.24	4.0%
8	Southwest Gas	$ 75.81	$ 2.28	3.0%
9	Spire Inc.	$ 79.83	$ 2.46	3.1%
	Average			**2.8%**

(a) Average of closing prices for 30 trading days ended Dec. 27, 2019.
(b) The Value Line Investment Survey, *Summary & Index* (Jan. 3, 2020).

DCF MODEL - GAS GROUP **Exhibit AMM-7**

GROWTH RATES

		(a)	(b)	(c)	(d)
		Earnings Growth			br+sv
	Company	V Line	IBES	Zacks	Growth
1	Atmos Energy Corp.	7.5%	7.2%	7.2%	12.2%
2	Chesapeake Utilities	9.0%	6.0%	7.0%	10.8%
3	New Jersey Resources	2.5%	6.0%	8.0%	4.7%
4	NiSource Inc.	12.5%	4.2%	5.3%	3.0%
5	Northwest Natural	27.0%	3.8%	5.0%	8.7%
6	ONE Gas, Inc.	8.0%	5.0%	6.0%	5.8%
7	South Jersey Industries	10.5%	4.6%	8.5%	10.6%
8	Southwest Gas	9.0%	8.2%	7.3%	7.8%
9	Spire Inc.	5.5%	2.4%	5.5%	5.5%

(a) The Value Line Investment Survey (Nov. 29, 2019).
(b) www.finance.yahoo.com (retrieved Dec. 30, 2019).
(c) www.zacks.com (retrieved Dec. 30, 2019).
(d) See Exhibit AMM-8.

DCF MODEL - GAS GROUP

DCF COST OF EQUITY ESTIMATES

		(a)	(a)	(a)	(a)
		Earnings Growth			**br+sv**
	Company	**V Line**	**IBES**	**Zacks**	**Growth**
1	Atmos Energy Corp.	9.7%	9.4%	9.3%	14.4%
2	Chesapeake Utilities	10.8%	7.8%	8.8%	12.6%
3	New Jersey Resources	5.4%	8.9%	10.9%	7.5%
4	NiSource Inc.	15.5%	7.2%	8.2%	6.0%
5	Northwest Natural	29.8%	6.5%	7.8%	11.5%
6	ONE Gas, Inc.	10.4%	7.4%	8.4%	8.2%
7	South Jersey Industries	14.5%	8.6%	12.5%	14.6%
8	Southwest Gas	12.0%	11.2%	10.3%	10.8%
9	Spire Inc.	8.6%	5.5%	8.6%	8.6%
	Average (b)	**11.0%**	**8.4%**	**9.4%**	**11.0%**
	Midpoint (b,c)	**11.5%**	**8.9%**	**10.1%**	**11.1%**

(a) Sum of dividend yield (Exhibit AMM-7, p. 1) and respective growth rate (Exhibit AMM-7, p. 2).
(b) Excludes highlighted figures.
(c) Average of low and high values.

DCF MODEL - GAS GROUP

SUSTAINABLE GROWTH RATE

		(a)	(a)	(a)			(b)	(c)		(d)	(e)		
		2023					**Adjustment**			**"sv" Factor**			
	Company	**EPS**	**DPS**	**BVPS**	**b**	**r**	**Factor**	**Adjusted r**	**br**	**s**	**v**	**sv**	**br + sv**
1	Atmos Energy Corp.	$5.60	$2.80	$56.05	50.0%	10.0%	1.0590	10.6%	5.3%	0.1237	0.5604	6.93%	**12.2%**
2	Chesapeake Utilities	$5.00	$2.15	$53.65	57.0%	9.3%	1.0852	10.1%	5.8%	0.0911	0.5529	5.04%	**10.8%**
3	New Jersey Resources	$2.35	$1.49	$21.30	36.6%	11.0%	1.0390	11.5%	4.2%	0.0098	0.4675	0.46%	**4.7%**
4	NiSource Inc.	$1.80	$1.10	$20.00	38.9%	9.0%	1.0251	9.2%	3.6%	(0.0185)	0.3333	-0.62%	**3.0%**
5	Northwest Natural	$3.50	$1.97	$29.40	43.7%	11.9%	1.0227	12.2%	5.3%	0.0546	0.6206	3.39%	**8.7%**
6	ONE Gas, Inc.	$4.75	$2.65	$47.90	44.2%	9.9%	1.0247	10.2%	4.5%	0.0223	0.5923	1.32%	**5.8%**
7	South Jersey Industries	$2.40	$1.40	$19.00	41.7%	12.6%	1.0401	13.1%	5.5%	0.0986	0.5250	5.17%	**10.6%**
8	Southwest Gas	$5.80	$2.60	$57.25	55.2%	10.1%	1.0499	10.6%	5.9%	0.0513	0.3811	1.95%	**7.8%**
9	Spire Inc.	$5.00	$2.67	$54.20	46.6%	9.2%	1.0271	9.5%	4.4%	0.0275	0.3978	1.09%	**5.5%**

SUSTAINABLE GROWTH RATE

		(a)	(a)	(f)	(a)	(a)	(f)	(g)	(a)	(a)		(h)	(a)	(a)	(g)
		2018			**2023**			**Chg**	**2023 Price**				**Common Shares**		
	Company	**Eq Ratio**	**Tot Cap**	**Com Eq**	**Eq Ratio**	**Tot Cap**	**Com Eq**	**Equity**	**High**	**Low**	**Avg.**	**M/B**	**2018**	**2023**	**Growth**
1	Atmos Energy Corp.	62.0%	$7,264	$4,501	65.0%	$12,500	$8,125	12.5%	$140.00	$115.00	$127.50	2.275	111.27	145.00	5.44%
2	Chesapeake Utilities	54.7%	$835	$456	65.0%	$1,650	$1,073	18.6%	$140.00	$100.00	$120.00	2.237	16.38	20.00	4.07%
3	New Jersey Resources	49.9%	$2,600	$1,297	59.5%	$3,220	$1,916	8.1%	$45.00	$35.00	$40.00	1.878	87.69	90.00	0.52%
4	NiSource Inc.	42.6%	$12,856	$5,483	47.0%	$15,000	$7,050	5.2%	$35.00	$25.00	$30.00	1.500	372.36	350.00	-1.23%
5	Northwest Natural	48.4%	$1,469	$711	52.5%	$1,700	$893	4.7%	$85.00	$70.00	$77.50	2.636	28.88	32.00	2.07%
6	ONE Gas, Inc.	61.8%	$3,328	$2,058	62.0%	$4,250	$2,635	5.1%	$135.00	$100.00	$117.50	2.453	52.57	55.00	0.91%
7	South Jersey Industries	37.5%	$3,374	$1,265	42.0%	$4,500	$1,890	8.4%	$45.00	$35.00	$40.00	2.105	79.55	100.00	4.68%
8	Southwest Gas	49.2%	$4,359	$2,146	54.0%	$6,550	$3,537	10.5%	$110.00	$75.00	$92.50	1.616	53.03	62.00	3.17%
9	Spire Inc.	54.5%	$4,156	$2,265	60.0%	$4,950	$2,970	5.6%	$105.00	$75.00	$90.00	1.661	50.67	55.00	1.65%

(a) The Value Line Investment Survey (Nov. 29, 2019).
(b) Computed using the formula 2*(1+5-Yr. Change in Equity)/(2+5 Yr. Change in Equity).
(c) Product of average year-end "r" for 2023 and Adjustment Factor.
(d) Product of change in common shares outstanding and M/B Ratio.
(e) Computed as 1 - B/M Ratio.
(f) Product of total capital and equity ratio.
(g) Five-year rate of change.
(h) Average of High and Low expected market prices divided by 2023 BVPS.

Atlantic Path 15 / Startrans / So. Cal Edison		*Pioneer Transmission*	
Jun-07	6.54%	Apr-08	6.81%
Jul-07	6.49%	May-08	6.79%
Aug-07	6.51%	Jun-08	6.93%
Sep-07	6.45%	Jul-08	6.97%
Oct-07	6.36%	Aug-08	6.98%
Nov-07	6.27%	Sep-08	7.15%

	Current		**Projected**	
Historical Baa Bond Yield	6.69%	(a)	6.69%	(a)
Current Baa Bond Yield	3.78%	(b)	4.93%	(c)
Change in Bond Yield	-2.91%		-1.76%	
Risk Premium/Interest Rate Relationship	-0.43216	(d)	-0.43216	(d)
Adjustment to Low-end Threshold	1.26%		0.76%	
Current Baa Bond Yield	3.78%		4.93%	
Original Threshold	1.00%		1.00%	
Adjustment	1.26%		0.76%	
Adjusted Low-end Threshold	**6.04%**		**6.69%**	

(a) Average Baa utility bond yield for 6-mo. periods ending Nov. 2007 and Sep. 2008.

(b) Average Baa utility bond yield for 6-months ended Dec. 2019.

(c) Average Baa utility bond yield for 2020-24 based on data from IHS Global Insight, Long-Term Macro Forecast - Baseline (Oct. 15, 2019); Energy Information Administration, Annual Energy Outlook 2020 (Jan. 29, 2020), Moody's Investors Service at www.credittrends.com.

(d) Exhibit AMM-12, page 4.

CAPM - CURRENT BOND YIELD **Exhibit AMM-10**

ELECTRIC GROUP

		(a)	(b)		(c)		(d)		(d)	(e)	
		Market Return (R_m)									
	Company	Div Yield	Proj. Growth	Cost of Equity	Risk-Free Rate	Risk Premium	Beta	Unadjusted K_e	Market Cap	Size Adjustment	CAPM Result
1	ALLETE	2.3%	9.3%	11.6%	2.3%	9.3%	0.65	8.3%	$4,100	1.26%	9.6%
2	Alliant Energy	2.3%	9.3%	11.6%	2.3%	9.3%	0.60	7.9%	$12,700	0.84%	8.7%
3	Ameren Corp.	2.3%	9.3%	11.6%	2.3%	9.3%	0.55	7.4%	$18,000	0.50%	7.9%
4	American Elec Pwr	2.3%	9.3%	11.6%	2.3%	9.3%	0.55	7.4%	$45,000	-0.29%	7.1%
5	Avangrid, Inc.	2.3%	9.3%	11.6%	2.3%	9.3%	0.40	6.0%	$15,000	0.50%	6.5%
6	Avista Corp.	2.3%	9.3%	11.6%	2.3%	9.3%	0.60	7.9%	$3,100	1.26%	9.1%
7	Black Hills Corp.	2.3%	9.3%	11.6%	2.3%	9.3%	0.70	8.8%	$4,700	0.82%	9.6%
8	CMS Energy Corp.	2.3%	9.3%	11.6%	2.3%	9.3%	0.50	6.9%	$17,000	0.50%	7.4%
9	Consolidated Edison	2.3%	9.3%	11.6%	2.3%	9.3%	0.45	6.5%	$29,000	0.50%	7.0%
10	Dominion Energy	2.3%	9.3%	11.6%	2.3%	9.3%	0.55	7.4%	$67,000	-0.29%	7.1%
11	DTE Energy Co.	2.3%	9.3%	11.6%	2.3%	9.3%	0.55	7.4%	$23,000	0.50%	7.9%
12	Duke Energy Corp.	2.3%	9.3%	11.6%	2.3%	9.3%	0.50	6.9%	$68,000	-0.29%	6.7%
13	Entergy Corp.	2.3%	9.3%	11.6%	2.3%	9.3%	0.60	7.9%	$23,000	0.50%	8.4%
14	Eversource Energy	2.3%	9.3%	11.6%	2.3%	9.3%	0.55	7.4%	$26,000	0.50%	7.9%
15	Exelon Corp.	2.3%	9.3%	11.6%	2.3%	9.3%	0.65	8.3%	$44,000	-0.29%	8.0%
16	FirstEnergy Corp.	2.3%	9.3%	11.6%	2.3%	9.3%	0.65	8.3%	$26,000	0.50%	8.8%
17	Fortis Inc.	2.3%	9.3%	11.6%	2.3%	9.3%	0.60	7.9%	$23,000	0.50%	8.4%
18	Hawaiian Elec.	2.3%	9.3%	11.6%	2.3%	9.3%	0.55	7.4%	$4,800	0.82%	8.2%
19	IDACORP, Inc.	2.3%	9.3%	11.6%	2.3%	9.3%	0.55	7.4%	$5,500	0.82%	8.2%
20	MGE Energy	2.3%	9.3%	11.6%	2.3%	9.3%	0.55	7.4%	$2,700	1.54%	8.9%
21	NextEra Energy, Inc.	2.3%	9.3%	11.6%	2.3%	9.3%	0.55	7.4%	$111,000	-0.29%	7.1%
22	NorthWestern Corp.	2.3%	9.3%	11.6%	2.3%	9.3%	0.60	7.9%	$3,700	1.26%	9.1%
23	OGE Energy Corp.	2.3%	9.3%	11.6%	2.3%	9.3%	0.75	9.3%	$8,400	0.84%	10.1%
24	Otter Tail Corp.	2.3%	9.3%	11.6%	2.3%	9.3%	0.70	8.8%	$2,000	1.54%	10.3%
25	Pinnacle West Capital	2.3%	9.3%	11.6%	2.3%	9.3%	0.55	7.4%	$11,000	0.84%	8.2%
26	Portland General Elec.	2.3%	9.3%	11.6%	2.3%	9.3%	0.60	7.9%	$5,000	0.82%	8.7%
27	PPL Corp.	2.3%	9.3%	11.6%	2.3%	9.3%	0.70	8.8%	$24,000	0.50%	9.3%
28	Pub Sv Enterprise Grp.	2.3%	9.3%	11.6%	2.3%	9.3%	0.65	8.3%	$31,000	-0.29%	8.0%
29	Sempra Energy	2.3%	9.3%	11.6%	2.3%	9.3%	0.75	9.3%	$40,000	-0.29%	9.0%
30	Southern Company	2.3%	9.3%	11.6%	2.3%	9.3%	0.50	6.9%	$64,000	-0.29%	6.7%
31	WEC Energy Group	2.3%	9.3%	11.6%	2.3%	9.3%	0.50	6.9%	$28,000	0.50%	7.4%
32	Xcel Energy Inc.	2.3%	9.3%	11.6%	2.3%	9.3%	0.50	6.9%	$33,000	-0.29%	6.7%
	Average (f)										**8.2%**
	Midpoint (f) (g)										**8.4%**

(a) Weighted average for dividend-paying stocks in the S&P 500 based on data from http://finance.yahoo.com (retrieved Jan. 3, 2020).
(b) Average of weighted average earnings growth rates from IBES, Zacks, and Value Line for dividend-paying stocks in the S&P 500 based on data from http://finance.yahoo.com (retrieved Jan. 3, 2020), www.valueline.com (retrieved Jan. 2, 2020), and www.zacks.com (retrieved Jan. 2, 2020).
(c) Average yield on 30-year Treasury bonds for the six-months ending Dec. 2019 based on data from https://fred.stlouisfed.org/.
(d) The Value Line Investment Survey (Oct. 25, Nov. 15 & Dec. 13 2019).
(e) Duff & Phelps, 2019 CRSP Deciles Size Study -- Supplementary Data Exhibits, Cost of Capital Navigator.
(f) Excludes highlighted figures.
(g) Average of low and high values.

CAPM - PROJECTED BOND YIELD

ELECTRIC GROUP

		(a)	(b)		(c)		(d)		(d)	(e)	
		Market Return (R_m)									
	Company	**Div Yield**	**Proj. Growth**	**Cost of Equity**	**Risk-Free Rate**	**Risk Premium**	**Beta**	**Unadjusted K_e**	**Market Cap**	**Size Adjustment**	**CAPM Result**
1	ALLETE	2.3%	9.3%	11.6%	3.1%	8.5%	0.65	8.6%	$4,100	1.26%	9.9%
2	Alliant Energy	2.3%	9.3%	11.6%	3.1%	8.5%	0.60	8.2%	$12,700	0.84%	9.0%
3	Ameren Corp.	2.3%	9.3%	11.6%	3.1%	8.5%	0.55	7.8%	$18,000	0.50%	8.3%
4	American Elec Pwr	2.3%	9.3%	11.6%	3.1%	8.5%	0.55	7.8%	$45,000	-0.29%	7.5%
5	Avangrid, Inc.	2.3%	9.3%	11.6%	3.1%	8.5%	0.40	6.5%	$15,000	0.50%	7.0%
6	Avista Corp.	2.3%	9.3%	11.6%	3.1%	8.5%	0.60	8.2%	$3,100	1.26%	9.4%
7	Black Hills Corp.	2.3%	9.3%	11.6%	3.1%	8.5%	0.70	9.0%	$4,700	0.82%	9.9%
8	CMS Energy Corp.	2.3%	9.3%	11.6%	3.1%	8.5%	0.50	7.3%	$17,000	0.50%	7.8%
9	Consolidated Edison	2.3%	9.3%	11.6%	3.1%	8.5%	0.45	6.9%	$29,000	0.50%	7.4%
10	Dominion Energy	2.3%	9.3%	11.6%	3.1%	8.5%	0.55	7.8%	$67,000	-0.29%	7.5%
11	DTE Energy Co.	2.3%	9.3%	11.6%	3.1%	8.5%	0.55	7.8%	$23,000	0.50%	8.3%
12	Duke Energy Corp.	2.3%	9.3%	11.6%	3.1%	8.5%	0.50	7.3%	$68,000	-0.29%	7.1%
13	Entergy Corp.	2.3%	9.3%	11.6%	3.1%	8.5%	0.60	8.2%	$23,000	0.50%	8.7%
14	Eversource Energy	2.3%	9.3%	11.6%	3.1%	8.5%	0.55	7.8%	$26,000	0.50%	8.3%
15	Exelon Corp.	2.3%	9.3%	11.6%	3.1%	8.5%	0.65	8.6%	$44,000	-0.29%	8.3%
16	FirstEnergy Corp.	2.3%	9.3%	11.6%	3.1%	8.5%	0.65	8.6%	$26,000	0.50%	9.1%
17	Fortis Inc.	2.3%	9.3%	11.6%	3.1%	8.5%	0.60	8.2%	$23,000	0.50%	8.7%
18	Hawaiian Elec.	2.3%	9.3%	11.6%	3.1%	8.5%	0.55	7.8%	$4,800	0.82%	8.6%
19	IDACORP, Inc.	2.3%	9.3%	11.6%	3.1%	8.5%	0.55	7.8%	$5,500	0.82%	8.6%
20	MGE Energy	2.3%	9.3%	11.6%	3.1%	8.5%	0.55	7.8%	$2,700	1.54%	9.3%
21	NextEra Energy, Inc.	2.3%	9.3%	11.6%	3.1%	8.5%	0.55	7.8%	$111,000	-0.29%	7.5%
22	NorthWestern Corp.	2.3%	9.3%	11.6%	3.1%	8.5%	0.60	8.2%	$3,700	1.26%	9.4%
23	OGE Energy Corp.	2.3%	9.3%	11.6%	3.1%	8.5%	0.75	9.5%	$8,400	0.84%	10.3%
24	Otter Tail Corp.	2.3%	9.3%	11.6%	3.1%	8.5%	0.70	9.0%	$2,000	1.54%	10.6%
25	Pinnacle West Capital	2.3%	9.3%	11.6%	3.1%	8.5%	0.55	7.8%	$11,000	0.84%	8.6%
26	Portland General Elec.	2.3%	9.3%	11.6%	3.1%	8.5%	0.60	8.2%	$5,000	0.82%	9.0%
27	PPL Corp.	2.3%	9.3%	11.6%	3.1%	8.5%	0.70	9.0%	$24,000	0.50%	9.5%
28	Pub Sv Enterprise Grp.	2.3%	9.3%	11.6%	3.1%	8.5%	0.65	8.6%	$31,000	-0.29%	8.3%
29	Sempra Energy	2.3%	9.3%	11.6%	3.1%	8.5%	0.75	9.5%	$40,000	-0.29%	9.2%
30	Southern Company	2.3%	9.3%	11.6%	3.1%	8.5%	0.50	7.3%	$64,000	-0.29%	7.1%
31	WEC Energy Group	2.3%	9.3%	11.6%	3.1%	8.5%	0.50	7.3%	$28,000	0.50%	7.8%
32	Xcel Energy Inc.	2.3%	9.3%	11.6%	3.1%	8.5%	0.50	7.3%	$33,000	-0.29%	7.1%
	Average (f)										**8.5%**
	Midpoint (f) (g)										**8.8%**

(a) Weighted average for dividend-paying stocks in the S&P 500 based on data from http://finance.yahoo.com (retrieved Jan. 3, 2020).
(b) Average of weighted average earnings growth rates from IBES, Zacks, and Value Line for dividend-paying stocks in the S&P 500 based on data from http://finance.yahoo.com (retrieved Jan. 3, 2020), www.valueline.com (retrieved Jan. 2, 2020), and www.zacks.com (retrieved Jan. 2, 2020).
(c) Average yield on 30-year Treasury bonds for 2020-23 based on data from the Value Line Investment Survey, Forecast for the U.S. Economy (Nov. 29, 2019); IHS Global Insight, Long-Term Macro Forecast - Baseline (Oct. 15, 2019); & Wolters Kluwer, Blue Chip Financial Forecasts (Dec. 1, 2019).
(d) The Value Line Investment Survey (Oct. 25, Nov. 15 & Dec. 13 2019).
(e) Duff & Phelps, 2019 CRSP Deciles Size Study -- Supplementary Data Exhibits, Cost of Capital Navigator.
(f) Excludes highlighted figures.
(g) Average of low and high values.

CAPM - CURRENT BOND YIELD

GAS GROUP

		(a)	(b)		(c)		(d)		(d)	(e)	
		Market Return (R_m)									
	Company	**Div Yield**	**Proj. Growth**	**Cost of Equity**	**Risk-Free Rate**	**Risk Premium**	**Beta**	**Unadjusted K_e**	**Market Cap**	**Size Adjustment**	**CAPM Result**
1	Atmos Energy Corp.	2.3%	9.3%	11.6%	2.3%	9.3%	0.60	7.9%	$12,800	0.84%	8.7%
2	Chesapeake Utilities	2.3%	9.3%	11.6%	2.3%	9.3%	0.65	8.3%	$1,500	1.58%	9.9%
3	New Jersey Resources	2.3%	9.3%	11.6%	2.3%	9.3%	0.70	8.8%	$3,900	1.26%	10.1%
4	NiSource Inc.	2.3%	9.3%	11.6%	2.3%	9.3%	0.55	7.4%	$9,700	0.84%	8.2%
5	Northwest Natural	2.3%	9.3%	11.6%	2.3%	9.3%	0.60	7.9%	$2,000	1.54%	9.4%
6	ONE Gas, Inc.	2.3%	9.3%	11.6%	2.3%	9.3%	0.80	9.7%	$2,800	1.54%	11.3%
7	South Jersey Industries	2.3%	9.3%	11.6%	2.3%	9.3%	0.80	9.7%	$2,800	1.54%	11.3%
8	Southwest Gas	2.3%	9.3%	11.6%	2.3%	9.3%	0.70	8.8%	$4,200	1.26%	10.1%
9	Spire Inc.	2.3%	9.3%	11.6%	2.3%	9.3%	0.65	8.3%	$3,800	1.26%	9.6%
	Average										**9.8%**
	Midpoint (f)										**9.8%**

(a) Weighted average for www.valueline.com (retrieved Jan. 2, 2020).
(b) Average of weighted average earnings growth rates from IBES, Zacks, and Value Line for dividend-paying stocks in the S&P 500 based on data from http://finance.yahoo.com (retrieved Jan. 3, 2020), www.valueline.com (retrieved Jan. 2, 2020), and www.zacks.com (retrieved Jan. 2, 2020).
(c) Average yield on 30-year Treasury bonds for the six-months ending Dec. 2019 based on data from https://fred.stlouisfed.org/.
(d) The Value Line Investment Survey (Nov. 29, 2019).
(e) Duff & Phelps, 2019 CRSP Deciles Size Study -- Supplementary Data Exhibits, Cost of Capital Navigator.
(f) Average of low and high values.

CAPM - PROJECTED BOND YIELD

GAS GROUP

		(a)	(b)		(c)		(d)		(d)	(e)	
		Market Return (R_m)									
	Company	**Div Yield**	**Proj. Growth**	**Cost of Equity**	**Risk-Free Rate**	**Risk Premium**	**Beta**	**Unadjusted K_e**	**Market Cap**	**Size Adjustment**	**CAPM Result**
1	Atmos Energy Corp.	2.3%	9.3%	11.6%	3.1%	8.5%	0.60	8.2%	$12,800	0.84%	9.0%
2	Chesapeake Utilities	2.3%	9.3%	11.6%	3.1%	8.5%	0.65	8.6%	$1,500	1.58%	10.2%
3	New Jersey Resources	2.3%	9.3%	11.6%	3.1%	8.5%	0.70	9.0%	$3,900	1.26%	10.3%
4	NiSource Inc.	2.3%	9.3%	11.6%	3.1%	8.5%	0.55	7.8%	$9,700	0.84%	8.6%
5	Northwest Natural	2.3%	9.3%	11.6%	3.1%	8.5%	0.60	8.2%	$2,000	1.54%	9.7%
6	ONE Gas, Inc.	2.3%	9.3%	11.6%	3.1%	8.5%	0.80	9.9%	$2,800	1.54%	11.4%
7	South Jersey Industries	2.3%	9.3%	11.6%	3.1%	8.5%	0.80	9.9%	$2,800	1.54%	11.4%
8	Southwest Gas	2.3%	9.3%	11.6%	3.1%	8.5%	0.70	9.0%	$4,200	1.26%	10.3%
9	Spire Inc.	2.3%	9.3%	11.6%	3.1%	8.5%	0.65	8.6%	$3,800	1.26%	9.9%
	Average										**10.1%**
	Midpoint (f)										**10.0%**

(a) Weighted average for www.valueline.com (retrieved Jan. 2, 2020).
(b) Average of weighted average earnings growth rates from IBES, Zacks, and Value Line for dividend-paying stocks in the S&P 500 based on data from http://finance.yahoo.com (retrieved Jan. 3, 2020), www.valueline.com (retrieved Jan. 2, 2020), and www.zacks.com (retrieved Jan. 2, 2020).
(c) Average yield on 30-year Treasury bonds for 2020-23 based on data from the Value Line Investment Survey, Forecast for the U.S. Economy (Nov. 29, 2019); IHS Global Insight, Long-Term Macro Forecast - Baseline (Oct. 15, 2019); & Wolters Kluwer, Blue Chip Financial Forecasts (Dec. 1, 2019).
(d) The Value Line Investment Survey (Nov. 29, 2019).
(e) Duff & Phelps, 2019 CRSP Deciles Size Study -- Supplementary Data Exhibits, Cost of Capital Navigator.
(f) Average of low and high values.

EMPIRICAL CAPM - CURRENT BOND YIELD

ELECTRIC GROUP

		(a)	(b)		(c)		(d)		(e)	(d)				(e)	(f)	
		Market Return (R_m)														
		Div	Proj.	Cost of	Risk-Free	Risk	Unadjusted RP		Beta Adjusted RP				Unadjusted	Market	Size	ECAPM
	Company	**Yield**	**Growth**	**Equity**	**Rate**	**Premium**	**Weight**	***RP[1]***	**Beta**	**Weight**	***RP[2]***	**Total RP**	**K_e**	**Cap**	**Adjustment**	**Result**
1	ALLETE	2.3%	9.3%	11.6%	2.3%	9.3%	25%	2.3%	0.65	75%	4.5%	6.8%	9.1%	$4,100	1.26%	10.4%
2	Alliant Energy	2.3%	9.3%	11.6%	2.3%	9.3%	25%	2.3%	0.60	75%	4.2%	6.5%	8.8%	$12,700	0.84%	9.6%
3	Ameren Corp.	2.3%	9.3%	11.6%	2.3%	9.3%	25%	2.3%	0.55	75%	3.8%	6.2%	8.5%	$18,000	0.50%	9.0%
4	American Elec Pwr	2.3%	9.3%	11.6%	2.3%	9.3%	25%	2.3%	0.55	75%	3.8%	6.2%	8.5%	$45,000	-0.29%	8.2%
5	Avangrid, Inc.	2.3%	9.3%	11.6%	2.3%	9.3%	25%	2.3%	0.40	75%	2.8%	5.1%	7.4%	$15,000	0.50%	7.9%
6	Avista Corp.	2.3%	9.3%	11.6%	2.3%	9.3%	25%	2.3%	0.60	75%	4.2%	6.5%	8.8%	$3,100	1.26%	10.1%
7	Black Hills Corp.	2.3%	9.3%	11.6%	2.3%	9.3%	25%	2.3%	0.70	75%	4.9%	7.2%	9.5%	$4,700	0.82%	10.3%
8	CMS Energy Corp.	2.3%	9.3%	11.6%	2.3%	9.3%	25%	2.3%	0.50	75%	3.5%	5.8%	8.1%	$17,000	0.50%	8.6%
9	Consolidated Edison	2.3%	9.3%	11.6%	2.3%	9.3%	25%	2.3%	0.45	75%	3.1%	5.5%	7.8%	$29,000	0.50%	8.3%
10	Dominion Energy	2.3%	9.3%	11.6%	2.3%	9.3%	25%	2.3%	0.55	75%	3.8%	6.2%	8.5%	$67,000	-0.29%	8.2%
11	DTE Energy Co.	2.3%	9.3%	11.6%	2.3%	9.3%	25%	2.3%	0.55	75%	3.8%	6.2%	8.5%	$23,000	0.50%	9.0%
12	Duke Energy Corp.	2.3%	9.3%	11.6%	2.3%	9.3%	25%	2.3%	0.50	75%	3.5%	5.8%	8.1%	$68,000	-0.29%	7.8%
13	Entergy Corp.	2.3%	9.3%	11.6%	2.3%	9.3%	25%	2.3%	0.60	75%	4.2%	6.5%	8.8%	$23,000	0.50%	9.3%
14	Eversource Energy	2.3%	9.3%	11.6%	2.3%	9.3%	25%	2.3%	0.55	75%	3.8%	6.2%	8.5%	$26,000	0.50%	9.0%
15	Exelon Corp.	2.3%	9.3%	11.6%	2.3%	9.3%	25%	2.3%	0.65	75%	4.5%	6.8%	9.1%	$44,000	-0.29%	8.9%
16	FirstEnergy Corp.	2.3%	9.3%	11.6%	2.3%	9.3%	25%	2.3%	0.65	75%	4.5%	6.8%	9.1%	$26,000	0.50%	9.7%
17	Fortis Inc.	2.3%	9.3%	11.6%	2.3%	9.3%	25%	2.3%	0.60	75%	4.2%	6.5%	8.8%	$23,000	0.50%	9.3%
18	Hawaiian Elec.	2.3%	9.3%	11.6%	2.3%	9.3%	25%	2.3%	0.55	75%	3.8%	6.2%	8.5%	$4,800	0.82%	9.3%
19	IDACORP, Inc.	2.3%	9.3%	11.6%	2.3%	9.3%	25%	2.3%	0.55	75%	3.8%	6.2%	8.5%	$5,500	0.82%	9.3%
20	MGE Energy	2.3%	9.3%	11.6%	2.3%	9.3%	25%	2.3%	0.55	75%	3.8%	6.2%	8.5%	$2,700	1.54%	10.0%
21	NextEra Energy, Inc.	2.3%	9.3%	11.6%	2.3%	9.3%	25%	2.3%	0.55	75%	3.8%	6.2%	8.5%	$111,000	-0.29%	8.2%
22	NorthWestern Corp.	2.3%	9.3%	11.6%	2.3%	9.3%	25%	2.3%	0.60	75%	4.2%	6.5%	8.8%	$3,700	1.26%	10.1%
23	OGE Energy Corp.	2.3%	9.3%	11.6%	2.3%	9.3%	25%	2.3%	0.75	75%	5.2%	7.5%	9.8%	$8,400	0.84%	10.7%
24	Otter Tail Corp.	2.3%	9.3%	11.6%	2.3%	9.3%	25%	2.3%	0.70	75%	4.9%	7.2%	9.5%	$2,000	1.54%	11.0%
25	Pinnacle West Capital	2.3%	9.3%	11.6%	2.3%	9.3%	25%	2.3%	0.55	75%	3.8%	6.2%	8.5%	$11,000	0.84%	9.3%
26	Portland General Elec.	2.3%	9.3%	11.6%	2.3%	9.3%	25%	2.3%	0.60	75%	4.2%	6.5%	8.8%	$5,000	0.82%	9.6%
27	PPL Corp.	2.3%	9.3%	11.6%	2.3%	9.3%	25%	2.3%	0.70	75%	4.9%	7.2%	9.5%	$24,000	0.50%	10.0%
28	Pub Sv Enterprise Grp.	2.3%	9.3%	11.6%	2.3%	9.3%	25%	2.3%	0.65	75%	4.5%	6.8%	9.1%	$31,000	-0.29%	8.9%
29	Sempra Energy	2.3%	9.3%	11.6%	2.3%	9.3%	25%	2.3%	0.75	75%	5.2%	7.5%	9.8%	$40,000	-0.29%	9.6%
30	Southern Company	2.3%	9.3%	11.6%	2.3%	9.3%	25%	2.3%	0.50	75%	3.5%	5.8%	8.1%	$64,000	-0.29%	7.8%
31	WEC Energy Group	2.3%	9.3%	11.6%	2.3%	9.3%	25%	2.3%	0.50	75%	3.5%	5.8%	8.1%	$28,000	0.50%	8.6%
32	Xcel Energy Inc.	2.3%	9.3%	11.6%	2.3%	9.3%	25%	2.3%	0.50	75%	3.5%	5.8%	8.1%	$33,000	-0.29%	7.8%
	Average (f)															**9.2%**
	Midpoint (f) (g)															**9.4%**

(a) Weighted average for dividend-paying stocks in the S&P 500 based on data from http://finance.yahoo.com (retrieved Jan. 3, 2020).
(b) Average of weighted average earnings growth rates from IBES, Zacks, and Value Line for dividend-paying stocks in the S&P 500 based on data from http://finance.yahoo.com (retrieved Jan. 3, 2020), www.valueline.com (retrieved Jan. 2, 2020), and www.zacks.com (retrieved Jan. 2, 2020).
(c) Average yield on 30-year Treasury bonds for the six-months ending Dec. 2019 based on data from https://fred.stlouisfed.org/.
(d) Roger A. Morin, "New Regulatory Finance," *Public Utilities Reports, Inc.* (2006) at 190.
(e) The Value Line Investment Survey (Oct. 25, Nov. 15 & Dec. 13 2019).
(f) Duff & Phelps, 2019 CRSP Deciles Size Study -- Supplementary Data Exhibits, Cost of Capital Navigator.
(f) Excludes highlighted figures.
(g) Average of low and high values.

EMPIRICAL CAPM - PROJECTED BOND YIELD

ELECTRIC GROUP

		(a)	(b)		(c)		(d)		(e)	(d)				(e)	(f)	
		Market Return (R_m)					Unadjusted RP		Beta Adjusted RP							
	Company	Div Yield	Proj. Growth	Cost of Equity	Risk-Free Rate	Risk Premium	Weight	RP^1	Beta	Weight	RP^2	Total RP	Unadjusted K_e	Market Cap	Size Adjustment	ECAPM Result
1	ALLETE	2.3%	9.3%	11.6%	3.1%	8.5%	25%	2.1%	0.65	75%	4.1%	6.3%	9.4%	$4,100	1.26%	10.6%
2	Alliant Energy	2.3%	9.3%	11.6%	3.1%	8.5%	25%	2.1%	0.60	75%	3.8%	5.9%	9.0%	$12,700	0.84%	9.9%
3	Ameren Corp.	2.3%	9.3%	11.6%	3.1%	8.5%	25%	2.1%	0.55	75%	3.5%	5.6%	8.7%	$18,000	0.50%	9.2%
4	American Elec Pwr	2.3%	9.3%	11.6%	3.1%	8.5%	25%	2.1%	0.55	75%	3.5%	5.6%	8.7%	$45,000	-0.29%	8.4%
5	Avangrid, Inc.	2.3%	9.3%	11.6%	3.1%	8.5%	25%	2.1%	0.40	75%	2.5%	4.7%	7.8%	$15,000	0.50%	8.3%
6	Avista Corp.	2.3%	9.3%	11.6%	3.1%	8.5%	25%	2.1%	0.60	75%	3.8%	5.9%	9.0%	$3,100	1.26%	10.3%
7	Black Hills Corp.	2.3%	9.3%	11.6%	3.1%	8.5%	25%	2.1%	0.70	75%	4.5%	6.6%	9.7%	$4,700	0.82%	10.5%
8	CMS Energy Corp.	2.3%	9.3%	11.6%	3.1%	8.5%	25%	2.1%	0.50	75%	3.2%	5.3%	8.4%	$17,000	0.50%	8.9%
9	Consolidated Edison	2.3%	9.3%	11.6%	3.1%	8.5%	25%	2.1%	0.45	75%	2.9%	5.0%	8.1%	$29,000	0.50%	8.6%
10	Dominion Energy	2.3%	9.3%	11.6%	3.1%	8.5%	25%	2.1%	0.55	75%	3.5%	5.6%	8.7%	$67,000	-0.29%	8.4%
11	DTE Energy Co.	2.3%	9.3%	11.6%	3.1%	8.5%	25%	2.1%	0.55	75%	3.5%	5.6%	8.7%	$23,000	0.50%	9.2%
12	Duke Energy Corp.	2.3%	9.3%	11.6%	3.1%	8.5%	25%	2.1%	0.50	75%	3.2%	5.3%	8.4%	$68,000	-0.29%	8.1%
13	Entergy Corp.	2.3%	9.3%	11.6%	3.1%	8.5%	25%	2.1%	0.60	75%	3.8%	5.9%	9.0%	$23,000	0.50%	9.5%
14	Eversource Energy	2.3%	9.3%	11.6%	3.1%	8.5%	25%	2.1%	0.55	75%	3.5%	5.6%	8.7%	$26,000	0.50%	9.2%
15	Exelon Corp.	2.3%	9.3%	11.6%	3.1%	8.5%	25%	2.1%	0.65	75%	4.1%	6.3%	9.4%	$44,000	-0.29%	9.1%
16	FirstEnergy Corp.	2.3%	9.3%	11.6%	3.1%	8.5%	25%	2.1%	0.65	75%	4.1%	6.3%	9.4%	$26,000	0.50%	9.9%
17	Fortis Inc.	2.3%	9.3%	11.6%	3.1%	8.5%	25%	2.1%	0.60	75%	3.8%	5.9%	9.0%	$23,000	0.50%	9.5%
18	Hawaiian Elec.	2.3%	9.3%	11.6%	3.1%	8.5%	25%	2.1%	0.55	75%	3.5%	5.6%	8.7%	$4,800	0.82%	9.5%
19	IDACORP, Inc.	2.3%	9.3%	11.6%	3.1%	8.5%	25%	2.1%	0.55	75%	3.5%	5.6%	8.7%	$5,500	0.82%	9.5%
20	MGE Energy	2.3%	9.3%	11.6%	3.1%	8.5%	25%	2.1%	0.55	75%	3.5%	5.6%	8.7%	$2,700	1.54%	10.3%
21	NextEra Energy, Inc.	2.3%	9.3%	11.6%	3.1%	8.5%	25%	2.1%	0.55	75%	3.5%	5.6%	8.7%	$111,000	-0.29%	8.4%
22	NorthWestern Corp.	2.3%	9.3%	11.6%	3.1%	8.5%	25%	2.1%	0.60	75%	3.8%	5.9%	9.0%	$3,700	1.26%	10.3%
23	OGE Energy Corp.	2.3%	9.3%	11.6%	3.1%	8.5%	25%	2.1%	0.75	75%	4.8%	6.9%	10.0%	$8,400	0.84%	10.8%
24	Otter Tail Corp.	2.3%	9.3%	11.6%	3.1%	8.5%	25%	2.1%	0.70	75%	4.5%	6.6%	9.7%	$2,000	1.54%	11.2%
25	Pinnacle West Capital	2.3%	9.3%	11.6%	3.1%	8.5%	25%	2.1%	0.55	75%	3.5%	5.6%	8.7%	$11,000	0.84%	9.6%
26	Portland General Elec.	2.3%	9.3%	11.6%	3.1%	8.5%	25%	2.1%	0.60	75%	3.8%	5.9%	9.0%	$5,000	0.82%	9.9%
27	PPL Corp.	2.3%	9.3%	11.6%	3.1%	8.5%	25%	2.1%	0.70	75%	4.5%	6.6%	9.7%	$24,000	0.50%	10.2%
28	Pub Sv Enterprise Grp.	2.3%	9.3%	11.6%	3.1%	8.5%	25%	2.1%	0.65	75%	4.1%	6.3%	9.4%	$31,000	-0.29%	9.1%
29	Sempra Energy	2.3%	9.3%	11.6%	3.1%	8.5%	25%	2.1%	0.75	75%	4.8%	6.9%	10.0%	$40,000	-0.29%	9.7%
30	Southern Company	2.3%	9.3%	11.6%	3.1%	8.5%	25%	2.1%	0.50	75%	3.2%	5.3%	8.4%	$64,000	-0.29%	8.1%
31	WEC Energy Group	2.3%	9.3%	11.6%	3.1%	8.5%	25%	2.1%	0.50	75%	3.2%	5.3%	8.4%	$28,000	0.50%	8.9%
32	Xcel Energy Inc.	2.3%	9.3%	11.6%	3.1%	8.5%	25%	2.1%	0.50	75%	3.2%	5.3%	8.4%	$33,000	-0.29%	8.1%
	Average (f)															**9.4%**
	Midpoint (f) (g)															**9.7%**

(a) Weighted average for dividend-paying stocks in the S&P 500 based on data from http://finance.yahoo.com (retrieved Jan. 3, 2020).
(b) Average of weighted average earnings growth rates from IBES, Zacks, and Value Line for dividend-paying stocks in the S&P 500 based on data from http://finance.yahoo.com (retrieved Jan. 3, 2020), www.valueline.com (retrieved Jan. 2, 2020), and www.zacks.com (retrieved Jan. 2, 2020).
(c) Average yield on 30-year Treasury bonds for 2020-23 based on data from the Value Line Investment Survey, Forecast for the U.S. Economy (Nov. 29, 2019); IHS Global Insight, Long-Term Macro Forecast - Baseline (Oct. 15, 2019); & Wolters Kluwer, Blue Chip Financial Forecasts (Dec. 1, 2019).
(d) Roger A. Morin, "New Regulatory Finance," *Public Utilities Reports, Inc.* (2006) at 190.
(e) The Value Line Investment Survey (Oct. 25, Nov. 15 & Dec. 13 2019).
(f) Duff & Phelps, 2019 CRSP Deciles Size Study -- Supplementary Data Exhibits, Cost of Capital Navigator.
(f) Excludes highlighted figures.
(g) Average of low and high values.

GAS GROUP

		(a)	(b)		(c)		(d)		(e)	(d)				(e)	(f)	
		Market Return (R_m)					Unadjusted RP		Beta Adjusted RP							
	Company	Div Yield	Proj. Growth	Cost of Equity	Risk-Free Rate	Risk Premium	Weight	*RP* [1]	Beta	Weight	*RP* [2]	Total RP	Unadjusted K_e	Market Cap	Size Adjustment	ECAPM Result
1	Atmos Energy Corp.	2.3%	9.3%	11.6%	2.3%	9.3%	25%	2.3%	0.60	75%	4.2%	6.5%	8.8%	$12,800	0.84%	9.6%
2	Chesapeake Utilities	2.3%	9.3%	11.6%	2.3%	9.3%	25%	2.3%	0.65	75%	4.5%	6.8%	9.1%	$1,500	1.58%	10.7%
3	New Jersey Resources	2.3%	9.3%	11.6%	2.3%	9.3%	25%	2.3%	0.70	75%	4.9%	7.2%	9.5%	$3,900	1.26%	10.8%
4	NiSource Inc.	2.3%	9.3%	11.6%	2.3%	9.3%	25%	2.3%	0.55	75%	3.8%	6.2%	8.5%	$9,700	0.84%	9.3%
5	Northwest Natural	2.3%	9.3%	11.6%	2.3%	9.3%	25%	2.3%	0.60	75%	4.2%	6.5%	8.8%	$2,000	1.54%	10.3%
6	ONE Gas, Inc.	2.3%	9.3%	11.6%	2.3%	9.3%	25%	2.3%	0.80	75%	5.6%	7.9%	10.2%	$2,800	1.54%	11.7%
7	South Jersey Industries	2.3%	9.3%	11.6%	2.3%	9.3%	25%	2.3%	0.80	75%	5.6%	7.9%	10.2%	$2,800	1.54%	11.7%
8	Southwest Gas	2.3%	9.3%	11.6%	2.3%	9.3%	25%	2.3%	0.70	75%	4.9%	7.2%	9.5%	$4,200	1.26%	10.8%
9	Spire Inc.	2.3%	9.3%	11.6%	2.3%	9.3%	25%	2.3%	0.65	75%	4.5%	6.8%	9.1%	$3,800	1.26%	10.4%
	Average															**10.6%**
	Midpoint (g)															**10.5%**

(a) Weighted average for www.valueline.com (retrieved Jan. 2, 2020).

(b) Average of weighted average earnings growth rates from IBES, Zacks, and Value Line for dividend-paying stocks in the S&P 500 based on data from http://finance.yahoo.com (retrieved Jan. 3, 2020), www.valueline.com (retrieved Jan. 2, 2020), and www.zacks.com (retrieved Jan. 2, 2020).

(c) Average yield on 30-year Treasury bonds for the six-months ending Dec. 2019 based on data from https://fred.stlouisfed.org/.

(d) Roger A. Morin, "New Regulatory Finance," *Public Utilities Reports, Inc.* (2006) at 190.

(e) The Value Line Investment Survey (Nov. 29, 2019).

(f) Duff & Phelps, 2019 CRSP Deciles Size Study -- Supplementary Data Exhibits, Cost of Capital Navigator.

(g) Average of low and high values.

EMPIRICAL CAPM - PROJECTED BOND YIELD

GAS GROUP

		(a)	(b)		(c)		(d)		(e)	(d)				(e)	(f)	
		Market Return (R_m)														
		Div	**Proj.**	**Cost of**	**Risk-Free**	**Risk**	**Unadjusted RP**		**Beta Adjusted RP**				**Unadjusted**	**Market**	**Size**	**ECAPM**
	Company	**Yield**	**Growth**	**Equity**	**Rate**	**Premium**	**Weight**	***RP*[1]**	**Beta**	**Weight**	***RP*[2]**	**Total RP**	**K_e**	**Cap**	**Adjustment**	**Result**
1	Atmos Energy Corp.	2.3%	9.3%	11.6%	3.1%	8.5%	25%	2.1%	0.60	75%	3.8%	5.9%	9.0%	$12,800	0.84%	9.9%
2	Chesapeake Utilities	2.3%	9.3%	11.6%	3.1%	8.5%	25%	2.1%	0.65	75%	4.1%	6.3%	9.4%	$1,500	1.58%	10.9%
3	New Jersey Resources	2.3%	9.3%	11.6%	3.1%	8.5%	25%	2.1%	0.70	75%	4.5%	6.6%	9.7%	$3,900	1.26%	10.9%
4	NiSource Inc.	2.3%	9.3%	11.6%	3.1%	8.5%	25%	2.1%	0.55	75%	3.5%	5.6%	8.7%	$9,700	0.84%	9.6%
5	Northwest Natural	2.3%	9.3%	11.6%	3.1%	8.5%	25%	2.1%	0.60	75%	3.8%	5.9%	9.0%	$2,000	1.54%	10.6%
6	ONE Gas, Inc.	2.3%	9.3%	11.6%	3.1%	8.5%	25%	2.1%	0.80	75%	5.1%	7.2%	10.3%	$2,800	1.54%	11.8%
7	South Jersey Industries	2.3%	9.3%	11.6%	3.1%	8.5%	25%	2.1%	0.80	75%	5.1%	7.2%	10.3%	$2,800	1.54%	11.8%
8	Southwest Gas	2.3%	9.3%	11.6%	3.1%	8.5%	25%	2.1%	0.70	75%	4.5%	6.6%	9.7%	$4,200	1.26%	10.9%
9	Spire Inc.	2.3%	9.3%	11.6%	3.1%	8.5%	25%	2.1%	0.65	75%	4.1%	6.3%	9.4%	$3,800	1.26%	10.6%
	Average															**10.8%**
	Midpoint (g)															**10.7%**

(a) Weighted average for www.valueline.com (retrieved Jan. 2, 2020).
(b) Average of weighted average earnings growth rates from IBES, Zacks, and Value Line for dividend-paying stocks in the S&P 500 based on data from http://finance.yahoo.com (retrieved Jan. 3, 2020), www.valueline.com (retrieved Jan. 2, 2020), and www.zacks.com (retrieved Jan. 2, 2020).
(c) Average yield on 30-year Treasury bonds for 2020-23 based on data from the Value Line Investment Survey, Forecast for the U.S. Economy (Nov. 29, 2019); IHS Global Insight, Long-Term Macro Forecast - Baseline (Oct. 15, 2019); & Wolters Kluwer, Blue Chip Financial Forecasts (Dec. 1, 2019).
(d) Roger A. Morin, "New Regulatory Finance," *Public Utilities Reports, Inc.* (2006) at 190.
(e) The Value Line Investment Survey (Nov. 29, 2019).
(f) Duff & Phelps, 2019 CRSP Deciles Size Study -- Supplementary Data Exhibits, Cost of Capital Navigator.
(g) Average of low and high values.

ELECTRIC UTILITY RISK PREMIUM

CURRENT BOND YIELDS

Current Equity Risk Premium

(a)	Avg. Yield over Study Period	8.10%
(b)	Average Utility Bond Yield	3.50%
	Change in Bond Yield	-4.60%
(c)	Risk Premium/Interest Rate Relationship	-0.4322
	Adjustment to Average Risk Premium	1.99%
(a)	Average Risk Premium over Study Period	3.79%
	Adjusted Risk Premium	**5.78%**

Implied Cost of Equity

(b)	Triple-B Utility Bond Yield	3.78%
	Adjusted Equity Risk Premium	5.78%
	Risk Premium Cost of Equity	**9.56%**

(a) Exhibit AMM-12, page 3.
(b) Average bond yield on all utility bonds and 'Baa' subset for the six-months ending Dec. 2019 based on data from Moody's Investors Service at www.credittrends.com.
(c) Exhibit AMM-12, page 4.

PROJECTED BOND YIELDS

Current Equity Risk Premium		
(a)	Avg. Yield over Study Period	8.10%
(b)	Average Utility Bond Yield 2020-2023	4.65%
	Change in Bond Yield	-3.45%
(c)	Risk Premium/Interest Rate Relationship	-0.4322
	Adjustment to Average Risk Premium	1.49%
(a)	Average Risk Premium over Study Period	3.79%
	Adjusted Risk Premium	**5.28%**
Implied Cost of Equity		
(b)	Triple-B Utility Bond Yield 2020-2023	4.93%
	Adjusted Equity Risk Premium	5.28%
	Risk Premium Cost of Equity	**10.21%**

(a) Exhibit AMM-12, page 3.

(b) Yields on all utility bonds and 'Baa' subset based on data from IHS Global Insight, Long-Term Macro Forecast - Baseline (Oct. 15, 2019); Energy Information Administration, Annual Energy Outlook 2020 (Jan. 29, 2020); & Moody's Investors Service at www.credittrends.com.

(c) Exhibit AMM-12, page 4.

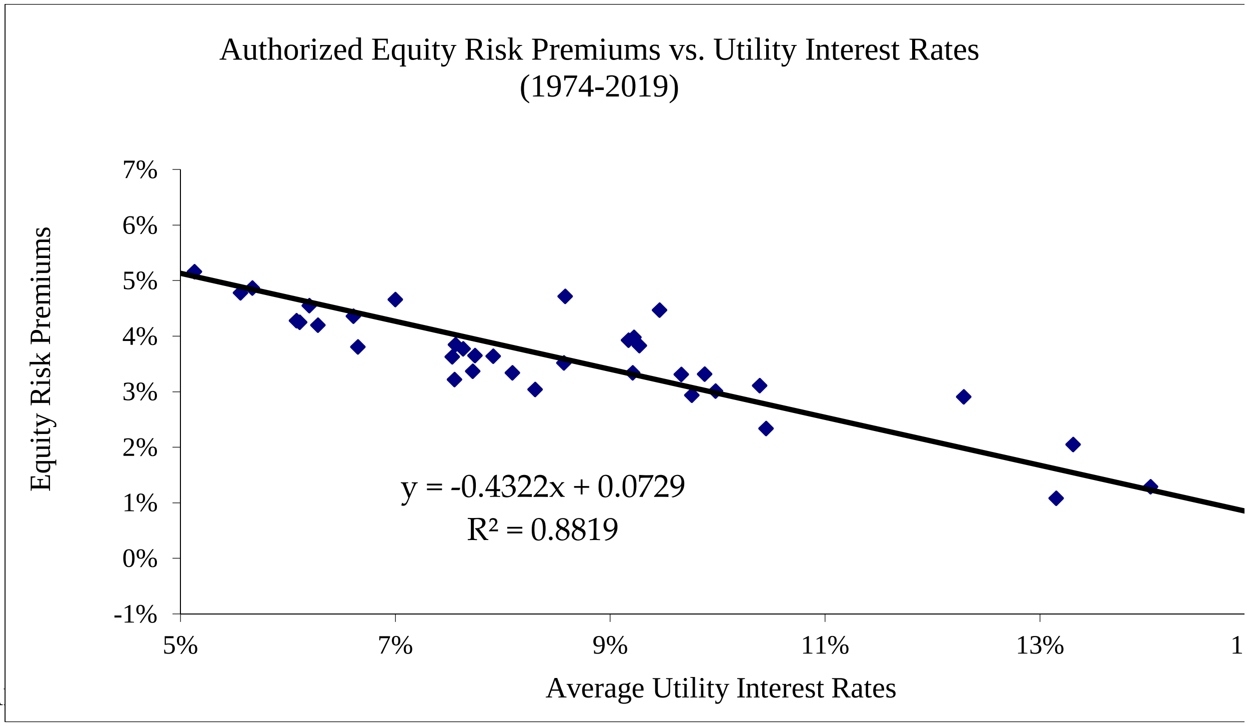
AUTHORIZED RETURNS

Year	(a) Allowed ROE	(b) Average Utility Bond Yield	Risk Premium
1974	13.10%	9.27%	3.83%
1975	13.20%	9.88%	3.32%
1976	13.10%	9.17%	3.93%
1977	13.30%	8.58%	4.72%
1978	13.20%	9.22%	3.98%
1979	13.50%	10.39%	3.11%
1980	14.23%	13.15%	1.08%
1981	15.22%	15.62%	-0.40%
1982	15.78%	15.33%	0.45%
1983	15.36%	13.31%	2.05%
1984	15.32%	14.03%	1.29%
1985	15.20%	12.29%	2.91%
1986	13.93%	9.46%	4.47%
1987	12.99%	9.98%	3.01%
1988	12.79%	10.45%	2.34%
1989	12.97%	9.66%	3.31%
1990	12.70%	9.76%	2.94%
1991	12.55%	9.21%	3.34%
1992	12.09%	8.57%	3.52%
1993	11.41%	7.56%	3.85%
1994	11.34%	8.30%	3.04%
1995	11.55%	7.91%	3.64%
1996	11.39%	7.74%	3.65%
1997	11.40%	7.63%	3.77%
1998	11.66%	7.00%	4.66%
1999	10.77%	7.55%	3.22%
2000	11.43%	8.09%	3.34%
2001	11.09%	7.72%	3.37%
2002	11.16%	7.53%	3.63%
2003	10.97%	6.61%	4.36%
2004	10.75%	6.20%	4.55%
2005	10.54%	5.67%	4.87%
2006	10.36%	6.08%	4.28%
2007	10.36%	6.11%	4.25%
2008	10.46%	6.65%	3.81%
2009	10.48%	6.28%	4.20%
2010	10.34%	5.56%	4.78%
2011	10.29%	5.13%	5.16%
2012	10.17%	4.26%	5.91%
2013	10.02%	4.55%	5.47%
2014	9.92%	4.41%	5.51%
2015	9.85%	4.37%	5.48%
2016	9.77%	4.11%	5.66%
2017	9.74%	4.07%	5.67%
2018	9.60%	4.34%	5.26%
2019	9.65%	3.86%	5.79%
Average	11.89%	8.10%	3.79%

(a) Major Rate Case Decisions, *Regulatory Focus* , Regulatory Research Associates; *UtilityScope Regulatory Service* , Argus.

(b) Moody's Investors Service.

REGRESSION RESULTS



SUMMA

Regression Statistics	
Multiple R	0.939084
R Square	0.881879
Adjusted R Square	0.879195
Standard Error	0.004807
Observations	46

ANOVA

	df	*SS*	*MS*	*F*	*Significance F*
Regression	1	0.007591161	0.00759116	328.500292	4.954E-22
Residual	44	0.001016776	2.3109E-05		
Total	45	0.008607937			

	Coefficients	*Standard Error*	*t Stat*	*P-value*	*Lower 95%*	*Upper 95%*	*Lower 95.0%*	*Upper 95.0%*
Intercept	0.072915	0.002057385	35.4407635	5.4169E-34	0.0687689	0.0770617	0.0687689	0.07706167
X Variable 1	-0.4322	0.023843696	-18.124577	4.954E-22	-0.48021072	-0.384103	-0.4802107	-0.3841031

GAS UTILITY RISK PREMIUM

CURRENT BOND YIELDS

Current Equity Risk Premium		
(a)	Avg. Yield over Study Period	7.93%
(b)	Single-A Utility Bond Yield	3.43%
	Change in Bond Yield	-4.50%
(c)	Risk Premium/Interest Rate Relationship	-0.4699
	Adjustment to Average Risk Premium	2.11%
(a)	Average Risk Premium over Study Period	3.63%
	Adjusted Risk Premium	**5.74%**
Implied Cost of Equity		
(b)	Single-A Utility Bond Yield	3.43%
	Adjusted Equity Risk Premium	5.74%
	Risk Premium Cost of Equity	**9.17%**

(a) Exhibit AMM-13, page 4.
(b) Average bond yield for six-months ending Dec. 2019 based on data from Moody's Investors Service at www.credittrends.com.
(c) Exhibit AMM-13, page 5.

PROJECTED BOND YIELDS

Current Equity Risk Premium		
(a)	Avg. Yield over Study Period	7.93%
(b)	Single-A Utility Bond Yield 2020-2023	4.58%
	Change in Bond Yield	-3.35%
(c)	Risk Premium/Interest Rate Relationship	-0.4699
	Adjustment to Average Risk Premium	1.57%
(a)	Average Risk Premium over Study Period	3.63%
	Adjusted Risk Premium	**5.20%**
Implied Cost of Equity		
(b)	Single-A Utility Bond Yield 2020-2023	4.58%
	Adjusted Equity Risk Premium	5.20%
	Risk Premium Cost of Equity	**9.78%**

(a) Exhibit AMM-13, page 4.
(b) Based on data from IHS Global Insight, Long-Term Macro Forecast - Baseline (Oct. 15, 2019); Energy Information Administration, Annual Energy Outlook 2020 (Jan. 29, 2020); Moody's Investors Service at www.credittrends.com.
(c) Exhibit AMM-13, page 5.

AUTHORIZED RETURNS

Year	Qtr.	(a) Allowed ROE	(b) Single-A Utility Bond Yield	Risk Premium
1980	1	13.45%	13.49%	-0.04%
	2	14.38%	12.87%	1.51%
	3	13.87%	12.88%	0.99%
	4	14.35%	14.11%	0.24%
1981	1	14.69%	14.77%	-0.08%
	2	14.61%	15.82%	-1.21%
	3	14.86%	16.65%	-1.79%
	4	15.70%	16.57%	-0.87%
1982	1	15.55%	16.72%	-1.17%
	2	15.62%	16.26%	-0.64%
	3	15.72%	15.88%	-0.16%
	4	15.62%	14.56%	1.06%
1983	1	15.41%	14.15%	1.26%
	2	14.84%	13.58%	1.26%
	3	15.24%	13.52%	1.72%
	4	15.41%	13.38%	2.03%
1984	1	15.39%	13.56%	1.83%
	2	15.07%	14.72%	0.35%
	3	15.37%	14.47%	0.90%
	4	15.33%	13.38%	1.95%
1985	1	15.03%	13.31%	1.72%
	2	15.44%	12.95%	2.49%
	3	14.64%	12.11%	2.53%
	4	14.44%	11.49%	2.95%
1986	1	14.05%	10.18%	3.87%
	2	13.28%	9.41%	3.87%
	3	13.09%	9.39%	3.70%
	4	13.62%	9.31%	4.31%
1987	1	12.61%	8.96%	3.65%
	2	13.13%	9.77%	3.36%
	3	12.56%	10.61%	1.95%
	4	12.73%	11.05%	1.68%
1988	1	12.94%	10.32%	2.62%
	2	12.48%	10.71%	1.77%
	3	12.79%	10.94%	1.85%
	4	12.98%	9.98%	3.00%
1989	1	12.99%	10.13%	2.86%
	2	13.25%	9.94%	3.31%
	3	12.56%	9.53%	3.03%
	4	12.94%	9.50%	3.44%

Year	Qtr.	(a) Allowed ROE	(b) Single-A Utility Bond Yield	Risk Premium
1990	1	12.60%	9.72%	2.88%
	2	12.81%	9.91%	2.90%
	3	12.34%	9.93%	2.41%
	4	12.77%	9.89%	2.88%
1991	1	12.69%	9.58%	3.11%
	2	12.53%	9.50%	3.03%
	3	12.43%	9.33%	3.10%
	4	12.38%	9.02%	3.36%
1992	1	12.42%	8.91%	3.51%
	2	11.98%	8.86%	3.12%
	3	11.87%	8.47%	3.40%
	4	11.94%	8.53%	3.41%
1993	1	11.75%	8.07%	3.68%
	2	11.71%	7.81%	3.90%
	3	11.39%	7.28%	4.11%
	4	11.15%	7.22%	3.93%
1994	1	11.12%	7.55%	3.57%
	2	10.81%	8.29%	2.52%
	3	10.95%	8.51%	2.44%
	4	11.64%	8.87%	2.77%
1995	1	(c)	--	--
	2	11.00%	7.93%	3.07%
	3	11.07%	7.72%	3.35%
1996	4	11.56%	7.37%	4.19%
	1	11.45%	7.44%	4.01%
	2	10.88%	7.98%	2.90%
	3	11.25%	7.96%	3.29%
1997	4	11.32%	7.62%	3.70%
	1	11.31%	7.76%	3.55%
	2	11.70%	7.88%	3.82%
	3	12.00%	7.49%	4.51%
	4	11.01%	7.25%	3.76%
1998	1	(c)	--	--
	2	11.37%	7.12%	4.25%
	3	11.41%	6.99%	4.42%
	4	11.69%	6.97%	4.72%
1999	1	10.82%	7.11%	3.71%
	2	10.82%	7.48%	3.34%
	3	(c)	--	--
	4	10.33%	8.05%	2.28%

AUTHORIZED RETURNS

Year	Qtr.	(a) Allowed ROE	(b) Single-A Utility Bond Yield	Risk Premium
2000	1	10.71%	8.29%	2.42%
	2	11.08%	8.45%	2.63%
	3	11.33%	8.25%	3.08%
	4	12.50%	8.03%	4.47%
2001	1	11.16%	7.74%	3.42%
	2	10.75%	7.93%	2.82%
	3	(c)	--	--
	4	10.65%	7.68%	2.97%
2002	1	10.67%	7.65%	3.02%
	2	11.64%	7.50%	4.14%
	3	11.50%	7.19%	4.31%
	4	10.78%	7.15%	3.63%
2003	1	11.38%	6.93%	4.45%
	2	11.36%	6.40%	4.96%
	3	10.61%	6.64%	3.97%
	4	10.84%	6.35%	4.49%
2004	1	11.10%	6.09%	5.01%
	2	10.25%	6.48%	3.77%
	3	10.37%	6.13%	4.24%
	4	10.66%	5.94%	4.72%
2005	1	10.65%	5.74%	4.91%
	2	10.52%	5.52%	5.00%
	3	10.47%	5.51%	4.96%
	4	10.40%	5.82%	4.58%
2006	1	10.63%	5.85%	4.78%
	2	10.50%	6.37%	4.13%
	3	10.45%	6.19%	4.26%
	4	10.14%	5.86%	4.28%
2007	1	10.44%	5.90%	4.54%
	2	10.12%	6.09%	4.03%
	3	10.03%	6.22%	3.81%
	4	10.27%	6.08%	4.19%
2008	1	10.38%	6.15%	4.23%
	2	10.17%	6.32%	3.85%
	3	10.49%	6.42%	4.07%
	4	10.34%	7.23%	3.11%
2009	1	10.24%	6.37%	3.87%
	2	10.11%	6.39%	3.72%
	3	9.88%	5.74%	4.14%
	4	10.27%	5.66%	4.61%

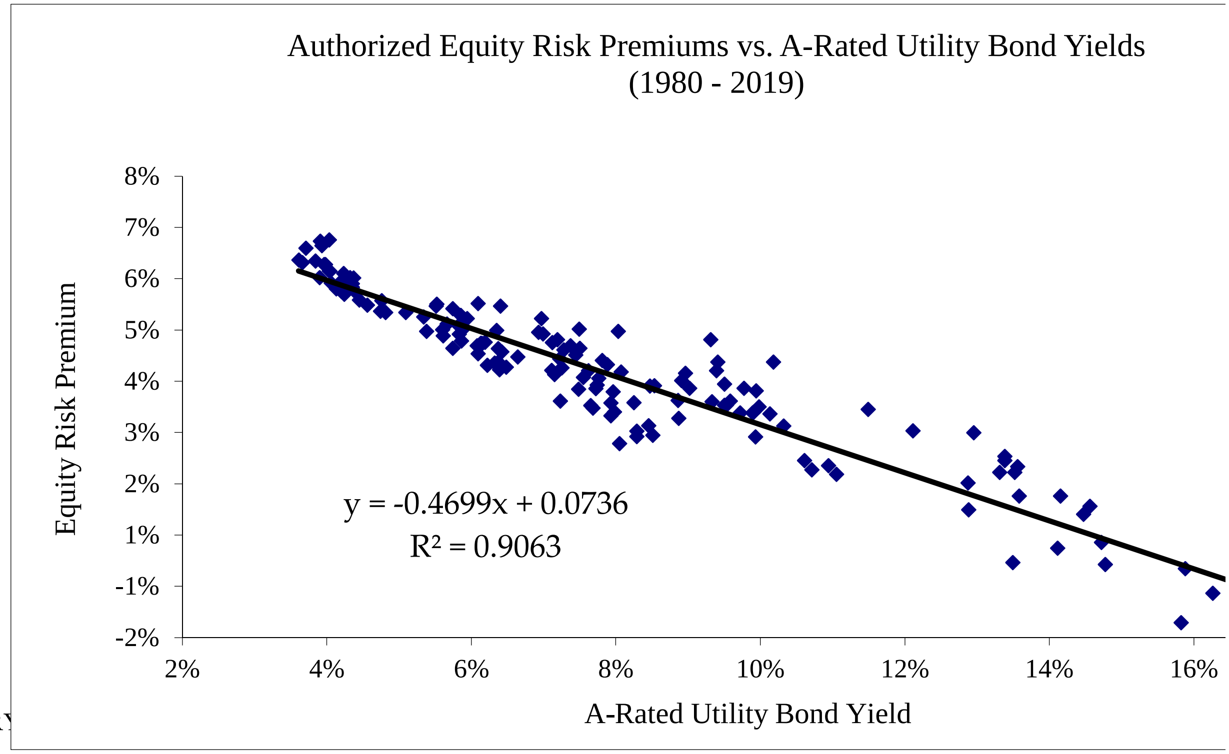
Year	Qtr.	(a) Allowed ROE	(b) Single-A Utility Bond Yield	Risk Premium
2010	1	10.24%	5.83%	4.41%
	2	9.99%	5.61%	4.38%
	3	9.93%	5.09%	4.84%
	4	10.09%	5.34%	4.75%
2011	1	10.10%	5.60%	4.50%
	2	9.85%	5.38%	4.47%
	3	9.65%	4.81%	4.84%
	4	9.88%	4.37%	5.51%
2012	1	9.63%	4.39%	5.24%
	2	9.83%	4.23%	5.60%
	3	9.75%	3.98%	5.77%
	4	10.07%	3.93%	6.14%
2013	1	9.57%	4.18%	5.39%
	2	9.47%	4.23%	5.24%
	3	9.60%	4.74%	4.86%
	4	9.83%	4.76%	5.07%
2014	1	9.54%	4.56%	4.98%
	2	9.84%	4.32%	5.52%
	3	9.45%	4.20%	5.25%
	4	10.28%	4.03%	6.25%
2015	1	9.47%	3.66%	5.81%
	2	9.43%	4.13%	5.30%
	3	9.75%	4.35%	5.40%
	4	9.68%	4.35%	5.33%
2016	1	9.48%	4.18%	5.30%
	2	9.42%	3.90%	5.52%
	3	9.47%	3.61%	5.86%
	4	9.68%	4.04%	5.64%
2017	1	9.60%	4.18%	5.42%
	2	9.47%	4.06%	5.41%
	3	10.14%	3.91%	6.23%
	4	9.68%	3.84%	5.84%
2018	1	9.68%	4.03%	5.65%
	2	9.43%	4.24%	5.19%
	3	9.69%	4.28%	5.41%
	4	9.53%	4.45%	5.08%
2019	1	9.55%	4.25%	5.30%
	2	9.73%	3.96%	5.77%
	3	9.80%	3.71%	6.09%
	4	9.73%	3.77%	5.96%
Average		**11.56%**	**7.93%**	**3.63%**

(a) Regulatory Research Associates, Inc., Major Rate Case Decisions, (Jan. 31, 2020, Jan. 14, 2016, Jan. 7, 2011, Apr. 5, 2004, Jan. 21, 1998, July 12, 1991, and Jan. 16, 1990).

(b) Moody's Investors Service.

(c) No decisions reported.

REGRESSION RESULTS



SUMMARY

Regression Statistics	
Multiple R	0.951996
R Square	0.906297
Adjusted R Square	0.905688
Standard Error	0.005049
Observations	156

ANOVA

	df	*SS*	*MS*	*F*	*Significance F*
Regression	1	0.037972191	0.03797219	1489.48482	4.5049E-81
Residual	154	0.003926	2.5494E-05		
Total	155	0.041898191			

	Coefficients	*Standard Error*	*t Stat*	*P-value*	*Lower 95%*	*Upper 95%*	*Lower 95.0%*	*Upper 95.0%*
Intercept	0.0736	0.001046755	70.2678	6.693E-119	0.07148533	0.075621	0.07148533	0.07562103
X Variable 1	-0.4699	0.012176339	-38.593844	4.5049E-81	-0.49398593	-0.445878	-0.4939859	-0.4458775

ELECTRIC GROUP

	Company	(a) Expected Return on Common Equity	(b) Adjustment Factor	(c) Adjusted Return on Common Equity
1	ALLETE	9.0%	1.0169	9.2%
2	Alliant Energy	10.0%	1.0227	10.2%
3	Ameren Corp.	10.5%	1.0337	10.9%
4	American Elec Pwr	10.5%	1.0288	10.8%
5	Avangrid, Inc.	5.5%	1.0076	5.5%
6	Avista Corp.	8.0%	1.0261	8.2%
7	Black Hills Corp.	9.5%	1.0263	9.7%
8	CMS Energy Corp.	13.5%	1.0391	14.0%
9	Consolidated Edison	8.5%	1.0222	8.7%
10	Dominion Energy	13.0%	1.0536	13.7%
11	DTE Energy Co.	9.5%	1.0449	9.9%
12	Duke Energy Corp.	8.5%	1.0201	8.7%
13	Entergy Corp.	11.5%	1.0330	11.9%
14	Eversource Energy	9.0%	1.0346	9.3%
15	Exelon Corp.	9.0%	1.0255	9.2%
16	FirstEnergy Corp.	16.0%	1.0387	16.6%
17	Fortis Inc.	6.5%	1.0351	6.7%
18	Hawaiian Elec.	9.5%	1.0233	9.7%
19	IDACORP, Inc.	9.5%	1.0175	9.7%
20	MGE Energy	10.5%	1.0255	10.8%
21	NextEra Energy, Inc.	12.5%	1.0299	12.9%
22	NorthWestern Corp.	9.0%	1.0163	9.1%
23	OGE Energy Corp.	11.5%	1.0181	11.7%
24	Otter Tail Corp.	11.0%	1.0293	11.3%
25	Pinnacle West Capital	10.5%	1.0195	10.7%
26	Portland General Elec.	9.0%	1.0152	9.1%
27	PPL Corp.	13.0%	1.0371	13.5%
28	Pub Sv Enterprise Grp.	11.0%	1.0239	11.3%
29	Sempra Energy	12.0%	1.0500	12.6%
30	Southern Company	12.5%	1.0283	12.9%
31	WEC Energy Group	12.0%	1.0176	12.2%
32	Xcel Energy Inc.	11.0%	1.0238	11.3%
	Average (d)			**10.7%**
	Midpoint (d, e)			**10.4%**

(a) The Value Line Investment Survey (Oct. 25, Nov. 15 & Dec. 13 2019).
(b) Adjustment to convert year-end return to an average rate of return from Exhibit AMM-6.
(c) (a) x (b).
(d) Excludes highlighted figures.
(e) Average of low and high values.

GAS GROUP

	Company	(a) Expected Return on Common Equity	(b) Adjustment Factor	(c) Adjusted Return on Common Equity
1	Atmos Energy Corp.	10.0%	1.0590	10.6%
2	Chesapeake Utilities	9.5%	1.0852	10.3%
3	New Jersey Resources	11.0%	1.0390	11.4%
4	NiSource Inc.	9.0%	1.0251	9.2%
5	Northwest Natural	11.5%	1.0227	11.8%
6	ONE Gas, Inc.	10.0%	1.0247	10.2%
7	South Jersey Industries	12.5%	1.0401	13.0%
8	Southwest Gas	10.0%	1.0499	10.5%
9	Spire Inc.	9.0%	1.0271	9.2%
	Average			**10.7%**
	Midpoint (d)			**11.1%**

(a) The Value Line Investment Survey (Nov. 29, 2019).
(b) Adjustment to convert year-end return to an average rate of return from Exhibit AMM-8.
(c) (a) x (b).
(d) Average of low and high values.

DIVIDEND YIELD

	Company	Industry Group	(a) Price	(b) Dividends	Yield
1	Allstate Corp.	Insurance (Prop/Cas.)	$ 111.29	$ 2.00	1.8%
2	Altria Group	Tobacco	$ 50.27	$ 3.36	6.7%
3	Amdocs Ltd.	IT Services	$ 71.31	$ 1.14	1.6%
4	Amer. Tower 'A'	Wireless Networking	$ 220.15	$ 4.42	2.0%
5	AT&T Inc.	Telecom. Services	$ 38.56	$ 2.08	5.4%
6	AvalonBay Communities	R.E.I.T.	$ 210.11	$ 6.40	3.0%
7	Bristol-Myers Squibb	Drug	$ 62.29	$ 1.80	2.9%
8	Brown-Forman 'B'	Beverage	$ 66.13	$ 0.70	1.1%
9	Campbell Soup	Food Processing	$ 48.18	$ 1.40	2.9%
10	Cboe Global Markets	Brokers & Exchanges	$ 118.29	$ 1.44	1.2%
11	Church & Dwight	Household Products	$ 69.87	$ 0.91	1.3%
12	Clorox Co.	Household Products	$ 151.68	$ 4.24	2.8%
13	CME Group	Brokers & Exchanges	$ 203.78	$ 3.00	1.5%
14	Coca-Cola	Beverage	$ 54.49	$ 1.66	3.0%
15	Colgate-Palmolive	Household Products	$ 68.36	$ 1.72	2.5%
16	Equity Residential	R.E.I.T.	$ 81.81	$ 2.41	2.9%
17	Federal Rlty. Inv. Trust	R.E.I.T.	$ 128.50	$ 4.22	3.3%
18	Gen'l Mills	Food Processing	$ 52.80	$ 1.96	3.7%
19	Hershey Co.	Food Processing	$ 147.25	$ 3.20	2.2%
20	Hormel Foods	Food Processing	$ 44.99	$ 0.93	2.1%
21	Intercontinental Exch.	Brokers & Exchanges	$ 93.09	$ 1.10	1.2%
22	Johnson & Johnson	Med Supp Non-Invasive	$ 142.77	$ 3.80	2.7%
23	Kellogg	Food Processing	$ 67.29	$ 2.32	3.4%
24	Kimberly-Clark	Household Products	$ 136.78	$ 4.28	3.1%
25	Lilly (Eli)	Drug	$ 126.57	$ 2.96	2.3%
26	Lockheed Martin	Aerospace/Defense	$ 392.84	$ 9.60	2.4%
27	McCormick & Co.	Food Processing	$ 168.99	$ 2.48	1.5%
28	McDonald's Corp.	Restaurant	$ 197.83	$ 5.00	2.5%
29	PepsiCo, Inc.	Beverage	$ 136.35	$ 3.95	2.9%
30	Procter & Gamble	Household Products	$ 124.12	$ 2.98	2.4%
31	Public Storage	R.E.I.T.	$ 211.13	$ 8.40	4.0%
32	Realty Income Corp.	R.E.I.T.	$ 73.98	$ 2.80	3.8%
33	Republic Services	Environmental	$ 89.30	$ 1.65	1.8%
34	Smucker (J.M.)	Food Processing	$ 104.08	$ 3.56	3.4%
35	Sysco Corp.	Retail/Wholesale Food	$ 83.78	$ 1.80	2.1%
36	Verizon Communic.	Telecom. Services	$ 60.72	$ 2.46	4.1%
37	Walmart Inc.	Retail Store	$ 118.98	$ 2.16	1.8%
38	Waste Management	Environmental	$ 113.20	$ 2.05	1.8%
	Average				**2.7%**

(a) Average of closing prices for 30 trading days ended Jan. 10, 2020.
(b) The Value Line Investment Survey, *Summary & Index* (Jan. 3, 2019).

GROWTH RATES

		(a)	(b)	(c)
		Earnings Growth Rates		
	Company	**V Line**	**IBES**	**Zacks**
1	Allstate Corp.	10.50%	9.17%	8.33%
2	Altria Group	8.50%	6.17%	6.40%
3	Amdocs Ltd.	10.00%	5.50%	8.50%
4	Amer. Tower 'A'	7.50%	22.80%	18.44%
5	AT&T Inc.	5.50%	4.16%	4.42%
6	AvalonBay Communities	n/a	2.54%	6.18%
7	Bristol-Myers Squibb	9.00%	15.05%	13.36%
8	Brown-Forman 'B'	14.50%	6.90%	7.50%
9	Campbell Soup	2.00%	7.36%	5.95%
10	Cboe Global Markets	14.50%	2.14%	5.91%
11	Church & Dwight	9.00%	8.03%	8.70%
12	Clorox Co.	3.50%	3.44%	5.08%
13	CME Group	3.00%	6.09%	8.03%
14	Coca-Cola	6.50%	5.08%	6.55%
15	Colgate-Palmolive	5.50%	0.89%	4.34%
16	Equity Residential	n/a	2.70%	6.18%
17	Federal Rlty. Inv. Trust	n/a	6.70%	4.63%
18	Gen'l Mills	4.50%	5.53%	7.00%
19	Hershey Co.	7.00%	8.04%	7.00%
20	Hormel Foods	10.50%	3.20%	6.06%
21	Intercontinental Exch.	10.50%	9.49%	8.53%
22	Johnson & Johnson	12.00%	5.87%	6.84%
23	Kellogg	3.50%	-0.70%	6.00%
24	Kimberly-Clark	7.50%	5.39%	5.49%
25	Lilly (Eli)	12.00%	11.80%	11.31%
26	Lockheed Martin	12.50%	13.55%	7.09%
27	McCormick & Co.	8.00%	6.10%	7.05%
28	McDonald's Corp.	8.50%	6.05%	8.42%
29	PepsiCo, Inc.	6.50%	4.24%	6.99%
30	Procter & Gamble	9.00%	8.37%	7.47%
31	Public Storage	n/a	17.00%	3.58%
32	Realty Income Corp.	n/a	5.45%	3.67%
33	Republic Services	11.50%	8.40%	8.38%
34	Smucker (J.M.)	3.50%	1.15%	2.50%
35	Sysco Corp.	10.50%	8.33%	9.87%
36	Verizon Communic.	4.00%	2.34%	3.22%
37	Walmart Inc.	7.50%	5.18%	4.95%
38	Waste Management	8.50%	8.25%	8.24%

(a) The Value Line Investment Survey (various editions as of Jan. 10, 2020).
(b) www.finance.yahoo.com (retrieved Jan 13, 2020).
(c) www.zacks.com (retrieved Jan. 20, 2019).

DCF COST OF EQUITY ESTIMATES

		(a)	(a)	(a)
		Cost of Equity Estimates		
	Company	**V Line**	**IBES**	**Zacks**
1	Allstate Corp.	12.3%	11.0%	10.1%
2	Altria Group	15.2%	12.9%	13.1%
3	Amdocs Ltd.	11.6%	7.1%	10.1%
4	Amer. Tower 'A'	9.5%	24.8%	20.4%
5	AT&T Inc.	10.9%	9.6%	9.8%
6	AvalonBay Communities	n/a	5.6%	9.2%
7	Bristol-Myers Squibb	11.9%	17.9%	16.2%
8	Brown-Forman 'B'	15.6%	8.0%	8.6%
9	Campbell Soup	4.9%	10.3%	8.9%
10	Cboe Global Markets	15.7%	3.4%	7.1%
11	Church & Dwight	10.3%	9.3%	10.0%
12	Clorox Co.	6.3%	6.2%	7.9%
13	CME Group	4.5%	7.6%	9.5%
14	Coca-Cola	9.5%	8.1%	9.6%
15	Colgate-Palmolive	8.0%	3.4%	6.9%
16	Equity Residential	n/a	5.6%	9.1%
17	Federal Rlty. Inv. Trust	n/a	10.0%	7.9%
18	Gen'l Mills	8.2%	9.2%	10.7%
19	Hershey Co.	9.2%	10.2%	9.2%
20	Hormel Foods	12.6%	5.3%	8.1%
21	Intercontinental Exch.	11.7%	10.7%	9.7%
22	Johnson & Johnson	14.7%	8.5%	9.5%
23	Kellogg	6.9%	2.7%	9.4%
24	Kimberly-Clark	10.6%	8.5%	8.6%
25	Lilly (Eli)	14.3%	14.1%	13.6%
26	Lockheed Martin	14.9%	16.0%	9.5%
27	McCormick & Co.	9.5%	7.6%	8.5%
28	McDonald's Corp.	11.0%	8.6%	10.9%
29	PepsiCo, Inc.	9.4%	7.1%	9.9%
30	Procter & Gamble	11.4%	10.8%	9.9%
31	Public Storage	n/a	21.0%	7.6%
32	Realty Income Corp.	n/a	9.2%	7.5%
33	Republic Services	13.3%	10.2%	10.2%
34	Smucker (J.M.)	6.9%	4.6%	5.9%
35	Sysco Corp.	12.6%	10.5%	12.0%
36	Verizon Communic.	8.1%	6.4%	7.3%
37	Walmart Inc.	9.3%	7.0%	6.8%
38	Waste Management	10.3%	10.1%	10.1%
	Average (b)	**10.7%**	**9.4%**	**9.3%**
	Midpoint (b,c)	**10.9%**	**10.6%**	**10.2%**

(a) Sum of dividend yield (Exhibit AMM-15, p. 1) and respective growth rate (Exhibit AMM-15, p. 2).
(b) Excludes highlighted figures.
(c) Average of low and high values.

CAPITAL STRUCTURE

ELECTRIC GROUP

		2018 Actual (a)		Projected (b)	
	Company	**Debt**	**Common Equity**	**Debt**	**Common Equity**
1	ALLETE	40.8%	59.2%	42.0%	58.0%
2	Alliant Energy	53.5%	44.6%	52.0%	48.0%
3	Ameren Corp.	52.1%	47.9%	49.5%	49.5%
4	American Elec Pwr	55.1%	44.9%	53.5%	46.5%
5	Avangrid, Inc.	27.2%	72.8%	38.0%	62.0%
6	Avista Corp.	51.2%	48.8%	50.0%	50.0%
7	Black Hills Corp.	56.4%	43.6%	55.5%	44.5%
8	CMS Energy Corp.	70.8%	29.2%	66.5%	33.0%
9	Consolidated Edison	51.9%	48.1%	50.5%	49.5%
10	Dominion Energy	61.2%	38.8%	59.0%	41.0%
11	DTE Energy Co.	56.0%	44.0%	54.0%	46.0%
12	Duke Energy Corp.	55.4%	44.6%	55.0%	44.5%
13	Entergy Corp.	64.1%	35.1%	60.5%	39.0%
14	Eversource Energy	54.1%	45.3%	53.0%	46.5%
15	Exelon Corp.	52.0%	48.0%	50.0%	50.0%
16	FirstEnergy Corp.	72.8%	26.9%	69.5%	30.5%
17	Fortis Inc.	57.3%	39.0%	52.0%	44.5%
18	Hawaiian Elec.	47.5%	51.7%	47.5%	52.0%
19	IDACORP, Inc.	43.6%	56.4%	43.5%	56.5%
20	MGE Energy	37.9%	62.1%	41.5%	58.5%
21	NextEra Energy, Inc.	43.8%	56.2%	49.5%	50.5%
22	NorthWestern Corp.	52.2%	47.8%	48.0%	52.0%
23	OGE Energy Corp.	44.0%	56.0%	45.0%	55.0%
24	Otter Tail Corp.	44.7%	55.3%	50.5%	49.5%
25	Pinnacle West Capital	49.0%	51.0%	44.5%	55.5%
26	Portland General Elec.	49.7%	50.3%	49.5%	50.5%
27	PPL Corp.	63.9%	36.1%	55.0%	45.0%
28	Pub Sv Enterprise Grp.	50.1%	49.9%	50.5%	49.5%
29	Sempra Energy	54.7%	45.2%	54.0%	46.0%
30	Southern Company	60.0%	39.6%	59.0%	41.0%
31	WEC Energy Group	51.3%	48.6%	51.5%	48.5%
32	Xcel Energy Inc.	57.0%	43.0%	58.0%	42.0%
	Average	**52.5%**	**47.2%**	**51.8%**	**48.0%**
	Average - Ex. High and Low	**52.7%**	**47.0%**	**51.7%**	**48.1%**

(a) Most recent SEC Form 10-K reports.

(b) The Value Line Investment Survey (Oct. 25, Nov. 15 & Dec. 13 2019).

GAS GROUP

		Sep. 30, 2019 (a)		Value Line Projected (b)	
	Company	**Debt**	**Common Equity**	**Debt**	**Common Equity**
1	Atmos Energy Corp.	38.0%	62.0%	35.0%	65.0%
2	Chesapeake Utilities	45.3%	54.7%	35.0%	65.0%
3	New Jersey Resources	50.1%	49.9%	40.5%	59.5%
4	NiSource Inc.	57.4%	42.6%	53.0%	47.0%
5	Northwest Natural	51.6%	48.4%	47.5%	52.5%
6	ONE Gas, Inc.	38.2%	61.8%	38.0%	62.0%
7	South Jersey Industries	62.5%	37.5%	58.0%	42.0%
8	Southwest Gas	50.8%	49.2%	46.0%	54.0%
9	Spire Inc.	45.5%	54.5%	40.0%	60.0%
	Average	**48.8%**	**51.2%**	**43.7%**	**56.3%**
	Average - Ex. High and Low	**48.4%**	**51.6%**	**42.9%**	**57.1%**

(a) Most recent SEC Form 10-K/10-Q reports.
(b) The Value Line Investment Survey (Nov. 29, 2019).

Before the Maryland Public Service Commission

Case No. _____

Prepared Direct Testimony of

Ajit Apte

On Behalf of

Baltimore Gas and Electric Company

May 15, 2020

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<u>**Spending Summary**</u>

The amounts set forth below represent the Multi-Year Plan ("MYP") capital and O&M budgeted amounts which are necessary to continue providing outstanding, safe and reliable electric and gas distribution service to customers.

Capital

Category	2021F	2022F	2023F
Capacity Expansion – Distribution	$52,702,201	$53,726,928	$70,806,630
Facilities Relocation – Distribution	$2,279,477	$2,791,498	$2,807,622
Facilities Relocation – Gas	$6,218,207	$6,567,594	$7,028,463
System Performance – Distribution	$84,194,278	$82,543,914	$81,824,594
System Performance – Substation	$67,405,994	$47,777,004	$38,465,790
System Performance – Protection & Control	$4,592,832	$4,641,535	$3,312,685
Total	**$217,392,989**	**$198,048,473**	**$204,245,784**

O&M

Category	2021F	2022F	2023F
Capacity Expansion – Distribution	$157,416	$159,684	$160,359
System Performance – Distribution	$267,197	$270,799	$314,823
System Performance – Substation	$1,141,372	$1,206,893	$1,316,303
System Performance – Protection & Control	$3,986,897	$4,072,977	$4,164,353
Vegetation Management	$33,446,553	$33,859,259	$34,811,755
Total	**$38,999,435**	**$39,569,612**	**$40,767,593**

I. INTRODUCTION

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. My name is Ajit Apte and my business address is Baltimore Gas and Electric Company ("BGE" or the "Company"), 2900 Lord Baltimore Dr., Baltimore, MD 21244.

Q. WHAT IS YOUR POSITION WITH BGE?

A. I am the Vice President of Technical Services for BGE. In that role I am responsible for leading asset and records management, distribution engineering, distribution planning, electric system reliability planning, investment strategy, project management, Smart Grid initiatives, and vegetation management.

Q. PLEASE DESCRIBE YOUR EDUCATIONAL BACKGROUND.

A. I earned a Bachelor of Engineering in Electrical Engineering from SV National Institute of Technology Surat, India, and a Master of Engineering in Microprocessor Systems from the Maharaja Sayajirao University of Baroda, India.

Q. PLEASE DESCRIBE YOUR BUSINESS EXPERIENCE.

A. Prior to my current role I was director of customer strategy and governance at BGE. In that role I developed and led an enhanced customer engagement strategy in support of BGE's customer-centric focus. For five years prior to joining BGE, I was director of information technology for Exelon Utilities, where I was responsible for metering, billing and customer care platforms post-launch. I have also held IT leadership positions at Constellation, where I worked for a decade after joining the company in 2002. I am a board member of Creative Alliance. Additionally, I have received the Professional Achievement Award from the

Society of Asian Scientists & Engineers in 2017 and I completed Howard County Leadership in 2019.

Q. HAVE YOU PREVIOUSLY TESTIFIED BEFORE THE MARYLAND PUBLIC SERVICE COMMISSION?

A. No, but I appeared before the Commission at one of its weekly Administrative Meetings in support of BGE's filing to enable residential customers to make bill payments through a wide variety of methods without incurring transaction fees.

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

A. The purpose of my Direct Testimony in this proceeding is to describe the Company's capital investment and operations and maintenance ("O&M") spending for 2021 through 2023 to ensure safe and reliable electric and gas system operations for our customers. For informational purposes, I have also included actual and projected capital and O&M costs for 2019 and 2020. Additionally, I will provide an explanation of the operational drivers of those costs, benefits for customers, as well as a comparison to recent historical expenditures.

Q. COULD YOU PLEASE PROVIDE AN OVERVIEW OF THE CAPITAL AND O&M REQUESTS BEING MADE IN THIS PROCEEDING?

A. For the three-year period of 2021 through 2023, BGE is projecting its capital investments to be $619.6 million and its O&M expenditures to be $119.3 million in the areas I am covering. As I will explain in more detail later on in my testimony, these investments and expenditures are important and necessary for BGE to operate and monitor its system, meet regulatory requirements and commitments, improve system performance, and continue to provide safe and reliable service to our customers.

Q. MR. APTE, HAVE THE CAPITAL AND O&M PLANS DISCUSSED IN YOUR TESTIMONY BEEN ADJUSTED IN LIGHT OF THE COVID-19 PANDEMIC AND THE VARIOUS EXECUTIVE ORDERS ISSUED BY MARYLAND GOVERNOR HOGAN IN RESPONSE TO THE PANDEMIC?

A. No, they have not. In Part 2 of his Direct Testimony, Company Witness Vahos discusses BGE's expectations about the impact of the pandemic and related executive orders on the Company's capital and O&M plans and how BGE expects any impacts will be addressed over the multi-year plan ("MYP") period.

Q. HOW IS THE REMAINDER OF YOUR TESTIMONY ORGANIZED?

A. The remainder of my testimony is organized into three sections. First, I will provide an overview of the Technical Services area and explain how it supports customer reliability and BGE operational goals. In this section, I will provide an explanation of the work performed in this area, the drivers of projects and the benefits that they deliver for our customers. Second, I will provide background on the budget process, the drivers of capital and O&M spending needs and a high-level summary of the 2021-2023 budget. Third, I will review in detail the spending requirements for each category, the key projects that drive that work and budget, and risk factors that can alter spending needs.

Q. ARE YOU SPONSORING ANY EXHIBITS IN THIS PROCEEDING?

A. Yes. I am sponsoring <u>Exhibit AA-1</u>. This exhibit provides details regarding the capital and O&M plans my testimony supports.

II. OVERVIEW OF RESPONSIBILITIES

Q. PLEASE PROVIDE AN OVERVIEW OF THE FUNCTIONS YOUR TESTIMONY IS COVERING.

A. My testimony supports areas responsible for delivering safe and reliable electric and gas distribution service for BGE's customers. Specifically, Technical Services is responsible for planning, managing, and overseeing electric distribution system capacity planning, implementing smart grid and other innovative programs, and maintaining the reliability of the electric distribution system, including vegetation management. It is also responsible for overseeing the Company's investment strategy, executing large, complex electric and gas distribution projects and reliability programs, as well as maintaining accurate and up-to-date records of BGE's electric and gas distribution systems. While Company Witness Burton is responsible for the planning, engineering and operations of the overall gas line of business, it is helpful to understand that the project management organization that I oversee serves to support the Gas Division in executing BGE's Strategic Infrastructure Development and Enhancement ("STRIDE") plan as well as the Company's largest, most complex gas projects. The vegetation management organization also supports gas operations in the maintenance of gas rights-of-way.

Ultimately, these areas are responsible for developing the operating plans for electric distribution system performance, capacity expansion, vegetation management, and electric and gas distribution facility relocations. Additionally, I will also cover substation and protection & control system performance plans. Each of these areas is critical to delivering safe and reliable service to BGE's customers. It is important to understand how these reliability activities fit with those sponsored by Company Witness Biagiotti. At a high-level, the categories in my testimony cover the development and implementation of long-term, strategic reliability improvement plans, whereas Company Witness Biagiotti's categories are responsible for operating and maintaining the electric system and implementing short-term tactical reliability plans.

Q. WHAT IS THE BUDGETED SPEND FOR THE CATEGORIES YOU ARE SUPPORTING IN YOUR TESTIMONY?

A. The budgeted capital and O&M spend is shown in Table 1 and Table 2, respectively.

Table 1: Capital Spend by Category

Category	**Historical**	**Bridge**	**Multi-Year Plan Period**		
	2019A	2020F	2021F	2022F	2023F
Capacity Expansion – Distribution	$52,027,002	$56,403,190	$52,702,201	$53,726,928	$70,806,630
Facilities Relocation – Distribution	$2,583,061	$2,358,659	$2,279,477	$2,791,498	$2,807,622
Facilities Relocation – Gas	$28,258,825	$9,491,796	$6,218,207	$6,567,594	$7,028,463
System Performance – Distribution	$96,313,365	$107,935,982	$84,194,278	$82,543,914	$81,824,594
System Performance – Substation	$37,479,378	$39,366,787	$67,405,994	$47,777,004	$38,465,790
System Performance – Protection & Control	$2,702,758	$2,546,559	$4,592,832	$4,641,535	$3,312,685
Total	**$219,364,389**	**$218,102,973**	**$217,392,989**	**$198,048,473**	**$204,245,784**

Table 2: O&M Spend by Category

Category	**Historical**	**Bridge**	**Multi-Year Plan Period**		
	2019A	2020F	2021F	2022F	2023F
Capacity Expansion – Distribution	$299,796	$153,336	$157,416	$159,684	$160,359
System Performance – Distribution	$524,915	$246,621	$267,197	$270,799	$314,823
System Performance – Substation	$826,219	$1,205,814	$1,141,372	$1,206,893	$1,316,303
System Performance – Protection & Control	$ –	$2,215,121	$3,986,897	$4,072,977	$4,164,353
Vegetation Management	$30,405,884	$32,249,983	$33,446,553	$33,859,259	$34,811,755
Total	**$32,056,814**	**$36,070,875**	**$38,999,435**	**$39,569,612**	**$40,767,593**

Q. HOW DOES THE CAPITAL AND O&M PLANNING PROCESS WORK AT BGE?

A. As discussed in Part 2 of the Direct Testimony of Company Witness Vahos, capital and O&M is separated into areas of spend, called categories, which are led by category managers. Within each category, there are projects which are owned by managers. These individuals identify the work and the associated capital and O&M requirements to run the business and create a five-year budget. These projects roll up to the Category Managers, who review the estimates, identify risks and changes to prior budgets and work with the project owners to make refinements. The categories are overseen by Executive Category Owners. I serve as an Executive Category Owner and in this role, I review and approve the work plans and the associated capital and O&M requirements. I also ensure that spending levels and plans are executed so that our customers continue to receive safe and reliable electric service. My testimony will discuss the categories of spend listed in Tables 1 and 2.

Q. PLEASE DESCRIBE THE CATEGORIES LISTED IN TABLES 1 AND 2.

A. The category descriptions are as follows:

<u>Capacity Expansion – Distribution:</u> This category includes the capital and O&M spend to support load growth while assuring that BGE operates a safe and reliable electric distribution system. Work performed in this area is driven by customer-specific requirements, aggregate customer demand, established system planning criteria and regulatory standards, as well as industry standards. Typical spend involves, but is not limited to, electric distribution infrastructure buildouts, as well as substation and circuit upgrades.

Facilities Relocation – Distribution: This category includes the capital spend to relocate BGE overhead and underground primary and secondary electric assets to support Federal, State, County and Municipal improvement projects.[1]

Facilities Relocation – Gas: This category includes the capital spend to relocate BGE gas assets to support Federal, State, County and Municipal improvement projects.[2]

System Performance – Distribution: This category includes the capital and O&M spend to execute long-term electric reliability initiatives and replace aging and obsolete infrastructure. Typical spend involves, but is not limited to, installation of distribution automation equipment, cable replacement, upgrading 4kV distribution system assets, and selective undergrounding or circuit reconfigurations to maintain and improve customer reliability.

System Performance – Substation: This category includes the capital and O&M spend to maintain and improve reliability, physical security, reduce fire-related risk and comply with Environmental Protection Agency ("EPA") regulations. Typical spend involves, but is not limited to, proactively replacing substation equipment such as transformers, circuit breakers and switches, installing anti-cut and anti-climb fences, remote monitoring equipment, fire detection and suppression systems, as well as transformer secondary oil containment pits.

System Performance – Protection & Control: This category includes the capital and O&M spend to maintain and improve the reliability and security of BGE's relay equipment and operational technology security. Typical spend involves, but is not

[1] It is common for projects in this area to receive contributions in aid of construction ("CIAC"). The budgeted amounts presented in my testimony reflect only BGE's portion of construction costs.
[2] The budgeted amounts presented in my testimony reflect only BGE's portion of construction costs.

limited to, proactively replacing relays and remote terminal units ("RTUs"), cyber asset inventory and change management and asset firmware management.

Vegetation Management: This category includes the O&M spend to ensure safe and reliable operations by maintaining minimum clearances for distribution equipment from brush and trees. Typical spend involves routine and reactive tree trimming, tree removal, herbicide treatment and mowing.

Q. CAN YOU DESCRIBE THE RISKS THAT COULD ALTER YOUR MYP PLANS?

A. Yes. I discussed the COVID-19 pandemic above. Beyond that, while BGE makes every effort to identify risks and carefully evaluate our work and budget estimates to ensure reasonableness, there are risks that will cause actual spending to be different than budget. Primarily, these risks include, but are not limited to, load growth, weather, field conditions, permitting, resource availability and outage availability. Additionally, there are risks that new legislation or regulation could require additional work that was either unanticipated or incremental to BGE's budget.

As I will discuss, BGE performs annual load projections in order to determine where there is a need for increased capacity on the system. Additionally, customer-specific requirements can drive capacity needs as well. To the extent customer loads differ from our projections or customer requirements change, BGE's capital requirements will change. Weather is also a significant variable. The number of storms and even active weather days can have a large impact on work and spending. BGE creates budget estimates based on historical weather levels but weather can vary substantially year to year. Also, field conditions can impact the cost of construction activities. As an example, hitting rock when attempting to install a new feeder can increase the cost of a job substantially. Lastly, many of the projects in BGE's portfolio are complex, long-duration projects that span several years. There are significant unknowns when a project is initially scoped and budgeted multiple years before execution. As the project advances through the design and engineering process, changes in budgets will occur.

III. CAPITAL INVESTMENT

A. CAPACITY EXPANSION - DISTRIBUTION

Q. PLEASE EXPLAIN THE DRIVERS OF CAPITAL SPEND IN CAPACITY EXPANSION AND THE TYPES OF PROJECTS BEING PLANNED.

A. As previously discussed, capacity expansion spend is to support expected load growth on the BGE electric distribution system. Annually, projected electric distribution loads are prepared for all feeders and substations in order to identify where any capacity additions or reconfigurations are needed in order to meet system planning criteria. As potential system planning violations are identified, BGE will assess the most effective solution to address the capacity shortages. Potential solutions can range from feeder extensions, feeder switching, capacitor installations, distribution automation, transformer additions and new feeders, to new substation builds. In selecting a solution, we balance and consider all relevant factors including cost, safety, outage frequency, outage duration and operational flexibility when evaluating the recommended solution. We also look to deliver innovative solutions, including non-wires alternatives ("NWA"), for our customers such as the Cold Spring Battery project that was put in service in 2018. The work in the Capacity Expansion category differs from the New Business category in that this spend is to construct the necessary electric distribution infrastructure to accommodate higher loads, whereas New Business spend is primarily to support new service connections to residential, commercial and industrial customers.

Q. WHAT IS DRIVING THE OVERALL TREND IN CAPITAL SPENDING IN THIS CATEGORY OVER THE 2021 TO 2023 TIME PERIOD?

A. The overall spend in capacity expansion over the 2021 to 2023 time period is being driven by projects required to build out the necessary electric distribution infrastructure to support area redevelopment efforts. Notable redevelopment efforts requiring this support include the redevelopment of the Port Covington peninsula, a 235-acre mostly industrial waterfront area in south Baltimore, as well as Tradepoint Atlantic, the redevelopment of the 3,300-acre industrial site that was formerly the Sparrows Point iron and steel mill. Additional drivers of spend include substation upgrades, circuit additions and/or upgrades to provide necessary system capacity, the Conservation Voltage Reduction program, as well as the deployment of Battery Energy Storage Systems at Fairhaven. Spend in 2023 is expected to be more pronounced than prior years mainly due to significant levels of work beginning to support the Port Covington redevelopment, including substation construction and redevelopment, as well as new feeder installations.

Q. HOW DOES THIS COMPARE TO PRIOR YEARS?

A. Spend in 2021 through 2023 is consistent with prior years. However, spend in capacity expansion tends to fluctuate with the start and finish of large, discrete capital projects.

B. FACILITIES RELOCATIONS

Q. PLEASE EXPLAIN THE DRIVERS OF CAPITAL SPEND IN FACILITIES RELOCATIONS AND THE TYPES OF PROJECTS BEING PLANNED.

A. As discussed earlier, facilities relocation projects are the result of federal, state, county and municipal right of way modifications where BGE has electric and gas distribution assets. Projects being planned are to deliver solutions that ensure safe and reliable operations of the electric and gas system for BGE's customers and the requesting agency.

Q. WHAT IS DRIVING THE OVERALL TREND IN CAPITAL SPENDING IN THESE CATEGORIES OVER THE 2021 TO 2023 TIME PERIOD?

A. We are budgeting to spend $2.3 million to $2.7 million per year on electric distribution projects and $6.2 million to $7.0 million per year on gas distribution projects. These estimates are developed based on historical average spending on these types of projects. Actual spending in this category will ultimately be driven by requests coming from external agencies.

Q. HOW DOES THIS COMPARE TO PRIOR YEARS?

A. Electric distribution relocation projects are right in-line with historical spend. Gas facility relocation projects are expected to be significantly lower than prior years. We are expecting to spend about $6.2 million in 2021 on gas relocations versus $9.5 million in 2020 and $28.3 million in 2019. Gas relocation spend was significantly higher in 2019 due to several large, complex projects including a gas transmission relocation at MD 175/295 and several other road and bridge projects driven by the Maryland State Highway Administration and various counties. The scopes of these projects were much more complex than traditional relocation projects and involved complex, horizontal directional drilling ("HDD") that drove higher costs.

C. SYSTEM PERFORMANCE - DISTRIBUTION

Q. PLEASE EXPLAIN THE DRIVERS OF CAPITAL SPEND IN SYSTEM PERFORMANCE – DISTRIBUTION AND THE TYPES OF PROJECTS BEING PLANNED.

A. As previously outlined, the System Performance – Distribution category is responsible for enhancing the reliability of the electric distribution system. The work and spend in this category is driven by several factors, including BGE's system-wide reliability standards as set forth in COMAR 20.50.12.02. Our investments in system performance are to ensure BGE continues to deliver first quartile System Average Interruption Frequency Index ("SAIFI") and Customer Average Interruption Index ("CAIDI") reliability performance for our customers.[3] It is important to note that while BGE has consistently delivered strong reliability performance, on-going investment will be required in order to maintain this level of reliability for our customers, as well as to meet tightening reliability standards. Major categories of spend include reliability work to reduce the frequency and duration of customer outages, aging infrastructure replacement, and 4kV conversion work.

Reliability work focuses on programs to maintain and further improve customer reliability and represents the majority of BGE's spend in System

[3] BGE measures its reliability performance according to IEEE standard 2.5 Beta methodology.

Performance – Distribution, accounting for $30 million to $40 million annually. Over the MYP period, BGE is planning to spend just under $10 million annually to install overhead and pad-mounted distribution automation equipment. This reduces the number of customers experiencing sustained interruptions by intelligently reconfiguring the distribution circuit following an outage. Additionally, we are investing about $5 million annually to install remote fault indicators to more quickly identify the location of faults along feeders, reducing patrol time spent identifying faults and thereby decreasing customer interruption durations. In addition, spending on reliability improvements include programs to address targeted customer reliability issues, such as customers experiencing multiple interruptions ("CEMI"), poorest performing feeders, and multiple device activations ("MDA"). Work under these programs includes selective undergrounding, circuit reconfiguration and additional tree trimming.

Aging infrastructure investment focuses on replacing aging and obsolete equipment to improve system reliability and accounts for approximately $25 million per year of BGE's spend in this category. Cable replacement is the primary driver of spend in this area at about $20 million per year. The purpose of this program is to strategically replace BGE's aging distribution cable, thereby improving the operation and reliability of the underground system while reducing maintenance spending. We prioritize cables for replacement on several factors including number of failures, frequency of failures and numbers of customers affected. Therefore, as we are replacing our most fault prone cables, we are helping address reliability by reducing our SAIFI as well as our CEMI for the benefit of our customers. This has the added benefit of helping us avoid costly repairs that would impact customers' bills.

Lastly, BGE is investing approximately $25 million in capital expenditures per year to retire its legacy 4kV system equipment. The work in this area is focused on upgrading 4kV infrastructure to modern 13kV standards, providing reliability, operational, and environmental benefits. In doing so, we are removing 4kV "islands" from our system to improve reliability and increase capacity. Converting 4kV to 13kV also provides safety improvements. Additionally, modernizing our infrastructure brings the benefit of creating a smarter grid that can facilitate customer interest in a greater array of energy offerings, such as rooftop solar.

Q. WHAT IS DRIVING THE OVERALL TREND IN CAPITAL SPENDING IN THIS CATEGORY OVER THE 2021 TO 2023 TIME PERIOD?

A. The category spend is consistent in 2021 through 2023 at approximately $82 million to $84 million per year. The majority of category spend is driven by programmatic work to improve reliability and replace aging infrastructure as discussed previously, which typically results in minimal year-over-year variability. The work to convert the legacy 4kV system consists of a series of projects targeting individual circuits and substations, which require extensive planning to avoid exacerbating reliability impacts when conducting this work. In addition, the category also includes discrete projects addressing specific customer or area issues. BGE strives to minimize the year-over-year variability introduced by these projects by sequencing them appropriately, thus keeping the overall category spend relatively flat.

Q. HOW DOES THIS COMPARE TO PRIOR YEARS?

A. Spend in 2021 through 2023 is slightly lower than prior years. This is largely driven by a modest decline in 4kV conversion projects of about $5 million versus 2020 and the completion of a feeder installation project to improve reliability.

<u>D. SYSTEM PERFORMANCE – SUBSTATION</u>

Q. PLEASE EXPLAIN THE DRIVERS OF CAPITAL SPEND IN SYSTEM PERFORMANCE - SUBSTATION AND THE TYPES OF PROJECTS BEING PLANNED.

A. This category is responsible for improving the reliability and physical security of our substations, reducing fire-related risk and complying with EPA regulations. Spend in this category is driven by several factors including substation security projects and proactive replacement of substation transformer oil containment pits, transformers and substation fire protection systems.

Substation security projects are executed in order to improve the physical security at substations through installing anti-cut and anti-climb fences, movement detectors, fence detectors and cameras along with remote monitoring. These projects promote the safety of our customers and ensure the reliability of our electric distribution system.

Substation transformer oil containment pit replacement projects are executed as pits are inspected or tested and determined to be of age or condition that require replacement to adhere to U.S. Code of Federal Regulations, Title 40, Chapter I – EPS, Subchapter D, Part 112 regulations.

Proactive transformer replacement projects are performed to help ensure reliable system operations as well as to control maintenance costs required on aging equipment. Transformers are prioritized based on condition and age to be replaced. BGE targets to replace two to four distribution substation transformers per year.

Lastly, BGE is executing substation fire protection system replacements to ensure safety and protect our critical substation equipment during a fire event.

Q. WHAT IS DRIVING THE OVERALL TREND IN CAPITAL SPENDING IN THIS CATEGORY OVER THE 2021 TO 2023 TIME PERIOD?

A. Spend in this category decreases from 2021 to 2023 driven by a peak in substation security spending in 2021 with a downward trend in that program thereafter. This overall trend is primarily due to focusing on large, complex sites first, which are more expensive in nature due to their enhanced security requirements.

Q. HOW DOES THIS COMPARE TO PRIOR YEARS?

A. Spending in 2021 and 2022 is higher than 2019 and 2020 driven by the previously mentioned peak in substation security spending. In 2023, spend returns to levels that are in line with spend in 2019 and 2020.

E. SYSTEM PERFORMANCE – PROTECTION & CONTROL

Q. PLEASE EXPLAIN THE DRIVERS OF CAPITAL SPEND IN SYSTEM PERFORMANCE - SUBSTATION AND THE TYPES OF PROJECTS BEING PLANNED.

A. System Performance Protection & Control capital investments are implemented to maintain or improve the reliability and security of BGE's Protection & Control infrastructure via lifecycle replacements of aging and hard to support equipment that presents an operability or reliability risk, or which incurs maintenance costs in excess of similar function equipment. Spend in this category is primarily driven by RTU replacements.

Q. WHAT IS DRIVING THE OVERALL TREND IN CAPITAL SPENDING IN THIS CATEGORY OVER THE 2021 TO 2023 TIME PERIOD?

A. Spend is consistent in 2021 and 2022 and modestly declines in 2023 driven by the replacement or upgrade of a targeted group of obsolete and difficult to support electric distribution RTUs.

Q. HOW DOES THIS COMPARE TO PRIOR YEARS?

A. Spend in 2021 through 2023 is higher than prior years, primarily due to operational technology security costs that reach steady state in 2021, in addition to the previously mentioned replacement or upgrade efforts on the targeted electric distribution RTUs.

IV. OPERATIONS & MAINTENANCE ACTIVITIES

A. CAPACITY EXPANSION - DISTRIBUTION

Q. WHAT IS DRIVING THE OVERALL TREND IN O&M SPENDING IN THIS CATEGORY OVER THE 2021 TO 2023 TIME PERIOD?

A. Spend is consistent over the 2021 to 2023 time period and is driven by feeder phase balancing and spend to develop scope for upcoming projects. Phase balancing addresses loading imbalances on distribution circuits that may cause an overload condition on one of the phases. BGE monitors loading on each circuit and, when appropriate, initiates projects to balance the loading on each phase. This provides greater operational flexibility and can eliminate the need for system upgrades that would otherwise be required when highly loaded phases reach their capacity.

Q. HOW DOES THIS COMPARE TO PRIOR YEARS?

A. Spend in 2021 to 2023 is consistent with prior years.

B. SYSTEM PERFORMANCE - DISTRIBUTION

Q. WHAT IS DRIVING THE OVERALL TREND IN O&M SPENDING IN THIS CATEGORY OVER THE 2021 TO 2023 TIME PERIOD?

A. Spend in 2021 to 2023 is flat and driven by the O&M portion of the customer reliability projects discussed previously in my testimony.

Q. HOW DOES THIS COMPARE TO PRIOR YEARS?

A. O&M expense in system performance is expected to be slightly lower than prior years.

C. SYSTEM PERFORMANCE – SUBSTATION

Q. WHAT IS DRIVING THE OVERALL TREND IN O&M SPENDING IN THIS CATEGORY OVER THE 2021 TO 2023 TIME PERIOD?

A. Spend in 2021 to 2023 is slightly increasing due to inflation and the initiation of a proactive transformer replacement program.

Q. HOW DOES THIS COMPARE TO PRIOR YEARS?

A. O&M spending is expected to be slightly higher than prior years due to the drivers just discussed.

<u>D. SYSTEM PERFORMANCE – PROTECTION & CONTROL</u>

Q. WHAT IS DRIVING THE OVERALL TREND IN O&M SPENDING IN THIS CATEGORY OVER THE 2021 TO 2023 TIME PERIOD?

A. Spend in 2021 to 2023 is consistent and driven by operational technology security costs.

Q. HOW DOES THIS COMPARE TO PRIOR YEARS?

A. Spend in this category is higher than prior years due to operational technology security costs that begin in 2020 and ramp up to steady state in 2021.

<u>E. VEGETATION MANAGEMENT</u>

Q. PLEASE EXPLAIN THE DRIVERS OF SPEND IN VEGETATION MANAGEMENT AND THE TYPES OF PROJECTS BEING PLANNED.

A. Spending in vegetation management is driven by several state and local laws and regulations including, but not limited to, the Maryland Electricity Service Quality and Reliability Act,[4] the Maryland Roadside Tree Law,[5] the Maryland Licensed Tree Expert Law[6] and the Chesapeake and Atlantic Coastal Bays Critical Area Protection Program.[7] The preventative and reactive vegetation management activities planned within this category are necessary for BGE to meet key safety and reliability metrics and reduce reliability impacts during inclement weather events. Activities include tree pruning, tree removals, mechanical clearing, control of vines, and the use of chemical methods of vegetation control. The combination

[4] Regulations implementing the vegetation management requirements of the Maryland Electricity Service Quality and Reliability Act (Public Utilities Article, §7-213) are set forth in COMAR 20.50.12.09.
[5] Md. Code Ann., Natural Resources Article, §5-401 through §5-411.
[6] Md. Code Ann., Natural Resources Article, §5-415 through §5-423.
[7] Md. Code Ann., Natural Resources Article, §8-1801 through §8-1817.

of preventative and corrective approaches provides a comprehensive vegetation management distribution maintenance program. BGE has 9,404 miles of overhead distribution circuit miles, 260 miles of gas rights-of-ways, and 266 substations maintained through these programs.

Q. WHAT IS DRIVING THE OVERALL TREND IN SPENDING IN THIS CATEGORY OVER THE 2021 TO 2023 TIME PERIOD?

A. The overall trend in spending over the 2021 to 2023 time period is relatively flat with minor variations driven by different planned scopes of work in each of the years. In general, BGE trims its system on four-year cycles and aims to cover about 25 percent of the system each year.; however, exact mileage will vary slightly from year to year.

Q. HOW DOES THIS COMPARE TO PRIOR YEARS?

A. Vegetation management work planned is consistent with prior years, however the costs reflect an increase in contracted rates due to a new contract at the end of 2019.

V. CONCLUSION

Q. DOES THIS CONCLUDE YOUR DIRECT TESTIMONY?

A. Yes, it does.

An Exelon Company

2020-2023 Plan Documentation – Capital and O&M

Executive Category Owner: Ajit Apte

Title: Vice President, Technical Services

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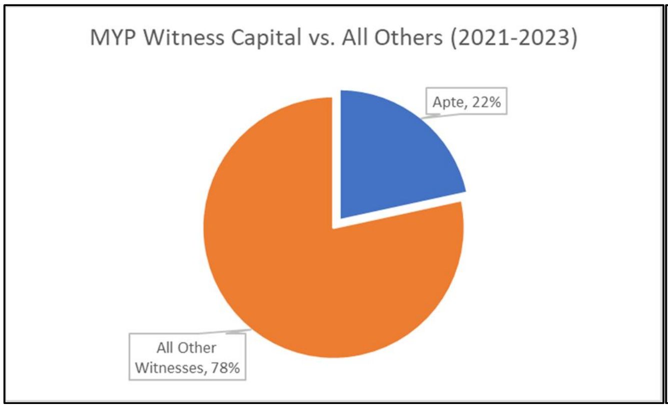
I. Financial Summary

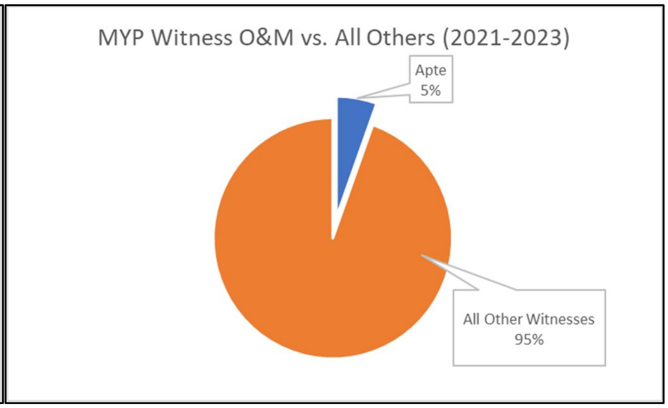
A. Capital

CATEGORY	2019A	2020F	2021F	2022F	2023F
CAPACITY EXPANSION – DISTRIBUTION	$52,027,002	$56,403,190	$52,702,201	$53,726,928	$70,806,630
SYSTEM PERFORMANCE – DISTRIBUTION	$96,313,365	$107,935,982	$84,194,278	$82,543,914	$81,824,594
SYSTEM PERFORMANCE – PROTECTION & CONTROL	$2,702,758	$2,546,559	$4,592,832	$4,641,535	$3,312,685
SYSTEM PERFORMANCE – SUBSTATION	$37,479,378	$39,366,787	$67,405,994	$47,777,004	$38,465,790
FACILITIES RELOCATION – ELECTRIC	$2,583,061	$2,358,659	$2,279,477	$2,791,498	$2,807,622
FACILITIES RELOCATION – GAS	$28,258,825	$9,491,796	$6,218,207	$6,567,594	$7,028,463
ANNUAL TOTALS FOR CAPITAL	**$219,364,389**	**$218,102,973**	**$217,392,989**	**$198,048,473**	**$204,245,784**

B. O&M

CATEGORY	2019A	2020F	2021F	2022F	2023F
CAPACITY EXPANSION – DISTRIBUTION	$299,796	$153,336	$157,416	$159,684	$160,359
SYSTEM PERFORMANCE – DISTRIBUTION	$524,915	$246,621	$267,197	$270,799	$314,823
SYSTEM PERFORMANCE – PROTECTION & CONTROL	$0	$2,215,121	$3,986,897	$4,072,977	$4,164,353
SYSTEM PERFORMANCE – SUBSTATION	$826,219	$1,205,814	$1,141,372	$1,206,893	$1,316,303
VEGETATION MANAGEMENT	$30,405,884	$32,249,983	$33,446,553	$33,859,259	$34,811,755
ANNUAL TOTALS FOR O&M	**$32,056,814**	**$36,070,875**	**$38,999,435**	**$39,569,612**	**$40,767,593**





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II. Capital Category Cashflows and Functions

A. Capacity Expansion – Distribution

Category	2019A	2020F	2021F	2022F	2023F
Capacity Expansion – Distribution	$52,027,002	$56,403,190	$52,702,201	$53,726,928	$70,806,630

- The Capacity Expansion – Distribution category includes projects developed to assure a safe and reliable electric distribution system, as well as to comply with regulatory and industry standards and to adhere to established system planning criteria. There are several sections in Title 20, Subtitle 50 of the Code of Maryland Regulations (COMAR 20.50) that directly apply to Capacity Expansion – Distribution, in particular, sections 20.50.02 (Engineering) and 20.50.07 (Quality of Service).
- Major projects in this category include building out necessary distribution infrastructure to support area redevelopment efforts (e.g., Port Covington, Tradepoint Atlantic, etc.), performing substation and circuit upgrades to provide necessary system capacity, deploying the Conservation Voltage Reduction program and deploying Battery Energy Storage Systems.
- The overall trends in costs are driven by customer requirements for in-service dates or capacity increases required to meet the aggregate demand of customers as well as the size and timing of the projects necessary to address these requirements. These result in year-to-year variability in the project work, which is apparent in the costs shown above.
- The increase in spending levels in 2023 is primarily due to significant levels of work scheduled to start in support of the Port Covington redevelopment effort, including substation construction and redevelopment and new feeder installations.

B. Facilities Relocation – Electric

Category	2019A	2020F	2021F	2022F	2023F
Facilities Relocation – Electric	$2,583,061	$2,358,659	$2,279,477	$2,791,498	$2,807,622

- This category funds relocation of BGE overhead and underground primary/secondary electric assets to support federal, state, county and municipality improvement projects, including new community infrastructure additions or upgrades. In electric distribution, most projects have a contribution in aid of construction. The budgeted amounts reflect BGE's portion of construction costs only.
- The year-to-year fluctuations in costs in this category represent changes in the Maryland Department of Transportation, State Highway Administration, and municipality plans and timing. BGE conducts monthly coordination meetings with all parties (including other service providers such as Verizon Wireless) to review forecasted projects and monitor the status of all projects in the plan. This allows BGE to identify emergent work.

C. Facilities Relocation – Gas

Category	2019A	2020F	2021F	2022F	2023F
Facilities Relocation – Gas	$28,258,825	$9,491,796	$6,218,207	$6,567,594	$7,028,463

- This category funds relocation of BGE gas assets to support federal, state, county and municipality improvement projects, including new community infrastructure additions or upgrades. In gas distribution, very few projects have a contribution in aid of construction. The budgeted amounts reflect BGE's portion of construction costs.
- The year-to-year fluctuations in costs in this category represent changes in the Maryland Department of Transportation, State Highway Administration and municipality plans and timing. BGE conducts monthly

coordination meetings with all parties (including other service providers such as Verizon Wireless) to review forecasted projects and monitor the status of all projects in the plan. This allows BGE to identify emergent work.

D. System Performance – Distribution

Category	2019A	2020F	2021F	2022F	2023F
System Performance – Distribution	$96,313,365	$107,935,982	$84,194,278	$82,543,914	$81,824,594

- The work in System Performance – Distribution is governed in part by Title 20, Subtitle 50 of the Code of Maryland Regulations (COMAR 20.50), specifically sections 20.50.12 (Service Quality and Reliability Standard) and 20.50.07 (Quality of Service).
- The work in this category includes:
    - Reliability work which focuses on reducing the frequency and duration of outages. Projects and programmatic work includes the installation of overhead and pad-mounted Distribution Automation (DA) equipment, installation of overhead and pad-mounted monitored fault indicators, and work to address targeted customer reliability issues, such as customers experiencing multiple interruptions (CEMI), poorest performing feeders and multiple device activation (MDA) work.
    - Aging infrastructure work is focused on replacing aging and obsolete equipment to improve system reliability. Project and programmatic work include cable replacement, which strategically replaces aging distribution cable, thereby improving the operability and reliability of the underground system. Work also includes the replacement of obsolete communications and equipment infrastructure.
    - Retirement of legacy 4 kV distribution system work is focused on upgrading 4 kV infrastructure to modern 13 kV standards, providing reliability, operational, and environmental benefits. Additionally, modernizing our infrastructure brings the benefit of creating a smarter grid that can facilitate customer interest in a greater array of energy offerings, such as rooftop solar. These projects require extensive planning to maintain system reliability while performing the work.
    - Customer reliability and support projects designed to address specific customer experiences and Public Service Commission requirements are also included within this category. Example projects include selective undergrounding and circuit reconfiguration to improve customer reliability.
- The overall downward trend in costs from 2020 to 2023 is driven by changes in discrete projects being executed in the capital plan. The majority of category spend is level for the period and is driven by programmatic work to improve reliability and replace aging infrastructure. Discrete projects and programs addressing specific customer or area issues end in 2020 resulting in the downward trend from 2020 to 2021.

E. System Performance – Protection & Control

Category	2019A	2020F	2021F	2022F	2023F
System Performance – Protection & Control	$2,702,758	$2,546,559	$4,592,832	$4,641,535	$3,312,685

- System Performance – Protection & Control capital investments are made to improve the reliability of BGE's Protection & Control infrastructure via lifecycle replacements of aging and hard-to-support equipment that presents a reliability risk, or which incurs maintenance costs in excess of similar functioning equipment. Additionally, this category funds capital projects that are designed to comply with system reliability metrics in COMAR 20.50.12.02, such as SAIFI and SAIDI. Lastly, projects in this category support implementation of new equipment aimed at enhancing system protection and monitoring, which facilitates real-time analysis of operational responses to system events. In addition:
    - Equipment replacements take the form of individual components or complete protective relay systems, remote terminal units (RTUs), metering and monitoring equipment, etc.
    - Distribution RTU replacements as part of the category's scope of work align with BGE plans for the upgrade of the existing Supervisor Control and Data Acquisition (SCADA) system with a new Advanced Distribution Management System (ADMS) SCADA.
    - Targeted relay replacements are designed to address aging electro-mechanical relay technologies and to enhance controls in an effort to avoid sustained outages.
- The costs trends in the System Performance – Protection & Control category are reasonably consistent with the ups and downs associated with project starts and completions. 2022 spend reflects execution of a new equipment pilot while the reduction in 2023 spend reflects completion of a targeted group of obsolete and difficult to support distribution RTUs.

F. System Performance – Substation

Category	2019A	2020F	2021F	2022F	2023F
System Performance – Substation	$37,479,378	$39,366,787	$67,405,994	$47,777,004	$38,465,790

- System Performance – Substation capital is used to improve reliability, physical security, reduce fire-related risk and comply with EPA regulations. After a significant increase in 2021 spending, annual spending drops in 2022 and 2023 as BGE implements the following improvements:
    - Reliability of BGE's substations is improved by replacing substation equipment prior to failures due to age and condition such as transformers, circuit breakers, circuit switchers, disconnect switches, insulators, potential transformers, coupling capacitor voltage transformers, lightning arresters, etc. Also, pilots of on-line monitoring equipment to support analytical tools and help make better maintenance versus replace decisions continue throughout the plan time horizon.
    - Physical security at substations is improved by installing anti-cut/anti-climb fences, movement detectors, fence detectors and cameras, along with remote monitoring.
    - Fire detection, alarm and suppression systems at substations are improved to protect equipment and personnel by upgrading as part of a best practices review.
    - Substation transformer secondary oil containment pits are replaced to comply with EPA regulations.
- The trend in this category is a result of a peak in substation security spending and a significant substation-related replacement project, the Notch Cliff Propane Plant Substation Replacement, that causes the category to peak in 2021.

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III. Capital Details

This Section provides additional details for capital projects with spending greater than $1 million in any year within the 2019-2023 time period for each of the categories below.

A. Capacity Expansion – Distribution

Project Name	53894: Gould St Station Upgrades			
2019A	**2020F**	**2021F**	**2022F**	**2023F**
	$5,279	$248,910	$1,233,285	$1,208,285
Problem Statement		**Solution Statement**		**Estimated / In-Service Date**
Large customer development in south Baltimore requested 34kV supply from diverse substations.		Make upgrades to Gould Street 34kV substation to allow a 34kV circuit to be extended from the substation.		December 2023

Project Name	54224: Westport Station Upgrades			
2019A	**2020F**	**2021F**	**2022F**	**2023F**
		$237,638	$800,818	$1,863,124
Problem Statement		**Solution Statement**		**Estimated / In-Service Date**
Large customer development in south Baltimore requested 34kV supply from diverse substations.		Make upgrades to Westport 34kV substation to allow a 34kV circuit to be extended from the substation.		December 2023

Project Name	54252: Port Covington New Feeders			
2019A	**2020F**	**2021F**	**2022F**	**2023F**
	$807,818	$842,047	$1,471,379	$8,383,093
Problem Statement		**Solution Statement**		**Estimated / In-Service Date**
Large development on Port Covington peninsula with projected loads in excess of 100MW. Existing infrastructure in the area is not sufficient to meet projected demand.		Construct a new 115-13 kV substation. Build new 13kV distribution feeders to supply the new loads.		After 2023

Project Name	56698: Future Stages of Cold Spring Battery Storage			
2019A	**2020F**	**2021F**	**2022F**	**2023F**
				$4,978,337
Problem Statement		**Solution Statement**		**Estimated / In-Service Date**
The Coldspring 115-13kV substation is approaching its loading capability based on peak summer conditions.		This project aims to address station overloads by employing utility scale energy storage. Battery energy storage will be used to peak shave overloads at the substation. Defers the cost of building a new substation.		After 2023

Project Name	59216: Feeder 33721 Extension for Shadyside			
2019A	**2020F**	**2021F**	**2022F**	**2023F**
	$1,116,360	$2,136,212		
Problem Statement		**Solution Statement**		**Estimated / In-Service Date**
A new substation transformer at Shadyside substation will require an additional 34kV sub-transmission supply circuit.		Extend a nearby Marriott Hill 34kV feeder to the Shadyside substation.		December 2021

Project Name	59335: Rock Ridge 33833 Reconductoring			
2019A	**2020F**	**2021F**	**2022F**	**2023F**
$1,111	$66		$8,926,303	$3,763,357
Problem Statement		**Solution Statement**		**Estimated / In-Service Date**
This project is required to address a 34kV contingency overload at winter peak conditions. The potential loss of another feeder will cause this one to exceed its emergency capacity.		Reconductor the feeder to increase capacity and address the contingency overload.		December 2023

Project Name	59398: Clare Street Substation 115/34kV Substation			
2019A	**2020F**	**2021F**	**2022F**	**2023F**
$221,524	$1,927,341	$1,997,000	$16,304,174	$17,207,019
Problem Statement		**Solution Statement**		**Estimated / In-Service Date**
Aging infrastructure at the Westport 34kV substation is a concern. Construction of a new susbstation is required to support existing generation, customer loads, and projected new customer loads in the area.		Build Clare Street 34kV substation on property adjacent to Westport 34kV substation.		December 2023

Project Name	59399: Clare Street Substation 34kV Feeders			
2019A	**2020F**	**2021F**	**2022F**	**2023F**
$19,075	$72,468	$152,673	$12,982	$5,356,503
Problem Statement		**Solution Statement**		**Estimated / In-Service Date**
Aging infrastructure at the Westport 34kV substation is a concern. Construction of a new susbstation is required to support existing generation, customer loads, and projected new customer loads in the area.		Supply existing Westport 34kV feeders from newly constructed Clare Street 34kV substation.		December 2023

Project Name	59403: Demo Westport #6 34kV Substation			
2019A	**2020F**	**2021F**	**2022F**	**2023F**
$12,139	$63,000	$64,575		$5,501,184
Problem Statement		**Solution Statement**		**Estimated / In-Service Date**
The existing Westport 34kV substation raises aging infrastructure concerns but is required to support existing generation, customer loads, and projected new customer loads in the area.		Rebuild Westport 34kV substation and demo existing substation to provide land for additional infrastructure upgrades on the Westport campus.		December 2023

Project Name	60032: Wilkens Avenue Install 4-13kV feeders			
2019A	**2020F**	**2021F**	**2022F**	**2023F**
$3,065,256	$13,352,127	$6,937,521	$187,969	
Problem Statement		**Solution Statement**		**Estimated / In-Service Date**
Aging substations within the West Baltimore area are planned to be retired and existing loads need to be resupplied from newly constructed Wilkens Avenue Substation.		Construct 10 distribution feeders from Wilkens Substation as the initial phase of offloading aging 4kV and 13kV substations in West Baltimore area.		January 2022

Project Name	60144: Loch Raven Substation			
2019A	**2020F**	**2021F**	**2022F**	**2023F**
$480,958	$981,469	$1,711,521	$230,955	$5,106,485
Problem Statement		**Solution Statement**		**Estimated / In-Service Date**
Existing substation in the area is approaching its capacity rating under summer peak conditions.		Construct new 115-13kV substation in nearby location and connect existing feeders to the station.		After 2023

Project Name	60145: Wilkens Avenue 80 MVA Substation			
2019A	**2020F**	**2021F**	**2022F**	**2023F**
$10,234,991				
Problem Statement		**Solution Statement**		**Estimated / In-Service Date**
Aging substations within the West Baltimore area are planned to be retired and a new substation is required to support customer loads in that area.		Construct new 115-13kV substation to serve West Baltimore area and improve reliability. Allows for eventual retirement of aging substations.		March 2020

Project Name	60195: Wilkens Avenue 115/13kV Substation – Phase 2			
2019A	**2020F**	**2021F**	**2022F**	**2023F**
			$11,817,952	
Problem Statement		**Solution Statement**		**Estimated / In-Service Date**
Carroll substation is aging and due to be retired. In addition, removing load from Carroll substation is required to reduce the overall size of planned Clare Street substation.		Construct new distribution feeders from Wilkens Avenue substation to facilitate unloading and ultimate retirement of Carroll substation.		December 2022

Project Name	60205: Shadyside 2nd 25 MVA (33-3)			
2019A	**2020F**	**2021F**	**2022F**	**2023F**
$2,370	$1,808,016	$1,227,011		
Problem Statement		**Solution Statement**		**Estimated / In-Service Date**
The Shadyside substation is nearing its winter capability. The existing substation transformer is supplying multiple busses and feeders without an alternate means to transfer all of the load.		Install a 25 MVA transformer to supply the 2nd substation bus which provides load relief and allows for maintenance switching. The second transformer will also enable the extension of future 13kV feeders.		June 2021

Project Name	60268: Shadyside New Feeder 8403			
2019A	**2020F**	**2021F**	**2022F**	**2023F**
		$2,612,816		
Problem Statement		**Solution Statement**		**Estimated / In-Service Date**
Distribution Operations is unable to schedule planned outages needed to maintain the Shadyside substation and the existing substation transformer. Also, existing 13kV feeder ties limit the ability to provide load relief and contingency switching options.		A new 13kV feeder from Shadyside substation will be extended to provide winter load relief and additional switching options.		December 2021

Project Name	60295: Fitzell 115-13kV Substation			
2019A	**2020F**	**2021F**	**2022F**	**2023F**
$17,180,147	$5,877,154			
Problem Statement		**Solution Statement**		**Estimated / In-Service Date**
Redevelopment of the Sparrows Point peninsula by Trade Point Atlantic will exceed the available capacity of distribution feeders in the area. The new loads are expected to approach 100 MW and many new loads will require redundant supplies for reliability.		Construct a new 115-34 kV and 115-13 kV substation. Build new 13kV and 34kV distribution feeders to supply the new loads.		June 2020

Project Name	60298: Port Covington 115-13kV Substation			
2019A	**2020F**	**2021F**	**2022F**	**2023F**
	$6,821,347	$1,423,332	$3,349,428	$14,180,914
Problem Statement		**Solution Statement**		**Estimated / In-Service Date**
Large development on Port Covington peninsula with projected loads in excess of 100MW. Existing infrastructure in the area is not sufficient to meet projected demand.		Construct a new 115-13 kV substation. Build new 13kV distribution feeders to supply the new loads.		After 2023

Project Name	60420: Fitzell Duct Bank for Feeders			
2019A	**2020F**	**2021F**	**2022F**	**2023F**
$7,404,114				
Problem Statement		**Solution Statement**		**Estimated / In-Service Date**
Need new feeders out of new substation to supply local area loads.		Build duct bank to route new feeders out of new substation.		December 2019

Project Name	60756: CVR Capacitor Bank Controllers			
2019A	**2020F**	**2021F**	**2022F**	**2023F**
$8,279,944	$5,743,194	$5,155,898	$3,991,019	
Problem Statement		**Solution Statement**		**Estimated / In-Service Date**
Conservation Voltage Reduction (CVR) is a program to improve the efficiency of the electric distribution system by optimizing voltage levels within the limits prescribed by ANSI standards and Code of Maryland Regulations. CVR benefits to customers include reductions in energy consumption and peak demand, reduction in BGE's infrastructure investment, reduction in energy losses and reduction in greenhouse gas emissions.		BGE started the full-scale CVR deployment in 2014 and plans to complete the deployment in 2022. In order to implement CVR, BGE is deploying new regulator and distribution capacitor bank controllers and is improving metering in distribution substations. The project will install approximately 4,800 capacitor bank controllers, 9,600 overhead and pad-mount voltage sensors, 80 voltage regulators, and will upgrade metering at 100 substations. BGE has deployed head-end control software to monitor and control all CVR devices. This project captures the cost of distribution assets deployed on the CVR program, predominantly regulator/capacitor bank controllers and associated equipment costs.		Monthly / Various

Project Name	61146: Conservation Voltage Reduction			
2019A	**2020F**	**2021F**	**2022F**	**2023F**
$1,842,126	$845,159	$948,300	$674,034	$50,000
Problem Statement		**Solution Statement**		**Estimated / In-Service Date**
Conservation Voltage Reduction (CVR) is a program to improve the efficiency of the electric distribution system by optimizing voltage levels within the limits prescribed by ANSI standards and Code of Maryland Regulations. CVR benefits to customers include reductions in energy consumption and peak demand, reduction in BGE's infrastructure investment, reduction in energy losses and reduction in greenhouse gas emissions.		BGE started the full-scale CVR deployment in 2014 and plans to complete the deployment in 2022. In order to implement CVR, BGE is deploying new regulator and distribution capacitor bank controllers and is improving metering in distribution substations. The project will install approximately 4,800 capacitor bank controllers, 9,600 overhead and pad-mount voltage sensors, 80 voltage regulators, and will upgrade metering at 100 substations. BGE has deployed head-end control software to monitor and control all CVR devices. This project captures the cost of substation assets deployed on the CVR program, including transformer load tap changer controllers and substation metering upgrades.		Monthly

Project Name	61742: Demo (Below Grade) Westport #8			
2019A	**2020F**	**2021F**	**2022F**	**2023F**
$18,906	$52,500	$4,010,040		
Problem Statement		**Solution Statement**		**Estimated / In-Service Date**
Retired underground infrastructure remains on a lot identified for a future substation that is needed to address aging infrastructure concerns.		Demolish and remove infrastructure.		December 2021

Project Name	62834: Newgate 8963/8964			
2019A	**2020F**	**2021F**	**2022F**	**2023F**
		$2,099,984	$53,514	
Problem Statement		**Solution Statement**		**Estimated / In-Service Date**
Newgate 8961 and Highlandtown 7876 feeders will be overloaded at peak summer conditions due to new customer development in Canton area.		Build two new feeders 8963 and 8964 from Newgate to mitigate 8961 and 7876 overloads.		June 2022

Project Name	62848: New Fitzell 34kV Feeders			
2019A	**2020F**	**2021F**	**2022F**	**2023F**
$129,556	$7,341,257	$3,193,406	$481,236	
Problem Statement		**Solution Statement**		**Estimated / In-Service Date**
Tradepoint Atlantic plans to redevelop the old Bethlehem Steel property on the Sparrows Point peninsula. The new 34kV customer load exceeds the capacity from existing circuits in the area.		Extend new 34kV feeders from the Fitzell substation to meet new customer needs and to improve reliability to existing customers. New 34kV feeders are needed to create proper supplies, ties, loops, etc. to supply new customer loads.		September 2022

Project Name	62865: New Fitzell 13kV Feeders			
2019A	**2020F**	**2021F**	**2022F**	**2023F**
$11,666	$1,638,806	$1,968,254	$202,130	
Problem Statement		**Solution Statement**		**Estimated / In-Service Date**
Tradepoint Atlantic plans to redevelop the old Bethlehem Steel property on the Sparrows Point peninsula. The new 13kV customer load exceeds the capacity from existing circuits in the area.		Extend new 13kV feeders from the Fitzell substation, as needed, to meet the new customer needs. New 13kV feeders are needed to create proper supplies, ties, loops, etc. to supply new customer loads.		June 2021

Project Name	62887: Marriott Hill 33721 Reconductoring			
2019A	**2020F**	**2021F**	**2022F**	**2023F**
	$1,302,961	$5,997,645		
Problem Statement		**Solution Statement**		**Estimated / In-Service Date**
A winter contingency overload is forecasted on Marriott Hill 34kV feeders.		Reconductor a 34 kV feeder to increase the feeder rating.		December 2021

Project Name	62903: Fairhaven Substation Battery			
2019A	**2020F**	**2021F**	**2022F**	**2023F**
$116,110	$1,821,915	$5,507,896		
Problem Statement		**Solution Statement**		**Estimated / In-Service Date**
A winter contingency overload is forecasted on Marriott Hill 34kV feeders.		Install a Battery Energy Storage System (BESS) to mitigate the forecasted overload.		December 2021

B. Facilities Relocations – Electric

Project Name	61049: Electric Facilities Relocations			
2019F	**2020F**	**2021F**	**2022F**	**2023F**
$2,592,809	$2,358,659	$2,279,477	$2,791,498	$2,807,622
Problem Statement		**Solution Statement**		**Estimated / In-Service Date**
Government agencies' road widening and storm water projects impact BGE assets on a regular basis.		Ensure BGE assets are relocated in ample time prior to the start of government agencies' projects.		Monthly / Various

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C. Facilities Relocation – Gas

Project Name	61051: Facilities Relocate Public NonBill Main			
2019A	**2020F**	**2021F**	**2022F**	**2023F**
$28,258,825	$9,491,796	$6,218,207	$6,567,594	$7,028,463
Problem Statement		**Solution Statement**		**Estimated / In-Service Date**
Facilities Relocation projects are driven by gas facilities that need to be relocated due to jurisdictional projects that have conflicts with the existing gas utility locations.		Gas relocation upgrades to the existing facilities in the BGE service territory (gas services, gas distribution and transmission mains).		Monthly / Various

D. System Performance – Distribution

Project Name	54928: West Hamilton 4521 & 4527 4kV Conversion			
2019A	**2020F**	**2021F**	**2022F**	**2023F**
			$6,576,151	

Problem Statement	**Solution Statement**	**Estimated / In-Service Date**
The West Hamilton 4521 and 4527 4kV feeders currently have both aging substation and distribution assets, limited load capacity and limited feeder restoration options.	The West Hamilton 4521 & 4527 4kV Conversion project is part of an overall effort to purge the BGE system of 4kV infrastructure due to aging assets, it’s limited load capacity and limited restoration options. The solution is to convert the feeder from 4kV to 13kV, providing higher load capacity, improving the restoration capability, and renewing aging infrastructure.	December 2022

Project Name	54931: West Hamilton 4533 4kV Conversion			
2019A	**2020F**	**2021F**	**2022F**	**2023F**
		$2,114,046		

Problem Statement	**Solution Statement**	**Estimated / In-Service Date**
The West Hamilton 4533 4kV feeder currently has both aging substation and distribution assets, limited load capacity and limited feeder restoration options.	The West Hamilton 4533 4kV Conversion project is part of an overall effort to purge the BGE system of 4kV infrastructure due to aging assets, it’s limited load capacity and limited restoration options. The solution is to convert the feeder from 4kV to 13kV, providing higher load capacity, improving the restoration capability, and renewing aging infrastructure.	December 2021

Project Name	55782: Monument St 4127 4kV Conversion			
2019A	**2020F**	**2021F**	**2022F**	**2023F**
		$1,185,761	$2,149,182	

Problem Statement	**Solution Statement**	**Estimated / In-Service Date**
The Monument Street 4127 4kV feeder currently has both aging substation and distribution assets, limited load capacity and limited feeder restoration options.	The Monument Street 4127 4kV Conversion project is part of an overall effort to purge the BGE system of 4kV infrastructure due to aging assets, it’s limited load capacity and limited restoration options. The solution is to convert the feeder from 4kV to 13kV, providing higher load capacity, improving the restoration capability, and renewing aging infrastructure	December 2022

Project Name	55783: Clifton Park 4827 4kV Conversion			
2019A	**2020F**	**2021F**	**2022F**	**2023F**
		$1,385,537	$3,889,413	
Problem Statement		**Solution Statement**		**Estimated / In-Service Date**
The Clifton Park 4827 4kV feeder currently has both aging substation and distribution assets, limited load capacity and limited feeder restoration options.		The Clifton Park 4827 4kV Conversion project is part of an overall effort to purge the BGE system of 4kV infrastructure due to aging assets, it's limited load capacity and limited restoration options. The solution is to convert the feeder from 4kV to 13kV, providing higher load capacity, improving the restoration capability, and renewing aging infrastructure.		December 2022

Project Name	55784: Clifton Park 4829 & 4834 4kV Conversion			
2019A	**2020F**	**2021F**	**2022F**	**2023F**
				$3,637,863
Problem Statement		**Solution Statement**		**Estimated / In-Service Date**
The Clifton Park 4829 and 4834 4kV feeders currently have both aging substation and distribution assets, limited load capacity and limited feeder restoration options.		The Clifton Park 4829 & 4834 4kV Conversion project is part of overall effort to purge the BGE system of 4kV infrastructure due to aging assets, it's limited load capacity and limited restoration options. The solution is to convert the feeder from 4kV to 13kV, providing higher load capacity, improving the restoration capability, and renewing aging infrastructure.		December 2023

Project Name	55824: Clifton Park 4835 & 4822 4kV Conversion			
2019A	**2020F**	**2021F**	**2022F**	**2023F**
$3,160,604				
Problem Statement		**Solution Statement**		**Estimated / In-Service Date**
The Clifton Park 4835 and 4822 4kV feeders has both aging substation and distribution assets, limited load capacity and limited feeder restoration options.		The Clifton Park 4835 & 4822 4kV Conversion project is part of an overall effort to purge the BGE system of 4kV infrastructure due to aging assets, it's limited load capacity and limited restoration options. The solution is to convert the feeder from 4kV to 13kV, providing higher load capacity, improving the restoration capability, and renewing aging infrastructure.		February 2020

Project Name	55825: Broadway Substation Removal			
2019A	2020F	2021F	2022F	2023F
	$500,000	$2,101,250		
Problem Statement		Solution Statement		Estimated / In-Service Date
The Broadway 4kV Substation currently has aging substation assets, limited load capacity and limited restoration options.		The Broadway 4kV Substation removal project is part of an overall effort to purge the BGE system of 4kV infrastructure due to aging assets, it's limited load capacity and limited restoration options. The solution is to remove all aging substation assets and demolish the 4kV substation to make the site suitable for resale or for future project needs, after all 4kV feeders that are a part of the substation have been converted and retired.		December 2021

Project Name	55826: Forest Park 4422 4kV Conversion			
2019A	2020F	2021F	2022F	2023F
$2,498,373				
Problem Statement		Solution Statement		Estimated / In-Service Date
The Forest Park 4422 4kV feeder has both aging substation and distribution assets, limited load capacity and limited feeder restoration options.		The Forest Park 4422 Conversion project is part of an overall effort to purge the BGE system of 4kV infrastructure due to aging assets, it's limited load capacity and limited restoration options. The solution is to convert the feeder from 4kV to 13kV, providing higher load capacity, improving the restoration capability, and renewing aging infrastructure.		February 2020

Project Name	56545: Diverse Routing			
2019A	2020F	2021F	2022F	2023F
	$1,159,537	$1,232,490	$1,339,427	$2,361,442
Problem Statement		Solution Statement		Estimated / In-Service Date
When supply circuits to BGE distribution substations are located within a common right of way, a common failure point is created. A failure within this common right of way could result in the total loss of substation supply. While these types of failure events are low probability, they have a large reliability impact due to the number of customers impacted.		The diverse routing project evaluates areas on the BGE system with common right of way and plans cost effective solutions to reduce common right of way exposure. Example solutions include: reconfiguring substation supply or adding additional infrastructure to reduce exposure.		Monthly / Various

Project Name	58206: New Fitzell Feeder - Resupply Shipyard/Retire Riverside Feeder			
2019A	**2020F**	**2021F**	**2022F**	**2023F**
	$3,121,638	$1,211,627	$243,084	
Problem Statement		**Solution Statement**		**Estimated / In-Service Date**
Aging infrastructure supplying the Shipyard switching station and its customer loads needs to be replaced and retired.		Extend new 34kV circuit from Fitzell to Shipyard to replace existing supply.		December 2022

Project Name	58376: Cedar Park to Waugh Chapel Wood Pole Line Replacement (Part C Distribution)			
2019A	**2020F**	**2021F**	**2022F**	**2023F**
$1,431,059				
Problem Statement		**Solution Statement**		**Estimated / In-Service Date**
The Cedar Park to Waugh Chapel wood pole line is very old, undersized, and needs to be replaced to bring it into compliance, improving the reliability of the line.		Reconductor Segment 5 feeder circuits of the wood pool line to meet BGE standards and increase feeder reliability.		December 2019

Project Name	58479: Street Light Voltage Blocker Installation Program			
2019A	**2020F**	**2021F**	**2022F**	**2023F**
$19	$3,436,839	$2,552,725		
Problem Statement		**Solution Statement**		**Estimated / In-Service Date**
This project aims to mitigate/eliminate contact voltage findings on metal light poles fed by a 2-wire system in Baltimore City.		Utilize a modified surge arrester to isolate (block) stray neutral voltage from getting onto poles.		Monthly / Various

Project Name	59311: Feeder Extension Shipley 33766 to BWI			
2019A	**2020F**	**2021F**	**2022F**	**2023F**
$20,220	$2,529,760			
Problem Statement		**Solution Statement**		**Estimated / In-Service Date**
BWI requires an additional 34kV supply and automatic high-side transfer to the BWI North substation for reliability and resiliency.		Extend a nearby 34kV feeder and install an automatic transfer scheme as needed to the high side of the BWI North substation.		November 2020

Project Name	59333: Dundalk 4841 & 4844 4kV Conversion			
2019A	**2020F**	**2021F**	**2022F**	**2023F**
	$2,919,369			
Problem Statement		**Solution Statement**		**Estimated / In-Service Date**
The Dundalk 4841 and 4844 4kV feeders currently have both aging substation and distribution assets, limited load capacity and limited feeder restoration options.		The Dundalk 4841 and 4844 4kV Conversion project is of part an overall effort to purge the BGE system of 4kV infrastructure. The solution is to convert the feeders from 4kV to 13kV, providing higher load capacity, improving the restoration capability, and renewing aging infrastructure.		December 2020

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Project Name	59334: Dundalk 4843 4kV Conversion			
2019A	**2020F**	**2021F**	**2022F**	**2023F**
	$984,720	$1,034,395		
Problem Statement		**Solution Statement**		**Estimated / In-Service Date**
The Dundalk 4843 4kV feeder currently has both aging substation and distribution assets, limited load capacity and limited feeder restoration options.		The Dundalk 4843 4kV Conversion project is part of an overall effort to purge the BGE system of 4kV infrastructure due to aging assets, it's limited load capacity and limited restoration options. The solution is to convert the feeder from 4kV to 13kV, providing higher load capacity, improving the restoration capability, and renewing aging infrastructure.		December 2021

Project Name	59336: Dundalk 4845 4kV Conversion			
2019A	**2020F**	**2021F**	**2022F**	**2023F**
	$1,313,064	$1,379,302		
Problem Statement		**Solution Statement**		**Estimated / In-Service Date**
The Dundalk 4845 4kV feeder currently has both aging substation and distribution assets, limited load capacity and limited feeder restoration options.		The Dundalk 4845 4kV Conversion project is part of an overall effort to purge the BGE system of 4kV infrastructure due to aging assets, it's limited load capacity and limited restoration options. The solution is to convert the feeder from 4kV to 13kV, providing higher load capacity, improving the restoration capability, and renewing aging infrastructure.		December 2021

Project Name	60230: Wagner Feeder 7818			
2019A	**2020F**	**2021F**	**2022F**	**2023F**
		$1,171,990		
Problem Statement		**Solution Statement**		**Estimated / In-Service Date**
The Wagner modular substation is aging and has become obsolete. The 13kV feeder must be resupplied to be able to remove the modular substation.		Extend a new feeder from nearby Wagner 13kV substation and tie into the existing feeder to allow the removal of the modular substation.		June 2021

Project Name	60296: Highlandtown 34037 34034 Francis Scott Key			
2019A	**2020F**	**2021F**	**2022F**	**2023F**
$1,752,679	$11,105,278			
Problem Statement		**Solution Statement**		**Estimated / In-Service Date**
Francis Scott Key (FSK) substation supply from Eastpoint has degraded reliability.		Re-supply FSK from Eastpoint to Highlandtown with underground feeds.		December 2020

Project Name	60696: Center 4261 4kV Conversion			
2019A	**2020F**	**2021F**	**2022F**	**2023F**
$1,578,368	$1,664,293			
Problem Statement		**Solution Statement**		**Estimated / In-Service Date**
The Center 4261 4kV feeder currently has both aging substation and distribution assets, limited load capacity and limited feeder restoration options.		The Center 4261 4kV Conversion project is part of an overall effort to purge the BGE system of 4kV infrastructure due to aging assets, it's limited load capacity and limited restoration options. The solution is to convert the feeder from 4kV to 13kV, providing higher load capacity, improving the restoration capability, and renewing aging infrastructure.		December 2020

Project Name	60702: Center 4268 4kV Conversion			
2019A	**2020F**	**2021F**	**2022F**	**2023F**
$51	$3	$1,956,005		
Problem Statement		**Solution Statement**		**Estimated / In-Service Date**
The Center 4268 4kV feeder currently has both aging substation and distribution assets, limited load capacity and limited feeder restoration options.		The Center 4268 4kV Conversion project is part of an overall effort to purge the BGE system of 4kV infrastructure due to aging assets, it's limited load capacity and limited restoration options. The solution is to convert the feeder from 4kV to 13kV, providing higher load capacity, improving the restoration capability, and renewing aging infrastructure.		December 2021

Project Name	60709: Center 4269 4kV Conversion			
2019A	**2020F**	**2021F**	**2022F**	**2023F**
($3,846)	$541,106	$2,855,538		
Problem Statement		**Solution Statement**		**Estimated / In-Service Date**
The Center 4269 4kV feeder currently has both aging substation and distribution assets, limited load capacity and limited feeder restoration options.		The Center 4269 4kV Conversion project is part of an overall effort to purge the BGE system of 4kV infrastructure due to aging assets, it's limited load capacity and limited restoration options. The solution is to convert the feeder from 4kV to 13kV, providing higher load capacity, improving the restoration capability, and renewing aging infrastructure.		December 2021

Project Name	60717: Center 4265, 4266 & 4267 4kV Conversion			
2019A	**2020F**	**2021F**	**2022F**	**2023F**
	$2,027,063	$3,116,171		
Problem Statement		**Solution Statement**		**Estimated / In-Service Date**
The Center 4265, 4266 and 4267 4kV feeders currently have both aging substation and distribution assets, limited load capacity and limited feeder restoration options.		The Center 4265, 4266 and 4267 4kV Conversion project is part of an overall effort to purge the BGE system of 4kV infrastructure due to aging assets, it's limited load capacity and limited restoration options. The solution is to convert the feeder from 4kV to 13kV, providing higher load capacity, improving the restoration capability, and renewing aging infrastructure.		December 2021

Project Name	60808: Padmounted Distribution Automation Reclosers and Sectionalization			
2019A	**2020F**	**2021F**	**2022F**	**2023F**
$4,083,427	$3,397,354	$3,355,291	$3,495,394	$3,494,956
Problem Statement		**Solution Statement**		**Estimated / In-Service Date**
The BGE underground system has minimal automation to sectionalize faults and autorestore the non-faulted customers. This program funds the installation of devices to allow automation to be deployed on the BGE underground system (which represents 60% of the total BGE system).		Locations are identified on the underground system where distribution automation and sectionalization can support improved reliability performance. Padmounted distribution automation equipment is installed at these select locations to reduce the customer count per segment and limit the outage impact to only those customers directly affected.		Monthly / Various

Project Name	61008 - Cedar Park to Waugh Chapel Wood Pole Line Replacement - Part D, Distribution			
2019A	**2020F**	**2021F**	**2022F**	**2023F**
	$1,596,283			
Problem Statement		**Solution Statement**		**Estimated / In-Service Date**
The Cedar Park to Waugh Chapel wood pole line is very old, undersized, and needs to be replaced to bring it into compliance, improving the reliability of the line.		Reconductor feeder circuits of the wood pool line to meet BGE standards and increase feeder reliability.		December 2020

Project Name	61104: Center 4260 4kV Conversion			
2019A	**2020F**	**2021F**	**2022F**	**2023F**
$1,124,291	$1,678,680			
Problem Statement		**Solution Statement**		**Estimated / In-Service Date**
The Center 4260 4kV feeder currently has both aging substation and distribution assets, limited load capacity and limited feeder restoration options.		The Center 4260 4kV Conversion project is part of an overall effort to purge the BGE system of 4kV infrastructure due to aging assets, it's limited load capacity and limited restoration options. The solution is to convert the feeder from 4kV to 13kV, providing higher load capacity, improving the restoration capability, and renewing aging infrastructure.		December 2020

Project Name	61105: Clifton Park 4823 4kV Conversion			
2019A	**2020F**	**2021F**	**2022F**	**2023F**
$3,610,649				
Problem Statement		**Solution Statement**		**Estimated / In-Service Date**
The Clifton Park 4823 4kV feeder has both aging substation and distribution assets, limited load capacity and limited feeder restoration options.		The Clifton Park 4823 Conversion project is part of an overall effort to purge the BGE system of 4kV infrastructure due to aging assets, it's limited load capacity and limited restoration options. The solution is to convert the feeder from 4kV to 13kV, providing higher load capacity, improving the restoration capability, and renewing aging infrastructure.		January 2020

Project Name	61130: TRIP-System Performance			
2019A	**2020F**	**2021F**	**2022F**	**2023F**
$1,206,149	$1,794,095	$1,732,867	$1,919,941	$1,897,286
Problem Statement		**Solution Statement**		**Estimated / In-Service Date**
Code of Maryland Regulations COMAR 20.50.12.03 require annual reporting of the poorest performing circuits on the BGE system. In addition to annual reporting BGE is required to conduct reliability improvement work to ensure a poorest performing feeder is not listed for three consecutive years. The program funds system enhancement or configurations to improve reliability performance to avoid three-peat listing on the poorest performing feeder list.		This program targets the poorest performing feeders on the BGE system. On a case by case basis, circuits are evaluated to determine possible actions to improve circuit reliability performance. Typical examples include the installation of distribution automation equipment, feeder reconfiguration, selective undergrounding, additional fusing and sectionalizing, enhanced vegetation management, and inspections.		Monthly / Various

Project Name	61132: Cable Replacement Primary Planned			
2019A	**2020F**	**2021F**	**2022F**	**2023F**
$18,469,537	$16,840,000	$16,920,000	$17,100,000	$17,100,000
Problem Statement		**Solution Statement**		**Estimated / In-Service Date**
As underground primary cable reaches its end of life, failure rates increase resulting in more frequent customer outages. This program funds the identification and replacement of aging cable to improve electric system reliability on the underground primary system.		Program replaces damaged and poor performing underground primary cable to reduce cable failure rates and improve system performance. Jobs are prioritized based on factors such as cable type, number of failures, number of customers affected, critical customers affected, frequency of failure, and their cost/benefit.		Monthly / Various

Project Name	61134: Cable Replacement Planned Secondary Residential, Industrial and Commercial			
2019A	**2020F**	**2021F**	**2022F**	**2023F**
$2,209,795	$2,200,000	$2,200,000	$2,200,001	$2,200,000
Problem Statement		**Solution Statement**		**Estimated / In-Service Date**
As underground secondary cable reaches its end of life, failure rates increase resulting in more frequent customer outages. This program funds the identification and replacement of aging cable to improve electric system reliability on the underground secondary system.		Program replaces damaged and poor performing underground secondary cable to reduce cable failure rates and improve system performance. Jobs are prioritized based on factors such as cable type, number of failures, number of customers affected, critical customers affected, frequency of failure, and their cost/benefit.		Monthly / Various

Project Name	61136: Reliability Process Initiative			
2019A	**2020F**	**2021F**	**2022F**	**2023F**
$5,029,118	$1,223,641			
Problem Statement		**Solution Statement**		**Estimated / In-Service Date**
This program investigates area-wide reliability issues and identifies worse than average reliability performance for the supplied BGE customers. This program funds reliability improvement efforts to correct larger scale area-wide issues. 2020 is the final year of the program and as needed similiar work will be conducted under other programs.		The reliability improvement work performed under this program includes, but is not limited to, installation of distribution automation equipment, feeder reconfiguration, selective undergrounding, additional fusing and sectionalizing, and enhanced vegetation management.		December 2020

Project Name	61139: Overhead Conductor Replacement			
2019A	**2020F**	**2021F**	**2022F**	**2023F**
$1,305,186	$1,333,667	$1,297,571	$1,434,504	$1,420,127
Problem Statement		**Solution Statement**		**Estimated / In-Service Date**
Certain locations in the overhead distribution system have smaller conductor wire than what would typically be used in the main stem of a circuit. This smaller wire impacts the ability to transfer loads under emergency or planned conditions.		Identify locations that have these operational impacts on the ability to transfer load, and prioritize and upgrade overhead conductor with appropriately rated wire for the application.		Monthly / Various

Project Name	61141: Multiple Device Activations Program - PSC			
2019A	**2020F**	**2021F**	**2022F**	**2023F**
$1,437,332	$1,303,894	$1,272,728	$1,390,137	$1,373,630
Problem Statement		**Solution Statement**		**Estimated / In-Service Date**
Code of Maryland Regulations COMAR 20.50.12.04 require the reporting and reliability improvement of protective devices which operate more than 5 times in a 12-month period, classified as Multiple Device Activation (MDA) devices.		The MDA program is designed to address devices that are reported or at risk of being reported to the PSC for failing to comply with the standard.		Monthly / Various

Project Name	61144: System Hardening			
2019A	**2020F**	**2021F**	**2022F**	**2023F**
$4,746,983	$2,667,282	$2,496,005	$2,723,763	$2,699,200
Problem Statement		**Solution Statement**		**Estimated / In-Service Date**
This program investigates targeted reliability issues and identifies worse than average reliability performance for the supplied BGE customers. This program funds reliability improvement efforts to correct targeted issues.		The reliability improvement work performed under this program includes, but is not limited to, installation of distribution automation equipment, feeder reconfiguration, selective undergrounding, Hendrix cable, additional fusing and sectionalizing, and enhanced vegetation management.		Monthly / Various

Project Name	61147: Overhead Distribution Automation Reclosers and Sectionalization			
2019A	**2020F**	**2021F**	**2022F**	**2023F**
$7,744,432	$6,060,294	$4,749,582	$5,110,092	$5,075,796
Problem Statement		**Solution Statement**		**Estimated / In-Service Date**
When a fault occurs on the BGE electric system, all customers on the segment and downstream are interrupted by the fault.		Locations are identified on the overhead system where distribution automation and sectionalization can support improved reliability performance. Polemount distribution automation equipment is installed at these select locations to reduce the customer count per segment and limit the outage impact to only those customers directly affected.		Monthly / Various

Project Name	61149: 4kV Reliability Improvement Program			
2019A	**2020F**	**2021F**	**2022F**	**2023F**
$277,195	$2,573,745	$2,097,228		
Problem Statement		**Solution Statement**		**Estimated / In-Service Date**
Improve reliability of underground 4kV equipment on the electric distribution system.		Proactively replace oil filled switches with vacuum fault interruptors to eliminate oil filled switch inspections in the 4kV underground system.		Monthly / Various

Project Name	61159: Customer Reliability Support Projects			
2019A	**2020F**	**2021F**	**2022F**	**2023F**
$5,821,428	$5,233,111	$5,557,155	$6,062,868	$7,654,704
Problem Statement		**Solution Statement**		**Estimated / In-Service Date**
As the existing electric infrastructure reaches its end of life and or new technologies are deployed by customers, momentary or sustained interruptions may occur more frequently. This program looks to identify system issues and upgrades to improve system reliability. When issues are identified, the most cost effective improvement solution is deployed to enhance electric system reliability.		Engineers and technicians investigate reliability issues and create a work plan to address those issues. The work conducted under this program consists of proactive and reactive work, large planned projects (using contractor resources), and small planned projects (using company resources). All options for reliability performance improvement are considered.		Monthly / Various

Project Name	61164: Customer Reliability Support Low Voltage Mitigation			
2019A	2020F	2021F	2022F	2023F
$3,094,148	$509,498	$1,245,544	$1,266,890	$1,292,189
Problem Statement		Solution Statement		Estimated / In-Service Date
BGE is required to provide voltage to our electric customers within a specified range. The deployment of a Conservation Voltage Reduction program on the BGE system to support energy conservation occasionally results in inadvertent low voltage.		On a case by case basis, this project proactively addresses low secondary voltages issues on the BGE electric system by evaluating system conditions and conducting system upgrades and modifications to improve voltage performance. Installation of voltage support equipment is also considered.		Monthly / Various

Project Name	61287: Philadelphia Road Substation Removal			
2019A	2020F	2021F	2022F	2023F
			$2,153,738	
Problem Statement		Solution Statement		Estimated / In-Service Date
The Philadelphia Road 4kV Substation currently has aging substation assets, limited load capacity and limited restoration options.		The Philadelphia Road 4kV Substation removal project is part of an overall effort to purge the BGE system of 4kV infrastructure due to aging assets, it's limited load capacity and limited restoration options. The solution is to remove all of the aging substation assets and to demolish the 4kV substation to make the site suitable for resale or for future project needs, after all 4kV feeders that are a part of the substation have been converted and retired.		December 2022

Project Name	61290: Dundalk Substation Removal			
2019A	2020F	2021F	2022F	2023F
			$1,008,576	
Problem Statement		Solution Statement		Estimated / In-Service Date
The Dundalk 4kV Substation currently has aging substation assets, limited load capacity and limited restoration options.		The Dundalk 4kV Substation removal project is part of an overall effort to purge the BGE system of 4kV infrastructure due to aging assets, it's limited load capacity and limited restoration options. The solution is to remove all of the aging substation assets and to demolish the 4kV substation to make the site suitable for resale or for future project needs, after all 4kV feeders that are a part of the substation have been converted and retired.		December 2022

Project Name	61330: Woodbrook Substation Removal			
2019A	**2020F**	**2021F**	**2022F**	**2023F**
			$1,000,001	
Problem Statement		**Solution Statement**		**Estimated / In-Service Date**
The Woodbrook 4kV Substation currently has aging substation assets, limited load capacity and limited restoration options.		The Woodbrook 4kV Substation removal project is part of an overall effort to purge the BGE system of 4kV infrastructure due to aging assets, it's limited load capacity and limited restoration options. The solution is to remove all of the aging substation assets and to demolish the 4kV substation to make the site suitable for resale or for future project needs, after all 4kV feeders that are a part of the substation have been converted and retired.		December 2022

Project Name	61435: Customers Experiencing Multiple Interruptions (CEMI) Program			
2019A	**2020F**	**2021F**	**2022F**	**2023F**
$1,496,323	$1,675,454	$1,660,546	$1,804,077	$1,762,788
Problem Statement		**Solution Statement**		**Estimated / In-Service Date**
Experiencing multiple interruptions to customer's electric service in a short period is a nuisance and reliability concern.		Engineers analyze the outage data and determine which customers fall under the multiple interruptions criteria (CEMI4/ CEMI7). Based on this analysis the feeders are assigned to the technicians to trouble shoot the issue based on their findings. System upgrades and reconfigurations are considered to improve reliability performance for the impacted customers.		Monthly / Various

Project Name	61499: Clifton Park 4832 4kV Conversion			
2019A	**2020F**	**2021F**	**2022F**	**2023F**
	$2,896,684			
Problem Statement		**Solution Statement**		**Estimated / In-Service Date**
The Clifton Park 4832 4kV feeder currently has both aging substation and distribution assets, limited load capacity and limited feeder restoration options.		The Clifton Park 4832 4kV Conversion project is part of an overall effort to purge the BGE system of 4kV infrastructure due to aging assets, it's limited load capacity and limited restoration options. The solution is to convert the feeder from 4kV to 13kV, providing higher load capacity, improving the restoration capability, and renewing aging infrastructure.		December 2020

Project Name	61500: Clifton Park 4836 4kV Conversion			
2019A	**2020F**	**2021F**	**2022F**	**2023F**
	$2,589,526			
Problem Statement		**Solution Statement**		**Estimated / In-Service Date**
The Clifton Park 4836 4kV feeder currently has both aging substation and distribution assets, limited load capacity and limited feeder restoration options.		The Clifton Park 4836 4kV Conversion project is part of an overall effort to purge the BGE system of 4kV infrastructure due to aging assets, it's limited load capacity and limited restoration options. The solution is to convert the feeder from 4kV to 13kV, providing higher load capacity, improving the restoration capability, and renewing aging infrastructure.		December 2020

Project Name	61503: Woodbrook 4401, 4409 & 4416 4kV Conversion			
2019A	**2020F**	**2021F**	**2022F**	**2023F**
$7,625	$2,816,161	$2,681,055		
Problem Statement		**Solution Statement**		**Estimated / In-Service Date**
The Woodbrook 4401, 4409 and 4416 4kV feeders currently have both aging substation and distribution assets, limited load capacity and limited feeder restoration options.		The Woodbrook 4401, 4409 and 4416 4kV Conversion project is part of an overall effort to purge the BGE system of 4kV infrastructure due to aging assets, it's limited load capacity and limited restoration options. The solution is to convert the feeders from 4kV to 13kV, providing higher load capacity, improving the restoration capability, and renewing aging infrastructure.		December 2021

Project Name	61504: Woodbrook 4403, 4407 & 4410 4kV Conversion			
2019A	**2020F**	**2021F**	**2022F**	**2023F**
$5,271,351	$4,022,458			
Problem Statement		**Solution Statement**		**Estimated / In-Service Date**
The Woodbrook 4403, 4407 and 4410 4kV feeders currently have both aging substation and distribution assets, limited load capacity and limited feeder restoration options.		The Woodbrook 4403, 4407 and 4410 4kV Conversion project is part of an overall effort to purge the BGE system of 4kV infrastructure due to aging assets, it's limited load capacity and limited restoration options. The solution is to convert the feeders from 4kV to 13kV, providing higher load capacity, improving the restoration capability, and renewing aging infrastructure.		December 2020

Project Name	61506: Woodbrook 4415 & 4418 4kV Conversion			
2019A	**2020F**	**2021F**	**2022F**	**2023F**
$4,630	$3,907,223			
Problem Statement		**Solution Statement**		**Estimated / In-Service Date**
The Woodbrook 4415 and 4418 4kV feeders currently have both aging substation and distribution assets, limited load capacity and limited feeder restoration options.		The Woodbrook 4415 and 4418 4kV Conversion project is part of an overall effort to purge the BGE system of 4kV infrastructure due to aging assets, it's limited load capacity and limited restoration options. The solution is to convert the feeders from 4kV to 13kV, providing higher load capacity, improving the restoration capability, and renewing aging infrastructure.		December 2020

Project Name	61524: Vacuum Breaker Mechanism Replacement Program			
2019A	**2020F**	**2021F**	**2022F**	**2023F**
$1,423,233	$810,303			
Problem Statement		**Solution Statement**		**Estimated / In-Service Date**
Vacuum breaker mechanism (VBM) devices are obsolete and are currently experienced increased failure rates due to age and are impacting customer reliability.		Obsolete VBM equipment is replaced with modern distribution automation equipment. The new equipment has fault interrupting and sectionalization capability.		Monthly / Various

Project Name	62641: Sentient Underground Fault Indicators			
2019A	**2020F**	**2021F**	**2022F**	**2023F**
$32	$3,344,303	$2,842,733	$2,877,624	$751,576
Problem Statement		**Solution Statement**		**Estimated / In-Service Date**
Identifying fault locations on the underground BGE system can be time consuming and delay restoration activities.		Electronic Fault Indicators with remote communications are installed on the BGE system to support the identification of the location of system faults. Knowing the fault locations expedites restoration efforts.		Monthly / Various

Project Name	62644: Sentient Overhead Fault Indicators			
2019A	**2020F**	**2021F**	**2022F**	**2023F**
$3,581,463	$1,174,512	$2,164,429	$2,202,160	$2,201,628
Problem Statement		**Solution Statement**		**Estimated / In-Service Date**
Identifying fault locations on the overhead BGE system can be time consuming and delay restoration activities.		Electronic Fault Indicators with remote communications are installed on the BGE system to support the identification of the location of system faults. Knowing the fault locations expedites restoration efforts.		Monthly / Various

Project Name	62920: Turnkey Cable Program			
2019A	**2020F**	**2021F**	**2022F**	**2023F**
				$4,413,835
Problem Statement		**Solution Statement**		**Estimated / In-Service Date**
As underground cable reaches its end of life, failure rates increase resulting in more frequent customer outages.		This program identifies large areas of suspect underground cable primary and loop cable. The identified area is turned over to a contract firm to conduct the design, obtain permits, and execute the work.		Monthly / Various

Project Name	63111: Polyseal Resupply			
2019A	**2020F**	**2021F**	**2022F**	**2023F**
				$3,497,465
Problem Statement		**Solution Statement**		**Estimated / In-Service Date**
34kV customer is currently fed from a substation that is an aging infrastructure concern.		Resupply customer via another substation to facilitate retirement of the aging substation.		November 2023

Project Name	63128: 33871_33872 Resupply			
2019A	**2020F**	**2021F**	**2022F**	**2023F**
				$1,748,660
Problem Statement		**Solution Statement**		**Estimated / In-Service Date**
34kV circuits supplied from a substation that is an aging infrastructure concern.		Resupply 34kV circuits from another substation to facilitate retirement of the aging substation.		November 2023

Project Name	65141: Calverton Road 4810 4kV Conversion			
2019A	**2020F**	**2021F**	**2022F**	**2023F**
		$3,190,812		
Problem Statement		**Solution Statement**		**Estimated / In-Service Date**
The Calverton Road 4810 4kV feeder currently has both aging substation and distribution assets, limited load capacity and limited feeder restoration options.		The Calverton Road 4810 4kV Conversion project is part of an overall effort to purge the BGE system of 4kV infrastructure due to aging assets, it's limited load capacity and limited restoration options. The solution is to convert the feeder from 4kV to 13kV, providing higher load capacity, improving the restoration capability, and renewing aging infrastructure.		December 2021

Project Name	65143: Calverton Road 4807 4kV Conversion			
2019A	**2020F**	**2021F**	**2022F**	**2023F**
		$1,408,749	$1,684,944	
Problem Statement		**Solution Statement**		**Estimated / In-Service Date**
The Calverton Road 4807 4kV feeder currently has both aging substation and distribution assets, limited load capacity and limited feeder restoration options.		The Calverton Road 4807 4kV Conversion project is part of an overall effort to purge the BGE system of 4kV infrastructure due to aging assets, it's limited load capacity and limited restoration options. The solution is to convert the feeder from 4kV to 13kV, providing higher load capacity, improving the restoration capability, and renewing aging infrastructure.		December 2022

Project Name	65145: Calverton Road 4803 & 4805 4kV Conversion			
2019A	**2020F**	**2021F**	**2022F**	**2023F**
			$3,085,107	$4,725,267
Problem Statement		**Solution Statement**		**Estimated / In-Service Date**
The Calverton Rd 4803 and 4805 4kV feeders currently have both aging substation and distribution assets, limited load capacity and limited feeder restoration options.		The Calverton Road 4803 and 4805 4kV Conversion project is part of an overall effort to purge the BGE system of 4kV infrastructure due to aging assets, it's limited load capacity and limited restoration options. The solution is to convert the feeders from 4kV to 13kV, providing higher load capacity, improving the restoration capability, and renewing aging infrastructure.		December 2023

Project Name	65211: Clifton Park 4824 4kV Conversion			
2019A	**2020F**	**2021F**	**2022F**	**2023F**
			$2,435,607	
Problem Statement		**Solution Statement**		**Estimated / In-Service Date**
The Clifton Park 4824 4kV feeder currently has both aging substation and distribution assets, limited load capacity and limited feeder restoration options.		The Clifton Park 4824 4kV Conversion project is part of an overall effort to purge the BGE system of 4kV infrastructure due to aging assets, it's limited load capacity and limited restoration options. The solution is to convert the feeder from 4kV to 13kV, providing higher load capacity, improving the restoration capability, and renewing aging infrastructure.		December 2022

Project Name	65212: Clifton Park 4830 4kV Conversion			
2019A	**2020F**	**2021F**	**2022F**	**2023F**
			$3,572,231	
Problem Statement		**Solution Statement**		**Estimated / In-Service Date**
The Clifton Park 4830 4kV feeder currently has both aging substation and distribution assets, limited load capacity and limited feeder restoration options.		The Clifton Park 4830 4kV Conversion project is part of an overall effort to purge the BGE system of 4kV infrastructure due to aging assets, it's limited load capacity and limited restoration options. The solution is to convert the feeder from 4kV to 13kV, providing higher load capacity, improving the restoration capability, and renewing aging infrastructure.		December 2022

Project Name	65213: Clifton Park 4826 & 4828 4kV Conversion			
2019A	**2020F**	**2021F**	**2022F**	**2023F**
				$3,125,546
Problem Statement		**Solution Statement**		**Estimated / In-Service Date**
The Clifton Park 4826 and 4828 4kV feeders currently have both aging substation and distribution assets, limited load capacity and limited feeder restoration options.		The Clifton Park 4826 and 4828 4kV Conversion project is part of an overall effort to purge the BGE system of 4kV infrastructure due to aging assets, it's limited load capacity and limited restoration options. The solution is to convert the feeders from 4kV to 13kV, providing higher load capacity, improving the restoration capability, and renewing aging infrastructure.		After 2023

Project Name	65242: Govans 4574 & 4578 4kV Conversion			
2019A	**2020F**	**2021F**	**2022F**	**2023F**
				$3,865,804
Problem Statement		**Solution Statement**		**Estimated / In-Service Date**
The Govans 4574 and 4578 4kV feeders currently have both aging substation and distribution assets, limited load capacity and limited feeder restoration options.		The Govans 4574 and 4578 4kV Conversion project is part of an overall effort to purge the BGE system of 4kV infrastructure due to aging assets, it's limited load capacity and limited restoration options. The solution is to convert the feeders from 4kV to 13kV, providing higher load capacity, improving the restoration capability, and renewing aging infrastructure.		December 2023

E. System Performance – Protection & Control

Project Name	61224: Remote Terminal Unit Replacements - Distribution			
2019A	**2020F**	**2021F**	**2022F**	**2023F**
$940,253	$1,140,601	$1,814,809	$2,091,504	$1,532,006
Problem Statement		**Solution Statement**		**Estimated / In-Service Date**
A portion of the BGE electric utility substation remote terminal units (RTUs) are equipped with RTU technology that is no longer vendor supported, does not facilitate enhanced security controls, and does not support device integration for control and data acquisition.		The RTU Replacements - Distribution program replaces distribution RTUs of high priority, primarily aimed at addressing aging SCADA RTU infrastructure. Scope may range from a legacy RTU replacement to replacement in concert with data integration and monitoring device upgrades. The cost and duration of projects are a function of size and complexity of the RTU and substation.		Monthly / Various

Project Name	61237: Replace Electromechanical Relays - 34kV			
2019A	**2020F**	**2021F**	**2022F**	**2023F**
$1,051,761	$400,000	$877,324	$897,948	$526,582
Problem Statement		**Solution Statement**		**Estimated / In-Service Date**
A portion of the BGE electric utility backbone sub-transmission system is protected by obsolete electromechanical (EM) distance and time overcurrent relays that are no longer vendor supported.		BGE will execute a program of EM relay upgrades across a body of 97 feeders aimed to install intelligent electronic relays (IEDs) that will enhance protection functions, real-time monitoring, and event recording in support of system event analysis.		Monthly / Various

F. System Performance – Substation

Project Name	61252: Riverside 34.5kV Substation Retirement			
2019A	**2020F**	**2021F**	**2022F**	**2023F**
				$2,153,800
Problem Statement		**Solution Statement**		**Estimated / In-Service Date**
Riverside 115-34.5 kV substation needs to be retired due to age and condition to prevent future reliability issues and safety concerns.		Implement a project to retire the Riverside 115-34.5 kV substation.		November 2023

Project Name	61267: Distribution Substation Spare Transformers			
2019A	**2020F**	**2021F**	**2022F**	**2023F**
$1,921,686	$1,250,000	$1,793,750	$1,838,550	$1,884,575
Problem Statement		**Solution Statement**		**Estimated / In-Service Date**
Need to maintain an adequate number of Spare Distribution Substation Transformers based on Distribution Planning requirements.		Implement program to adhere to Distribution Planning requirements to maintain an adequate number of Distribution Substation Spare Transformers to react to historical levels of transformer failures.		Monthly / Various

Project Name	61343: Dolfield Substation Flood Hardening			
2019A	**2020F**	**2021F**	**2022F**	**2023F**
$714,012	$3,820,318			
Problem Statement		**Solution Statement**		**Estimated / In-Service Date**
Dolfield substation has been identified as being high risk for substation flooding. Dolfield is a Tier 1 substation situated along Gwynns Falls in Baltimore County. A flood plain study was performed and identified that the majority of the 13kV equipment at Dolfield falls within the 100-year flood plain.		Implement a project to build a flood wall in the substation along Gwynns Falls to permanently reduce the risk of flooding of the substation.		December 2020

Project Name	61349: Distribution Substation Transformer Pit Upgrades			
2019A	**2020F**	**2021F**	**2022F**	**2023F**
$6,102,130	$5,852,415	$5,193,529	$6,558,607	$6,966,148
Problem Statement		**Solution Statement**		**Estimated / In-Service Date**
Distribution Substation Transformer secondary oil containment pits need to be replaced due to age and condition to comply with U.S. Code of Federal Regulations, Title 40, Chapter I - EPS, Subchapter D, Part 112 regulations.		Implement program to upgrade Distribution Substation Transformer secondary containment pits due to age or condition (malfunctioning based on inspections and testing).		Monthly / Various

Project Name	61365: Distribution Substation Fire Protection Upgrades			
2019A	**2020F**	**2021F**	**2022F**	**2023F**
$4,351,872	$4,042,341	$2,916,141	$3,675,388	$4,253,977
Problem Statement		**Solution Statement**		**Estimated / In-Service Date**
Fire protection at BGE's Distribution Substations needs improvement to address safety and equipment issues during a fire event.		Implement program to upgrade the fire protection of BGE's Distribution Substations as a result of a best practices review.		Monthly / Various

Project Name	61369: Replace Aging Distribution Substation Equipment			
2019A	**2020F**	**2021F**	**2022F**	**2023F**
$77,598	$303,622	$387,862	$564,001	$1,149,152
Problem Statement		**Solution Statement**		**Estimated / In-Service Date**
Replacement of substation equipment such as lightning arresters, Coupling Capacitor Voltage Transformers (CCVTs), and circuit switchers is required due to condition and age to prevent impacting reliability.		Continue proactive replacement program to prevent equipment from failing and impacting reliability.		Monthly / Various

Project Name	61377: Distribution Substation Security			
2019A	**2020F**	**2021F**	**2022F**	**2023F**
$23,360,873	$22,441,323	$47,078,336	$29,429,466	$14,689,827
Problem Statement		**Solution Statement**		**Estimated / In-Service Date**
Physical security of BGE's Distribution Substations needs improvement to protect the reliability of customers served by them.		Implement a program to upgrade physical security of BGE's Distribution Substations as a result of a best practices review. Increase in spending in 2021 and 2022 due to addressing/completing critical sites.		After 2023

Project Name	62509: Notch Cliff Propane Plant Substation Replacement			
2019A	**2020F**	**2021F**	**2022F**	**2023F**
		$7,161,015		
Problem Statement		**Solution Statement**		**Estimated / In-Service Date**
Electric Distribution Substation serving Notch Cliff Propane Plant needs replacement due to condition and age. The Propane Plant is a critical gas plant used to serve gas to our customers during extremely cold temperatures and peak use days.		Implement project to replace existing substation with a new substation designed to meet current standards.		September 2021

Project Name	63038: Proactive Distribution Substation Transformer Replacement			
2019A	**2020F**	**2021F**	**2022F**	**2023F**
	$75,000	$2,700,000	$5,399,871	$7,200,063
Problem Statement		**Solution Statement**		**Estimated / In-Service Date**
BGE's aging Distribution Substation transformers are aging, requiring more maintenance and are more susceptible to failure. Without proactively replacing them, failures could occur and negatively impact reliability.		Implement a Proactive Distribution Transformer Replacement program. Prioritize replacements based on condition and age. Program to be ramped up to replace 2 transformers in 2021 to 4 transformers in 2023.		Monthly / Various

IV. O&M Category Cashflows and Functions

A. Capacity Expansion – Distribution

Category	2019A	2020F	2021F	2022F	2023F
Capacity Expansion – Distribution	$299,796	$153,336	$157,416	$159,684	$160,359

- The Capacity Expansion – Distribution category includes projects developed to industry standards and established system planning criteria to assure a safe and reliable electric distribution system. The O&M portion of the Capacity Expansion category includes two projects:
    - Scoping Budget – solutions to system capacity issues require focused scoping and analysis before they can be formally initiated.
    - Feeder Phase Balancing – this project addresses loading imbalances on distribution circuits that may cause an overload condition on one of the circuit phases.
- The overall trend in costs for this category during the period 2020-2023 is flat, and workloads are not expected to increase over this time period.

B. System Performance – Distribution

Category	2019A	2020F	2021F	2022F	2023F
System Performance – Distribution	$524,915	$246,621	$267,197	$270,799	$314,823

- There are several sections in Title 20, Subtitle 50 of the Code of Maryland Regulations (COMAR 20.50) that directly apply to System Performance – Distribution, in particular, sections 20.50.12 (Service Quality and Reliability Standard) and 20.50.07 (Quality of Service).
- The budget for this category includes the O&M portion of funding for reliability programs to reduce the frequency and duration of customer outages.
- The decrease in O&M between 2019 and 2020 is due to the conclusion of the cable injection program.
- The overall trend in this category during the 2020-2023 period is essentially flat, with slight increases as capital projects and programs increase in expenditures for inflation.

C. System Performance – Protection & Control

Category	2019A	2020F	2021F	2022F	2023F
System Performance – Protection & Control	$-	$2,215,121	$3,986,897	$4,072,977	$4,164,353

- BGE has decided to expand the scope of physical and electronic security governance to enhance the security of its energy delivery infrastructure. The Company's operational technology O&M expenditures are designed to maintain compliance with the Company's requirements for operational technology for facilities outside of a medium or high impact NERC CIP classification.
- The primary driver of this category is the operational technology O&M expenditures. This spending scales up from $2.2 million in 2020 to a relatively steady state in 2022 at $4.1 million.
- Remaining O&M expenditures in this category maintain operational support software for installed protection and control infrastructure.

D. System Performance – Substation

Category	2019A	2020F	2021F	2022F	2023F
System Performance – Substation	$826,219	$1,205,814	$1,141,372	$1,206,893	$1,316,303

- These programs:
  - Improve the reliability of BGE's substations by reducing wildlife-related events and by replacing transformers before failures due to age and condition. The O&M costs related to capital transformer replacements are for the temporary installation of mobile transformers.
  - Improve the ability to react to substation fires by preparing pre-fire plans, reviewing pre-fire plans, and training local fire departments every 5 years.
  - Comply with EPA regulations for reviewing and recertifying substation Spill Prevention Control and Containment plans every 5 years.
- The overall trend in this category is slightly up for inflation and the addition of a proactive transformer replacement project.

E. Vegetation Management

Category	2019A	2020F	2021F	2022F	2023F
Vegetation Management	$30,405,884	$32,249,983	$33,446,553	$33,859,259	$34,811,755

- The programs within this category are designed and executed to maintain compliance with all federal, state, and local laws and regulations including but not limited to: Maryland Electricity Service Quality and Reliability Act, Maryland Roadside Tree Law, Maryland License Tree Expert Law, and Chesapeake and Atlantic Coastal Bays Critical Area Protection Program.
- The vegetation management category is designed to promote system safety and reliability by maintaining minimum clearances for transmission and distribution equipment from brush and trees. Program activities include routine and reactive tree trimming, tree removal, herbicide treatment, and mowing, on approximately 540 miles of overhead transmission rights-of way, 9,404 miles of overhead distribution circuit miles, 260 miles of gas rights-of-way, and 266 substations.
- The preventative and reactive vegetation management activities within this category are necessary for BGE to meet key safety and system reliability metrics, and to provide storm hardening measures to reduce reliability impacts during inclement weather events.
- The overall cost trend in this category reflects an increase in contracted labor rates for vegetation management beginning in 2020. Other year-to-year fluctuations are due to differences in the planned scopes of work in the remaining years.

V. O&M Project Details

Capacity Expansion – Distribution
Major Cost Drivers by Project

Instructions:

List actual O&M expenses by project for 2019; provide a high-level description of the types of costs within the project, and discuss the key drivers of each type. Also list forecasted O&M expenses for 2020-2023.

#	Project	Description and Key Drivers	2019 Actuals	2020 Forecast	2021 Forecast	2022 Forecast	2023 Forecast
1	3 Projects with no year >= $1 million		299,796	153,336	157,416	159,684	160,359
2	**Total**		**$ 299,796**	**$ 153,336**	**$ 157,416**	**$ 159,684**	**$ 160,359**

System Performance – Distribution
Major Cost Drivers by Project

Instructions:

List actual O&M expenses by project for 2019; provide a high-level description of the types of costs within the project, and discuss the key drivers of each type. Also list forecasted O&M expenses for 2020-2023.

#	Project	Description and Key Drivers	2019 Actuals	2020 Forecast	2021 Forecast	2022 Forecast	2023 Forecast
1	6 Projects with no year >= $1 million		524,915	246,621	267,197	270,799	314,823
2	**Total**		**$ 524,915**	**$ 246,621**	**$ 267,197**	**$ 270,799**	**$ 314,823**

System Performance – Protection & Control
Major Cost Drivers by Project

Instructions:

List actual O&M expenses by project for 2019; provide a high-level description of the types of costs within the project, and discuss the key drivers of each type. Also list forecasted O&M expenses for 2020-2023.

#	Project	Description and Key Drivers	2019 Actuals	2020 Forecast	2021 Forecast	2022 Forecast	2023 Forecast
1	66683: Operational Technology Security Governance O&M	This category funds the execution of the BGE operational technology compliance projects designed to maintain compliance with the Company's requirements for operational technology for facilities outside of a medium or high NERC criticality classification. These activities include but are not limited to cyber asset inventory and assessment, baseline setting and change management via security controls evaluation and verifications, asset firmware patch management, cyber vulnerability assessment, cyber asset information management, etc. This project is predominantly labor.		2,215,121	3,986,897	4,072,977	4,164,353
	Total		**$ -**	**$ 2,215,121**	**$ 3,986,897**	**$ 4,072,977**	**$ 4,164,353**

System Performance – Substation
Major Cost Drivers by Project

Instructions:

List actual O&M expenses by project for 2019; provide a high-level description of the types of costs within the project, and discuss the key drivers of each type. Also list forecasted O&M expenses for 2020-2023.

#	Project	Description and Key Drivers	2019 Actuals	2020 Forecast	2021 Forecast	2022 Forecast	2023 Forecast
	4 Projects with no year >= $1 million		826,219	1,205,814	1,141,372	1,206,893	1,316,303
	Total		$ 826,219	$ 1,205,814	$ 1,141,372	$ 1,206,893	$ 1,316,303

Vegetation Management
Major Cost Drivers by Project

Instructions:

List actual O&M expenses by project for 2019; provide a high-level description of the types of costs within the project, and discuss the key drivers of each type. Also list forecasted O&M expenses for 2020-2023.

#	Project	Description and Key Drivers	2019 Actuals	2020 Forecast	2021 Forecast	2022 Forecast	2023 Forecast
1	61054:Vegetation Management Distribution Reactive	Distribution Corrective Maintenance Tree Trimming Driven by Work Orders Generated from Customer Care and Billing (CC&B), Mobile Dispatch System (MDS), and Contractor Assistance Requests. This project is predominantly labor.	2,758,636	3,072,437	3,227,903	3,391,345	3,563,075
2	61055:Vegetation Management Distribution Routine	Preventative maintenance routine tree trimming conducted on distribution feeders for safety and reliability of the overhead electric grid. -This project is predominantly labor.	24,935,085	25,946,898	26,676,936	26,894,427	27,508,985
3	61058:Vegetation Management Substation Vegetation Management - Distribution / Transmission	Vegetation management preventative maintenance program to maintain clearances and prevent conflicts between vegetation and BGE's distribution and transmission substation equipment that could result in outages and equipment damage. This project is predominantly labor. The transmission amounts do not impact MYP rates.	1,024,542	1,107,017	1,135,125	1,163,788	1,220,981
4	61059: Vegetation Management - Gas Right of Way G1753	Preventative vegetation management program which uses tree trimming and mowing to clear lines of sight and enable aerial and ground inspections of the gas transmission system. This project is predominantly labor.	862,742	955,832	1,190,873	1,143,876	1,200,531
5	2 Projects with no year >= $1 million		824,879	1,167,799	1,215,716	1,265,823	1,318,183
6	**Total**		**$ 30,405,884**	**$ 32,249,983**	**$ 33,446,553**	**$ 33,859,259**	**$ 34,811,755**

Before the Maryland Public Service Commission

Case No. _____

Prepared Direct Testimony of

Robert D. Biagiotti, P.E.

On Behalf of

Baltimore Gas and Electric Company

May 15, 2020

TABLE OF CONTENTS

Spending Summary

The amounts set forth below represent the Multi-Year Plan capital and O&M budgeted amounts which are necessary to continue providing outstanding, safe and reliable electric and gas distribution service to customers.

Capital

Category	2021F	2022F	2023F
Corrective Maintenance - Distribution	$ 65,098,049	$ 70,082,055	$ 70,817,525
Corrective Maintenance - Substations	$ 7,416,337	$ 8,838,232	$ 8,653,201
New Business - Electric	$ 58,919,156	$ 70,285,613	$ 68,168,748
New Business - Gas	$ 57,118,555	$ 59,843,971	$ 64,284,165
Outdoor Lighting	$ 19,783,551	$ 22,810,168	$ 22,320,660
Storm	$ 5,192,972	$ 5,377,957	$ 5,499,621
Tools	$ 4,740,248	$ 4,962,528	$ 5,045,975
Total	**$ 218,268,868**	**$ 242,200,524**	**$ 244,789,895**

O&M

Category	2021F	2022F	2023F
Corrective Maintenance - Distribution	$ 64,922,207	$ 67,229,034	$ 69,568,296
Corrective Maintenance - Substation	$ 6,758,566	$ 6,447,666	$ 6,114,748
New Business - Electric	$ 257,330	$ 263,756	$ 270,359
Outdoor Lighting	$ 4,125,048	$ 4,353,692	$ 4,628,326
Preventative Maintenance - Distribution	$ 7,572,157	$ 8,255,645	$ 7,479,081
Preventative Maintenance - Protection & Control	$ 1,139,545	$ 1,182,961	$ 1,145,390
Preventative Maintenance - Substation	$ 4,409,075	$ 4,540,580	$ 4,786,676
Storm	$ 37,410,339	$ 38,512,587	$ 39,399,132
Tools	$ 6,535,841	$ 6,079,143	$ 6,109,010
Total	**$ 133,130,108**	**$ 136,865,064**	**$ 139,501,018**

I. QUALIFICATIONS

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. My name is Robert D. Biagiotti and my business address is Baltimore Gas and Electric Company ("BGE" or the "Company"), 1068 N. Front Street, Baltimore, MD 21202.

Q. WHAT IS YOUR POSITION WITH BGE?

A. I am the Vice President of Electric Distribution for BGE. In that role, I lead the efforts of BGE employees and contractors in daily electric distribution system operations, construction and maintenance activities, electric first response, and electric and gas dispatch and am responsible for design and engineering activities for new business (electric and gas), outdoor lighting and the reliability of the electric distribution system.

Q. PLEASE DESCRIBE YOUR EDUCATIONAL BACKGROUND.

A. I earned a Bachelor of Science Degree in Electrical Engineering from Virginia Polytechnic Institute and State University, along with a Minor in Mathematics. I also have a Master's Degree in Business Administration from Loyola University of Maryland. I have been a Licensed Professional Engineer in the State of Maryland since February 2000.

Q. PLEASE DESCRIBE YOUR BUSINESS EXPERIENCE.

A. I have held numerous technical and leadership positions during my 29-year tenure with BGE. Most recent to my current role, I served as Vice President of Customer Operations and Chief Customer Officer as well as Vice President of Gas Distribution. I am a senior member of the Institute of Electrical and Electronics

Engineers ("IEEE"), a past chairman of the Baltimore Chapter of the IEEE-Power Engineering Society, and a past member of the Southeastern Electric Exchange's Power Quality and Reliability Committee. I am also a past member of the American Gas Association Operations Management Committee. I am a past director of the Howard County Community Action Council and currently serve on the boards of the College Bound Foundation, Stevenson University and Catholic Charities of Baltimore. I am also a 2010 graduate of Leadership Maryland – Howard County.

Q. HAVE YOU PREVIOUSLY TESTIFIED BEFORE THE MARYLAND PUBLIC SERVICE COMMISSION?

A. I testified before the Commission in Case No. 9331 in support of BGE's application for approval of the Company's first gas Strategic Infrastructure Development and Enhancement ("STRIDE") plan and associated cost recovery mechanism. I have also appeared before the Commission at several of its weekly Administrative Meetings to discuss the work completed under the Company's STRIDE plan.

II. PURPOSE OF TESTIMONY

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

A. The purpose of my testimony is to describe capital and operations and maintenance ("O&M") spending for 2021 through 2023 necessary to support the safe and reliable operations and maintenance of the electric distribution system and to support new service connections. For informational purposes, I have also included actual and budgeted capital and O&M costs for 2019 and 2020. My testimony will also describe drivers of capital and O&M spend, the outlook for that spend and an explanation of variances. Furthermore, I will describe the capital and O&M spending for 2021 through 2023 for certain categories related to the substations on BGE's electric distribution system as well as the actual and budgeted capital and O&M costs for 2019 and 2020 for informational purposes only.

Q. COULD YOU PLEASE PROVIDE AN OVERVIEW OF THE CAPITAL AND O&M REQUESTS BEING MADE IN THIS PROCEEDING?

A. For the three-year period of 2021 through 2023, BGE is projecting its capital investments to be $705.3 million and its O&M expenditures to be $409.5 million in the areas I am covering. As I will explain in more detail later on in my testimony, these investments and expenditures are important and necessary for BGE to operate and monitor its system, meet regulatory requirements and commitments, improve system performance, and continue to provide safe and reliable service to our customers.

Q. MR. BIAGIOTTI, HAVE THE CAPITAL AND O&M PLANS DISCUSSED IN YOUR TESTIMONY BEEN ADJUSTED IN LIGHT OF THE COVID-19 PANDEMIC AND THE VARIOUS EXECUTIVE ORDERS ISSUED BY MARYLAND GOVERNOR HOGAN IN RESPONSE TO THE PANDEMIC?

A. No, they have not. In Part 2 of his Direct Testimony, Company Witness Vahos discusses BGE's expectations about the impact of the pandemic and related executive orders on the Company's capital and O&M plans and how BGE expects any impacts will be addressed over the Multi-Year Plan ("MYP") period.

Q. HOW IS THE REMAINDER OF YOUR TESTIMONY ORGANIZED?

A. I will provide an overview of the Electric Distribution area including recent operational performance. With that background, I will describe the 2021 through 2023 budgeted capital and O&M spend and the work that makes up that spend. Then, I will describe the BGE budget planning process, drivers of spend and the risks that could alter spending needs. Finally, I will provide details of the work BGE will perform and the associated capital and O&M spend.

Q. ARE YOU SPONSORING ANY EXHIBITS IN THIS PROCEEDING?

A. Yes. I am sponsoring Exhibit RDB-1. This exhibit provides details regarding the capital and O&M plans my testimony supports.

III. OVERVIEW

Q. WHAT FUNCTIONS DOES THE ELECTRIC DISTRIBUTION DIVISION SUPPORT?

A. The Electric Distribution division supports the safe and reliable operation and maintenance of BGE's electric distribution system and provides support for new service connections. More specifically, the division includes:

- the 24/7 control room that supports outage restoration and response to other emergent events;
- field resources, called Service Operators, that respond to outages and assist emergency responders such as police and firefighters;
- field crews that construct and maintain the overhead and underground distribution systems and support storm restoration;

- a dispatch organization to effectively and efficiently route resources to emergent work;
- a New Business group that supports new service connections and changes to existing services including support for distributed generation;
- a Work Management organization that plans work for our field crews;
- engineering teams that monitor system reliability and issue work to improve service to our customers; and
- an Outdoor Lighting organization that installs and maintains unmetered lighting infrastructure including streetlights and private lights.

Regarding reliability management, it is helpful to understand how the Electric Distribution division and Technical Services division, which is led by Company Witness Apte, work together. The Technical Services division has resources that evaluate the overall reliability performance of the electric system, develop programs to manage reliability and recommend associated funding levels. It also includes a Projects and Program Management organization to manage the reliability plans to improve overall system performance. The Electric Distribution division contains the employees who implement the plans developed by Technical Services. Said another way, Technical Services develops and implements long-term strategic reliability improvement plans and Electric Distribution operates and maintains the electric system and implements short-term tactical reliability plans. Company Witness Apte discusses the capital and O&M spend that he is responsible for in his Direct Testimony.

Q. WHAT FUNCTIONS WILL YOUR TESTIMONY COVER?

A. My testimony will cover the capital and O&M spending necessary to maintain safe and reliable service to our customers and support customer growth in the following functional areas:

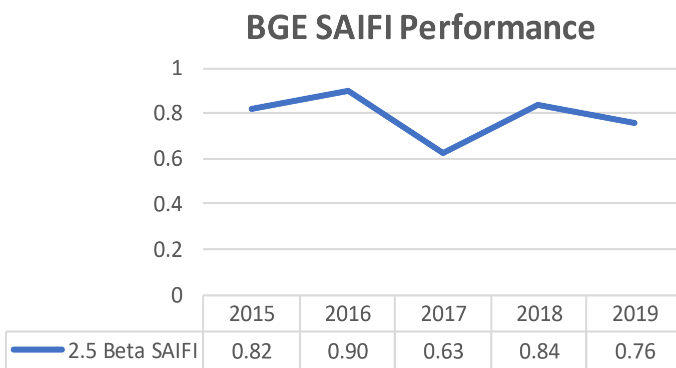
- corrective maintenance of electric distribution and substation infrastructure;
- preventative maintenance of electric distribution, protection & control and substation infrastructure;
- new service connections and changes and/or upgrades to existing services;
- new streetlights and private lights and maintenance of the existing lighting system;
- storm restoration support; and
- new and replacement tools for our field crews.

Q. WHAT HAS BEEN THE OPERATING PERFORMANCE OF THE ELECTRIC DISTRIBUTION SYSTEM?

A. Charts 1 and 2 show the five-year history for System Average Interruption Frequency Index ("SAIFI"), Customer Average Interruption Duration Index ("CAIDI") and System Average Interruption Duration Index ("SAIDI") performance.[1]

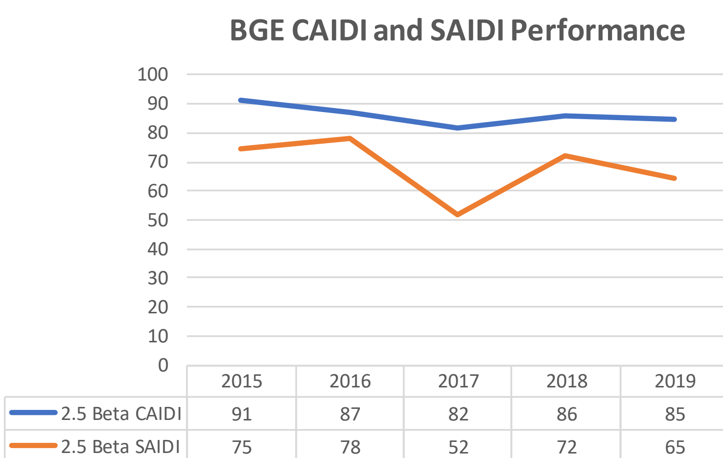
[1] SAIFI measures how often a customer can expect to experience an outage, CAIDI measures average outage duration if an outage is experienced, or average restoration time, and SAIDI measures average outage duration per customer.

Chart 1: BGE SAIFI Performance*



*Excludes planned outages

Chart 2: BGE CAIDI and SAIDI Performance*



*Excludes Planned Outages

BGE's historical capital investment and O&M spend along with its effective management of these resources and continuous improvement efforts have placed BGE among the best performing utilities in the country. In 2019, BGE had its second best SAIFI and CAIDI ever, placing it well within 1st quartile for both metrics when compared to peer utilities. Since 2011, SAIFI, CAIDI and SAIDI have improved by 38.2%, 38.8% and 62.2%, respectively, when compared to 2019. While BGE has made great strides in reducing the number and duration of outages, we need continued investment to maintain this performance and meet increasing customer expectations.

Q. WHAT IS THE BUDGETED SPEND FOR THE ELECTRIC DISTRIBUTION AND SUBSTATION CATEGORIES YOU ARE TESTIFYING ABOUT?

A. The budgeted capital and O&M spend is shown in Tables 1 and 2, respectively.

Table 1: Capital Spend by Category*

Category	**2019A**	**2020F**	**2021F**	**2022F**	**2023F**
Corrective Maintenance - Distribution	$ 75,332,811	$ 65,520,081	$ 65,098,049	$ 70,082,055	$ 70,817,525
Corrective Maintenance - Substations	$ 11,493,533	$ 9,795,522	$ 7,416,337	$ 8,838,232	$ 8,653,201
New Business - Electric	$ 53,881,128	$ 60,586,208	$ 58,919,156	$ 70,285,613	$ 68,168,748
New Business - Gas	$ 60,259,203	$ 58,295,768	$ 57,118,555	$ 59,843,971	$ 64,284,165
Outdoor Lighting	$ 16,639,501	$ 20,222,713	$ 19,783,551	$ 22,810,168	$ 22,320,660
Storm	$ 9,611,664	$ 5,080,929	$ 5,192,972	$ 5,377,957	$ 5,499,621
Tools	$ 4,771,306	$ 5,886,143	$ 4,740,248	$ 4,962,528	$ 5,045,975
Total	**$ 231,989,146**	**$ 225,387,364**	**$ 218,268,868**	**$ 242,200,524**	**$ 244,789,895**

*New Business – Electric and New Business - Gas are net of Contributions in Aid of Construction (CIAC)

Table 2: O&M Spend by Category

Category	**2019A**	**2020F**	**2021F**	**2022F**	**2023F**
Corrective Maintenance - Distribution	$ 58,945,131	$ 62,493,666	$ 64,922,207	$ 67,229,034	$ 69,568,296
Corrective Maintenance - Substation	$ 9,150,728	$ 6,682,627	$ 6,758,566	$ 6,447,666	$ 6,114,748
New Business - Electric	$ 112,067	$ 254,129	$ 257,330	$ 263,756	$ 270,359
Outdoor Lighting	$ 4,390,366	$ 4,164,529	$ 4,125,048	$ 4,353,692	$ 4,628,326
Preventative Maintenance - Distribution	$ 9,279,714	$ 8,417,525	$ 7,572,157	$ 8,255,645	$ 7,479,081
Preventative Maintenance - Protection & Control	$ 1,007,517	$ 1,136,055	$ 1,139,545	$ 1,182,961	$ 1,145,390
Preventative Maintenance - Substation	$ 2,927,119	$ 4,261,554	$ 4,409,075	$ 4,540,580	$ 4,786,676
Storm	$ 41,866,473	$ 36,178,836	$ 37,410,339	$ 38,512,587	$ 39,399,132
Tools	$ 4,871,308	$ 6,586,986	$ 6,535,841	$ 6,079,143	$ 6,109,010
Total	**$ 132,550,423**	**$ 130,175,907**	**$ 133,130,108**	**$ 136,865,064**	**$ 139,501,018**

Q. HOW DOES THE CAPITAL AND O&M PLANNING PROCESS WORK AT BGE?

A. As discussed in Part 2 of the Direct Testimony of Company Witness Vahos, capital and O&M is separated into areas of spend, called categories, which are led by category managers. Within each category, there are projects which are owned by managers. These individuals identify the work and the associated capital and O&M requirements to run the business and create a five-year budget. These projects roll up to the Category Managers, who review the estimates, identify risks and changes to prior budgets and work with the project owners to make refinements. The categories are overseen by Executive Category Owners. I serve as an Executive Category Owner and in this role, I review and approve the work plans and the associated capital and O&M requirements. I also ensure that spending levels and plans are executed so that our customers continue to receive safe and reliable electric service. My testimony will discuss the categories of spend listed in Tables 1 and 2.

Q. PLEASE DESCRIBE THE CATEGORIES LISTED IN TABLES 1 AND 2.

A. The category descriptions are as follows:

<u>Corrective Maintenance - Distribution</u>: This category includes the capital and O&M spend to repair or replace electric distribution system material and equipment and remediate voltage and clearance concerns identified through our inspection programs, in addition to the management of reactive work. Typical spend involves investment in poles, transformers, switches, wire, cable and miscellaneous materials and support structures. It also includes the O&M spend required to

respond to streetlight and private light outages and the labor for our 24/7 first responders called Service Operators.

Corrective Maintenance – Substation: This category includes the capital and O&M spend to repair or replace electric system substation material and equipment in order to provide continuous reliability to our customers. Typical spend involves investment in substation transformers, capacitors, circuit breakers, storm water management and facilities upgrades, and substation fences.

Preventative Maintenance – Distribution:[2] This category includes the O&M spend to perform distribution system inspections of poles, the AC network system, 34.5kV equipment, distribution automation devices, transformers, line clearances, contact voltage and other infrastructure to ensure the safety and reliability of the distribution system. The results of these inspections impact our Corrective Maintenance - Distribution category.

Preventative Maintenance – Protection & Control: This category includes the O&M spend to perform calibration and functional control checks of relay equipment to ensure the safety and reliability of the electric system. The results of these checks impact our Corrective Maintenance - Substation category.

Preventative Maintenance - Substation: This category includes the O&M spend to perform visual and infrared inspections of substations as well as inspections and tests of various equipment including transformers, breakers, batteries, reactors, backup generators, and more. The results of these inspections often impact our Corrective Maintenance - Substation category.

[2] The inspections under the Preventative Maintenance – Distribution, Protection & Control and Substation programs categories are set forth in the Company's O&M Manual that is filed with the Commission pursuant to COMAR 20.50.12.10A.

New Business - Electric: This category includes the capital and O&M spend to engineer, design and install infrastructure to support new electric services to residential, commercial and industrial customers. It also includes support for net meter customer installations.

New Business - Gas: This category includes the capital spend to engineer, design and install infrastructure to support new gas services to residential, commercial and industrial customers.

Outdoor Lighting: This category includes the capital and O&M spend to design and maintain unmetered streetlights and private lights and install new streetlight services to municipalities and new private light services to residential, commercial and industrial customers. Spend includes lighting poles, lighting fixtures and the cable and wire that deliver electricity.

Storm: This category includes the capital and O&M to respond to safety concerns, restore electric system outages and repair or replace damaged infrastructure resulting from storms.

Tools: This category includes the capital and O&M spend to purchase new and replacement tools that enable electric and gas field crews to perform their construction, operation and maintenance activities safely and efficiently.

Q. WHAT ARE THE DRIVERS OF CAPITAL AND O&M SPEND?

A. The primary drivers of capital and O&M spend are described below:

Reliability: BGE monitors system reliability and identifies work to maintain reliability in areas of the system that are performing well and improve reliability in areas of the system that are not meeting expected performance. Work is identified through routine operations and through inspection and maintenance programs focused on resolving reliability concerns before they impact our customers. As an example, BGE has a Targeted Reliability Improvement Program ("TRIP"), that inspects the worst performing feeders annually and creates work to improve performance.

Reliability work includes inspection, tree trimming, repair and replacement of aging poles, wires, cable and equipment and reconfiguring the system to allow for faster outage restoration. Additionally, as outages occur, our first responders and field crews repair and replace equipment to restore service. Similar reliability management applies to substations, where substation transformers, switches, protection and control equipment and other physical infrastructure are inspected, repaired and replaced to maintain reliability performance.

As mentioned previously in my testimony, the Technical Services division performs reliability work focused on long-term solutions meant to improve overall performance system wide, while Electric Distribution manages emergent reliability events and short-term tactical reliability improvement jobs.

<u>Load Growth</u>: As new residential, commercial and industrial customers request new services or upgrades to existing services, capital investment is required to install the infrastructure (meters, cable, wire, gas lines, poles, etc.) necessary to support that new or increasing load. This same concept also applies to lighting as municipalities request new streetlights and residential and commercial customers request private lights.

<u>Weather</u>: Weather events are a large driver of electric system outages that result in capital investment and O&M spend. Summer and winter storms with high winds, heavy rain, ice and snow can damage equipment requiring repair and

replacement. Additionally, resources are staffed to patrol the system, stand by downed wires, replace blown fuses and repair minor equipment damage. Furthermore, for larger storms, storm center personnel are staffed to provide support for the restoration effort.

Safety: BGE continually evaluates new tools and equipment to reduce risk to our customers and field crews. Consequently, we invest in new tools, technology and safety equipment to safeguard customers and drive our injury rate down.

Q. CAN YOU DESCRIBE THE RISKS THAT COULD ALTER YOUR BUDGET PLANS?

A. Yes. While BGE makes every effort to identify risks inherent to our activity and carefully evaluate our budget estimates to ensure accuracy, there are risks that will cause actual costs to vary from budget. Primarily, these risks include load growth, weather, field conditions, reliability, policy, regulation and permitting.

BGE uses residential market studies to estimate the number of new service starts annually and this information is used to estimate commercial new service starts. To the extent that customer demand is greater than those estimates, more capital investment will be required.

Weather is also a significant variable. The number of storms and even active weather days can have a large impact on planned work. BGE creates budget estimates based on historical weather levels but weather varies year to year.

Also, field conditions can impact the cost of construction activities. As an example, hitting rock when attempting to install underground cable for new service connections can increase the cost of a job substantially.

The reliability performance of the electric system plays a large role in budget estimation. BGE has strong analytics to predict reliability and the investment necessary to maintain expected performance levels. However, if cable, poles, transformers or other equipment fail at rates higher than predicted, additional investment may be necessary to ensure reliability performance.

Lastly, policy, regulation and permitting can impact budget plans. As an example, if regulators were to mandate system inspections not in our work plan, costs would increase to support the additional inspection labor and resulting corrective actions. As it relates to permitting, if county or state agencies enact stricter permit requirements, those new requirements could increase costs.

IV. CAPITAL SPEND DETAIL

Q. WHAT ARE THE KEY PROJECTS AND ACTIVITIES DRIVING CAPITAL SPEND?

A. The key capital projects and budget drivers are broken out by category spend below.

Corrective Maintenance – Distribution

Table 3: Corrective Maintenance – Distribution Capital Budget

Category	2019A	2020F	2021F	2022F	2023F
Corrective Maintenance - Distribution	$75,332,811	$65,520,081	$65,098,049	$70,082,055	$70,817,525

The Corrective Maintenance - Distribution category funds asset investments identified through inspection programs and general operation of the electric distribution system. The primary drivers of this spend include:

- replacement of aging poles, transformers, underground cable, capacitors, AC network equipment, switching devices and other miscellaneous equipment;
- reinforcement of aging poles;
- remediation of electric line clearance concerns found through BGE's Distribution Line Clearance Program;
- response to Company equipment damage caused by the public or contractors working near BGE lines (e.g. cable damage due to third-party excavation);
- repair of underground faults; and
- remediation of stray voltage found through BGE's Contact Voltage program.

The spending in 2019 is higher due to a higher number of priority work orders to perform capital replacements and repairs. These work orders were reactive, meaning they were not planned but rather identified during inspection and operation of the electric system. The number in 2019 was far more than the historical average.

The budget increase from 2021 to 2022 is due to allocation of general and administrative expenses. These expenses can vary year to year based on the amount of capital worked within BGE and within the category of spend. Aside from that variance, the trend is flat from 2021 through 2023.

Corrective Maintenance – Substation

Table 4: Corrective Maintenance – Substation Capital Budget

Category	2019A	2020F	2021F	2022F	2023F
Corrective Maintenance - Substations	$ 11,493,533	$ 9,795,522	$ 7,416,337	$ 8,838,232	$ 8,653,201

The Corrective Maintenance - Substation category funds asset investments identified through inspection programs and general operation of the electric system. The primary drivers of the spend include:

- replacement of substation transformers, air break switches, surge arrestors, capacitors & grounding grids;
- replacement of oil circuit breakers with gas circuit breakers or vacuum circuit breakers;
- storm water management and facilities upgrades identified by the Maryland Department of the Environment and county agencies;
- replacement of substation fences for safety concerns; and
- replacement of substation roofs.

Annual spending in this category can vary based on identified substation maintenance. As examples, 2019 actual spend exceeds the 2020 budget due to an unplanned replacement of a failed 110kV transformer, work necessary to improve drainage at our Chesapeake Beach Yard, and repairs to our Paca Substation roof. In 2020, a collapsed duct bank at Center substation will be rebuilt. Once completed, the budget goes down in 2021 but then back up in 2022 and 2023 to support life-cycle backup generator replacements.

New Business – Electric

Table 5: New Business – Electric Capital Budget

Category	2019A	2020F	2021F	2022F	2023F
New Business - Electric	$53,881,128	$60,586,208	$58,919,156	$70,285,613	$68,168,748

The New Business – Electric category funds the capital spend required to install new electric supplies, upgrade existing supplies, relocate existing infrastructure and extend circuits to new load centers. The drivers of this spend include:

- new residential housing;
- new commercial and industrial customer load;
- upgrades to existing industrial, commercial and residential supplies as a result of increasing load;
- relocation of existing infrastructure;
- extension of circuits to supply new load centers;
- emergent technologies such as electric vehicles, distributed generation (e.g. solar) and 5G (Distributed Antenna); and
- design and engineering services.

BGE continually supports economic growth including large mixed-use developments (areas that support residential and commercial interests) such as Port Covington and Towson Row and commercial developments including projects such as the Tradepoint Atlantic (Sparrows Point) expansion and the Baltimore Convention Center expansion, to name just a few.

The New Business category budget estimates are based on projected housing starts and can, therefore, vary year to year commensurate with those estimates. As an example, the trend reflects an expected slowdown in the housing industry in

2020 resulting in fewer residential connections in 2021 (resulting in a lower budget) but that work is expected to increase again in 2022 (resulting in a higher budget).

New Business – Gas

Table 6: New Business - Gas Capital Budget

Category	2019A	2020F	2021F	2022F	2023F
New Business - Gas	$60,259,203	$58,295,768	$57,118,555	$59,843,971	$64,284,165

While the Electric Distribution area primarily manages the electric distribution system and associated substations, gas services are included in our new business work due to the synergies of engineering, designing and constructing new services within the same organization using similar resources. As a result, many of the drivers of spend are similar between gas and electric. However, the following drivers are specific to the New Business – Gas category:

- the proposed Pay-it-Forward Program which allows BGE to use expected revenues to offset customer costs for main extensions on new projects for residential, commercial and industrial customers;[3] and
- gas reinforcements to upgrade existing BGE infrastructure as a result of new customer loads.

Examples of large gas projects include the Port Covington development and Naval Academy upgrade along with mixed-use developments at Two Rivers and Southlake. Like the electric side, the trend in New Business – Gas is a slowdown in the housing industry in 2020 with a corresponding drop in 2021.

[3] At the time of filing this MYP application, BGE's Pay-it-Forward Program has not been acted upon by the Commission.

Outdoor Lighting

Table 7: Outdoor Lighting Capital Budget

Category	2019A	2020F	2021F	2022F	2023F
Outdoor Lighting	$16,639,501	$20,222,713	$19,783,551	$22,810,168	$22,320,660

The Outdoor Lighting category funds the investment to support new BGE owned unmetered lighting installations and upgrade of existing lighting fixtures. Specifically, the category includes:

- installation of cable, wire, lighting poles and fixtures to supply new streetlights for municipal customers and private lights for residential and commercial customers;
- changeout of existing lighting fixtures with new modern fixtures, most typically high efficiency Light-Emitting Diode ("LED") lights;
- design of lighting systems; and
- replacement of aging cable that supplies lighting infrastructure to improve reliability.

The overall trend for the Outdoor Lighting category is a slight increase, driven mostly by growth in private lighting including customer requests to change-out high intensity discharge ("HID") lighting for LED lighting to lower their monthly bills. The higher budget in 2020 includes funding for a customer-facing outdoor lighting outage management tool that will improve customer satisfaction by allowing customers to report light outages on an interactive, online map and receive estimated time of restoration updates, and increase operational efficiency through more effective resource dispatching for repairs.

Storm

Table 8: Storm Capital Budget

Category	2019A	2020F	2021F	2022F	2023F
Storm	$9,611,644	$5,080,929	$5,192,972	$5,377,957	$5,499,621

The Storm capital budget is based on a five-year average of minor storms with actual spending being higher or lower depending on the number and severity of storm activity.[4] The budget supports capital replacement of poles, wire, transformers, switching devices and other capital equipment damaged during storms. The trend is flat except for inflation in labor and material costs. The 2019 actual spend is higher than the 2020 budget due to higher storm levels than the five-year average.

Tools

Table 9: Tools Capital Budget

Category	2019A	2020F	2021F	2022F	2023F
Tools	$ 4,771,306	$ 5,886,143	$ 4,740,248	$ 4,962,528	$ 5,045,975

The Tools capital budget supports the purchase of tools, instruments and personal protective equipment that can be capitalized and is inclusive of gas and electric tool needs. The budget is used to replace tools and instruments past their useful life, purchase new improved tools and instruments that increase the safety and efficiency of our field forces and purchase equipment that protects our field forces from hazards. The budget is flat from 2021 through 2023 aside from increases due to inflation. The budget increased in 2020 to support a project to install substation breaker remote racking which will improve safety for field forces.

[4] BGE does not budget capital for Major Storms

Also included in 2020 is the purchase of specialized leak survey equipment and capital tools associated with increased staffing of gas staff personnel and related vehicles.

V. O&M SPEND DETAIL

Q. WHAT ARE THE KEY PROJECTS AND ACTIVITIES DRIVING O&M SPEND?

A. Like capital, the key projects and drivers are discussed by category below.

Corrective Maintenance – Distribution

Table 10: Corrective Maintenance – Distribution O&M Budget

Category	2019A	2020F	2021F	2022F	2023F
Corrective Maintenance - Distribution	$58,945,131	$62,493,666	$64,922,207	$67,229,034	$69,568,296

The Corrective Maintenance - Distribution O&M category funds BGE's first responders known as Service Operators, non-capital work identified through inspection programs, response to customer power quality concerns and correction of maintenance problems found through general operation of the electric distribution system. Also, as it relates to inspection programs, this category funds equipment that is repaired to restore its intended function. More specifically, the primary drivers of this spend include:

- first responder labor in support of priority safety calls, outage response and corrective maintenance repairs;
- equipment repairs identified through inspection programs and operation of the electric system. Examples include correcting rusting/leaking transformers, repairing distribution automation radio equipment and installing animal guards on overhead equipment;

- response to customer power quality concerns such as low voltage, flickering lights and radio frequency interference;
- remediation of electric line clearance concerns found through BGE's Distribution Line Clearance Program;
- repair of underground faults; and
- remediation of stray voltage found through BGE's Contact Voltage program.

The trend for this category is flat aside from increases due to inflation of labor and material costs.

Corrective Maintenance – Substation

Table 11: Corrective Maintenance – Substation O&M Budget

Category	2019A	2020F	2021F	2022F	2023F
Corrective Maintenance - Substation	$ 9,150,728	$ 6,682,627	$ 6,758,566	$ 6,447,666	$ 6,114,748

The Corrective Maintenance – Substation O&M category funds are used to perform corrective maintenance on relay and substation assets, on substation facilities (including roofs, fences, and storm water management ponds), to install mobile transformers during emergent events, and to manage environmental risks through oil leak mitigation and response. BGE is investing in substation asset replacements which are expected to reduce corrective maintenance over time which is reflected in these budget projections.

New Business – Electric

Table 12: New Business - Electric O&M Budget

Category	2019A	2020F	2021F	2022F	2023F
New Business - Electric	$112,067	$254,129	$257,330	$263,756	$270,359

New Business – Electric O&M includes training of new BGE personnel to plan, design, and construct New Business infrastructure. This spend also includes Department of Transportation training for existing BGE personnel. Lastly, the budget supports third-party surveys of BGE customers to assess residential and commercial satisfaction with New Business services. The spend increased from 2019 to 2020 because BGE will implement additional designer training to further educate our workforce and better serve our customers.

Outdoor Lighting

Table 13: Outdoor Lighting O&M Budget

Category	2019A	2020F	2021F	2022F	2023F
Outdoor Lighting	$4,390,366	$4,164,529	$4,125,048	$4,353,692	$4,628,326

This category of spend includes installation, change and maintenance of customer-owned unmetered street-lighting equipment requested by a City, Town, County or other Municipality or Public Agency or by an incorporated association of local residents. It also includes lighting designs that cannot be capitalized.

The Outdoor Lighting O&M category budget estimates are primarily driven by the volume of work associated with customer owned lights. To the extent the estimates for this work go up or down, the budget is adjusted accordingly. For example, in 2019, BGE experienced many requests to upgrade customer-owned poles and install LED fixtures resulting in higher spend, but that work is expected to reduce in 2020, resulting in a lower budget estimate. Each year is adjusted to the expected customer-owned streetlight work plus inflation.

Preventative Maintenance – Distribution

Table 14: Preventative Maintenance – Distribution O&M Budget

Category	2019A	2020F	2021F	2022F	2023F
Preventative Maintenance - Distribution	$9,279,714	$8,417,525	$7,572,157	$8,255,645	$7,479,081

The Preventative Maintenance Distribution category funds the various inspection programs that BGE utilizes to maintain the safety and reliability of the electric distribution system (not including substations). The primary drivers of this category spend include:

- various programs to inspect overhead and underground equipment on the 34.5kV, 13.2kV and 4kV systems. Examples include inspection of poles, transformers, capacitors, switching equipment and AC network devices;
- the Distribution Line Clearance Program which ensures that clearance of electric lines to roads, buildings and other structures meet code requirements; and
- the Contact Voltage Program which identifies stray voltage on streetlight poles, fences and other customer accessible area for remediation by BGE.

The workload and resulting costs in this category are flat, except for the Contact Voltage program where we currently anticipate performing a quality assurance audit in 2020 and 2022, but not in 2021 and 2023. This accounts for the spending increase in those years. The 2019 actual spend is greater than the 2020 budget estimate as a result of a planned increase in the number of recloser, capacitor and pad-mounted equipment inspections performed in 2019.

Preventative Maintenance – Protection & Control

Table 15: Preventative Maintenance – Protection & Control O&M Budget

Category	2019A	2020F	2021F	2022F	2023F
Preventative Maintenance - Protection & Control	$ 1,007,517	$ 1,136,055	$ 1,139,545	$ 1,182,961	$ 1,145,390

The Preventative Maintenance – Protection & Control category funds the calibration and functional control checks of various relay equipment BGE utilizes to maintain the safety and reliability of the electric system. The primary drivers of this category include:

- testing of circuit relays and protection schemes;
- testing of transformer and feeder relays and protection schemes; and
- testing of capacitor relays and protection schemes.

The trend in this category is flat.

Preventative Maintenance – Substation

Table 16: Preventative Maintenance – Substation O&M Budget

Category	2019A	2020F	2021F	2022F	2023F
Preventative Maintenance - Substation	$ 2,927,119	$ 4,261,554	$ 4,409,075	$ 4,540,580	$ 4,786,676

The Preventative Maintenance – Substation category funds the various inspection and maintenance programs within substations that BGE utilizes to maintain the safety and reliability of the electric system. The primary drivers of this category include:

- monthly and bi-monthly substation inspections;
- inspection and testing of various substation equipment including transformers, breakers, batteries, reactors, and backup generators;

- infrared inspections; and
- inspection and/or testing of various other components including building roofs, fire control systems, and HVAC systems.

The budget increased in 2020 due to the start of a program to inspect substation control house roofs and ventilation systems and the addition of employee on-the-job training occurring during preventative maintenance inspections. The budget is otherwise flat plus inflation.

Storm

Table 17: Storm O&M Budget

Category	2019A	2020F	2021F	2022F	2023F
Storm	$41,866,473	$36,178,836	$37,410,339	$38,512,587	$39,399,132

The Storm O&M budget is based on a five-year average of minor storms plus $10 million annually for major storms.[5] This budget supports storm restoration efforts. Examples include:

- trimming fallen trees or broken tree limbs to access electric lines;
- reconnecting wires that have fallen to the ground;
- replacing blown fuses;
- standing by downed wires for public safety;
- inspecting circuits to identify causes of outages;
- storm center staff and leadership support; and
- first responder labor to address public safety concerns.

The trend for this category is flat except for inflation in labor and material costs.

[5] $10 million is the five-year average consistent with Commission precedent.

Tools

Table 18: Tools O&M Budget

Category	2019A	2020F	2021F	2022F	2023F
Tools	$4,871,308	$6,586,986	$6,535,841	$6,079,143	$6,109,010

The Tools O&M budget supports the purchase of tools, instruments and personal protective equipment that do not meet capital threshold levels and is inclusive of gas and electric needs. The budget is used to buy new or replace existing lower cost tools (tools less than $500), instruments and personal protective equipment used to perform field construction and maintenance functions. The spend also includes the testing, inspection and repair of these resources.

The budget increased in 2020 and continues from 2021 through 2023 due to tool purchases to support the increased hiring of gas and electric trainees and additional testing of portable protective grounds to align safety practices between Exelon Utilities operating companies. In addition, eight new vehicles will be purchased each year in 2020 and 2021 to support gas operations. There is an additional increase in those years to support the outfitting of those vehicles with tools and equipment.

Q. DOES THIS CONCLUDE YOUR TESTIMONY?

A. Yes.

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2020F-2023F Plan Documentation – Capital and O&M

Executive Category Owner: Robert D. Biagiotti

Title: Vice President, Electric Operations

BGE
An Exelon Company

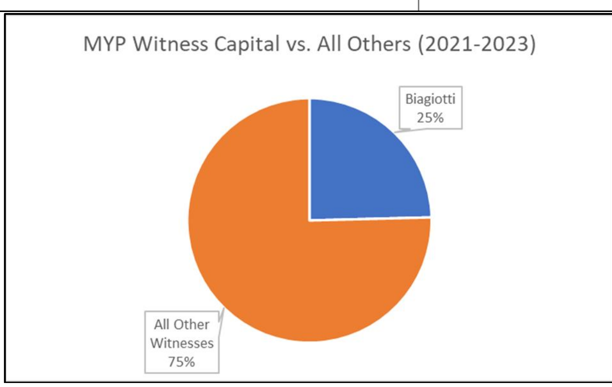
I. Financial Summary

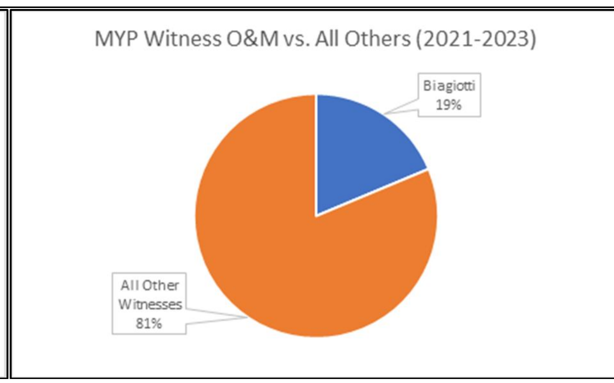
A. Capital

CATEGORY	2019A	2020F	2021F	2022F	2023F
CORRECTIVE MAINTENANCE - DISTRIBUTION	$75,332,811	$65,520,081	$65,098,049	$70,082,055	$70,817,525
CORRECTIVE MAINTENANCE - SUBSTATION	$11,493,533	$9,795,522	$7,416,337	$8,838,232	$8,653,201
NEW BUSINESS - ELECTRIC	$53,881,128	$60,586,208	$58,919,156	$70,285,613	$68,168,748
NEW BUSINESS - GAS	$60,259,203	$58,295,768	$57,118,555	$59,843,971	$64,284,165
OUTDOOR LIGHTING	$16,639,501	$20,222,713	$19,783,551	$22,810,168	$22,320,660
STORM	$9,611,664	$5,080,929	$5,192,972	$5,377,957	$5,499,621
TOOLS	$4,771,306	$5,886,143	$4,740,248	$4,962,528	$5,045,975
ANNUAL TOTALS FOR CAPITAL	**$231,989,146**	**$225,387,364**	**$218,268,868**	**$242,200,524**	**$244,789,895**

B. O&M

CATEGORY	2019A	2020F	2021F	2022F	2023F
CORRECTIVE MAINTENANCE - DISTRIBUTION	$58,945,131	$62,493,666	$64,922,207	$67,229,034	$69,568,296
CORRECTIVE MAINTENANCE - SUBSTATION	$9,150,728	$6,682,627	$6,758,566	$6,447,666	$6,114,748
PREVENTATIVE MAINTENANCE - DISTRIBUTION	$9,279,714	$8,417,525	$7,572,157	$8,255,645	$7,479,081
PREVENTATIVE MAINTENANCE - PROTECTION & CONTROL	$1,007,517	$1,136,055	$1,139,545	$1,182,961	$1,145,390
PREVENTATIVE MAINTENANCE - SUBSTATION	$2,927,119	$4,261,554	$4,409,075	$4,540,580	$4,786,676
NEW BUSINESS - ELECTRIC	$112,067	$254,129	$257,330	$263,756	$270,359
OUTDOOR LIGHTING	$4,390,366	$4,164,529	$4,125,048	$4,353,692	$4,628,326
STORM	$41,866,473	$36,178,836	$37,410,339	$38,512,587	$39,399,132
TOOLS	$4,871,308	$6,586,986	$6,535,841	$6,079,143	$6,109,010
ANNUAL TOTALS FOR O&M	**$132,550,423**	**$130,175,907**	**$133,130,108**	**$136,865,064**	**$139,501,018**





II. Capital Category Cashflows and Functions

A. Corrective Maintenance – Distribution

Category	2019A	2020F	2021F	2022F	2023F
Corrective Maintenance – Distribution	$75,332,811	$65,520,081	$65,098,049	$70,082,055	$70,817,525

- Corrective Maintenance – Distribution is comprised of work to replace defective distribution material and equipment identified through inspection programs included in BGE's O&M manual filed with the Maryland PSC pursuant to the Code of Maryland Regulation (COMAR) 20.50.12,11 or identified on an emergent basis through daily operation of the electric system.
- Major components of this category include the replacement of material and equipment such as cable, poles, transformers, switchgear and capacitors.
- Corrective maintenance occurs after outage reporting or resulting from inspections and is aimed at replacing defective equipment so it can perform its intended function.
- As a rule, if the specific equipment or component requiring maintenance has degraded or failed, the action required to replace that equipment is classified as corrective maintenance.
- The overall trend in Corrective Maintenance – Distribution reflects expectations of relatively consistent levels of work year to year with some increase for inflation. The budget increase from 2021 to 2022 is due to allocation of general and administrative (G&A) expenses. The G&A expenses can vary year to year based on the amount of capital work within BGE and within the category of spend.

B. Corrective Maintenance – Substation

Category	2019A	2020F	2021F	2022F	2023F
Corrective Maintenance – Substation	$11,493,33	$9,795,522	$7,416,337	$8,838,232	$8,653,201

- Capital expenditures in this category result from the substation maintenance backlog and from emergent system events.
- Corrective Maintenance – Substation, like Corrective Maintenance – Distribution, includes work to replace defective substation material and equipment identified through inspection programs included in BGE's O&M manual filed with the Maryland PSC pursuant to the Code of Maryland Regulation (COMAR) 20.50.12,11 or identified on an emergent basis through daily operation of the electric system. The type of capital work included in Corrective Maintenance – Substation includes:
    - Substation transformer replacements
    - Air break switch replacements
    - Surge arrestor replacements
    - Capacitor replacements
    - Oil circuit breaker (OCB) replacements
    - Grounding grid upgrades
    - Storm water management and facility upgrades (identified by the Maryland Department of the Environment and county agencies)

- Fence upgrades

- The 2019-2023 trend in capital spending in the Corrective Maintenance – Substation category reflects:
  - $2.5 million for the unplanned replacement of the 110-1 Shipley transformer, Chesapeake Beach Yard drainage system, and the Paca Substation roof; all in 2019.
  - One-time spend of $2.6 million in 2020 for collapsed duct bank rebuilds.
  - Levelized spending to historical levels in 2022 and 2023 after the addition of a generator replacement program.

C. New Business – Electric

Category	2019A	2020F	2021F	2022F	2023F
New Business – Electric	$53,881,128	$60,586,208	$58,919,156	$70,285,613	$68,168,748

- Customer requests for electric services include new services, feeder extensions/upgrades, and relocations to accommodate new electric services or upgrades or modifications to existing services. Some examples include:
  - 5G Upgrades/Distributed Antennae – Metered cell site antennae attached to street light poles (this project covers any BGE capital equipment that may be required)
  - Electric vehicle chargers
  - Clean Energy Jobs Act (CEJA) which will increase solar work, resulting in upgrades or modifications to existing services
  - New residential developments/subdivisions
  - Mixed-use developments with commercial and residential projects
  - Commercial and industrial projects
- The trend in New Business – Electric capital reflects an expected near-term slowdown in the housing industry in 2020 which results in fewer New Business residential connections in 2021 and an expected rebound in housing starts in 2021/2022. In addition, more customer requests for new services (for EV chargers, etc.) are also causing an uptick in spending levels.

D. New Business – Gas

Category	2019A	2020F	2021F	2022F	2023F
New Business – Gas	$60,259,203	$58,295,768	$57,118,555	$59,843,971	$64,284,165

- Customer requests for gas services include new services, main extensions/upgrades, and relocations to accommodate new gas services or upgrades or modifications to existing services. Some examples include:
  - Commercial and industrial gas projects
  - New residential developments/subdivisions
  - Mixed-use developments with commercial and residential projects
  - Proposed Pay-it-Forward Program which allows BGE to use expected revenues to offset customer costs for main extensions on new projects for residential, commercial and industrial customers -

    - Gas reinforcements to upgrade the existing BGE infrastructure that are required strictly by the addition of new customer load. (Gas reinforcements to address system performance and/or reliability are included in other categories.)

- The trend in New Business – Gas, like electric, reflects a slowdown in the housing industry in 2020 with a corresponding drop in investment levels in 2021. Over the forecast period, the cost associated with the proposed Pay It Forward program also grows to approximately $5 million in 2023. Note - at the time of filing this MYP application, BGE's Pay-it-Forward Program has not been acted upon by the Commission.

E. Outdoor Lighting

Category	2019A	2020F	2021F	2022F	2023F
Outdoor Lighting	$16,639,501	$20,222,713	$19,783,551	$22,810,168	$22,320,660

- This category includes new installations and changes of company-owned unmetered street lighting supplied from overhead or underground facilities on dedicated public streets and roads where requested by a municipal agency or an incorporated association of residents.
- The category also includes:
    - Installation and changes of unmetered outdoor lighting on private property, for residential or commercial areas where requested by residential and commercial customers.
    - Replacement of cable supplying street lighting and private lighting systems across the service territory to restore lights to service and improve outdoor lighting reliability.
    - Testing of smart lighting controls and smart fixtures/sensors and related software.
    - Implementation of a customer-facing outage mapping IT platform.

- The overall trend in this category is up slightly. The increase in 2020 is driven by growth of private lighting customers changing out old lighting fixtures for high efficiency LED lighting. Also, contributing to the increase is development of an online outage map tool for our customers to report light outages. The drop from 2020 to 2021 is driven by completion of the outage map project. A further increase is expected in 2022 to account for expected growth of new private lighting customers.

F. Storm

Category	2019A	2020F	2021F	2022F	2023F
Storm	$9,611,644	$5,080,929	$5,192,972	$5,377,957	$5,499,621

- The costs in the storm category are based on the five-year average of storm costs and are only budgeted for minor storms. 2020 cost levels reflect that five-year average and the remainder of the years trend up slightly for inflation. The 2019 storm season was very active resulting in a higher than average minor storm cost.
- This category supports the repairs during restoration of BGE's electric distribution system due to weather/storm activity.
- Examples of this include but are not limited to:
    - Replacing wires, cable, poles and crossarms.
    - Replacing damaged equipment such as transformers and reclosers.

- Capital expended for major storms is charged at the time of the storm and is not budgeted.

G. Tools

Category	2019A	2020F	2021F	2022F	2023F
Tools	$4,771,306	$5,886,143	$4,740,248	$4,962,528	$5,045,975

- The capital tool account is used for the purchase of gas and electric tools, instruments, and personal protective equipment (except fire retardant clothing) with a single item typically costing $500 or more.
- The tools, instruments and personal protective equipment are used during training, installing new infrastructure, and maintaining existing infrastructure.
- The spending trend is flat or slightly up for inflation, with a higher spend in 2020. Higher 2020 spend is driven by reaching full implementation of the substation breaker remote racking safety project in 2020 (piloted in 2019). Additionally, 2020 funding requirements are driven by purchasing specialized leak survey equipment, the need for capital tools for vehicles and to support staffing increases in gas construction.

III. Capital Details

This Section provides additional details for capital projects with spend greater than $1 million in any year within the 2019-2023 time period for each of the categories below.

A. Corrective Maintenance – Distribution

Project Name	55734: Overhead Distribution Transformer Material Costs Associated with Project 60505			
2019A	**2020F**	**2021F**	**2022F**	**2023F**
$1,778,760	$1,787,493	$1,832,180	$1,877,940	$1,924,951
Problem Statement		**Solution Statement**		**Estimated / In-Service Date**
An overhead distribution transformer fails or is damaged.		The overhead distribution transformer is replaced. Project 55734 tracks the overhead transformer material costs associated with this replacement. ITN 60505 tracks the labor and misc. costs associated with this replacement.		Monthly / Various

Project Name	60472: Buried Primary Cable Main Faults			
2019A	**2020F**	**2021F**	**2022F**	**2023F**
$3,502,669	$2,455,505	$2,467,468	$2,710,497	$2,781,016
Problem Statement		**Solution Statement**		**Estimated / In-Service Date**
A fault occurs on primary cable mains causing an outage.		Cable fault is located, excavated and defective cable is replaced.		Monthly / Various

Project Name	60473: Buried Primary Cable Fused Faults			
2019A	**2020F**	**2021F**	**2022F**	**2023F**
$3,049,607	$5,387,165	$5,296,010	$5,975,506	$6,147,529
Problem Statement		**Solution Statement**		**Estimated / In-Service Date**
A fault occurs on primary cable taps causing an outage.		Cable fault is located, excavated and defective cable is replaced.		Monthly / Various

Project Name	60474: Buried Secondary Cable Industrial and Commercial Faults			
2019A	**2020F**	**2021F**	**2022F**	**2023F**
$1,420,535	$1,246,540	$1,284,670	$1,360,799	$1,408,961
Problem Statement		**Solution Statement**		**Estimated / In-Service Date**
A fault occurs on secondary (lower voltage) cable causing an outage to industrial and commercial customers.		Cable fault is located, excavated and defective cable is replaced.		Monthly / Various

Project Name	60475: Buried Secondary Cable Residential Faults			
2019A	**2020F**	**2021F**	**2022F**	**2023F**
$1,566,892	$1,678,251	$1,720,474	$1,825,849	$1,881,928
Problem Statement		**Solution Statement**		**Estimated / In-Service Date**
A fault occurs on secondary (lower voltage) cable causing an outage to residential customers.		Cable fault is located, excavated and defective cable is replaced.		Monthly / Various

Project Name	60477: Pad-mounted Distribution Transformer Replacements - Planned			
2019A	**2020F**	**2021F**	**2022F**	**2023F**
$2,360,078	$3,156,808	$3,280,721	$3,860,645	$3,964,850
Problem Statement		**Solution Statement**		**Estimated / In-Service Date**
A pad-mounted distribution transformer is identified for replacement through an inspection program.		Pad-mounted distribution transformer is replaced.		Monthly / Various

Project Name	60504: Damages-Underground, Outdoor Lighting and Customer Requests			
2019A	**2020F**	**2021F**	**2022F**	**2023F**
$5,447,069	$2,924,735	$2,917,439	$3,251,686	$3,302,103
Problem Statement		**Solution Statement**		**Estimated / In-Service Date**
Underground or outdoor lighting equipment is damaged or a customer requests service from BGE related to distribution equipment.		Damaged equipment is replaced or the customer request is fullfilled.		Monthly / Various

Project Name	60505: Distribution Equipment Replacement – Emergent			
2019A	**2020F**	**2021F**	**2022F**	**2023F**
$16,665,389	$11,714,301	$11,548,857	$12,484,532	$12,419,184
Problem Statement		**Solution Statement**		**Estimated / In-Service Date**
BGE first responders identify defective or damaged distribution equipment.		Distribution equipment is replaced.		Monthly / Various

Project Name	60506: Overhead Equipment Replacement - Planned			
2019A	**2020F**	**2021F**	**2022F**	**2023F**
$1,716,001	$1,157,017	$1,144,072	$1,260,160	$1,278,147
Problem Statement		**Solution Statement**		**Estimated / In-Service Date**
Overhead equipment is identified for replacement through an inspection program.		Overhead equipment is replaced.		Monthly / Various

Project Name	60508: Distribution Line Capacitor Replacements - Planned			
2019A	**2020F**	**2021F**	**2022F**	**2023F**
$1,004,706	$1,177,721	$1,204,613	$1,239,976	$1,268,938
Problem Statement		**Solution Statement**		**Estimated / In-Service Date**
A distribution capacitor is identified for replacement through an inspection program.		Distribution capacitor is replaced.		Monthly / Various

Project Name	60796: Buried Outdoor Lighting Cable Faults			
2019A	**2020F**	**2021F**	**2022F**	**2023F**
$3,163,010	$2,741,912	$2,725,506	$3,149,692	$3,208,632
Problem Statement		**Solution Statement**		**Estimated / In-Service Date**
An outdoor lighting cable faults causing an outage.		Cable fault is located, excavated and defective cable is replaced.		Monthly / Various

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Project Name	60806: Outdoor Lighting Outage – Diagnose and Replace			
2019A	**2020F**	**2021F**	**2022F**	**2023F**
$898,981	$808,522	$934,870	$1,026,416	$1,077,500
Problem Statement		**Solution Statement**		**Estimated / In-Service Date**
An outdoor light is out of service.		The outdoor light problem is diagnosed and defective equipment is replaced.		Monthly / Various

Project Name	61131: Buried Primary Cable Replacement- Emergent			
2019A	**2020F**	**2021F**	**2022F**	**2023F**
$2,540,071	$2,216,808	$2,216,415	$2,221,016	$2,220,815
Problem Statement		**Solution Statement**		**Estimated / In-Service Date**
A buried primary cable fails leading to a decision that the cable has exceeded its useful life.		The cable is replaced.		Monthly / Various

Project Name	61154: Pole Program BGE-Verizon Pole Removals			
2019A	**2020F**	**2021F**	**2022F**	**2023F**
$1,345,300	$1,584,000	$1,584,038	$1,583,949	$1,584,033
Problem Statement		**Solution Statement**		**Estimated / In-Service Date**
When a BGE pole that has Verizon Wireless equipment attached is replaced, the old pole is left for Verizon to remove and transfer their equipment to the new pole.		Verizon removes the old pole and charges BGE for the service.		Monthly / Various

Project Name	61160: Pole Replacements - Planned			
2019A	**2020F**	**2021F**	**2022F**	**2023F**
$7,200,634	$6,260,143	$6,156,165	$5,824,633	$5,869,220
Problem Statement		**Solution Statement**		**Estimated / In-Service Date**
A pole is identified for replacement through an inspection program.		The defective pole is replaced.		Monthly / Various

Project Name	61161: Pole Replacements - Emergent			
2019A	**2020F**	**2021F**	**2022F**	**2023F**
$580,984	$1,018,917	$709,558	$806,351	$775,939
Problem Statement		**Solution Statement**		**Estimated / In-Service Date**
A pole is identified as needing immediate replacement, through inspection or other means.		The defective pole that requires immediate attention is replaced.		Monthly / Various

Project Name	61163: Emergency Response			
2019A	**2020F**	**2021F**	**2022F**	**2023F**
$4,118,612	$4,007,728	$4,016,877	$4,411,444	$4,499,518
Problem Statement		**Solution Statement**		**Estimated / In-Service Date**
Outages or unsafe conditions are reported or identified.		First responder restores service or mitigates unsafe conditions.		Monthly / Various

Project Name	61464: Damages - Overhead			
2019A	**2020F**	**2021F**	**2022F**	**2023F**
$6,406,637	$4,794,660	$4,759,292	$5,262,272	$5,344,840
Problem Statement		**Solution Statement**		**Estimated / In-Service Date**
Overhead equipment is damaged.		Damaged equipment is replaced.		Monthly / Various

Project Name	61523: Duct Line Cable Replacement - Emergent			
2019A	**2020F**	**2021F**	**2022F**	**2023F**
$4,785,243	$3,998,393	$3,928,664	$4,227,961	$4,199,001
Problem Statement		**Solution Statement**		**Estimated / In-Service Date**
A duct line cable fails or has exceeded its useful life.		Defective cable is removed from the duct line and replaced or a section of cable is replaced in the manhole.		Monthly / Various

Project Name	60482: Underground Equipment Replacement - Emergent			
2019A	**2020F**	**2021F**	**2022F**	**2023F**
$1,356,325	$625,250	$631,238	$673,310	$685,730
Problem Statement		**Solution Statement**		**Estimated / In-Service Date**
Underground equipment fails or is damaged.		Underground equipment is replaced.		Monthly / Various

Project Name	61133: Buried Secondary Cable Replacement – Emergent			
2019A	**2020F**	**2021F**	**2022F**	**2023F**
$1,001,215	$800,000	$800,000	$799,999	$799,999
Problem Statement		**Solution Statement**		**Estimated / In-Service Date**
Buried secondary cable fails leading to a decision that the cable has exceeded its useful life.		Cable is replaced.		Monthly / Various

B. Corrective Maintenance – Substation

Project Name	55965: Distribution Substation Routine Oil Circuit Breaker Replacements Only			
2019A	2020F	2021F	2022F	2023F
$4,262,359	$4,625,063	$4,445,172	$5,351,381	$5,075,774
Problem Statement		Solution Statement		Estimated / In-Service Date
Oil Circuit Breakers (OCB) have a history of failure and are an aging asset to be retired from the BGE system.		On-going program to replace ~700 Oil Circuit Breakers on BGE's system.		Monthly / Various

Project Name	59119: Center 13248 Collapsed Duct Bank Rebuild Section 1			
2019A	2020F	2021F	2022F	2023F
$527,046	$1,294,321			
Problem Statement		Solution Statement		Estimated / In-Service Date
Duct banks going into Center substation switchgear building #1 have shifted downwards due to soil settlement resulting in visible shear pressure on multiple cables in the shifted ducts.		Replace the affected ducts at Center substation.		June 2020

Project Name	59462: Replace Failed Distribution Transformer - Shipley 110-1 Capital			
2019A	2020F	2021F	2022F	2023F
$1,081,335				
Problem Statement		Solution Statement		Estimated / In-Service Date
The Shipley 110-1 Transformer failed on 9/1/2018. Mobile Transformer #19 was installed as a temporary replacement.		New transformer installation completed to replace failed Shipley 110-1 transformer allowing the station to be returned to normal configuration.		March 2019

Project Name	60528: Substation Capital Corrective Maintenance Tasks - Distribution Other Equipment			
2019A	2020F	2021F	2022F	2023F
$3,123,810	$551,199	$877,504	$766,681	$783,749
Problem Statement		Solution Statement		Estimated / In-Service Date
Other miscellaneous items fail within a substation, such as generators, switches, bushings, breakers, etc. and have to be replaced on an emergency basis.		The items are replaced.		Monthly / Various

Project Name	60529: Replace Failed Distribution Substation Transformers			
2019A	2020F	2021F	2022F	2023F
$344,212	$1,087,122	$1,110,432	$1,300,548	$1,303,387
Problem Statement		Solution Statement		Estimated / In-Service Date
Distribution substation transformers fail.		Replace failed distribution transformers.		Monthly / Various

Project Name	66690: Center 13248 Collapsed Duct Bank Rebuild Section 2			
2019A	**2020F**	**2021F**	**2022F**	**2023F**
	$1,310,323			

Problem Statement	Solution Statement	Estimated / In-Service Date
Duct banks going into Center substation switchgear building #2 have shifted downwards due to soil settlement resulting in visible shear pressure on multiple cables in the shifted ducts.	Replace the affected ducts at Center Substation.	December 2020

C. New Business – Electric

Project Name	55451: Distributed Energy Interconnection/Solar			
2019A	**2020F**	**2021F**	**2022F**	**2023F**
$(66,136)	$902,473	$901,768	$1,484,510	$1,618,436
Problem Statement		**Solution Statement**		**Estimated / In-Service Date**
The MD PSC instituted regulatory requirements (Maryland Code §7-306 and COMAR 20.50.10) to ensure all MD utilities were able to capture, track and reimburse customers for all excess customer-generation that flows to BGE's grid. A customer installs a renewable energy resource such as solar and BGE needs to install infrastructure to connect the customer to the BGE grid.		Install poles, wire, cable, switching equipment and other infrastructure as necessary to connect the renewable resource to the BGE grid.		Monthly / Various

Project Name	57562: New Business TURF VALLEY Feeder 7650			
2019A	**2020F**	**2021F**	**2022F**	**2023F**
$1,844,246				
Problem Statement		**Solution Statement**		**Estimated / In-Service Date**
Extend Feeder 7650 & 7278 to Turf Valley community to support residential and commercial growth and reliability.		Project was completed.		October 2019

Project Name	58509: New Business Electric Weller Development Chapter 1			
2019A	**2020F**	**2021F**	**2022F**	**2023F**
$16,727	$1,800,267	$857,505	$963,254	$1,039,162
Problem Statement		**Solution Statement**		**Estimated / In-Service Date**
Weller Development is requesting new services to support development of Port Covington, which includes mixed use residential, retail, commercial and garages.		BGE coordinates with Weller Development and installs the requested services.		Monthly / Various

Project Name	60752: New Business Electric Residential New			
2019A	**2020F**	**2021F**	**2022F**	**2023F**
$25,449,869	$25,143,041	$24,879,351	$28,660,348	$29,031,836
Problem Statement		**Solution Statement**		**Estimated / In-Service Date**
New residents, real estate developers and builders in Maryland request electric main, services and meters for new homes and developments. Ongoing large scale projects include Tanyard Cove, Melford Town Center, Martin Farms, Two Rivers and Southlake.		BGE engineers, designs, and constructs the electric infrastructure, services, and meters entailed in supplying electricity to the customers' homes or real estate developments.		Monthly / Various

Project Name	60753: New Business Electric Commercial and Industrial New Small Medium			
2019A	**2020F**	**2021F**	**2022F**	**2023F**
$7,158,663	$7,087,332	$6,580,683	$7,641,615	$7,458,676
Problem Statement		**Solution Statement**		**Estimated / In-Service Date**
New Commercial and Industrial customer requests for electric mains, services and meters for new projects. This includes temporary services, cell sites, and traffic signals. Example jobs include WAWA stores, Royal Farms stores, and schools.		BGE engineers, designs, and constructs the electric infrastructure, services, and meters, to deliver the requested electric loads to the customer.		Monthly / Various

Project Name	60760: New Business Electric Residential Change			
2019A	**2020F**	**2021F**	**2022F**	**2023F**
$6,410,078	$4,936,424	$4,296,101	$5,864,762	$5,615,156
Problem Statement		**Solution Statement**		**Estimated / In-Service Date**
Existing electric residential customers request changes, removal, upgrades or relocation of their main, services and meters for their homes.		BGE engineers, designs, and constructs the electric infrastructure, services and meters to deliver the requested electric service changes to the customers.		Monthly / Various

Project Name	60761: New Business Electric Commercial and Industrial Change / Relocation Small Medium			
2019A	**2020F**	**2021F**	**2022F**	**2023F**
$4,505,810	$3,199,347	$2,811,295	$3,141,943	$3,186,698
Problem Statement		**Solution Statement**		**Estimated / In-Service Date**
Existing Commercial and Industrial customers request changes, upgrades, or relocations of electric mains, services and meters for projects.		BGE engineers, designs, and constructs the electric infrastructure, services and meters to deliver the requested electric loads to the customer.		Monthly / Various

Project Name	60762: New Business Electric Commercial & Industrial New Large			
2019A	**2020F**	**2021F**	**2022F**	**2023F**
$3,433,842	$2,572,177	$5,908,374	$6,380,565	$3,629,783
Problem Statement		**Solution Statement**		**Estimated / In-Service Date**
New large load Commercial and Industrial customers request electric mains, services, and meters for new projects. These large load customers may require feeder extensions and/or significant upgrades to existing BGE infrastructure.		BGE engineers, designs, and constructs the electric infrastructure, services and meters to deliver the requested new electric loads to the customer.		Monthly / Various

Project Name	60763: New Business Electric Commercial & Industrial Change/Relocation Large			
2019A	**2020F**	**2021F**	**2022F**	**2023F**
$546,935	$1,480,287	$1,977,626	$3,117,123	$2,765,279
Problem Statement		**Solution Statement**		**Estimated / In-Service Date**
Existing electric Commercial and Industrial customers request changes, upgrades, or relocation of mains, services, and meters for projects. Pending jobs include Kimbrough Ambulatory Care Center, Patapsco Feeder Wastewater Treatment Plant, Vernon Pumping Station Phase 1 & 2, and the Baltimore Convention Center.		BGE engineers, designs, and constructs the electric infrastructure, services and meters to deliver the requested changes/relocations of electric loads to the customer.		Monthly / Various

Project Name	61437: Connected Communities			
2019A	**2020F**	**2021F**	**2022F**	**2023F**
$172,653	$7,367,123	$7,096,706	$9,142,963	$9,225,201
Problem Statement		**Solution Statement**		**Estimated / In-Service Date**
Connecting communities through technology inclusive of commercial customers installing antennas for advanced cell service for their customers and EV Chargers for the public to utilize with electric vehicles.		BGE engineers, designs, and constructs the electric infrastructure to deliver electricity so the commercial entities can deliver cellular transmission functionality and deploy EV Chargers.		Monthly / Various

Project Name	61461: New Business Net Metering			
2019A	**2020F**	**2021F**	**2022F**	**2023F**
$392,859	$1,479,727	$1,996,880	$2,215,614	$2,855,215
Problem Statement		**Solution Statement**		**Estimated / In-Service Date**
The MD PSC instituted regulatory requirements (Maryland Code §7-306 and COMAR 20.50.10) to ensure all MD utilities were able to capture, track and reimburse customers for all excess customer-generation that flows to BGE's grid. A customer installs a renewable energy resource such as solar and BGE needs to track and reimburse the customer for the excess energy that flows into the BGE grid.		Install a net meter. This type of meter tracks the amount of energy that flows to and from the customer so that BGE can determine how much (net) generation flows into the BGE grid. This capability does not exist with standard meters.		Monthly / Various

Project Name	61462: New Business Elecric Tradepoint Atlantic			
2019A	**2020F**	**2021F**	**2022F**	**2023F**
$2,984,173	$2,663,475	$1,537,281	$1,593,413	$1,659,633
Problem Statement		**Solution Statement**		**Estimated / In-Service Date**
New commercial and industrial strategic customer(s) request electric main(s), service(s) and meter(s) for new projects. New Business has seen an uptick in the volume of jobs. Pending jobs include Volkswagen.		BGE is obligated to supply electric to the customers facilities. BGE engineers, designs, and constructs the electric infrastructure, service(s) and meter(s) to deliver the requested electric load(s) to the customer.		After 2023

D. New Business – Gas

Project Name	58510: New Business Gas Weller Development Chapter 1			
2019A	**2020F**	**2021F**	**2022F**	**2023F**
$1,344	$1,179,044	$460,080	$260,636	$288,720
Problem Statement		**Solution Statement**		**Estimated / In-Service Date**
New commercial and residential customer(s) request gas main(s), service(s) and meter(s) for new projects. New Business has seen an uptick in the volume of jobs. Pending jobs are for Port Covington and include mixed use residential, retail, commercial including garages.		BGE engineers, designs, and constructs the gas infrastructure, service(s), and meter(s) to deliver the requested gas load(s) to the customer.		Monthly / Various

Project Name	58968: New Business Crain Highway Conway Road Gas Approach			
2019A	**2020F**	**2021F**	**2022F**	**2023F**
$4,093,616	$772,900			
Problem Statement		**Solution Statement**		**Estimated / In-Service Date**
New development (Twin River) of 500 homes is in need of gas supply and the current local line does not have enough pressure.		Install new main from Crain HIghway through Conway Road to reach the new development. Build a new regulator station to handle the Over High Pressure (OHP) needed for the area.		March 2020

Project Name	60779: CORE Gas Baltimore City Removals			
2019A	**2020F**	**2021F**	**2022F**	**2023F**
$1,689,104	$1,002,608	$1,027,673	$1,053,340	$1,079,709
Problem Statement		**Solution Statement**		**Estimated / In-Service Date**
Baltimore City Project CORE needs gas disconnected on abandoned row homes so the buildings can be razed.		BGE provides services to disconnect the gas service in the street so buildings can be safely razed.		Monthly / Various

Project Name	60780: New Business Gas Residential Changes			
2019A	**2020F**	**2021F**	**2022F**	**2023F**
$12,758,894	$8,993,353	$9,333,135	$9,944,549	$10,427,333
Problem Statement		**Solution Statement**		**Estimated / In-Service Date**
Homeowners wish to increase their gas load to their homes to accommodate more gas appliances.		BGE engineers, designs, and constructs gas services to deliver the new gas load to the customer's premises. This may involve extending the main and installing a service line from the main to the premises.		Monthly / Various

Project Name	60781: New Business Gas Commercial and Industrial Change /Relocation Small Medium			
2019A	**2020F**	**2021F**	**2022F**	**2023F**
$3,325,947	$3,024,895	$3,223,475	$3,284,780	$3,445,246
Problem Statement		**Solution Statement**		**Estimated / In-Service Date**
Commercial and Industrial customers wish to increase/relocate their existing gas load to their premises to accommodate more gas load.		BGE engineers, designs, and constructs gas services to deliver the new gas load to the customer's premises. This may involve extending the main and installing a service line from the main to the premises.		Monthly / Various

Project Name	60782: New Business Gas Residential New			
2019A	**2020F**	**2021F**	**2022F**	**2023F**
$18,382,409	$18,675,631	$19,629,491	$20,618,544	$22,219,395
Problem Statement		**Solution Statement**		**Estimated / In-Service Date**
New residents, real estate developers and builders in Maryland request gas main, services and meters for new homes and developments. Ongoing large scale projects include Tanyard Cove, Monarch Glenn Gas Approach Main, Martin Farms, Two Rivers and Rolands Height.		BGE engineers, designs, and constructs gas services to deliver the new gas load to the customer's premises. This may involve extending the main and installing a service line from the main to the premises.		Monthly / Various

Project Name	60783: New Business Gas Commercial and Industrial Conversion			
2019A	**2020F**	**2021F**	**2022F**	**2023F**
$1,234,254	$6,262,787	$3,362,100	$3,920,406	$4,618,874
Problem Statement		**Solution Statement**		**Estimated / In-Service Date**
Commercial and Industrial customers wish to switch their current fuel source from electric, propane, or oil that is used for heating or powering machinery to more cost efficient, natural gas.		BGE engineers, designs, and constructs gas services to deliver the new gas load to the customer's premises. This may involve extending the main and installing a service line from the main to the premises.		Monthly / Various

Project Name	60784: New Business Gas Residential Conversion			
2019A	**2020F**	**2021F**	**2022F**	**2023F**
$5,933,679	$7,187,025	$8,253,900	$8,879,403	$9,839,971
Problem Statement		**Solution Statement**		**Estimated / In-Service Date**
Residential customers wish to switch their current fuel source from electric, propane, or oil that is used for heating or cooking to more cost efficient, natural gas.		BGE engineers, designs, and constructs gas services to deliver the new gas load to the customer's premises. This may involve extending the main and installing a service line from the main to the premises.		Monthly / Various

Project Name	60788: New Business Gas Commercial and Industrial New Large			
2019A	**2020F**	**2021F**	**2022F**	**2023F**
$2,689,150	$1,937,375	$2,568,562	$2,789,082	$2,775,377
Problem Statement		**Solution Statement**		**Estimated / In-Service Date**
New Commercial and Industrial customers request gas mains, services, and meters for new projects. These large load customers may require main extensions, new regulator stations, and/or significant upgrades to existing BGE infrastructure. Pending jobs include Merriweather Development with mixed-use residential, retail, and commercial customers.		BGE engineers, designs, and constructs gas services to deliver the new gas load to the customer's premises. This may involve extending the main and installing a service line from the main to the premises.		Monthly / Various

Project Name	60789: New Business Gas Commercial and Industrial Change /Relocation Large			
2019A	**2020F**	**2021F**	**2022F**	**2023F**
$407,673	$823,897	$904,045	$914,191	$1,102,907
Problem Statement		**Solution Statement**		**Estimated / In-Service Date**
Existing gas Commercial and Industrial customers request changes, upgrades, or relocation of mains, services, and meters for projects. Pending jobs include the Baltimore Convention Center.		BGE engineers, designs, and constructs gas services to deliver the new gas load to the customer's premises. This may involve extending the main and installing a service line from the main to the premises.		Monthly / Various

Project Name	60791: New Business Gas Commercial and Industrial New Small Medium			
2019A	**2020F**	**2021F**	**2022F**	**2023F**
$6,855,135	$7,109,029	$7,452,830	$7,478,449	$7,708,749
Problem Statement		**Solution Statement**		**Estimated / In-Service Date**
New Commercial and Industrial customer requests for new gas mains, services and meters for gas load.		BGE engineers, designs, and constructs gas services to deliver the new gas load to the customer's premises. This may involve extending the main and installing a service line from the main to the premises.		Monthly / Various

Project Name	61463: New Business Gas Tradepoint Atlantic			
2019A	**2020F**	**2021F**	**2022F**	**2023F**
$2,822,336	$1,254,124	$828,337	$623,792	$699,163
Problem Statement		**Solution Statement**		**Estimated / In-Service Date**
New commercial and industrial customer(s) request gas main(s), service(s) and meter(s) for new projects. New Business has seen an uptick in the volume of jobs. Pending jobs include Volkswagen.		BGE engineers, designs, and constructs the gas infrastructure , service(s) and meter(s) to deliver the requested gas load(s) to the customer.		Monthly / Various

E. Outdoor Lighting

Project Name	60795: Buried Outdoor Lighting Cable Replacement - Planned			
2019A	**2020F**	**2021F**	**2022F**	**2023F**
$6,258,030	$4,107,500	$4,008,631	$4,539,887	$4,607,124
Problem Statement		**Solution Statement**		**Estimated / In-Service Date**
An outdoor lighting cable fails leading to a decision that the cable has exceeded its useful life.		The cable is replaced.		Monthly / Various

Project Name	60798: Street Lighting Installs - Utility Owned			
2019A	**2020F**	**2021F**	**2022F**	**2023F**
$421,252	$845,780	$919,979	$1,035,084	$1,066,035
Problem Statement		**Solution Statement**		**Estimated / In-Service Date**
A municipal agency or incorporated association of local residents requests the installation of a new unmetered overhead or underground fed street light.		The street light is installed pursuant to the Service Tariff.		Monthly / Various

Project Name	60800: Street Lighting Changes - Utility Owned			
2019A	**2020F**	**2021F**	**2022F**	**2023F**
$2,961,619	$1,846,674	$1,915,263	$2,062,997	$2,150,561
Problem Statement		**Solution Statement**		**Estimated / In-Service Date**
A municipal agency or incorporated association of local residents requests the changeout or conversion of an unmetered overhead or underground fed street light.		The street light is changed out or converted pursuant to the Service Tariff.		Monthly / Various

Project Name	60801: Private Area Lighting Installs			
2019A	**2020F**	**2021F**	**2022F**	**2023F**
$2,907,373	$4,505,804	$4,875,793	$6,280,548	$7,251,237
Problem Statement		**Solution Statement**		**Estimated / In-Service Date**
A customer requests the installation of a new private area light.		The private area light is installed pursuant to the Service Tariff.		Monthly / Various

Project Name	60802: Private Area Lighting Changes			
2019A	**2020F**	**2021F**	**2022F**	**2023F**
$2,308,873	$5,341,643	$5,392,114	$5,842,986	$4,082,620
Problem Statement		**Solution Statement**		**Estimated / In-Service Date**
A customer, municipal agency or incorporated association of local residents requests changeout or conversion of company-owned, unmetered, overhead or underground supplied, private area lighting.		The private area light is changed out or converted per the Service Tariff.		Monthly / Various

Project Name	60803: Outdoor Lighting Cable Associated with Customer Owned Street Lights			
2019A	**2020F**	**2021F**	**2022F**	**2023F**
$1,434,897	$1,819,193	$1,827,621	$2,139,028	$2,235,442
Problem Statement		**Solution Statement**		**Estimated / In-Service Date**
Additional BGE street light cable may be necessary to supply a customer-owned street light.		Street light cable is installed to supply a customer-owned street light.		Monthly / Various

Project Name	61090: Smart Lighting			
2019A	**2020F**	**2021F**	**2022F**	**2023F**
$347,457	$1,756,119	$844,150	$909,638	$927,641
Problem Statement		**Solution Statement**		**Estimated / In-Service Date**
BGE needs to innovate to provide better solutions for our customers. New technologies can improve the efficiency, reliability and long-term maintenance costs of outdoor lighting.		Research new technologies and implement where business case benefit is realized. Examples include smart lighting controls, outage mapping, smart fixtures/sensors and related software.		Monthly / Various

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F. Storm

Project Name	61414: Minor Storm Capital			
2019A	**2020F**	**2021F**	**2022F**	**2023F**
$9,611,664	$5,080,929	$5,192,972	$5,377,957	$5,499,621
Problem Statement		**Solution Statement**		**Estimated / In-Service Date**
Minor storms cause outages to BGE customers and damage to distribution equipment.		BGE crews restore electric service and replace damaged equipment due to minor storms.		Monthly / Various

G. Tools

Project Name	60099: Substation Tools Capital			
2019A	**2020F**	**2021F**	**2022F**	**2023F**
$1,717,794	$1,517,544	$663,732	$680,309	$697,340
Problem Statement		**Solution Statement**		**Estimated / In-Service Date**
New and replacement tools are necessary to operate and maintain substations.		Provide capital tools (defined as greater than $500) to substation field personnel.		Monthly / Various

Project Name	60103: Overhead Distribution Tools Capital			
2019A	**2020F**	**2021F**	**2022F**	**2023F**
$1,252,460	$1,000,851	$1,061,217	$1,051,493	$1,116,807
Problem Statement		**Solution Statement**		**Estimated / In-Service Date**
New and replacement tools are necessary to operate and maintain the overhead distribtion system.		This capital tool project is for the purchase of PPE, tools, safety equipment and instruments greater than $500 per item for the employees in this department. Provide capital tools (defined as greater than $500) to distribution field personnel.		Monthly / Various

Project Name	60107: Gas Distribution Tools Capital			
2019A	**2020F**	**2021F**	**2022F**	**2023F**
$774,927	$1,707,991	$1,747,113	$1,790,750	$1,835,577
Problem Statement		**Solution Statement**		**Estimated / In-Service Date**
New and replacement tools are necessary to operate and maintain the gas distribution system.		Funding identified for stock and non-stock specialty tools needed to operate transmission/distribution pipelines. Provide capital tools (defined as greater than $500) to gas distribution field personnel.		Monthly / Various

IV. O&M Category Cashflows and Functions

A. Corrective Maintenance – Distribution

Category	2019A	2020F	2021F	2022F	2023F
Corrective Maintenance – Distribution	$58,945,131	$62,493,666	$64,922,207	$67,229,034	$69,568,296

- Corrective Maintenance – Distribution is comprised of work to repair defective distribution material and equipment identified through inspection programs included in BGE's O&M manual filed with the Maryland PSC pursuant to the Code of Maryland Regulation (COMAR) 20.50.12,11. It also includes response to emergent events and repair of material and equipment identified through daily operation of the electric system.
- Major components of this category include emergency response (specifically, first responder assessment), routine maintenance and repairs associated with cable faults, transformers, capacitors, distribution automation (DA) equipment, and wires.
- Corrective maintenance occurs after outage reporting or as a result of inspections and is aimed at repairing defective equipment so it can perform its intended function to provide safe and reliable service to our customers.
- As a rule, if the specific equipment or component requiring maintenance has degraded or failed, the action required to repair it is classified as corrective maintenance.
- The overall trend in Corrective Maintenance – Distribution expense increases year to year primarily driven by labor cost increases and increases in indirect costs.

B. Corrective Maintenance – Substation

Category	2019A	2020F	2021F	2022F	2023F
Corrective Maintenance – Substation	$9,150,728	$6,682,627	$6,758,566	$6,447,666	$6,114,748

- Corrective Maintenance – Substation funds are used to perform corrective maintenance on relay and substation assets, on substation facilities (including roofs, fences, and storm water management ponds), to install mobile transformers during emergent events, and to manage environmental risks through oil leak mitigation and response.
- BGE is investing in updating substation assets with the expectation of an overall flat to slight decline in Corrective Maintenance – Substation costs over the 2020 to 2023 time period as a result.

C. Preventative Maintenance – Distribution

Category	2019A	2020F	2021F	2022F	2023F
Preventative Maintenance – Distribution	$9,279,714	$8,417,525	$7,572,157	$8,255,645	$7,479,081

- This category includes work performed as a preventative measure, including inspections and testing, to support the reliability and safety of distribution equipment and infrastructure. The programs through which this work is performed are included in BGE's O&M Manual filed with the Maryland PSC in compliance with COMAR 20.50.12.10.
- For the most part, the workload and resulting costs in this category are flat, except for the Contact Voltage program where we currently anticipate performing a quality assurance audit in 2020 and 2022, but not in 2021 and 2023.

D. Preventative Maintenance – Protection & Control

Category	2019A	2020F	2021F	2022F	2023F
Preventative Maintenance – Protection & Control	$1,007,517	$1,136,055	$1,139,545	$1,182,961	$1,145,390

- This category maximizes asset performance and effectiveness to support the safe and reliable operation of the electric system through performing preventive maintenance activities on distribution-level relay equipment. This work includes calibration and functional control checks of relay equipment as detailed in BGE's O&M Manual filed with the Maryland PSC.
- Distribution preventative maintenance is generally governed by COMAR 20.50.12.10.
- The trend in expense is flat for this category, and work levels are not anticipated to change over the time horizon shown. Maintenance benefits obtained from the replacement of aging relay equipment are expected to offset inflation in this area.

E. Preventative Maintenance – Substation

Category	2019A	2020F	2021F	2022F	2023F
Preventative Maintenance – Substation	$2,927,119	$4,261,554	$4,409,075	$4,540,580	$4,786,676

- This category maximizes asset performance and effectiveness to support the safe and reliable operation of the electric system through performing preventive maintenance activities on distribution-level substation equipment. This work includes inspection, testing, calibration, lubrication, and functional checks. This work drives a portion of the corrective maintenance workload. The work varies widely because the equipment in a distribution substation varies widely.
- Preventative Maintenance – Substation work supports the safe and effective operation of electric substations through monthly or bi-monthly substation inspections.
- Distribution-level work is governed predominantly by COMAR 20.50.12.10.
- The increase from 2019 to 2020 is due to the start of two new maintenance programs. The trend in expense is very slightly up for this category and work levels aren't anticipated to change over the time horizon shown. Inflation will drive the increase that is shown in this category.

F. New Business – Electric

Category	2019A	2020F	2021F	2022F	2023F
New Business – Electric	$112,067	$254,129	$257,330	$263,756	$270,359

- New Business – Electric includes training of new BGE personnel to plan, design, and construct New Business gas and electric infrastructure. This also includes Department of Transportation and PSC-mandated training for existing BGE personnel.
- New Business – Electric also includes funding for a third-party to survey BGE customers for New Business satisfaction, both residential and commercial.

G. Outdoor Lighting

Category	2019A	2020F	2021F	2022F	2023F
Outdoor Lighting	$4,390,366	$4,164,529	$4,125,048	$4,353,692	$4,628,326

- The decrease from 2019 to 2020 is driven by fewer planned customer-owned LED conversions. The overall trend in this category is slightly up due to increased customer interest in customer-owned lighting conversions to LED and inflation.
- The category includes installation, change and maintenance of customer-owned unmetered street lighting services (for municipalities or in an unincorporated community).
- Lighting design that cannot be capitalized (for customer-owned lights) is also included in this category.

H. Storm

Category	2019A	2020F	2021F	2022F	2023F
Storm	$41,866,473	$36,178,836	$37,410,339	$38,512,587	$39,399,132

- This category supports the repairs and back office coordination support for the restoration of BGE's electric distribution and transmission system due to minor and major weather/storm activity.
- Expenditure levels in the storm category are based on the five-year average of minor storm costs, plus an additional $10.2 million per year for major storm O&M. The 2020 budget reflects that five-year average, plus $10.2 million, and the remainder of the years trend up slightly for inflation. The 2019 storm season was very active resulting in higher than average minor storm costs. There were no major storms in 2019.

I. Tools

Category	2019A	2020F	2021F	2022F	2023F
Tools	$4,871,308	$6,586,986	$6,535,841	$6,079,143	$6,109,010

- Tools, instruments, and personal protective equipment are used during training, installing new infrastructure, and maintaining existing infrastructure.
- The BGE tool category covers gas and electric distribution; the only difference from the capital category is that these costs are for items that cost less than $500, including flame resistant personal protective equipment.
- The overall trend over is flat to very slightly up due to inflation. However, the Gas Distribution Tools project drops significantly after 2021. This is a result of the addition of approximately 8 gas crew trucks per year in 2020 and 2021. Each truck will be equipped with approximately $85,000 of tools that are charged to this project, resulting in approximately $680,000 per year of additional O&M tool expense.
- The O&M account also includes the testing, inspecting, and repairing of tools.

V. Appendices – O&M Project Details

Corrective Maintenance - Distribution
Major Cost Drivers by Project

Instructions:

List actual O&M expenses by project for 2019; provide a high-level description of the types of costs within the project, and discuss the key drivers of each type.

#	Project	Description and Key Drivers	2019 Actuals	2020 Forecast	2021 Forecast	2022 Forecast	2023 Forecast
1	60473: Buried Primary Fused Faults	Cost for remediation of Primary fused faults which includes material and labor.	1,016,620	2,135,069	2,212,284	2,311,218	2,415,658
2	60475: Cable Faults Secondary Residential	Cost for remediation of Secondary Residential grade fused faults which includes material and labor.	889,000	1,020,352	1,062,131	1,104,832	1,146,472
3	60489: Routine Maintenance Projects	Costs for routine overhead and underground maintenance projects which includes material and labor.	2,021,495	2,210,965	2,241,436	2,284,058	2,336,917
4	60490: Equipment Diagnostic & Repair	Costs for repairs, test and refurbishment of distribution equipment which includes material and labor.	869,124	1,597,867	1,658,262	1,711,875	1,742,587
5	60491: Capacitor O&M	Costs for repairs and/or replacement of distribution capacitors which includes material and labor.	1,064,663	1,822,044	1,869,588	1,914,762	1,991,939
6	60493: Distribution Automation O&M	Cost for remediation of issues on distribution automation equipment which includes material and labor.	1,071,484	1,389,446	1,449,297	1,583,156	1,652,269
7	60494: Voltage Quality House Calls O&M	Cost for remediation of customer issues related to voltage quality which includes material and labor.	1,444,264	1,389,076	1,414,540	1,453,740	1,509,617
8	60502: Contact Voltage Program	Costs for remediation of safety issues related to contact voltage which includes material and labor.	1,341,914	1,042,233	1,385,132	808,308	817,173
9	60504: C Order - Damages - Electric	Costs for remediation of damages to BGE's equipment which includes material and labor.	1,817,496	1,518,719	1,580,428	1,642,505	1,694,540
10	60505: Distribution Reactive Workload	Costs for remediation of BGE equipment due to weather (non-storm), vegetation, environmental or various other causes which includes material and labor.	4,698,534	3,798,338	3,870,659	3,935,832	3,961,162
11	60506: Overhead Lines RM43	Cost for remediation of issues identified during inspections conducted specifically per the Maryland Reliability Standards (RM43) Overhead Line Inspection Program guidelines. Work identified within this program includes replacing arresters, conductors, cross arms, and animal guards which includes material and labor.	1,655,630	1,213,091	1,246,461	1,284,454	1,321,143
12	60805: Outdoor Lighting Preservation - Diagnosis and Repair Customer Owned	Costs for the diagnosis and repair of customer owned outdoor lighting which includes material and labor.	3,136,801	2,545,450	2,770,066	2,570,175	2,678,535
13	60806: Outdoor Lighting Preservation - Diagnosis and Repair Utility Owned	Costs for the diagnosis and repair of BGE owned outdoor lighting which includes material and labor.	2,637,628	2,198,435	2,225,979	2,517,771	2,755,712
14	61138: Routine Operations Projects	Costs for routine overhead and underground operational tasks such as inspect and patrol, feeder inspections, switching and yard work which includes material and labor.	17,993,283	20,612,019	21,136,478	22,680,092	23,420,800
15	61163: Restore Overhead -Emergency Response	Costs for the initial assessment and remediation of emergent issues on BGE's electric distribution system which includes material and labor.	14,647,793	15,808,133	16,494,610	17,047,004	17,658,965
16	15 Projects with no year >= $1 million		2,639,402	2,192,429	1,627,556	1,695,593	1,740,370
17	**Total**		**$ 58,945,131**	**$ 62,493,666**	**$ 64,244,907**	**$ 66,545,375**	**$ 68,843,859**

Corrective Maintenance - Substation
Major Cost Drivers by Project

Instructions:

List actual O&M expenses by project for 2019; provide a high-level description of the types of costs within the project, and discuss the key drivers of each type. Also list forecasted O&M expenses for 2020-2023.

#	Project	Description and Key Drivers	2019 Actuals	2020 Forecast	2021 Forecast	2022 Forecast	2023 Forecast
1	60048: Distribution Substation Maintenance	PM programs identify emergent substation facilities issues to be repaired. This includes distribution facilities such as roof, fence, stormwater ponds, gates, and other non-high voltage assets.	971,311	1,204,728	1,360,283	982,744	873,144
2	60534: Substation O&M Corrective Maintenance Tasks - Distribution Other Equipment	This project covers repair work on breakers (air, gas, oil, vacuum); transformers; air break Switches; surge arrestors, capacitors and similar substation equipment classified as a distribution asset. If equipment is not properly maintained, there could be impacts to system reliability. Corrective maintenance is necessary to make the system safe for operations.	3,611,571	3,241,631	3,273,011	3,301,142	3,044,282
3	60536: Substation O&M Corrective Maintenance Tasks - Environmental Response	This project covers environmental clean-up for leaking equipment. The 2019 Waugh Chapel B41 breaker failure and oil remediation caused program to exceed historical spending levels.	1,960,188	382,558	382,918	395,885	413,108
4	7 Projects with no year >= $1 million		2,607,658	1,853,710	1,742,354	1,767,895	1,784,214
5	**Total**		**$ 9,150,728**	**$ 6,682,627**	**$ 6,758,566**	**$ 6,447,666**	**$ 6,114,748**

Preventative Maintenance - Distribution
Major Cost Drivers by Project

Instructions:

List actual O&M expenses by project for 2019; provide a high-level description of the types of costs within the project, and discuss the key drivers of each type. Also list forecasted O&M expenses for 2020-2023.

#	Project	Description and Key Drivers	2019 Actuals	2020 Forecast	2021 Forecast	2022 Forecast	2023 Forecast
1	61017: Pole Inspection & Treatment Preventative Maintenance	Perform inspections of wood poles on the electric distribution system. Identify defects that affect the pole strength and treat, reinforce, restore, or replace pole if required. This project is labor.	2,997,256	2,770,901	2,783,107	2,811,111	2,785,610
2	61020: Contact Voltage Inspections Preventative Maintenance	Detect and remediate contact voltages of 6V and higher inside and outside of the Contact Voltage Risk Zones (CVRZs). Test equipment for sensitivity to voltage levels up to 6 volts or higher on publicly accessible equipment. All equipment shall be repaired if greater than 1 volt. This project is labor.	2,635,549	2,165,527	1,302,861	1,868,785	1,298,572
3	22 Projects with no year >= $1 million		3,646,909	3,481,097	3,486,189	3,575,749	3,394,899
4	**Total**		**$ 9,279,714**	**$ 8,417,525**	**$ 7,572,157**	**$ 8,255,645**	**$ 7,479,081**

Preventative Maintenance - Protection & Control
Major Cost Drivers by Project

Instructions:

List actual O&M expenses by Project for 2019; provide a high-level description of the types of costs within the Project, and discuss the key drivers of each type. Also list forecasted O&M expenses for 2020-2023. Only yellow cells can be modified.

#	Project	Description and Key Drivers	2019 Actuals	2020 Forecast	2021 Forecast	2022 Forecast	2023 Forecast
1	61029: Relay O&M Preventative Maintenence Tasks - Distribution	This work includes calibration and functional control checks of relay equipment as detailed in the O&M manual filed with the Maryland PSC.	1,007,517	1,136,055	1,139,545	1,182,961	1,145,390
2	No Projects with no year >= $1 million						
3	**Total**		**$ 1,007,517**	**$ 1,136,055**	**$ 1,139,545**	**$ 1,182,961**	**$ 1,145,390**

Preventative Maintenance - Substation
Major Cost Drivers by Project

Instructions:

List actual O&M expenses by project for 2019; provide a high-level description of the types of costs within the project, and discuss the key drivers of each type. Also list forecasted O&M expenses for 2020-2023.

#	Project	Description and Key Drivers	2019 Actuals	2020 Forecast	2021 Forecast	2022 Forecast	2023 Forecast
1	61032: Substation O&M Preventative Maintenance Tasks - Distribution Other Equipment	This program inspects and tests the various distribution equipment within substations other than distribution breaker and distribution transformer equipment. This includes equipment such as batteries, switches, reactors and backup generators. Infrared testing and fire system inspections are also included in this project. Distribution preventative maintenance tasks are mandated by regulation through the PSC O&M Manual. This project is predominantly labor.	1,320,640	2,238,698	2,320,104	2,415,360	2,500,668
2	5 Projects with no year >= $1 million		1,606,479	2,022,856	2,088,971	2,125,220	2,286,008
3	**Total**		**$ 2,927,119**	**$ 4,261,554**	**$ 4,409,075**	**$ 4,540,580**	**$ 4,786,676**

New Business - Electric
Major Cost Drivers by Project

Instructions:

List actual O&M expenses by project for 2019; provide a high-level description of the types of costs within the project, and discuss the key drivers of each type. Also list forecasted O&M expenses for 2020-2023.

#	Project	Description and Key Drivers	2019 Actuals	2020 Forecast	2021 Forecast	2022 Forecast	2023 Forecast
1	4 Projects with no year >= $1 million		112,067	254,129	257,330	263,756	270,359
2	**Total**		**$ 112,067**	**$ 254,129**	**$ 257,330**	**$ 263,756**	**$ 270,359**

Outdoor Lighting
Major Cost Drivers by Project

Instructions:

List actual O&M expenses by project for 2019; provide a high-level description of the types of costs within the project, and discuss the key drivers of each type. Also list forecasted O&M expenses for 2020-2023.

#	Project	Description and Key Drivers	2019 Actuals	2020 Forecast	2021 Forecast	2022 Forecast	2023 Forecast
1	60797: Outdoor Lighting Streetlight Installs	Labor and material cost to install unmetered customer-owned street lights at the request of the customer.	1,531,624	2,212,255	2,295,108	2,406,664	2,566,506
2	60799: Outdoor Lighting Streetlight Changes - Customer Owned	Labor and material cost to change/convert unmetered customer-owned street lights at the request of the customer.	2,791,515	1,795,368	1,771,881	1,887,601	2,000,559
3	3 Projects with no year >= $1 million		67,227	156,906	58,059	59,427	61,261
4	**Total**		**$ 4,390,366**	**$ 4,164,529**	**$ 4,125,048**	**$ 4,353,692**	**$ 4,628,326**

Storm
Major Cost Drivers by Project

Instructions:
List actual O&M expenses by project for 2019; provide a high-level description of the types of costs within the project, and discuss the key drivers of each type. Also list forecasted O&M expenses for 2020-2023.

#	Project	Description and Key Drivers	2019 Actuals	2020 Forecast	2021 Forecast	2022 Forecast	2023 Forecast
1	61413: Minor Storm O&M	O&M costs associated with the coordination and restoration of BGE's Electric system due to weather. This project will include work such as repairing wires or cable, vegetation management, replacing damaged equipment and emergency operations center support staff. This project consists of labor.	41,477,831	25,978,836	27,210,308	28,312,390	29,199,074
2	61418: Major Storm O&M	O&M costs associated with the coordination and restoration of BGE's Electric system due to a significant weather event. This project will include work such as repairing wires or cable, vegetation management, replacing damaged equipment and emergency operations center support staff. This project consists of labor.	388,642	10,200,000	10,200,031	10,200,197	10,200,058
3	No Projects with no year >= $1 million						
4	**Total**		**$ 41,866,473**	**$ 36,178,836**	**$ 37,410,339**	**$ 38,512,587**	**$ 39,399,132**

Tools
Major Cost Drivers by project

Instructions:

List actual O&M expenses by project for 2019; provide a high-level description of the types of costs within the project, and discuss the key drivers of each type. Also list forecasted O&M expenses for 2020-2023.

#	Project	Description and Key Drivers	2019 Actuals	2020 Forecast	2021 Forecast	2022 Forecast	2023 Forecast
1	60096: Underground Tools O&M	This project is primarily personal protective equipment (PPE) for employees. This project also includes hand tools and batteries.	604,626	1,291,119	1,007,582	1,283,637	1,065,212
2	60104: Overhead Tools O&M	This project is primarily personal protective equipment (PPE) for employees. This project also includes hand tools, batteries and hotline tools (shotgun sticks, hot sticks, etc.).	2,131,764	2,279,857	2,419,857	2,352,613	2,548,927
3	60109: Gas Distribution Tools - O&M	This project is primarily personal protective equipment (PPE) for employees. This project also includes hand tools. Testing and calibration of instruments and equipment are also included.	1,462,152	2,330,772	2,406,034	1,722,982	1,766,114
4	5 Projects with no year >= $1 million		672,766	685,238	702,368	719,911	728,757
5	**Total**		**$ 4,871,308**	**$ 6,586,986**	**$ 6,535,841**	**$ 6,079,143**	**$ 6,109,010**

Before the Maryland Public Service Commission

Case No. _____

Prepared Direct Testimony of

A. Christopher Burton

On Behalf of

Baltimore Gas and Electric Company

May 15, 2020

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<u>Spending Summary</u>

The amounts set forth below represent the Multi-Year Plan capital and O&M budgeted amounts which are necessary to continue providing outstanding, safe and reliable gas service to customers.

Capital

Category	2021F	2022F	2023F
Gas Capacity Expansion	$14,793,986	$19,408,025	$20,379,473
Gas Infrastructure Modernization Program	$161,260,400	$164,846,843	$163,394,398
Gas System Performance	$73,721,586	$101,818,767	$83,726,152
Gas Corrective Maintenance - Capital	$44,416,434	$38,071,220	$32,331,406
Total Gas Executive Category (Capital)	**$294,192,406**	**$324,144,855**	**$299,831,429**

O&M

Category	2021F	2022F	2023F
Gas Corrective Maintenance - O&M	$53,265,395	$49,712,320	$46,988,075
Gas Preventative Maintenance	$38,288,596	$38,498,463	$39,547,607
Total Gas Executive Category (O&M)	**$91,553,991**	**$88,210,783**	**$86,535,682**

I. INTRODUCTION AND PURPOSE

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. My name is A. Christopher Burton and my business address is Baltimore Gas and Electric Company ("BGE" or the "Company"), 1699 Leadenhall St., Baltimore, MD 21230.

Q. WHAT IS YOUR POSITION WITH BGE?

A. I am the Vice President of Gas Distribution for BGE. In that role I oversee the day-to-day operations and the long-term planning of the natural gas distribution and transmission systems of the Company, including oversight of safety, reliability, efficiency, and customer service.

Q. PLEASE DESCRIBE YOUR EDUCATIONAL BACKGROUND.

A. I earned a Bachelor of Science Degree in Electrical Engineering from Virginia Polytechnic and State University. I also have a Master's Degree in Business Administration from the University of Baltimore.

Q. PLEASE DESCRIBE YOUR BUSINESS EXPERIENCE.

A. I have worked for BGE since 1983. In my years at BGE, I have held numerous technical and leadership positions. Most recently I served as Vice President of Electric Distribution where I led the efforts of BGE employees and contractors in daily electric distribution operations, construction and maintenance activities, and gas first response. In that role I was also responsible for design and engineering activities for new business and the reliability of the electric distribution system. Additionally, I have held senior leadership positions in strategic planning and development, customer accounts and metering services, gas and electric operations and planning, and asset management services. I have also led large Company projects including BGE's transition to customer choice and the implementation of smart grid. I am a past chairman of the Power Engineering Society, Baltimore Chapter, and I currently serve as chair of the STEM committee for the Baltimore Area Council Boy Scouts of America. I am also a past member of the board of directors for St. Vincent de Paul of Baltimore, and a current board member of the St. Joseph Medical Center Foundation. I am a graduate of Leadership Baltimore County and a member of the Greater Baltimore Committee's Leadership Class of 2014.

Q. HAVE YOU PREVIOUSLY TESTIFIED BEFORE THE MARYLAND PUBLIC SERVICE COMMISSION?

A. Yes. I testified before the Maryland Public Service Commission (the "Commission") in Case No. 9484 in support of BGE's application for adjustments to gas base rates. In addition, I testified before the Commission in Case No. 9468 in support of BGE's application for a second accelerated gas asset replacement plan known as the Strategic Infrastructure Development and Enhancement, or "STRIDE," program, and associated cost recovery mechanism. Finally, I have also appeared before the Commission on multiple occasions in legislative style hearings and at administrative meetings on a variety of subjects.

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

A. The purpose of my testimony is to provide support with respect to the gas business components of BGE's request for a Multi-Year Plan ("MYP"). My testimony provides an explanation of the gas operating areas of BGE and reviews gas capital and operations and maintenance ("O&M") expenditure categories as they relate to those areas. In addition, I will explain key initiatives and cost drivers that impact O&M and capital that are reflected in the current plan for the Gas Division for each of the years 2021 through 2023. For informational purposes, I have also included actual and projected capital and O&M costs for 2019 and 2020.

Q. COULD YOU PLEASE PROVIDE AN OVERVIEW OF THE CAPITAL AND O&M REQUESTS BEING MADE IN THIS PROCEEDING?

A. For the three-year period of 2021 through 2023, BGE is forecasting its total capital investments to be $918.2 million and its total O&M expenditures to be $266.3 million in the areas I am covering. As I'll explain in more detail later in my testimony, these investments and expenditures are important and necessary for BGE to operate and monitor its gas system, meet regulatory requirements and commitments, improve system performance, and continue to provide safe and reliable service to our gas customers.

Q. MR. BURTON, HAVE THE CAPITAL AND O&M PLANS DISCUSSED IN YOUR TESTIMONY BEEN ADJUSTED IN LIGHT OF THE COVID-19 PANDEMIC AND THE VARIOUS EXECUTIVE ORDERS ISSUED BY MARYLAND GOVERNOR HOGAN IN RESPONSE TO THE PANDEMIC?

A. No, they have not. Company Witness Vahos in Part 2 of his Direct Testimony discusses BGE's expectations about the impact of the pandemic and related executive orders on the Company's capital and O&M plans and how BGE expects any impacts will be addressed over the MYP period.

Q. HOW IS THE REMAINDER OF YOUR TESTIMONY ORGANIZED?

A. The remainder of my testimony begins with an overview of the Gas Division's areas of responsibilities as well as a general description of the BGE gas system followed by highlights of our performance accomplishments. I will then discuss the Gas Executive Category, focusing on an overview of the total capital investments first and, later, O&M expenditures. As part of my discussion, I also provide a more detailed view of each category of work that drives gas capital investments and O&M expenditures. This includes a description and overview of the type of work within the category, key drivers, the category historical spend for 2019, the forecast spend for 2020, and the Multi-Year Plan forecast for 2021 through 2023 along with spending trends, and how the plan was developed.

Q. ARE YOU SPONSORING ANY EXHIBITS IN THIS PROCEEDING?

A. Yes. I am sponsoring Exhibit ACB-1. This exhibit provides details regarding the capital and O&M plans my testimony supports.

II. OVERVIEW OF THE GAS DIVISION AND GAS SYSTEM

Q. MR. BURTON, PLEASE DESCRIBE THE GAS DIVISION'S RESPONSIBILITIES.

A. BGE's Gas Division is responsible for the planning, engineering, operation, maintenance, and control of BGE's gas distribution and transmission systems, including the monitoring of overall system health and operational performance. These activities not only involve gas distribution and transmission pipeline assets but also BGE's gas facilities, such as the Spring Gardens Liquefied Natural Gas ("SGLNG") Plant, district regulating stations, gate stations, and the gas control room. In addition, the Gas Division performs corporate gas emergency preparation, gas odor and emergency response efforts, supports gas system expansion, and manages BGE's accelerated gas asset replacement program, known as the STRIDE program. Finally, the Gas Division includes damage prevention for the Company – for both gas and electric areas of the business.

Regarding STRIDE and other program and project management, it is helpful to understand how the Gas Division and Technical Services Division, which is led by Company Witness Apte, work together. The Technical Services Division includes a Projects and Program management organization to manage STRIDE and certain other gas projects to improve overall system performance and reliability. Company Witness Apte discusses the Gas capital that he is responsible for in his Direct Testimony.

Q. COULD YOU PROVIDE AN OVERVIEW OF BGE'S GAS SYSTEM?

A. Certainly. BGE serves nearly 700,000 gas customers across a service territory of more than 800 square miles, which encompasses Baltimore City and all or parts of nine counties in central Maryland. BGE operates and maintains more than 150 miles of transmission-rated gas pipeline,[1] more than 7,400 miles of distribution main, over 6,300 miles of gas service, 643 district regulating stations (comprised of equipment that allows gas pressure to be reduced from a higher pressure system to a lower one), two peak-shaving plants, and twelve gate stations that connect upstream interstate pipelines to deliver gas to our customers.

[1]Gas transmission-rated pipe is very similar to distribution pipe, except that transmission-rated pipe is defined as main that operates at a higher material stress level compared to distribution main.

Q. PLEASE DESCRIBE THE OPERATING PRESSURE SYSTEMS. DOES BGE HAVE ANY LOW PRESSURE GAS INFRASTRUCTURE?

A. BGE has four main pressure systems:

- The Low Pressure ("LP") System has a maximum operating pressure of about 1/3 psig[2] (10" water column) and is the primary system for delivering gas to Baltimore City customers and customers in portions of Baltimore and Anne Arundel Counties, with several other smaller systems scattered throughout BGE's gas service territory. The LP System is the only BGE pressure system that operates at a utilization pressure threshold, meaning that no pressure regulation is used at the customer's premise. BGE has about 1,109 miles of LP main (15% of the gas distribution system) remaining on its system.[3]
- The Medium Pressure ("MP") System has a maximum operating pressure of 10 psig and consists of the large supply pipelines that deliver gas to the Baltimore City LP System through district regulating stations, with additional MP Systems scattered throughout the service territory as well. As a result of STRIDE and other programs, portions of the LP System, upon replacement, are being converted to the Company's MP System. BGE has about 614 miles of MP main (8% of the gas distribution system).
- The High Pressure ("HP") System has a maximum operating pressure of 99 psig and is BGE's most prevalent gas system, being the primary system for

[2] Pounds per square inch (gauge)
[3] From 2015-2019 BGE has made significant progress in reducing the amount of LP main on our system, eliminating 203 miles of LP main and moving customers to higher pressure systems. This is discussed in more detail later in my testimony.

most gas customers. The HP System provides gas to most customers outside of the Baltimore City area, and, as a result of STRIDE and other programs, portions of the LP System are being converted to HP through replacement. BGE has about 5,269 miles of HP main (71% of the gas distribution system).

- The Over High Pressure ("OHP") System consists of a group of systems with various maximum operating pressures,[4] all exceeding the maximum HP System pressure. The OHP System is comprised of both distribution and transmission main and delivers gas from BGE's gate stations across our system to be delivered to lower pressure systems via district regulating stations. BGE has about 451 miles of OHP distribution main (6% of the gas distribution system) and 152 miles of OHP transmission main.

Q. CAN YOU PROVIDE SOME INFORMATION ON THE AGE OF BGE'S NATURAL GAS SYSTEM?

A. Yes. Although BGE works diligently to identify and replace or repair aging gas system infrastructure, many of BGE's gas system assets have been in service for a significant period of time, given the fact that BGE is the nation's first gas utility, founded in 1816. About one-third of the Company's gas distribution mains, one-quarter of gas services, and half of the transmission mains are over 50 years old. In addition, both peak-shaving plants were originally constructed more than 50 years ago. While age is not the only determining factor in the performance of gas system assets, it is a driver behind the amount of outmoded materials BGE currently has in

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[4] In general, these pressures range from 200 to 300 psig, although there is a 436 psig and 720 psig system as well.

service on its gas system. For example, approximately 15% of the Company's gas distribution system – encompassing 1,083 miles of gas main and over 75,000 services – consists of outmoded materials such as cast iron, bare steel, and copper.

I believe it is important to share this information because it provides context to the important work that the gas organization performs on a regular basis with respect to safety and customer reliability, as well as the environmental benefits that come from reducing aged infrastructure. This includes BGE's STRIDE program and other work that I describe later in my testimony.

Q. MR. BURTON, COULD YOU SUMMARIZE THE PROGRESS BGE HAS MADE WITH RESPECT TO REPLACING AGING INFRASTRUCTURE?

A. Yes. Over the last five years (2015-2019), BGE has retired 210 miles, or about 16%, of cast iron main and 19 miles, or about 55%, of bare steel main on the Company's system. As part of these retirements, BGE has made significant progress in reducing the LP System, eliminating over 200 miles of LP main (about 15%) over the same time period. The vast majority of this replacement work has been performed as part of BGE's Operation Pipeline program, which is a significant portion of BGE's STRIDE program. Both of these programs are discussed in more detail later in my testimony. These replacements not only eliminate the poorest performing gas mains, but also improve safety and reliability by adding safety features and bringing the gas system up to the Company's current standards and practices.

In addition to main replacement work, BGE has also been steadily replacing outmoded, poor performing gas services through STRIDE and other programs. Over the last five years, BGE has eliminated over 18,000 bare steel services, nearly

6,000 copper services, and over 20,000 pre-1970 ¾" high pressure steel services. Furthermore, LP service reductions over the same five-year period have been about 25,000 services.

BGE has also been focused on other pipeline infrastructure replacements. BGE has targeted some of its oldest transmission main, replacing about 3 miles of transmission main in the last five years, including 13% of BGE's oldest transmission pipeline. These replacements are made with stronger materials, allowing the new pipelines to no longer operate at transmission levels,[5] improving safety and reliability on the system. In addition, BGE has continued work to modernize and replace assets in the Company's gate stations[6], including security.

Finally, BGE has continued to update and replace assets and equipment in the Company's peak shaving facilities – the SGLNG Plant and the Notch Cliff Propane-Air ("NCPA") Plant – to ensure safe and reliable operation at these facilities. These projects include replacing and installing new process equipment and process instrumentation, emergency generators, fire protection and safety monitoring systems (such as gas detection and oxygen sensing) and building and security enhancements. For example, one of the projects involved replacing the salt bath heater at the SGLNG Plant that was 48 years old and demonstrating a decline in performance. In addition, we have also modernized communication systems that provide control and data acquisition for these facilities.

[5] Replacement of transmission mains with thicker and/or stronger materials result in the mains no longer operating at higher stress levels, which define pipe as transmission. Distribution mains operate with higher safety factors for the main.

[6] Gate Stations are located where BGE takes custody of gas deliveries from interstate pipelines. BGE measures, odorizes, and regulates pressures at these facilities.

Q. WOULD YOU DESCRIBE THE ENVIRONMENTAL BENEFITS OF THE REPLACEMENT WORK THE GAS DIVISION HAS PERFORMED?

A. Yes. Natural gas contains methane (CH_4) and carbon dioxide (CO_2), both known greenhouse gases ("GHGs"). Any time that natural gas leaks from BGE's gas distribution system infrastructure, methane and carbon dioxide escape into the atmosphere. As leaks are repaired and aging assets are replaced, the avenues by which the methane and carbon dioxide escape are closed off and less methane and carbon dioxide are introduced into the environment. Infrastructure replacement through STRIDE and other programs contains asset replacements that significantly reduce natural gas leaks as aged and sometimes leaky gas assets are replaced with new non-leaking assets. These replacements effectively reduce the amount of GHG emissions associated with gas leaks on BGE's system. From 2015 through 2019, these replacement efforts have reduced the annual GHGs by nearly 40,000 metric tons of carbon dioxide equivalent ("CO_{2e}"), which is the equivalent of GHG emissions from 8,600 passenger vehicles per year or 4.4 million gallons of gasoline consumed.

Q. ARE THERE OTHER PERFORMANCE ACCOMPLISHMENTS YOU WOULD LIKE TO DISCUSS?

A. Yes. First, the quantity of leak repairs on gas mains has been trending downward, with a 7% decrease between 2018 and 2019 alone. In fact, main leak repairs have decreased every year back to 2016 and are 20% lower than they were at their height in 2014. For service leak repairs,[7] BGE has also observed a decrease every year

[7] Service leak repair numbers do not include "fitter" leaks. Fitter leaks are leaks on above-ground equipment in the vicinity of the meter and are often plumbing-like in nature.

since their highest mark in 2016 – a 45% reduction in that time span. Between 2018 and 2019 alone, service leak repairs decreased nearly 18%. These reductions also accompany a reduction in the leak backlog of 44% compared to 2018. Thus, not only did BGE have less leak repairs in 2019, the Company also carried over less leaks discovered in 2019 to be repaired in 2020. While I am optimistic about the future of our leak trends, it is important to note that outside factors can influence the number of leaks on the system in any given year. This includes factors such as weather, construction and other ground disturbances, and where BGE is in its leak survey cycle. The current leak survey program surveys our entire system over a three-year period, meaning that annual variability can be expected based on the geographic location and breakdown of infrastructure materials being surveyed in any given year. That said, overall the aged infrastructure replacement programs, like those in STRIDE, are making an impact on the leaks observed on the system. Certainly, without these programs, the quantity of leak repairs would have been higher.

I am particularly proud of our Gas Emergency Response team as BGE continues to be among industry leaders in gas odor response. In 2019, for example, BGE responded to 99.97% of reported gas odors in 60 minutes or less – a particularly remarkable achievement considering the volume of gas odors – over 26,000 gas odor calls. It is important to note that BGE receives customer odor calls anytime a customer believes they smell gas or have a gas related issue. Not all of these calls result in a leak or issue with BGE's system, but can be related to other causes, such as customer equipment issues or sewer gas. Not only did BGE respond within 60 minutes 99.97% of the time, the average response time was 21.7 minutes

– the first time BGE has broken the 22-minute average. In fact, over the last five years, BGE had only 48 odor calls where the response time was greater than 60 minutes out of almost 141,000 odor calls – a 99.97% success rate. This is a significant improvement from 2012, when BGE had 88 odor calls with a response time over 60 minutes in just one year.[8]

BGE has made significant accomplishments and continues to improve the Company's damage prevention practices. From 2015 to 2019, BGE's gas damage rate (damages per 1,000 tickets) improved from 0.97 to 0.80 or 17% while continuing to be among the top of the industry. This demonstrates BGE's commitment to reducing risk of excavation damage, a top risk noted by the federal Pipeline and Hazardous Materials Safety Administration ("PHMSA") of the U.S. Department of Transportation ("DOT"), as well as increasing public safety and excavator education toward safe digging practices. BGE has also focused on minimizing electric damages on the system. We are committed as a company to continuing to improve damage prevention practices by implementing advanced analytics toward excavation and locating activity, as well as meaningfully engaging with the excavator community to promote safe digging practices.

Q. MR. BURTON, CAN YOU PLEASE DESCRIBE BGE'S CAPITAL AND O&M PLANNING PROCESS?

A. As discussed in Part 2 of the Direct Testimony of Company Witness Vahos, capital and O&M is separated into areas of spend, called categories, which are led by Category Managers. Within each category, there are projects which are owned by

[8] In 2012, BGE had a total of 20,593 odor calls, resulting in a 99.57% response rate within 60 minutes.

managers. These individuals identify the work and the associated capital and O&M requirements to run the business and create a five-year budget. These projects roll up to the Category Managers, who review the work and estimates, identify risks and changes to prior budgets and work with the project owners to make refinements. Ultimately, I review and approve the work plans and the associated capital and O&M requirements.

Q. PLEASE FURTHER DESCRIBE THE GAS EXECUTIVE CATEGORY FOR WHICH YOU ARE THE EXECUTIVE CATEGORY OWNER.

A. The Gas Executive Category includes five subcategories, three of which are capital only, one of which is solely O&M, and one of which is both. While I discuss these in more detail later in my testimony, I provide a brief summary below:

- Gas Capacity Expansion: Capital Gas Category for addressing inadequate capacity on the gas distribution and transmission systems.
- Gas Infrastructure Modernization Program ("GIMP"): Capital Gas Category for asset replacements made through BGE's STRIDE plan.
- Gas System Performance: Capital Gas Category for improving or maintaining the safety and reliability of the gas system, often through replacement of existing assets.
- Gas Corrective Maintenance: Capital and O&M Gas Category comprised of programs that address reactive repairs or maintenance to BGE's gas assets.
- Gas Preventative Maintenance: O&M Gas Category comprised of programs that target mitigating system risk and maintaining reliability through proactive maintenance.

Q. WHAT IS THE IMPACT OF CHANGES IN THE REGULATORY/LEGISLATIVE ENVIRONMENT WITH RESPECT TO BGE POLICY GOALS AND SUPPORTING PROGRAMS FOR GAS?

A. As changes occur in the regulatory environment, BGE assesses how the new regulations are to be met and, as necessary, we are required to adjust our standards and plans accordingly. The changes can occur through a variety of sources, and depending on the changes, this can result in changes to our plans. For example, there is currently a bill in Annapolis that could result in a change in where we locate service regulators, which could add costs to our existing work and perhaps even create a new program. The current three year forecasted plan does not take this into account, and adjustments would need to be made.

The gas industry has a strict regulatory environment with both federal (Title 49 Part 192 of the Code of Federal Regulations ("CFR")) and state regulations (the Code of Maryland Regulations ("COMAR")) Title 20, Subtitles 55 and 57). These regulations often are drivers and impact the course of business. BGE takes these regulations seriously, and often tries to stay ahead of the industry with company standards and practices that further enhance public safety as new regulations are considered. Over the years, changes in the regulations have resulted in Transmission Integrity Management Program ("TIMP") and Distribution Integrity Management Program ("DIMP") development obligations, operator qualifications, and new security guidelines.

III. CAPITAL INVESTMENTS

Q. MR. BURTON, PLEASE DESCRIBE THE PLANNING PROCESS FOR CAPITAL INVESTMENTS IN GAS.

A. Within the categories I discussed earlier, the majority of BGE's gas distribution and transmission system work is designed to address various types of need. Most of the program planning is done by evaluating long-term goals, historical patterns, and anticipated future requirements, all of which are used to set the plan. As part of the planning process, BGE Gas Division evaluates and plans:

- How to meet regulatory and code requirements and commitments, including both current and anticipated future changes, as set forth by PHMSA and/or the Commission (through the Public Utilities Article or COMAR).
- System performance needs, which includes safety and reliability related activities and aging infrastructure replacement efforts.
- Capacity expansion, which includes load growth, capacity requirements, poor supply, and supporting system performance activities.
- System maintenance activities, both preventative and corrective, which are either planned work over the course of the year, or anticipated work that will be discovered through other means, such as inspection programs.

Q. PLEASE PROVIDE MORE DETAIL ON THE DEVELOPMENT OF THE CAPITAL PLAN.

A. Most of the work in the capital categories is planned primarily based on historical system requirements. Thus, estimates for these programs are often based on historical trends within the program. Typically, most projects are scoped and known about a year ahead of time, unless they are very large.

As an example, BGE's Gas Infrastructure Improvement Program (often referred to as the Main Replacement Program) addresses gas main segments in most need of replacement, whether it be due to poor performance or engineering standards issues. For some of the work, BGE performs an annual risk assessment to analyze gas mains and determine those most fit for replacement; however, this assessment is done on an annual basis to ensure the latest data can be used. In addition, discovered field conditions lend further observations that result in main replacement opportunities. These conditions could lead to main replacement work that occurs with only a week's notice. However, despite the number of unknowns, BGE is able to draw on historical trends to develop a plan for future work.

Finally, the three-year operating plan for each category also assesses the overall capital plan and balances the availability of resources with the timing of work. Where applicable, work may be adjusted from one year to the next to ensure the plan is appropriately balanced from an overall cost and a resource perspective.

Q. WOULD YOU PLEASE SUMMARIZE THE FORECASTED GAS CAPITAL INVESTMENTS FOR 2021 THROUGH 2023 IN YOUR EXECUTIVE CATEGORY?

A. Certainly. The forecasted capital investments for the Gas Executive Category are set forth in the table below.

Category	Historical	Bridge	Multi-Year Plan Period		
	2019A	**2020F**	**2021F**	**2022F**	**2023F**
Gas Capacity Expansion	$10,952,173	$20,994,107	$14,793,986	$19,408,025	$20,379,473
Gas Infrastructure Modernization Program	$166,976,412	$159,678,746	$161,260,400	$164,846,843	$163,394,398
Gas System Performance	$69,812,643	$92,142,465	$73,721,586	$101,818,767	$83,726,152
Gas Corrective Maintenance - Capital	$46,999,412	$49,734,279	$44,416,434	$38,071,220	$32,331,406
Total Gas Executive Category (Capital)	**$294,740,640**	**$322,549,597**	**$294,192,406**	**$324,144,855**	**$299,831,429**

Q. WHAT ARE THE OVERALL TRENDS AND DRIVERS OVER THE NEXT THREE YEARS?

A. Overall, capital investments in the Gas Executive Category are relatively steady, with a minor fluctuation of about 10% in 2022 as a transmission line replacement project is planned for construction in that year. We will continue to address aging infrastructure with our replacement investments, including our STRIDE work, which is a significant portion of our overall forecast. In addition, much of the remaining work performed is required to maintain compliance with regulations and engineering standards. As the replacement programs and other compliance activities are at steady state, this results in a flat trend over the next three years.

Q. HOW DO THE 2021–2023 FORECASTED GAS CAPITAL INVESTMENTS COMPARE TO PREVIOUS YEARS?

A. The forecasts for 2021 through 2023 are very similar to BGE's historical spend of about $295 million in 2019 and forecasted $323 million in 2020. Similar to the three-year plan, fluctuations occur as we plan and perform larger projects over time.

III.A. CAPITAL INVESTMENTS – GAS CAPACITY EXPANSION

Q. MR. BURTON, PLEASE DESCRIBE THE GAS CAPACITY EXPANSION CATEGORY AND DISCUSS KEY DRIVERS FOR THE WORK.

A. The Gas Capacity Expansion category is designed to address inadequate capacity on the gas distribution and transmission systems. The work ensures system capacity and reliability for gas customers in all weather conditions down to design day conditions (the coldest day BGE plans for, defined as 2.7°F average temperature with 15 mph winds).

One of the primary key drivers for this work is collective load growth. As gas customer growth occurs over time, the gas system must be reinforced to ensure both new and existing customers have reliable service. In addition, other changes to the gas system configuration, generally driven by STRIDE pressure conversion work, warrant system reinforcements as well. The vast majority of aging infrastructure replacement investments have been focused on pressure conversion and eliminating LP (and in some cases MP) pressure systems. To accomplish this, the higher pressure systems need reinforcement to ensure the capacity is available as work continues. Finally, poor supply conditions or other system constraints can drive the need for reinforcement to maintain reliable service. [9]

Q. HOW IS THE GAS CAPACITY EXPANSION CATEGORY ORGANIZED AND WHAT DO THE PROJECTS INVOLVE?

A. The Gas Capacity Expansion category work is managed within the Gas System Reinforcement Program. Work generally involves extending, replacing, and/or

[9] Poor gas supply indicates that a customer or group of customers may not be able to maintain gas service in all conditions. This is typically as a result of inadequate pressures, either observed in the field or predicted.

connecting mains as well as installing new district regulator stations or upgrading existing ones.

Q. PLEASE DISCUSS THE CAPITAL INVESTMENT AND TRENDS FOR THE GAS CAPACITY EXPANSION CATEGORY FOR 2021 THROUGH 2023.

A. The forecasted capital investments for the Gas Capacity Expansion category are shown in the table below. With the exception of a decrease in 2021 (compared to 2020) and the increase from 2021 to 2022, the capital investment for Gas Capacity Expansion trends flat. Investment in this category fluctuates as various jobs are planned and prioritized with the timing of other work performed in the Gas business.

Category	Historical	Bridge	Multi-Year Plan Period		
	2019A	2020F	2021F	2022F	2023F
Gas Capacity Expansion	$10,952,173	$20,994,107	$14,793,986	$19,408,025	$20,379,473

Q. HOW DOES THE THREE-YEAR PLAN COMPARE TO THE 2020 FORECAST AND 2019 ACTUAL SPEND?

A. The three-year plan is in line with the forecasted investment of $21 million for 2020. The actual investment in 2019 is lower at $11 million; however, work in the category was lower in order to balance resources to other work in the Gas business.

Q. HOW WAS THE PLAN DEVELOPED FOR THIS CATEGORY?

A. BGE does not know all of the discrete jobs needed in the category; however, looking at trends of the type and volume of work required in the near term, such as in calendar year 2020, we can anticipate future needs for potential projects, while for projects that are anticipated several years out, it may not always be clear as to when the exact timing is required, particularly as growth can change over time. In addition, the Company will need to continue to invest to strengthen MP and HP systems to accommodate LP conversions over time as BGE continues its STRIDE asset replacement work.

III.B. CAPITAL INVESTMENTS – GAS INFRASTRUCTURE MODERNIZATION PROGRAM (GIMP)

Q. MR. BURTON, PLEASE DESCRIBE THE GIMP CATEGORY AND DISCUSS KEY DRIVERS FOR THE WORK.

A. Certainly. The GIMP category is designed to modernize BGE's gas distribution assets. This category differs from the Gas System Performance category in that it isolates and captures the costs related only to BGE's STRIDE program. The goals of the category are to improve safety and reliability of the gas system through replacement of outmoded and poor performing assets, focusing on meeting BGE's goals with respect to replacement timelines to meet STRIDE goals. Through STRIDE, BGE is committed to replacing approximately 48 miles of cast iron and bare steel main (including LP main and other ancillary mains) per year along with associated bare steel and copper services. In addition, BGE is replacing approximately 5,000-6,000 pre-1970 ¾" high pressure steel services per year. These assets represent the poorest performing assets on the system and collectively generate the greatest percentage of leaks on the system. Replacement of these assets not only improves the safety and reliability of BGE's gas system, but also has environmental benefits through GHG emission reduction. Looking ahead, the gas main and service projects in 2021 through 2023 that I discuss later in my testimony will result in a reduction of nearly 1.1 million metric tons of CO_{2e}, the GHG equivalent of a reduction of 1.3 billion pounds of coal burned. This category also is responsible for eliminating LP Systems as part of its replacement strategy and thereby furthering safety for BGE customers.

Q. HOW IS THE GIMP CATEGORY ORGANIZED AND WHAT DO THE PROJECTS INVOLVE?

A. The GIMP category work is managed in three parts. First, BGE Operation Pipeline is a program focused on the replacement of cast iron and bare steel main, along with bare steel and copper services through larger scale projects. This approach allows BGE to limit public disruption in a given area while eliminating all outmoded infrastructure in that area over a period of time, as opposed to returning multiple times to perform incremental replacement for varying assets. Furthermore, BGE's Operation Pipeline affords the opportunity to enhance system safety and reliability by converting from LP to higher pressure systems, which is done as replacements occur. The projects within the Operation Pipeline program typically involve installation of new mains and services, plumbing and meter work (for pressure conversions), and abandonment of existing mains and services.

The next two areas are very similar. The Proactive ¾" Service Renewal Program and Reactive ¾" Service Renewal Program are both service replacement programs designed to replace pre-1970 ¾" high pressure steel services, which is the asset with the highest leak rate on BGE's system. The first program replaces services proactively while the second replaces them when encountered in the field through leak survey, customer reported leaks, or other maintenance activities.

Q. PLEASE DISCUSS THE CAPITAL INVESTMENT AND TRENDS FOR THE GIMP CATEGORY FOR 2021 THROUGH 2023.

A. The forecasted capital investments for the GIMP category are shown in the table below. Investment in this category is forecasted to be relatively flat, as the volume of work is anticipated to be steady.

Category	Historical	Bridge	Multi-Year Plan Period		
	2019A	2020F	2021F	2022F	2023F
Gas Infrastructure Modernization Program	$166,976,412	$159,678,746	$161,260,400	$164,846,843	$163,394,398

Q. HOW DOES THE THREE-YEAR PLAN COMPARE TO THE 2020 FORECAST AND 2019 ACTUAL SPEND?

A. The three-year plan is in line with the forecasted investment of $160 million for 2020 and the actual spend of $167 million in 2019.

Q. HOW WAS THE PLAN DEVELOPED FOR THIS CATEGORY?

A. Overall, work in the category is fairly predictable and steady, as the STRIDE goals set the mileage and service targets moving forward. For Operation Pipeline, BGE analyzes the historic costs of the program and forecasts the anticipated spend to achieve the mileage targets. The Company takes a similar tact for both service replacement programs.

III.C. CAPITAL INVESTMENTS – GAS SYSTEM PERFORMANCE CATEGORY

Q. MR. BURTON, PLEASE DESCRIBE THE GAS SYSTEM PERFORMANCE CATEGORY AND DISCUSS KEY DRIVERS FOR THE WORK.

A. The Gas System Performance Category is designed to maintain or improve the safety and reliability of the gas distribution and transmission systems primarily though the replacement of assets. The goals of the category are to reduce risk by deploying strategies such as:

- Replacement of outmoded and poor performing assets to address leaks and other performance issues, supporting BGE's long-term goals of eliminating cast iron and bare steel mains, along with outmoded services;
- Reduction of the LP system and other overpressurization risks through additional layers of protection;
- Enhancement of system integration to improve reliability;
- Performance of work to meet DIMP and TIMP plans as well as application of current engineering standards and best practices; and
- Replacement and upgrading of plant equipment and facilities to improve safety and reliability.

Q. HOW IS THE CATEGORY ORGANIZED AND WHAT DO THE PROJECTS INVOLVE?

A. The Gas System Performance category work is managed among several areas and certain large and complex projects. A summary of the major areas are as follows:

- Gas Infrastructure Improvement Program: Often referred to as the Main Replacement Program, this program identifies and replaces or remediates main segments on the gas distribution system that typically have a history of poor performance or other risks that warrant replacement. These risks are identified through BGE's Optimain program or through field observation and can include issues such as leaks or breaks, corrosion or graphitization, shallow or exposed mains, or replacement of targeted main assets. The work in this program supplements BGE's goals of eliminating cast iron and bare steel main, along with reduction in LP System infrastructure.

- Non-STRIDE Gas Main Replacements: Similar to the BGE Operation Pipeline program under GIMP, this program addresses large scale main replacement work both in size and scope, but outside of the STRIDE program. In general, work in this program replaces cast iron or bare steel main with larger scale projects than those performed under the Main Replacement Program.
- Major Plant Infrastructure Program: Peak shaving facilities and other gas facility assets, such as distribution automation, require periodic replacement or upgrade to ensure safe and reliable operations. This program evaluates the performance and life cycle of equipment and replaces accordingly.
- Valve Replacement and Overpressurization Protection Program: This program addresses potential risks related to system overpressurization, mostly on the LP System. Work typically includes eliminating single points of separation between pressure systems, such as valves, district regulator station work to reduce overpressurization risk, and installation of additional overpressurization protection or monitoring.
- Distribution System Reliability: This program addresses regions of the distribution system identified with having potential reliability concerns, generally as a result of single point of failure conditions. Work typically involves installation of main to interconnect existing systems, or installation of district regulator stations.

Lastly, there are four major complex discrete projects in the three-year plan for the Gas System Performance category. These projects are as follows:

- Granite Pipeline Replacement: There are two projects in the plan targeting the replacement of portions of BGE's oldest transmission line, known as the Granite Line. By replacing these end of life mains, BGE will be able to employ stronger materials that will eliminate the transmission classification and construct the pipeline with modern construction techniques and engineering standards.
- Owings Mills Gate Station: The interstate transmission pipeline, TransCanada, delivers gas to BGE's system at numerous locations, including Owings Mills Gate Station. As a result of upgrade and replacement work being performed by TransCanada, BGE is rebuilding the gate station to accommodate these changes and installing necessary equipment to ensure safe and reliable operation.
- Downtown Pipeline: The project is to install a new, 30" pipeline in the downtown area of Baltimore City. The purpose of the pipeline is to begin the effort to replace large diameter cast iron main in the region.

Q. PLEASE DISCUSS THE CAPITAL INVESTMENT AND TRENDS FOR THE GAS SYSTEM PERFORMANCE CATEGORY FOR 2021 THROUGH 2023.

A. The forecasted capital investments for the Gas System Performance category is shown in the table below. Investment in this category is forecasted to vary year to year as a result of the timing of larger infrastructure projects such as Granite pipeline replacement and Owings Mills Gate Station.

Category	Historical	Bridge	Multi-Year Plan Period		
	2019A	2020F	2021F	2022F	2023F
Gas System Performance	$69,812,643	$92,142,465	$73,721,586	$101,818,767	$83,726,152

Q. HOW DOES THE THREE-YEAR PLAN COMPARE TO THE 2020 FORECAST AND 2019 ACTUAL SPEND?

A. The three-year plan is in line with the forecasted investment of $92.1 million for 2020 and the actual spend of $69.8 million in 2019. Similarly, large project construction that occurs in some years result in fluctuations in the overall spend year to year.

Q. HOW WAS THE PLAN DEVELOPED FOR THIS CATEGORY?

A. Overall, work in the category is fairly predictable and steady, as BGE trends the needs for each program based on past performance. Thus, most of the programs within this category fluctuate only slightly and can be planned accordingly. The variability in annual expenditures is driven by larger projects, such as transmission replacement work, that requires more capital in the years of construction compared to previous years in which only planning occurred. Where possible, the timing of these larger projects is planned to be spaced out, to prevent resource issues and establish realistic construction timing to perform the work, while also taking into account the timing of system needs.

III.D. CAPITAL INVESTMENTS – GAS CORRECTIVE MAINTENANCE CATEGORY

Q. MR. BURTON, PLEASE DESCRIBE THE GAS CORRECTIVE MAINTENANCE CATEGORY AND DISCUSS THE KEY DRIVERS FOR THE WORK.

A. The Gas Corrective Maintenance category includes both capital and O&M components. In this section I describe the capital portion only. The capital component of the Gas Corrective Maintenance category is comprised of capital programs that address BGE gas mains, services, and meters that require immediate attention in a reactive manner. In general, these programs involve replacement activities, but also include work necessary to define the scope of reactive work which may result in replacement or work performed to extend the useful life of the asset. This reactive capital work is identified through the course of routine inspection programs, field observations, or customer reports of gas odors. Incoming gas corrective maintenance capital work can be seasonal in nature, due to both the prevalence of gas odor calls during colder seasons vs. warmer weather as well as seasonality in the leak survey cycle.

Q. HOW IS THE CATEGORY MANAGED AND WHAT DO THE PROJECTS INVOLVE?

A. The Gas Corrective Maintenance category capital component is managed through programs that address a variety of reactive replacement or life extending activities identified via surveys, inspections, or customer calls. There is also a program that addresses third-party damages that result in infrastructure replacement, as well as a program that addresses replacements that occur as the result of emergency events.

The scope of work that falls into this category can range widely; from replacement of a single customer meter to the reactive replacement of several hundred feet of gas main.

Q. PLEASE DISCUSS THE CAPITAL INVESTMENT AND TRENDS FOR THE CORRECTIVE MAINTENANCE CATEGORY FOR 2021 THROUGH 2023.

A. The budgeted capital investments for the Corrective Maintenance category is shown in the table below. Investment in this category is projected to decrease year over year as an expected result of planned work in the GIMP and System Performance programs.

Category	Historical	Bridge	Multi-Year Plan Period		
	2019A	2020F	2021F	2022F	2023F
Gas Corrective Maintenance - Capital	$46,999,412	$49,734,279	$44,416,434	$38,071,220	$32,331,406

Q. HOW DOES THE THREE-YEAR PLAN COMPARE TO THE 2020 BUDGET AND 2019 ACTUAL SPEND?

A. The three-year plan is in line with the budgeted investment of $49.7 million for 2020. The actual spend for 2019 was $46.9 million; the increase from 2019 to 2020 is due to the inclusion of gas leak scoping, which is the excavation and investigation needed to determine the location of leaks and the appropriate approach to remedy the problem.

Q. HOW WAS THE PLAN DEVELOPED FOR THIS CATEGORY?

A. Work in the category is reactive, however the plan is developed using primarily historical performance and cost data. As GIMP and System Performance work proceeds to eliminate the poorest performing gas infrastructure, BGE's Gas

Division anticipates a continued reduction in the number of incoming gas leaks and a reduction in spend on corrective maintenance as a result.

IV. OPERATIONS & MAINTENANCE

Q. MR. BURTON, COULD YOU PLEASE DESCRIBE THE PLANNING PROCESS FOR OPERATIONS & MAINTENANCE IN GAS?

A. Similar to the capital planning process discussed above, the plan developed to operate and maintain BGE's gas distribution and transmission system is divided into areas designed to address various types of maintenance work. As part of that planning process, the BGE Gas Division evaluates and plans preventative maintenance cycles for distribution, transmission, and plant infrastructure, and anticipates corrective maintenance.

As with the capital plan, the various O&M work and financial requirements are budgeted for five years. For O&M the planning is derived by reviewing historical patterns and using those to set a five-year plan.

Q. COULD YOU PROVIDE MORE DETAIL ON THE DEVELOPMENT OF THE O&M PLAN?

A. The Gas Division's O&M plan consists of a Corrective Maintenance category and a Preventative Maintenance category, each of which is divided into several programs. Gas Corrective Maintenance is comprised of programs that address reactive work and repairs to BGE's gas plants, mains, and services. This category directly supports BGE's goals to maintain a safe and reliable gas distribution system, mitigate public safety risks, and provide a timely response to emergent repair needs. The plan for corrective maintenance is highly correlated with the plan for preventative maintenance as historical trends of results from the preventative maintenance programs are used to determine forecasted corrective maintenance volumes.

The Preventative Maintenance category includes programs targeted at mitigating system risk and maintaining reliability which are tied to various compliance targets. This routine maintenance keeps assets in optimal condition and minimizes downtime and costly repairs or replacements. Preventative maintenance cycles typically range from one to three years.

Q. COULD YOU PLEASE SUMMARIZE THE BUDGETED GAS O&M EXPENSES FOR 2021 THROUGH 2023 IN YOUR EXECUTIVE CATEGORY?

A. Certainly. The budgeted O&M expenses for the Gas Executive Category is shown in the table below:

Category	Historical	Bridge	Multi-Year Plan Period		
	2019A	2020F	2021F	2022F	2023F
Gas Corrective Maintenance - O&M	$66,968,459	$55,869,448	$53,265,395	$49,712,320	$46,988,075
Gas Preventative Maintenance	$32,806,628	$36,310,608	$38,288,596	$38,498,463	$39,547,607
Total Gas Executive Category (O&M)	**$99,775,087**	**$92,180,056**	**$91,553,991**	**$88,210,783**	**$86,535,682**

Q. WHAT ARE THE OVERALL TRENDS AND DRIVERS OVER THE NEXT THREE YEARS?

A. Overall, the budgeted O&M plans for the Gas Executive Category for 2021-2023 will be reduced year-over-year from $91.5 million in 2021 to $86.5 million in 2023. These budgeted reductions are in response to the capital plan which will bring improved system performance and asset reliability, reducing the need for reactive replacements and repairs. Areas that are driven by compliance targets will experience increases attributable to labor and material inflation year-over-year as BGE continues to ensure the safe operation of our gas infrastructure.

The Gas Preventative Maintenance category budget sees year-over-year increases from $38.2 million in 2021 to $39.5 million in 2023, which are attributed to labor and material costs.

Q. HOW DOES THE O&M PLAN FOR THE GAS EXECUTIVE CATEGORY COMPARE TO PREVIOUS YEARS?

A. The O&M plan for 2021 through 2023 continues the downward trend of the 2020 budget.

IV.A. OPERATIONS & MAINTENANCE – GAS CORRECTIVE MAINTENANCE PROGRAM

Q. MR. BURTON, PLEASE DESCRIBE THE GAS CORRECTIVE MAINTENANCE CATEGORY AND DISCUSS THE KEY DRIVERS FOR THE WORK.

A. The O&M component of the Gas Corrective Maintenance category is divided into areas that address reactive repairs to BGE's gas plants, mains, and services. This category's activities directly support BGE's initiatives to maintain a safe and reliable gas distribution system, mitigate public safety risks, and provide a timely response to emergent repair needs.

As with the capital component of Gas Corrective Maintenance, work within the Gas Corrective Maintenance O&M category is also chiefly driven by the results of leak surveys, corrosion surveys, and customer reported gas odors. This category is also driven by seasonal influences such as weather and the leak survey cycle.

Q. HOW IS THE GAS CORRECTIVE MAINTENANCE CATEGORY MANAGED AND WHAT DOES THE WORK INVOLVE?

A. The O&M component of the Gas Corrective Maintenance category is managed programmatically, with a separate work and financial budget for each area of work. These areas include: Emergency Response, gas leak repairs, corrosion abatement repairs, and gas plant equipment corrective maintenance.

- Emergency Response: Supports BGE's commitment to respond to customer-reported gas odors within 60 minutes. Emergency Response is BGE's 24/7 operation that provides trained BGE personnel to respond to every reported gas odor, assess the situation, and make repairs when necessary to ensure the safety of our customers and the safe operation of the BGE gas distribution system. In addition to customer-reported gas odors, Emergency Response also responds to reports of damages to BGE's equipment and requests from 911 dispatchers to assist fire departments with fire calls, and possible carbon monoxide releases.
- Gas Leak Repairs: Prioritizes and addresses gas leaks reported on the gas distribution system. Leaks are reported by customers or are detected during Preventative Maintenance leak surveys. BGE utilizes both internal and contractor work force to repair gas leaks. As previously mentioned in the capital portion of my testimony, gas leak repairs can be addressed via capital (replacement of the asset) or O&M (repair of the asset.)
- Corrosion Abatement Repairs: Ensures BGE's compliance with 49 CFR Part 192 for Corrosion Control, which states that "All buried or submerged pipeline installed after July 31, 1971, must be protected against external

corrosion…" Similarly, refer to 49 CFR 195.236, 238, and 242 for Liquid Propane Pipelines. BGE employs specialized contractors to perform maintenance and repairs on the preventative maintenance identified locations of the gas distribution and transmission pipelines where cathodic protection is required or deficient.

- Gas Plant Corrective Maintenance: SGLNG and NCPA production plants and distribution, automation, and control assets have equipment that requires periodic repairs or upgrades as part of regular component life cycles and resulting from preventative maintenance inspections. This program provides the staff and funding to perform corrective maintenance to gas plant and distribution equipment as needed to maintain reliable operations.

The scope of work in this category ranges from minor repairs or adjustments of fittings to the installation of permanent remedies to repair leaks on assets that once repaired can be expected to maintain useful life for some time.

Q. PLEASE DISCUSS THE O&M EXPENSES AND TRENDS FOR THE CORRECTIVE MAINTENANCE CATEGORY FOR 2021 THROUGH 2023.

Category	Historical	Bridge	Multi-Year Plan Period		
	2019A	2020F	2021F	2022F	2023F
Corrective Maintenance Gas	$ 66,968,459	$ 55,869,448	$ 53,265,395	$ 49,712,320	$ 46,988,075

A. As an expected result of the GIMP projects and planned system performance work, the forecast for gas leak repairs is expected to be lowered year-over-year. Other areas in Corrective Maintenance are expected to experience incremental increases attributed to labor and material costs.

Q. HOW DOES THE THREE-YEAR PLAN COMPARE TO THE 2020 BUDGET AND 2019 ACTUAL SPEND?

A. The years 2021-2023 are aligned with the 2020 budget for Gas Corrective Maintenance O&M. This reduction was achieved through the phase out of the use of supplemental resources from out-of-state that carried a higher cost than is anticipated in future budget years.

IV.B. OPERATIONS & MAINTENANCE – GAS PREVENTATIVE MAINTENANCE PROGRAM

Q. MR. BURTON, PLEASE DESCRIBE THE GAS PREVENTATIVE MAINTENANCE CATEGORY AND DISCUSS KEY DRIVERS FOR THE WORK.

A. The Gas Preventative Maintenance category includes activities targeted at mitigating system risk and maintaining reliability. These activities are tied to various compliance targets. The category consists of scheduled, routine maintenance to keep assets in optimal condition and minimize downtime and expensive repair costs. Maintenance cycles typically range from one to three years.

The Gas Preventative Maintenance category is driven by inspections of BGE's gas infrastructure and the necessary maintenance activities to prevent degradation of performance as a result of corrosion or external force damage. Compliance is also a driver for this category as many of the inspection programs BGE employs to maintain the safe operation of our gas infrastructure are directed by regulations.

Q. HOW IS THE GAS PREVENTATIVE MAINTENANCE CATEGORY MANAGED AND WHAT DO THE PROJECTS INVOLVE?

A. The Preventative Maintenance category is divided into areas that address regular, periodic inspection and maintenance of gas distribution, transmission, and plant assets and infrastructure. Additionally, the BGE Damage Prevention program is funded in this category. The areas include:

- Crossbores – Inspection of sewer lines/drains to determine if a horizontal bore may have drilled through a sewer line or drain.
- Meter corrosion – Inspecting and painting meter manifolds and assets where corrosion is already present or is forming.
- Pipeline corrosion control – Inspecting steel gas mains and service assets for proper cathodic protection.
- Gas Plants – Preventative maintenance activities to maintain the liquefication, compression and other equipment.
- Transmission Integrity Management – Inspections and analysis of all transmission pipelines to ensure that transmission assets are in good condition, are performing properly, and risks are managed properly.
- Leak Surveys – Performing periodic leak surveys of all gas distribution assets. The entire distribution system is surveyed at least every three years.
- Damage Prevention – This includes oversight of BGE's locating contractor, quality audits of utility locating work, and outreach to and education of the excavator community.

Q. PLEASE DISCUSS THE O&M EXPENSES AND TRENDS FOR THE PREVENTATIVE MAINTENANCE CATEGORY FOR 2021 THROUGH 2023.

A. The costs in Preventative Maintenance Gas (shown in the table below) are held generally flat from 2021 through 2022 with increases attributable to labor and material costs. There is planned maintenance in 2023 that includes painting of the SGLNG storage tanks. The painting of the tanks is protection against corrosive elements and extends the useful life of the SGLNG storage tanks.

Category	Historical	Bridge	Multi-Year Plan Period		
	2019A	2020F	2021F	2022F	2023F
Gas Preventative Maintenance	$32,806,628	$36,310,608	$38,288,596	$38,498,463	$39,547,607

Q. HOW DOES THE THREE-YEAR PLAN COMPARE TO THE 2020 BUDGET AND 2019 ACTUAL SPEND?

A. The 2020 budget and 2019 actuals for Gas Preventative Maintenance do not include a Gas Plant staffing increase that is planned for 2021, the first year of the three-year plan. This staffing increase is temporary to train new staff to replace employees who are expected to retire. Absent that increase the plan is aligned with prior years.

Q. DOES THIS CONCLUDE YOUR TESTIMONY?

A. Yes.

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2020-2023 Plan Documentation – Capital and O&M

Executive Category Owner: A. Christopher Burton

Title: Vice President, Gas

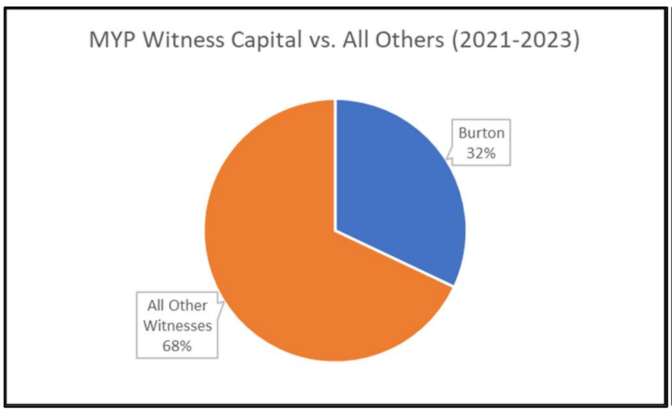
I. Financial Summary

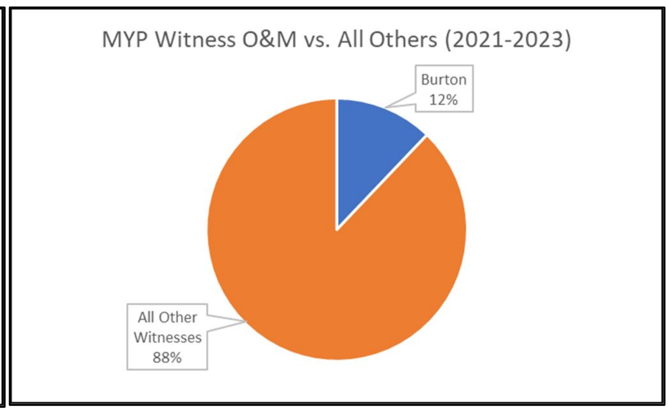
A. Capital

CATEGORY	2019A	2020F	2021F	2022F	2023F
CAPACITY EXPANSION - GAS	$10,952,173	$20,994,107	$14,793,986	$19,408,025	$20,379,473
CORRECTIVE MAINTENANCE - GAS	$46,999,412	$49,734,279	$44,416,434	$38,071,220	$32,331,406
GAS INFRASTRUCTURE MAINTENANCE PROGRAM (GIMP)	$166,976,412	$159,678,746	$161,260,400	$164,846,843	$163,394,398
SYSTEM PERFORMANCE - GAS	$69,812,643	$92,142,465	$73,721,586	$101,818,767	$83,726,152
ANNUAL TOTALS FOR CAPITAL	**$294,740,640**	**$322,549,597**	**$294,192,406**	**$324,144,855**	**$299,831,429**

B. O&M

CATEGORY	2019A	2020F	2021F	2022F	2023F
CORRECTIVE MAINTENANCE - GAS	$66,968,459	$55,869,448	$53,265,395	$49,712,320	$46,988,075
PREVENTATIVE MAINTENANCE - GAS	$32,806,628	$36,310,608	$38,288,596	$38,498,463	$39,547,607
ANNUAL TOTALS FOR O&M	**$99,775,087**	**$92,180,056**	**$91,553,991**	**$88,210,783**	**$86,535,682**





II. Capital Category Cashflows and Functions

A. Capacity Expansion – Gas

Category	2019A	2020F	2021F	2022F	2023F
Capacity Expansion – Gas	$10,952,173	$20,994,107	$14,793,986	$19,408,025	$20,379,473

- The work in this category addresses inadequate capacity on the gas distribution and transmission systems as forecasted in the gas system model or observed in physical system data.
- This work is necessary to resolve issues such as (but not limited to):
  - Collective load growth on the gas system from customer additions and increasing load from existing customers.
  - Changes in system configuration resulting from BGE's aging infrastructure programs, such as STRIDE, and low pressure and medium pressure system conversions, which are performed to increase the safety and reliability of the gas system.
  - Supply and other system constraints.
- This work reinforces the system by increasing system capacity and/or system pressure by:
  - Constructing district regulator stations.
  - Extending, replacing and/or connecting mains.
  - Performing other work.
- The work ensures system capacity and reliability for customers in all weather conditions down to design day conditions (2.7°F average temperature with 15 mph winds).
- Investment in this category fluctuates as various jobs are planned and prioritized with the timing of other work performed in the gas business.

B. Corrective Maintenance – Gas

Category	2019A	2020F	2021F	2022F	2023F
Corrective Maintenance – Gas	$46,999,412	$49,734,279	$44,416,434	$38,071,220	$32,331,406

- Corrective Maintenance – Gas capital expenditures are comprised of programs to replace gas mains and services on a reactive basis. Work that is typically capital corrective maintenance includes:
  - Emergent gas main and service replacement for areas requiring replacement that are not included in the targeted system performance programs.
  - Joint encapsulation which is the installation of steel or fiberglass around the joint to extend its life and reliability.
  - Internal joint sealing, which is the robotic installation of joint sealant from inside a cast iron main.
  - Scoping gas leaks, which is excavation and investigation to determine the location of leaks and the appropriate approach to remedy the problem. This activity is split between capital and O&M.
- All of the projects in this area are trending down over the 2021-2023 period as a result of BGE's Gas Infrastructure Modernization Program (GIMP) and planned system performance programs.

C. Gas Infrastructure Modernization Program (GIMP)

Category	2019A	2020F	2021F	2022F	2023F
GIMP	$166,976,412	$159,678,746	$161,260,400	$164,846,843	$163,394,398

- BGE's STRIDE or GIMP (Gas Infrastructure Modernization Program) program is designed to accelerate the modernization of BGE's gas distribution assets.
- Through 2022, expenditure growth is due to expected inflation. In 2023, total costs decline because the ¾" high pressure steel proactive service replacement program ends.
- The general goals of these investments are to:
  - Reduce leaks and thereby improve safety and lessen environmental impacts.
  - Enhance customer safety and reliability, including converting from low pressure to higher pressure systems.
- Long-term strategies to achieve these goals are to:
  - Eliminate cast iron and bare steel main and associated metallic services through Operation Pipeline. Operation Pipeline is a systematic replacement approach applied to BGE's aging gas infrastructure that facilitates conversion of low-pressure gas systems to regulated pressure systems.
  - Eliminate pre-1970 ¾" high-pressure steel services through the Service Replacement Program. These services are predominantly being replaced with high density polyethylene plastic.

D. System Performance – Gas

Category	2019A	2020F	2021F	2022F	2023F
System Performance – Gas	$69,812,643	$ 92,142,465	$ 73,721,586	$101,818,767	$ 83,726,152

- System Performance – Gas projects are designed to maintain or improve the safety and reliability of the gas distribution system primarily through replacement or upgrading of existing assets.
- The general goals of these investments are to reduce risks including:
  - Reducing leaks and thereby improving safety and lessening environmental impacts.
  - Reducing and avoiding unplanned customer interruptions.
  - Reducing other risks such as overpressurization, excavation damage, or natural causes (e.g., flooding).
- Long-term strategies to achieve these goals are:
  - Eliminate cast iron and bare steel mains.
  - Eliminate low-pressure systems.
  - Reduce the population of metallic services and replace them with modern high-density polyethylene (HDPE) services.
  - Increase system connectivity to improve reliability, simplify operation of the system and allow for reduced outages by adding alternative supply paths. Alternative supply paths allow work to be performed without taking customers out of service.
  - Replacement/modernization of gate station, gas plant, and other operational equipment needed to maintain gas supply.

- The variability in annual expenditures is driven by large projects such as gas transmission project spend that is capital intensive and sometimes of short duration.

III. Capital Details

This Section provides additional details for capital projects with spend greater than $1 million in any year within the 2019-2023 time period for each of the categories below.

A. Capacity Expansion

Project Name	60701: Reinforcement - Gas System Reinforcements			
2019A	**2020F**	**2021F**	**2022F**	**2023F**
$10,952,173	$20,994,107	$14,793,986	$19,408,025	$20,379,473
Problem Statement		**Solution Statement**		**Estimated / In-Service Date**
Over time, collective load growth on the gas distribution and transmission systems from the addition of customers or increasing load from existing customers can result in inadequate capacity on the system. In addition, similar effects occur from system configuration changes resulting from BGE aging infrastructure replacement programs, primarily the conversion of the low-pressure systems.		This program develops jobs that address inadequate capacity by identifying system issues such as, but not limited to, a history of poor supply, forecasted insufficient pressures, and undersized regulator equipment.		Monthly / Various

B. Corrective Maintenance – Gas

Project Name	58365: Emergent Capital Gas Main Replacements			
2019A	**2020F**	**2021F**	**2022F**	**2023F**
$4,468,511	$4,870,209	$3,283,620	$3,311,614	$3,421,378

Problem Statement	**Solution Statement**	**Estimated / In-Service Date**
BGE's cast iron main and bare steel mains have significantly higher leak rates than systems made of modern materials.	BGE will replace its cast iron systems with modern materials and upgrade system pressure in locations where it is feasible and economical to do so when planning work or in an emergent situation requiring an immediate corrective maintenance replacement.	Monthly / Various

Project Name	60517: Damages - Gas Facilities			
2019A	**2020F**	**2021F**	**2022F**	**2023F**
$1,281,762	$1,080,956	$1,143,487	$1,153,273	$1,201,627

Problem Statement	**Solution Statement**	**Estimated / In-Service Date**
Gas facilities are damaged.	This project funds the repair of damaged gas facilities.	Monthly / Various

Project Name	60523: Leaks - Capital Leak Repairs			
2019A	**2020F**	**2021F**	**2022F**	**2023F**
$40,512,156	$38,312,332	$34,871,556	$28,976,814	$23,183,257

Problem Statement	**Solution Statement**	**Estimated / In-Service Date**
BGE is responsible for the ongoing maintenance of its gas infrastructure, including corrective maintenance and gas leak repairs that are covered in this program.	BGE maintains staffing to address the corrective maintenance needs of the gas system.	Monthly / Various

Project Name	66375: Leaks - Gas Scoping			
2019A	**2020F**	**2021F**	**2022F**	**2023F**
	$4,323,555	$4,234,272	$3,972,932	$3,839,368

Problem Statement	**Solution Statement**	**Estimated / In-Service Date**
BGE is responsible for the ongoing maintenance of its gas infrastructure, including corrective maintenance and gas leak repairs that are covered in this program.	BGE maintains staffing to identify the corrective maintenance needs of the gas system.	Monthly / Various

C. Gas Infrastructure Maintenance Program (GIMP)

Project Name	60522: Leaks - 3/4 Reactive Renewals STRIDE			
2019A	**2020F**	**2021F**	**2022F**	**2023F**
$6,234,566	$6,458,064	$4,136,740	$3,281,723	$1,544,060
Problem Statement		**Solution Statement**		**Estimated / In-Service Date**
The rate of leaks on ¾" pre-1970 high pressure steel services has increased as documented in BGE's STRIDE filings.		When a leak is discovered on a ¾" pre-1970 high pressure steel service, the service is replaced rather than repaired.		Monthly / Various

Project Name	60677: BGE Operation Pipeline			
2019A	**2020F**	**2021F**	**2022F**	**2023F**
$122,468,407	$120,352,364	$120,692,755	$122,035,734	$126,829,973
Problem Statement		**Solution Statement**		**Estimated / In-Service Date**
BGE's cast iron main and bare steel mains have significantly higher leak rates than systems made of modern materials.		BGE will replace its cast iron and bare steel systems with modern materials and eliminate low pressure systems as part of its replacement plan.		Monthly / Various

Project Name	61528: Proactive 3/4 Service Renewal Program			
2019A	**2020F**	**2021F**	**2022F**	**2023F**
$38,273,414	$32,868,318	$36,430,905	$39,529,386	$35,020,365
Problem Statement		**Solution Statement**		**Estimated / In-Service Date**
The rate of leaks on ¾" pre-1970 high pressure steel services has increased as documented in BGE's STRIDE filings.		To avoid future leaks on ¾" pre-1970 high pressure steel services, they will be proactively replaced as part of BGE's STRIDE program.		Monthly / Various

D. System Performance – Gas

Project Name	55633: Granite Pipeline-Stokes Drive-Russell Rd			
2019A	**2020F**	**2021F**	**2022F**	**2023F**
$454,849	$1,300,936	$1,843,902	$4,451,921	$409,262
Problem Statement		**Solution Statement**		**Estimated / In-Service Date**
Several of BGE's gas transmission lines were built more than 50 years ago. These lines have risk because they operate at relatively high pressures compared to the strength of the pipe.		Replacement of the Granite transmission main with higher strength pipe and up-to-date construction techniques and standards.		After 2023

Project Name	58028: Downtown Pipeline Phase 1 (Mt Royal Ave)			
2019A	**2020F**	**2021F**	**2022F**	**2023F**
$870,107	$128,139	$12,357,354	$13,269,451	$14,958,298
Problem Statement		**Solution Statement**		**Estimated / In-Service Date**
BGE has several large diameter (20+ inches) medium pressure (~10 psig) cast iron mains that traverse downtown Baltimore. Cast iron mains have higher leak rates than other asset classes.		BGE will construct a large principal supply line (30") to displace the flow of gas on the large diameter cast iron mains in Baltimore.		December 2023

Project Name	58034: Non-STRIDE Corrective Maintenance Gas Main Replacements			
2019A	**2020F**	**2021F**	**2022F**	**2023F**
$398,317	$11,031,664	$11,758,275	$12,062,836	$15,210,916
Problem Statement		**Solution Statement**		**Estimated / In-Service Date**
BGE's cast iron main and bare steel mains have significantly higher leak rates than systems made of modern materials.		BGE will replace its cast iron and bare steel systems with modern materials and eliminate low pressure systems as part of its replacement plan.		Monthly / Various

Project Name	58194: System Reliability - Gas Distribution			
2019A	**2020F**	**2021F**	**2022F**	**2023F**
$1,147,635	$4,601,313	$4,898,729	$5,028,705	$4,980,986
Problem Statement		**Solution Statement**		**Estimated / In-Service Date**
Parts of BGE's gas system have "single point of failure" conditions, which leave customers vulnerable to gas outages should an event occur.		Enhance interconnectivity of the system to improve redundant supplies and integrated pressure systems.		Monthly / Various

Project Name	58447: Harbor Crossing - Upgrades for In-Line Inspection			
2019A	**2020F**	**2021F**	**2022F**	**2023F**
$20,156	$5,185,771			
Problem Statement		**Solution Statement**		**Estimated / In-Service Date**
The gas transmission main that crosses under the river parallel to the Key Bridge cannot be inspected directly.		BGE will install facilities that allow for the use of in-line inspection tools.		December 2020

Project Name	58477: Severn River Bridge Main Replacement			
2019A	**2020F**	**2021F**	**2022F**	**2023F**
$86	$5,110,686	$1,324,360		
Problem Statement		**Solution Statement**		**Estimated / In-Service Date**
The existing gas main on the Severn River bridge is no longer easily accessible, has a leak history and is undersized for the increasing load in the county.		Replace the existing main with a larger one.		December 2021

Project Name	58539: Upgrades for Gas Transmission In-Line Inspection			
2019A	**2020F**	**2021F**	**2022F**	**2023F**
				$1,895,986
Problem Statement		**Solution Statement**		**Estimated / In-Service Date**
Requirements from PHMSA for inspection of transmission lines are increasing.		BGE can improve the effectiveness of our transmission line inspections using in-line inspection tools.		After 2023

Project Name	59322: Spring Gardens Liquified Natural Gas (LNG) Boil Off Compressor			
2019A	**2020F**	**2021F**	**2022F**	**2023F**
$1,167,866	$2,971,628			
Problem Statement		**Solution Statement**		**Estimated / In-Service Date**
LNG tanks emit a constant stream of vaporizing gas from the supercooled liquid called “boil off gas”. Existing compressors are getting old.		BGE compresses the gas into the distribution system. A new compressor will be added to ensure adequate capacity.		July 2021

Project Name	59616: Howard County Station 489 Heater Replacement			
2019A	**2020F**	**2021F**	**2022F**	**2023F**
$398,620	$1,346,399			
Problem Statement		**Solution Statement**		**Estimated / In-Service Date**
When gas is regulated from very high pressures to relatively low pressures the gas temperature decreases. If the temperature falls low enough condensate can form that can damage or interfere with certain pipeline components/systems. Existing heaters are nearing their end of life.		BGE heats gas at certain locations based on the temperature drop. A new heater will be installed.		November 2020

Project Name	60080: Granite Pipeline-Gate Station to Lord Baltimore			
2019A	**2020F**	**2021F**	**2022F**	**2023F**
$609,928	$1,196,732		$19,490,386	
Problem Statement		**Solution Statement**		**Estimated / In-Service Date**
Several of BGE’s gas transmission lines were built more than 50 years ago. These lines have risk because they operate at relatively high pressures compared to the strength of the pipe.		Replacement of the Granite transmission main with higher strength pipe and up-to-date construction techniques and standards.		After 2023

Project Name	60666: Gas Infrastructure Improvements			
2019A	**2020F**	**2021F**	**2022F**	**2023F**
$31,141,748	$20,823,678	$19,311,111	$19,496,937	$20,361,548
Problem Statement		**Solution Statement**		**Estimated / In-Service Date**
BGE is required to regularly evaluate risk on its system and take measures to reduce those specific risks. These risks can be identified through engineering analysis or field observation of specific issues.		BGE replaces or remediates segments in a manner consistent with the goals of replacing cast iron and bare steel main and eliminating low pressure systems.		Monthly / Various

Project Name	60685: Plant Major Infrastructure - Gas Asset Replacement Program			
2019A	**2020F**	**2021F**	**2022F**	**2023F**
$4,705,959	$7,552,447	$8,115,317	$8,353,107	$8,168,822
Problem Statement		**Solution Statement**		**Estimated / In-Service Date**
LNG and Notch Cliff propane air production plants and distribution automation and control assets have components that require periodic replacement or upgrade as part of regular component life cycles.		Perform engineering and life cycle analysis and replace or upgrade components as needed to maintain reliable operations.		Monthly / Various

Project Name	60691: Gate Station-Manor			
2019A	**2020F**	**2021F**	**2022F**	**2023F**
$6,828,670				
Problem Statement		**Solution Statement**		**Estimated / In-Service Date**
The interstate transmission pipeline that delivers gas to BGE's territory is upgrading their portion of the gate station. This will increase the delivery pressure at which BGE takes custody of the gas and will require BGE to take over regulation and heating functions.		BGE will rebuild the gate station along this interstate pipeline to accommodate higher pressures and install necessary equipment for safe and reliable operation.		September 2019

Project Name	60693: Gate Station-Owings Mills			
2019A	**2020F**	**2021F**	**2022F**	**2023F**
	$2,268,875	$2,527,573	$11,432,838	$8,082,134
Problem Statement		**Solution Statement**		**Estimated / In-Service Date**
The interstate transmission pipeline that delivers gas to BGE's territory is upgrading their portion of the gate station. This will increase the delivery pressure at which BGE takes custody of the gas and will require BGE to take over regulation and heating functions.		BGE will rebuild the gate station along this interstate pipeline to accommodate higher pressures and install necessary equipment for safe and reliable operation.		December 2023

Project Name	60704: Plant Major Infrastructure - Valve House Phase 4			
2019A	**2020F**	**2021F**	**2022F**	**2023F**
$260,833	$6,880,875			
Problem Statement		**Solution Statement**		**Estimated / In-Service Date**
The Valve House piping infrastructure is old and leak-prone.		Switch distribution lines from the valve house lines to the new distribution header.		November 2020

Project Name	60705: Leadenhall Isolation / Removal of Existing Header			
2019A	**2020F**	**2021F**	**2022F**	**2023F**
	$122,903	$4,562,987		
Problem Statement		**Solution Statement**		**Estimated / In-Service Date**
The Valve House piping infrastructure is old and leak-prone.		Isolate and remove the existing header and connection points that are integrated with decommissioned facilities.		December 2021

Project Name	61207: Granite Pipeline-Leakin Park			
2019A	**2020F**	**2021F**	**2022F**	**2023F**
$10,347,040	$120,000			
Problem Statement		**Solution Statement**		**Estimated / In-Service Date**
Several of BGE's gas transmission lines were built more than 50 years ago. These lines have risk because they operate at relatively high pressures compared to the strength of the pipe.		Replacement of the Granite transmission main with higher strength pipe and up-to-date construction techniques and standards.		August 2019

Project Name	61208: Gas Facility Security			
2019A	**2020F**	**2021F**	**2022F**	**2023F**
$4,470,041	$13,263,807	$388,132	$390,993	$2,450,532
Problem Statement		**Solution Statement**		**Estimated / In-Service Date**
BGE has critical facilities that need to be protected.		Implement increased security measures at critical facilities.		After 2023

Project Name	61212: Valve Replacement Program			
2019A	**2020F**	**2021F**	**2022F**	**2023F**
$2,872,088	$6,483,252	$4,864,403	$5,991,051	$5,623,378
Problem Statement		**Solution Statement**		**Estimated / In-Service Date**
Pressure control devices (valves and pressure regulators) that are single points of failure present a higher risk of overpressurizing a system.		Remove single points of failure. Add redundant valves where single valves exist and are still used.		Monthly / Various

Project Name	61526: Inactive Service Abandonment Program			
2019A	**2020F**	**2021F**	**2022F**	**2023F**
$3,038,835	$1,159,430	$1,250,994	$1,324,429	$1,380,057
Problem Statement		**Solution Statement**		**Estimated / In-Service Date**
Some gas services do not serve a customer but remain connected to the gas system.		BGE analyzes the use of services and selectively retires services that are not in use.		Monthly / Various

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IV. O&M Category Cashflows and Functions

A. Corrective Maintenance – Gas

Category	2019A	2020F	2021F	2022F	2023F
Corrective Maintenance – Gas	$66,968,459	$55,869,448	$53,265,395	$49,712,320	$46,988,075

- Corrective Maintenance Gas – O&M is comprised of programs that address reactive repairs to BGE's gas mains and services.
    - Major components of this category include Emergency Response, which supports BGE's commitment to respond to customer-reported gas odors within 60 minutes; gas leak repairs, corrosion abatement repairs, and gas plant equipment maintenance.
    - Through BGE's various preventative maintenance and proactive infrastructure replacement programs we expect to reduce spending on reactive repairs over the 2020-2023 plan as fewer assets will require reactive attention.
    - Emergency Response costs are held generally flat with some variability in expenses as the result of adding trainees to back-fill retiring Emergency Response personnel. Emergency Response is BGE's 24/7 operation that responds to reported gas odors, damages, or carbon monoxide calls, as well as requests to assist local fire departments.
    - This category directly supports BGE's initiatives to maintain a safe and reliable gas distribution system, mitigate public safety risks, and provide a timely response to emergent repair needs.

B. Preventative Maintenance – Gas

Category	2019A	2020F	2021F	2022F	2023F
Preventative Maintenance – Gas	$32,806,628	$36,310,608	$38,288,596	$38,498,463	$39,547,607

- The Preventative Maintenance – Gas category includes programs targeted at mitigating system risk and maintaining reliability. These programs are primarily compliance driven. Examples of these compliance standards include Department of Transportation 192 regulations such as sub-part 614 for a Damage Prevention Plan, 723 for Leak Survey requirements, and 495 for Corrosion Control, as well as mitigation activities included in BGE's TIMP (sub-part O) and DIMP Plans (sub-part P).
    - The category consists of scheduled, routine maintenance to keep assets in optimal condition and minimize or prevent downtime and expensive repair costs. Maintenance cycles typically range from one to three years depending on the program and particular asset.
    - The Gas Preventative Maintenance programs include:
        - Cross bores
        - Meter corrosion
        - Pipeline corrosion control
        - Gas Plants
        - Integrity Management Programs
        - Leak Surveys
        - Damage Prevention
- The costs in Preventative Maintenance – Gas are generally flat plus expected inflation, with exceptions for storage tank painting in 2023 (Major Maintenance) and gas plant maintenance between 2020 and 2021.

V. O&M Project Details

Corrective Maintenance - Gas
Major Cost Drivers by Project

Instructions:

List actual O&M expenses by project for 2019; provide a high-level description of the types of costs within the project, and discuss the key drivers of each type. Also list forecasted O&M expenses for 2020-2023.

#	Project	Description and Key Drivers	2019 Actuals	2020 Forecast	2021 Forecast	2022 Forecast	2023 Forecast
1	60512: Gas Service Response - Emergency Response	Qualified personnel to provide emergency response to gas odor calls. Personnel respond, make safe, perform repairs, remove/install equipment, perform PSC inspections, respond to carbon monoxide calls, and provide distribution system support. This project is predominantly labor. Safety, reliability, customers, and compliance are key drivers.	10,894,438	11,122,351	12,281,047	11,796,961	12,903,271
2	60515: Leaks - O&M Leak Repairs	Qualified personnel to respond, make safe, and repair/replace assets as needed to remediate gas leaks. This includes labor to repair or replace gas infrastructure that is leaking. Leaks are identified by BGE leak surveys and customer reports of odors. Safety, reliability, customers, and compliance are key drivers.	48,532,311	28,133,687	24,407,583	21,546,780	17,849,174
3	60516: Emergency Events	BGE and contract labor to repair gas system damage caused by a contractor, customer, or another third party. This project has an O&M/Capital split. The amounts shown represent the anticipated uncollectible amounts for these corrective orders.	377,789	1,028,532	1,083,479	1,124,660	1,168,248
4	60520: Gas Plant Operations-Gas Plant Distribution Equipment Maintenance	Labor as necessary to perform corrective maintenance to gas plant and distribution equipment as needed to maintain reliable operations. Safety and reliability are key drivers. Scheduling is subject to regulation.	2,098,557	2,371,735	2,436,972	2,495,352	2,580,639
5	60521: Integrity Management-Corrosion Maintenance	Labor to perform installation of galvanic and impressed current cathodic protection systems in all new and existing BGE buried or submerged steel pipelines. Approximately 1,200 repairs are completed annually. Safety and reliability are key drivers. Scheduling is subject to regulation.	4,237,202	2,966,317	3,049,208	3,089,956	3,135,547
6	66375: Leaks - Gas Scoping	Labor to perform actions necessary to diagnose gas main and service leaks and determine nature of required repair or replacement.		9,640,976	9,378,246	9,013,522	8,687,742
7	3 Projects with no year >= $1 million		828,162	605,850	628,860	645,089	663,454
8	**Total**		**$ 66,659,617**	**$ 55,869,448**	**$ 53,265,395**	**$ 49,712,320**	**$ 46,988,075**

Preventative Maintenance - Gas
Major Cost Drivers by Project

Instructions:
List actual O&M expenses by project for 2019; provide a high-level description of the types of costs within the project, and discuss the key drivers of each type. Also list forecasted O&M expenses for 2020-2023.

#	Project	Description and Key Drivers	2019 Actuals	2020 Forecast	2021 Forecast	2022 Forecast	2023 Forecast
1	58445: Crossbores - Sewer Lateral Inspections	This project is labor with appropriate Operator Qualifications (OQ) to perform the investigation of existing cross-bores which is an intersection of one underground utility by a second underground utility that compromises the integrity of either utility and poses a risk to the system. Approximately 1,000 inspections per year are performed.	593,562	1,107,250	1,137,969	1,152,407	1,167,872
2	58660: Meter Corrosion Plan OM	This project is labor with OQ qualifications to inspect meter piping to determine corrosion impact (stage 1 and 2) which can cause specific materials to lose integrity and result in gas leaks. Approximately 1,000 of these are performed each year.	128,548	1,384,062	1,422,450	1,440,529	1,459,803
3	60667: Gas Distribution Operations Budget	This project is labor with OQ qualifications to perform annual compliance inspections on all gas regulators, critical system valves, and gate stations, as well as recurring odor tests across the gas service territory. Workload in this project is heavily driven by regulation.	4,416,687	5,714,927	5,821,909	5,931,030	6,109,923
4	60668: Gas Plant Operations-Gas Plant Operations Budget	This project funds the staffing levels to safely operate and maintain the gas plants and distribution system and perform required periodic preventative maintenance. This includes inspections, minor preventative maintenance, responding to requests to bring the plant on or off line, etc. Compliance requirements are a key driver.	12,286,833	12,423,787	13,726,271	13,606,188	13,648,151
5	60672: Integrity Management - Gas Management	Qualified personnel performing inspections and analysis of all transmission pipeline to ensure that transmission assets are in good condition, are performing properly, and that risks are managed properly as described by the Transmission Integrity Management Program (TIMP).	2,556,889	2,121,202	2,156,938	2,173,509	2,188,398
6	60678: Corrosion Control	This project is labor with OQ qualifications to conduct approximately 25,000 compliance monitoring inspections annually, broken into one, three and ten-year intervals depending on the location and assets. Both company and contractor personnel are utilized to complete the required inspection and remedial investigation workload each year. Compliance requirements and staffing levels are key drivers.	2,874,533	3,352,927	3,427,271	3,463,934	3,505,741
7	60679: Leak Survey	Personnel with with OQ qualifications to conduct leakage surveys across the gas distribution system on an annual and recurring three-year interval basis depending on the location and assets. BGE conducts a survey of approximately 3,000 miles of gas main and over 200,000 gas services each year. Compliance requirements and staffing levels are key drivers.	5,221,213	5,101,185	5,375,072	5,436,656	5,338,084
8	60688: Plant Major Maintenance	Qualified personnel to perform preventative maintenance tasks that are large in scope and non-routine in nature such as tank painting, pump skid installation project and pump overhauls. Compliance requirements and staffing levels are key drivers.	885,037	1,276,632	1,352,393	1,402,823	2,186,539
9	61220: Damage Prevention	This project is predominantly labor with OQ qualifications to perform oversight and execution of BGE's Damage Prevention Plan activities. This includes oversight of BGE's locating contractors, quality audits of utility locating work, and outreach to and education of the excavator community. Compliance requirements and staffing levels are key drivers.	3,025,387	3,028,636	3,068,321	3,091,386	3,143,094
10	2 Projects with no year >= $1 million		817,939	800,000	800,002	800,001	800,002
11	**Total**		**$ 32,806,628**	**$ 36,310,608**	**$ 38,288,596**	**$ 38,498,463**	**$ 39,547,607**

Before the Maryland Public Service Commission

Case No.________

Prepared Direct Testimony of

Tamla A. Olivier

On Behalf of

Baltimore Gas and Electric Company

May 15, 2020

Spending Summary

The amounts set forth below represent the Multi-Year Plan ("MYP") capital and O&M budgeted amounts which are necessary to continue providing outstanding, safe and reliable electric and gas distribution service to customers.

Capital

Category	2021F	2022F	2023F
Customer Operations	**$13,944,406**	**$9,431,381**	**$9,577,780**

O&M

Category	2021F	2022F	2023F
Customer Operations	**$111,456,230**	**$110,877,626**	**$110,782,016**

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I. QUALIFICATIONS

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS

A. My name is Tamla A. Olivier and my business address is Baltimore Gas and Electric Company ("BGE" or the "Company"), 2 Center Plaza, 110 West Fayette Street, Baltimore, Maryland, 21201.

Q. WHAT IS YOUR POSITION WITH BGE?

A. I am Senior Vice President of Customer Operations and Chief Customer Officer for BGE. In that capacity, I am responsible for overseeing the processes, systems, and planning that support internal and external customer interfaces, including BGE's customer contact centers, billing, accounts receivable and related services, service quality investigations, field and meter services, customer compliance and claims, and energy assistance.

Q. PLEASE DESCRIBE YOUR EDUCATIONAL BACKGROUND.

A. I earned a Bachelor of Science degree in Labor Relations from Cornell University.

Q. PLEASE DESCRIBE YOUR BUSINESS EXPERIENCE.

A. I joined BGE in my current position in January of 2020. I have been a key member of the Constellation and BGE Home leadership teams for nearly ten years. As president and chief executive officer, BGE HOME, and senior vice president, Constellation, I was a nationally recognized leader responsible for guiding and growing one of the largest home energy service operations in the nation. I joined Constellation in 2010 as executive director of human resources and was promoted to vice president in 2013 overseeing all human resources efforts for Constellation's commercial retail and wholesale businesses, as well as enterprise risk management for Exelon.

Prior to joining Constellation, I was a vice president at T. Rowe Price where I worked for 11 years supporting the retail, information technology, and global investment operations organizations. There, I introduced a supervisor program that successfully prepared high potential diverse talent for broader people management roles across the organization.

I have also held leadership roles with United Defense, where I led the implementation of the People Capability Maturity Model, facilitating an organizational shift from a manufacturing environment to a system integration and software development powerhouse; and with Wells Fargo, where I was the strategic human resources partner to the default servicing and affordable housing divisions, leading a team responsible for developing leadership competencies that drove new behaviors in leaders to act as change agents as the organization embraced and transitioned to a customer-centric strategy.

I am an executive committee member for Ronald McDonald House of Maryland and an executive committee member for Catholic Charities where I lead the human resources committee. I am also co-chair of the women's leadership council for My Sister's Place Women's Center and serve on the Archdiocese of Baltimore School Board. I am a member of the Center Club board of governors and formerly served on the board for Partners In Excellence, a program that provides young people with partial, need-based scholarships for Baltimore City Catholic Schools.

Q. HAVE YOU PREVIOUSLY SUBMITTED TESTIMONY TO THE PUBLIC SERVICE COMMISSION OF MARYLAND?

A. No.

II. PURPOSE OF TESTIMONY

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

A. My testimony provides an explanation of the Customer Operations areas of BGE and reviews the capital and operations and maintenance ("O&M") expenditure categories as they relate to those areas. I will speak to the value Customer Operations brings to BGE's customers and, as I will explain in the next section of my testimony, how we have delivered outstanding customer satisfaction scores for the past three years. In addition, I will discuss how we have continued to enhance self-service options through various channels including the website, mobile app, and interactive voice response ("IVR") functionality to provide customers easy access to their account including usage information. We have also remained steadfast in our focus on the needs of limited income customers by developing business solutions for what faces this vulnerable community. Finally, I will explain key activities, cost drivers and risks that could impact capital and O&M that are reflected in the current plan for Customer Operations for each of the years 2021 through 2023, and that will allow us to continue providing outstanding customer service to BGE customers.

Q. COULD YOU PLEASE PROVIDE AN OVERVIEW OF THE CAPITAL AND O&M REQUESTS BEING MADE IN THIS PROCEEDING?

A. For the three-year period of 2021 through 2023, BGE is projecting its capital investments to be $33.0 million and its O&M expenditures to be $333.1 million in the areas I am covering. As I will explain in more detail later on in my testimony, these investments and expenditures are important and necessary for BGE to oversee the processes, systems and planning that support internal and external customer interfaces, including BGE's customer contact centers, billing, accounts receivable and related services, service quality investigations, field and meter services for activities related to customers starting and stopping services, customer compliance and claims, and energy assistance.

Q. MS. OLIVIER, HAVE THE CAPITAL AND O&M PLANS DISCUSSED IN YOUR TESTIMONY BEEN ADJUSTED IN LIGHT OF THE COVID-19 PANDEMIC AND THE VARIOUS EXECUTIVE ORDERS ISSUED BY MARYLAND GOVERNOR HOGAN IN RESPONSE TO THE PANDEMIC?

A. No, they have not. Company Witness Vahos discusses BGE's expectations about the impact of the pandemic and related executive orders on the Company's capital and O&M plans and how BGE expects any impacts will be addressed over the MYP period. Given the suspension of terminations of service for nonpayment and the reconnection of previously terminated accounts, the Company anticipates that uncollectible expenses will increase. As a result, the Company will track and record the incremental amounts in a regulatory asset as Company Witness Vahos details in Part 2 of his Direct Testimony.

Q. HOW IS THE REMAINDER OF YOUR TESTIMONY ORGANIZED?

A. First, I will provide an overview of BGE's customer satisfaction performance in recent years. Next, I will provide an overview of Customer Operations and the specific areas of responsibility. Finally, I will describe the 2021 through 2023 budgeted capital and O&M spend and the work that makes up that spend. For informational purposes, I have also included actual and projected Capital and O&M costs for 2019 and 2020. I will also describe the BGE budget planning process and the risks that could alter spending needs.

Q. ARE YOU SPONSORING ANY EXHIBITS IN THIS PROCEEDING?

A. Yes. I am sponsoring <u>Exhibit TAO-1</u>. This exhibit provides details regarding the capital and O&M plans my testimony supports.

III. CUSTOMER SATISFACTION

Q. PLEASE DESCRIBE BGE'S PERFORMANCE IN CUSTOMER SATISFACTION IN RECENT YEARS.

A. As discussed in the Direct Testimonies of Company Witness Vahos, BGE has delivered superior customer satisfaction scores for the past three years. Customer satisfaction among our residential customers has continued to rise and is currently at an all-time high. In particular, the areas of community involvement and energy efficiency are the main drivers that customers indicate they are most satisfied with. More than 90% of residential customers are satisfied with BGE and the service we provide.

Our small business customers echo the sentiment of our residential customers as indicated by the high scores they give to BGE in surveys completed by leading market research firms. Most notably, BGE ranked number one in the J.D. Power 2019 Electric Utility Business Customer Satisfaction Study℠ for customer satisfaction among electric business customers in the East Large segment. This is the third-straight year BGE received the highest score among large electric utilities in its region. In addition, for the past two years, BGE ranked number one for Customer Satisfaction with Business Natural Gas Service in the East Region among utilities ranked by J.D. Power in the 2019 Gas Utility Business Customer Satisfaction Study.℠

BGE has been recognized for best in class business customer engagement in the leading study of utility industry brand health and business customer experience released by Escalent, a top human behavior and analytics firm. The study, Cogent Syndicated Utility Trusted Brand & Customer Engagement™: Business, included BGE among 18 Utility Business Customer Champions. Escalent's Engaged Customer Relationship ("ECR") index score for BGE was 813 (out of 1,000), the highest among East Region utilities. The ECR measures how engaged customers are with their utility. Overall, more than 90% of small business customers are satisfied with BGE and the service we provide.

Regarding our largest business customers, those with accounts managed by dedicated account representatives, over 90% of those customers are satisfied with BGE and the service we provide.

IV. <u>OVERVIEW OF CUSTOMER OPERATIONS</u>

Q. HOW MANY CUSTOMERS DOES CUSTOMER OPERATIONS SERVE?

A. Customer Operations serves over 1.3 million electric customers, of which over 90% are residential, and nearly 700,000 gas customers, of which over 93% are residential, across the Company's service territory. BGE's service area encompasses Baltimore City and all or part of ten Central Maryland counties.

Q. PLEASE DESCRIBE THE CUSTOMER OPERATIONS RESPONSIBILITY AREAS FURTHER.

A. 1. **Customer Contact/Customer Care Center** – This area is responsible for providing customer service to BGE customers by answering calls and represents approximately 25% of all O&M expenditures over the MYP. This is primarily an inbound call center where customers can resolve questions such as bill or third-party supplier inquiries, stop/start/transfer service, and obtain other services. In addition, customers can utilize various channels including e-mail, live chat, and integrated voice response ("IVR") to receive customer service and support. Costs related to this organization are those associated with answering customer inquiries and managing customer requests, such as those for emergency calls, billing calls, collection calls, new business calls, establishing new service, and service orders stopping or moving service to a different location. Also, we have developed a specialized group in the Care Center to handle limited income customer inquiries pertaining to billing information, grant status, agency referrals, energy assistance, and energy conservation.

2. Customer Financial Operations – This area is responsible for billing, payment processing and credit and collection activities for all customers and represents approximately 20% of all O&M expenditures over the MYP. Additional activities include credit/security deposit management, collection actions and protection against unauthorized appropriation of services. This area also focuses on the needs of limited income customers by developing business solutions and partnering with outside agencies to provide support to this vulnerable community.

3. Field and Meter Services – Field and Meter Services is responsible for the procurement and installation of new gas and electric meters when reactive or planned meter work results in the removal or replacement of meter assets and represents the entirety of the capital and over 20% of all O&M expenditures over the MYP. Additional activities include execution of meter maintenance, meter readings, start and stop service orders, meter testing, appointment scheduling, meter accessibility activities, and Smart Grid/advanced metering infrastructure ("AMI") operations including monitoring systems.

4. Customer Strategy and Governance – This area is responsible for the development and management of customer electronic channels and customer experience activities and represents approximately 20% of O&M expenditures over the MYP. This area also provides functional support of multiple systems including billing systems, customer care systems, management of customer advocacy activities, business and IT planning, and project and change management activities. Additional activities include maintaining self-service options through various channels including website, mobile application and IVR functionality to provide easy access for account management including electronic payments, energy management tools, outage status and reporting, the ability to easily start or stop electric and gas service at a customer's address and many types of proactive notifications through email, phone, text messaging, and push notification alerts through the BGE mobile application.

5. Claims – This area pursues the recovery of the costs that BGE incurs as a result of damage to BGE equipment caused by individuals and businesses and represents a small percentage of O&M expenditures over the MYP. In addition, this group manages claims made against the Company for property damage or personal injuries.

6. Uncollectibles – This budget includes uncollectible expenses associated with distribution services (electric and gas) and gas commodity purchases associated with BGE's standard offer service and represents over 10% of O&M expenditures over the MYP.

V. CAPITAL AND O&M ACTIVITIES

Q. WHAT ARE THE CAPITAL AND O&M REQUIREMENTS FOR THE CUSTOMER OPERATIONS AREA PLANNED THROUGH THE 2021-2023 MYP PERIOD?

A. The budgeted capital and O&M spend is shown below in Tables 1 and 2, respectively. For informational purposes, I have also included actual and projected Capital and O&M costs for 2019 and 2020.

Table 1. Customer Operations Capital Summary

Category	Historical	Bridge	MYP		
	2019	2020	2021	2022	2023
Customer Operations	$18,351,228	$14,998,198	$13,944,406	$9,431,381	$9,577,780

Table 2. Customer Operations O&M Summary

Category	Historical	Bridge	MYP		
	2019	2020	2021	2022	2023
Customer Operations	$110,130,330	$110,155,039	$111,456,230	$110,877,626	$110,782,016

Q. COULD YOU PLEASE PROVIDE AN OVERVIEW OF THE CAPITAL AND O&M REQUESTS BEING MADE IN THIS PROCEEDING?

A. As noted previously, for the three-year period of 2021 through 2023, Customer Operations is projecting its total capital investments to be $33.0 million and its total O&M expenditures to be $333.1 million. These investments and expenditures are important and necessary for BGE to continue providing outstanding customer service to BGE customers. Labor and staff augmentation comprise approximately two thirds of the overall O&M expense. Due to efforts to manage costs, the overall trend in O&M spending is effectively flat while capital spending decreases over the MYP period.

Q. CAN YOU DESCRIBE THE RISKS THAT COULD ALTER YOUR MYP PLANS?

A. While BGE makes every effort to identify risks and carefully evaluate our work and budget estimates to ensure reasonableness, there are risks that will cause actual spending to be different than budget. Primarily, these risks include, but are not limited to, weather, field conditions, permitting, resource availability and outage availability. We continue to manage through the risks of COVID-19 by helping our customers with access to power and extending payment arrangements. As systems and processes continue to evolve, the timing of system implementations and their dependencies on other system implementations could cause timing risk. Additionally, there are risks that new legislation or regulation could require additional work that was either unanticipated or incremental to BGE's budget.

Weather is also a significant variable. The number of storms and even active weather days can have a large impact on work and spending. BGE creates budget estimates based on historical weather levels but weather can vary substantially year to year. Also, field conditions can impact the cost of construction activities. As an example, when gas service locations are noted incorrectly in historical records, additional excavations may be required.

Q. PLEASE DESCRIBE THE CAPITAL AND O&M PLANNING PROCESS AT BGE.

A. As discussed in Part 2 of the Direct Testimony of Company Witness Vahos, capital and O&M is separated into areas of spend, called categories, which are led by Category Managers. Within each category, there are projects which are owned by managers. These individuals identify the work and the associated capital and O&M requirements to run the business and create a 5-year budget. These projects roll up to the Category Managers, who review the estimates, identify risks and changes to prior budgets and work with the project owners to make refinements. The categories are overseen by Executive Category Owners. I serve as an Executive Category Owner and, in this role, I review and approve the work plans and the associated capital and O&M requirements. I also ensure that spending levels and plans are executed so that our customers continue to receive safe and reliable electric service.

Q. PLEASE DESCRIBE THE CUSTOMER OPERATIONS CAPITAL ACTIVITIES IN MORE DETAIL.

A. Capital activity in Customer Operations resides within the Customer Operations Field & Meter Services organization. This capital activity is primarily driven by the cost of new gas and electric meters when reactive or planned meter work results in the removal or replacement of meter assets. It also includes costs associated with the termination/ abandonment of electric or natural gas service where there has not been an active customer for an extended period of time and the meter or valve is not accessible, resulting in the need to remove the service in order to abandon the meter. Table 1 above provides the actual and projected Customer Operations capital spending summary for the time periods indicated.

Meter purchases and labor/contracting related costs to perform the reactive or planned work that results in replacing or removing meter assets are the two largest components of investments for Customer Operations. The overall trend in capital spending is a reduction in 2022 and 2023 of about 48%, as a result of reaching steady state in 2021 with gas service abandonment work. This is partially offset by other increases including inflation. BGE’s historical spend of $18.4 million in 2019 is higher than the MYP years due to higher spending in 2019 on the Gas Meter Relocation and Protection Program, as discussed further below.

Q. HAS THE COMPANY COMPLETED THE GAS METER RELOCATION AND PROTECTION PROGRAM THAT WAS ADDRESSED IN CASE NOS. 9484 AND 9610?

A. Yes, the Gas Meter Relocation and Protection Program was successfully completed in 2019. This safety program involved moving gas meters outside of customer garages and installing barriers to the meters to protect them from being struck by vehicles. For planning purposes, a small amount of capital spend is included in 2020 and 2021 for the potential of any newly identified customers that require their gas meters to be relocated and protected.

Q. PLEASE DESCRIBE THE CUSTOMER OPERATIONS O&M ACTIVITIES.

A. Table 2 above provides the actual and projected Customer Operations O&M for the time periods indicated, and the previous section of my testimony provides details on Customer Operations O&M activities. The majority of Customer Operations' costs are related to labor (employees and staff augmentation) and are approximately two-thirds of the MYP spend. The remaining spend is comprised of contracting, uncollectibles and other miscellaneous. The overall trend in O&M spending over the 2019-2023 time period is effectively flat.

Q. DO YOU HAVE ANY FINAL COMMENTS?

A. Yes. Due to efforts to manage costs, the overall trend in O&M spending is effectively flat while capital spending decreases over the MYP period.

Q. DOES THIS CONCLUDE YOUR TESTIMONY?

A. Yes.

An Exelon Company

2020-2023 Plan Documentation – Capital and O&M

Executive Category Owner: Tamla A. Olivier

Title: Senior Vice President, Customer Operations

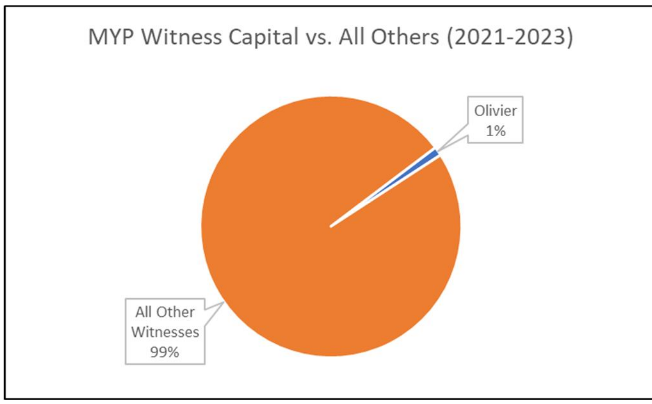
I. Financial Summary

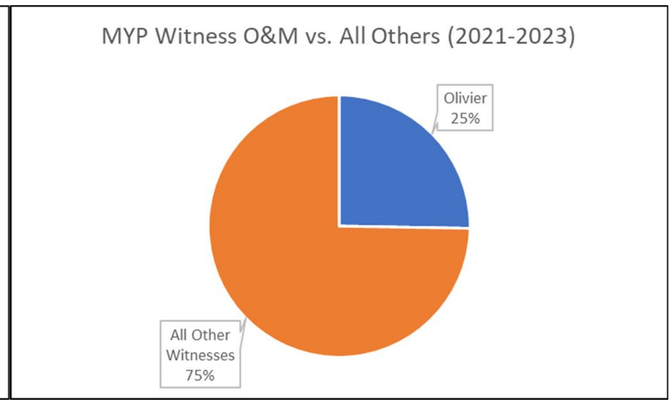
A. Capital

CATEGORY	2019A	2020F	2021F	2022F	2023F
CUSTOMER OPERATIONS	$18,351,228	$14,998,198	$13,944,406	$9,431,381	$9,577,780
ANNUAL TOTALS FOR CAPITAL	**$18,351,228**	**$14,998,198**	**$13,944,406**	**$9,431,381**	**$9,577,780**

B. O&M

CATEGORY	2019A	2020F	2021F	2022F	2023F
CUSTOMER OPERATIONS	$110,130,330	$110,155,039	$111,456,230	$110,877,626	$110,782,016
ANNUAL TOTALS FOR O&M	**$110,130,330**	**$110,155,039**	**$111,456,230**	**$110,877,626**	**$110,782,016**





II. Capital Category Cashflows and Functions

A. Customer Operations

Category	2019A	2020F	2021F	2022F	2023F
Customer Operations	$18,351,228	$14,998,198	$13,944,406	$9,431,381	$9,577,780

- Customer Operations is responsible for the daily operation of BGE's customer interfacing departments including Customer Care/Contact Center, Credit and Collections, Billing and Payments, Field & Meter Services and Claims. It is also responsible for the development of strategic customer platforms, customer channels and related technologies. Capital spending categories include:
    - Meter Cost – Costs associated with the acquisition of gas and electric meters for new customers and replacements.
    - Gas Dig Ups – Costs associated with termination/abandonment of natural gas service where the meter or valve is not accessible, and service must be dug up in order to abandon the meter (for non-collection or branch services, etc.). The costs to remove the meters are capitalized as cost of removal.
    - Reactive Gas and Electric Meter Work – Meter maintenance work that results in the replacement/installation of new meter assets/equipment.
    - Smart Grid/AMI – Continued build out of Smart Grid/AMI technology for large commercial customers as well as to enable the eventual replacement of the MV-90 (Electric) and Metretek (Gas) meter reading systems.

- The overall trend in capital spending over the 2020-2023 time period reflects a significant decrease in 2022 resulting from the reduction of the Gas Dig-Ups required in 2021. In general, other items are trending slightly up with inflation.

III. Significant Capital Projects

This Section provides additional details for capital projects with spend greater than $1 million in any year within the 2019-2023 time period for each of the categories below.

A. Customer Operations

Project Name	60595: Gas Dig-Ups			
2019A	**2020F**	**2021F**	**2022F**	**2023F**
$4,162,435	$5,351,800	$4,417,503	$720,003	$720,000
Problem Statement		**Solution Statement**		**Estimated / In-Service Date**
Gas meters need to be removed from premises where there has been no service agreement and there is no access to the meter. Completion of these activities is heavily dependent on coordination with property owners.		Field and Meter Services (F&MS) identifies gas meters that require removal and contracts the service abandonment work.		Monthly / Various

Project Name	60601: Meter Cost			
2019A	**2020F**	**2021F**	**2022F**	**2023F**
$5,073,128	$4,128,000	$4,230,586	$4,336,247	$4,444,797
Problem Statement		**Solution Statement**		**Estimated / In-Service Date**
Meters are needed to perform new business and maintenance work. Stocked equipment is needed by field groups to maintain meters.		Meters are purchased by supply and are charged to Field and Meter Services (F&MS) through the meter allocation calculated by Financial Operations. Equipment withdrawals from RBC warehouse are charged to this project.		Monthly / Various

Project Name	60602: Capital Meter Work Electric			
2019A	**2020F**	**2021F**	**2022F**	**2023F**
$1,914,829	$1,870,065	$1,818,650	$ 2,027,113	$2,012,105
Problem Statement		**Solution Statement**		**Estimated / In-Service Date**
Electric meters are damaged, malfunction, stolen, or become obsolete.		F&MS identifies meters that need to be removed from the system. Labor and materials are provided to remove old meters and install new meters. Meters are charged to project 60601.		Monthly / Various

Project Name	60707: Gas Distribution Meter Protection			
2019A	**2020F**	**2021F**	**2022F**	**2023F**
$3,951,293	$575,056	$120,376		
Problem Statement		**Solution Statement**		**Estimated / In-Service Date**
Meters that are vulnerable to vehicular traffic can be damaged and cause uncontrolled release of gas. In 2016, BGE and the PSCED agreed that BGE would identify gas meters located in garages and relocate and protect these meters as appropriate.		Inspect metering equipment and move or protect as needed to remove/reduce vehicular traffic threat.		Monthly / Various

<table>
<tr><th>Project Name</th><td colspan="4">60603: Capital Meter Work Gas</td></tr>
<tr><th>2019A</th><th>2020F</th><th>2021F</th><th>2022F</th><th>2023F</th></tr>
<tr><td>$1,261,930</td><td>$959,580</td><td>$996,952</td><td>$766,834</td><td>$777,522</td></tr>
<tr><th colspan="2">Problem Statement</th><th colspan="2">Solution Statement</th><th>Estimated / In-Service Date</th></tr>
<tr><td colspan="2">Gas meters are damaged, malfunction, stolen, become obsolete.</td><td colspan="2">F&MS identifies gas meters that need to be removed from the system. Labor and material are provided to remove old meters and install new meters. Meters are charged to project 60601.</td><td>Monthly / Various</td></tr>
</table>

IV. O&M Category Cashflows and Functions

A. Customer Operations

Category	2019A	2020F	2021F	2022F	2023F
Customer Operations	$110,130,330	$110,155,039	$111,456,230	$110,877,626	$110,782,016

- Customer Operations is responsible for the daily operation of BGE's customer interfacing departments including Customer Care/Contact Center; credit and collections, billing and payments, Field Meter Services and Claims. It is also responsible for the development of strategic customer platforms, customer channels and related technologies.
  - Customer Care/Contact Center – Primarily an inbound call center where customers can get answers to questions related to bill inquiries or third party suppliers, can stop/start/transfer service, and obtain a host of other services. Customers can utilize various channels including e-mail, chat, and telephone to receive customer service and support. Customer Care/Contact Center costs are those associated with answering customer inquiries and issuing customer orders for emergency calls, billing calls, collection calls, new business calls, establishing new service, and service orders stopping or starting service at an existing location.
  - Customer Financial Operations – Costs associated with credit/security deposit management, billing, payment processing, collection actions in BGE offices and in the field, limited income activities, processing of bankruptcy orders and revenue protection activities.
  - Field & Meter Services – Costs associated with meter reading, meter maintenance scheduling and repairs, service orders, the meter accessibility program, operation of the energy measurement center for meter testing compliance, and Smart Grid/AMI operations including licensing fees for associated meter systems.
  - Customer Strategy and Governance – Costs associated with development and management of customer e-channels and customer experience improvement activities; functional support of multiple systems including billing systems, customer care systems, management of customer advocacy activities, support of the division's financial, business, and IT planning, project and change management activities.
  - Claims – Costs associated with claims made against the company for property damage and personal injuries. Labor associated with the billing and collection of damages to company facilities.
  - Uncollectibles:
    - Final bills are rendered after service has been suspended either due to being disconnected by BGE for non-payment or upon leaving the BGE service territory (voluntary termination).
    - If the account goes unpaid, it is written off seven months after final billing consistent with approved regulatory requirements.
    - For customer bankruptcies, BGE creates a pre-petition account to segregate any balances up to the filing date. This account is written off within 30 days. A post-petition account is created for any arrearages accrued after the filing date. The customer is held financially responsible for the post-petition account. If the petition is ultimately dismissed, the balance that was written off is charged back to the post-petition account.

- The overall trend of expenses in this category in the 2020 through 2023 timeframe reflects our expectations for productivity improvements to counter inflationary pressures. Examples include the upgrades to the Customer Care and Billing (CC&B) system, the Customer Experience Wrapper, and additional capabilities for representatives to allow them to handle multiple customer requests and complete calls more quickly.

V. O&M Details

Customer Operations
Major Cost Drivers by Project

Instructions:
List actual O&M expenses by project for 2019; provide a high-level description of the types of costs within the project, and discuss the key drivers of each type. Also list forecasted O&M expenses for 2020-2023.

#	Project	Description and Key Drivers	2019 Actuals	2020 Forecast	2021 Forecast	2022 Forecast	2023 Forecast
1	60557: Revenue Protection	Labor and materials for Revenue Protection department.	3,487,446	3,462,299	3,505,034	3,559,468	3,627,379
2	60558: Collections Operations	The Collections Operations costs are primarily labor costs for field collection activities.	2,947,961	2,931,356	2,619,412	2,660,980	2,703,529
3	60560: Revenue Processing	Labor and vendor costs for Revenue Processing department.	1,843,738	1,946,941	2,500,186	2,531,764	2,580,798
4	60561: Credit Services	Labor, staff augmentation, credit tools, and vendor costs for Credit Services department.	2,592,168	2,958,527	2,978,642	2,985,709	3,028,662
5	60562: Billing Services Office	Back office work for Billing Services. Key driver is labor.	4,642,025	6,360,171	6,764,997	6,769,313	6,932,420
6	60563: Case Management	Labor, office supplies, training, and telecommunications for Case Management department.	1,798,135	2,013,287	2,039,440	2,072,106	2,125,518
7	60564: Settlements	Damages paid by BGE to claimants where BGE has liability for either personal injuires or property damages.	4,017,076	1,020,530	1,020,828	1,020,805	1,046,359
8	60565: Customer Care Call Center	The Customer Care Center is the primary means for customers to contact BGE. Major cost drivers are labor, staff augmentation, and vendor costs for interactive voice response (IVR), bilingual and translation services, outbound dialer, software licenses, and other contracts.	24,081,400	26,314,863	26,759,934	27,060,864	27,563,260
9	60570: System Support Data Management	Labor, staff augmentation, project backfill resources, and vendor contracts for electronic invoice presentment (EDI), literature fulfillment and outreach communications, and bill payment solutions.	1,384,990	1,254,111	1,563,512	1,577,821	1,611,840
10	60571: Customer Operations & Support	Labor for production support and IT projects.	793,173	1,206,399	1,522,781	1,542,987	1,576,129
11	60572: Customer Strategy & Governance	Labor, vendor contracts, staff augmentation, and related costs.	1,216,695	1,409,898	1,360,996	1,373,676	1,398,466
12	60573: eChannels	Labor cost associated with the operations of the eChannels department.	1,017,185	1,072,826	1,074,705	1,082,007	956,316
13	60574: Bill Print	RR Donnelley printing services.	1,853,060	2,138,501	2,165,438	2,162,708	2,160,537
14	60575: Postage & Delivery	U.S. Postal Services (USPS) postage and delivery costs.	5,407,770	6,053,867	6,243,477	6,441,124	6,647,226
15	60578: Customer Care Center	This project funds staff augmentation for the call center to ensure that the call center meets RM43 service quality regulations. The RM43 regulations include reliability and service quality standards intended to enhance performance.	1,400,338	1,806,115	1,799,264	1,792,269	1,785,471
16	60582: Customer Experience Quality Assurance	Quality Assurance ensures that BGE provides customers with a premier experience by monitoring calls, email, and chats. Key driver is labor.	1,519,820	1,596,968	1,709,555	1,736,960	1,780,752
17	60583: Customer Project Planning & Support	Labor for Customer Project Planning and Support department.	1,067,863	1,195,338	1,207,861	936,308	964,171
18	60585: Customer Operations VP - O&M	Management and administration of Vice President's office for Customer Operations. VP office also contains budget for outside consultants, incentives, and memberships.	956,066	1,845,856	1,841,048	1,854,645	1,882,872
19	60588: Customer Operations Claims	Labor for operation of Claims department which handles the intake, investigation and disposition of all defensive claims against BGE. Also includes the investigation, billing and collection of damages done to BGE property and equipment.	1,887,865	1,736,515	1,757,200	1,782,090	1,824,129

Customer Operations
Major Cost Drivers by Project

Instructions:

List actual O&M expenses by project for 2019; provide a high-level description of the types of costs within the project, and discuss the key drivers of each type. Also list forecasted O&M expenses for 2020-2023.

#	Project	Description and Key Drivers	2019 Actuals	2020 Forecast	2021 Forecast	2022 Forecast	2023 Forecast
20	60589: Accounts Receivable Management Field	Service order work, cut in/cut out, gas continuous service, reconnect collection cuts, investigate switched meters. Key driver is labor..	3,945,568	3,321,038	3,365,735	3,423,502	3,504,170
21	60607: Meter Reading	Meter Reading. Key driver is labor.	2,509,619	1,715,318	1,639,718	1,583,273	1,440,739
22	60608: Energy Metering Center O&M Blended	Energy Metering Center training, annual meter inventory, meter sorting, meter data maintenance, radian standards (Field Meter Testing), administrative support. Key driver is labor.	1,554,960	1,063,193	1,079,682	1,098,177	1,127,299
23	60615: O&M Meter Work Electric	Reactive Work - Raise/fix buried electric meter boxes, cut in/cut out, repair/maintain/inspect electric meters, field verifications, AMI interface management unit installations, surge protector BGE Home, repair sunken underground, investigate awitched meters. Key driver is labor.	2,841,491	2,996,324	3,063,726	3,096,431	3,193,534
24	60616: O&M Meter Work Gas	Reactive Work - Maintain/repair/inspect gas meters, gas farm tap maintenance, gas continuous service, meter multiplier field verification, paint meter, repair rusted meter bars, investigate switched meters. Key driver is labor.	8,452,129	7,743,389	7,218,931	6,888,498	6,640,225
25	60656: Write Offs Gas O&M	Represents the projected amounts of write-offs for gas utility service.	4,332,944	4,045,737	4,321,129	4,214,240	4,205,592
26	61009: Fuel Fund Contribution	Bad debt expense associated with BGE funding 1/3 of customer arrearages if the Fuel Fund and the customer combine to fund 2/3 of the customer's arrearage.	1,450,776	1,600,000	1,600,000	1,800,000	1,800,000
27	61012: Write Offs Electric O&M	Represents the projected amounts of write-offs for electric utility service.	4,293,982	4,191,730	4,476,221	4,365,800	4,356,866
28	61013: Third Party Collections	Third party collection agency commissions for collection on inactive customer accounts.	1,326,817	1,214,116	1,238,267	1,244,762	1,247,343
29	61067: Smart Grid Software / Hardware Maintenance Costs	Costs to maintain software/hardware costs of AMI systems. Key driver is IT licensing fees.	1,399,992	2,168,508	2,285,847	2,404,935	2,465,138
30	61073: Smart Grid Operations	Smart Grid Meter Data monitoring and management. Key driver is labor.	3,065,908	2,224,212	2,269,140	2,318,400	2,385,585
31	61584: Accts Receivables Management	Contract Callers Inc.(CCI) vendor contract and labor.	3,159,843	3,402,423	3,476,222	3,556,046	3,644,546
32	61585: Business Customer Service Team	The Business Customer Service Team is the primary means for mid-sized customers to contact and do business with BGE. The key driver is labor.	957,671	1,294,021	1,311,215	1,332,424	1,366,489
33	65731: Customer Operations Savings for EU Analytics Customer 1	Impact of EU Analytics opportunities on Customer Operations Group.		(1,360,000)	(1,850,000)	(1,850,000)	(1,850,000)
34	65732: Customer Operations Savings for EU Analytics Customer 2	Impact of EU Analytics opportunities on Customer Operations Group.			(50,000)	(360,000)	(1,280,000)
35	65733: Customer Operations Cost Transformation Initiative (CTI)	Impact of CTI opportunities on Customer Operations Group.		(2,079,000)	(2,938,000)	(3,728,000)	(4,384,000)
36	25 Projects with no year >= $1 million		6,923,856	8,289,662	8,514,087	8,545,534	8,722,656
37	**Total**		**$ 110,130,330**	**$ 110,155,039**	**$ 111,456,230**	**$ 110,877,626**	**$ 110,782,016**

BEFORE THE MARYLAND PUBLIC SERVICE COMMISSION

CASE NO.________

DIRECT TESTIMONY

OF

MARK WARNER

ON BEHALF OF

BALTIMORE GAS AND ELECTRIC COMPANY

April 24, 2020

TABLE OF CONTENTS

I. INTRODUCTION

Q: What is your name, business address, and business affiliation?

A: My name is Mark Warner and my business address is 417 Denison Street, Highland Park, New Jersey, 08904. I am presently employed as a Vice President at Gabel Associates, Inc. ("Gabel Associates"), an energy, environmental, and public utility consulting firm. Gabel Associates specializes in energy consulting with deep experience in energy procurement, project development, energy policy, environmental analysis, in-depth economic analysis, and overall energy markets including generation, regional operators (especially PJM), and utilities.

Q: What is your professional experience and educational background?

A: At Gabel Associates, I lead a team of analysts that provides specialized economic, financial, environmental, and policy analysis related to energy markets and a variety of clean energy technology applications. I have been leading technical teams for over 35 years across a variety of utility industries, and I have been specializing in energy market policy and analysis since 2001. I have recognized expertise in economic modeling and policy development for new clean energy technologies, particularly regarding utility implications and market impact. My primary focus areas include renewable energy, energy storage, microgrids, advanced "behind the meter" energy project development, and electric vehicles, particularly Plug-In Electric Vehicles ("PEVs"). I support a wide variety of public and private clients, including energy utilities, and I interact closely with a variety of government agencies and regulatory authorities. I lead our firm's practice on PEV research and policy development, where we have been active for approximately four years. I am a co-founder of the ChargEVC[1] electric vehicle coalition, which is currently active in New Jersey and beyond, and I lead the research, analysis, and policy development efforts of that group. I received my education from the Georgia Institute of Technology where I received a B.S. and M.S in Mechanical Engineering. I was recognized as Clean Energy Market

[1] ChargEVC is a not-for-profit coalition of diverse stakeholders that support development of the electric vehicle market in New Jersey. Stakeholders include all four New Jersey electric utilities, both local and national environmental groups, New Jersey car retailers, vehicle manufacturers, charging companies, consumer advocates, and others.

Innovator of the Year by the New Jersey Board of Public Utilities in 2008, and I served on the board of the Mid-Atlantic Solar Industry Association for four years.

Q: What experience do you have with the electric vehicle market?

A: The emerging PEV market has been my primary focus area for the last four years. I routinely monitor industry developments, support a variety of clients with specialized market research, work with utilities that are developing programs as a subject matter expert, and interact with a wide variety of policy makers in multiple states regarding market development initiatives for PEVs. A key focus area has been the development of new tools and methodologies for assessing PEV impacts on energy markets and utility infrastructure, and rigorous methods for analyzing and documenting potential benefits, costs, and the net-benefits resulting from widespread PEV adoption. I have worked with nine different utilities in five different states on the development of their PEV programs, including tasks such as forecasting, opportunity assessment, strategic planning, PEV program design, budgeting, regulatory filing support (including preparation of testimony), benefit-cost analysis, and program implementation support. In addition, in support of market development efforts by ChargEVC in New Jersey, I was the lead investigator for a comprehensive benefit-cost study for the State entitled *Electric Vehicles in New Jersey, Costs and Benefits: The Opportunities, Impacts, and Market Barriers to Widespread Vehicle Electrification in New Jersey*.[2] This analysis was unique because it is based on detailed simulation modeling of both impacted energy markets and physical infrastructure loading, tuned specifically for conditions in New Jersey. Those tools and datasets have been refined over the last two years to enable a highly specialized assessment of PEV impacts on the electricity markets and infrastructure, and rigorous determination of benefits, costs, and Benefit-Cost Analysis ("BCA") using net-benefit merit tests specific to the utility PEV programs. I am also a frequent public speaker in a wide variety of forums regarding the electric vehicle market, policy development for electric vehicles, and utility implications of widespread electric vehicle adoption.

[2] See http://www.chargevc.org/wp-content/uploads/2018/03/ChargEVC-New-Jersey-Study.pdf.

Q. **Have you prepared a BCA in your direct testimony?**

A. Yes, I have. I developed projections of benefits and potential costs, and I prepared the BCA based on multiple perspectives that examine both the market-wide impact of vehicle electrification, as well as merit tests customized for each of the utility program offerings. These offering-specific merit tests are needed since each utility offering impacts the market in different ways. To the greatest extent possible, these merit tests were adapted from standardized tests typically used for evaluating utility energy efficiency programs.

Q: **What is the purpose of your direct testimony?**

A: The purpose of my direct testimony is to present the methodology and results of the BCA that was performed regarding the suite of PEV charging program offerings developed by Baltimore Gas and Electric Company ("BGE" or the "Company"), approved by the Maryland Public Service Commission ("Commission"), and subsequently implemented by BGE.

Q: **Can you provide an executive summary of the BCA and the associated results?**

A: This analysis quantifies the physical impacts of PEV use, grid loading changes that result from vehicle charging, and net changes in emissions (from both the tailpipe and the power plant). These physical impacts are translated to economic consequences for three impacted populations – utility customers (ratepayers), PEV owner/operators, and society at large. These economic factors consider changes in the cost of electricity induced by vehicle charging, savings in vehicle operating expense, and savings due to reduced emissions, among other factors. The economic considerations are combined into merit tests that quantify the net benefit-cost ratio from a variety of perspectives, including a portfolio level view, a market-wide societal cost test, and detailed merit tests customized for each utility offering depending on how each program directly impacts the market. The following chart summarizes the benefit/cost ratios quantified for each of these perspectives.

Figure 1: Merit Test Summary – Primary Case

	Primary Case			
	B/C Ratio	Net Benefit NPV	Impacted Group	Impacts Considered
Portolio Ratepayer Impact (Offerings 1-4)	2.63	$65,554,485	Ratepayers	Electricity Costs & Emissions
Market-Wide SCT (Natural)	2.12	$4,774,113,349	All	Electricity $, PEV OpEx, Emissions
Market-Wide SCT (Managed)	3.10	$6,145,656,982	All	Electricity $, PEV OpEx, Emissions
Offering 1: Residential Whole-House TOU	N/A	$349,925	Ratepayers	Electricity Costs Only (8-yr life)
Offering 2: Residential Smart L2 Off-Peak	2.95	$906,300	Ratepayers	Electricity Costs Only (8-yr life)
Offering 3: Commercial Multi-family	1.71	$5,672,114	Ratepayers	Electricity Costs & Emissions
Offering 4: Public Charging (DCFC & L2)	2.85	$58,626,147	Ratepayers	Electricity Costs & Emissions

The portfolio view, which presents a composite view of net benefit across all the utility offerings, *provides a strong benefit/cost ratio of 2.63*, reflecting the beneficial impact of increased PEV adoption on both ratepayer costs and the benefits of reduced emissions. A sensitivity analysis that considers only the monetized impacts on ratepayers (without emission benefits) was also considered, resulting in a net portfolio benefit ratio of 1.76.

Given the broad and transformative impact of vehicle electrification, I believe that the Societal Cost Test ("SCT") provides the best overall measure of net benefit. Based on a market-wide SCT that considers all costs and benefits, in the case where most residential charging happens in off-peak times (as encouraged by utility programs, i.e. the "Managed Charging" case), benefits exceed costs by a factor of 3.10. Considering a more conservative case where charging is not shifted to off-peak times (i.e. the "Natural Charging case), the market-wide benefits exceed costs by a factor of 2.12. The difference between the Managed and Natural charging cases quantifies the merit of the offerings being implemented by BGE to shift vehicle charging loads to off-peak times.

Offerings 2, 3, and 4 each demonstrate a benefit/cost ratio exceeding 1.0, confirming that the net-present-value of benefits exceeds costs. The Whole-House TOU offering does not have a benefit/cost ratio result because there are no costs associated with that offering.

Based on these collective outcomes, the BGE electric vehicle charging program delivers a strong net benefit for utility ratepayers and other impacted sub-populations. The details of both the methodology and results for this analysis are set forth in the sections below.

II. BENEFIT-COST ANALYSIS APPROACH AND METHODOLOGY

Q: Did you evaluate BGE's PEV charging programs for benefits and costs?

A: Yes. I evaluated the impacts expected to result from the programs and related PEV use. Based on these impacts, I prepared a detailed inventory of projected benefits and potential costs. This portfolio of benefits and costs was used to quantify the outcome of a variety of net-benefit merit tests. Many of the impacts from PEV use result from vehicle charging impacts on electricity markets and utility infrastructure. These impacts have physical, market, and environmental dimensions that can be quantified on an economic basis, in addition to broader strategic implications. The BCA is therefore based primarily on quantifying the net impact of displacing gasoline consumption with electricity use, and considering the impact of that change on the electricity market, implications for utility infrastructure, changes in environmental emissions, and other relevant factors for impacted populations.

Q: What are the objectives and scope of the BCA?

A: BGE commissioned this BCA study to provide a comprehensive and rigorous perspective on the costs and benefits associated with vehicle electrification in general, and the proposed utility PEV-charging offerings, in particular. The resulting analysis was designed to account for the emerging nature of the EV market, recognizes the need to adapt typical merit tests to the needs of the EV market and associated utility programs, and provides a combination of tests that, taken together, provide more complete insight than any single test could provide. This approach responds to challenges identified by the Commission in Order No. 88997.[3] The resulting analysis scope includes market-wide impacts across multiple sub-populations through an inclusive accounting of numerous costs and benefits associated with overall vehicle electrification, but also very narrow tests that consider how a particular utility offering impacts the PEV market and the direct impacts on ratepayers through changes in the cost of electricity (among other considerations).

[3] Case No. 9478, Order No. 88997 (MD PSC, Jan. 14, 2019).

Q: What assumptions were used regarding PEV adoption?

A: The BCA analysis is based on a forecast of PEV adoption within the BGE electric distribution service territory from 2020 through 2035. That 15-year period was used as the basis for evaluation since it allows for appropriate calculation of "lifetime savings" typically included in the net benefit-cost tests. This time period reflects the combination of the duration of BGE's PEV charging programs and the typical PEV service life, assumed to be eight years based on a typical PEV warranty.

This forecast builds on a forecasting methodology developed over the last three years across a variety of territories and is based on the most recent information available about historical PEV sales in Maryland. The forecast accounts for growth of the PEV fleet through new sales, as well as vehicle retirements and transfer of vehicles into and out of the state, covering both Battery Electric Vehicles ("BEVs") and Plug-in Hybrid Vehicles ("PHEVs") segments.[4] The overall PEV-forecast is used for the market-wide tests as described in more detail below, but the number of directly impacted vehicles is used for merit tests on an individual program offering.

The vehicle adoption forecast blends an extrapolation of historical sales in the short term, with transition to an aggressive but realistic growth in adoption through 2035. The forecast starts with the number of PEVs registered in Maryland as of the end of 2019, as reported by the Maryland Motor Vehicle Administration as retrieved through the State's online Open Portal. Allocation to utility territory was based on mapping by the Electric Power Research Institute, which indicated a relatively stable 55% fraction of statewide PEV sales in the BGE service territory over time. This fraction was used to translate the Maryland State forecast into the PEV population (of both BEVs and PHEVs) in the BGE service territory.

The forecast builds on these "current market" benchmarks based on sales growth assumptions. These growth assumptions reflect PEV sales growth in the state in the most

[4] BEVs are pure battery electric vehicles that are powered exclusively from batteries charged from an external source (typically the public electric grid). PHEVs are plug-in hybrid electric vehicles which run predominantly on battery power and can be charged from an external source, but also include a fueled internal combustion engine that can charge the battery when the state of charge is low. BEVs and PHEVs are referred to collectively as PEVs.

recent years, within the context of Maryland being a zero emissions vehicle ("ZEV") state[5] with significant market development aspirations. Key assumptions include:

- Combined PEV sales in the state have been increasing over the last few years, although unevenly. BEV sales were significantly stronger than PHEV sales, and the trend in the state – consistent with national sales trends – is that BEV sales will continue to outpace PHEV sales.
- The forecast assumes a strong re-bound from the soft growth evidenced in 2019 as more vehicles (with lower prices) become available, with growth increasing to the highest levels previously demonstrated in the Maryland market (65% for BEVs). Sales growth past that peak declines gradually consistent with the profile typical in emerging markets as they achieve scale. PHEVs are assumed to have lower sales growth than BEVs as noted above. The assumptions reflect current market conditions in the state, including no additional stimulus through a vehicle rebate program, but strong action to expand consumer awareness and increase the level of fast public charging available. These growth rates assume that a strong supply of newly announced PEVs are available in the state (i.e. no supply limitations).
- These assumptions are rooted strongly in recent PEV sales in Maryland, as informed by benchmarking (on sales growth trends) in other ZEV states. They are still considered fairly aggressive, however, with high levels of sales growth leading to approximately a third of the light duty vehicle population being electrified by 2032. This is consistent with global leadership aspirations, which are (a) other ZEV states and European nations that are targeting 30-35% electrification in the 2030 – 2035 timeframe, and (b) the fact that many major PEV suppliers are projecting that 30%-50% of their sales volume will be electrified by approximately 2035. This forecast therefore reflects a balance between historical sales trends in Maryland, and assumptions of strong growth on par with a market leadership position. Under

[5] ZEV states are those states that follow the California clean air standards. Those states have set goals for adoption of clean energy vehicle technology, particularly increased use of plug-in electric vehicles. The ZEV states, like Maryland, are market leaders in PEV adoption, and typically benefit from formal goal setting, state-level market development programs, and advantaged allocation of PEV products to the state.

these assumptions, approximately 80% of new light duty vehicle sales are projected to be electrified in 2035, which is a very high electrification fraction.

- These assumptions result in a projected 111,000 PEVs in the BGE service territory by the end of 2025, growing to approximately 1.2 million PEVs by 2035. As noted above, the BEV and PHEV population are forecasted separately, allowing for a detailed characterization of how those vehicle classes each impact the BCA results.

Q: Does this forecast account for recent market developments related to the COVID-19 crisis and other developments?

A: No. This forecast was developed in January of 2020, before the COVID-19 crisis forced a global economic slow-down. It also predated recent changes in the petroleum market due to intentional over-supply conditions forced by Russia and Saudi Arabia. After considering a range of possible responses to these recent and extreme global developments, I believe it is appropriate to retain the current vehicle forecast as the best available planning assumption long term. The primary reason for this approach is that these recent events are unusually extreme, and it is impossible to predict with any certainty an alternative forecast with improved credibility. In addition, this forecast is over a 15-year period, and it is possible that the short-term impact of recent events may be small in the context of this longer-term planning horizon. This BCA therefore depends on a forecast view consistent with broader market trends evident in January 2020 as a planning assumption, and once the impacts of the recent economic distortions are better understood, updates to the forecast can be made if needed. Similar considerations apply to forecasts used in the BCA related to long-term costs of electricity and the cost of gasoline.

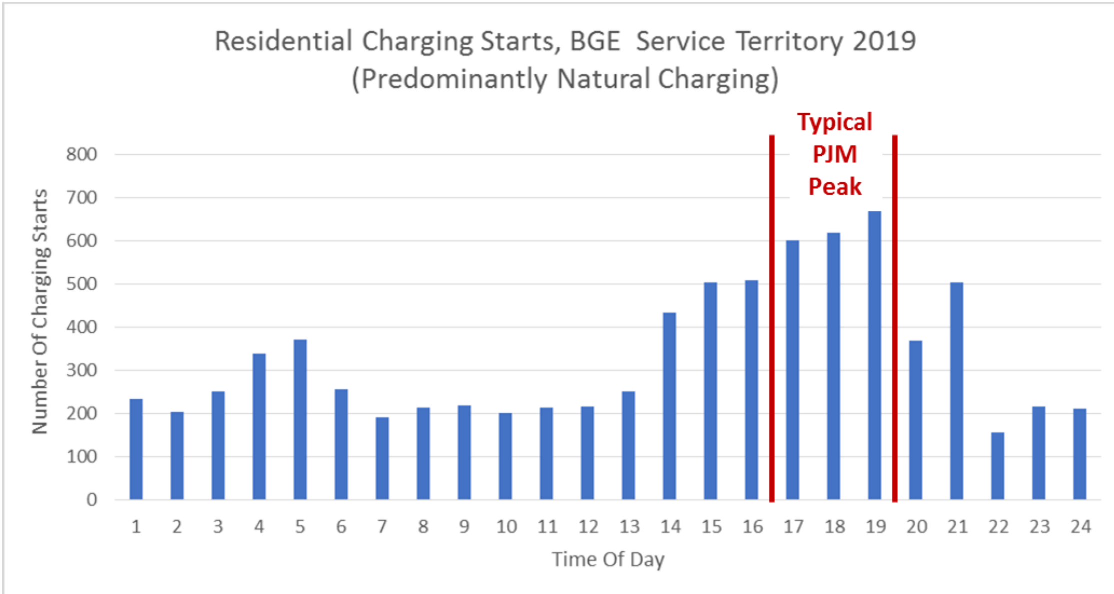
Q: How does the analysis quantify physical impacts from PEV adoption?

A: The model translates the number of PEVs on the road (from the forecast described above) into predominantly physical impacts on miles driven (gasoline versus electric), changes in electricity consumption (in megawatt hours ("MWhs")), changes in load profile (time-of-day MW distributions), and the resulting changes in emissions (net between tailpipe and power plant). These impacts are calculated for the baseline case (where there is no growth in PEV use), and the PEV adoption case under both "natural" and "managed" charging scenarios. Natural charging assumes that there are no programs or policies to influence charging behavior, and that residential charging loads begin to ramp up when most drivers return home from work. Managed charging assumes that policies and programs are in place to influence when charging happens, moving residential vehicle charging load from on-peak times to preferred off-peak periods. These physical impacts, for each of the three cases (baseline, natural, and managed), are calculated for each year from 2020 to 2035. The impact of PEV adoption is calculated as the difference in each impact-parameter between the PEV adoption cases and the baseline case.

Q: Why is it important to account for "Natural" and "Managed" Charging?

A: The majority of PEV charging will take place in the home, typically during overnight hours. The timing of these residential charging transactions determines the *power* impacts of vehicle charging on the distribution system, transmission assets, and generation capacity, and whether PEV charging creates additional peak load that would incur additional costs for all ratepayers and could force significant grid reinforcement investments. Numerous studies have demonstrated, however, that residential PEV charge timing can be flexible and is highly responsive to programs or policies that encourage more optimal charging profiles. This is a high impact consideration, since "natural charging" coincides strongly with existing peak conditions that drive significant ratepayer costs. The chart below illustrates aggregate residential load under natural charging conditions in the BGE service territory during 2019 and demonstrates a high degree of overlap with typical PJM peak periods.

Figure 2: Natural Charging – PJM Coincidence



Quantifying loading profiles under the "natural" and "managed" charging scenarios allows the value of managed charging to be determined, especially for utility EV programs that are specifically designed to shift PEV charging load to off-peak periods.

Q: How do these physical impacts translate into costs and benefits?

A: All of the physical impacts are further quantified in terms of their economic cost to various impacted population sub-groups. The total cost for each of the three cases (baseline with no PEV use growth, with PEVs under natural charging, and with PEVs under managed charging) are computed considering the cost of electricity, operating expenses for vehicles, and the costs associated with emissions. If costs go down in the PEV case compared with the baseline, they are considered a benefit for the BCA calculation. If costs go up in the PEV case compared with the baseline, they are considered a cost for the BCA calculation. Some other direct costs and benefits, such as the tax incentives associated with a PEV purchase (a benefit) or the expense to install vehicle charging infrastructure (a cost), are also calculated to provide a complete view of the cost and benefit portfolios. The BCA model maps these costs and benefits to three impacted populations: utility customers that do not drive PEVs (i.e. non-participants), PEV owner/operators, and society at large, the latter of which collectively bears the consequences of externalities such as air pollution or greenhouse gas emissions. Some benefits attributed to "society at large" also apply to utility customers, since they also bear the cost of environmental impacts directly. The Net Present Value ("NPV") of all costs and benefits are computed based on a discount rate of 6.42%, which was provided by BGE based on the Company's net of tax Weighted Average Cost of Capital from a settlement in its last rate case. Note that benefit/cost ratio results are not strongly dependent on the discount rate selected, since it typically applies equally to both costs and benefits.

Q: What methods were used to quantify costs and benefits for utility customers due to changes in electricity costs?

A: Determining how PEV charging affects electricity costs is a primary focus for the BCA analysis, and those impacts are quantified through a comprehensive model that examines wholesale market impacts, implications for capacity and transmission costs, and impacts on the distribution revenues collected by the utility. Both aggregate and unit-cost impacts are quantified to allow for the determination of electricity cost changes that affect all ratepayers. If rates are determined to go down in a PEV adoption case (relative to the baseline), that is considered a ratepayer benefit. The key electricity cost components considered are summarized as follows:

Utility Distribution Costs: The utility provided information regarding gross utility distribution revenue requirements. Based on this historical information, a baseline utility distribution revenue requirement was established for 2020 and projected forward using an electricity cost escalation rate of 0.8% per year. This rate was synthesized using United States Energy Information Administration ("EIA") statistics on distribution revenue growth. These gross costs represent the relatively fixed costs for utility distribution services, not including the PEV charging programs, which are accounted for as a separate cost.

a. **Wholesale Costs**: PEV charging, especially if done during off-peak times, changes the shape of the aggregate load curve. This modified load curve results in a change in the average wholesale cost of electricity since more electricity is purchased during lower-cost, off-peak times. Gabel Associates forecasts these impacts based on a detailed asset dispatch simulation using AURORAxmp ("AURORA"). AURORA is an industry-leading software and data package that simulates the hourly commitment and dispatch of electric generators to serve load, recognizing utility-level peak demand, transmission constraints, operational characteristics of generators, delivered fuel prices, and emissions prices, among other factors. Gabel Associates completed hour-by-hour market simulations using AURORA, for every year from 2020 to 2035, for each of the three cases (baseline, with PEVs natural charging, and with PEVs managed charging). Total wholesale electricity costs ($ per year) and generation emissions (tons of CO_2, NO_X, and SO_2) are the primary outputs of the simulation. Many other studies on PEV benefits are based on generalized assumptions about PJM costs or emission profiles. By contrast, this study looks at wholesale electricity costs (and emission) impacts based on detailed PJM dispatch simulations (for the BGE zone).

b. **Capacity and Transmission Costs**: The physical impact model summarized above can be used to create an aggregate load curve associated with PEV charging. This model accounts for the fact that vehicle charging takes place across a variety of segments (at home, at work, at public chargers, etc.), and computes the aggregate load impact for both the natural and managed charging cases. Separately, an analysis of the historical PJM-wide coincident peaks used for allocation of capacity and transmission costs was conducted.[6] The majority of peak obligation for BGE occurred during hour-18. The PEV charging load during the hour-18 period, for both the natural and managed charging cases, was used as an indicator for potential PEV charging impacts for peak-related costs. PJM costs for capacity (NITS cost estimates, in $/MW-day) and

[6] RTO (PJM) costs, specifically for capacity and transmission, are based on an iterative process of peak load calculations that feed into forward forecasts used to allocate cost obligations to each Local Delivery Area. Capacity cost allocations are more market driven, while transmission costs are more of a "fixed cost" allocation driven by real-world transmission construction planning. Given the significant, and persistent, impact that EV charging is likely to have on real coincident peak, this BCA analysis reflects an expectation that PJM planning will begin to reflect the load-shape impacts of PEV charging, thereby resulting in real-world impacts on ratepayer costs.

transmission ($/MW for the year) were projected through 2035 based on recent PJM market data. The capacity and transmission costs, multiplied by the PEV charging loads at PJM-wide peak times (during hour-18), allow for an estimate of potential capacity and transmission costs associated with PEV charging. These are generally additional costs compared with the no-PEV baseline case since load (in MW) has increased. A capacity reserve factor of 8.89% was used based on recent PJM guidance, along with a transmission and distribution efficiency factor of 92.851% based on information about losses from PJM.

c. **Ratepayer impact:** This analysis, based on the multiple factors noted above, computes an estimate of aggregate electricity cost impacts as would be monetized to ratepayers on their utility bills. It is difficult, however, to project exactly how those cost impacts would translate to specific customer rates. Some of these impacts, particularly peak loading changes that affect capacity and transmission costs, may exhibit a delay compared with when physical consumption changes affect the market. For example, PJM estimates (and allocations) of capacity and transmission costs typically depend on several years of a change in peak loading before those profiles affect capacity planning and percolate through the market as revised cost allocations. In addition, how cost changes (especially from PJM) manifest in customer utility bills will depend on utility decisions regarding cost allocation during rate cases (including both cost allocations across rate classes, as well as the distribution of costs across billing determinants within a given tariff), as well as the tariff structures approved by the regulatory body. Precise projections of exactly how any EV-charging impacts on cost-of-service impacts actual ratepayer bills are therefore beyond the scope of this study. Regardless, I believe the cost impacts estimated in this analysis are realistic estimates of how real macro-economic costs will change in response to the project EV-charging loads, and that those costs will eventually impact real utility customer billing in a proportional way. They are therefore a reasonable indicator of ratepayer benefit (or cost) impacts suitable for use in a benefit/cost analysis.

d. **Total Electricity Costs:** Impacts on utility distribution costs, wholesale electricity costs, and capacity and transmission costs are considered in detail as part of the BCA. Changes in these costs, between the PEV and baseline cases, indicate how electricity costs change *for all ratepayers* as a result of PEV charging. This model captures several dynamics associated with PEV charging impacts on electricity costs:

- Overall electricity use (total MWhs) goes up due to the increased electricity use associated with vehicle charging;
- Unit costs (dollars per kilowatt hour ("kWh")) go down due to the combination of dilution of distribution costs through increased MWh volume and reductions in average wholesale unit costs due to more optimal loading (*i.e.*, wholesale load-shaping with larger fractions of total wholesale costs being in lower off-peak times);
- Capacity and transmission costs go up due to the increasing load, although they increase more for natural charging than managed charging;
- Of these three effects, the dilution effect is the strongest and generally results in a net reduction in unit costs, on a per-kWh basis as monetized to all ratepayers through lower utility bill costs;
- This change in aggregate costs (between the with-PEV and baseline cases) is applied against just the baseline load to determine the impact on utility customers that do not drive a PEV; and
- The above dynamics are captured as appropriate for each utility PEV charging program, since each program impacts the market differently. The residential smart charging programs, for example, focus on shifting charging load to off-peak periods, while other offerings such as the Multi-Unit Dwelling ("MUD") charger rebate encourage adoption that would not otherwise happen and results in broader electricity cost impacts (including dilution and load-shaping). Each merit test includes

the electricity cost impacts that are appropriate for that offering's market impact.

Q: What methods were used to quantify costs and benefits for PEV drivers?

A: Impacts on vehicle operating expense were computed based on both the difference between fueling with electricity versus gasoline, combined with projected changes in maintenance expense. It costs less to "fuel" a PEV with electricity than it does to fuel a traditional vehicle with gasoline based on differences in vehicle efficiencies and basic energy costs (electricity versus gasoline). Furthermore, early market evidence suggests that PEVs cost less to maintain due to the simplified drive train. The combination of these two factors generate significant savings in operating expense for PEV owners/operators. The fuel savings are computed based on a projection of electricity and gasoline prices and average vehicle efficiency factors (miles/kWh, or miles/gallon)[7], while maintenance savings are estimated based on results from a vehicle maintenance study by the American Automobile Association ("AAA") on a per-mile basis.[8] To ensure a fair comparison, an additional expense is assumed for PEV owners based on replenishment of the infrastructure funding lost through avoided State and federal gasoline taxes. Details on these calculations are provided below.

a. Vehicle Charging Electricity Costs: Since most PEV charging happens at home (75%-85%), the residential cost of electricity is used for computing the costs of vehicle charging given average miles driven and average vehicle efficiency (in miles/kWh) for each year in the study period. The all-in residential cost of electricity was provided by the utility for 2020, and those costs were projected through 2035 based on the electricity cost escalation factor extracted from EIA data. The model computed BEV and PHEV charging costs separately, given unique efficiency parameters for each.

[7] As noted in the discussion of vehicle forecast, these long-term projections of gasoline and electricity prices were based on long term trends evident before the recent pandemic and crash of oil prices. Given that the extent and duration of those events are highly uncertain, the original forecasts (developed before the pandemic) have been used as the best planning assumption available.

[8] American Automobile Association, *Your Driving Costs*, 2019 Edition.

b. Cost of Gasoline: EIA projections[9] on the cost of gasoline through 2035 were used as the basis for the cost of fueling traditional vehicles and the fueled fraction of PHEV travel, as normalized by a comparison of Maryland versus national gasoline costs from the price tracking website gasbuddy.com. Projections of fuel costs, combined with projections of the average miles driven and average vehicle efficiency (in miles/gallon) of the base of light duty vehicles being displaced by PEVs, were used to compute gasoline costs for each year in the study period.

c. Infrastructure Tax Adders: An operating expense for PEV drivers is added that is equivalent to the federal and state gas taxes to ensure fair comparison between gasoline-fueled and electrically-powered scenarios. The current gas tax in Maryland, combining both federal and state taxes, is 53.7 cents/gallon. That is translated to a cost-per-mile based on average vehicle efficiency (miles/gallon) for each year in the study period and is included as an operating expense for PEV drivers. Note that most studies do not account for the need of PEVs to equitably contribute to transportation infrastructure funding, and including this cost for PEV drivers puts the BCA analysis on a more fair apples-to-apples comparison basis, and represents a more conservative assumption about PEV benefits given that gas tax replenishment policies have not been implemented.

d. Maintenance Costs: A variety of recent studies have documented early market experience with the costs of maintaining traditional vehicles compared with electric vehicles (both BEVs and PHEVs). I used the 2019 data from AAA for these factors (as cited above) and applied the relevant maintenance costs per mile to each vehicle type to determine changes in maintenance costs. The general trend is that maintenance costs for PEVs are lower than with traditional vehicles, given the simplified drive train, and the elimination of routine maintenance such as oil changes and tune-ups.

[9] United States Energy Information Administration, Energy Outlook 2019, published January 24, 2019, Table 12.

e. PEV Operating Expense: PEV driver operating expenses are determined based on the combination of the costs of electricity for vehicle charging, the costs of gasoline, maintenance costs, and the transportation infrastructure tax replenishment adder.

f. Traditional Vehicle Operating Expense: Costs to operate a traditional (internal combustion) vehicle in Maryland are significant, amounting to approximately $29.2 billion over the period in gasoline and maintenance expense (for the group of vehicles displaced by PEVs). PEVs cost approximately half as much to operate as a traditional vehicle, and the reductions in operating expenses associated with vehicle electrification therefore represent billions of dollars of increased disposable income for Maryland households as high levels of adoption are achieved. These savings are accessible by any Maryland household that makes use of an electrified vehicle.

Q: Are there other costs and benefits that accrue to PEV drivers?

A: Yes, in addition to impacts from fueling and maintenance costs, PEV drivers experience both a price premium for the initial vehicle purchase (a cost), and a one-time federal tax incentive associated with their new vehicle purchase (a benefit), and a variety of non-economic advantages.

a. PEVs of all types currently command a price premium, measured as the higher average Manufacturers Suggested Retail Price or "MSRP" for typical PEVs compared with traditional internal combustion engine vehicles. This cost premium is declining over time, based on increasing competition, larger industry scale, and especially the reduced cost of vehicle batteries. An estimate for this price premium over time was based on projections by NREL[10]. This price premium is considered an incremental cost absorbed by PEV drivers.

b. The federal government provides a tax credit for the purchase of a qualified PEV. The amount of the credit varies by vehicle type and range, up to a maximum of $7,500. It

[10] National Renewable Energy Laboratory, Electrification Futures Study – End Use Technology Costs and End Use Projections through 2050, Published 2017.

is generally modeled as a benefit, since that economic incentive flows to Maryland PEV owners from an external source (*i.e.*, the federal government). That tax credit begins to decline when at least 200,000 PEVs from a particular manufacturer have been sold within the United States, and several market leaders (such as Tesla and Chevrolet) have already surpassed that threshold. As part of the BCA analysis, an assessment of cumulative sales rates for different PEV manufacturers was completed to determine the current average incentive level available, and the expected decline rate, based on volume-weighted sales in the U.S. Overall, the average incentive declines as more manufacturers surpass the 200,000-vehicle threshold. This declining incentive is included as a benefit for all PEVs purchased in the BGE service territory through 2026 (for BEVs) and 2028 (for PHEVs).

c. PEV owner/operators (and drivers) enjoy a variety of non-monetary benefits, including the potential for increased safety (due to a lower center of gravity and state of the art safety features), reduced road noise, increased "fueling" convenience (no trips to the gas station), fewer maintenance events, elimination of State vehicle inspections, state of the art design with desired technical features, appreciation for the environmental, societal, and geopolitical benefits associated with reduced petroleum use, and an enjoyable driving experience. While these non-economic considerations are very important to many PEV drivers and consumers, they are difficult to quantify economically and were therefore not considered as part of the formal BCA. These benefits are significant, however, and should be considered as important context in PEV adoption policies and program evaluations.

Q: What methods were used to quantify the economic impact of changes in emissions realized by society at large?

A: Current levels of vehicle emissions impose significant costs on society through health care expenses, extreme weather damage, lost worker and business productivity, asset devaluation, etc. Although frequently considered an "externality," there is real economic value that accrues to society due to the avoided emissions enabled by widespread PEV adoption. More generally, greenhouse gases (especially CO_2) are widely considered the primary drivers of climate change, which imposes significant costs as well. The BCA model calculates the value of these avoided emissions based on net change in emissions per year and societal-cost-per-ton factors provided by independent sources as noted below.

a. Emission Changes: The model considers CO_2, NOx, and SO_2, and models emissions in the baseline case (traditional vehicle only, fueled by gasoline) compared with emissions in the PEV adoption case using predominantly electricity instead of gasoline (100% electricity for BEVs, and a combination of electricity and gasoline use for PHEVs). This model considers the *net* impact of the change in fueling considering both emissions at the vehicle tailpipe and emissions at the electricity generation facility. Emission factors for electricity generation were calculated based on dispatch simulation by AURORA for the actual vehicle charging loads projected. Emission factors for the mobile sources (pounds of emissions per gallon of fuel consumed) were from estimates of the United States Environmental Protection Agency ("EPA").[11]

b. Economic Value Of Reduced CO_2 Emissions: To determine the economic value of reduced CO_2 emissions, the BCA model uses the "Social Cost of Carbon for Regulatory Impact Analysis - Under Executive Order 12866" produced by the Interagency Working Group on Social Cost of Greenhouse Gases, United States Government, as updated August 2016. Specifically, the analysis used the "3% Average" case that represents a mid-point of the three primary CO_2 cost scenarios. This analysis, when adjusted to nominal dollars/ton in each year of emissions, provides an economic estimate of the value of avoided CO_2 emissions. Since CO_2 is easily and widely dispersed from any source regionally, economic impact factors are the same for both mobile and stationary electricity generation sources.

c. Economic Value of Reduced NOx and SO_2 Emissions: To quantify the benefits of SO_2 and NOx reductions, the model incorporates results from a recent EPA study that allocates public health costs associated with emissions across a variety of segments on a nominal dollar per ton of emissions basis. That EPA study provides different factors

[11] United States Environmental Protection Agency, Average Annual Emissions and Fuel Consumption for Gasoline-Fueled Passenger Cars and Light Trucks, published in October 2008.

for "on-road" mobile sources and stationary sources at electricity generation plants. The difference between these factors therefore accounts for not just the changes in the amount of emissions, but the fact that *vehicle electrification changes where the emissions happen* – shifting from typically more developed and populated areas along roadways to more remote power plant locations.[12]

d. The model computes the total emissions from gasoline use in the baseline case and the PEV case, and based on that difference, applies the economic factors to determine total environmental costs. As a general trend, overall economic costs due to emissions decline significantly due to PEV adoption given the lower net emissions rate and the shift in emissions geography. *These impacts are recognized by "society at large," but are also felt by utility customers since air quality affects all residents of the State.*

Q: Are there any other costs or benefits incorporated into the model?

A: In addition to the benefits and costs realized directly by the three primary sub-populations (PEV drivers, utility customers, and society at large), the model also accounts for a variety of other economic impacts on other market participants as summarized below:

a. <u>Utility Investments in Charging Infrastructure</u>: BGE is proposing a variety of customer offerings that provide equipment and services that directly support customers driving a PEV, and development of the PEV market overall in support of State goals. These utility costs include the capital and expense associated with delivering those programs, rate incentives, and general costs associated with information technology, data and network licenses, program administration, and customer education and outreach. This portfolio of utility program costs is comprehensive and includes all potential program costs subject to recovery from ratepayers. These costs are recognized when incurred according to the program deployment plan and, to ensure fair capture of full program costs, extend in time beyond currently approved budgets where appropriate. The utility cost plan is summarized in the following figure.

[12] United States Environmental Protection Agency, Technical Support Document, Estimating Benefit Per Ton Benefit of PM2.5 Precursors from 17 Sectors, Published February 2018.

Figure 3: BGE PEV Cost Plan[13]

	Deployment Goals	Costs
Offering 1: Wholehouse TOU Rate	Unlimited, 400 assumed	$0
Offering 2: Residential Smart Charging	1000 L2 EVSE	$300,000
Offering 3: Multi-Family Charging	700 L2 EVSE	$4,133,165
Offering 4: Utility Owned Public DCFC	150 Cnfg1, 25 Cnfg2, 25 Cnfg3	$17,675,000
Billing, IT, Admin, Marketing	N/A	$5,871,312
Total:		**$27,979,477**

Note that Offering 3 (for MUD chargers) is approved to support both Direct Current Fast Chargers ("DCFCs") and Level Two Chargers ("L2s") in those settings. Current program applications have been exclusively for L2s so far, and the program was modeled as an L2-only program in the BCA. That simplifying assumption can be revisited if program results indicate new DCFC interest in that segment.

b. **Revenues from Utility-Owned Charging Infrastructure:** BGE is approved to develop, own, and operate public charging infrastructure. This program includes both lower-power L2s, as well as higher-power DCFCs that address consumer concerns about range anxiety. The cost plan includes an 80%/20% split between L2 and DCFC, as currently approved. The Company will charge PEV drivers for use of these facilities at Commission-approved rates, the revenues of which will be used to offset ratepayer impacts. These revenues are captured as a benefit since they offset costs.

c. **Utility Investments in Grid Reinforcement:** Beyond the PEV programs noted above, there may be the need for additional utility investment in grid reinforcement. As PEV adoption grows, the Company will be required to deliver more electricity in support of vehicle charging. An *estimate* of these potential grid reinforcement investments, which are longer-term in nature, has been provided to ensure complete characterization of PEV adoption costs. See the section below on potential utility distribution impacts and how those potential costs were determined. Note that these costs have been included

[13] For Offering 4, Configuration 1 refers to sites with two dual-port L2 chargers, configuration 2 refers to sites with two 50KW DCFC and two dual-port L2, and configuration 3 refers to sites with two 150KW DCFC and two dual-port L2.

in the BCA as a possible longer-term cost for completeness, but they are not formally budgeted as part of the current utility program proposal.

d. **Investments by Non-Utility Entities in Charging Infrastructure:** In addition to actions by utilities, other market participants will be making incremental investments as part of more widespread PEV adoption. Primary examples include customer investments in electric vehicle chargers (commercial and residential), and investments by private capital in public charging infrastructure. A detailed model to estimate total infrastructure requirements across a variety of segments has been developed, including chargers in residential settings, workplace chargers, fleet chargers, and a variety of public chargers. The investment in a growing base of charging infrastructure is based on the vehicle adoption forecast noted above. Unit costs for different types of chargers have been estimated based on market data, while also ensuring consistency with cost assumptions inherent in the utility program filing. In most cases, both equipment costs and installation costs have been considered, which vary considerably by segment. Long-term estimates of those costs have been included (net of utility incentives) as part of the costs associated with market-wide vehicle electrification. Under this methodology, the combination of utility investments and non-utility investments fully capture the charging infrastructure investment requirements over time.

Q: Will there be impacts on utility distribution infrastructure resulting from PEV charging, and were those costs included?

A: Yes, it would be prudent to assume distribution system impacts due to increased loading from PEV charging longer term, especially in the residential sector where most charging takes place, and we have included an estimate of those costs in this analysis. We did not assess the physical impacts on the BGE distribution infrastructure at an engineering level as part of this study. However, Gabel Associates has conducted in-depth engineering analysis of PEV implications on utility infrastructure for other territories.[14] Those studies

[14] Detailed physical infrastructure impact studies were completed for a utility in New Jersey as part of the ChargEVC market opportunity assessment (Electric Vehicles in New Jersey – Costs and Benefits, ChargEVC, principle investigator Mark Warner, Gabel Associates, Inc. and Energy Initiatives Group LLC, January 26, 2018), and also specifically for the utility infrastructure on Long Island (Electric Vehicles On

identified several general conclusions that we believe are applicable across a variety of territories, and those guidelines were used to *estimate* potential costs for grid reinforcement resulting from PEV charging loads in the BGE service territory. In particular, utility infrastructure impacts vary over time as the PEV population increases, and it is useful to think about utility response (and associated costs) in three phases. Key guidelines for characterizing these three phases include:

a. When the PEV population is small (as an aggregate percentage of the overall light duty vehicle population in the territory), there is generally sufficient capacity within the distribution system to handle those incremental PEV charging loads, although clustering affects (*i.e.*, multiple PEVs within a single neighborhood) could cause localized distribution system loading issues.

b. During this early market phase, vehicle charging impacts, if they emerge, will be relatively localized and can be dealt with within the boundaries of routine maintenance and upgrade budgets already supported by the utility.

c. Based on consideration of a wide variety of PEV loading scenarios, my analysis suggests that more systemic loading impacts on the distribution system will emerge first on residential single-phase transformers. Larger impacts on conductor capacity, sub-station elements, line taps, load protection equipment, and transmission infrastructure would likely emerge in the longer term, if they emerge at all. The timing, and impact scope, of PEV charging depends heavily on residential PEV charging patterns, and managed charging – if fully deployed – can defer (but probably not completely eliminate) these impacts in time. The PEV programs being offered by BGE are intended to encourage residential managed charging. Note: the potential beneficial impact for managed charging is very large since it can (1) defer when residential charging starts (until after the PJM peak), and (2) spread the charging load over time. This load optimization avoids a potential increase in PJM allocation of increased capacity and transmission costs, as well as potential deferral, reduction, and partial

Long Island – Costs and Benefits, Principal Investigator: Mark Warner, Gabel Associates, Inc. and Energy Initiatives Group LLC, July 10, 2018).

elimination of grid reinforcement investments. An analysis of residential charging transactions in Maryland indicates that residential vehicles typically stay plugged-in approximately eight hours overnight, but only require about two hours of charging on average. Given the flexibility that most EV drivers have regarding overnight charging, the *charging load could be deferred until after the peak period and reduced by approximately a factor of four*. This trend has been consistent across multiple territories in other states that I have studied. This reality quantifies the potential for positive impact – through both reduced capacity and transmission costs and deferred or avoided grid reinforcement – from managed charging programs.

d. Once the PEV population exceeds the number of single-phase transformers, distribution loading issues will become more common since that condition begins to guarantee multiple vehicle charging loads on a given residential transformer. Past that point, more proactive grid reinforcement would be prudent to ensure responsible support for increased loading related to PEV charging. However, not all residential PEV charging happens at the same power levels and loads can range from 1.3 kW (for a typical "Level 1" charger, more typically used by PEV owners) to a higher-powered 7.2 kW charger (for a L2 solution favored by BEV owners with larger batteries). The model accounts for this portfolio of diverse loads on the electric distribution system and estimates that, *in the case where natural charging is dominant*, more systemic impacts will begin to emerge once the number of PEVs exceeds approximately 0.75 times the number of single-phase transformers. By comparison, in the case where managed charging is dominant, more system impacts are estimated to emerge when the number of PEVs exceeds approximately 2.7 times the number of single-phase transformers. For a given number of transformers and PEV adoption rate, this analysis can estimate when system grid reinforcement becomes necessary for both the natural and managed cases.

e. There are approximately 179,000 single phase transformers currently in BGE's service territory. Based on the current projection for PEV adoption in the BGE territory, more proactive grid reinforcement begins to become important around 2025 if natural charging is the dominant residential charging behavior. In the case of high levels of managed charging, grid reinforcements are deferred beyond 2035. This dynamic highlights the economic and strategic value of managed charging and why it is an important element of the BGE PEV charging program.

f. The associated grid reinforcement costs are scheduled in the cost model over time in proportion to PEV adoption, beginning in 2025 for the natural charging case, and assumes that the reinforcement takes place over a 15-year period. This high-level analysis assumes complete upgrade replacement of impacted single-phase transformers, at a cost of $15,000 each, although other technical options (such as feeder reorganization) may be determined to be optimal at that time. This analysis is significant, however, in that it assumes that eventually an upgrade of most, if not all, of the residential transformer base may be required. The costs for that reinforcement, from 2025 through 2035, are accounted for in this analysis as a market-wide cost. I consider this a highly conservative assumption since it reflects significant reinforcement investments that may ultimately not be required if other alternatives – such as strong managed charging programs or other feeder re-organization strategies – are ultimately used instead. No costs for grid reinforcement are required in the managed charging case, since the BCA model suggests that strategy defers impacts beyond the scope of this analysis study period.

g. Distribution impacts will be felt most strongly on residential circuits, where the majority of vehicle charging electricity is delivered. Impact on commercial circuits, for workplace, fleet, public charging, and other specialized infrastructure (*i.e.*, electric buses, etc.) have not been assessed in detail. While those installations are much smaller in number (compared with residential chargers), they may have higher power requirements that need to be assessed on a case-by-case basis.

h. The above guidelines demonstrate the importance of strong deployment of effective managed charging programs, especially for residential customers. While offering price signals that defer the start of charging into off-peak hours is a very effective strategy short term, eventually, as PEV penetration increases, these programs will be able to more actively coordinate vehicle charging through staggered starts, power throttling, and potentially curtailment in extreme cases. If managed charging is not implemented, larger impacts on infrastructure are likely to result as represented in the grid reinforcement costs associated with natural charging, in addition to potential increases in allocated PJM capacity and transmission costs. As noted above, effective managed charging programs reduce or mitigate distribution impacts by about a factor of four.

i. Note that these upgrades, although motivated by PEV loads, will also accomplish other reinforcement objectives, potentially including improved instrumentation, better resiliency, improved overall capacity, etc. Many of these transformers would require upgrades over a similar period anyway, even if PEV adoption did not happen. This assumption of full transformer upgrades is therefore extremely conservative, and probably overstates the costs that should be "booked" to PEV adoption, while also understating the associated benefits.

Q: How did the analysis determine merit for the utility programs?

A: Merit tests assess the *net* impact of benefits after costs are accounted for. A wide variety of merit tests are available, and they differ based on which costs and benefits are included, and which impacted populations are considered.[15] Numerous studies on vehicle electrification have focused primarily on market-wide net benefits considering the full impact of all electric vehicles on the road. This approach is helpful for understanding the overall policy merit of vehicle electrification, but implicitly overstates benefits associated with a particular utility offering since it considers the impact of *all* PEVs, beyond the market-impact scope of a particular utility proposal. In addition, other studies have attempted to evaluate utility PEV programs based exclusively on traditional – and relatively standardized – net benefit programs associated with energy efficiency ("EE") filings. Those protocols, if applied simplistically with narrow boundaries, can be confounded by the fact that vehicle charging *increases* electricity consumption, which is fundamentally different than the outcome expected from an EE measure. It is therefore

[15] California Standard Practice Manual, *Economic Analysis Of Demand Side Programs And Projects*, California Public Utilities Commission, October 2001, *available a*t:

http://www.cpuc.ca.gov/uploadedFiles/CPUC_Public_Website/Content/Utilities_and_Industries/Energy_-_Electricity_and_Natural_Gas/CPUC_STANDARD_PRACTICE_MANUAL.pdf necessary to apply the principles associated with standard tests to conditions applicable to the PEV market. Specifically, I consider two different views on net benefit that together provide a comprehensive perspective on the utility programs being offered. These two perspectives are based on a market-wide[16] SCT, and customized merit tests for each of the utility offerings that focus on non-participating utility customer impacts (*i.e.*, impacts on utility customers that do not own a PEV). Details on those merit tests are summarized below.

a. **Portfolio Merit Test:** The costs and benefits of each of the BGE offerings (1 through 4) noted below can be combined to provide a view of the net benefit at the overall program level. Since this test is an aggregation of the offering-specific tests, it provides a narrow assessment of the net impacts on non-participating ratepayers (*i.e.*, *all* utility customers that don't own a PEV) for the overall program.

b. **Market-Wide Merit:** The SCT measures net costs based on the total costs of the program, including both the utility's costs and the costs incurred by all other market participants. Similarly, all benefits are included, regardless of the impacted population, including externalities. The SCT used in this analysis is based on the standard EE-focused SCT as applied to PEVs and is an intentionally broad test that helps determine if society is better- or worse-off overall as a result of the tested market change (*i.e.*, increased PEV adoption). My design of this SCT is consistent with other studies that have attempted to quantify SCT-merit for utility PEV programs.

c. **Merit Per Utility Program Offering**: In addition to the market-wide SCT described above, I also designed customized merit tests per utility program offering. This approach is necessary since particular offerings impact the market in very different ways. The impact of a residential off-peak Time-Of-Use ("TOU") rate (BGE's Offerings 1 and 2), for example, affects the market in a fundamentally different way than public charging offerings (BGE's Offering 4). This per-offering merit assessment only considers costs and benefits that are directly tied to the particular offering. In

[16] In the context of the SCT, "market-wide" means the number of PEVs in the BGE service territory, but also reflects pricing dynamics based on the PJM market, of which BGE is a part.

general, these are very narrow tests that focus on utility customer impacts from the recovered cost of the PEV offering, and the benefits that are realized directly by all utility customers through either changes in electricity costs (as evident on their utility bill) or the value of cleaner air through PEV-induced emission reductions. *Unlike the market-wide SCT, which considers the impacts of all electric vehicles on the road in the utility territory, these per-offering tests capture only benefits induced by the directly impacted PEVs.*

d. **Multiple Perspectives:** Providing multiple perspectives on merit, including a market-wide SCT, a customized test per utility program offering and a portfolio test provides an appropriate, fair, and comprehensive perspective on both the overall program and the individual offerings. The SCT provides important context for market-wide impacts from vehicle electrification overall, and reflects a broad scope of market development activities that implicitly include the utility program. In parallel, the per-offering merit tests are highly customized to reflect the impacts of each offering, and the impact-scope (*i.e.*, number of vehicles and number of directly impacted customers) associated with the scope and design of each offering. The portfolio test quantifies the impact on utility customers from the offerings in aggregate.

Q: Can the results of the offering merit tests be combined to provide a perspective on net benefit of the overall portfolio of offerings?

A: Yes, a merit test that considers the *composite* net benefit of the portfolio of Offerings 1 – 4 is included in this BCA. This test aggregates the total costs, and all benefits, for each of the included offerings to provide a portfolio-level view. As with the offering-specific merit tests outlined below, this analysis considers only the costs and benefits that directly impact ratepayers, i.e. utility customers that do not own an EV. Both electricity cost impacts and emission impacts are considered in the primary case. A sensitivity case considers only electricity cost impacts as realized by ratepayers. This portfolio-level test provides the best perspective on how the overall program will impact ratepayers.

Q: Why did you use the SCT as the market-wide merit test?

A: Widespread PEV adoption will introduce profound changes in electricity markets and infrastructure, with a related beneficial net-impact on energy use, emissions, economics, and numerous other factors. Therefore, there is an impact beyond that experienced by PEV owner/operators, and significant societal benefit associated with PEV adoption externalities. I therefore consider the SCT to be a strong measure of market-wide merit for PEV adoption, and it provides important context for considering strategic and policy implications of the overall vehicle electrification transition of which the utility programs are an instrumental part.

Q: How are the benefits and costs described above considered in the SCT?

A: As noted above, the market-wide SCT incorporates *all* costs and benefits associated with PEV adoption in BGE's service territory regardless of the sub-group impacted. The following inventory of benefits and costs were included over the analysis period from 2020 – 2035 (methodologies for quantifying these elements are summarized in the sections above).

a. **Dilution of Utility Revenues:** An estimate of how unit-costs (dollars/kWh) of the relatively fixed utility distribution revenue requirements are diluted as volume increases due to vehicle charging. This effect is the reverse of the dynamic associated with EE programs that decrease overall consumption volume and lead to increased ratepayer unit costs, but in this case is strongly beneficial. These dilution impacts on a per-kWh basis are applied to the non-PEV charging loads (*i.e.*, electricity use by utility customers that do not own a PEV and who are not participating in the utility PEV Program) to determine utility customer impacts.

b. **Avoided Wholesale Electricity Costs:** Projected changes in wholesale unit costs due to changes of the aggregate load profile, particularly the increased fraction of overall consumption in lower-cost, off-peak times. In most cases, this is a benefit since average wholesale electricity costs decline as PEV charging increases off-peak consumption (especially with managed charging). These wholesale cost changes are applied to the non-PEV charging loads (*i.e.*, electricity use by utility customers not participating in the utility PEV Program) to determine utility customer impacts.

c. **Capacity and Transmission:** An estimate of how incremental vehicle charging loads would change capacity and transmission costs. Transmission and distribution losses and typical PJM capacity reserve factors are taken into consideration. A projection of both capacity and transmission costs, based on recent and projected cost factors, were used as the basis for estimating these impacts. Specifically, the projected charging load (from all charging segments) during the peak period during hour-18, compared with the typical BGE baseline at those times, is the basis for these costs. Since PEV charging typically imposes an incremental load, these are typically incremental costs in the BCA. Note that two variations of the SCT are provided, reflecting the natural and managed charging scenarios that introduce variations in the capacity and transmission impacts as well as variations in the wholesale price impacts noted above.

d. **Net Value of Avoided Emissions:** The economic value of changes in physical air emissions induced by PEV charging, including the benefit of reduced CO_2 and NOx, as offset slightly by an increase in SO_2. These economic factors reflect changes in where the emissions take place: vehicle emissions are lower in high population density areas along roadways; and higher in less populated areas near power plants. When the economic impact of net emissions goes down, these impacts are captured as a benefit, but when the economic impact of net emissions goes up, this impact is captured as a cost.

e. **Net Savings on PEV Driver Operating Expenses:** The long-term net savings for PEV owner/operators based on avoided gasoline costs, incurred costs of electricity for charging, and changes in costs for maintenance. This analysis also assumes that PEVs incur an additional expense to replace lost gas tax revenues so that roadway funding is retained. These impacts are all (strongly) beneficial over the period and are included as a benefit.

f. **Utility PEV Program Investments:** Capital and expenses for the utility PEV program, to be recovered from utility customers through rates. The majority of these programs are related to providing charging infrastructure, encouraging the adoption of managed charging solutions and related off-peak rate incentives, and other rate-related incentives. The overall PEV program budget includes all elements of program costs, including administration, IT integration costs, ongoing data license and network costs, and marketing and outreach programs. This cost plan is comprehensive and has been expanded over the full study period (2020 – 2035) and, in some cases, includes costs not currently in the utility program budget to ensure a full and complete accounting for costs.

g. **Utility Revenues for Utility-Owned Public Charging:** The utility will be collecting revenues from PEV drivers that use utility-owned and operated public chargers. Those revenues will be used to offset the recovery from ratepayers for those investments and are therefore are included as a benefit.

h. **Utility Operating Costs for Utility-Owned Public Chargers:** For the utility-owned and operated public chargers, there is an operating cost related to the cost of electricity used by the charger. These costs are included as a cost in the net benefit test.

i. **Utility Investments in Grid Reinforcement:** Estimated costs for utility reinforcement of the distribution system medium-term, with costs beginning in 2030. Only costs through 2035, which is the boundary for this analysis period, are included.

j. **Non-Utility Investments in Charging Infrastructure:** Potential costs incurred by non-utility market participants (PEV drivers and other private investors) for charging infrastructure over the analysis period *net* of any investments made by the utility through the program.

k. **PEV Driver Vehicle Purchase Premium:** An estimate of the purchase premium paid by purchasers of PEVs, captured as a cost.

l. **Value of Federal Tax Credits for PEV Purchase:** The federal tax incentive provided for PEVs, declining over time, based on distinct eligibility rules for BEVs and PHEVs, captured as a benefit.

The following figure summarizes how each of these elements were included in the SCT:

Figure 4: Market-Wide Societal Cost Test

Market-Wide Societal Cost Test		
Economic Impact	**Impacted Population**	**Cost or Benefit**
Impacts on Electricity costs (monetized to ratepayers)		
Changes in average wholesale electricity costs	Ratepayer	Usually A Benefit
Dilution of utility distribution revenues	Ratepayer	Benefit
Changes in capacity and transmission costs	Ratepayer	Usually A Cost
NET value of avoided emissions	Society at large	Benefit
NET value of reduced vehicle operating expense	EV owner/operators	Benefit
Utility EV program investments	Ratepayer	Cost
Utility revenues from public charging	Ratepayer	Benefit
Costs of electricity supply for utility owned chargers	Ratepayer	Cost
Potential utility investments in grid reinforcement	Ratepayer	Cost
Non-utility investments in charging infrastructure	EV owners and others	Cost
EV purchase premium	EV drivers	Cost
Federal tax incentives for EV purchase	EV drivers	Benefit

The SCT result is based on a benefit/cost ratio (NPV of benefits divided by the NPV of costs) and the NPV of benefits minus costs (per year) over the analysis period. A benefit/cost ratio over 1.0 is considered beneficial and implies that the benefits exceed the costs.

Q: How were the net benefits of the specific utility offerings assessed?

A: The offering-specific merit tests quantify the costs and benefits specific to each utility offering. These are very narrow tests designed to focus on impacts for non-participating utility ratepayers (*i.e.*, all utility customers that do not drive a PEV). These tests are based on the costs specific to the offering under consideration, and the scale of the offering (*i.e.*, number of participants and/or vehicles impacted). In contrast to the SCT – which compares the market with PEVs to the market without PEVs – these offering-specific tests focus on the direct change created in the market by the utility program. Each utility offering is targeted at different customer groups, and has a different market impact, which motivates the need for these customized merit tests. These tests have been specifically designed to quantify the net benefit of utility offerings that impose recovery costs on ratepayers, and the benefit realized by all ratepayers. These benefits vary by offering depending on the impact, but generally reflect how electricity costs for all ratepayers are affected by the offering, and in some cases the value of induced environmental benefits as well. As with most typical net benefit tests, the merit test quantifies a benefit/cost ratio based on the NPV of benefits divided by NPV of costs. What differs in each merit test is the portfolio of benefits and costs included for each utility offering, and the scope of offering costs and impacts considered for each.

Q: If these offering-specific merit tests are intended to quantify ratepayer impact, why are environmental benefits included?

A: As noted, in most cases the merit tests focus on the impact that vehicle charging associated with the specific offering will have on the cost of electricity for all ratepayers. In some cases, an offering also has significant indirect impact through environmental benefits. I believe it is fair to account for the value of environmental benefits for offerings that are instrumental in inducing increased PEV adoption, especially since improved air quality is an essential motivation (and impact of) PEV adoption and positively impacts all ratepayers. Unlike the SCT, however, only the subset of environmental benefits that are directly induced by the offering are considered, and only those environmental benefits that affect all ratepayers are considered. For most of the offers, a sensitivity analysis was also completed to assess net benefit if only monetized impact on non-participating utility customers is considered. The sections below outline the specific costs and benefits associated with each customized offering merit test.

Q: What methodology was used for calculating net benefits for Offering 1, the residential "whole-house" TOU rate?

A: Offering 1 is targeted to new or existing PEV drivers who want to charge their vehicle at home, but do not elect to participate in the BGE managed charging program (Offering 2). Existing PEV owners, who likely already have a home charging solution in place, are primary targets for this solution. Offering 1 considers PEV charging as part of overall household load and provides an incentive for *all* electricity consumption during off-peak times as defined by the applicable tariff. The customer is free to charge their PEV with any charger they desire, and no incentive related to the charging hardware itself is provided by BGE. Offering 1 is a rate incentive implemented through a revenue-neutral tariff, and the economic benefit is realized directly by the customer through electricity cost savings on their electric bill. Since the tariff is does not generate costs that are passed on to other non-participating ratepayers, there are no costs recognized in the BCA for this offering. This merit test is very narrow and reflects only the impact the offering has on shifting load to off-peak times; dilution is not considered as a benefit, since these customers are assumed to be charging anyway and the only impact of the offering is to influence *when* they charge. The only benefit considered is therefore the avoided costs associated with increased capacity and transmission impacts. A "success factor" is included to capture the fraction of kWh that are actually shifted to off-peak times, and this factor was developed based on the success rates exhibited by similar programs in other territories. There are no costs for this offer since the rate incentive is revenue neutral, and there are no equipment-related costs.

Q: What methodology was used for calculating net benefits for Offering 2, the residential smart charging program?

A: Offering 2 is a highly strategic platform solution that is targeted to new PEV drivers. The platform established through this offer could be the basis for expanded and more sophisticated managed charging programs over time. The offering allows the customer to select a networkable L2 charger from a BGE-approved list and provides a $300 rebate that can be applied against both equipment and installation costs. Participants in this program are also able to opt-in to a specialized EV-TOU tariff that has been approved by the Commission and is available to customers as of May 1, 2020. Customers that participate in the charger rebate program are not required to opt-into the EV-TOU tariff, although most customers are expected to take advantage of the savings this new tariff provides. This EV-TOU tariff does not result in costs that are passed on to other non-participating ratepayers. As a result, no incentive-costs are recognized in the BCA for this offering. The transaction information required to compute the off-bill incentive is collected by the Company directly from the networked residential charger. This offering has two market impacts: (a) it addresses consumer barriers for customers that are uncertain about how to charge their vehicles at home; and more importantly; and (b) it enables managed charging programs that encourage residential charging at optimal off-peak times. Customers are assumed to participate in the program for eight years, consistent with a typical PEV warranty period. This merit test is very narrow, however, and reflects only the impact the offering has on shifting load to off-peak times. Dilution is not considered as a benefit, because these customers are assumed to be charging anyway, and the primary impact of the offering is to influence *when* they charge. The only benefit considered is therefore the avoided cost associated with increased capacity and transmission costs. A "participation factor" is included to represent the fraction of customers that receive a charger rebate that opt-in to the EV-TOU tariff. A "success factor" is included to capture the fraction of kWhs that are actually shifted to off-peak times, and this factor was developed based on the success rates exhibited by similar programs in other territories. The costs included are the cost of the networked charger rebate, and the associated network and service fees. Other important strategic benefits, such as increased PEV adoption resulting from addressing consumer adoption barriers related to home charging uncertainty, and the fact that some of the start-up costs associated with this offering (especially regarding IT integration) could be leveraged through future programs, are not explicitly quantified in this analysis. If included, they would make the BCA outcome stronger. In addition, the transaction data collected through this program will be instrumental in future program design and optimization, ongoing benefit-cost analysis, and program evaluation, measurement, and verification. BGE is making the EV-TOU tariff available to any EV driver that has a networked charger that can provide the necessary transaction data to the utility for purposes of determining the incentive. That second group of participating customers, the population of which could be much larger than those customers in the rebated-charger program, could increase benefits associated with this program significantly. That secondary customer group has not been included in this initial BCA pending launch of the EV-TOU and better characterization of that additional customer group.

Q: What methodology was used for calculating net benefits for Offering 3, the MUD charger solution?

A: Offering 3 addresses the fact that residential chargers in MUDs are virtually non-existent in Maryland (and most other states). This segment includes all Maryland residents that live in MUD settings with shared lots, shared parking decks, or on-street parking. Many consumers that cannot count on a routine charging solution at home will simply choose not to drive a PEV, and the absence of chargers in the multi-family environment is therefore a major barrier for those consumers. Offering 3 specifically addresses a need not being met by the competitive market, and the PEV drivers impacted by this offering are expected to mostly be *new* PEV drivers. The multi-family solution offers the commercial customer (typically the property owner, property management company, or homeowner association) BGE incentives for 50% up to $5,000 per port for the purchase and installation of L2 chargers and 50% up to $15,000 per DCFC station, for a maximum incentive of $25,000 per site.[17] An additional rate incentive is provided, which will offset 50% of the demand charges typically induced by vehicle chargers on commercial tariffs, based on the

[17] As noted above, Offering 3 is approved to provide either DCFC or L2 in MUD settings, but given the general lack of MUD customer interest in DCFC so far, the BCA assumed that this program is exclusively L2. That simplifying assumption can be revisited if program results indicate an increased interest in DCFC over time.

nameplate capacity of the chargers installed. BGE will be able to collect transaction information from all chargers provided through this offering, which will help improve utility understanding of potential grid impacts from vehicle charging. Since the availability of these MUD chargers is instrumental in enabling PEV adoption for these consumers, this merit test includes the dilution effect associated with the vehicle charging consumption (kWh) for directly-impacted PEV drivers and consideration of the environmental value associated with charging of the supported vehicles. These environmental impacts are appropriate to include since the induced emission reductions benefit all ratepayers through cleaner air. For completeness, a sensitivity scenario was considered that included only the monetized impact on non-participating utility customer utility bills (without consideration of environmental externalities). The costs included are the costs of the utility offering itself, which is primarily the cost of the networked charger rebate (including installation), the associated network and service fees, and the value of the demand charge offset incentive provided to the commercial customer.

Q: What methodology was used for calculating net benefits for Offering 4, utility-owned public charging?

A: Offering 4 addresses the critical market need for public charging, including both lower-powered L2 chargers and higher-powered DCFC facilities. The single largest consumer adoption barrier for PEVs is the lack of a sufficient number of locations for public use (especially "quick charge" DCFC). These facilities have distinct and legitimate use cases that address the needs of both long-distance drivers and local drivers that find themselves in a "must charge" situation due to driving beyond their vehicle range. Although the need for these chargers is relatively rare when compared with the number of times the driver of a traditional vehicle visits a gas station to refuel, public chargers are nonetheless necessary. Consumer attitude surveys have consistently identified the shortage of public charging as a consumer barrier, even when the driver has access to charging at home or work or a PEV with a large battery. Improving access to these facilities is therefore a critical market development need that is only partially being met by the competitive market. The utility-owned public chargers will be targeted at those segments that are not well-served by private investors today. Under Offering 4, BGE will charge PEV drivers for the charging services delivered, and those expected revenues are included as a benefit that offsets the ratepayer recovery burden. The cost plan for this offer reflects the current BGE intention to include both lower powered DCFC (50KW) and newer high powered DCFC (150KW) consistent with rapidly advancing market trends. The addition of higher powered DCFC is significant since it provides greater convenience for the PEV driver through shorter charge times, is the preferred technology for fleet operators, and provides greater charging capacity to the market (i.e. a 150KW charger can support at least twice as many charging transactions in a day compared with a 50KW charger, especially as the number of PEVs with higher powered DCFC capacity increases). This offering-specific net benefit test is very narrow and captures the dilution effect associated with the electricity volume delivered by these facilities and the value of the emissions reduction associated with the vehicle charging delivered by these public chargers. For completeness, a sensitivity scenario was considered that included only the monetized impact on non-participating utility customer utility bills (without consideration of environmental externalities). The costs include the cost for the equipment and installation, and ongoing supply costs of the delivered electricity.

Q: What combination of costs and benefits were included in each of the offering-specific merit tests?

A: Please see the figure below.

Figure 5: Offering-Specific Merit Tests

Offering-Specific Merit Tests		
Merit Test	**Impacted Population**	**Cost or Benefit**
Offering 1: Residential Whole-house TOU rate		
Avoided peaking cost increases due to off-peak charging	Ratepayer	Benefit
Program costs (none in this case)	Ratepayer	Cost
Rate incentive (none, revenue netural)	Ratepayer	Cost
Offering 2: Residential Smart Charging		
Avoided peaking cost increases due to off-peak charging	Ratepayer	Benefit
Program costs (equipment/installation rebate)	Ratepayer	Cost
Rate incentive (off peak, off-bill)	Ratepayer	Cost
Offering 3: Multi-Family Charger Solution		
Value of diluated distribution costs (for volume delivered)	Ratepayer	Benefit
Value of reshaping wholesale load (for volume delivered)	Ratepayer	Usually a Benefit
Environmental benefit for enabled vehicles	Ratepayer	Benefit
Costs of increased load at peak time	Ratepayer	Cost
Program costs (equipment/installation rebate)	Ratepayer	Cost
Rate incentive (demand charge offset)	Ratepayer	Cost
SENSITIVITY: Electricity costs only, no emissions value		
Offering 4: Utility Owned Chargers For Public Use		
Value of diluated distribution costs (for volume delivered)	Ratepayer	Benefit
Value of reshaping wholesale load (for volume delivered)	Ratepayer	Usually a Benefit
Environmental benefit for enabled vehicles	Ratepayer	Benefit
Costs of increased load at peak time	Ratepayer	Cost
Program costs (equipment/installation rebate)	Ratepayer	Cost
Rate incentive (demand charge offset)	Ratepayer	Cost
SENSITIVITY: Electricity costs only, no emissions value		

III. BENEFIT-COST ANALYSIS RESULTS

Q: How would you summarize your overall conclusions?

A: This analysis represents an evaluation of both physical and economic impacts from widespread PEV adoption in the BGE service territory. Detailed projections of the benefits and costs are summarized in the sections below, as used in a portfolio assessment of all offers taken together, a market-wide SCT, and customized net benefit calculations for the offering-specific merit tests. The portfolio test represents a composite view of net benefit across all offers, aggregating the impacts that each offer has on the market. It is therefore a strong indicator of overall program merit. The SCT demonstrates that increased PEV adoption market-wide (within BGE's service territory), considering a wide range of costs and benefits by a variety of market participants, delivers substantial positive net benefit for both the natural and managed charging scenarios. Net benefit for the managed scenario is significantly higher than in the natural case, due to reduced peak loading and deferral of grid reinforcement costs. Customized tests for each offering, refined to reflect only the costs, benefits, and market impact associated with each offering, demonstrate similar net benefit. Based on these results, it is my assessment that expanded market-wide PEV charging and adoption in the BGE service territory delivers significant public benefits, the projected benefits exceed expected costs, and that net benefits are realized by all impacted populations, including utility customers. In addition, the individual programs offered by the Company each demonstrate positive net benefit, based on a customized merit test that considers the unique impact and scale of each particular utility offering. The following figure summarizes those merit test results for the primary case:

Figure 6: Merit Test Summary – Primary Case

	Primary Case			
	B/C Ratio	**Net Benefit NPV**	**Impacted Group**	**Impacts Considered**
Portolio Ratepayer Impact (Offerings 1-4)	2.63	$65,554,485	Ratepayers	Electricity Costs & Emissions
Market-Wide SCT (Natural)	2.12	$4,774,113,349	All	Electricity $, PEV OpEx, Emissions
Market-Wide SCT (Managed)	3.10	$6,145,656,982	All	Electricity $, PEV OpEx, Emissions
Offering 1: Residential Wholehouse TOU	N/A	$349,925	Ratepayers	Electricity Costs Only (8-yr life)
Offering 2: Residential Smart L2 Off-Peak	2.95	$906,300	Ratepayers	Electricity Costs Only (8-yr life)
Offering 3: Commercial Multi-family	1.71	$5,672,114	Ratepayers	Electricity Costs & Emissions
Offering 4: Public Charging (DCFC & L2)	2.85	$58,626,147	Ratepayers	Electricity Costs & Emissions

A variety of sensitivities were also considered, looking only at monetized electricity cost impacts directly evident to non-participating utility customers (*i.e.*, ratepayers that do not use a PEV) on their utility bill. The following figure summarizes the results of that sensitivity case.

Figure 7: Merit Test Summary – Sensitivity Cases

	Sensitivity			
	B/C Ratio	**Net Benefit NPV**	**Impacted Group**	**Sensitivity**
Portolio Ratepayer Impact (Offerings 1-4)	1.76	$30,504,717	Ratepayers	Electricity Cost Impacts Only
Offering 3: Commercial Multi-family	0.48	-$4,169,955	Ratepayers	Electricity Cost Impacts Only
Offering 4: Public Charging (DCFC & L2)	2.06	$33,418,447	Ratepayers	Electricity Cost Impacts Only

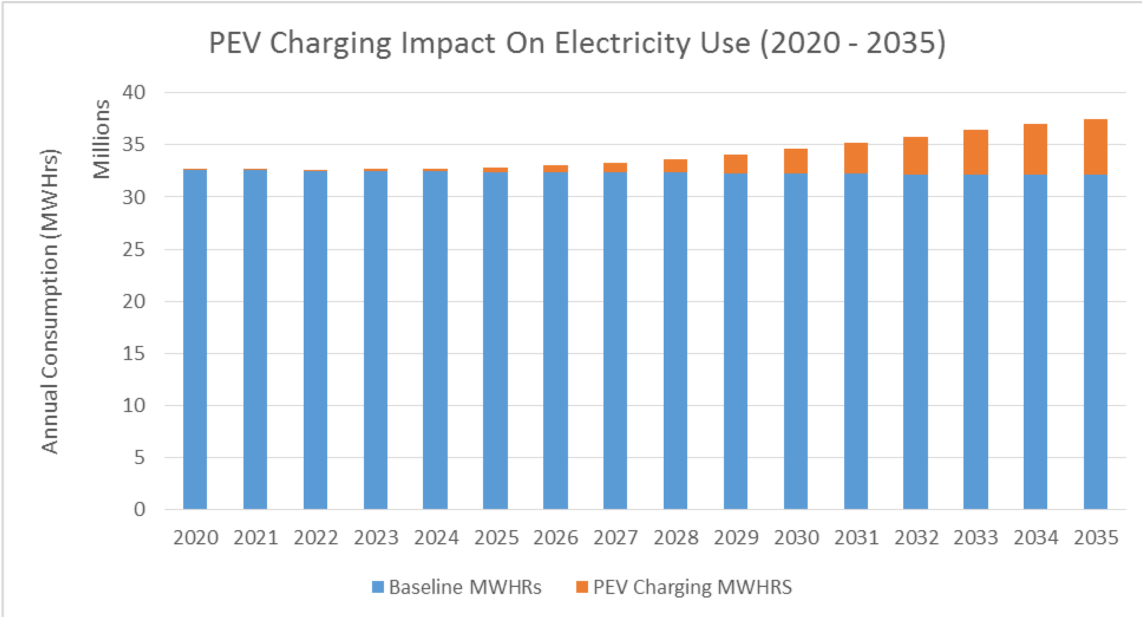
Q: In summary, what are the physical impacts of increased PEV charging and use in the BGE service territory?

A: Widespread PEV charging and adoption is projected to displace significant gasoline consumption, increase electricity use overall with modest impacts on PJM coincident peak (especially if managed charging is dominant in the residential sector), and reduce transportation-induced air emissions. Key results include the following.

a. In BGE's service territory over the period from 2020 through 2035, PEVs will account for 112.2 billion electrically-powered miles, resulting in an estimated displacement of 4.8 billion gallons of gasoline. This displacement of gasoline with electricity will have a profound impact for PEV drivers, resulting in changes in vehicle operating expenses, as quantified in the economic sections below. It also results in cleaner air and reduced CO2 emissions, and changes in grid loading as detailed further below.

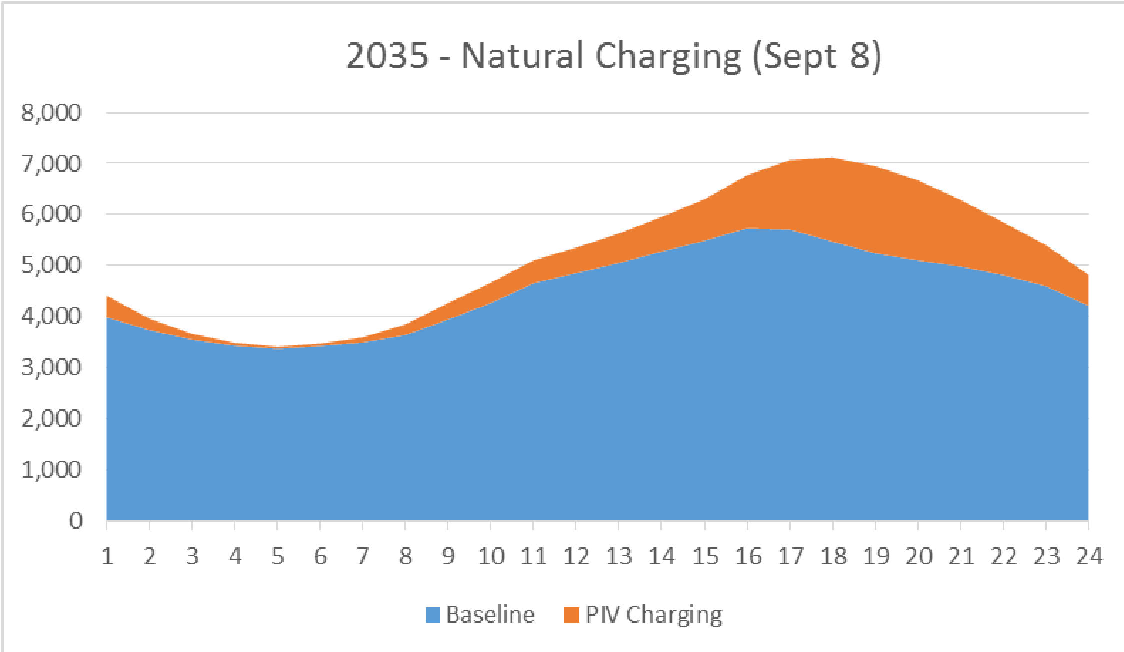
b. Electricity use is projected to increase due to PEV charging. PEVs will require an estimated 4,568 kWh per year for charging for each vehicle (average over the period 2020 to 2035). PEVs will add an estimated 68.9 GWh of electricity consumption in 2020, increasing in lockstep with PEV adoption to 5,424 GWh of electricity consumption in 2035 (in both cases, as measured at the customer meter). By 2035, PEV charging (across all sectors) will represent 14% of all electricity consumption. These changes in electricity volume will have a significant, but predominantly beneficial, impact on ratepayer economics as quantified in the merit tests outlined below, since overall utilization of the distribution system increases significantly. The following figure illustrates the impact of PEV charging on electricity use compared with baseline consumption.

Figure 8: PEV Charging Impact On Electricity Use



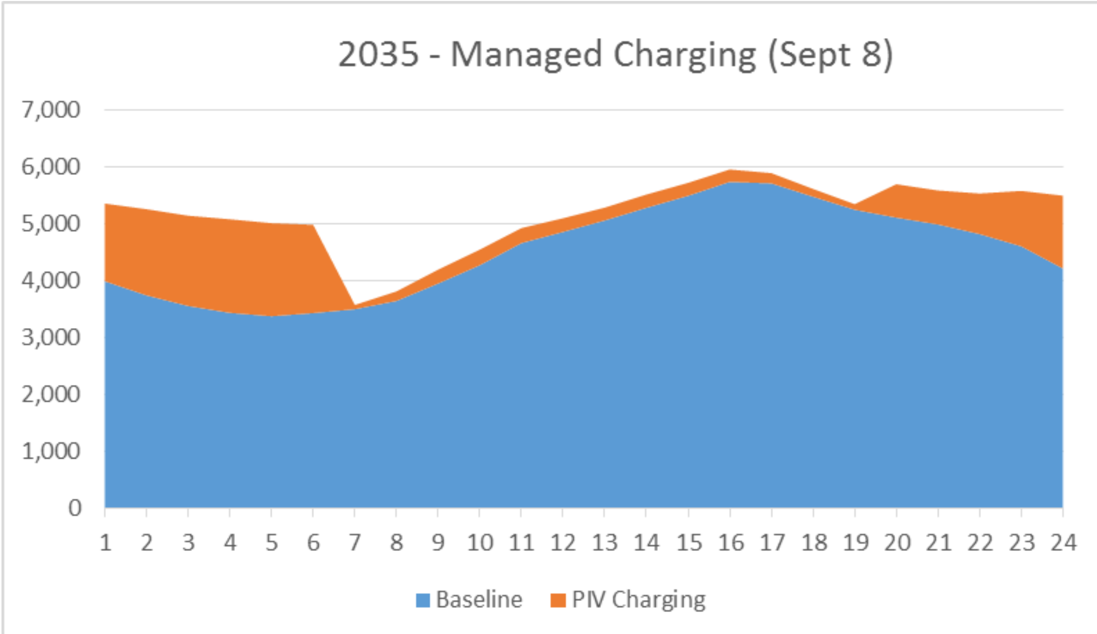
c. In addition to adding to overall electricity consumption, PEV charging will also change the shape of the aggregate load curve. These load profile changes could have both harmful and beneficial impacts on electricity costs: charging that takes place during off-peak times can be beneficial, but costs could increase if vehicle charging introduces additional peak load that increases PJM zonal capacity and transmission obligations short-term, or additional grid reinforcement obligations long-term. The following figure illustrates the charging profile for a representative day in 2035 in the case where natural charging dominates, considering home charging, commercial charging (for workplace and fleet charging), and public charging.

Figure 9 - A: PEV Natural Charging Profile, Representative Day In 2035



d. Managed charging (in the residential sector) changes the impact vehicle charging has on overall aggregate load shape significantly. Not only can additional PJM-coincident peak load be avoided, but maximum peak for the day is only slightly higher than the baseline scenario. Reducing the "load shape impacts" of vehicle charging can avoid additional ratepayer costs associated with allocated capacity and transmission costs medium-term (as those physical impacts eventually percolate through the market), but also defer and minimize the amount of grid reinforcement that may be required. The following figure illustrates the impact of vehicle charging in 2035 on a representative day and can be compared directly with the natural charging case shown above.

Figure 9 - B: PEV Managed Charging Profile, Representative Day In 2035



e. Although increased electricity use increases power plant emissions, tailpipe emissions are eliminated through PEV use, and the *net* impact is highly beneficial. After accounting for both tailpipe and power plant impacts, every electrically-fueled mile in BGE's service territory is projected to be 75% cleaner than a gasoline-fueled mile (average over the period), and this "cleanup factor" will increase as the fraction of electricity supplied by renewable sources grows. A total of 69.9 billion pounds of CO_2 are projected to be avoided over the period, along with 163.3 million avoided pounds of NOx. Net SO_2 is expected to increase slightly, adding a total of 11.4 million pounds of additional SO_2 over the period.

f. Most of the economic benefits quantified below are induced by the physical impact that vehicle charging has on gasoline consumption, changes in electricity consumption (and the impact on costs), and reductions in emissions.

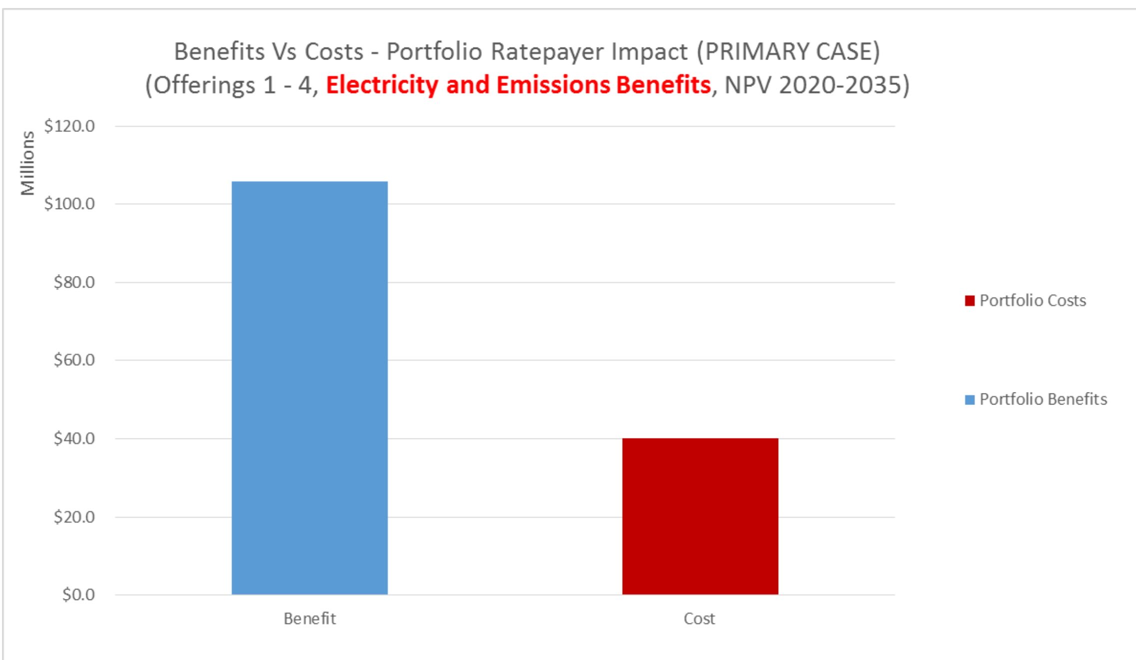
Q: What would the BCA results be if you considered the offerings at a portfolio level?

A: When combining the costs and benefits of Offerings 1 through 4 (as quantified further below), the portfolio delivered a net benefit on an NPV basis with a ***Benefit/Cost ratio of 2.63***. This portfolio considers only electricity cost impacts for Offerings 1 and 2 (i.e. the impacts of shifting load to off-peak times), and both the electricity cost and emissions impacts of Offerings 3 and 4 (which induce additional PEV adoption). These results demonstrate that benefits strongly outweigh costs for all ratepayers, and that there is public benefit to implementing BGE's offerings (1 through 4) when considered in aggregate. The following figures summarize benefits and costs for this test.

Figure 10: Factors Included In Portfolio Merit Test (Primary Case)

	Benefit	Cost
Portfolio Benefits	$105,720,696	0
Portfolio Costs	0	$40,166,210
Total:	$105,720,696	$40,166,210
Benefit To Cost Ratio:	2.63	
NPV of Net Benefits:	$65,554,485	

Figure 11: Benefits and Costs for the Portfolio Merit Test (Primary Case)



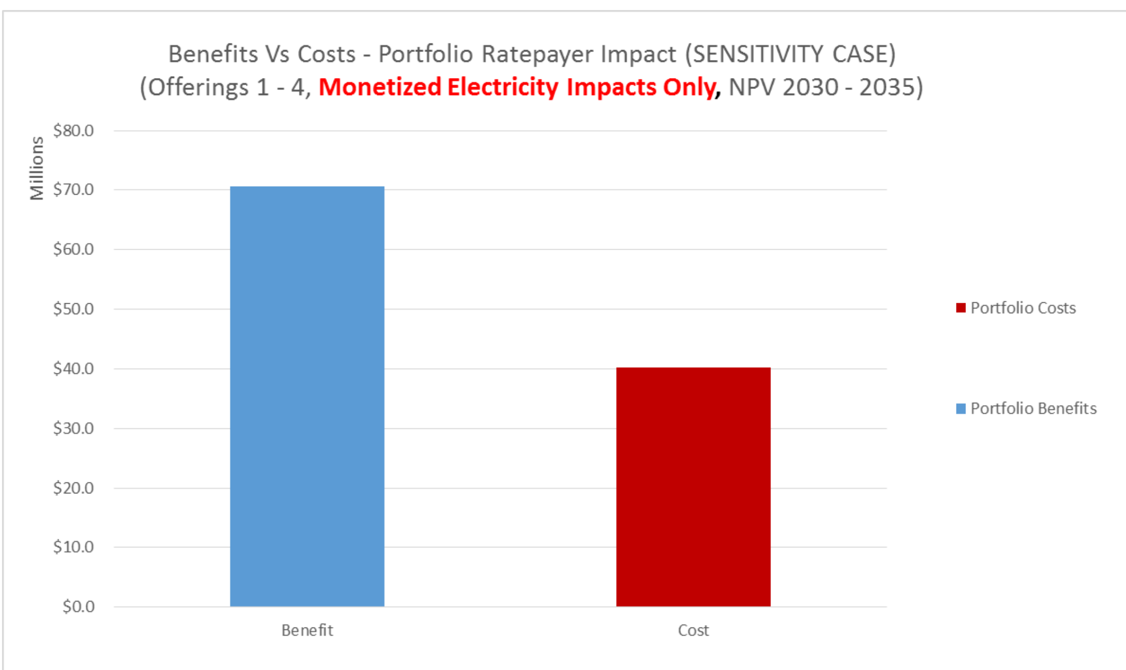
Q: How would the Portfolio BCA outcome change the sensitivity case where only impacts on electricity costs are considered?

A: Even on that narrow basis, the aggregate portfolio still delivers a net benefit on an NPV basis, with a ***Benefit/Cost ratio of 1.76***. This sensitivity characterizes the net benefit in the very narrow case where only impacts on electricity costs are considered, ignoring the environmental benefits realized by all ratepayers due to the portfolio as represented in the primary BCA case noted above. Despite restricting benefits exclusively to monetized economic impacts visible on customer utility bills, the portfolio of programs delivers net benefit. The following figures summarize benefits and costs for this test.

Figure 12: Factors Included in the Portfolio Merit Test (Sensitivity Case)

	Benefit	Cost
Portfolio Benefits	$70,670,927	0
Portfolio Costs	0	$40,166,210
Total:	$70,670,927	$40,166,210
Benefit To Cost Ratio:	1.76	
NPV of Net Benefits:	$30,504,717	

Figure 13: Benefits and Costs for the Portfolio Merit Test (Sensitivity Case)



Q: What are your net-benefit conclusions based on the market-wide Societal Cost Test?

A: The economic benefits and costs were combined to determine *net* benefit using the SCT as described in the methodology section above. ***The market-wide SCT delivered a net benefit on an NPV basis, with a SCT Benefit/Cost ratio of 2.12 for the natural charging case, and a significantly higher ratio of 3.10 for the managed charging case.*** This difference in outcome reflects the avoidance of additional capacity and transmission costs and deferred distribution-reinforcement costs resulting from managed charging. These results demonstrate that benefits strongly outweigh costs, and that there is public benefit to vehicle electrification overall, based on market development costs that include BGE's offerings. The multiple sub-populations' impacts (utility customers, PEV drivers, society at large) realize a net benefit (on an NPV basis) of $4.8 billion over the period for the natural charging case, and $6.1 billion under managed charging. The following chart summarizes how benefits and costs were combined in the SCT and the resulting net benefit ratio for both the natural and managed charging cases. Note that the managed charging case is the most relevant, because BGE's program includes a scalable platform for widespread managed charging, especially in the residential sector.

Figure 14: Market-wide SCT: Natural Charging

	Benefit	**Cost**
Benefit: Electricity Cost Reductions	$561,128,776	0
Benefit: PEV OpEx	$5,938,524,813	0
Benefit: Emission Reductions	$2,096,998,402	0
Benefit: Federal Tax Incentives	$378,048,728	0
Benefit: Revenues From Charger Use	$57,646,014	0
Cost: Electricity Cost Increases	$0	$488,211,162
Cost: Private EVSE Investment	$0	$1,604,238,419
Cost: Utility Incentives	$0	$23,351,890
Cost: Incremental PEV Costs	$0	$1,252,964,117
Cost: Potential Grid Reinforcement	$0	$889,467,796
Total:	$9,032,346,732	$4,258,233,383
Benefit To Cost Ratio:	2.12	
NPV of Net Benefits:	$4,774,113,349	

Figure 15: Market-wide SCT: Natural Charging

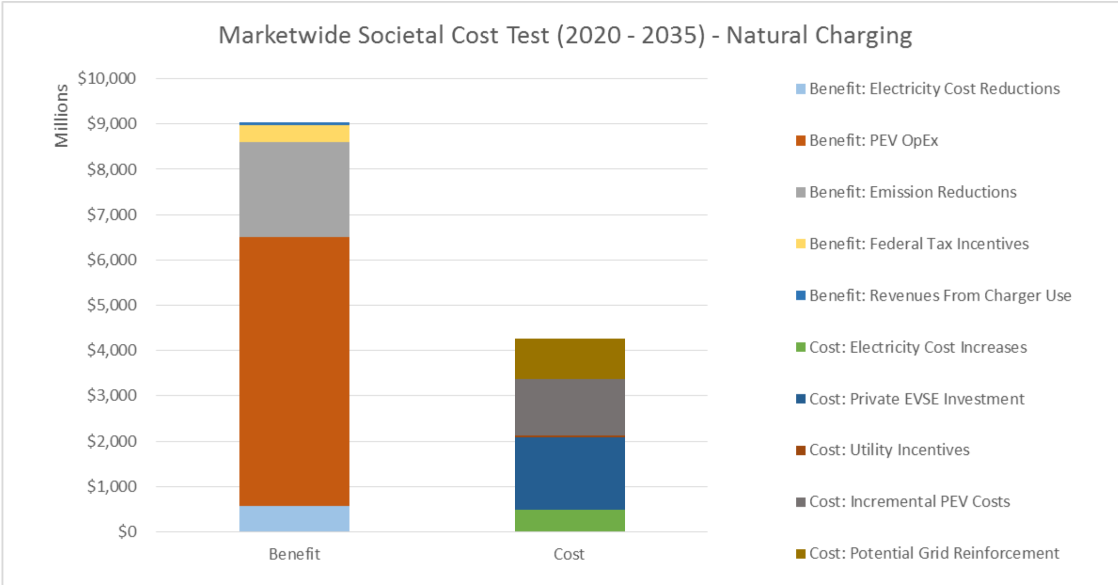
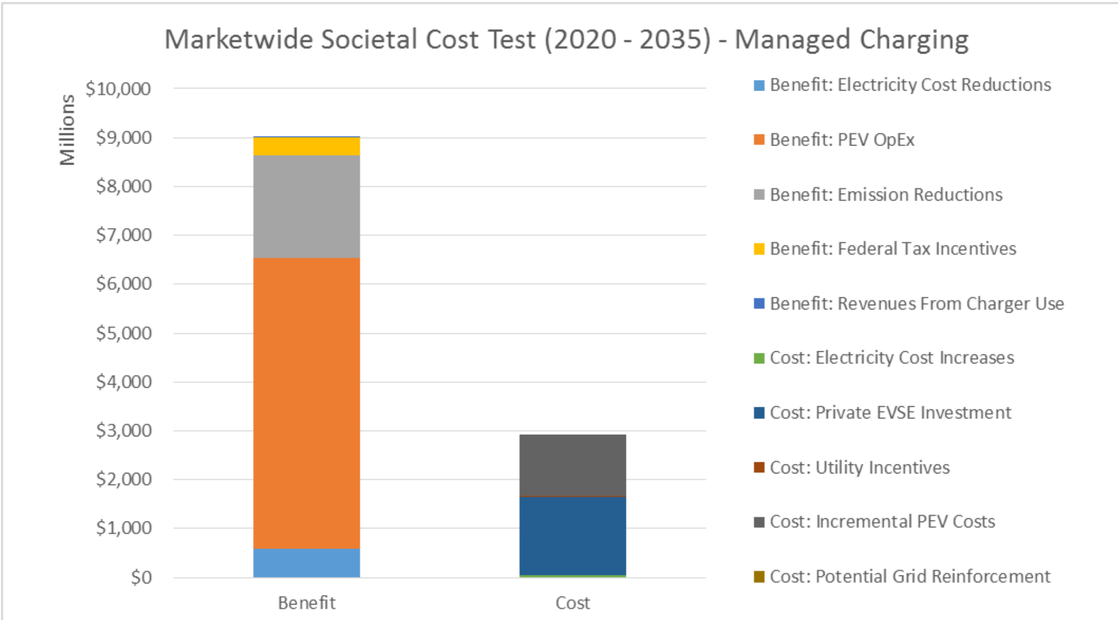


Figure 16: Market-wide SCT: Managed Charging

	Benefit	Cost
Benefit: Electricity Cost Reductions	$595,256,525	0
Benefit: PEV OpEx	$5,938,524,813	0
Benefit: Emission Reductions	$2,096,998,402	0
Benefit: Federal Tax Incentives	$378,048,728	0
Benefit: Revenues From Charger Use	$212,534	0
Cost: Electricity Cost Increases	$0	$40,263,074
Cost: Private EVSE Investment	0	$1,604,238,419
Cost: Utility Incentives	0	$23,351,890
Cost: Incremental PEV Costs	0	$1,252,964,117
Cost: Potential Grid Reinforcement	0	$0
Total:	$9,009,041,003	$2,920,817,500
Benefit To Cost Ratio:	3.10	
NPV of Net Benefits:	$6,145,656,982	

Figure 17: Market-wide SCT: Managed Charging



Q: What are the costs, benefits, and net benefit result associated with the merit test applied to Offering 1 (Whole-House TOU rate)?

A: It is not possible to calculate a benefit-cost ratio for Offering 1 because there are no costs for this program: there are no equipment costs; and the whole-house TOU is revenue neutral. The program is considered beneficial, however, since it delivers $350 million in general utility customer savings due to the value of shifting residential charging loads to off-peak times.

Q: What are the costs, benefits, and net benefit result associated with the merit test applied to Offering 2 (Residential Smart Charging)?

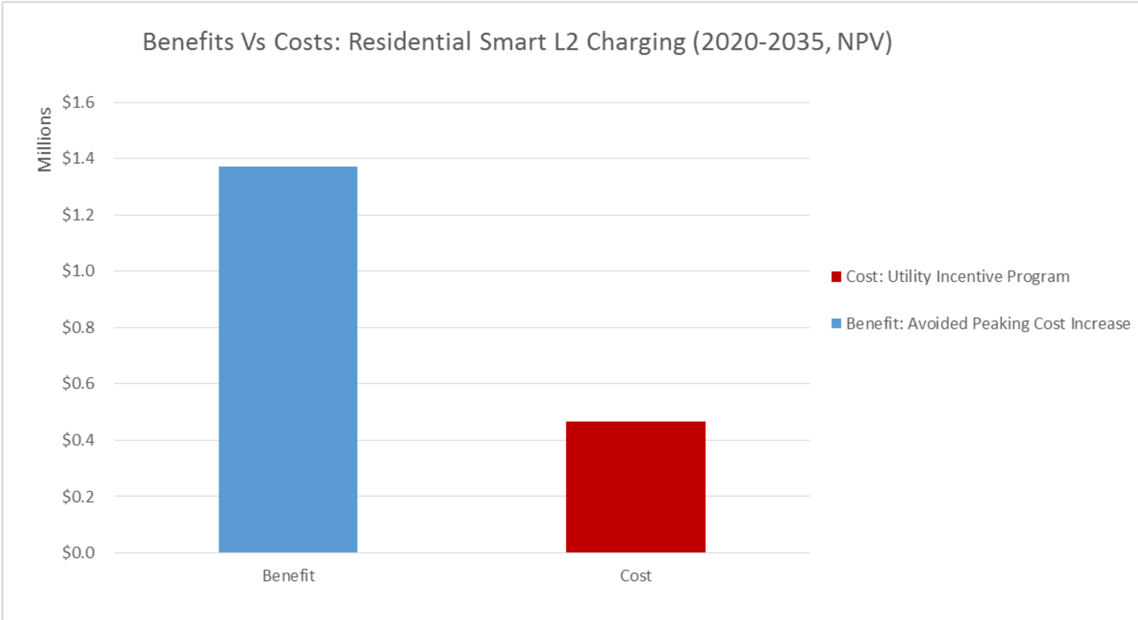
A: Offering 2 delivered a net benefit on an NPV basis, with a ***Benefit/Cost ratio of 2.95***. As described in the methodology section above, this is a very narrow test that considers only impacts on utility customers, including the costs of the BGE offering and *only* the benefits related to shifting charging load to off-peak periods. These results demonstrate that benefits outweigh costs for all BGE customers as realized through monetized changes in electricity costs for all ratepayers, and that there is therefore public benefit to implementing BGE's Offering 2. This offering is also strategic because it addresses consumer concerns about how they will charge their vehicle at home, and therefore helps encourage PEV adoption (and market growth) while also shifting charging loads to off-peak periods. This initial offering also results in the development of a scalable platform that allows BGE to interact with smart electric vehicle supply equipment ("EVSE") in the home, creating opportunities for more advanced managed charging mechanisms in the future as charging loads increase (coordinated start scheduling, power throttling, demand-response style curtailment, and ultimately Vehicle-to-Grid[18] ("V2G") capability). The platform developed with this offering can be reused for potential future managed charging programs. Those benefits are not quantified in the BCA outcome, but should be considered as strategic implications of significant merit. The following figures summarize benefits and costs for this test. As noted in the methodology section above, this test currently considers only the subset of rebated-charger customers that opt-in to the off-peak incentive program. BGE is offering the off-peak incentive to additional customers that did not get a charger rebate, and these customers will generate significant additional benefits and an associated increase in the benefit/cost ratio.

Figure 18: Factors Included in the Offering 2 Merit Test

	Benefit	Cost
Benefit: Avoided Peaking Cost Increase	$1,371,282	0
Cost: Utility Incentive Program	0	$464,982
Total:	$1,371,282	$464,982
Benefit To Cost Ratio:	2.95	
NPV of Net Benefits:	$906,300	

[18] "Vehicle-to-Grid" refers to the capability of smart EVSE to control a bi-directional flow of energy either into, or out of, the vehicle battery. When electricity is flowing from the battery to the grid, it is acting as a storage asset that can be used to shave peak load or firm local power quality. Managing a large and distributed group of V2G-capable vehicles can help optimize grid loading and reduce ratepayer costs. This technology can also allow the vehicle battery to power the home or building, providing resiliency value during extreme grid outage events.

Figure 19: Benefits and Costs for the Offering 2 Merit Test



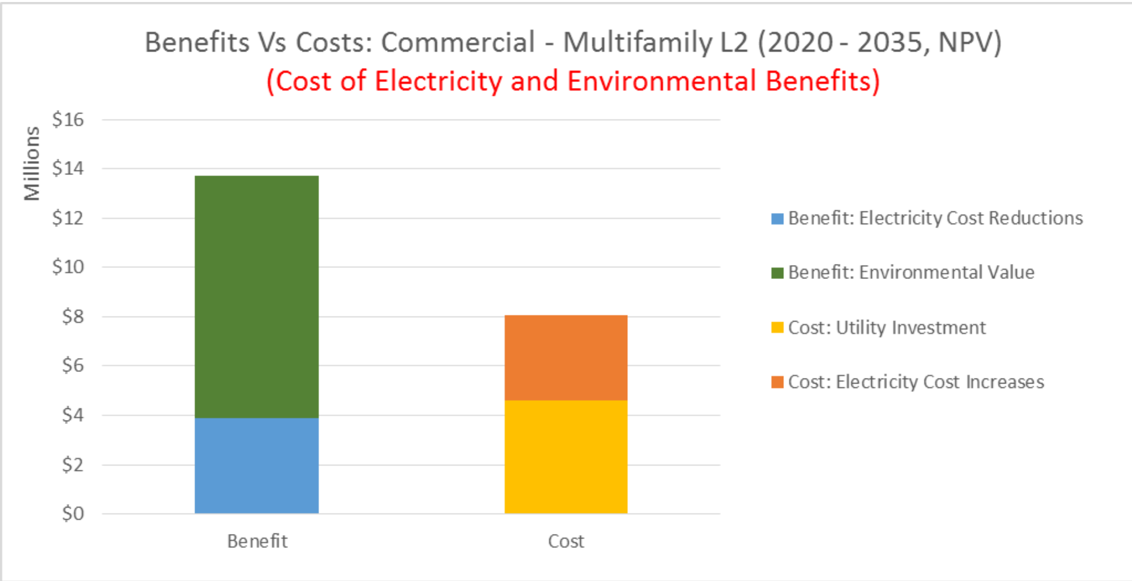
Q: What are the costs, benefits, and net benefit result associated with the merit test applied to Offering 3 (Commercial MUD L2), for the principal case where both electricity cost impacts and environmental impacts are considered?

A: Offering 3 delivered a net benefit on an NPV basis, with a ***Benefit/Cost ratio of 1.71***. As described in the methodology section above, this is a very narrow test that only considers impacts on utility customers, including the costs of the BGE offering and both the direct economic impacts (through electricity costs) and environmental benefits (which also impacts all ratepayers). This analysis considered both the beneficial impacts of dilution and aggregate load reshaping, but also the incremental costs of capacity and transmission costs due to charging by these customers at PJM-coincident peak times (hour-18). These results demonstrate that benefits outweigh costs for all ratepayers, and that there is public benefit to implementing BGE's Offering 3. The following figures summarize benefits and costs for this test.

Figure 20: Factors Included in the Offering 3 Merit Test (Primary Case)

	Benefit	Cost
Benefit: Electricity Cost Reductions	$3,871,529	0
Benefit: Environmental Value	$9,842,069	0
Cost: Electricity Cost Increases	$0	3,445,820
Cost: Utility Investment	0	$4,595,664
Total:	$13,713,598	$8,041,484
Benefit To Cost Ratio:	1.71	
NPV of Net Benefits:	$5,672,114	

Figure 21: Benefits and Costs for the Offering 3 Merit Test (Primary Case)



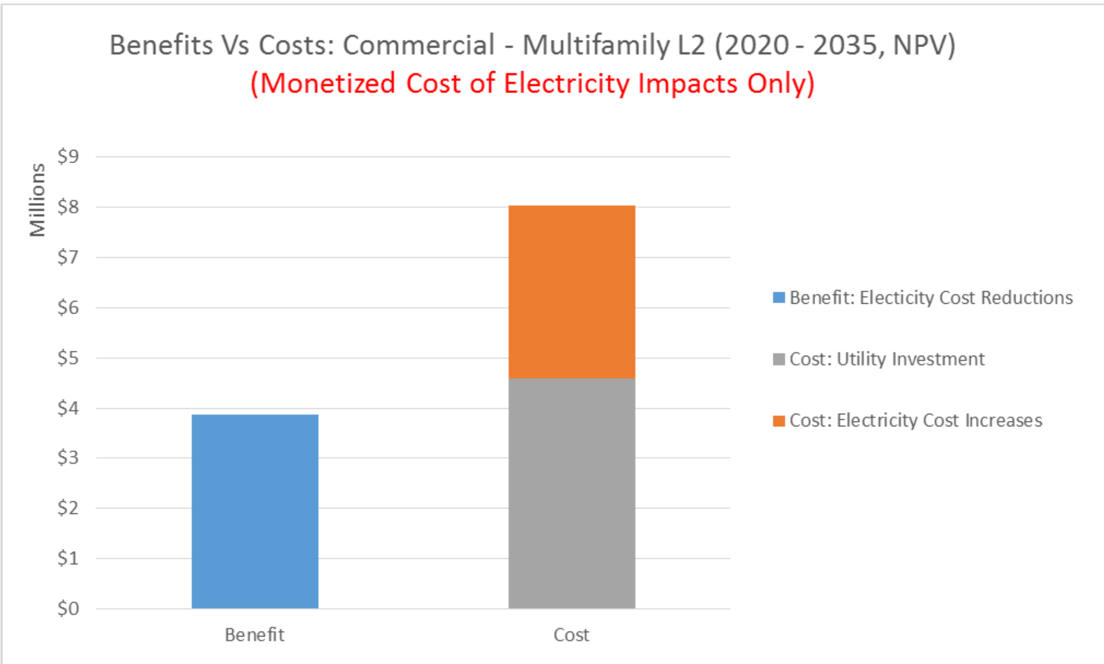
Q: How would the BCA outcome change for Offering 3 (Commercial MUD L2) in the sensitivity case where only monetized impacts on electricity costs are considered?

A: On that narrow basis, Offering 3 does not deliver a net benefit on an NPV basis, with a ***Benefit/Cost ratio of 0.48.*** The fact that the Benefit/Cost ratio is below 1.0 implies that costs exceed benefits. This is a very narrow test, however, and discounts the fact that charging infrastructure is typically not available for consumers that reside in a MUD, and that without access to routine charging they would be unlikely to adopt a PEV. Strategically, *this offering addresses equity concerns in the market*, and helps ensure access to charging infrastructure across the socio-economic spectrum. The environmental (and other) benefits enabled by this offer should be considered as demonstrated in the primary cost noted above. This sensitivity, however, characterizes the net benefit in the very narrow case where only monetized impacts on electricity costs are considered. The following figures summarize benefits and costs for this test.

Figure 22: Factors Included in the Offering 3 Merit Test (Sensitivity Case)

	Benefit	Cost
Benefit: Electicity Cost Reductions	$3,871,529	0
Cost: Electricity Cost Increases	$0	3,445,820
Cost: Utility Investment	0	$4,595,664
Total:	$3,871,529	$8,041,484
Benefit To Cost Ratio:	0.48	
NPV of Net Benefits:	-$4,169,955	

Figure 23: Benefits and Costs for the Offering 3 Merit Test (Sensitivity Case)



Q: What are the costs, benefits, and net benefit result associated with the merit test applied to Offering 4 (utility-owned chargers for public use), for the principal case where both electricity cost impacts and environmental impacts are considered?

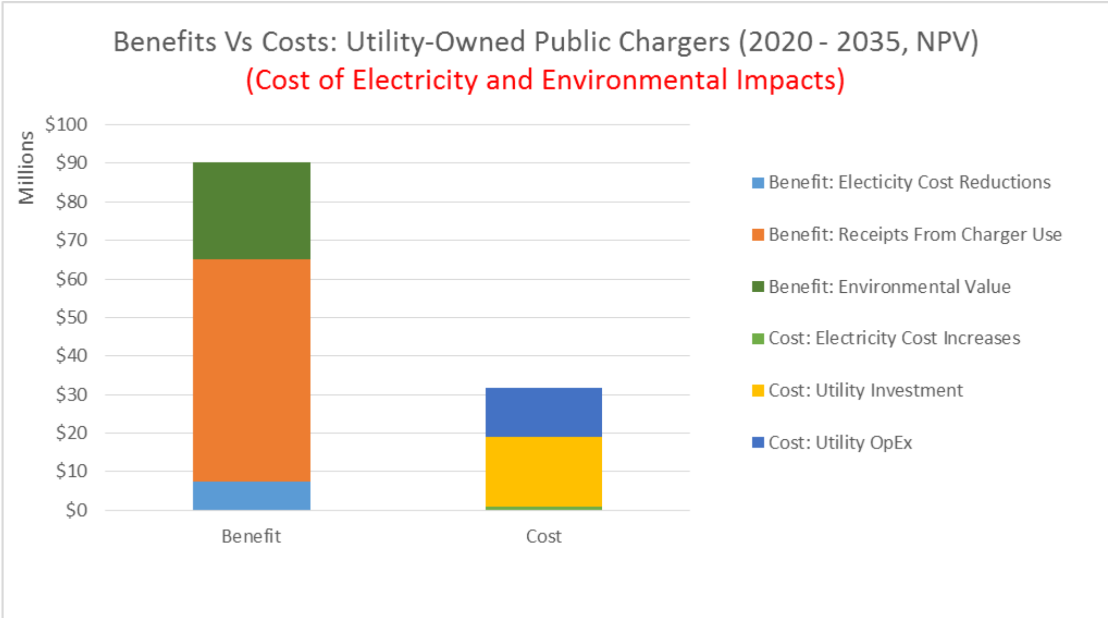
A: Offering 4 delivered a net benefit on an NPV basis, with a ***Benefit/Cost ratio of 2.85***[19]***.*** As described in the methodology section above, this is a very narrow test that considers only impacts on utility customers, including the costs of the BGE offering and both the direct economic impacts (through electricity costs) and environmental benefits (which impact all ratepayers). These results demonstrate that benefits strongly outweigh costs for all ratepayers, and that there is public benefit to implementing BGE's Offering 4. The following figures summarize benefits and costs for this test.

Figure 24: Factors Included in the Offering 4 Merit Test (Primary Case)

	Benefit	Cost
Benefit: Electicity Cost Reductions	$7,432,178	0
Benefit: Receipts From Charger Use	$57,646,014	0
Benefit: Environmental Value	$25,207,700	0
Cost: Electricity Cost Increases	0	$799,230
Cost: Utility Investment	0	$18,348,390
Cost: Utility OpEx	0	$12,512,125
Total:	$90,285,891	$31,659,744
Benefit To Cost Ratio:	2.85	
NPV of Net Benefits:	$58,626,147	

[19] For reference, the B/C ratio for Offering 4 using only lower powered 50KW chargers is 2.31, all other assumptions not impacted by this change being the same. The inclusion of higher-powered 150KW chargers, in a 50/50 split, results in a higher B/C ratio due to the impact of increased utilization (a larger number of shorter duration sessions) and a higher congestion threshold. This outcome reflects the benefit of incorporating higher powered chargers in the BGE program, in addition to increased consumer convenience and market impact, and reduced risks that utility investments will be rendered obsolete by rapidly evolving DCFC technology.

Figure 25: Benefits and Costs for the Offering 4 Merit Test (Primary Case)



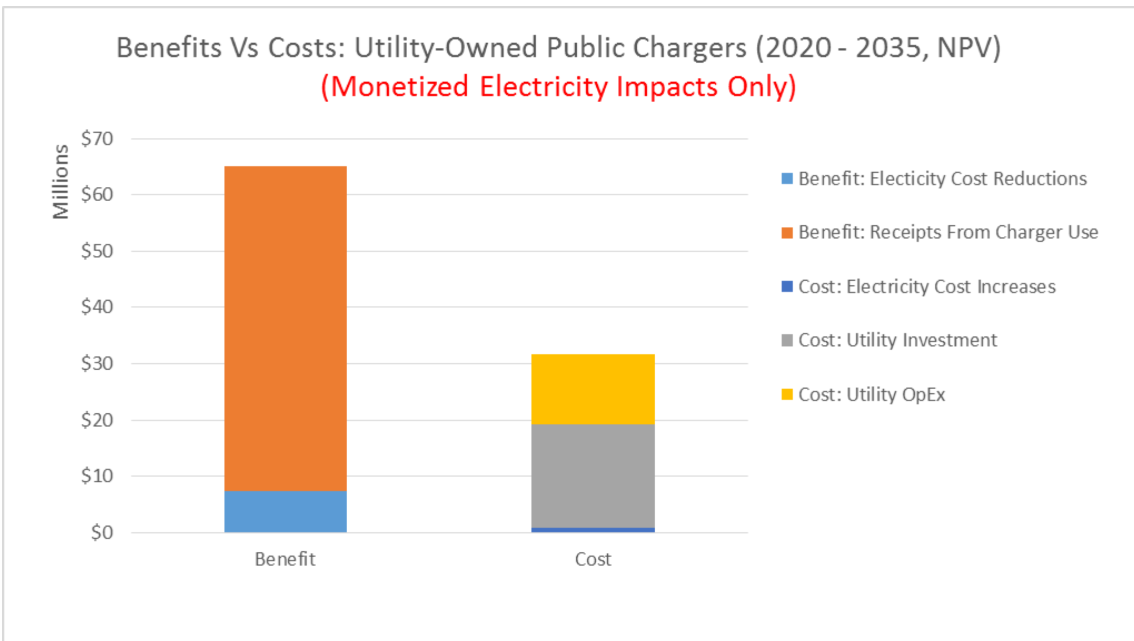
Q: How would the BCA outcome change for Offering 4 (utility-owned chargers for public use) in the sensitivity case where only monetized impacts on electricity costs are considered?

A: Even on that narrow basis, Offering 4 still delivers a net benefit on an NPV basis, with a ***Benefit/Cost ratio of 2.06.*** This sensitivity characterizes the net benefit in the very limited case where only monetized impacts on electricity costs are considered, discounting the environmental benefits realized by all ratepayers due to this offering as represented in the primary BCA case noted above. This offering is also highly strategic since it ensures availability of the charging infrastructure needed to address consumer range anxiety concerns, with a focus on serving areas not well-supported by the competitive market and providing for appropriate geographic coverage of charging facilities. The equipment and services used by the utility in implementation of this offering will be provided by the competitive market, and these utility investments therefore help stimulate growth in that industry. The following figures summarize benefits and costs for this test.

Figure 26: Factors Included in the Offering 4 Merit Test (Sensitivity Case)

	Benefit	Cost
Benefit: Electicity Cost Reductions	$7,432,178	0
Benefit: Receipts From Charger Use	$57,646,014	0
Cost: Electricity Cost Increases	0	$799,230
Cost: Utility Investment	0	$18,348,390
Cost: Utility OpEx	0	$12,512,125
Total:	$65,078,192	$31,659,744
Benefit To Cost Ratio:	2.06	
NPV of Net Benefits:	$33,418,447	

Figure 27: Benefits and Costs for the Offering 4 Merit Test (Sensitivity Case)



IV. CONCLUSIONS

Q: In summary, what were the results of your analysis?

A: The utility PEV program is projected to be cost-effective and is expected to provide quantified net benefits to BGE's customers. The market-wide SCT and each of the offering-specific merit tests deliver positive *net* benefits after accounting for estimated potential costs, and all deliver a benefit/cost ratio greater than 1.0. Several sensitivities were included, reflecting offering-specific merit tests where environmental value was not included. In all those cases except one (for Offering 2, multi-family charging solution), the electricity-cost-impact-only sensitivity (without environmental value) was still greater than one, indicating that non-participating ratepayers will realize a direct economic benefit as realized directly on their electricity bill. These conclusions were also true when considering all the offerings in aggregate through a portfolio merit test.

Q: What conclusions do you draw from these results?

A: Based on these results, it is my assessment that the projected benefits exceed expected costs and are strongly beneficial on a net basis across all merit tests considered. For utility ratepayers in particular, increases in electricity costs (due to PEV program costs and potential grid reinforcement) are more than offset by decreases in utility costs (due to beneficial PEV impacts related to vehicle charging), and these benefits accrue to utility customers that do not own a PEV. The managed charging programs offered by the utility are critical to achieving these ratepayer benefits.

Q: Does this conclude your testimony?

A: Yes, but I reserve the right to modify this analysis or conclusions if new information is made available.

Before the Maryland Public Service Commission

Case No. ___________

Prepared Direct Testimony of

Jason M. B. Manuel

On Behalf of

Baltimore Gas and Electric Company

March 2, 2020

List of Issues and Major Conclusions

- Five-year average demand and throughput allocators are appropriate and are a more accurate representation of the demands on the distribution system over time for gas residential and firm customers (Schedules D and C). Single-year demand and throughput allocators are most appropriate for the gas interruptible customers (Schedules ISS, IS, and EG).

- Pursuant to the Settlement Agreement approved by the Commission in Case No. 9610, the Company initiated discussions with Staff, OPC, MEG, C.P. Crane, and H.A. Wagner regarding ways to improve the gas cost of service study (GCOSS). The Company's proposed 2019 GCOSS reflects adjustments to allocators discussed with stakeholders, including creating a separate allocator for costs related to its large customer service representatives and revising the Schedule EG demand allocator.

- Consistent with the proposed filing requirements included in the Work Group Implementation Report submitted to the Commission in Case No. 9618, the GCOSS incorporates the ratemaking adjustments to the 2019 historical test year proposed by Company Witness Vahos in Part 1 of his Direct Testimony.

Table of Contents

I. INTRODUCTION AND STATEMENT OF PURPOSE

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. My name is Jason M. B. Manuel and my business address is Baltimore Gas and Electric Company (BGE or the Company), 2 Center Plaza, 110 West Fayette Street, Baltimore, Maryland 21201.

Q. WHAT IS YOUR POSITION WITH BGE?

A. I am the Manager, Revenue Policy for BGE. My current responsibilities include BGE ratemaking activities at the Maryland Public Service Commission (PSC or Commission) and the Federal Energy Regulatory Commission (FERC), and coordination of various regulatory filings and compliance matters.

Q. PLEASE DESCRIBE YOUR BUSINESS EXPERIENCE, EDUCATIONAL BACKGROUND, AND INVOLVEMENT WITH CIVIC ORGANIZATIONS.

A. I have been employed by BGE for over seventeen years, serving in various capacities in Finance and Accounting, Customer Operations, and Regulatory prior to assuming my current position. Before coming to BGE, I was employed as an auditor at Ernst & Young LLP, one of the "Big 4" accounting firms, and as a project engineer for AMETEK, Inc., a manufacturing conglomerate. I hold a Bachelor of Science Degree in Mechanical Engineering from Lehigh University and a Master's Degree in Business Administration with a Concentration in Accounting from the University of Maryland – College Park. I am a Certified Public Accountant and a member of the American Institute of Certified Public Accountants. I volunteer as an ice hockey and adaptive lacrosse coach for children with special needs, serving not-for-profit organizations in the Baltimore area. I also coach youth girls' lacrosse and field hockey, serving various recreation councils in Baltimore County.

Q. HAVE YOU PREVIOUSLY TESTIFIED BEFORE THE MARYLAND PUBLIC SERVICE COMMISSION?

A. Yes. I testified before the Commission in Case No. 9096 concerning depreciation rates and accounting for asset retirement obligations, in Case No. 9208 in support of tariff changes for BGE's Smart Grid Initiative, in Case No. 9230 regarding the Company's gas and electric rate design proposals as well as other revisions to the BGE Retail Gas and Electric Service Tariffs, in Case No. 9484 pertaining to the Company's gas rate design proposals, and in Case No. 9610 concerning a cost of service study of electric distribution costs that could reasonably be functionalized to Standard Offer Service. I also sponsored testimony in Case No. 9610 pertaining to the Company's gas and electric cost of service studies and have had the opportunity to address the Commission during various legislative-style hearings.

Q. WHAT IS THE PURPOSE OF YOUR DIRECT TESTIMONY?

A. The purpose of my Direct Testimony is to sponsor the Company's 2019 Gas Distribution Cost of Service Study (GCOSS). The cost allocation methodologies and procedures are consistent with those proposed by the Company in Case No. 9610, including the use of five-year and single-year demand and throughput allocators, but with two notable areas of change. First, changes were made to the GCOSS pursuant to the Settlement Agreement approved by the Commission in Case No. 9610. Second, for this multi-year plan proceeding, changes were made to the GCOSS model to reflect ratemaking adjustments to the 2019 historical test year as proposed in Part 1 of the

Direct Testimony of Company Witness Vahos. The results of the GCOSS provided in the attached exhibits are based on the 12-month period ending December 31, 2019.

My testimony will provide a general framework for Company Witness Fiery to apply in her rate design testimony, including the Relative Rates of Return (RROR) by customer class and the cost components determined in the GCOSS.[1]

Q. PLEASE DESCRIBE THE ORGANIZATION OF YOUR DIRECT TESTIMONY.

A. First, I will discuss the purpose and theory behind developing an embedded COSS and the goals that are sought through these analyses.

Second, I will outline the basic processes involved in developing the GCOSS that I am sponsoring in this proceeding.

Third, I will discuss the Company's recommended approach for demand and throughput allocators.

Fourth, I will explain changes made to the GCOSS resulting from the Settlement Agreement approved by the Commission in Case No. 9610 and the Work Group activities in Case No. 9618.

Lastly, I will describe the results of the GCOSS as provided in the exhibits outlined below. I will detail the RRORs as well as the results of the customer charge components by class.

Q. ARE YOU SPONSORING ANY EXHIBITS?

A. Yes. The exhibits presented with my testimony are organized as follows:

- <u>Exhibit JMBM-1</u> provides the GCOSS relative rates of return;

[1] The phrase "Relative Rates of Return" refers to the rate of return of each customer class relative to the system average.

- Exhibit JMBM-2 provides the summary results of the GCOSS;
- Exhibit JMBM-3 provides the GCOSS monthly customer costs;
- Exhibit JMBM-4 provides the GCOSS five-year comparison of annual system class demand allocators and the effect on the various class RRORs; and
- Exhibit JMBM-5 provides a summary of the 2019 GCOSS using 2019 demand and throughput allocators.

II. OVERVIEW OF COST OF SERVICE STUDY THEORY

Q. PLEASE PROVIDE A HIGH-LEVEL OVERVIEW OF A COST OF SERVICE STUDY.

A. The primary objective of an embedded cost of service study is to present a reasonable representation of the cost allocation of the Company's costs during the study period and revenue responsibility among its customer classes, based upon principles of cost causation and revenue responsibility. The end result is to ascertain whether each customer class' revenue is covering its fair share of costs. The 2019 GCOSS results included in my Direct Testimony provide a depiction of the rates of return for each gas customer class relative to the system average. These relative rates of return provide guidance for the distribution of the necessary revenue changes among the customer classes. When revenue changes do not take relative rates of return into consideration, under-earning customer classes may continue to under-earn and over-earning classes may continue to over-earn, perpetuating interclass subsidies among rate payers.

Another objective of an embedded cost of service study is to provide a guide for proper rate design. When rate design is not in line with the classification of cost components, there can be a disconnect between the pricing signals to customers and the cost to provide service to those customers, which can result in intraclass subsidies. Company Witness Fiery will provide in her Direct Testimony further detail on the use of cost of service study results in proper ratemaking.

Q. PLEASE SUMMARIZE THE KEY PROCESSES INVOLVED IN THE DEVELOPMENT OF THE GAS COST OF SERVICE STUDY.

A. There are generally three basic steps to measure customer class responsibility for rate base and expense. These three steps are: (1) functionalization; (2) classification; and (3) allocation.

Functionalization is the process of dividing rate base and expense components of the cost of service study into specified utility functions based on the characteristics of those components. BGE functionalizes its gas delivery service assets and related expenses as either production, storage or distribution operations. All of these costs, however, are recovered through base distribution charges. Gas commodity costs, on the other hand, are recovered through BGE's Rider 2 – Gas Commodity Price and are not included in the GCOSS.

Classification is the process of separating the functionalized rate base and expenses into categories that relate to how costs are caused. Distribution-related costs are primarily classified between demand and customer- related components. Demand-related costs are generally driven by customer class non-coincident peak (NCP) and/or coincident peak (CP) demand levels (discussed in more detail later in my testimony), while customer-related costs are driven by the number and cost of customers connecting to gas mains and the necessary requirements for the utility to service those customers (i.e., metering, meter reading, account processing, and billing systems). There are some instances in which distribution costs (though minor in relative cost significance) are variable with customer class consumption; in those instances, expenses would be classified as energy-related.

Allocation is the final refinement process, whereby rate base and expenses in each of the classified cost categories are assigned to customer classes according to customer load impositions on the distribution system and/or customer connection requirements. Company costs are directly assigned to the specific customer classes whenever the costs are known to be related to investments or expenses that serve only a particular customer or group of customers (i.e., meters). When the costs are not directly assignable to customer classes (i.e., mains), they are allocated using an appropriate methodology that best represents the cost causation principles of those elements. That methodology varies depending on the nature of the item being allocated and the data available at the time of the analysis.

III. CALENDAR YEAR 2019 COMPANY RECOMMENDED GAS COST OF SERVICE STUDY

Q. PLEASE SUMMARIZE THE COMPANY'S CUSTOMER-CLASS GAS COST OF SERVICE MODEL.

A. The GCOSS that I am sponsoring was developed to assign and allocate each element of revenues, rate base, and expenses to the Company's gas customer classes. The costs embedded in the 12 months ending December 31, 2019 are identified using the FERC Uniform System of Accounts. Allocations of these costs are made in a manner that follows principles of cost causation. These costs are broken down into categories, such as gas plant in service (GPIS), depreciation expenses, and operation and maintenance (O&M) expenses. The allocation of these categories flows into many of the other allocations in the GCOSS. The recommended study utilizes five-year average demand and throughput allocators for Schedules D and C and single-year (calendar year 2019) demand and throughput allocators for Schedules IS, ISS, EG, and PLG, both of which I will explain in detail later in my testimony.[2] I will also describe other class allocations of these rate base and expense items below. See Exhibit JMBM-1 for a summary of GCOSS results.

Q. PLEASE DESCRIBE THE ALLOCATION OF COSTS TO CUSTOMER CLASS IN EXHIBIT JMBM-2.

A. As noted previously, the final step in the GCOSS process is allocation. During this step, rate base and expenses in each of the classified cost categories are assigned to customer classes according to demand on the distribution system, customer-based requirements, usage, and/or revenues. When allocating distribution costs in the GCOSS, it is important to understand the concept of Non-Coincident Peak (NCP) demand. Any gas delivery system must be sized and built to provide safe and reliable service to all of its firm service customers at all times. This idea is demonstrated by the NCP demand that correlates to the highest hourly demand reached by each customer class and does not necessarily coincide with the total system peak. To provide safe and reliable service, this maximum peak demand level must be considered when designing

[2] The results of the GCOSS using 2019 demand and throughput allocators can be found in Exhibit JMBM-5.

and planning the system. The NCP is used to allocate certain demand-related investments such as gas mains.

Another form of peak demand is the Coincident Peak (CP) demand, also described as the Peak Day allocator. The peak day is the single day that represents potential peak sendout under design day conditions.[3] The peak day sendout is determined by summing the hourly demands for each gas day (a 24-hour period beginning at 10:00 a.m. Eastern Standard Time) and then selecting the day with the highest sendout during the year. The peak day in 2019 occurred on January 21. The Peak Day allocator is used to allocate gas production and storage related assets, such as liquefied natural gas (LNG) plant equipment, that are typically only used during system peak scenarios.

Customer-related distribution GPIS FERC accounts (plant accounts 380 through 387) such as services, meters, and regulators are allocated to the customer classes according to the number of customers/meters and the level of investment related to size/type of equipment.

Another major allocator used to allocate GPIS is the LABOR allocator. The LABOR allocator is an internally developed allocator that is a combination of labor related expenses included in production, storage, O&M, and administrative and general expenses.[4] This combination of expenses provides a comprehensive allocator that can be used to allocate a variety of labor-related general plant expenses that are used to serve all customer classes in proportion with the expenses outlined above.

[3] BGE's design day conditions are defined as 2.7°F average temperature with 15 mph winds.

[4] Internally developed allocators are allocators that are calculated within the COSS model itself and are based on combinations of accounts that are allocated with externally developed allocators. Externally developed allocators are allocators calculated outside of the COSS using company records and data.

The remaining items such as depreciation and O&M expenses are allocated based on the corresponding plant accounts associated with the depreciation or O&M expenses. For example, maintenance expenses related to service lines recorded in FERC Account 892 – Maintenance of Services are allocated based on the allocated balances of FERC plant account 380 - Services.

IV. DEMAND AND THROUGHPUT ALLOCATORS

Q. PLEASE DEFINE THE TERMS "DEMAND" AND "THROUGHPUT" IN THE CONTEXT OF YOUR GCOSS TESTIMONY.

A. "Demand" refers to the amount of gas consumed over a limited period of time (i.e., a single peak day) during the year, while "throughput" refers to the total gas consumed over the entire calendar year.

Q. WHAT DEMAND AND THROUGHPUT ALLOCATORS ARE YOU PROPOSING TO USE?

A. As noted previously, I am proposing to utilize five-year average demand and throughput allocators for Schedules D and C and single-year (calendar year 2019) demand and throughput allocators for the remaining schedules.

Q. PLEASE SUMMARIZE THE RECENT BGE RATE CASE HISTORY ON THIS TOPIC.

A. In Order No. 87591 in Case No. 9406, the Commission directed the Company to continue presenting cost of service studies with single-year demand allocators while still providing the five-year demand allocator study for both gas and electric in future rate cases.[5] Additionally, in Order No. 88975 in Case No. 9484, the Commission wrote that the use of the five-year average demand and throughput allocators "may be a reasonable approach to be explored in future rate cases."[6] In the Settlement Agreement of Case No. 9610, the settling parties agreed to continue to propose a COSS which includes a one-year demand allocator. A summary of the five-year gas demand data and the impact on all class RRORs is provided in Exhibit JMBM-4. Exhibit JMBM-5 presents the summary results of the GCOSS for all classes using the single-year 2019 demand allocators, pursuant to the Settlement Agreement in Case No. 9610. In this case, and consistent with the Company's proposals in Case Nos. 9484 and 9610, I propose to use a combination of the two allocation methods as detailed by Schedule in Table 1 below.

Table 1: Summary of Demand and Throughput Allocators

Gas Rate Schedule	Demand and Throughput Allocators
Schedule D	Five-Year Average
Schedule C	Five-Year Average
Schedule ISS	Single-Year
Schedule IS	Single-Year
Schedule EG	Single-Year
Schedule PLG	Single-Year

[5] In Order No. 87591 in Case No. 9406, the Commission directed BGE to continue to provide the five-year demand study as opposed to directing the company to completely abandon the idea of average demand allocators.
[6] See Case No. 9484; Order No. 88975 at 78.

The throughput allocators are noted in the GCOSS as ALLTHRUPUT, WFIRMTHRUPUT and FIRMTHRUPUT, while the demand allocators are noted as NCP and PDAY.

Q. HOW DID YOU DETERMINE WHICH RATE CLASSES WOULD USE THE FIVE-YEAR AVERAGE?

A. In order to determine which rate schedules should use the five-year average methodology for demand and throughput allocators, a regression analysis was performed. A regression is a common statistical analysis that is used to help determine the strength of the relationship between multiple variables. In my analysis, the dependent variable was daily demand values from 2015 to 2019 and the independent variable for gas was daily heating degree day values from 2015 to 2019.[7] I included heating degree days and excluded cooling degree days from my analysis as the gas distribution system only experiences a spike in demand during the heating season.[8]

The results of my analyses are shown below in Table 2. Schedule EG was excluded because we do not have five years of data for this rate class in isolation and one of the largest Schedule EG-eligible units was added within the last five years, which would skew the data.[9] Schedule PLG was excluded as these gas lamps continuously burn throughout the day, independent of the weather. The R^2 value in a regression is known

[7] Heating degree days are a measure of how cold the outside air temperature is and are defined relative to a baseline temperature. A heating degree day is calculated by subtracting the average dry bulb temperature for each day of the year from the baseline temperature of 65 degrees Fahrenheit, excluding days that would yield a negative result.

[8] Cooling degree days are a measure of how hot the outside temperature is and are also defined relative to a base temperature. A cooling degree day is calculated by subtracting the baseline temperature of 65 degrees Fahrenheit from the average temperature heat index for each day of the year, excluding days that would yield a negative result.

[9] Schedule EG was proposed by the Company and agreed upon in the Settlement Agreement of Case No. 9610. Schedule EG therefore became effective December 17, 2019.

as the coefficient of determination. The R^2 value is used to represent the amount of variation in the dependent variable that can be explained by the independent variable(s). For example, the R^2 value for gas Schedule D is 0.9567, which represents that 95.67% of the total variation in daily demand values can be explained by the relationship between daily heating degree day values and daily demand values. This is an extremely strong relationship, as the range for the R^2 value is between 0 and 1, with 0 having no relationship and 1 having a perfect relationship. As shown in Table 2, the regression results for gas Schedules D and C all show strong relationships and that is the reason they were selected to use the five-year average demand and throughput allocators. The weaker relationships shown for the remaining schedules warrant the use of the single-year demand and throughput allocators.

Table 2: Summary of Regression Results

Gas Rate Schedule	R^2 Value
Schedule D	0.9567
Schedule C	0.9139
Schedule ISS	0.6679
Schedule IS	0.5398

Q. PLEASE EXPLAIN WHY A FIVE-YEAR AVERAGE MAY BE MORE APPROPRIATE THAN A SINGLE-YEAR.

A. In my opinion, the method I am proposing is a more accurate representation of the demands on the Company's Distribution System. As described above, there is a strong relationship between weather and the demand of the proposed five-year average rate classes. By using a five-year average, the volatility of these allocators due to variations in weather would be smoothed out and there would not be large differences from one year to the next. Any change would be gradual over time. As shown in Exhibit JMBM-4, using single calendar year demand and throughput allocators results in significant variations in rates of return from one year to the next due to changes in weather. However, weather is not the sole determining factor in how the company sizes and builds its distribution system. The company does not size the system for mild weather years; instead, it is sized based on the expected demand on the system. Using a five-year average will decrease the volatility from year to year and provide a stable allocation that is more representative of the cost causation of the demand and throughput related elements for these rate classes.

Additionally, all of the rate classes that are being proposed to use the five-year average approach are decoupled. That means that these rate class' revenues are based on weather-normalized sales volumes so it is reasonable that the demand and throughput should be normalized as well. Otherwise, the relative rates of return for these classes would be skewed by weather-normalized revenues offset by weather-sensitive costs that are not normalized.

V. CHANGES MADE TO THE GCOSS PRESENTED IN THIS CASE

A. Changes Resulting from Case No. 9610

Q. HAVE YOU MADE ANY CHANGES TO ALLOCATION METHODOLOGIES USED IN THE GCOSS AS A RESULT OF THE SETTLEMENT AGREEMENT APPROVED IN CASE NO. 9610?

A. Yes. As part of the Settlement Agreement approved by the Commission in Case No. 9610, the Company agreed to create a separate allocator for costs related to its large customer service representatives. The Company's recommended GCOSS includes the new internal allocator, LABORLC, in order to allocate large customer service group activity to the C, IS, ISS, and EG classes. Large customer service group activity is included as separate lines within the Administrative and General Expenses and the Taxes Other than Income Taxes sections in the GCOSS.

Additionally, in compliance with Commission Order No. 89400 and the Settlement Agreement in Case No. 9610, the new union sick day regulatory asset is amortized over ten years. The amortization expense is reflected within the new "407 – REG ASSET – UNION SICK BANK" line item of the Depreciation and Amortization Expense section of the GCOSS.

Finally, the Company's recommended GCOSS adjusts the NCP demand allocator for Schedule EG by using the average 2019 demand for all active winter hours. This represents a change from the approach taken in Case No. 9610, where the Company based its Schedule EG demand allocator on the highest winter peak demand for all eligible Schedule EG customers. As part of the Case No. 9610 Settlement Agreement, the Company agreed to discuss with various interested stakeholders ways to improve the cost of service study; in particular, the demand allocator proposed for Schedule EG. Pursuant to the agreement, the Company invited Staff, OPC, MEG, C.P. Crane, and H. A. Wagner to a meeting to discuss its newly proposed demand allocator. During this meeting, the Company discussed its proposal and the reasons supporting it. The Company solicited feedback, and no party objected to or supported the proposal.

The Company believes the proposed demand allocator is reasonable for a number of reasons. The allocator utilizes single-year demand data and focuses on the winter period (November – March), both of which are attributes consistent with BGE's and Staff's recommended approach for interruptible classes in numerous prior rate cases. The Company's proposed allocator takes an averaging approach, which will help stabilize the allocator year-over-year, a benefit particularly important in a multi-year plan that uses the cost of service study as a guide for setting rates for several years. Finally, the allocator produces reasonable RROR results for Schedule EG.

On this last point, the Company's proposed allocator appropriately reflects the Schedule EG operational availability and communication requirements. As described in the Schedule EG tariff, "The availability of a Customer to use gas at any time is dependent on operating conditions and system constraints." This means that Schedule EG customers have to ask permission to operate, a condition of availability unique to Schedule EG. The proposed NCP allocator produces RROR results that, when properly used as a guide for setting rates, should result in lower distribution rates than the interruptible classes given the restricted level of service.

Q. ARE THERE ANY OTHER ASPECTS OF THE SETTLEMENT AGREEMENT THAT YOU WOULD LIKE TO DISCUSS AT THIS TIME?

A. Yes. As part of the Case No. 9610 Settlement Agreement, the Company agreed to "engage in further discussions with Staff, OPC, and other interested stakeholders regarding ways to improve the electric and gas COSS …". The Company and interested stakeholders met in February and the Company is open to further discussions. In the interim, and as discussed in more detail below, the Company and various stakeholders participating in the Case No. 9618 Work Group reached a consensus to incorporate Commission-approved ratemaking adjustments into the GCOSS.

B. Changes Resulting from Case No. 9618

Q. HAS THE COMPANY MADE ANY ADJUSTMENTS TO THE GCOSS AS A RESULT OF THE WORK GROUP ACTIVITIES IN CASE NO. 9618?

A. Yes. The Company has incorporated the ratemaking adjustments to the 2019 historical test year that Company Witness Vahos proposes in Part 1 of his Direct Testimony and exhibits. This approach is consistent with the filing requirements included in the Work Group Implementation Report submitted to the Commission on December 20, 2019 in Case No. 9618.

Q. HOW HAS THE COMPANY INCORPORATED THE PROPOSED RATEMAKING ADJUSTMENTS INTO THE GCOSS MODEL?

A. The Company has included the proposed ratemaking adjustments in the GCOSS based on the FERC account(s) predominately impacted by the adjustment. The activity for all adjustments is then summed by FERC account and provided in the GCOSS model as a separate column titled "2019 Proforma Adjustment Balances."

Q. DID THE WORK GROUP IN CASE NO. 9618 PROVIDE ANY ADDITIONAL GUIDANCE RELATED TO THE USE OF THE GCOSS IN A MYP?

A. Yes. The proposed GCOSS based on the 12-months ending December 31, 2019, serves as a guide for ratemaking for all three years of the multi-year plan, as recommended by the Case No. 9618 Work Group. In its Order No. 89482, the Commission expressed agreement with the use of a single cost of service study to be used as a guide to set class revenue allocations for the duration of the multi-year plan period.[10]

VI. SUMMARY GCOSS RESULTS

Q. WOULD YOU PLEASE REVIEW THE OVERALL RESULTS OF THE GCOSS?

A. The GCOSS customer class relative rates of return for the 12 months ending December 31, 2019, are shown in Table 3 and summarized below.

Table 3: Summary of GCOSS Relative Rates of Return

Gas Rate Schedule	Relative Rate of Return
Schedule D	1.02
Schedule C	0.92
Schedule ISS	1.04
Schedule IS	0.81
Schedule EG	4.62
Schedule PLG	8.09

Schedule D – Residential (including Grantors of Rights-of-Way) is earning a rate of return within the system average return band width of +/- 10% at a relative rate of return of 1.02. This is very similar to the RROR of 1.01 calculated in the Company's recommended GCOSS in Case No. 9610.

Schedule C – General Service is earning a rate of return within the system average return band width of +/- 10% at a relative rate of return of 0.92. This is very similar to

[10] Order No. 89482 at 28, para. 55.

the RROR of 0.94 calculated in the Company's recommended GCOSS in Case No. 9610.

Schedule ISS – Interruptible Small Volume Service is earning a rate of return within the system average return band width of +/- 10% at a relative rate of return of 1.04. This represents an improvement over the RROR of 1.38 calculated in the Company's recommended GCOSS in Case No. 9610.

Schedule IS – Interruptible Large Volume Service is earning a rate of return below the system average return band width of +/- 10% at a relative rate of return of 0.81. This represents an improvement over the RROR of 0.72 calculated in the Company's recommended GCOSS in Case No. 9610.

Schedule EG – Interruptible Gas-Fired Electric Generation Service is earning a rate of return above the system average return band width of +/- 10% at a relative rate of return of 4.62. This represents a deterioration in the RROR of 4.23 calculated in the Company's recommended GCOSS in Case No. 9610.

Schedule PLG – Private Area Lighting – Gas is earning a return well above the system average return band width of +/- 10% at a relative rate of return of 8.09. This represents an improvement over the RROR of 9.80 calculated in the Company's recommended GCOSS in Case No. 9610. It should be noted that Schedule PLG has not historically received a revenue increase and is closed to new customers.

Q. PLEASE SUMMARIZE THE CUSTOMER CHARGE RESULTS SHOWN IN EXHIBIT-JMBM-3.

A. The purpose of the customer charge component of the COSS is to portray the customer-based costs by customer class that should be recovered through the customer charge. Table 4 shows the Customer Charge Component by customer class.

Table 4: Customer Charge Components

Gas Rate Schedule	GCOSS Customer Component
Schedule D	$24.73
Schedule C	$105.15
Schedule ISS	$704.90
Schedule IS	$1,305.24
Schedule EG	$3,112.48

The Direct Testimony of Company Witness Fiery will provide recommended changes to Customer Charges over the multi-year plan.

VII. CONCLUSION

Q. CAN YOU PLEASE SUMMARIZE YOUR TESTIMONY?

A. Certainly. My testimony sponsors the Calendar Year 2019 Company Recommended GCOSS. The GCOSS incorporates changes resulting from Case Nos. 9618 and 9610. These changes include adding the ratemaking adjustments to the Company's 2019 historical test year and various changes discussed with all parties to the Settlement Agreement in Case No. 9610. All remaining cost allocation methodologies and procedures are consistent with those proposed by the Company in Case No. 9610, including the use of five-year and single-year demand and throughput allocators.

Exhibit JMBM-2, the summary results of the BGE GCOSS, provides a framework for Company Witness Fiery to apportion the overall requested gas revenue requirement in a fair and reasonable manner, as developed by Company Witness Vahos. Exhibit JMBM-3 displays the monthly customer costs by rate schedule as derived from the GCOSS – these monthly costs will be used as a guideline for Company Witness Fiery's proposal to change gas Customer Charges.

Q. DOES THIS CONCLUDE YOUR DIRECT TESTIMONY?

A. Yes.

Comparison of Customer Class Relative Rate of Returns (RROR)

2019 GCOSS	
Rate Schedule	RROR
D*	1.02
C	0.92
ISS	1.04
IS	0.81
EG	4.62
PLG	8.09
System Total	1.00

* includes Grantors of Rights-of-Way

BALTIMORE GAS & ELECTRIC COMPANY
COMPANY RECOMMENDED GAS COST OF SERVICE STUDY
12 MONTHS ENDED DECEMBER 31, 2019
PROPOSED STUDY

	SUMMARY OF RESULTS-1	ALLOC	TOTAL COMPANY (1)	TOTAL RESIDENTIAL D (2)	TOTAL GENERAL SERVICE C (3)	SMALL INTERRUPTIBLE ISS (4)	LARGE INTERRUPTIBLE IS (5)	ELECTRIC GENERATION EG (6)	OUTDOOR LIGHTING PLG (7)
1	**DEVELOPMENT OF RATE BASE**								
2									
3	GAS PLANT IN SERVICE	PAGES 2-3	3,273,402,791	2,083,778,560	954,791,230	16,359,080	199,115,847	19,317,655	40,419
4	PLUS: ADDITIONS TO UTILITY PLANT	PAGE 3	238,049,811	172,573,404	54,648,123	754,964	9,188,825	882,649	1,846
5	LESS: RESERVE FOR DEPRECIATION	PAGES 4-5	723,308,627	478,656,181	200,819,409	3,114,520	37,037,678	3,672,402	8,438
6	NET PLANT IN SERVICE	PAGE 5	2,788,143,975	1,777,695,783	808,619,944	13,999,524	171,266,994	16,527,902	33,828
7	RATE BASE ADDITIONS	PAGE 6	54,539,063	34,060,631	18,971,415	119,233	1,243,057	142,754	1,974
8	RATE BASE DEDUCTIONS	PAGE 7	831,325,127	533,947,621	242,218,760	3,825,999	46,877,383	4,446,059	9,306
9	TOTAL RATE BASE	PAGE 7	2,011,357,911	1,277,808,794	585,372,599	10,292,758	125,632,667	12,224,597	26,496
10									
11									
12	**DEVELOPMENT OF RETURN**								
13									
14	OPERATING REVENUES								
15	DISTRIBUTION REVENUES	PAGE 8	563,487,634	379,350,306	147,040,714	2,445,804	27,317,484	7,309,247	24,079
16	OTHER OPERATING REVENUES	PAGE 8	10,492,801	9,187,233	1,225,508	6,096	73,745	148	71
17	TOTAL GAS OPERATING REVENUES		573,980,435	388,537,539	148,266,222	2,451,901	27,391,229	7,309,395	24,150
18									
19	OPERATING EXPENSES:								
20	OPERATION & MAINTENANCE EXPENSE	PAGES 9-11	244,354,941	166,899,815	63,121,746	967,577	12,007,685	1,355,450	2,669
21	DEPRECIATION & AMORT EXPENSE	PAGES 12-13	116,361,911	83,963,153	27,603,430	358,340	4,023,986	411,994	1,008
22	TAXES OTHER THAN INCOME TAXES	PAGE 14	62,879,923	40,126,908	17,825,499	311,987	4,045,265	568,984	1,279
23									
24	FEDERAL, STATE & LOCAL INCOME TAXES	PAGE 14	21,490,175	13,933,621	5,326,760	128,465	856,871	1,239,483	4,975
25	PLUS: INVESTMENT TAX CREDIT ADJUSTMENT	PAGE 14	0	0	0	0	0	0	0
26									
27	TOTAL OPERATING EXPENSE	PAGE 14	445,086,950	304,923,497	113,877,436	1,766,368	20,933,807	3,575,912	9,931
28									
29	PLUS: OTHER UTILITY OPERATING INC (EXP)	PAGE 14	5,273,847	3,427,544	1,410,008	30,891	367,763	37,563	79
30	PLUS: GAIN FROM DISP OF UTILITY PLANT	PAGE 14	0	0	0	0	0	0	0
31	NET OPERATING INCOME	PAGE 14	134,167,332	87,041,587	35,798,794	716,424	6,825,184	3,771,046	14,298
32									
33	RATE OF RETURN (PRESENT)	PAGE 15	6.67%	6.81%	6.12%	6.96%	5.43%	30.85%	53.96%
34	RELATIVE RATE OF RETURN	PAGE 15	1.00	1.02	0.92	1.04	0.81	4.62	8.09
35									
36	RATE OF RETURN (EQUALIZED)	PAGE 15	7.28%	7.28%	7.28%	7.28%	7.28%	7.28%	7.28%
37	SALES REVENUE REQ EQUALIZED ROR	PAGE 15	580,401,404	387,604,566	156,444,820	2,491,179	30,519,462	3,334,363	7,014

COMPANY 2019 GCOSS Monthly Customer Costs*

COST COMPONENT	TOTAL RESIDENTIAL D	TOTAL GENERAL SERVICE C	SMALL INTERRUPTIBLE ISS	LARGE INTERRUPTIBLE IS	ELECTRIC GENERATION EG
CUSTOMER SERVICES	$6.88	$25.43	$174.75	$223.66	$221.54
CUSTOMER METERS	$11.55	$55.91	$359.55	$774.15	$2,879.89
CUSTOMER REGULATORS	$1.18	$19.23	$160.19	$299.45	$0.00
CUSTOMER METER READING	$0.18	$0.22	$8.24	$8.30	$8.44
CUSTOMER RECORDS AND COLLECTIONS	$4.59	$4.26	$2.17	$2.16	$2.19
CUSTOMER SERVICE AND INFORMATION	$0.43	$0.43	$0.43	$0.43	$0.43
CUSTOMER OTHER	($0.07)	($0.34)	($0.43)	($2.91)	($0.00)
TOTAL CUSTOMER COMPONENT	$24.73	$105.15	$704.90	$1,305.24	$3,112.48

*Based on BGE's proposed authorized rate of return of 7.28%.

2019 GCOSS 5-Year Demand Allocator Study
TRENDS AND CHANGES IN RELATIVE RATE OF RETURNS

	D	C	ISS	IS	EG	PLG
2015	0.96	1.08	0.85	0.75	3.87	6.25
2016	1.03	0.93	0.86	0.77	3.24	6.05
2017	1.07	0.85	0.82	0.76	3.08	6.21
2018	1.04	0.87	1.18	0.92	3.65	7.70
2019	1.03	0.88	1.09	0.87	4.77	8.28
5 Yr Avg	1.02	0.92	0.95	0.81	3.69	8.19
Proposed	1.02	0.92	1.04	0.81	4.62	8.09

Notes:

(1) RRORs developed by using the Calendar Year 2019 Recommended Gas Actual Embedded Cost of Service Study (GCOSS) and applying each year's specific Throughput, CP and NCP demand allocators to produce a corresponding RROR result.

(2) The 5 Year Average RRORs were developed by inserting the average of 2015 - 2019 Throughput, CP and NCP demand allocators into the Calendar Year 2019 Recommended Gas Actual Embedded Cost of Service Study.

(3) Schedule EG Throughput, CP and NCP demand allocators for calendar years 2015 - 2017 utilized 2018 values, as Schedule EG was not implemented until Case No. 9610 and data prior to 2018 was not readily available.

2019 GCOSS 5-Year Demand Allocator Study
COMPARISON OF DEMAND ALLOCATORS (THERMS)

NCP Therms	
D	
2015	281,638
2016	233,498
2017	219,735
2018	253,816
2019	252,255
5 Yr Avg	248,188
Proposed	248,188
C	
2015	133,066
2016	128,153
2017	130,390
2018	145,298
2019	142,448
5 Yr Avg	135,871
Proposed	135,871
ISS	
2015	3,603
2016	3,140
2017	3,115
2018	2,919
2019	3,025
5 Yr Avg	3,160
Proposed	3,025
IS	
2015	45,138
2016	38,422
2017	38,158
2018	40,958
2019	41,158
5 Yr Avg	40,767
Proposed	41,158
EG	
2015	-
2016	-
2017	-
2018	4,951
2019	3,950
5 Yr Avg	-
Proposed	3,950
PLG	
2015	9
2016	8
2017	8
2018	7
2019	6
5 Yr Avg	7
Proposed	6

CP Therms	
D	
2015	5,488,094
2016	4,707,615
2017	4,545,682
2018	5,379,667
2019	4,951,407
5 Yr Avg	5,014,493
Proposed	5,014,493
C	
2015	2,667,435
2016	2,305,893
2017	2,454,581
2018	2,837,395
2019	2,663,584
5 Yr Avg	2,585,778
Proposed	2,585,778
ISS	
2015	2,976
2016	2,520
2017	2,520
2018	2,616
2019	1,584
5 Yr Avg	2,443
Proposed	1,584
IS	
2015	17,376
2016	17,640
2017	8,280
2018	6,336
2019	2,832
5 Yr Avg	10,493
Proposed	2,832
EG	
2015	-
2016	-
2017	-
2018	-
2019	-
5 Yr Avg	-
Proposed	-
PLG	
2015	209
2016	169
2017	162
2018	157
2019	149
5 Yr Avg	169
Proposed	149

2019 GCOSS 5-Year Demand Allocator Study
COMPARISON OF DEMAND ALLOCATIONS (PERCENTAGES)

NCP %		CP %	
D		D	
2015	60.8%	2015	67.1%
2016	57.9%	2016	66.9%
2017	56.1%	2017	64.8%
2018	56.7%	2018	65.4%
2019	57.0%	2019	65.0%
5 Yr Avg	58.0%	5 Yr Avg	65.9%
Proposed	**57.4%**	**Proposed**	**65.9%**
C		C	
2015	28.7%	2015	32.6%
2016	31.8%	2016	32.8%
2017	33.3%	2017	35.0%
2018	32.4%	2018	34.5%
2019	32.2%	2019	35.0%
5 Yr Avg	31.7%	5 Yr Avg	34.0%
Proposed	**31.4%**	**Proposed**	**34.0%**
ISS		ISS	
2015	0.8%	2015	0.0%
2016	0.8%	2016	0.0%
2017	0.8%	2017	0.0%
2018	0.7%	2018	0.0%
2019	0.7%	2019	0.0%
5 Yr Avg	0.7%	5 Yr Avg	0.0%
Proposed	**0.7%**	**Proposed**	**0.0%**
IS		IS	
2015	9.7%	2015	0.2%
2016	9.5%	2016	0.3%
2017	9.7%	2017	0.1%
2018	9.1%	2018	0.1%
2019	9.3%	2019	0.0%
5 Yr Avg	9.5%	5 Yr Avg	0.1%
Proposed	**9.5%**	**Proposed**	**0.0%**
EG		EG	
2015	-	2015	-
2016	-	2016	-
2017	-	2017	-
2018	1.1%	2018	0.0%
2019	0.9%	2019	0.0%
5 Yr Avg	-	5 Yr Avg	-
Proposed	**0.9%**	**Proposed**	**0.0%**
PLG		PLG	
2015	0.0%	2015	0.0%
2016	0.0%	2016	0.0%
2017	0.0%	2017	0.0%
2018	0.0%	2018	0.0%
2019	0.0%	2019	0.0%
5 Yr Avg	0.0%	5 Yr Avg	0.0%
Proposed	**0.0%**	**Proposed**	**0.0%**

BALTIMORE GAS & ELECTRIC COMPANY
GAS COST OF SERVICE STUDY USING 2019 DEMAND AND THROUGHPUT ALLOCATORS
12 MONTHS ENDED DECEMBER 31, 2019

	SUMMARY OF RESULTS-1	ALLOC	TOTAL COMPANY (1)	TOTAL RESIDENTIAL D (2)	TOTAL GENERAL SERVICE C (3)	SMALL INTERRUPTIBLE ISS (4)	LARGE INTERRUPTIBLE IS (5)	ELECTRIC GENERATION EG (6)	OUTDOOR LIGHTING PLG (7)
1	**DEVELOPMENT OF RATE BASE**								
2									
3	GAS PLANT IN SERVICE	PAGES 2-3	3,273,402,791	2,073,541,727	970,393,809	16,022,503	194,529,445	18,875,600	39,706
4	PLUS: ADDITIONS TO UTILITY PLANT	PAGE 3	238,049,811	172,098,745	55,371,940	739,307	8,975,801	862,205	1,813
5	LESS: RESERVE FOR DEPRECIATION	PAGES 4-5	723,308,627	476,618,732	203,841,350	3,052,776	36,196,212	3,591,251	8,306
6	NET PLANT IN SERVICE	PAGE 5	2,788,143,975	1,769,021,740	821,924,399	13,709,035	167,309,034	16,146,554	33,213
7	RATE BASE ADDITIONS	PAGE 6	54,539,063	34,020,386	19,042,454	116,766	1,217,160	140,386	1,912
8	RATE BASE DEDUCTIONS	PAGE 7	831,325,127	531,565,001	245,850,275	3,747,562	45,809,691	4,343,458	9,141
9	TOTAL RATE BASE	PAGE 7	2,011,357,911	1,271,477,125	595,116,578	10,078,239	122,716,503	11,943,481	25,985
10									
11									
12	**DEVELOPMENT OF RETURN**								
13									
14	OPERATING REVENUES								
15	DISTRIBUTION REVENUES	PAGE 8	563,487,634	379,350,306	147,040,714	2,445,804	27,317,484	7,309,247	24,079
16	OTHER OPERATING REVENUES	PAGE 8	10,492,801	9,187,233	1,225,508	6,096	73,745	148	71
17	TOTAL GAS OPERATING REVENUES		573,980,435	388,537,539	148,266,222	2,451,901	27,391,229	7,309,395	24,150
18									
19	OPERATING EXPENSES:								
20	OPERATION & MAINTENANCE EXPENSE	PAGES 9-11	244,354,941	166,344,535	63,969,001	949,867	11,759,330	1,329,583	2,624
21	DEPRECIATION & AMORT EXPENSE	PAGES 12-13	116,361,911	83,751,706	27,916,459	352,033	3,937,288	403,431	994
22	TAXES OTHER THAN INCOME TAXES	PAGE 14	62,879,923	39,991,937	18,042,735	307,081	3,975,405	561,496	1,268
23									
24	FEDERAL, STATE & LOCAL INCOME TAXES	PAGE 14	21,490,175	14,235,461	4,865,331	138,225	992,787	1,253,374	4,998
25	PLUS: INVESTMENT TAX CREDIT ADJUSTMENT	PAGE 14	0	0	0	0	0	0	0
26									
27	TOTAL OPERATING EXPENSE	PAGE 14	445,086,950	304,323,639	114,793,527	1,747,206	20,664,810	3,547,884	9,884
28									
29	PLUS: OTHER UTILITY OPERATING INC (EXP)	PAGE 14	5,273,847	3,407,639	1,440,346	30,237	358,844	36,703	77
30	PLUS: GAIN FROM DISP OF UTILITY PLANT	PAGE 14	0	0	0	0	0	0	0
31	NET OPERATING INCOME	PAGE 14	134,167,332	87,621,539	34,913,042	734,931	7,085,263	3,798,214	14,343
32									
33	RATE OF RETURN (PRESENT)	PAGE 15	6.67%	6.89%	5.87%	7.29%	5.77%	31.80%	55.20%
34	RELATIVE RATE OF RETURN	PAGE 15	1.00	1.03	0.88	1.09	0.87	4.77	8.28
35									
36	RATE OF RETURN (EQUALIZED)	PAGE 15	7.28%	7.28%	7.28%	7.28%	7.28%	7.28%	7.28%
37	SALES REVENUE REQ EQUALIZED ROR	PAGE 15	580,401,404	386,168,497	158,645,509	2,444,100	29,867,752	3,268,647	6,900

Before the Maryland Public Service Commission

Case No. ___________

Prepared Direct Testimony of

April M. O'Neill

On Behalf of

Baltimore Gas and Electric Company

March 2, 2020

<u>List of Issues and Major Conclusions</u>

- Five-year average demand and throughput allocators are appropriate and are a more accurate representation of the demands on the distribution system over time for electric residential customers (Schedules R and RL). Single-year demand and throughput allocators are appropriate for the remaining rate schedules. However, consistent with the Settlement Agreement approved by the Commission in Case No. 9610, single-year demand allocators continue to be included for all electric rate schedules.

- Pursuant to the Settlement Agreement in Case No. 9610, the recommended electric cost of service study assigns common plant by FERC account, proposes a new AMI allocator, adjusts costs for large customer service representatives, and continues to include a one-year demand allocator.

- Consistent with the filing requirements included in the December 20, 2019 Implementation Report submitted by the Working Group in Case No. 9618, the electric cost of service study incorporates the 2019 historical test year ratemaking adjustments as proposed in Part 1 of the Direct Testimony of Company Witness Vahos.

Table of Contents

I. INTRODUCTION AND STATEMENT OF PURPOSE

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. My name is April M. O'Neill and my business address is Baltimore Gas and Electric Company (BGE or the Company), 2 Center Plaza, 110 West Fayette Street, Baltimore, Maryland 21201.

Q. WHAT IS YOUR POSITION WITH BGE?

A. I am employed by BGE as a Principal Rate Analyst in the Strategy and Regulatory Affairs division.

Q. PLEASE DESCRIBE YOUR EDUCATIONAL BACKGROUND.

A. I earned my Bachelor of Science degree in Computer Accounting from Stevenson University in 1998. I am a Certified Public Accountant with an active license.

Q. PLEASE DESCRIBE YOUR PROFESSIONAL EXPERIENCE.

A. I joined BGE as a Principal Rate Analyst in February 2019. Soon after starting at BGE, I became involved in the Company's preparation for Case No. 9610. Ultimately, my responsibilities in Case No. 9610 related to the revenue requirement and electric distribution cost of service study including the development of the cost of service study, review of related allocation factors, assisting with cost of service testimony and preparation of data request responses. Prior to joining BGE, I was employed for 14 years at Constellation Energy, serving in various capacities within Wholesale Operations and Finance and Accounting. My responsibilities included the coordination and preparation of a daily profit statement presenting realized, gross margin income statement activity for the commercial business, coordination and review of the monthly close process and the coordination of the U.S. Securities and Exchange Commission reporting process, including the consolidation, preparation and review of financial statements and footnote disclosures. Before joining Constellation, I was employed as a Manager of Corporate Accounting at Laureate Education, Inc. and a Senior Auditor at Allfirst Financial, Inc.

Q. HAVE YOU PREVIOUSLY TESTIFIED BEFORE THE MARYLAND PUBLIC SERVICE COMMISSION (COMMISSION)?

A. No.

Q. WHAT IS THE PURPOSE OF YOUR DIRECT TESTIMONY?

A. The purpose of my Direct Testimony is to sponsor the Company's 2019 Electric Distribution Cost of Service Study (ECOSS). The results of the ECOSS provided in the attached exhibits are based on the 12-month period ended December 31, 2019. Consistent with the filing requirements included in the December 20, 2019 Implementation Report submitted by the Working Group in Case No. 9618, the ECOSS has been adjusted to reflect the 2019 historical test year ratemaking adjustments as proposed in Part 1 of the Direct Testimony of Company Witness Vahos.

My testimony will provide a general framework for Company Witness Fiery to apply in her rate design testimony, including the Relative Rates of Return (RROR) by customer class and the cost components determined in the ECOSS.[1]

My testimony will also discuss how the Company complied with the Cost of Service Study (COSS) provisions agreed to in the Settlement Agreement approved by the Commission in Case No. 9610 related to the Company's preparation of the cost of service studies.

[1] The phrase "Relative Rates of Return" refers to the rate of return of each customer class relative to the system average.

Q. PLEASE DESCRIBE THE ORGANIZATION OF YOUR DIRECT TESTIMONY.

A. First, I will discuss the purpose and theory behind developing an embedded COSS and the goals that are sought through these analyses.

Second, I will outline the basic processes involved in developing the ECOSS that I am sponsoring in this proceeding.

Third, I will discuss changes made to the ECOSS the Company is recommending in this case.

Fourth, I will discuss how changes were made to the ECOSS to reflect items agreed to in the Settlement Agreement in Case No. 9610.

Lastly, I will describe the results of the ECOSS as provided in the exhibits outlined below. I will detail the RROR as well as the results of the customer charge components by class.

Q. ARE YOU SPONSORING ANY EXHIBITS?

A. Yes. The exhibits presented with my testimony are organized as follows:

- Exhibit AMO-1 provides the ECOSS relative rates of return;
- Exhibit AMO-2 provides the summary results of the ECOSS;
- Exhibit AMO-3 provides the ECOSS monthly customer costs;
- Exhibit AMO-4 provides the ECOSS five-year comparison of annual system class demand allocators and the effect on the various class RRORs; and
- Exhibit AMO-5 provides a summary of the 2019 ECOSS using single-year demand and throughput allocators.

II. <u>OVERVIEW OF COST OF SERVICE STUDY THEORY</u>

Q. PLEASE PROVIDE A HIGH-LEVEL OVERVIEW OF A COST OF SERVICE STUDY.

A. The primary objective of an embedded cost of service study is to present a reasonable representation of the cost allocation of the Company's costs during the study period and revenue responsibility among its customer classes, based upon principles of cost causation and revenue responsibility. The end result is to ascertain whether each customer class' revenue is covering its fair share of costs. The 2019 ECOSS results included in my Direct Testimony provide a depiction of the rates of return for each electric customer class relative to the system average. These RROR provide guidance for the distribution of the necessary revenue changes among the customer classes. When revenue changes do not take relative rates of return into consideration, under-earning customer classes may continue to under-earn and over-earning classes may continue to over-earn, perpetuating interclass subsidies among rate payers.

Another objective of an embedded cost of service study is to provide a guide for proper rate design. When rate design is not in line with the classification of cost components, there can be a disconnect between the price signals given to customers and the cost to provide service to those customers, which can result in intraclass subsidies. Company Witness Fiery will provide in her Direct Testimony further detail on the use of cost of service study results in proper ratemaking.

Q. PLEASE SUMMARIZE THE KEY PROCESSES INVOLVED IN THE DEVELOPMENT OF THE COST OF SERVICE STUDY.

A. There are generally three basic steps to measure customer class responsibility for rate base and expense. These three steps are: (1) functionalization; (2) classification; and (3) allocation. Functionalization is the process of dividing rate base and expense components of the cost of service study into specified utility functions based on the characteristics of those components.

BGE functionalizes its electric delivery service assets and related expenses as transmission or distribution operations. Electric transmission costs, which are subject to the jurisdiction of the Federal Energy Regulatory Commission (FERC), are not included in the ECOSS for the purpose of distribution service ratemaking before the Commission. Electric supply costs recovered through BGE's Rider 1 – Standard Offer Service procurement are also not included in the ECOSS analysis for the purpose of distribution service ratemaking before the Commission.

Classification is the process of separating the electric functionalized rate base and expenses into categories that relate to how costs are caused. Distribution-related costs are primarily classified between demand- and customer- related components. Demand-related costs are generally driven by customer class non-coincident peak (NCP) and/or coincident peak (CP) demand levels (discussed in more detail later in my testimony), while customer-related costs are driven by the number and cost of customers connecting to electric transformers (i.e., service drops) and the necessary requirements for the utility to service those customers (i.e., metering, meter reading, account processing, and billing systems). There are some instances in which distribution costs (though minor in relative cost significance) are variable with customer class consumption; in those instances, expenses would be classified as energy-related.

Allocation is the final refinement process, whereby rate base and expenses in each of the classified cost categories are assigned to customer classes according to customer load impositions on the distribution system and/or customer connection requirements. Company costs are directly assigned to the specific customer classes whenever the costs are known to be related to investments or expenses that serve only a particular customer or group of customers. When the costs are not directly assignable to customer classes, they are allocated using an appropriate methodology that best aligns with the cost causation of those elements. That methodology varies depending on the nature of the item being allocated and the data available at the time of the analysis.

Q. HAS THE COMPANY MADE ANY ADJUSTMENTS TO THE ECOSS IN THIS PROCEEDING?

A. Yes. Consistent with the filing requirements agreed to in the Work Group Implementation Report submitted to the Commission on December 20, 2019, in Case No. 9618, the Company has incorporated in the ECOSS the ratemaking adjustments to the 2019 historical test year that Company Witness Vahos proposes in Part 1 of his Direct Testimony and exhibits.

Q. HOW ARE RATEMAKING ADJUSTMENTS INCORPORATED INTO THE ECOSS MODEL?

A. Each ratemaking adjustment is analyzed individually to determine the FERC account(s) that are predominantly impacted. The activity for all adjustments is then summed by FERC account and entered into the ECOSS model in a new column titled "2019 Proforma Adjustment Balances."

Q. DOES THE COMPANY PLAN TO SUBMIT ANY ADDITIONAL ECOSS IN SUPPORT OF THE MULTI-YEAR PLAN?

A. No. The proposed ECOSS I am submitting provides a reasonable representation of each rate class' contribution to the Company's revenue requirement and the results will serve as a guide for the rate design in the multi-year plan. The rate design for the multi-year plan will be guided by the results of this ECOSS. In its Order No. 89482, the Commission expressed agreement with the use of a single COSS to be used as a guide to set class revenue allocations for the duration of the multi-year plan period.[2]

Q. HAVE THE ADJUSTMENTS IMPACTED THE RELATIVE RATES OF RETURN PRESENTED IN THE ECOSS?

A. No. Below in Table 1 is a comparison of the Company proposed ECOSS relative rates of return without any adjustments and the relative rates of return of the ECOSS with adjustments. As Table 1 demonstrates, there is not a material change in the RRORs after incorporating the ratemaking adjustments. The RRORs for the customer classes Schedules R and RL actually remain the same.

[2] Order No. 89482 at 28, para. 55.

Table 1: Impacts of Pro Forma HTY Adjustments to Company-Proposed Relative Rates of Return (RROR) Recommended for Revenue Allocation[3]

Electric Rate Schedule	RROR without Adjustments	RROR with Adjustments
Schedule R	0.67	0.67
Schedule RL	0.95	0.95
Schedule G	1.05	1.06
Schedule GS	1.63	1.65
Schedule GL	1.65	1.66
Schedule P	1.01	1.00
Schedule SL	1.42	1.46
Schedule PL	4.08	4.09
Schedule T	11.65	11.95
System Total	1.00	1.00
Combined R/RL	*0.69*	*0.69*

III. CALENDAR YEAR 2019 COMPANY RECOMMENDED ELECTRIC COST OF SERVICE STUDY

Q. PLEASE SUMMARIZE THE COMPANY'S CUSTOMER-CLASS ELECTRIC COST OF SERVICE MODEL.

A. The ECOSS is 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. Using the FERC Uniform System of Accounts, the ECOSS identifies

[3] Schedule EVP is not included in Table 1. Schedule EVP was newly created during 2019 at the direction of the Commission in Order No. 88997 and was intended to incentivize the deployment of charging infrastructure in furtherance of state policy goals and commitments for the electrification of Maryland's transportation sector. Given Schedule EVP's recent creation and the relatively nascent market for EV charging stations, it is premature to rely on the results of the ECOSS where Schedule EVP is concerned. For these reasons, BGE is not recommending any changes to Schedule EVP rates in this proceeding. BGE will continue to track the revenues and costs associated with utility-owned charging stations under Schedule EVP for use in future cost of service studies. See the 2019 ECOSS presented on Exhibit AMO-2 for the Schedule EVP 2019 RROR.

electric distribution system embedded costs for the 2019 calendar year. As noted earlier in my testimony, the ECOSS excludes all electric transmission investment and related operations and maintenance (O&M) expenses and excludes Rider 1 electric supply costs (i.e., standard offer service (SOS) procurement).

The CP and NCP demand are important allocators in the ECOSS. CP demand is the demand of individual customer classes that coincides (in time) with the peak demand of the whole system. NCP demand represents the actual individual peak demands of each customer class although the individual class peak demands do not necessarily coincide with the time the system peak happens. For example, in 2019 the BGE system CP demand of 6,700 MW occurred on July 21, 2019, at the hour ending at 6:00 p.m. Although the system peak (CP) occurred in July 2019, the demands for Schedules G and GS peaked in August 2019, which was not coincident with the system peak.

In the ECOSS, distribution 34 kV, 13 kV, and secondary plant and associated O&M components are classified as demand-related and allocated to the customer classes based on each class' contribution to the total NCP kW, at their respective voltage levels. As a primary allocator of demand components, NCP is employed in the ECOSS to reflect how substations and distribution feeders are actually planned and sized. Distribution feeders are planned and sized based more on substation load center peak demands - as opposed to total system peak demand which drives network transmission facilities. Service and meter plant and associated O&M expenses are classified as customer-related and allocated to the classes based on weighted customer investment or the number of customers or meters in each rate class. Costs associated with billing functions are classified as customer-related and are generally driven by the number of customers in each class.

Q. WHY IS THE NCP USED TO ALLOCATE DEMAND-RELATED DISTRIBUTION INVESTMENT IN THE ECOSS?

A. Use of the NCP in the allocation of demand-related distribution investment is the generally-accepted methodology in ECOSS development. For example, a cost allocation manual issued by the National Association of Regulatory Utility Commissioners (NARUC) notes that area loads are major factors in sizing distribution equipment and that the customer class NCP demand allocation method is normally used to allocate distribution substations and primary feeders.[4]

Distribution substations and distribution feeder connections, down to the secondary transformer, are planned such that sufficient capacity is available to meet customer loads at localized voltage service levels - as compared to network transmission facilities constructed to meet system-wide capacity requirements (where the use of a system coincident peak allocator may be more appropriate).

In general, electric distribution facilities do not function as a single integrated system in meeting system peak demand. Substation area peak loads are the major factor in sizing electric distribution equipment, and customer class NCPs are the more typically accepted approach for allocating the demand-related component of distribution plant. For example, a substation load center might have a large concentration of residential air-conditioning end-use customers. As a result, distribution substations and feeders in this load center are typically going to be sized

[4] NARUC Electric Utility Cost Allocation Manual at 97 (Jan. 1992).

according to the late afternoon or early evening high demand summer peaks when air-conditioning use is most prevalent for residential customers. Alternatively, certain distribution substations and feeders may have a large concentration of electric resistance heating end-use customers that drive a winter peak. As a result, distribution substation and feeders in this load center are typically going to be sized according to the high demand winter peaks when electric heating use is prevalent.

Other substation load centers may be dominated by peak loads that are mixed with industrial processing or other business profiles. These peak loads should be less weather sensitive and more of a function of economic activity when compared to residential peaks. Substations and feeders serving these loads are likely sized to accommodate cyclical production requirements as opposed to serving seasonal weather sensitive peaks.

The use of an NCP allocator does not consider when the total system peak is recorded, but instead reflects more closely the diversity in customer group load patterns.

Q. PLEASE EXPLAIN MORE SPECIFICALLY HOW THE NCP ALLOCATOR IS USED IN THE ECOSS.

A. Demand-related costs are allocated to customer rate classes based on the corresponding NCP demand, adjusted for losses at each predominant voltage level. The NCP allocator is based on each customer class' highest hourly kW demand. For each month, the maximum hourly demand observed for every customer class - regardless of the hour or the day - is determined. Each class' contribution to the NCP is calculated by dividing that class' maximum hourly demand by the sum of every class' maximum hourly demand. This process develops the system allocators used to assign distribution demand-related costs to the various customer classes. As explained later, the ECOSS I am sponsoring uses demand allocators based upon an average of demands observed for each customer class over the last five years (2015 – 2019) for Schedules R and RL.[5] Single-year demand allocators continue to be used for the other customer classes.

In the ECOSS, the Company measures residential customer peak kW demand (Schedule R, Schedule RL) in aggregate on an hourly basis. The Schedule R and RL individual peaks are then determined at the time of the total residential peak (i.e., coincident peak with the total residential peak).

Similar to residential peak demand, the Company measures small commercial customer peak demand (Schedule G and Schedule GS) in aggregate on an hourly basis. The Schedule G and GS individual peaks are determined at the time of the total small commercial peak.

The cost causality concept behind treating all residential customers as one demand group and all small commercial customers as another single-demand group in the NCP allocator is to aggregate similar distribution service requirements. The Company plans and builds distribution substations and distribution feeders such that sufficient capacity is available to meet peak customer loads whenever they may occur. The Company's engineers do not look at the split of customers between Schedules R and RL or Schedules G and GS when designing the distribution system. Although slight variations may exist in on-premise meter sizes or service connections, Schedules RL and GS were established to allow for time-of-use commodity pricing. Schedule RL

[5] For purposes of the ECOSS, Schedule R includes a small group of residential customers taking electric service under Schedules EV and RD.

customers may choose to change to Schedule R service and vice versa at any time and Schedule GS customers may choose to change to Schedule G service and vice versa at any time.

Q. DOES BGE'S ECOSS RECOGNIZE THE USE OF VARIOUS DELIVERY SERVICE VOLTAGE LEVELS IN ALLOCATING DISTRIBUTION INVESTMENT AMONG CUSTOMER CLASSES?

A. Yes. The ECOSS recognizes that the distribution system consists of several voltage level grids and identifies customer class cost responsibility at each of the grid levels. The distribution voltage level grids are segmented by: (1) sub-transmission voltages at 34 kV; (2) primary voltages at 13 kV; and (3) secondary voltage. Recognizing this distinction in service voltages ensures that only the loads of those customers who benefit from the facilities are included in the corresponding NCP allocators.

Q. DOES NCP DEMAND USED IN THE COMPANY'S ECOSS INCLUDE SYSTEM LOSSES?

A. Yes. System energy losses occur in the transformation of power from higher to lower voltage levels of service and also in the distribution of power to load centers in general. System losses are included in the development of the NCP allocator. The Company's 34 kV, 13 kV, and secondary NCP demand allocators are adjusted to account for appropriate line losses as well as to reflect the removal of demands not associated with the corresponding voltage level allocator. The NCP allocators used in the Company's ECOSS are net of system losses.

IV. CHANGES MADE TO THE ECOSS PRESENTED IN THIS CASE

Q. ARE THERE ANY NEW RATE SCHEDULES PRESENTED IN THE 2019 ECOSS?

A. Yes. In Order No. 88997 in Case No. 9478, the Commission directed the Company to create a separate rate class for utility-owned public electric vehicle charging stations.[6] The Company complied with this order in 2019, and thus I have added a separate column, Schedule EVP, for this new rate schedule.

Q. HAVE YOU MADE ANY CHANGES TO ALLOCATION METHODOLOGIES USED IN THE ECOSS SINCE THE COMPANY'S LAST BASE RATE PROCEEDING?

A. Yes, there are two new allocators, as well as changes to several existing allocators. The first new allocator is customer-related and is used to allocate the EV program regulatory asset approved in Order No. 88997 in Case No. 9478. This new customer allocator is labeled as CUST_EV in the model.

The second new allocator was created to allocate large customer service group activity to Schedules GL, P and T. This was agreed to by the Company as part of the Settlement Agreement in Case No. 9610. Large customer service group activity is represented as its own line within the Administrative and General Expenses and Taxes Other than Income Taxes sections in the model. The associated new internal allocator is labeled LABORLC in the model.

Additionally, there were several changes made to customer allocators. First, the customer allocators labeled CUST_370DIR and CUST_370DIRO in the model

[6] Order No. 88997 at 66.

were updated. These allocators are used for AMI activity. Based on an analysis of the market and operational-side benefits from Case No. 9406, I am proposing a new method that allocates 48.6% of AMI meters based on the replacement cost of AMI meters consistent with previous rate cases, 28.2% based on NCP at primary voltages at 13 kV, and 23.2% based on MWH sales at premises. The Company agreed to this change as part of the Settlement Agreement in Case No. 9610. In addition, this change aligns with Order No. 87884 in Case No. 9418 for Potomac Electric Power Company, and the Commission approved Proposed Order of the Public Utility Law Judge in Order No. 89227 in Case No. 9602 for Delmarva Power and Light Company. Finally, consistent with Order No. 88997 in Case No. 9478, the customer allocator labeled CUST_371DIR in the model has been updated to directly allocate activity to Schedule EVP.

Q. HAVE YOU MADE ANY OTHER CHANGES TO THE ECOSS PRESENTED IN CASE NO. 9610?

A. Yes. I have added several rows for new FERC accounts that now have activity, for example, "Reg. Asset – Union Sick Bank." This line represents amortization expense for the new union sick day regulatory asset, not included in rate base, that is amortized over ten years as agreed to by the Company as part of the Settlement Agreement in Case No. 9610. I also renamed several rows to be more transparent in what they represent. Next, I have removed several rows that are not used and are not likely to be used in the future in the ECOSS. Finally, I have expanded the Common Plant – Non-AMI and Common Plant – AMI sections to include FERC account detail as agreed to by the Company as part of the Settlement Agreement in Case No. 9610.

Q. PLEASE SUMMARIZE THE CHANGES THE COMPANY AGREED TO AS PART OF THE SETTLEMENT AGREEMENT IN CASE NO. 9610.

A. The Company agreed to the following:

- Assign common plant by FERC account;
- Propose a COSS which is adjusted for AMI allocation;
- Propose a COSS which is adjusted for large customer service representatives;
- Propose a COSS which continues to include a one-year demand allocator; and
- Engage in further discussions with Staff, OPC, and other interested stakeholders regarding ways to improve the COSS.

The Company has incorporated into the ECOSS additional FERC detail for common plant, updated the AMI allocator, created a new allocator for the large customer service group, and continued to present the COSS with a single-year demand allocator, while still proposing the five-year demand allocator for certain customer classes. In addition, the Company met with interested stakeholders in February to discuss the changes made to the 2019 ECOSS as part of the Settlement Agreement and discuss ways to continue to improve the ECOSS in future periods.

Q. WHAT DEMAND AND THROUGHPUT ALLOCATORS ARE YOU PROPOSING TO USE?

A. In Order No. 87591 in Case No. 9406, the Commission directed the Company to continue presenting cost of service studies with single-year demand allocators while still providing the five-year demand allocator study for both gas and electric in future rate cases.[7] Additionally, in Order No. 88975 in Case No. 9484, the Commission wrote that the use of the five-year average demand and throughput allocators "may be a reasonable approach to be explored in future rate cases."[8] A summary of the five-year electric demand data and the impact on class RRORs is provided in Exhibit AMO-4. Exhibit AMO-5 presents the summary results of the ECOSS using the single-year 2019 demand allocators, consistent with the Settlement Agreement in Case No. 9610. In this case, I propose to use a combination of the two allocation methods: the five-year average demand allocators and single-year demand allocators, which are detailed by Schedule in Table 2 below. The throughput allocators are noted in the ECOSS as ENEPS, EPOLR, and ENESUBT, while the demand allocators are noted as DEMPROD, DEMDSUBT, DEMDPRI, and DEMDSEC.

Table 2: Summary of Demand and Throughput Allocators[9]

Electric Rate Schedule	Demand and Throughput Allocators
Schedule R	Five-Year Average
Schedule RL	Five-Year Average
Schedule G	Single-Year
Schedule GS	Single-Year
Schedule GL	Single-Year
Schedule P	Single-Year
Schedule SL	Single-Year
Schedule PL	Single-Year
Schedule T	Single-Year

[7] In Order No. 87591 in Case No. 9406, the Commission directed BGE to continue to provide the five-year demand study as opposed to directing the company to completely abandon the idea of average demand allocators.
[8] See Case No. 9484; Order No. 88975 at 78.
[9] Schedule EVP is not included in Table 2. Single-Year demand and throughput allocators were used for Schedule EVP in the 2019 ECOSS.

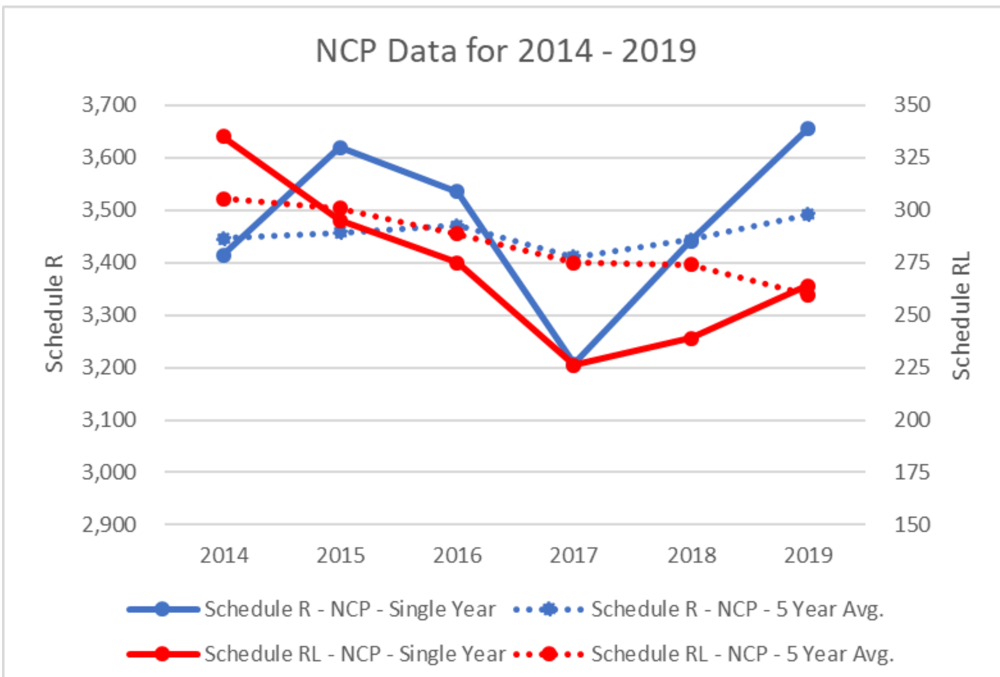
Q. HOW DID YOU DETERMINE WHICH RATE CLASSES WOULD USE THE FIVE-YEAR AVERAGE?

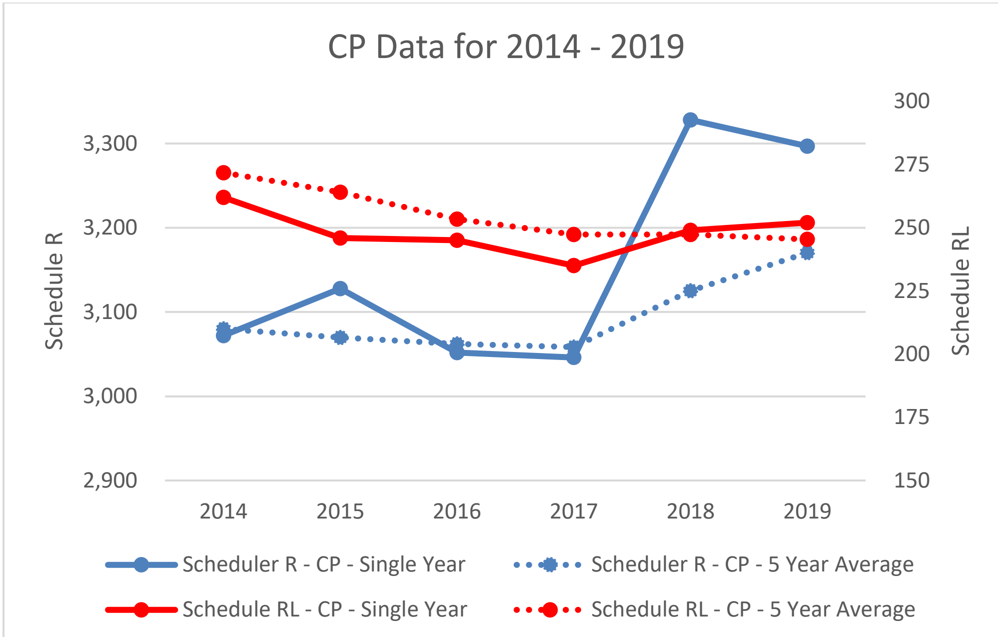
A. Residential class consumption is more sensitive to weather. In years where there is abnormal weather, using single-year NCP or CP demand to allocate costs in the ECOSS may shift costs to and from these classes year over year. For example, a very hot summer or very cold winter would result in residential classes having a higher NCP or CP. Higher NCPs and CPs cause a higher percentage of demand-related costs to be allocated and lower the class RROR. Alternatively, milder years would have the effect of shifting a lower percentage of demand-related costs to the same classes causing a higher RROR. Applying a five-year average to the residential classes that are most sensitive to weather, normalizes the allocation of demand-related costs.

Additionally, the residential rate classes that are being proposed to use the five-year average approach are decoupled. That means that these rate class' revenues are based on weather-normalized sales volumes so it is reasonable that the demand and throughput should be normalized as well. Otherwise, the relative rates of return for these classes would be skewed by weather-normalized revenues offset by weather-sensitive costs that are not normalized.

Q. PLEASE EXPLAIN WHY A FIVE-YEAR AVERAGE MAY BE MORE APPROPRIATE THAN A SINGLE-YEAR.

A. In my opinion, the method I am proposing is a more accurate representation of the demands on the Company's Distribution System. As described above, there is a strong relationship between weather and the demand of the proposed five-year average rate classes. By using a five-year average, the volatility of these allocators due to variations in weather would be smoothed out and there would not be large differences from one year to the next. Any change would be more gradual over time. As shown in the graphs below, using single calendar year demand and throughput allocators results in significant year over year changes in NCP and CP. Using a five-year average will decrease the volatility from year to year and provide a stable allocation that is more representative of the cost causation of the demand and throughput related elements for these rate classes.





V. SUMMARY ECOSS RESULTS

Q. WOULD YOU PLEASE REVIEW THE OVERALL RESULTS OF THE ECOSS?

A. The ECOSS customer class rates of return and relative rates of return for the 12 months ended December 31, 2019 are shown in Table 3 and summarized below. All of the customer class RROR are relatively consistent with the RROR calculated in the Company's recommended ECOSS in its most recent electric base rate proceeding, Case No. 9610.

Table 3: Summary of ECOSS Relative Rates of Return Recommended for Revenue Allocation Purposes[10]

Electric Rate Schedule	Relative Rate of Return
Schedule R	0.67
Schedule RL	0.95
Schedule G	1.06
Schedule GS	1.65
Schedule GL	1.66
Schedule P	1.00
Schedule SL	1.46
Schedule PL	4.09
Schedule T	11.95

Schedule R – Residential Service (including Schedules EV and RD) is earning a return below the system average return band width of +/- 10% -- at a relative rate of return ratio of 0.67. This is very similar to the RROR of 0.68 calculated in the Company's recommended ECOSS in Case No. 9610.

Schedule RL - Residential Optional Time-of-Use is earning a return slightly below the system average return band width of +/- 10% -- at a relative rate of return ratio of 0.95. This represents an improvement over the RROR of 0.89 calculated in the Company's recommended ECOSS in Case No. 9610.

Schedule G – General Service (including Schedule GU) is earning a return slightly above the system average return band width of +/- 10% -- at a relative rate of return ratio

[10] Schedule EVP is not included in Table 3. See the 2019 ECOSS presented on Exhibit AMO-2 for the Schedule EVP 2019 RROR.

of 1.06. This represents an improvement over the RROR of 0.89 calculated in the Company's recommended ECOSS in Case No. 9610.

Schedule GS – General Service Small (a relatively small schedule in terms of number of customers who otherwise qualify for service under Schedule G but have opted for time-of-use rates) is earning a return above the system average return band width of +/- 10% -- at a relative rate of return ratio of 1.65. This represents a slight deterioration in the RROR of 1.48 calculated in the Company's recommended ECOSS in Case No. 9610.

Schedule GL – General Service Large is earning a return above the system average rate of return band width of +/- 10% -- at a relative rate of return ratio of 1.66. This is very similar to the RROR of 1.61 calculated in the Company's recommended ECOSS in Case No. 9610.

Schedule P – Primary Voltage Service is earning a return within the system average rate of return band width of +/- 10% -- at a relative rate of return ratio of 1.00. This represents an improvement over the RROR of 1.16 calculated in the Company's recommended ECOSS in Case No. 9610.

Schedule SL – Street Lighting is earning a return that is above the system return band width of +/- 10% -- at a relative rate of return ratio of 1.46. This represents an improvement over the RROR of 1.74 calculated in the Company's recommended ECOSS in Case No. 9610.

Schedule PL – Private Area Lighting is earning a return that is well above the system average return band width of +/- 10% -- at a relative rate of return ratio of 4.09. This represents an improvement over the RROR of 4.23 calculated in the Company's recommended ECOSS in Case No. 9610.

Schedule T – Transmission Voltage Service is earning a return significantly above the system average return band width of +/- 10% -- at a relative rate of return ratio of 11.95. This represents an improvement over the RROR of 13.03 calculated in the Company's recommended ECOSS in Case No. 9610.

Q. PLEASE SUMMARIZE THE CUSTOMER CHARGE RESULTS SHOWN IN EXHIBIT-AMO-3.

A. The purpose of the customer charge component of the COSS is to portray the customer-based costs by customer class that should be recovered through the customer charge. Table 4 shows the Customer Charge Component by customer class.

Table 4: Customer Charge Components

Electric Rate Schedule	ECOSS Customer Component
Schedule R	$16.96
Schedule RL	$18.65
Schedule G	$28.57
Schedule GS	$51.10
Schedule GL	$117.18
Schedule P	$1,196.90
Schedule T	$5,867.20
Combine R/RL	*$17.03*

The Direct Testimony of Company Witness Fiery will provide recommended changes to Customer Charges over the multi-year plan.

VI. CONCLUSION

Q. CAN YOU PLEASE SUMMARIZE YOUR TESTIMONY?

A. Certainly. My testimony includes the Calendar Year 2019 Company Recommended ECOSS. The ECOSS incorporates the same cost allocation methodologies and procedures proposed by the Company in BGE's prior electric rate proceeding, Case No. 9610, with two notable exceptions: the incorporation of ratemaking adjustments to the 2019 historical test year and the previously discussed items the Company agreed to in the Settlement Agreement in Case No. 9610.

In Exhibit AMO-2, the summary results of the BGE ECOSS, provides a framework for Company Witness Fiery to apportion in a fair and reasonable manner the overall electric revenue requirement as developed by Company Witness Vahos. In Exhibit AMO-3, displayed are the monthly customer costs by rate schedule as derived from the ECOSS – these monthly costs will be used as a guideline for Company Witness Fiery's proposal to change Customer Charges.

Q. DOES THIS CONCLUDE YOUR DIRECT TESTIMONY?

A. Yes.

Comparison of Customer Class Relative Rates of Return (RROR)

2019 ECOSS	
Rate Schedule	RROR
R**	0.67
RL	0.95
G***	1.06
GS	1.65
GL	1.66
P	1.00
SL	1.46
PL	4.09
T	11.95
EVP	-0.88
System Total	1.00

** includes Schedules EV and RD

*** includes Schedule GU

BALTIMORE GAS AND ELECTRIC COMPANY
COMPANY RECOMMENDED ELECTRIC COST OF SERVICE STUDY
FOR THE 12 MONTHS ENDING DECEMBER 31, 2019

		TOTAL RETAIL (1)	RESIDENTIAL SERVICE R (2)	RES LARGE TIME OF DAY RL (3)	GENERAL SERVICE G (Incl. Sch. GU) (4)	GENERAL SERVICE-SMALL GS (5)	GENERAL SERVICE-LARGE GL (6)	PRIMARY SERVICE P (7)	STREET LIGHTING SL (8)	PRIVATE AREA LIGHTING PL (9)	TRANSMISSION SERVICE - 115kV T (10)	UTILITY OWNED EV CHARGING EVP (11)
1	**SUMMARY OF RESULTS**											
2												
3	**DEVELOPMENT OF RATE BASE**											
4	ELECTRIC PLANT IN SERVICE	6,759,014,420	3,807,337,570	278,100,787	601,010,380	44,270,969	1,347,697,180	439,321,393	167,842,901	71,293,559	1,867,910	271,772
5	PLUS: ADDITIONS TO UTILITY PLANT	735,087,992	396,665,617	27,873,695	92,029,479	7,629,500	141,506,995	54,015,285	7,932,586	3,387,009	3,921,052	126,774
6	LESS: RESERVE FOR DEPRECIATION	2,591,688,976	1,460,770,509	106,084,383	233,932,973	17,129,738	513,629,564	169,383,405	62,669,598	26,641,180	1,345,048	102,579
7	NET PLANT IN SERVICE	4,902,413,435	2,743,232,678	199,890,098	459,106,885	34,770,731	975,574,611	323,953,272	113,105,889	48,039,388	4,443,914	295,968
8	RATE BASE ADDITIONS	36,590,301	20,492,882	1,508,201	3,245,488	246,087	7,374,274	2,433,581	897,270	379,394	11,567	1,555
9	RATE BASE DEDUCTIONS	1,367,080,249	754,704,618	54,018,863	139,515,507	10,239,980	275,930,381	88,514,316	29,454,968	12,533,072	2,120,831	47,714
10	TOTAL RATE BASE	3,571,923,487	2,009,020,943	147,379,437	322,836,866	24,776,839	707,018,505	237,872,538	84,548,190	35,885,711	2,334,650	249,808
11												
12	**DEVELOPMENT OF RETURN**											
13	OPERATING REVENUES											
14	DISTRIBUTION REVENUE	1,169,456,727	591,062,941	43,685,806	127,764,410	10,724,171	266,883,648	79,867,824	25,370,081	19,349,150	4,748,652	47
15	OTHER OPERATING REVENUE	46,119,777	37,586,004	3,019,085	2,097,185	86,291	2,366,697	718,283	118,600	92,675	34,723	234
16	TOTAL OPERATING REVENUE	1,215,576,504	628,648,946	46,704,891	129,861,594	10,810,462	269,250,345	80,586,107	25,488,680	19,441,824	4,783,375	281
17												
18	OPERATING EXPENSES											
19	OPERATION & MAINTENANCE	447,205,167	277,347,521	17,477,255	46,011,857	2,697,785	68,325,504	25,303,485	7,335,367	2,661,384	43,524	1,484
20	DEPRECIATION & AMORT EXPENSE	335,276,887	179,917,535	12,994,746	39,208,110	3,286,543	66,793,358	24,171,236	5,193,148	2,212,877	1,479,870	19,464
21	TAXES OTHER THAN INCOME TAX	171,721,550	86,489,399	6,162,291	19,539,386	1,544,776	38,764,715	13,991,378	2,996,561	1,469,556	759,847	3,642
22												
23	FEDERAL, STATE & LOCAL INCOME TAXES	27,692,749	(1,013,413)	994,573	2,471,613	550,732	17,403,936	1,677,775	1,815,882	3,203,516	596,877	(8,742)
24												
25	TOTAL OPERATING EXPENSES	981,896,353	542,741,042	37,628,865	107,230,967	8,079,836	191,287,513	65,143,874	17,340,958	9,547,333	2,880,118	15,847
26												
27	PLUS											
28	ADJUSTMENTS TO INCOME	10,365,699	5,817,820	455,499	722,270	68,126	2,071,388	787,213	309,078	131,285	2,519	500
29												
30	NET OPERATING INCOME (EARNINGS)	244,045,850	91,725,724	9,531,525	23,352,897	2,798,752	80,034,220	16,229,446	8,456,801	10,025,776	1,905,776	(15,066)
31												
32												
33	RATE OF RETURN (PRESENT)	6.83%	4.57%	6.47%	7.23%	11.30%	11.32%	6.82%	10.00%	27.94%	81.63%	-6.03%
34	RELATIVE RATE OF RETURN (PRESENT)	1.00	0.67	0.95	1.06	1.65	1.66	1.00	1.46	4.09	11.95	-0.88
35												
36	RATE OF RETURN (EQUALIZED)	7.28%	7.28%	7.28%	7.28%	7.28%	7.28%	7.28%	7.28%	7.28%	7.28%	7.28%
37	SALES REVENUE REQ EQUALIZED ROR	1,191,517,472	666,296,274	45,338,202	127,970,841	9,351,429	227,476,518	81,368,427	22,194,566	9,121,445	2,353,848	45,922

COMPANY 2019 ECOSS Monthly Customer Costs*

COST COMPONENT	RESIDENTIAL SERVICE R	RES LARGE TIME OF DAY RL	GENERAL SERVICE G (Incl. Sch. GU)	GENERAL SERVICE-SMALL GS	GENERAL SERVICE-LARGE GL	PRIMARY SERVICE P	TRANSMISSION SERVICE - 115kV T	UTILITY OWNED EV CHARGING EVP
CUSTOMER SERVICES	$2.09	$3.09	$1.77	$1.95	$3.13	$0.00	$0.00	$1.51
CUSTOMER METERS	$8.58	$8.95	$20.64	$43.20	$107.51	$1,173.72	$5,797.73	$20.05
CUSTOMER METER READING	$0.21	$0.00	$0.28	$0.00	$0.61	$11.16	$16.83	$0.00
CUSTOMER RECORDS AND COLLECTIONS	$5.36	$5.53	$5.54	$5.51	$5.47	$5.47	$5.75	$1.44
CUSTOMER SERVICE AND INFORMATION	$0.26	$0.26	$0.27	$0.27	$0.27	$0.27	$0.27	$0.26
CUSTOMER OTHER	$0.46	$0.82	$0.07	$0.17	$0.19	$6.28	$46.62	$1,759.44
TOTAL CUSTOMER COMPONENT	$16.96	$18.65	$28.57	$51.10	$117.18	$1,196.90	$5,867.20	$1,782.70

*Based on BGE's proposed authorized rate of return of 7.28%.

2019 ECOSS 5-Year Demand Allocator Study
TRENDS AND CHANGES IN RELATIVE RATES OF RETURN

	R	RL	G	GS	GL	P	SL	PL	T	EVP
2015	0.69	0.86	0.83	2.48	1.60	1.18	1.66	4.31	13.05	-
2016	0.69	0.95	0.82	2.39	1.60	1.13	1.73	4.41	13.27	-
2017	0.71	1.19	0.92	1.64	1.47	1.03	1.65	4.15	13.20	-
2018	0.67	1.17	0.88	1.47	1.60	1.14	1.73	4.23	13.04	-
2019	0.63	0.97	1.11	1.72	1.74	1.06	1.48	4.12	11.95	(0.88)
5 Yr Avg	0.69	0.97	0.96	2.02	1.62	0.94	1.43	4.11	12.10	(0.88)
Proposed	0.67	0.95	1.06	1.65	1.66	1.00	1.46	4.09	11.95	(0.88)

Notes:

(1) 2015-2019 RRORs developed by using the Calendar Year 2019 Recommended Electric Actual Embedded Cost of Service Study and applying each year's specific Throughput, CP and NCP demand allocators to produce a corresponding RROR result.

(2) The 5 Year Average RRORs were developed by inserting the average of 2015-2019 Throughput, CP and NCP demand allocators into the Calendar Year 2019 Recommended Electric Actual Embedded Cost of Service Study.

(3) Since EVP is a new schedule in 2019 and does not have historical data, Calendar Year 2019 data was used for the 5 Year Average.

2019 ECOSS 5-Year Demand Allocator Study
COMPARISON OF DEMAND ALLOCATORS (MW)

	NCP at Distribution Service		
	34KV	**13KV**	**Secondary**
R			
2015	3,620	3,577	3,470
2016	3,536	3,494	3,389
2017	3,207	3,169	3,074
2018	3,442	3,401	3,299
2019	3,655	3,611	3,503
5 Yr Avg	3,492	3,450	3,347
Proposed	3,492	3,450	3,347
RL			
2015	295	291	282
2016	275	272	264
2017	226	223	216
2018	239	236	229
2019	264	261	253
5 Yr Avg	260	257	249
Proposed	260	257	249
G			
2015	678	670	650
2016	664	656	636
2017	581	574	557
2018	622	615	597
2019	592	585	567
5 Yr Avg	627	620	601
Proposed	592	585	567
GS			
2015	37	37	36
2016	37	37	36
2017	44	43	42
2018	49	48	47
2019	48	47	46
5 Yr Avg	43	42	41
Proposed	48	47	46
GL			
2015	1,727	1,647	1,536
2016	1,683	1,608	1,504
2017	1,602	1,535	1,442
2018	1,628	1,548	1,457
2019	1,615	1,540	1,429
5 Yr Avg	1,651	1,576	1,474
Proposed	1,615	1,540	1,429
P			
2015	892	728	-
2016	869	725	-
2017	882	674	-
2018	863	690	-
2019	861	667	-
5 Yr Avg	873	697	-
Proposed	861	667	-
SL			
2015	59	58	56
2016	53	52	50
2017	54	53	51
2018	51	50	48
2019	51	50	48
5 Yr Avg	54	53	51
Proposed	51	50	48
PL			
2015	23	23	22
2016	21	21	20
2017	23	23	22
2018	23	23	22
2019	23	23	22
5 Yr Avg	23	23	22
Proposed	23	23	22
EVP			
2015	-	-	-
2016	-	-	-
2017	-	-	-
2018	-	-	-
2019	0	0	0
5 Yr Avg	0	0	0
Proposed	0	0	0
Total			
2015	7,331	7,031	6,052
2016	7,138	6,865	5,899
2017	6,619	6,294	5,404
2018	6,917	6,611	5,699
2019	7,109	6,784	5,868
5 Yr Avg	7,023	6,718	5,785
Proposed	6,942	6,619	5,708

	CP
R	
2015	3,128
2016	3,052
2017	3,046
2018	3,328
2019	3,297
5 Yr Avg	3,170
Proposed	3,170
RL	
2015	246
2016	245
2017	235
2018	249
2019	252
5 Yr Avg	245
Proposed	245
G	
2015	592
2016	604
2017	510
2018	559
2019	517
5 Yr Avg	556
Proposed	517
GS	
2015	38
2016	40
2017	43
2018	48
2019	46
5 Yr Avg	43
Proposed	46
GL	
2015	1,541
2016	1,499
2017	1,415
2018	1,437
2019	1,387
5 Yr Avg	1,456
Proposed	1,387
P	
2015	793
2016	781
2017	764
2018	749
2019	750
5 Yr Avg	767
Proposed	750
SL	
2015	-
2016	4
2017	4
2018	8
2019	2
5 Yr Avg	4
Proposed	2
PL	
2015	-
2016	1
2017	2
2018	4
2019	1
5 Yr Avg	2
Proposed	1
EVP	
2015	-
2016	-
2017	-
2018	-
2019	-
5 Yr Avg	-
Proposed	-
T	
2014	82
2015	80
2016	75
2017	81
2018	85
5 Yr Avg	81
Proposed	85
Total	
2015	6,420
2016	6,306
2017	6,094
2018	6,463
2019	6,337
5 Yr Avg	6,324
Proposed	6,203

2019 ECOSS 5-Year Demand Allocator Study
COMPARISON OF DEMAND ALLOCATIONS (PERCENTAGES)

	NCP at Distribution Service (MW) %		
	34KV	13KV	Secondary
R			
2015	49.4%	50.9%	57.3%
2016	49.5%	50.9%	57.5%
2017	48.5%	50.3%	56.9%
2018	49.8%	51.4%	57.9%
2019	51.4%	53.2%	59.7%
5 Yr Avg	49.7%	51.4%	57.9%
Proposed	50.3%	52.1%	58.6%
RL			
2015	4.0%	4.1%	4.7%
2016	3.9%	4.0%	4.5%
2017	3.4%	3.5%	4.0%
2018	3.5%	3.6%	4.0%
2019	3.7%	3.8%	4.3%
5 Yr Avg	3.7%	3.8%	4.3%
Proposed	3.7%	3.9%	4.4%
G			
2015	9.2%	9.5%	10.7%
2016	9.3%	9.6%	10.8%
2017	8.8%	9.1%	10.3%
2018	9.0%	9.3%	10.5%
2019	8.3%	8.6%	9.7%
5 Yr Avg	8.9%	9.2%	10.4%
Proposed	8.5%	8.8%	9.9%
GS			
2015	0.5%	0.5%	0.6%
2016	0.5%	0.5%	0.6%
2017	0.7%	0.7%	0.8%
2018	0.7%	0.7%	0.8%
2019	0.7%	0.7%	0.8%
5 Yr Avg	0.6%	0.6%	0.7%
Proposed	0.7%	0.7%	0.8%
GL			
2015	23.6%	23.4%	25.4%
2016	23.6%	23.4%	25.5%
2017	24.2%	24.4%	26.7%
2018	23.5%	23.4%	25.6%
2019	22.7%	22.7%	24.4%
5 Yr Avg	23.5%	23.5%	25.5%
Proposed	23.3%	23.3%	25.0%
P			
2015	12.2%	10.4%	0.0%
2016	12.2%	10.6%	0.0%
2017	13.3%	10.7%	0.0%
2018	12.5%	10.4%	0.0%
2019	12.1%	9.8%	0.0%
5 Yr Avg	12.4%	10.4%	0.0%
Proposed	12.4%	10.1%	0.0%
SL			
2015	0.8%	0.8%	0.9%
2016	0.7%	0.8%	0.8%
2017	0.8%	0.8%	0.9%
2018	0.7%	0.8%	0.8%
2019	0.7%	0.7%	0.8%
5 Yr Avg	0.8%	0.8%	0.9%
Proposed	0.7%	0.8%	0.8%
PL			
2015	0.3%	0.3%	0.4%
2016	0.3%	0.3%	0.3%
2017	0.3%	0.4%	0.4%
2018	0.3%	0.3%	0.4%
2019	0.3%	0.3%	0.4%
5 Yr Avg	0.3%	0.3%	0.4%
Proposed	0.3%	0.3%	0.4%
EVP			
2015	-	-	-
2016	-	-	-
2017	-	-	-
2018	-	-	-
2019	0.0%	0.0%	0.0%
5 Yr Avg	0.0%	0.0%	0.0%
Proposed	0.0%	0.0%	0.0%
Total			
2015	100.0%	100.0%	100.0%
2016	100.0%	100.0%	100.0%
2017	100.0%	100.0%	100.0%
2018	100.0%	100.0%	100.0%
2019	100.0%	100.0%	100.0%
5 Yr Avg	100.0%	100.0%	100.0%
Proposed	100.0%	100.0%	100.0%

	CP %
R	
2015	48.7%
2016	48.4%
2017	50.0%
2018	51.5%
2019	52.0%
5 Yr Avg	50.1%
Proposed	51.1%
RL	
2015	3.8%
2016	3.9%
2017	3.9%
2018	3.9%
2019	4.0%
5 Yr Avg	3.9%
Proposed	3.9%
G	
2015	9.2%
2016	9.6%
2017	8.4%
2018	8.6%
2019	8.2%
5 Yr Avg	8.8%
Proposed	8.3%
GS	
2015	0.6%
2016	0.6%
2017	0.7%
2018	0.7%
2019	0.7%
5 Yr Avg	0.7%
Proposed	0.7%
GL	
2015	24.0%
2016	23.8%
2017	23.2%
2018	22.2%
2019	21.9%
5 Yr Avg	23.0%
Proposed	22.4%
P	
2015	12.4%
2016	12.4%
2017	12.5%
2018	11.6%
2019	11.8%
5 Yr Avg	12.1%
Proposed	12.1%
SL	
2015	0.0%
2016	0.1%
2017	0.1%
2018	0.1%
2019	0.0%
5 Yr Avg	0.1%
Proposed	0.0%
PL	
2015	0.0%
2016	0.0%
2017	0.0%
2018	0.1%
2019	0.0%
5 Yr Avg	0.0%
Proposed	0.0%
EVP	
2015	0.0%
2016	0.0%
2017	0.0%
2018	0.0%
2019	0.0%
5 Yr Avg	0.0%
Proposed	0.0%
T	
2015	1.3%
2016	1.3%
2017	1.2%
2018	1.3%
2019	1.3%
5 Yr Avg	1.3%
Proposed	1.4%

COMPANY EXHIBIT AMO-5

BALTIMORE GAS AND ELECTRIC COMPANY
ELECTRIC COST OF SERVICE STUDY USING 2019 CURRENT YEAR DEMAND ALLOCATORS
FOR THE 12 MONTHS ENDING DECEMBER 31, 2019

		TOTAL RETAIL (1)	RESIDENTIAL SERVICE R (2)	RES LARGE TIME OF DAY RL (3)	GENERAL SERVICE G (Incl. Sch. GU) (4)	GENERAL SERVICE-SMALL GS (5)	GENERAL SERVICE-LARGE GL (6)	PRIMARY SERVICE P (7)	STREET LIGHTING SL (8)	PRIVATE AREA LIGHTING PL (9)	TRANSMISSION SERVICE - 115kV T (10)	UTILITY OWNED EV CHARGING EVP (11)
1	**SUMMARY OF RESULTS**											
2												
3	**DEVELOPMENT OF RATE BASE**											
4	ELECTRIC PLANT IN SERVICE	6,759,014,420	3,866,911,377	275,969,587	588,581,269	43,268,309	1,315,290,185	429,213,127	166,817,867	70,823,618	1,867,901	271,179
5	PLUS: ADDITIONS TO UTILITY PLANT	735,087,992	399,605,330	27,770,047	91,422,039	7,580,499	139,919,044	53,493,004	7,885,017	3,365,216	3,921,051	126,745
6	LESS: RESERVE FOR DEPRECIATION	2,591,688,976	1,482,719,086	105,298,660	229,351,732	16,760,160	501,685,917	165,669,550	62,289,532	26,466,933	1,345,046	102,360
7	NET PLANT IN SERVICE	4,902,413,435	2,783,797,621	198,440,974	450,651,576	34,088,648	953,523,311	317,036,581	112,413,351	47,721,901	4,443,907	295,564
8	RATE BASE ADDITIONS	36,590,301	20,823,494	1,496,293	3,176,465	240,519	7,194,335	2,377,811	891,514	376,755	11,563	1,552
9	RATE BASE DEDUCTIONS	1,367,080,249	764,701,569	53,660,065	137,425,300	10,071,336	270,483,236	86,841,218	29,277,503	12,451,708	2,120,699	47,615
10	TOTAL RATE BASE	3,571,923,487	2,039,919,546	146,277,202	316,402,741	24,257,831	690,234,411	232,573,175	84,027,362	35,646,947	2,334,771	249,502
11												
12	**DEVELOPMENT OF RETURN**											
13	OPERATING REVENUES											
14	DISTRIBUTION REVENUE	1,169,456,727	591,062,941	43,685,806	127,764,410	10,724,171	266,883,648	79,867,824	25,370,081	19,349,150	4,748,652	47
15	OTHER OPERATING REVENUE	46,119,777	37,625,414	3,018,406	2,089,149	85,625	2,345,591	710,460	118,090	92,441	34,369	234
16	TOTAL OPERATING REVENUE	1,215,576,504	628,688,355	46,704,211	129,853,558	10,809,795	269,229,239	80,578,284	25,488,171	19,441,590	4,783,020	281
17												
18	OPERATING EXPENSES											
19	OPERATION & MAINTENANCE	447,205,167	280,146,462	17,382,922	45,450,029	2,652,553	66,848,520	24,719,711	7,310,146	2,649,824	43,544	1,457
20	DEPRECIATION & AMORT EXPENSE	335,276,887	181,669,261	12,931,907	38,841,979	3,257,005	65,839,156	23,877,080	5,162,402	2,198,781	1,479,870	19,446
21	TAXES OTHER THAN INCOME TAX	171,721,550	87,386,017	6,110,283	19,359,058	1,530,141	38,292,191	13,836,247	2,982,376	1,463,045	758,559	3,633
22												
23	FEDERAL, STATE & LOCAL INCOME TAXES	27,692,749	(2,821,312)	1,063,369	2,841,094	580,533	18,371,121	2,014,149	1,840,561	3,214,831	597,127	(8,724)
24												
25	TOTAL OPERATING EXPENSES	981,896,353	546,380,427	37,488,482	106,492,160	8,020,232	189,350,987	64,447,187	17,295,485	9,526,481	2,879,100	15,812
26												
27	PLUS											
28	ADJUSTMENTS TO INCOME	10,365,699	5,927,524	451,574	699,382	66,279	2,011,712	768,599	307,191	130,420	2,519	499
29												
30	NET OPERATING INCOME (EARNINGS)	244,045,850	88,235,452	9,667,304	24,060,780	2,855,843	81,889,963	16,899,696	8,499,876	10,045,529	1,906,440	(15,032)
31												
32												
33	RATE OF RETURN (PRESENT)	6.83%	4.33%	6.61%	7.60%	11.77%	11.86%	7.27%	10.12%	28.18%	81.65%	-6.02%
34	RELATIVE RATE OF RETURN (PRESENT)	1.00	0.63	0.97	1.11	1.72	1.74	1.06	1.48	4.12	11.95	-0.88
35												
36	RATE OF RETURN (EQUALIZED)	7.28%	7.28%	7.28%	7.28%	7.28%	7.28%	7.28%	7.28%	7.28%	7.28%	7.28%
37	SALES REVENUE REQ EQUALIZED ROR	1,191,517,472	674,215,000	45,040,169	126,347,984	9,220,535	223,230,492	79,911,464	22,082,826	9,070,212	2,352,945	45,845

Before the Maryland Public Service Commission

Case No. ________

Prepared Direct Testimony of

Lynn K. Fiery

On Behalf of

Baltimore Gas and Electric Company

May 15, 2020

List of Issues and Major Conclusions

- BGE proposes a three-year Multi-Year Plan ("MYP") utilizing base revenue at current rates and forecasted, weather adjusted billing determinants for each MYP Rate Year as the basis to develop the distribution rate design that supports BGE's proposed change in distribution revenues during the forecasted years of 2021-2023.

- As explained by Company Witnesses Case and Vahos, in recognition of the impact the COVID-19 pandemic has had on customers, BGE is proposing a plan to not increase base distribution revenues in 2021 or 2022. As the Company is not proposing any changes to revenue allocations or overall rate design in 2021 or 2022, the result is *no* increases on the base distribution portion of electric and gas customer bills.

- In 2023, the Company is proposing an overall increase of 4.8% in total electric bills and 9.5% in total gas bills. In 2023, the total bill for an average residential electric customer is expected to be about $113.35 and the total bill for an average residential customer receiving both electric and gas service is expected to be about $167.83.

- Over the entire MYP period, the Company's proposal results in an average annual change of 1.6% in total electric bills and 3.2% in total gas bills. The average annual change on residential combined electric and gas customer bills would be $4.29 per month (or about 2.8%). The average annual residential electric customer bill would increase $2.09 per month (or about 2.0%) over the MYP period.

- BGE is proposing a gradual increase to Customer Charges for certain gas and electric classes in 2023, inasmuch as the current charges are not recovering the level of customer costs supported by the Gas Cost of Service Study as presented by Company Witness Manuel and the Electric Cost of Service Study as presented by Company Witness O'Neill.

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I. INTRODUCTION AND STATEMENT OF PURPOSE

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. My name is Lynn K. Fiery and my business address is Baltimore Gas and Electric Company ("BGE" or the "Company"), 2 Center Plaza, 110 West Fayette Street, Baltimore, Maryland 21201.

Q. WHAT IS YOUR POSITION WITH BGE?

A. I am the Manager of Rate Administration in the Strategy and Regulatory Affairs division. My current responsibilities include the design and administration of BGE's Gas and Electric Service Rates and Tariffs.

Q. PLEASE DESCRIBE YOUR BUSINESS EXPERIENCE AND EDUCATIONAL BACKGROUND.

A. I have been employed by the Company since 2013, serving in various capacities in Accounting before assuming my current position in June 2017. Prior to BGE, I was employed as an auditor at PricewaterhouseCoopers LLC. I hold a Bachelor of Science Degree in Business Administration with a concentration in Accounting from Bucknell University. I am a Certified Public Accountant and hold an inactive license in Maryland.

Q. HAVE YOU PREVIOUSLY TESTIFIED BEFORE THE MARYLAND PUBLIC SERVICE COMMISSION?

A. Yes. I previously testified before the Maryland Public Service Commission ("Commission") in Case No. 9484 sponsoring BGE's Gas Cost of Service Study and I sponsored testimony in Case No. 9610 regarding BGE's electric and gas rate design proposals.

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

A. The purpose of my Direct Testimony is to propose the revenue allocation, rate design, and tariff changes for BGE's Multi-Year Plan ("MYP") for the years of 2021-2023. BGE is not proposing an increase to electric and gas base distribution revenues in 2021 or 2022 and is proposing to increase revenues in 2023, as developed in Part 2 of the Direct Testimony of Company Witness Vahos. My testimony proposes specific rates for each customer class that will allow BGE to collect the electric and gas revenues proposed by Company Witness Vahos and shown below in Tables 1 and 2, respectively:

Table 1. – Multi-Year Plan Summary - Electric

	Proposed Change in Electric Revenue	% Change
Rate Year 1	$0	0%
Rate Year 2	$0	0%
Rate Year 3	$140.4 million	4.8%

Table 2. – Multi-Year Plan Summary - Gas

	Proposed Change in Gas Revenue	% Change
Rate Year 1	$0	0%
Rate Year 2	$0	0%
Rate Year 3	$94.9 million	9.5%

My testimony outlines a proposed allocation of the electric and gas revenue changes among the customer classes, which is based primarily upon the relative returns of each class calculated in the Calendar Year 2019 Company Recommended

Electric Cost of Service Study ("ECOSS") and the Calendar Year 2019 Company Recommended Gas Cost of Service Study ("GCOSS"), as developed in the Direct Testimonies of Company Witness O'Neill and Company Witness Manuel, respectively. For Rate Years 1 and 2 (2021 and 2022), given the Company's proposal to not increase distribution base revenues, I am also proposing to maintain the current revenue levels for each electric and gas rate class. In other words, I am not proposing to reallocate revenues among the rate classes during 2021 and 2022. However, I do propose an allocation of the revenue increases proposed by Company Witness Vahos among the electric and gas rate classes for Rate Year 3, in 2023, guided by the results of the ECOSS and GCOSS sponsored by Company Witnesses O'Neill and Manuel, respectively.

Additionally, as the ECOSS and GCOSS demonstrate, the current functionalized customer component cost levels for certain electric and gas customer classes warrant an increase in the level of fixed Customer Charges. Therefore, I am proposing new Customer Charges for certain classes in 2023, the third year of the MYP rate effective period, that reflect a partial move towards the full level supported in the ECOSS and GCOSS for those classes.

Finally, I am proposing modifications to the Company's electric and gas tariffs. I am proposing new electric and gas Riders for any potential adjustments ordered by the Commission as part of the Annual Informational Filing process and the Final Reconciliation after the end of the MYP period, in accordance with the MYP pilot framework established in Order No. 89482 and described in the Direct Testimony of Company Witness Case. I am also explaining how the Company proposes to handle gas Rider 12 - Gas Administrative Charge ("GAC") updates within the context of an

MYP. Lastly, I have also proposed several miscellaneous housekeeping tariff changes.

Q. PLEASE EXPLAIN WHEN THE COMPANY PROPOSES RATES TO BECOME EFFECTIVE IN EACH YEAR OF THE MYP.

A. The Company has proposed that distribution base rate changes occur on January 1, 2021, January 1, 2022, and January 1, 2023, which are referred to in my testimony as Rate Year 1 ("RY1"), Rate Year 2 ("RY2"), and Rate Year 3 ("RY3"), respectively. Although BGE is not proposing a base distribution revenue increase in RY1 and RY2, as will be discussed later in my testimony, rate changes are required in each year to account for the 2021 and 2022 billing determinants which are forecasted in this MYP. Thus, even though the Company is proposing new base distribution *rates* for 2021 and 2022, the rates have been calculated so that the base distribution *revenues* in those years, in total and for each rate class, remains constant. To the extent there are any differences between the forecasted and actual 2021-2023 billing determinants, the Rider 25 and Rider 8 electric and gas decoupling mechanisms will adjust rates to true-up any related revenue differences for customer classes that are decoupled.

Q. PLEASE SUMMARIZE THE EXHIBITS PRESENTED IN YOUR TESTIMONY.

A. My testimony is supported by the following five exhibits:

Company Exhibit LKF-1 contains an analysis of the impact of increasing the Customer Charge for Schedule R and Schedule D customers during the third year of the MYP.

Company Exhibit LKF-2 contains the supporting data for the electric base distribution rates during the MYP rate effective years (the “E-Sheets”), contained in Supplement 650.

Company Exhibit LKF-3 contains the Electric Service Tariff sheets of Supplement 650 to P.S.C. Md. E-6 including the rates for RY1, RY2, and RY3, proposed to become effective January 1, 2021 in RY1, January 1, 2022 in RY2, and January 1, 2023 in RY3. The proposed electric MYP Reconciliation Rider is also contained in Exhibit LKF-3. Two sets of pages are submitted in the Exhibit: (1) in the format prescribed in COMAR 20.07.04.09, except that deletions are shown only with strike outs and do not include brackets; and (2) a clean version without revision markings.

Company Exhibit LKF-4 contains the supporting data for the gas base distribution rates during the MYP rate effective years (the “G-Sheets”), contained in Supplement 467.

Company Exhibit LKF-5 contains the Gas Service Tariff sheets of Supplement 467 to P.S.C. Md. G-9 including the rates for RY1, RY2, and RY3, proposed to become effective January 1, 2021 in RY1, January 1, 2022 in RY2, and January 1, 2023 in RY3. The proposed gas MYP Reconciliation Rider is also contained in Exhibit LKF-5. Two sets of pages are submitted in the Exhibit: (1) in the format prescribed in COMAR 20.07.04.09, except that deletions are shown only with strike outs and do not include brackets; and (2) a clean version without revision markings.

II. RATE DESIGN PRINCIPLES

Q. WHAT ARE THE BASIC PRINCIPLES BEHIND EFFECTIVE RATE DESIGN?

A. An effective rate design incorporates the principles of cost causation, intergenerational equity, price signaling, reasonableness, gradualism, and both inter-class and intra-class equity. These are documented by experts within the area of utility ratemaking and are principles employed by this Commission in prior base rate case proceedings as well as by numerous other commissions around the country.[1]

Q. DOES THE COMPANY'S CURRENT RATE DESIGN REFLECT THESE PRINCIPLES?

A. Generally, yes, although there are certain changes to the current rate design that, if made, would demonstrate a better adherence to these principles. For example, according to the principle of cost causation, costs should be borne by the customers on whose behalf the costs are incurred. The Company's proposed revenue allocation methodologies, a two-step approach for electric and gas, are an example of how cost causation can be addressed by using the results of the ECOSS and GCOSS to move customer class returns closer to the system average return. As a result, costs will be borne by the appropriate customers. However, BGE's proposed methodology also incorporates the principle of gradualism, whereby rates are moved by incremental steps rather than by drastic changes.[2]

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[1] *Principles of Public Utility Rates*, Second Edition 1988, by James Bonbright, Albert Danielsen and David Kamerschen, is a well-known reference for the rate design professional.

[2] The definition of the word gradualism per Dictionary.com reads "the principle or policy of achieving some goal by gradual steps rather than by drastic change." http://dictionary.reference.com/browse/Gradualism

Q. IN WHAT OTHER WAYS DOES COST CAUSATION AFFECT THE COMPANY'S RATE DESIGN?

A. The Company's rate design should be consistent with the nature of the costs incurred in providing service to customers. In other words, fixed and demand-related costs (costs that do not vary with the total amount of electricity or gas delivered) should be recovered through fixed monthly rates and rates that reflect a customer's demand on the system, respectively, while variable costs (costs that increase or decrease as the total amount of electricity or gas delivered changes) should be recovered through rates that vary based on the amount of electricity and gas delivered to a customer. Adherence to this aspect of rate design has, at times in the past, been considered along with other policy objectives such as the desire to support conservation goals.[3] However, incorporation of the principle of cost causation into rate design and the desire to support energy efficiency goals need not be mutually exclusive.

As I will discuss further, the results of the 2019 ECOSS and GCOSS lead me to propose that certain Customer Charges should be increased in the current proceeding to better align the rate design with the nature and level of the costs incurred to serve those customers.

Q. WOULD YOU PLEASE EXPLAIN THE COMPANY'S CURRENT RATE STRUCTURE?

[3] *Re Baltimore Gas and Electric Co.*, Case No. 9326, Order No. 86060 at 105 (Dec. 13, 2013).

A. BGE's distribution rate structures primarily include the use of a Customer Charge, a Demand Charge and a Delivery Service Charge.[4] The Customer Charge is the fixed, monthly charge on a customer bill that is intended to recover those operating costs that are caused by customers connecting to the gas or electric grid. The Demand Charge is a charge for certain rate schedules based on the maximum load over a measured period that is designed to recover the costs driven by the customer class' peak loads. The Delivery Service Charge is a volumetric charge meant to recover the costs caused by customers' energy usage (or those costs which vary as the customer usage varies). To the extent possible, these charges should follow cost causation as determined in the ECOSS and GCOSS, and be balanced appropriately with other goals, such as energy efficiency.

Q. WOULD YOU PLEASE EXPLAIN THE COMPANY'S CURRENT CUSTOMER CHARGES AND WHICH COSTS THEY ARE DESIGNED TO RECOVER?

A. All customer classes, except for electric Schedules SL and PL and gas Schedule PLG, currently have a Customer Charge.[5] These charges are designed to recover costs that are incurred on a per-customer basis, which I will refer to as fixed costs. Fixed costs typically include those costs that vary with the number of customers: administrative costs such as billing and customer care; gas and electric meter costs; gas regulators; and the costs associated with the electric service connection from the local

[4] Outdoor lighting customers on electric Schedules SL and PL, and gas Schedule PLG have rate elements appropriate for those services. Certain gas schedules also have an Information Fee to recover the costs of processing daily meter reading data. Also, the terms Demand Charge and Delivery Service Charge are used in the Retail Electric Service Tariff and the terms Demand Price and Delivery Price are used for the Retail Gas Service Tariff. Where the terms Demand Charge and Delivery Service Charge are used in my testimony, the statements also apply to the gas Demand Price and Delivery Price.

[5] Schedules SL and PL do have monthly fixed rental charges for Company-owned fixtures.

transformer (near the premise) to the meter. These costs, as analyzed in the ECOSS and GCOSS, are presented in Company Exhibit AMO-3 of Company Witness O'Neill's Direct Testimony and in Company Exhibit JMBM-3 of Company Witness Manuel's Direct Testimony, respectively. While BGE's current Customer Charges for the residential electric and gas classes recover a portion of the fixed costs incurred in serving customers, they are not set at a level to recover all the fixed costs.

Q. WHAT ARE THE EFFECTS OF A RATE STRUCTURE THAT DOES NOT FOLLOW COST CAUSATION AS YOU DESCRIBED?

A. Rates that do not follow cost causation create intra-class inequities and send incorrect price signals to customers. For example, customers receive strong price signals from retail electric and gas supply prices because these prices are based upon the actual commodity costs borne by suppliers on a per-unit basis. When they reduce consumption, customers save money as energy providers supply less energy and costs are reduced on a per-unit basis. Alternatively, the costs to construct and maintain the distribution system are generally fixed or a function of customer demand levels and not a function of the total amount of energy delivered to customers. This follows from the certainty that customers need distribution service to deliver energy to their premise whether they use a lower than average amount of energy, an average amount of energy, or an above average amount of energy over a certain period. In fact, if customers are to have the ability to use energy at all, the distribution system must always be safely and reliably operating and available to them (except for interruptible gas service customers during a distribution system interruption).

Furthermore, the distribution system must be designed to meet the requirements of the customer peak demand to be placed on the system. In fact, the Company's cost to serve a customer is related more to that customer's peak demand than the total amount of energy used by that customer over a period of time. This is primarily due to the fact that substations and other distribution equipment must be sized to meet the demand of the customer peak load in order to maintain reliability. For example, if an electric customer's peak hourly usage is 60 kilowatts of electricity, the electric distribution system must be designed and built to transport 60 kilowatts of electricity per hour regardless of the amount of electricity the customer uses the rest of the day.

The rate schedules for all customer classes (except PL and PLG) also include a volumetric component which currently recovers a significant amount of the distribution portion of the customer bill (approximately 79% and 70% for electric and gas residential customers, respectively) – a greater percentage than what the ECOSS and GCOSS support being recovered through volumetric rates.[6] In other words, when customers reduce their consumption they may save money through reduced delivery service charges, but the overall costs to support the distribution system are not correspondingly reduced (as these costs are primarily customer-related or demand-related). Recovery of fixed (customer-related) and demand-related costs through volumetric rates creates intra-class inequities.

Q. PLEASE FURTHER EXPLAIN HOW INTRA-CLASS INEQUITIES ARE CREATED WHEN FIXED COSTS ARE NOT RECOVERED THROUGH FIXED CHARGES.

A. Intra-class inequities are created or allowed to persist when fixed costs are not recovered through fixed charges because different residential customers, like all

[6] The COSS shows that volumetric rates should recover 66% and 51% of electric and gas distribution revenues, respectively, for the residential classes. (Derived from Supplemental Schedule V.A.)

customers, use varying levels of energy. When fixed costs (or costs that do not vary with the total amount of energy delivered) are recovered through fixed charges, customers pay for the portion of fixed costs they cause the Company to incur, regardless of their energy usage. However, when fixed costs are instead recovered through variable charges, customers with higher usage are paying for a higher portion of fixed costs than customers with lower usage. This means that customers with higher than average usage are subsidizing the fixed costs of those customers with lower than average usage even though the vast majority of the costs to serve those customers are the same. Under the Company's current rate structure, a large portion of fixed costs are recovered through the variable charges on a customer's bill, which does not follow the principle of cost causation. Effective rate design should follow cost causation, with consideration for gradualism. The proposed Customer Charge increases discussed later in my testimony are a step towards reducing the intra-class inequities between the recovery of fixed and variable costs.

Q. IS THE COMPANY PROPOSING TO MAKE CHANGES TO THE CUSTOMER CHARGE OR DEMAND CHARGE FOR ANY RATE SCHEDULES IN THIS CASE?

A. Yes. For certain rate classes the Company is proposing changes in 2023 to the proportion of base distribution revenues recovered from rate elements such as the Customer Charge or the Demand Charge.

III. ALLOCATION OF THE PROPOSED CHANGE IN ELECTRIC REVENUE

Q. HOW DO THE RESULTS OF THE ECOSS INFLUENCE YOUR PROPOSAL FOR REVENUE ALLOCATION?

A. Electric cost of service studies have been accepted by the Commission in past proceedings as a reasonable method for determining which classes are under- or over-earning, based on the relative rate of return (the "RROR"), and therefore which classes should receive more, or less, of the proposed change in revenues. The following table shows the results from the Company's 2019 ECOSS, as supported in Company Witness O'Neill's Direct Testimony.

Table 3. - 2019 Electric Cost of Service Study Results[7]

Tariff Class	ECOSS RROR
R[8]	0.67
RL	0.95
G/GU	1.06
GS	1.65
GL	1.66
P	1.00
T	11.95
SL	1.46
PL	4.09
Total System	**1.00**
R/RL Combined	0.69

Q. HOW DO YOU PROPOSE TO APPORTION THE PROPOSED ELECTRIC REVENUE INCREASE IN RY3 AMONG THE CUSTOMER CLASSES?

A. I propose to apportion the revenue increase in RY3 such that each customer class' rate of return moves toward or within a reasonable band (+/- 10%) around the system average rate of return, consistent with the Company's proposed methodology in

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[7] *See* Direct Testimony of Company Witness O'Neill, pg. 8, Table 1.

[8] For purposes of the ECOSS, Schedule R includes residential customers taking electric service under Schedules EV and RD.

recent rate cases.[9] Consistent with the Commission's recent orders in Case Nos. 9299, 9326, 9406, and 9484, I propose to use a two-step process to accomplish this goal.

In the first step, I propose to move the RROR for classes that are under-earning with a RROR below 0.90 closer to the system average while adhering to the principle of gradualism. Schedule R is the only class whose RROR is below 0.90 and I propose that it receive a step one adjustment such that it moves 50% of the way to the desired band around the system average return in RY3. This results in a step one adjustment for Schedule R that moves the RROR from 0.67 to 0.78. Following the Commission's general precedent to not decrease electric revenues when the overall revenue requirement is increasing, I do not propose revenue reductions for those classes that are over-earning by more than 10% of the system average.

In step two, I propose that the remaining revenue increase be allocated to existing rate classes in proportion to base distribution revenues, after step one. However, BGE is not proposing any revenue change for Schedules PL and T as their RRORs are already 4.09 and 11.95, respectively, about four and twelve times the system average.[10] I have also excluded Schedule EVP from receiving any of the revenue increase.[11]

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[9] *See* Case No. 9299, Direct Testimony of Michael J. Cloyd, page 11, lines 7-10, and Case No. 9326, Direct Testimony of Michael J. Cloyd, page 12, lines 14-16; Case No. 9406, Direct Testimony of John C. Frain, page 18, lines 14-15; Case No. 9484, Direct Testimony of Jason M. B. Manuel, page 11, lines 13-15; and Case No. 9610, Direct Testimony of Lynn K. Fiery, page 17, line 6-8.

[10] Schedules T and PL did not receive revenue increases in recent BGE Case Nos. 9610 and 9406.

[11] Schedule EVP is the Utility Owned Electric Vehicle Public Charging Rate Schedule. The rates charged under this rate schedule are currently market-based as approved by the Commission in Case No. 9478. *See* Commission Letter Order dated June 19, 2019 in reference to Maillog #22843. As accepted by the Commission, BGE calculates the Schedule EVP rates semi-annually. Specifically, as part of the EV Portfolio Semi-Annual Report in Case No. 9478, BGE reviews rates charged by third-party charging station vendors across the state of Maryland and analyzes whether any adjustments to Schedule EVP rates are appropriate.

The total distribution revenue allocation to each electric rate schedule is the sum of the allocations from steps one and two.

Q. PLEASE PROVIDE AN OVERVIEW OF THE RESULTS OF YOUR TWO-STEP REVENUE APPORTIONMENT FOR RY3.

A. The results of my two-step revenue increase apportionment are displayed in Table 4 below, and in Company Exhibit LKF-2, Sheet E-2.

Table 4. - Rate Year 3 Electric Distribution Revenue Increase by Customer Class[12]
($ Millions)

Class	Step 1	Step 2	Total	% of Total
R	$21.9	$64.0	$86.0	61.25%
RL	--	$4.6	$4.6	3.28%
G	--	$11.8	$11.8	8.38%
GS	--	$1.0	$1.0	0.69%
GU	--	$0.0	$0.0	0.02%
GL	--	$27.3	$27.3	19.41%
P	--	$7.1	$7.1	5.04%
T	--	--	--	0.00%
SL	--	$2.7	$2.7	1.94%
PL	--	--	--	0.00%
Total	**$21.9**	**$118.4**	**$140.4**	**100%**

Q. CAN YOU PLEASE DISCUSS THE REVENUE ALLOCATION TO SCHEDULE R IN MORE DETAIL?

A. The ECOSS performed and discussed by Company Witness O'Neill reveals that the Schedule R customer class is still under-earning as compared to the system average return. Table 6 shows the history of Schedule R's RROR from the ECOSS filed in the last six Company rate cases.

Thus, given that the rates are currently market-based, BGE has excluded Schedule EVP from the revenue allocation in this case.

[12] Total may not sum due to rounding.

Table 5. - Schedule R RRORs

Rate Case	Schedule R RROR
Case No. 9299	0.69
Case No. 9326	0.61
Case No. 9355	0.75
Case No. 9406	0.69
Case No. 9610	0.68
2019 ECOSS	0.67

Schedule R has not seen much improvement in its RROR since 2012. Schedule R had a slight improvement in Case No. 9355 as a result of the Commission's Order in Case No. 9326 which directed that Schedule R receive a step one increase equal to 50% of the overall increase. However, since that time, Schedule R has continued to not earn the authorized return and has experienced continued declines in its RROR in each subsequent rate case. In each case, the Company has attempted to move Schedule R towards unity by proposing revenue allocations to Schedule R targeting a specific RROR closer to a 10% band around the system average. However, in each instance, the Commission instead authorized a smaller portion of the overall increase be allocated to Schedule R. Recognizing the decisions of the Commission in prior cases and the principle of gradualism, I am proposing a step one increase for Schedule R that moves it towards, but not entirely to, the reasonable band around the system average. With the Schedule R RROR at 0.67 in the current ECOSS, I propose a step one allocation that moves the class 50% of the way to a RROR of 0.90.

IV. ELECTRIC RATE DESIGN

Q. PLEASE DESCRIBE THE GENERAL LAYOUT OF THE E-SHEETS SHOWN IN COMPANY EXHIBIT LKF-2.

A. Sheet E-1 is a summary of the revenue derived from each rate schedule under the proposed new rates. The summary also shows, by customer class, the percent increase in RY3 in base distribution revenues as a percentage of total distribution revenues, and the percent increase in customers' total electric bills, using estimated electric supply revenues assuming all customers purchase their electricity from BGE.[13] Sheet E-2 derives the allocation of the total proposed increase to the rate Schedules using the two-step process. Sheet E-3 provides the proposed revenue allocations for each year of the MYP by customer class. However, as discussed previously, the Company is not proposing to change 2021 and 2022 revenue allocations.

Sheets E-4 through E-13 show the development of the new rates proposed for each year during the MYP period. Although BGE is not proposing a revenue increase in RY1 and RY2, rate changes will occur in each year to account for the effective delivery rate as a result of Rider 25 adjustments. For each schedule, the weather-adjusted billing determinants forecasted for the particular Rate Year are multiplied by the current rates in effect during that Rate Year to derive revenue at current rates. Any allocated increase for each schedule is then added to the schedule's revenues at current rates and distributed, using the same weather-adjusted billing determinants, over the individual rate elements as discussed later in my testimony.

Sheet E-14 shapes the Schedule RD Time-of-use Pilot rates based on the proposed allocated increase to Schedule R.[14] The rate design of Schedule RD

[13] Commodity revenues are estimated by applying current supply rates to forecasted billing determinants for each rate year.

[14] The methodology used to shape Schedule RD distribution rates is consistent with the approach used in Supplement 621 to P.S.C. Md E-6 and approved by the Commission in their December 6, 2018 letter order, as well as the recommendations of the Public Conference 44 ("PC 44") – Rate Design Working Group Report, filed on February 9, 2018, and the related Commission Letter Orders dated November 27, 2017 and May 7, 2018.

distribution rates is designed to be revenue neutral with respect to the Schedule R customer class.

Sheet E-15 derives the effective Rider 25 rate for each Rate Year based on revenue targets set in BGE's most recent rate case (Case No. 9610) and the forecasted change in number of customers in each Rate Year. Sheet E-16 calculates the percent increase and average monthly increase in the customers' total electric bills by customer class, assuming all customers purchase their electricity from BGE. Sheet E-17 compares bills at the current rates to bills at the proposed rates for residential customers at different monthly usage levels. Sheet E-18 compares the monthly bills at current rates to bills at the proposed rates for the average combined gas and electric service residential customer. Sheets E-19 and E-20 also provide bill impacts for small (Schedule G) and large (Schedule GL) commercial classes, respectively.

Q. IN YOUR PROPOSALS BELOW TO ADJUST THE DELIVERY SERVICE CHARGE, YOU DISCUSS THE PROPOSED RATE RELATIVE TO THE CURRENT "EFFECTIVE RATE." WHAT DOES "EFFECTIVE RATE" MEAN?

A. The "effective rate" refers to the net Delivery Service Charge, which is calculated by adding the base Delivery Service Charge with the Rider 25 adjustment for each of the decoupled classes.[15] I use the effective rate for purposes of this discussion as both components of the net Delivery Service Charge will be determined as a result of this base rate case proceeding in similar fashion to the rates resulting from our last base rate case. For each Rate Year, a Rider 25 revenue adjustment is included in the rate calculation based on the forecasted change in number of customers. Thus, to get

[15] The electric decoupled customer classes are Schedules R, RL, G, GS, and GL.

a complete picture of the rates billed to customers for costs determined in the context of a base rate case proceeding, we need to net all rates (the base Delivery Service Charge and Rider 25 rate) designed to recover those costs to arrive at an effective rate. These adjustments are shown in Company Exhibit LKF-2, Sheet E-15.

Q. PLEASE EXPLAIN THE COMPANY'S PROPOSED CHANGES TO ELECTRIC CUSTOMER CHARGES.

A. I am proposing a gradual increase to the fixed Customer Charge in RY3 for the Schedule R electric rate class, in order to move the fixed cost recovery closer to the level supported by the 2019 ECOSS. This proposal also serves to reduce the difference in the distribution rates between Schedule R and RL (non-TOU and TOU). As discussed later in my testimony, BGE believes that Schedules R and RL should ultimately have the same distribution rates. However, adhering to the principle of gradualism and to avoid rate shock, I am proposing to move towards equivalent distribution rates for the R/RL classes in this case by gradually increasing the Customer Charge for Schedule R towards the level supported in the 2019 ECOSS for the combined R/RL class of $17.03. The current Customer Charges for Schedule R and RL are $8.00 and $12.00, respectively. Since Schedule RL is already significantly closer to the ECOSS-supported level of cost for a combined R/RL class, I am proposing no change to its Customer Charge in this case.

This same situation exists for commercial customers who are eligible to take service under Schedules G and GS (non-TOU and TOU, respectively). The current Customer Charges for Schedules G and GS are $12.40 and $18.60, respectively. As such, I am proposing that the Schedule G Customer Charge be increased in 2023, such that it is closer to the current Schedule GS Customer Charge. I am also proposing to increase the Customer Charges for Schedules GL and P in order to move these classes towards the level supported in the ECOSS.

It is important to note that this proposal only takes the fixed cost recovery for Schedules R, G, GL, and P *closer* to the level supported in the 2019 ECOSS to better align rates with cost causation. This proposal is outlined below in Table 6. The proposed customer charge increases will occur in RY3 of the MYP period.

Table 6. – 2023 Customer Charge Proposal

Customer Class	Cost	Current	RY1	RY2	RY3
Schedule R[16]	$17.03	$8.00	$8.00	$8.00	$9.00
Schedule G	$28.57	$12.40	$12.40	$12.40	$14.00
Schedule GL	$117.18	$88.00	$88.00	$88.00	$97.00
Schedule P	$1196.90	$600.00	$600.00	$600.00	$660.00

Q. PLEASE DESCRIBE THE IMPACTS OF THIS CHANGE TO RESIDENTIAL ELECTRIC CUSTOMERS.

A. As shown in Company Exhibit LKF-1, an average Schedule R customer using 839 kWh per month is economically indifferent to the proposed Customer Charge increase. In other words, based upon the proposed revenue increase, a customer would receive the same increase to their bill in RY3 whether my proposed Customer Charge and volumetric Delivery Service Charge rate design is accepted or whether the full RY3 increase is assigned to the volumetric Delivery Service Charge.

Q. WOULD INCREASING THE CUSTOMER CHARGE FOR CERTAIN ELECTRIC CLASSES AS YOU ARE PROPOSING AFFECT THE

[16] The customer-related cost presented in the table for Schedule R is from the combined R/RL class in the 2019 ECOSS. *See* Direct Testimony of Company Witness O'Neill, pg. 23, Table 4.

CURRENT PRICE SIGNALS GIVEN TO CUSTOMERS TO ENCOURAGE ENERGY EFFICIENCY?

A. A significant portion of a customer's bill is for the electric commodity, such that 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.[17] In addition, having a significantly different Customer Charge for Schedule RL as compared to Schedule R could dis-incentivize customers from choosing TOU commodity rates. Such an action may negatively impact the number of customers who shift their load from periods of peak demand, working against the energy policy goal to reduce demand in Maryland. As demonstrated in the table below, even with the proposed Customer Charge increase, 92% of the total average electric residential customer bill would be recovered through volumetric rates as opposed to a fixed charge.[18]

Table 7. – Summary of Exhibit LKF-1

Comparison of Bills for Average Electric Schedule R Customers	Bill at Current Rates	Proposed Bill with increased Customer Charge	Proposed Bill without increased Customer Charge
Total Charges	$107.07	$113.35	$113.35
% of Fixed Total Charges	8%	8%	7%
% of Variable Total Charges	92%	92%	93%

Furthermore, an increase in the Customer Charge has a minimal impact on the percentage of the total average residential customer bill that would be recovered through volumetric as opposed to fixed charges. The fixed Customer Charge

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[17] At current rates, approximately 58% of an average residential electric customer's bill is commodity-related.

[18] *See* Company Exhibit LKF-1 for further information on the impact based on differing usage levels for electric and gas residential customers.

increases I am proposing, therefore, would not have a meaningful impact on the price signals encouraging energy conservation received by residential customers.

A. Schedules R and RL – Residential Service

Q. ARE YOU PROPOSING THAT THE RESIDENTIAL CUSTOMER CLASSES BE COMBINED INTO ONE CLASS IN THIS CASE?

A. No. However, in RY3 I do propose movement towards equalizing Schedules R and RL distribution rates. The only difference between these two schedules is the ability for customers to choose standard or time-of-use *commodity* rates. This differentiation in the commodity to reflect the time-of-use offering of RL is still appropriate and the Company will continue to provide that option. Previously, different meters were required for customers served under each schedule and the cost of each meter type was different, which substantiated the need for different distribution rates. With the installation of smart meters across the residential class, the customer-related costs to serve Schedules R and RL are no longer substantially different.[19] Furthermore, except for customers who choose to opt out of receiving a Smart Meter, there are no differences in eligibility for the customers who can be served under Schedules R and RL.[20] With one phone call to BGE, a residential customer can now switch from Schedule R to RL or vice versa. Any differences between the classes in the ECOSS are due to the mix of customers who have historically chosen each schedule. Given that these two schedules do not offer different distribution service but are designed to offer different SOS commodity rates – Time-of-use (TOU) and non-Time-of-use (non-TOU) – it follows cost causation principles, and simply makes sense, to equalize

[19] *See* Company Witness O'Neill Exhibit AMO-3.
[20] This is not true in the case of a customer who chooses to opt out of receiving a smart meter. In such a case, the customer is ineligible to be on Schedule RL.

their distribution rates and consider them as one combined class. Company Witness O'Neill presented the 2019 ECOSS results of a combined R/RL class in her Direct Testimony.[21] However, adhering to the principle of gradualism, I am only proposing to move the Schedule R Customer Charge closer to the Schedule RL Customer Charge.

Q. HOW DID YOU ASSIGN THE INCREASE FOR SCHEDULE R AND RL TO THE SCHEDULES' RATE ELEMENTS?

A. I am proposing to increase the Customer Charge for Schedule R closer to the current level of the Customer Charge for Schedule RL and the ECOSS-supported level to move the R/RL class rates closer to alignment in RY3 of the MYP. The Customer Charge, as proposed, increases from $8.00 to $9.00 for Schedule R customers in RY3, accounting for $13.7 million of the $86.0 million total proposed revenue increase for this schedule. The remaining revenue increase I propose to recover through the Delivery Service Charge. The changes for Schedules R and RL are shown in Company Exhibit LKF-2, Sheet E-4 and E-5, respectively. The table below summarizes the proposed rate structure in RY3 of the MYP period.

Table 8. – RY3 Rate Structure

	RY3
Schedule R	
Customer Charge	$9.00
Distribution Charge	$0.04250
Schedule RL	
Customer Charge	$12.00
Distribution Charge	$0.04189

[21] *See* Company Witness O'Neill Direct Testimony pg. 8 and pg. 23.

Q. WHAT IS THE IMPACT OF THE PROPOSED REVENUE INCREASE ON RESIDENTIAL ELECTRIC CUSTOMERS' BILLS?

A. The following table shows the monthly bill impact by Rate Year for the average Schedule R customer using 839 kWh per month.[22]

Table 9. – Schedule R Three-Year Bill Impact

Schedule R	Rate Year 1	Rate Year 2	Rate Year 3
Change in Average Monthly Bill	$-	$-	$6.28
Percentage Change in Avg Monthly Bill	-	-	5.86%

Q. WHAT IS SCHEDULE EV AND HOW HAS IT BEEN TREATED FOR RATEMAKING PURPOSES IN THE PAST?

A. Schedule EV offers customers with electric vehicles whole house time-of-use rates for commodity.[23] This schedule is treated consistently with Schedule R for distribution ratemaking purposes.

Q. WHAT IS SCHEDULE RD AND HOW HAS IT BEEN TREATED FOR RATEMAKING PURPOSES IN THE PAST?

A. Schedule RD is the Time-of-Use Pilot established through the Public Conference 44 Rate Design working group. The distribution time-of-use rates were designed to be revenue neutral to Schedule R, with the Customer Charge set at the same level as Schedule R and the Delivery Service Charge shaped into an on-peak rate and an off-peak rate based on the current Schedule R rate. I have applied the same shaping methodology as used in Case No. 9610 and in Supplement 621 to P.S.C. Md E-6,

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[22] *See* Company Exhibit LKF-2, Sheet E-17.

[23] This is an existing Electric Vehicle rate schedule and is not the rider created as a part of Case No. 9478. BGE also offers as part of its residential program EV portfolio an EV Only Time-of-Use ("TOU") rate, created as part of Case 9478, which is available to customers as of May 1, 2020.

which maintains the same on-peak to off-peak ratio. The shaping of the Schedule RD rates is included in Company Exhibit LKF-2, Sheet E-14.

B. <u>Schedules G, GP, GS – General Service Small, and GU – Unmetered</u>

Q. HOW DID YOU ASSIGN THE INCREASE FOR SCHEDULES G, GP, GS, AND GU TO THE SCHEDULES' RATE ELEMENTS?

A. I am proposing to increase the Customer Charge for Schedule G to move it closer to the current level of the Customer Charge for Schedule GS and the ECOSS-supported level, to move the G and GS class rates closer to alignment in RY3 of the MYP. The G and GS schedules have a similar relationship to the R and RL class discussion earlier. As such, it is appropriate to also move these schedules closer to alignment. Therefore, the Customer Charge, as proposed, increases from $12.40 to $14.00 for Schedule G customers in RY3, accounting for $2.1 million of the $11.8 million total proposed revenue increase for this schedule. The remaining revenue increase I propose to recover through the Delivery Service Charge. The rates charged for primary service have historically been set at 96% of secondary service and my proposal is to reflect that same relationship in the proposed rates.[24] I am proposing to allocate the entire revenue increase in RY3 for Schedule GU to the Delivery Service Charge. The changes for Schedules G, GS, and GU are shown in Company Exhibit LKF-2 in Sheets E-6, E-7, and E-8, respectively. The table below summarizes the proposed rate structure for RY3.

[24] The primary and secondary rates for Schedule G/GP from Case No. 9610 diverged from this historical relationship.

Table 10. – RY3 Rate Structure

	RY3
Schedule G/GP	
Customer Charge	$14.00
Distribution Charge (G)	$0.03911
Distribution Charge (GP)	$0.03755
Schedule GS	
Customer Charge	$18.60
Distribution Charge	$0.03687
Schedule GU	
Customer Charge	$6.00
Distribution Charge	$0.03966

C. Schedule GL – General Service Large

Q. HOW DO YOU PROPOSE TO APPORTION THE REVENUE REQUIREMENT TO THE VARIOUS RATE ELEMENTS IN SCHEDULE GL?

A. As discussed earlier in my testimony, I propose to increase the Customer Charge from $88.00 to $97.00, and then recover approximately 55% of the remaining revenue increase via the Demand Charge, and 45% via the Delivery Service Charge for RY3. This allocation improves the overall rate design by gradually increasing the demand-related and customer-related revenue to more closely follow the ECOSS.[25] The rates charged for primary service have historically been set at 96% of secondary service and my proposal is to reflect that same relationship in the proposed 2023 rates. The changes for Schedule GL are shown in Company Exhibit LKF-2 in Sheets E-9. The table below summarizes the proposed rate structure in RY3.

[25] The ECOSS supports a Demand Charge of $8.00/KW for Schedule GL in total. *See* Supplemental Schedule V.A. ECOSS.

Table 11. – RY3 Rate Structure

	RY3
Schedule GL/GLP	
Customer Charge	$97.00
Distribution Charge - Secondary	$0.01942
Demand Charge - Secondary	$4.50
Distribution Charge – Primary	$0.01864
Demand Charge – Primary	$4.32

D. Schedule P – Primary Voltage Service

Q. HOW DO YOU PROPOSE TO APPORTION THE REVENUE REQUIREMENT TO THE VARIOUS RATE ELEMENTS IN SCHEDULE P?

A. I propose that the revenue increase in RY3 for Schedule P be allocated between the Demand Charge, Customer Charge and the Delivery Service Charge. I propose to increase the Customer Charge from $600.00 to $660.00, with the remaining revenue recovered approximately 55% via the Demand Charge, and 45% via the Delivery Service Charge. This allocation improves the overall rate design by increasing the demand related revenue to more closely follow the ECOSS.[26] This change is shown in Company Exhibit LKF-2, Sheet E-10. The table below summarizes the proposed rate structure in RY3.

Table 12. – RY3 Rate Structure

	RY3
Schedule P	
Customer Charge	$660.00
Distribution Charge	$0.00614
Demand Charge	$3.25

[26] The 2019 ECOSS supports a Demand Charge of $5.50/KW for Schedule P. *See* Supplemental Schedule V.A. ECOSS

E. Schedule T – Transmission Voltage Service

Q. IS THE COMPANY PROPOSING ANY CHANGES TO THE SCHEDULE T RATES?

A. No. The Company is not proposing any changes to Schedule T rates; these rates will remain constant over the MYP period.

F. Schedule SL – Street Lighting

Q. HOW DO YOU PROPOSE TO APPORTION THE INCREASE IN REVENUE REQUIREMENT TO THE VARIOUS RATE ELEMENTS IN SCHEDULE SL?

A. I propose that 85% of the increase be allocated to the Delivery Service Charge and 15% to the facilities charges (cable, lamp fixtures and poles) and maintenance charges for RY3. Since Case No. 9406, the Schedule SL Delivery Service Charge received $2.6 million in revenue decreases due to the removal of Nuclear Decommissioning Revenues and the TCJA rate reduction.[27] In both of those filings, no portion of the decrease was allocated to the facilities charges or the maintenance charges. In Case No. 9610, the Schedule SL Delivery Service Charge received an $0.455 million revenue increase, which partially offset the previous decreases. In fact, immediately following Case No. 9406, the Delivery Service Charge recovered 12% of Schedule SL revenues, but current rates only recover 3% in the Delivery Service Charge. With my proposal in this case, the Delivery Service Charge will recover 12% of Schedule SL revenues in RY3. The proposed rate change is shown in Company Exhibit LKF-2, Sheet E-12.

[27] *See* ML# 206432 and ML# 218500 which the Commission approved in orders dated December 21, 2016 and January 31, 2018, respectively.

G. Schedule PL – Private Area Lighting

Q. IS THE COMPANY PROPOSING ANY CHANGES TO THE SCHEDULE PL RATES?

A. No. The Company is not proposing any changes to Schedule PL rates, these rates will remain constant over the MYP period.

V. ALLOCATION OF THE PROPOSED CHANGE IN GAS REVENUE

Q. HOW DO THE RESULTS OF THE GCOSS INFLUENCE YOUR PROPOSAL FOR REVENUE ALLOCATION?

A. Gas cost of service studies have been accepted by the Commission in past proceedings as a reasonable method for determining which classes are under- or over-earning, based on the RROR. The cost of service study is used as a guide to determine which classes should receive more, or less, of the proposed revenue changes. The following table shows the results from the Company's 2019 GCOSS, as supported in Company Witness Manuel's Direct Testimony.

Table 13. - 2019 Gas Cost of Service Study Results[28]

Tariff Class	GCOSS RROR
D	1.02
C	0.92
ISS	1.04
IS	0.81
EG	4.62
PLG	8.09
Total System	**1.00**

[28] *See* Company Exhibit JMBM-1.

Q. HOW DO YOU PROPOSE TO APPORTION THE PROPOSED GAS REVENUE INCREASE AMONG THE CUSTOMER CLASSES?

A. Similar to the electric revenue allocation, I propose to apportion the revenue increase in RY3 such that each customer class' rate of return moves toward or within a reasonable band (+/- 10%) around the system average rate of return. I also propose to use the same two-step approach described previously in my testimony for apportioning the electric revenue increase.

In the first step, I propose to move the RROR for classes that are under-earning with a RROR below 0.90 closer to the system average. Schedule IS is the only class below the 10% band around the system average with a RROR of 0.81 and I propose a step one adjustment that moves it to a RROR of 0.90. Following the Commission's general precedent to not decrease gas revenues allocated to an individual customer class when the overall total revenue requirement is increasing, I do not propose step one revenue reductions for those classes – Schedules EG and PLG – that are over-earning by more than 10% of system average.

In step two, I propose that the remaining proposed revenue increase be allocated to the customer classes in proportion to the adjusted historical year base distribution revenues, with two exceptions. As Schedule PLG is closed to new customers and continues to significantly over-earn at eight times the system average, I propose that none of the revenue increase be allocated to that schedule. I also propose to exclude Schedule EG from receiving a revenue increase in this case since they are also significantly over-earning at about four and half times the system average.

The total distribution revenue allocation to each gas rate schedule is the sum of the allocations from steps one and two.

Q. PLEASE PROVIDE AN OVERVIEW OF THE RESULTS OF YOUR TWO-STEP REVENUE APPORTIONMENT IN THIS CASE.

A. The results of my two-step revenue increase apportionment are displayed in the table below and in Company Exhibit LKF-4, Sheet G-3.

Table 14. - Rate Year 3 Gas Distribution Revenue Increase by Customer Class[29]
($ Millions)

Class	Step 1	Step 2	Total	% of Total
D	**--**	**$63.8**	**$63.8**	**67.23%**
C	**--**	**$25.3**	**$25.3**	**26.62%**
IS	**$1.0**	**$4.4**	**$5.4**	**5.73%**
ISS	**--**	**$0.4**	**$0.4**	**0.42%**
EG	**--**	**--**	**--**	**--**
PLG	**--**	**--**	**--**	**--**
Total	**$1.0**	**$93.9**	**$94.9**	**100%**

VI. GAS RATE DESIGN

Q. PLEASE DESCRIBE THE GENERAL LAYOUT OF THE G-SHEETS SHOWN IN COMPANY EXHIBIT LKF-4.

A. Sheet G-1 is a summary of the revenue derived from each schedule under the proposed new rates. This summary also shows, by customer class, the percent increase in RY3 in base distribution revenues as a percentage of total distribution revenues, and the percent increase in customers' total gas bills, using estimated commodity revenues assuming all customers purchase their gas from BGE.[30] Sheet G-2 shows the allocation of the proposed increase to the individual rate schedules (steps one and two). Sheet G-3 provides the proposed revenue allocations for each

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[29] Total may not sum due to rounding.

[30] Commodity revenues are estimated by applying current commodity rates to forecasted billing determinants for each rate year.

year of the MYP by customer class. However, as discussed previously, the Company is not proposing to change 2021 or 2022 revenue allocations.

Sheets G-4 through G-9 show the development of the new rates proposed for each year during the MYP period. Although BGE is not proposing a revenue increase in RY1 or RY2, rate changes will occur each year to account for the effective delivery rate as a result of Rider 8 (Monthly Rate Adjustment) and Rider 12 (Gas Administrative Charge) adjustments. Specifically, Rider 12 recovers certain commodity-related costs that were included in the base distribution revenue requirement ultimately determined in BGE's most recent gas rate case, Case No. 9610, and will recover similar commodity-related costs included in the revenue requirement calculated in this case.[31] In addition, Rider 8 target revenues were reduced by the amount recalculated under Rider 12 based upon the Case No. 9610 test year data. The result is a decrease in Rider 8 target revenue and an increase in gas commodity rates. For each schedule, the weather-adjusted billing determinants forecasted for the particular Rate Year are multiplied by the rates from the current rates in effect during that Rate Year to derive revenue at currently effective rates. Any allocated base revenue increase for each schedule is then added to the schedule's revenues at current rates and distributed, using the same weather-adjusted billing determinants, over the individual rate elements as discussed later in my testimony.

Sheet G-10 derives the effective Rider 8 and Rider 12 rates for each Rate Year based on revenue targets set in BGE's most recent rate case (Case No. 9610) and the forecasted change in number of customers in each Rate Year. Sheet G-11 calculates

[31] BGE filed revised Gas Administrative Charge calculations in January 2020 reflecting the Case No. 9610 test year data (Mail Log #228317), which the Commission approved on February 26, 2020.

the Optional Firm Delivery Prices for Schedules IS, ISS, and EG and the Distribution Interruption Penalty Prices that a Schedule IS, ISS, or EG customer will be assessed in the event a customer under those schedules uses non-compliant gas during a distribution system interruption. As the Company is not proposing revenue changes for 2021 and 2022, the Company is proposing that the OFDS rates and revenues for those years also do not change. Sheet G-12 and Sheet G-13 compare bills at the current rates to bills at the proposed rates at different monthly usage levels for residential (Schedule D) and non-residential firm service customers (Schedule C), respectively. Sheet G-14 compares the monthly bills at current rates to the monthly bills at the proposed rates for the average combined gas and electric service residential customer. Sheet G-15 calculates the percent increase in the customers' total bills by customer class, with the assumption that all customers purchased the gas commodity from BGE.

Q. IN YOUR PROPOSALS BELOW TO ADJUST DELIVERY SERVICE CHARGES, YOU DISCUSS THE PROPOSED RATE RELATIVE TO THE CURRENT "EFFECTIVE RATE". WHAT IS THE "EFFECTIVE RATE"?

A. The "effective rate" refers to the net Delivery Price, which is calculated by netting the base Delivery Price rate with the effect of Rider 8 (Monthly Rate Adjustment) and Rider 12 (Gas Administrative Charge). As discussed in the Electric Rate Design Issues section of my testimony, I use the effective rate for purposes of this discussion to get a complete picture of the rates billed to customers for costs determined in the context of a base rate case proceeding. For gas decoupled rate schedules, we need to net all rates (the base Delivery Price, the Rider 8 rate, and the Rider 12 rate) designed to recover those costs to arrive at an effective rate.[32] These adjustments are shown in Company Exhibit LKF-4, Sheet G-10.

Q. PLEASE EXPLAIN THE COMPANY'S PROPOSED CHANGES TO GAS CUSTOMER CHARGES.

A. I am proposing an increase to the fixed Customer Charge in RY3 for the Schedule D, Schedule C, and Schedule ISS gas rate classes, in order to move the fixed cost recovery for these classes closer to the level supported by the 2019 GCOSS. The Customer Charges for these classes were all increased slightly in Case No. 9610, but there continues to be a large difference between the current Customer Charge and the level supported by the 2019 GCOSS as shown below in Table 15.

It is important to note that this proposal only takes the fixed cost recovery for Schedules D, C, and ISS closer to the level supported in the 2019 GCOSS to better align rates with cost causation. The proposed customer charge increase is included in RY3 of the MYP period.

Table 15. - Customer Charge Proposal

Customer Class	Cost[33]	Current	RY1	RY2	RY3
D	$24.73	$14.25	$14.25	$14.25	$15.25
C	$105.15	$36.30	$36.30	$36.30	$38.00
ISS	$704.90	$363.50	$363.50	$363.50	$375.00

Q. PLEASE DESCRIBE THE IMPACTS OF THIS CHANGE TO RESIDENTIAL GAS CUSTOMERS.

[32] The gas decoupled customer classes are Schedules D and C.
[33] *See* Company Exhibit JMBM-4.

A. As shown in Company Exhibit LKF-1, an average Schedule D customer using 56 therms per month is economically indifferent to the proposed Customer Charge increase. In other words, based upon the proposed revenue increase, a customer using 56 therms per month would essentially receive the same increase to their bill in RY3 whether my proposed Customer Charge and volumetric Delivery Price rate design is accepted or whether the full RY3 increase is assigned to the volumetric Delivery Price.

Q. WOULD INCREASING THE CUSTOMER CHARGE FOR CERTAIN GAS CLASSES, AS YOU ARE PROPOSING, AFFECT THE CURRENT PRICE SIGNALS GIVEN TO CUSTOMERS TO ENCOURAGE ENERGY EFFICIENCY?

A. As I mentioned in my discussion of electric rate design, a significant portion of a customer's bill is for the gas commodity, such that 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.[34] As demonstrated in the table below for RY3, even with the proposed Customer Charge increase, 79% of the total average gas residential customer bill would be recovered through volumetric rates as opposed to a fixed charge.[35]

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[34] At current rates, approximately 31% of an average residential gas customer's bill is commodity-related.

[35] *See* Company Exhibit LKF-1 for further information on the impact based on differing usage levels for gas residential customers.

Table 16. - Summary of Exhibit LKF-1

Comparison of Bills for Average Gas Schedule D Customers	Bill at Current Rates	Proposed Bill with increased Customer Charge	Proposed Bill without increased Customer Charge
Total Charges	$74.97	$83.00	$82.99
% of Fixed Total Charges	22%	21%	20%
% of Variable Total Charges	78%	79%	80%

Furthermore, an increase in the Customer Charge has a minimal impact on the percentage of the total average residential customer bill that would be recovered through volumetric as opposed to fixed charges. The fixed Customer Charge increases I am proposing, therefore, would not have a meaningful impact on the price signals encouraging energy conservation received by residential customers.

A. <u>Schedule D & Grantors of Rights-of-Way (Grantors) - Residential Service</u>

Q. HOW DO YOU PROPOSE TO ALLOCATE THE REVENUE INCREASE ASSIGNED TO THE RESIDENTIAL CLASS AMONG THE RATE ELEMENTS?

A. I propose to recover a portion of the proposed revenue increase through an increase to the Customer Charge in RY3 and the remaining RY3 revenue increase through the Delivery Price. As discussed earlier in my testimony, I propose to increase the Customer Charge from $14.25 to $15.25 for Schedule D customers in RY3, accounting for $7.9 million of the $63.8 million total proposed revenue increase for this schedule. The remaining revenue increase I propose to recover through the Delivery Price of $0.7154 per therm, which is an increase from the 2023 effective rate of $0.5898 per therm. These changes are shown in Company Exhibit LKF-4, Sheet G-4. The table below summarizes the proposed rate structure in RY3 of the MYP period.

Table 17. – RY3 Rate Structure

	RY3
Schedule D	
Customer Charge	$15.25
Distribution Charge	$0.7154

Q. WHAT IS THE IMPACT OF THE PROPOSED REVENUE INCREASE ON RESIDENTIAL GAS CUSTOMERS' BILLS?

A. The following table shows the monthly bill impact by Rate Year for the average Schedule D customer using 56 therms per month.[36]

Table 18. – Schedule D Three-Year Bill Impact

Schedule D	Rate Year 1	Rate Year 2	Rate Year 3
Change in Monthly Bill	$--	$--	$8.04
Percentage Change in Monthly Bill	--	--	10.73%

Q. WHAT ARE GRANTORS AND HOW HAVE THEY BEEN TREATED FOR RATEMAKING PURPOSES IN THE PAST?

A. Grantors are a very small number of residential customers who have an interstate natural gas pipeline located on their property and take service directly from the interstate pipeline. They are treated as residential customers for ratemaking purposes, consistent with precedent in prior rate cases.

B. <u>Schedule C – General Service</u>

Q. HOW DID YOU ASSIGN THE INCREASE FOR SCHEDULE C – GENERAL SERVICE TO THE SCHEDULE'S RATE ELEMENTS?

[36] *See* Company Exhibit LKF-4, Sheet G-12.

A. I propose to recover a portion of the proposed $25.3 million RY3 revenue increase allocated to Schedule C through an increase to the Customer Charge in RY3 and the remaining RY3 increase through the Delivery Price. As discussed earlier in my testimony, I propose to increase the Customer Charge for Schedule C customers from $36.30 to $38.00, accounting for $0.9 million of the $25.3 million total proposed revenue increase for this schedule. In RY1 and RY2, the first and second block Delivery Prices are adjusted for the effective rate adjustment only. In RY3, for the first block (the first 10,000 therms per month), I propose a Delivery Price of $0.5605 per therm and a second block (all therms over 10,000) Delivery Price of $0.2942 per therm. These changes maintain the current proportional relationship between the first and second blocks, which is consistent with past practice. These changes are shown in Company Exhibit LKF-4, Sheet G-5. The table below summarizes the proposed rate structure in RY3 of the MYP period.

Table 19. – RY3 Rate Structure

	Rate Year 3
Schedule C	
Customer Charge	$38.00
Info Fee	$65.00
Delivery Fee	
First 10,000 therms	$0.5605
All over 10,000 therms	$0.2942

C. <u>Schedules IS, ISS, EG - Interruptible Service</u>

Q. HOW DO YOU PROPOSE TO APPORTION THE REVENUE REQUIREMENT TO THE VARIOUS RATE ELEMENTS IN INTERRUPTIBLE SERVICE SCHEDULES IS AND ISS?

A. Consistent with the Company's prior rate cases, I propose to allocate the RY3 revenue increase for Schedules IS and ISS such that the revenue from the Delivery Price is equal to the total revenues from the Customer Charge, Information Fee, and Demand Price.

For Schedule IS – Interruptible Large Volume Service, I propose a Demand Price of $1.1314 per therm in RY3, an increase from $0.8323 per therm. I also propose a Delivery Price of $0.0808 per therm in RY3, an increase from $0.0712 per therm. These changes are shown in Company Exhibit LKF-4, Sheet G-6.

For Schedule ISS – Interruptible Small Volume Service, as discussed earlier in my testimony, I propose to increase the Customer Charge from $363.50 to $375.00 in RY3. I propose a Demand Price of $1.2513 per therm in RY3, an increase from $1.0538 per therm. I also propose a Delivery Price of $0.1405 per therm in RY3, an increase from $0.1190 per therm. These changes are shown in Company Exhibit LKF-4, Sheet G-7.

As discussed previously, I have not recommended any of the proposed revenue increase be allocated to Schedule EG and therefore, no changes are necessary to the Customer Charge, Demand Price, or Delivery Price. This is reflected in Company Exhibit LKF-4, Sheet G-8. The table below summarizes the proposed rate structure for Schedules IS and ISS in RY3 of the MYP period.

Table 20. – RY3 Rate Structure

	Rate Year 3
Schedule IS	
Customer Charge	$1,250.00
Info Fee	$65.00
Demand Price	$1.1314
Delivery Price	$0.0808
Schedule ISS	
Customer Charge	$375.00
Info Fee	$65.00
Demand Price	$1.2513
Delivery Price	$0.1405

Q. HOW ARE THE PROPOSED OPTIONAL FIRM DELIVERY SERVICE ("OFDS") PRICES AND DISTRIBUTION INTERRUPTION PENALTY PRICES CALCULATED?

A. The derivation of the proposed OFDS Prices and Distribution Interruption Penalty Prices are shown in Company Exhibit LKF-4, Sheet G-11. The OFDS Prices for Schedules IS, ISS, and EG are designed to result in customers being charged equivalent Schedule C firm delivery rates. Since the Company is not proposing a revenue increase for RY1 or RY2, the Company is proposing to keep OFDS rates for those years constant with current prices. The specific OFDS Prices proposed for RY3 are calculated by first deriving an effective volumetric demand rate based upon the total class demand revenue and total class volumes, respectively. Then, the proposed Schedules IS, ISS, and EG Delivery Prices and effective volumetric demand rates are subtracted from the Schedule C Delivery Prices first and second block to arrive at first and second block OFDS Prices, respectively.

The Company is proposing to keep the Distribution Interruption Penalty Price for each interruptible schedule constant with current prices for RY1 and RY2, as there is no proposed base distribution revenue increase for those years. The RY3 Distribution Interruption Penalty Price for each interruptible schedule is calculated by multiplying the proposed first block OFDS Prices by 1.5, and the Excessive Use Interruption Penalty Prices are calculated by multiplying the proposed first block OFDS Prices by 2, as described in the Company's Tariff.[37]

D. <u>Schedule PLG - Private Area Lighting - Gas</u>

Q. PLEASE DESCRIBE THE GAS PRIVATE AREA LIGHTING RATE CLASS AND YOUR RATE DESIGN PROPOSAL.

A. The Gas Private Area Lighting rate Schedule is a very small customer class that is closed to new customers. As this class is significantly over-earning (8.09 RROR), I propose to leave their rates unchanged. In this regard, the existing rates will continue to serve as a disincentive to these customers to keep their continuously-burning gas lamps in service, which is a good objective as BGE can no longer get replacement parts for these gas lamps. This disincentive would affect 128 customers. See Company Exhibit LKF-4, Sheet G-9 for the effect of leaving these rates unchanged.

<u>VII. STRIDE SURCHARGE AND MISCELLANEOUS</u>

Q. IS THE COMPANY PROPOSING ANY CHANGES TO GAS RIDER 16 STRIDE (STRATEGIC INFRASTRUCTURE DEVELOPMENT AND ENHANCEMENT) SURCHARGE?

A. No, the Company is not proposing any changes to Rider 16 or the STRIDE program as a result of the MYP in this proceeding. The STRIDE Rider 16 will function in the

[37] For extremely large users (over 575 therms per hour), the penalty price is increased from a 50% adder on top of the first block OFDS Price to a 100% adder on the first block OFDS Price.

same manner that it always has. Each year, by November 1, BGE will file a proposed project list and surcharge calculations, as well as a list of proposed non-STRIDE gas asset replacement work. By March 15 of each year following completion of the annual STRIDE project work, BGE will file program and project cost variance information, along with a reconciliation of the prior year STRIDE surcharge to actual results.

Q. DOES THE COMPANY PROPOSE THAT THE STRIDE SURCHARGE BE RESET AT THE SAME TIME THE RATES FOR RY1 APPROVED IN THIS PROCEEDING BECOME EFFECTIVE?

A. Yes. Consistent with the process used in prior rate cases, including Case Nos. 9355, 9406, 9484, and 9610, the Company is proposing that the STRIDE surcharge be reset as of January 1, 2021, such that the STRIDE surcharge going forward does not include the recovery of investments included in base distribution rates as a result of this MYP. As the revenue requirement proposed by Company Witness Vahos includes recovery of forecasted STRIDE investments through the end of 2020, BGE will file to reduce the STRIDE surcharge when those amounts are approved and included in base rates.

Q. WHAT DO YOU EXPECT WILL HAPPEN TO THE STRIDE SURCHARGE OVER THE COURSE OF THE MYP?

A. Once the STRIDE surcharge hits the cap over the course of this MYP, it will remain capped until new base rates are approved in the rate case following this MYP, as required in Order No. 84982. In the event there is an over-collection through the surcharge over the course of the MYP, it will be handled consistent with how STRIDE surcharge over-collections have previously been handled when the surcharge has been capped: any over-collections will be tracked, with carrying costs accrued, until such time as they can be included in a future uncapped STRIDE surcharge. In Part 2 of Company Witness Vahos' Direct Testimony, he explains how STRIDE investments and surcharge revenues are included in the proposed MYP base distribution revenue requirement calculations.

Q. HAS THE COMPANY DEVELOPED ELECTRIC AND GAS RIDERS THAT CAN BE USED FOR CERTAIN RECONCILIATIONS UNDER THE MYP?

A. Yes. The Company is proposing the establishment of electric and gas Riders for use in the Final Reconciliation after the conclusion of the MYP rate effective period. The proposed Riders are also designed so that they can be used in connection with the Annual Informational Filings over the course of the MYP, if the Commission were to find in that context that a rate adjustment is appropriate, as I discuss further below.

Q. CAN YOU PLEASE EXPLAIN HOW THE RECONCILIATIONS UNDER THE PROPOSED RIDERS WOULD WORK?

A. Yes. Consistent with Commission Order No. 89482, the Riders would establish a reconciliation that provides a mechanism to flow through rates differences between forecasted amounts built into the MYP rates and actual revenues, expenses, and investments in each MYP year, subject to a review and Commission determination. These differences are termed an "Imbalance" in the proposed Riders. An Imbalance represents the annual revenue requirement as calculated using actual rate base and operating income, subject to review. The actual revenue requirement in the Company's proposed reconciliation would be calculated in the same manner as approved by the Commission in this MYP proceeding, and in the manner presented in Company Exhibit DMV-2E and DMV-2G of Part 2 of Company Witness Vahos' Direct Testimony.

Q. IS THE COMPANY PROPOSING THAT AN ANNUAL INFORMATIONAL FILING WOULD WORK DIFFERENTLY THAN THE FINAL RECONCILIATION?

A. In connection with an Annual Informational Filing, these Riders can be used to credit any Imbalance where the Commission determined the Imbalance represented a significant difference to the detriment of ratepayers.

Q. ARE THERE ANY OTHER ASPECTS OF THE PROPOSED RECONCILIATION RIDERS WHICH YOU WISH TO DISCUSS?

A. Yes. Any Imbalance associated with the Final Reconciliation would be credited or charged to customers over a time period as specified by the Commission. Additionally, the Company is proposing that rates included on customer bills pursuant to the Riders would be determined for each rate schedule by first allocating the Imbalance in proportion to each rate classes' amount of base distribution revenues in the final year of the MYP. The resulting amounts are then divided by the estimated billing determinants, per kilowatt-hour or per fixture, for each applicable Schedule. Finally, the Company is proposing that the resulting rate would be included in the Distribution Charge on the Customer's monthly bill. The proposed Riders are included in Company Exhibits LKF-3 and LKF-5.

Q. WHAT IS THE PURPOSE OF RIDER 12, GAS ADMINISTRATIVE CHARGE?

A. Rider 12, Gas Administrative Charge (GAC) recovers the gas commodity-related portion of certain costs, which are both distribution and commodity-related, by applying an amount or percentage of those costs to the Rider 2, Gas Commodity Price. Through the GAC mechanism, a portion of the following costs are included as adders to BGE's Gas Commodity Price and removed from BGE's gas base rates: a) credit and collections; b) commodity billing; c) uncollectibles; and d) the PSC assessment.[38]

Q. HOW WILL THE GAC WORK WITH AN APPROVED MYP?

A. Because the MYP approved in this proceeding would only be a pilot, I am not proposing changes to Rider 12. Instead, I am proposing that the test year data that is used in the determination of the GAC be based on the annual average of the forecasted data included in the MYP.

Q. WHY ARE YOU PROPOSING AVERAGE MYP AMOUNTS BE USED AS TEST YEAR DATA FOR THE GAC?

A. Utilizing average amounts over the MYP as the test year data for GAC purposes reduces the administrative burden of the GAC for all stakeholders over the MRP, while still ensuring that costs are assigned between customers appropriately. Normally, the GAC is reset for certain items following a rate case, including the rate of return used in certain calculations and the test year data I discussed previously. If the GAC does not use average MYP data as test year data for GAC purposes, the Company will need to make annual GAC filings before the beginning of each MYP period in addition to the annual filing required by October 1st each year in order to properly align the GAC with the base rate changes. Under the Company's proposal, the annual GAC filings can continue on their current schedule, and there will only

[38] Gas Rider 12, the GAC, also includes a storage inventory component and a commodity cash working capital component, neither of which have gas distribution base rate implications.

need to be one additional GAC filing after the new base rates become effective January 1, 2021, to reset the GAC rate for the rate of return authorized in the MYP as well as the average annual MYP data.

Q. HOW WILL THE DECOUPLING MECHANISMS, ELECTRIC RIDER 25 AND GAS RIDER 8, OPERATE DURING THE MYP RATE YEARS?

A. The decoupling mechanisms will largely operate in the same manner they do today under a historical test year rate case except it will use the budgeted test year data instead of historical test year data. As such, the Company is not proposing any modifications to electric Rider 25 or gas Rider 8.

Q. ARE THERE ANY OTHER MISCELLANEOUS CHANGES YOU ARE PROPOSING TO MAKE TO THE TARIFFS?

A. Yes, I am proposing miscellaneous "housekeeping" revisions to certain riders in the Electric Service Tariff, specifically changes to electric Riders 6 and 32. The proposed changes are reflected in Company Exhibit LKF-3. They do not in any way modify or revise the current services that we provide, or the terms and conditions under which we provide them.

VIII. <u>CONCLUSION</u>

Q. PLEASE SUMMARIZE YOUR PREPARED DIRECT TESTIMONY.

A. Consistent with recent BGE rate cases, I propose to apportion the 2023 revenue increase using a two-step process such that each customer class' rate of return moves toward or within a reasonable band (+/- 10%) around the system average rate of return. I propose to increase the Customer Charges in 2023 for certain electric classes (Schedules R, G, GL and P) and certain gas classes (Schedules D, C and ISS) by moving the charge closer to the current Customer Component level supported by the 2019 Cost of Service Studies.

As the vast majority of BGE's residential gas customers also receive electric service from the Company, I calculated the bill increase for an average combined gas and electric residential customer in Company Exhibit LKF-2, Sheet E-18. Under the proposed rates, an average combined electric and gas residential customer using 56 therms and 609 kWh each month will see a total monthly bill increase as shown below in Table 21. However, even with the impact of the requested relief and excluding changes in average usage, the total bill for an average residential customer receiving both electric and gas service from BGE will be 22% lower than a decade ago. This includes the reduction in average usage for residential electric and gas customers since the EmPOWER Maryland programs were implemented as well as a decline in commodity prices.

Table 21. – Combined Electric and Gas Residential Monthly Bill Impacts by Rate Year

Date	Increase in Monthly Bill	% Increase
RY1	$0	0%
RY2	$0	0%
RY3	$12.87	8.3%

Q. DOES THIS CONCLUDE YOUR PREPARED DIRECT TESTIMONY?

A. Yes.

BALTIMORE GAS AND ELECTRIC COMPANY
COMPARISON OF BILLS FOR
Electric Schedule R Customers With and Without Proposed RY3 Customer Charge

		MONTHLY USE (KWH)	BILL AT CURRENT RATES	PROPOSED BILL with increased Customer Charge	PROPOSED BILL without increased Customer Charge
< A >	**Approximate 25% Percentile**				
	Distribution Charges	381	$24.47	$27.87	$27.32
	Taxes & Surcharges	381	$0.61	$0.61	$0.61
	Energy Charges	381	$28.08	$28.08	$28.08
	Total Charges	**381**	**$53.16**	**$56.56**	**$56.01**
	% of Fixed Total Charges	**381**	**16%**	**16%**	**15%**
	% of Variable Total Charges	**381**	**84%**	**84%**	**85%**
	% of Fixed Delivery Charges	**381**	**37%**	**36%**	**32%**
	% of Variable Delivery Charges	**381**	**63%**	**64%**	**68%**
< B >	**Approximate 75% Percentile**				
	Distribution Charges	1140	$57.28	$65.45	$65.81
	Taxes & Surcharges	1140	$1.19	$1.19	$1.19
	Energy Charges	1140	$84.03	$84.03	$84.03
	Total Charges	**1140**	**$142.50**	**$150.67**	**$151.03**
	% of Fixed Total Charges	**1140**	**6%**	**6%**	**6%**
	% of Variable Total Charges	**1140**	**94%**	**94%**	**94%**
	% of Fixed Delivery Charges	**1140**	**16%**	**16%**	**14%**
	% of Variable Delivery Charges	**1140**	**84%**	**84%**	**86%**
< C >	**Break-Even**				
	Distribution Charges	839	$44.27	$50.55	$50.55
	Taxes & Surcharges	839	$0.96	$0.96	$0.96
	Energy Charges	839	$61.84	$61.84	$61.84
	Total Charges	**839**	**$107.07**	**$113.35**	**$113.35**
	% of Fixed Total Charges	**839**	**8%**	**8%**	**7%**
	% of Variable Total Charges	**839**	**92%**	**92%**	**93%**
	% of Fixed Delivery Charges	**839**	**21%**	**20%**	**18%**
	% of Variable Delivery Charges	**839**	**79%**	**80%**	**82%**
< D >	**Average (Mean)**				
	Distribution Charges	839	$44.27	$50.55	$50.55
	Taxes & Surcharges	839	$0.96	$0.96	$0.96
	Energy Charges	839	$61.84	$61.84	$61.84
	Total Charges	**839**	**$107.07**	**$113.35**	**$113.35**
	% of Fixed Total Charges	**839**	**8%**	**8%**	**7%**
	% of Variable Total Charges	**839**	**92%**	**92%**	**93%**
	% of Fixed Delivery Charges	**839**	**21%**	**20%**	**18%**
	% of Variable Delivery Charges	**839**	**79%**	**80%**	**82%**

		CURRENT RATES	PROPOSED RATES with Customer Charge Increase	PROPOSED RATES Without Customer Charge Increase
Electric Supply	per kWh	**$ 0.07371**	**$ 0.07371**	**$ 0.07371**
Standard Offer Service Rate	per kWh	$ 0.07220	$ 0.07220	$ 0.07220
Energy Cost Adjustment (Rider 8)	per kWh	$ 0.00151	$ 0.00151	$ 0.00151
Delivery				
Fixed Delivery Charges	per month	**$ 8.00**	**$ 9.00**	**$ 8.00**
Variable Delivery Charges	per kWh	**$ 0.04323**	**$ 0.04952**	**$ 0.05071**
Customer Charge (Schedule R)	per month	**$ 8.00**	**$ 9.00**	**$ 8.00**
EmPOWER MD Chg		**$ 0.00830**	**$ 0.00830**	**$ 0.00830**
Energy Efficiency (Rider 2)	per kWh	$ 0.00466	$ 0.00466	$ 0.00466
Peak Time Rebates (Rider 26)	per kWh	$ 0.00019	$ 0.00019	$ 0.00019
Demand Response (Rider 15)	per kWh	$ 0.00345	$ 0.00345	$ 0.00345
Distribution Chg		**$ 0.03493**	**$ 0.04122**	**$ 0.04241**
Distribution Charge (Schedule R)	per kWh	$ 0.03621	$ 0.04250	$ 0.04369
Administrative Cost Adjustment (Rider 10)	per kWh	$ (0.00128)	$ (0.00128)	$ (0.00128)
Taxes & Surcharges				
MD Universal Service Program	per month	**$ 0.32**	**$ 0.32**	**$ 0.32**
Environmental Surcharge	per kWh	**$ 0.000143**	**$ 0.000143**	**$ 0.000143**
Franchise Tax	per kWh	**$ 0.000620**	**$ 0.000620**	**$ 0.000620**

BALTIMORE GAS AND ELECTRIC COMPANY
COMPARISON OF BILLS FOR
Gas Schedule D Customers With and Without Proposed RY3 Customer Charge

		MONTHLY USE (therms)	BILL AT CURRENT RATES	PROPOSED BILL with increased Customer Charge	PROPOSED BILL without increased Customer Charge
< A >	**Approximate 25% Percentile**				
	Distribution Charges	20	$29.00	$32.51	$31.87
	Taxes & Surcharges	20	$0.08	$0.08	$0.08
	Energy Charges	20	$8.14	$8.14	$8.14
	Total Charges	**20**	**$37.22**	**$40.73**	**$40.09**
	% of Fixed Total Charges	**20**	**44%**	**42%**	**41%**
	% of Variable Total Charges	**20**	**56%**	**58%**	**59%**
	% of Fixed Delivery Charges	**20**	**55%**	**52%**	**49%**
	% of Variable Delivery Charges	**20**	**45%**	**48%**	**51%**
< B >	**Approximate 75% Percentile**				
	Distribution Charges	69	$60.24	$69.91	$70.13
	Taxes & Surcharges	69	$0.28	$0.28	$0.28
	Energy Charges	69	$28.07	$28.07	$28.07
	Total Charges	**69**	**$88.59**	**$98.26**	**$98.48**
	% of Fixed Total Charges	**69**	**18%**	**18%**	**17%**
	% of Variable Total Charges	**69**	**82%**	**82%**	**83%**
	% of Fixed Delivery Charges	**69**	**26%**	**24%**	**22%**
	% of Variable Delivery Charges	**69**	**74%**	**76%**	**78%**
< C >	**Break-Even**				
	Distribution Charges	56	$51.96	$59.99	$59.98
	Taxes & Surcharges	56	$0.23	$0.23	$0.23
	Energy Charges	56	$22.78	$22.78	$22.78
	Total Charges	**56**	**$74.96**	**$83.00**	**$82.99**
	% of Fixed Total Charges	**56**	**22%**	**21%**	**20%**
	% of Variable Total Charges	**56**	**78%**	**79%**	**80%**
	% of Fixed Delivery Charges	**56**	**30%**	**28%**	**26%**
	% of Variable Delivery Charges	**56**	**70%**	**72%**	**74%**
< D >	**Average (Mean)**				
	Distribution Charges	56	$51.96	$59.99	$59.98
	Taxes & Surcharges	56	$0.23	$0.23	$0.23
	Energy Charges	56	$22.78	$22.78	$22.78
	Total Charges	**56**	**$74.96**	**$83.00**	**$82.99**
	% of Fixed Total Charges	**56**	**22%**	**21%**	**20%**
	% of Variable Total Charges	**56**	**78%**	**79%**	**80%**
	% of Fixed Delivery Charges	**56**	**30%**	**28%**	**26%**
	% of Variable Delivery Charges	**56**	**70%**	**72%**	**74%**

		CURRENT RATES	PROPOSED RATES with Customer Charge Increase	PROPOSED RATES Without Customer Charge Increase
Gas Supply	per therm	**$ 0.4068**	**$ 0.4068**	**$ 0.4068**
Monthly Commodity Rate	per therm	$ 0.3868	$ 0.3868	$ 0.3868
Gas Administrative Charge	per therm	$ 0.0200	$ 0.0200	$ 0.0200
Delivery				
Fixed Delivery Charges	per month	**$ 16.25**	**$ 17.25**	**$ 16.25**
Customer Charge (Schedule D)	per month	$ 14.25	$ 15.25	$ 14.25
STRIDE (Rider 16)	per month	$ 2.00	$ 2.00	$ 2.00
Variable Delivery Charges	per therm	**$ 0.6376**	**$ 0.7632**	**$ 0.7809**
Distribution Charge (Schedule D)	per therm	$ 0.5898	$ 0.7154	$ 0.7331
EmPOWER MD Chg (Rider 1)	per therm	$ 0.0447	$ 0.0447	$ 0.0447
Gas Choice & Reliability Charge (Rider 7)	per therm	$ 0.0031	$ 0.0031	$ 0.0031
Taxes & Surcharges				
Variable Taxes	per therm	**$ 0.00402**	**$ 0.00402**	**$ 0.00402**

BALTIMORE GAS AND ELECTRIC COMPANY
APPORTIONMENT OF PROPOSED ELECTRIC BASE RATE
REVENUE CHANGE TO CLASSES OF SERVICE
Rate Year 1

	RATE SCHEDULE	REFERENCE	ADDITIONAL REVENUE REQUIREMENT (1)	PERCENT INCREASE IN CUSTOMERS' TOTAL ELECTRIC BILLS (a) (2)	PERCENT INCREASE IN TOTAL ELECTRIC DISTRIBUTION REVENUE (b) (3)
1.	SCHEDULE R	*(SHEET E-4)*	$ -	0.0%	0.0%
2.	SCHEDULE RL	*(SHEET E-5)*	$ -	0.0%	0.0%
3.	SCHEDULE G	*(SHEET E-6)*	$ -	0.0%	0.0%
4.	SCHEDULE GU	*(SHEET E-6)*	$ -	0.0%	0.0%
5.	SCHEDULE GS	*(SHEET E-7)*	$ -	0.0%	0.0%
6.	SCHEDULE GL	*(SHEET E-9)*	$ -	0.0%	0.0%
7.	SCHEDULE P	*(SHEET E-10)*	$ -	0.0%	0.0%
8.	SCHEDULE T	*(SHEET E-11)*	$ -	0.0%	0.0%
9.	SCHEDULE SL	*(SHEET E-12)*	$ -	0.0%	0.0%
10.	SCHEDULE PL	*(SHEET E-13)*	$ -	0.0%	0.0%
11.	TOTAL		$ -	0.0%	0.0%
12.	TOTAL REQUIRED CHANGE IN BASE REVENUE		$ -		
13.	DIFFERENCE FROM REVENUE REQUIRED		$ -		

BALTIMORE GAS AND ELECTRIC COMPANY
APPORTIONMENT OF PROPOSED ELECTRIC BASE RATE
REVENUE CHANGE TO CLASSES OF SERVICE
Rate Year 2

	RATE SCHEDULE	REFERENCE	ADDITIONAL REVENUE REQUIREMENT (1)	PERCENT INCREASE IN CUSTOMERS' TOTAL ELECTRIC BILLS (a) (2)	PERCENT INCREASE IN TOTAL ELECTRIC DISTRIBUTION REVENUE (b) (3)
1.	SCHEDULE R	*(SHEET E-4)*	$ -	0.0%	0.0%
2.	SCHEDULE RL	*(SHEET E-5)*	$ -	0.0%	0.0%
3.	SCHEDULE G	*(SHEET E-6)*	$ -	0.0%	0.0%
4.	SCHEDULE GU	*(SHEET E-6)*	$ -	0.0%	0.0%
5.	SCHEDULE GS	*(SHEET E-7)*	$ -	0.0%	0.0%
6.	SCHEDULE GL	*(SHEET E-9)*	$ -	0.0%	0.0%
7.	SCHEDULE P	*(SHEET E-10)*	$ -	0.0%	0.0%
8.	SCHEDULE T	*(SHEET E-11)*	$ -	0.0%	0.0%
9.	SCHEDULE SL	*(SHEET E-12)*	$ -	0.0%	0.0%
10.	SCHEDULE PL	*(SHEET E-13)*	$ -	0.0%	0.0%
11.	TOTAL		$ -	0.0%	0.0%
12.	TOTAL REQUIRED CHANGE IN BASE REVENUE		$ -		
13.	DIFFERENCE FROM REVENUE REQUIRED		$ -		

BALTIMORE GAS AND ELECTRIC COMPANY
APPORTIONMENT OF PROPOSED ELECTRIC BASE RATE
REVENUE CHANGE TO CLASSES OF SERVICE
Rate Year 3

	RATE SCHEDULE	REFERENCE	ADDITIONAL REVENUE REQUIREMENT (1)	PERCENT INCREASE IN CUSTOMERS' TOTAL ELECTRIC BILLS (a) (2)	PERCENT INCREASE IN TOTAL ELECTRIC DISTRIBUTION REVENUE (b) (3)
1.	SCHEDULE R	*(SHEET E-4)*	$ 85,962,722	6.2%	15.9%
2.	SCHEDULE RL	*(SHEET E-5)*	$ 4,599,411	4.5%	11.4%
3.	SCHEDULE G	*(SHEET E-6)*	$ 11,764,674	4.5%	11.1%
4.	SCHEDULE GU	*(SHEET E-6)*	$ 26,722	6.7%	11.1%
5.	SCHEDULE GS	*(SHEET E-7)*	$ 963,610	4.1%	11.0%
6.	SCHEDULE GL	*(SHEET E-9)*	$ 27,248,411	3.8%	11.1%
7.	SCHEDULE P	*(SHEET E-10)*	$ 7,082,083	2.1%	10.9%
8.	SCHEDULE T	*(SHEET E-11)*	-	0.0%	0.0%
9.	SCHEDULE SL	*(SHEET E-12)*	$ 2,717,910	8.2%	10.5%
10.	SCHEDULE PL	*(SHEET E-13)*	$ -	0.0%	0.0%
11.	TOTAL		$ 140,365,543	4.8%	13.3%
12.	TOTAL REQUIRED CHANGE IN BASE REVENUE		$ 140,367,000		
13.	DIFFERENCE FROM REVENUE REQUIRED		$ (1,457)		

(a) Percent Increase in Customers' Total Bills from Sheet E-16.

(b) Derived from Sheet E-16 (Increase in Customers' Electric Bills divided by Distribution Revenues from Customers' BGE Bills).

BALTIMORE GAS AND ELECTRIC COMPANY
ALLOCATION OF PROPOSED 2023 ELECTRIC BASE RATE
REVENUE CHANGE TO CLASSES OF SERVICE

STEP 1 - ALLOCATION OF REVENUE INCREASE

RATE SCHEDULE	BASE RATE REVENUE AT CURRENT RATES	RELATIVE ROR	STEP 1 REVENUE ALLOCATION (a)	BASE REVENUE AFTER STEP 1
	(1)	(2)	(3)	(4) = (1) + (3)
1. SCHEDULE R	$ 518,323,008	0.67	$ 21,943,951	$ 540,266,959
2. SCHEDULE RL	$ 38,798,242	0.95	$ -	$ 38,798,242
3. SCHEDULE G	$ 99,193,274	1.06	$ -	$ 99,193,274
5. SCHEDULE GU	$ 225,449	1.06	$ -	$ 225,449
4. SCHEDULE GS	$ 8,126,535	1.65	$ -	$ 8,126,535
6. SCHEDULE GL	$ 229,914,609	1.66	$ -	$ 229,914,609
7. SCHEDULE P	$ 59,693,128	1.00	$ -	$ 59,693,128
8. SCHEDULE T	$ 2,346,735	11.95	$ -	$ 2,346,735
9. SCHEDULE SL	$ 22,937,462	1.46	$ -	$ 22,937,462
10. SCHEDULE PL	$ 19,351,786	4.09	$ -	$ 19,351,786
11. TOTAL	$ 998,910,228		$ 21,943,951	$ 1,020,854,179

STEP 2 - ALLOCATION OF REMAINING REVENUE INCREASE TO ALL RATE SCHEDULES, EXCLUDING SCHEDULES T AND PL

	MYP REVENUE INCREASE
	(5)
12. REQUIRED CHANGE IN BASE RATE REVENUE TO BE ALLOCATED	$ 140,367,000

RATE SCHEDULE	BASE REVENUE AFTER STEP 1	PERCENT OF TOTAL (b)	STEP 2 REVENUE ALLOCATION	TOTAL BASE REVENUE ALLOCATION	PERCENT OF TOTAL DISTRIBUTION INCREASE
	(6) = (4)	(7)	(8) = ((5) - (3)) * 7	(9) = (3) + (8)	(10)
13. SCHEDULE R	$ 540,266,959	54.07%	$ 64,034,127	$ 85,978,078	61.25%
14. SCHEDULE RL	$ 38,798,242	3.88%	$ 4,598,489	$ 4,598,489	3.28%
15. SCHEDULE G	$ 99,193,274	9.93%	$ 11,756,697	$ 11,756,697	8.38%
16. SCHEDULE GU	$ 225,449	0.02%	$ 26,721	$ 26,721	0.02%
17. SCHEDULE GS	$ 8,126,535	0.81%	$ 963,182	$ 963,182	0.69%
18. SCHEDULE GL	$ 229,914,609	23.01%	$ 27,250,197	$ 27,250,197	19.41%
19. SCHEDULE P	$ 59,693,128	5.97%	$ 7,075,016	$ 7,075,016	5.04%
20. SCHEDULE T	$ 2,346,735	-	$ -	$ -	0.00%
21. SCHEDULE SL	$ 22,937,462	2.30%	$ 2,718,620	$ 2,718,620	1.94%
22. SCHEDULE PL	$ 19,351,786	-	$ -	$ -	0.00%
23. TOTAL	$ 1,020,854,179	100.0%	$ 118,423,049	$ 140,367,000	100.00%
24. TOTAL REVENUE INCREASE				$ 140,367,000	

(a) See BGE Supplemental V.A. ECOSS Page 16 for Schedule R Step 1 Allocation. As discussed in my testimony, the Schedule R Step 1 Allocation moves the class 50% towards a RROR of 0.90.
(b) Excludes Schedules T and PL.

BALTIMORE GAS AND ELECTRIC COMPANY
SUMMARY OF ALLOCATION OF PROPOSED ELECTRIC MYP BASE RATE REVENUE
CHANGE BY RATE SCHEDULE OVER MYP PERIOD

(1)	(2)	(3)	(4)	(5)	(6)
				Total Revenue Increase	
	Rate Year 1	Rate Year 2	Rate Year 3	($)	(%)
1. MYP REVENUE REQUIREMENT	$ -	$ -	$ 140,367,000	$ 140,367,000	
RATE SCHEDULE					
2. SCHEDULE R	$ -	$ -	$ 85,978,078	$ 85,978,078	61.3%
3. SCHEDULE RL	$ -	$ -	$ 4,598,489	$ 4,598,489	3.3%
4. SCHEDULE G	$ -	$ -	$ 11,756,697	$ 11,756,697	8.4%
5. SCHEDULE GU	$ -	$ -	$ 26,721	$ 26,721	0.0%
6. SCHEDULE GS	$ -	$ -	$ 963,182	$ 963,182	0.7%
7. SCHEDULE GL	$ -	$ -	$ 27,250,197	$ 27,250,197	19.4%
8. SCHEDULE P	$ -	$ -	$ 7,075,016	$ 7,075,016	5.0%
9. SCHEDULE T	$ -	$ -	$ -	$ -	0.0%
10. SCHEDULE SL	$ -	$ -	$ 2,718,620	$ 2,718,620	1.9%
11. SCHEDULE PL	$ -	$ -	$ -	$ -	0.0%
12. TOTAL	$ -	$ -	$ 140,367,000	$ 140,367,000	100.0%

BALTIMORE GAS AND ELECTRIC COMPANY
PROPOSED CHANGE IN ELECTRIC SERVICE TARIFF
SCHEDULE R - RESIDENTIAL SERVICE
Rate Year 1 - 2021

Rate Year 1

	WEATHER ADJUSTED BILLING DETERMINANTS (1)	REVENUE AT CURRENT RATES: CURRENT RATES (2)	RIDER 25 ADJ. (a) (3)	EFFECTIVE RATE (4)=(2)+(3)	REVENUE AT CURRENT RATES (5) = (1) x (4)	WEATHER ADJUSTED BILLING DETERMINANTS (6)	PROPOSED CHANGE IN REVENUE: PROPOSED RATES (7)	REVENUE AT PROPOSED RATES (8) = (6) x (7)	CHANGE IN BASE REVENUE: REVENUE (9) = (8) - (5)	PERCENT (10) = (9) / (5)
1. CUSTOMER CHARGE	BILLS					BILLS				
Schedule R	13,514,961	$ 8.00		$ 8.00	$ 108,119,686	13,514,961	$ 8.00	$ 108,119,686	$ -	0.0%
	kWh					kWh	$/kWh			
2. DELIVERY SERVICE CHARGE										
Schedule R	11,235,369,008	$ 0.03507	$ 0.00144	$ 0.03651	$ 410,203,322	11,235,369,008	0.03651	$ 410,203,322	$ -	0.0%
3. TOTAL REVENUE					$ 518,323,008			$ 518,323,008	$ -	0.0%

4. TOTAL REVENUE ALLOCATED $ -
5. DIFFERENCE FROM REVENUE ALLOCATED $ -

BALTIMORE GAS AND ELECTRIC COMPANY
PROPOSED CHANGE IN ELECTRIC SERVICE TARIFF
SCHEDULE R - RESIDENTIAL SERVICE
Rate Year 2 - 2022

Rate Year 2

	WEATHER ADJUSTED BILLING DETERMINANTS (1)	REVENUE AT CURRENT RATES: CURRENT RATES (2)	RIDER 25 ADJ. (a) (3)	EFFECTIVE RATE (4)=(2)+(3)	REVENUE AT CURRENT RATES (5) = (1) x (4)
1. CUSTOMER CHARGE	BILLS				
Schedule R	13,583,281	$ 8.00		$ 8.00	$ 108,666,249
	kWh				
2. DELIVERY SERVICE CHARGE					
Schedule R	11,352,319,553	$ 0.03651	$ (0.00018)	$ 0.03633	$ 412,429,769
3. TOTAL REVENUE					$ 521,096,018

	WEATHER ADJUSTED BILLING DETERMINANTS (6)	PROPOSED CHANGE IN REVENUE: PROPOSED RATES (7)	REVENUE AT PROPOSED RATES (8) = (6) x (7)	CHANGE IN BASE REVENUE: REVENUE (9) = (8) - (5)	PERCENT (10) = (9) / (5)
1. CUSTOMER CHARGE	BILLS				
Schedule R	13,583,281	$ 8.00	$ 108,666,249	$ -	0.0%
	kWh	$/kWh			
2. DELIVERY SERVICE CHARGE					
Schedule R	11,352,319,553	0.03633	$ 412,429,769	$ -	0.0%
3. TOTAL REVENUE			$ 521,096,018	$ -	0.0%
4. TOTAL REVENUE ALLOCATED				$ -	
5. DIFFERENCE FROM REVENUE ALLOCATED				$ -	

BALTIMORE GAS AND ELECTRIC COMPANY
PROPOSED CHANGE IN ELECTRIC SERVICE TARIFF
SCHEDULE R - RESIDENTIAL SERVICE
Rate Year 3 - 2023

Rate Year 3

	WEATHER ADJUSTED BILLING DETERMINANTS (1)	REVENUE AT CURRENT RATES: CURRENT RATES (2)	RIDER 25 ADJ. (a) (3)	EFFECTIVE RATE (4)=(2)+(3)	REVENUE AT CURRENT RATES (5) = (1) x (4)	WEATHER ADJUSTED BILLING DETERMINANTS (6)	PROPOSED CHANGE IN REVENUE: PROPOSED RATES (7)	REVENUE AT PROPOSED RATES (8) = (6) x (7)	CHANGE IN BASE REVENUE: REVENUE (9) = (8) - (5)	PERCENT (10) = (9) / (5)
1. CUSTOMER CHARGE	BILLS					BILLS				
Schedule R	13,694,561	$ 8.00		$ 8.00	$ 109,556,487	13,694,561	$ 9.00	$ 123,251,047	$ 13,694,561	12.5%
	kWh					kWh	$/kWh			
2. DELIVERY SERVICE CHARGE										
Schedule R	11,489,373,793	$ 0.03633	$ (0.00012)	$ 0.03621	$ 416,030,225	11,489,373,793	0.04250	$ 488,298,386	$ 72,268,161	17.4%
3. TOTAL REVENUE					$ 525,586,712			$ 611,549,433	$ 85,962,722	16.4%

4. TOTAL REVENUE ALLOCATED	$ 85,978,078
5. DIFFERENCE FROM REVENUE ALLOCATED	$ (15,357)

(a) Effective adjustment calculated on Sheet E-15

BALTIMORE GAS AND ELECTRIC COMPANY
PROPOSED CHANGE IN ELECTRIC SERVICE TARIFF
SCHEDULE RL - RESIDENTIAL SERVICE
Rate Year 1 - 2021

Rate Year 1

	WEATHER ADJUSTED BILLING DETERMINANTS (1)	REVENUE AT CURRENT RATES: CURRENT RATES (2)	RIDER 25 ADJ. (a) (3)	EFFECTIVE RATE (4)=(2)+(3)	REVENUE AT CURRENT RATES (5) = (1) x (4)
1. CUSTOMER CHARGE	BILLS				
Schedule RL	700,115	$ 12.00		$ 12.00	$ 8,401,377
	kWh			$/kWh	
2. DELIVERY SERVICE CHARGE					
Schedule RL	826,001,760	$ 0.03538	$ 0.00142	$ 0.03680	$ 30,396,865
3. TOTAL REVENUE					$ 38,798,242

2021 - MYP Rate Year 1

	WEATHER ADJUSTED BILLING DETERMINANTS (6)	PROPOSED CHANGE IN REVENUE: PROPOSED RATES (7)	REVENUE AT PROPOSED RATES (8) = (6) x (7)	CHANGE IN BASE REVENUE: REVENUE (9) = (8) - (5)	PERCENT (10) = (9) / (5)
1. CUSTOMER CHARGE	BILLS				
Schedule RL	700,115	$ 12.00	$ 8,401,377	$ -	0.0%
	kWh	$/kWh			
2. DELIVERY SERVICE CHARGE					
Schedule RL	826,001,760	0.03680	$ 30,396,865	$ -	0.0%
3. TOTAL REVENUE			$ 38,798,242	$ -	0.0%
4. TOTAL REVENUE ALLOCATED				$ -	
5. DIFFERENCE FROM REVENUE ALLOCATED				$ -	

BALTIMORE GAS AND ELECTRIC COMPANY
PROPOSED CHANGE IN ELECTRIC SERVICE TARIFF
SCHEDULE RL - RESIDENTIAL SERVICE
Rate Year 2 - 2022

Rate Year 2

	WEATHER ADJUSTED BILLING DETERMINANTS	REVENUE AT CURRENT RATES: CURRENT RATES	RIDER 25 ADJ. (a)	EFFECTIVE RATE	REVENUE AT CURRENT RATES
	(1)	(2)	(3)	(4)=(2)+(3)	(5) = (1) x (4)
1. CUSTOMER CHARGE	BILLS				
Schedule RL	703,302	$ 12.00		$ 12.00	$ 8,439,618
	kWh			$/kWh	
2. DELIVERY SERVICE CHARGE					
Schedule RL	834,657,338	$ 0.03680	$ (0.00019)	$ 0.03661	$ 30,556,805
3. TOTAL REVENUE					$ 38,996,423

2022 - MYP Rate Year 2

	WEATHER ADJUSTED BILLING DETERMINANTS	PROPOSED CHANGE IN REVENUE: PROPOSED RATES	REVENUE AT PROPOSED RATES	CHANGE IN BASE REVENUE: REVENUE	PERCENT
	(6)	(7)	(8) = (6) x (7)	(9) = (8) - (5)	(10) = (9) / (5)
1. CUSTOMER CHARGE	BILLS				
Schedule RL	703,302	$ 12.00	$ 8,439,618	$ -	0.0%
	kWh	$/kWh			
2. DELIVERY SERVICE CHARGE					
Schedule RL	834,657,338	0.03661	$ 30,556,805	$ -	0.0%
3. TOTAL REVENUE			$ 38,996,423	$ -	0.0%
4. TOTAL REVENUE ALLOCATED				$ -	
5. DIFFERENCE FROM REVENUE ALLOCATED				$ -	

BALTIMORE GAS AND ELECTRIC COMPANY
PROPOSED CHANGE IN ELECTRIC SERVICE TARIFF
SCHEDULE RL - RESIDENTIAL SERVICE
Rate Year 3 - 2023

Rate Year 3

	WEATHER ADJUSTED BILLING DETERMINANTS	REVENUE AT CURRENT RATES: CURRENT RATES	RIDER 25 ADJ. (a)	EFFECTIVE RATE	REVENUE AT CURRENT RATES
	(1)	(2)	(3)	(4)=(2)+(3)	(5) = (1) x (4)
1. CUSTOMER CHARGE	BILLS				
Schedule RL	708,711	$ 12.00		$ 12.00	$ 8,504,527
	kWh			$/kWh	
2. DELIVERY SERVICE CHARGE					
Schedule RL	845,479,981	$ 0.03661	$ (0.00016)	$ 0.0365	$ 30,817,745
3. TOTAL REVENUE					$ 39,322,272

2023 - MYP Rate Year 3

	WEATHER ADJUSTED BILLING DETERMINANTS	PROPOSED CHANGE IN REVENUE: PROPOSED RATES	REVENUE AT PROPOSED RATES	CHANGE IN BASE REVENUE: REVENUE	PERCENT
	(6)	(7)	(8) = (6) x (7)	(9) = (8) - (5)	(10) = (9) / (5)
1. CUSTOMER CHARGE	BILLS				
Schedule RL	708,711	$ 12.00	$ 8,504,527	$ -	0.0%
	kWh	$/kWh			
2. DELIVERY SERVICE CHARGE					
Schedule RL	845,479,981	0.04189	$ 35,417,156	$ 4,599,411	14.9%
3. TOTAL REVENUE			$ 43,921,683	$ 4,599,411	11.7%
4. TOTAL REVENUE ALLOCATED				$ 4,598,489	
5. DIFFERENCE FROM REVENUE ALLOCATED				$ 922	

(a) Effective adjustment calculated on Sheet E-15

BALTIMORE GAS AND ELECTRIC COMPANY
PROPOSED CHANGE IN ELECTRIC SERVICE TARIFF
SCHEDULE G - GENERAL SERVICE
Rate Year 1 - 2021

Rate Year 1

	WEATHER ADJUSTED BILLING DETERMINANTS	REVENUE AT CURRENT RATES: CURRENT RATES	EFFECTIVE RIDER 25 ADJ. (a)	CURRENT EFFECTIVE RATES	REVENUE AT CURRENT RATES
	(1)	(2)	(3)	(4) = (2) + (3)	(5) = (1) x (4)
1. CUSTOMER CHARGE	BILLS				
Schedule G	1,291,521	$ 12.40		$ 12.40	$ 16,014,854
Schedule G Primary (GP)	196	$ 12.40		$ 12.40	$ 2,430
	kWh	$/kWh	$/kWh	$/kWh	
2. DELIVERY SERVICE CHARGE					
Schedule G	2,446,608,171	0.03194	0.00204	0.03398	$ 83,135,746
Schedule G Primary (GP)	1,383,415	0.02909		0.02909	$ 40,244
3. TOTAL REVENUE					$ 99,193,274

	WEATHER ADJUSTED BILLING DETERMINANTS	PROPOSED CHANGE IN REVENUE: PROPOSED RATES	REVENUE AT PROPOSED RATES	CHANGE IN BASE REVENUE: REVENUE	PERCENT
	(6)	(7)	(8) = (6) x (7)	(9) = (8) - (5)	(10) = (9) / (5)
1. CUSTOMER CHARGE	BILLS				
Schedule G	1,291,521	$ 12.40	$ 16,014,854	$ -	0.0%
Schedule G Primary (GP)	196	$ 12.40	$ 2,430	$ -	0.0%
	1,291,716		$ 16,017,284	$ -	
	kWh	$/kWh			
2. DELIVERY SERVICE CHARGE					
Schedule G	2,446,608,171	0.03398	$ 83,135,746	$ -	0.0%
Schedule G Primary (GP)	1,383,415	0.02909	$ 40,244	$ -	0.0%
	2,447,991,586		$ 83,175,990	$ -	
3. TOTAL REVENUE			$ 99,193,274	$ -	0.0%
4. TOTAL REVENUE ALLOCATED				$ -	
5. DIFFERENCE FROM REVENUE ALLOCATED				$ -	

BALTIMORE GAS AND ELECTRIC COMPANY
PROPOSED CHANGE IN ELECTRIC SERVICE TARIFF
SCHEDULE G - GENERAL SERVICE
Rate Year 2 - 2022

Rate Year 2

	WEATHER ADJUSTED BILLING DETERMINANTS	REVENUE AT CURRENT RATES: CURRENT RATES	EFFECTIVE RIDER 25 ADJ. (a)	CURRENT EFFECTIVE RATES	REVENUE AT CURRENT RATES	WEATHER ADJUSTED BILLING DETERMINANTS	PROPOSED CHANGE IN REVENUE: PROPOSED RATES	REVENUE AT PROPOSED RATES	CHANGE IN BASE REVENUE: REVENUE	CHANGE IN BASE REVENUE: PERCENT
	(1)	(2)	(3)	(4) = (2) + (3)	(5) = (1) x (4)	(6)	(7)	(8) = (6) x (7)	(9) = (8) - (5)	(10) = (9) / (5)
1. CUSTOMER CHARGE	BILLS					BILLS				
Schedule G	1,294,529	$ 12.40		$ 12.40	$ 16,052,166	1,294,529	$ 12.40	$ 16,052,166	$ -	0.0%
Schedule G Primary (GP)	196	$ 12.40		$ 12.40	$ 2,435	196	$ 12.40	$ 2,435	$ -	0.0%
						1,294,726		$ 16,054,601	$ -	
	kWh	$/kWh	$/kWh	$/kWh		kWh	$/kWh			
2. DELIVERY SERVICE CHARGE										
Schedule G	2,410,169,150	0.03398	0.00060	0.03458	$ 83,343,649	2,410,169,150	0.03458	$ 83,343,649	$ -	0.0%
Schedule G Primary (GP)	1,362,811	0.02909		0.02909	$ 39,644	1,362,811	0.02909	$ 39,644	$ -	0.0%
						2,411,531,961		$ 83,383,293	$ -	
3. TOTAL REVENUE					$ 99,437,894			$ 99,437,894	$ -	0.0%
4. TOTAL REVENUE ALLOCATED									$ -	
5. DIFFERENCE FROM REVENUE ALLOCATED									$ -	

BALTIMORE GAS AND ELECTRIC COMPANY
PROPOSED CHANGE IN ELECTRIC SERVICE TARIFF
SCHEDULE G - GENERAL SERVICE
Rate Year 3 - 2023

Rate Year 3

	WEATHER ADJUSTED BILLING DETERMINANTS	REVENUE AT CURRENT RATES: CURRENT RATES	EFFECTIVE RIDER 25 ADJ. (a)	CURRENT EFFECTIVE RATES	REVENUE AT CURRENT RATES	WEATHER ADJUSTED BILLING DETERMINANTS	PROPOSED CHANGE IN REVENUE: PROPOSED RATES	REVENUE AT PROPOSED RATES	CHANGE IN BASE REVENUE: REVENUE	PERCENT
	(1)	(2)	(3)	(4) = (2) + (3)	(5) = (1) x (4)	(6)	(7)	(8) = (6) x (7)	(9) = (8) - (5)	(10) = (9) / (5)
1. CUSTOMER CHARGE	BILLS					BILLS				
Schedule G	1,297,538	$ 12.40		$ 12.40	$ 16,089,477	1,297,538	$ 14.00	$ 18,165,538	$ 2,076,062	12.9%
Schedule G Primary (GP)	197	$ 12.40		$ 12.40	$ 2,441	197	$ 14.00	$ 2,756	$ 315	12.9%
						1,297,735		$ 18,168,294	$ 2,076,376	
	kWh	$/kWh	$/kWh	$/kWh		kWh	$/kWh			
2. DELIVERY SERVICE CHARGE										
Schedule G	2,383,471,793	0.03458	0.00047	0.03505	$ 83,540,686	2,383,471,793	0.03911	$ 93,217,582	$ 9,676,896	11.6%
Schedule G Primary (GP)	1,347,715	0.02909		0.02909	$ 39,205	1,347,715	0.03755	$ 50,607	$ 11,402	29.1%
						2,384,819,508		$ 93,268,189	$ 9,688,298	
3. TOTAL REVENUE					$ 99,671,809			$ 111,436,483	$ 11,764,674	11.8%
4. TOTAL REVENUE ALLOCATED									$ 11,756,697	
5. DIFFERENCE FROM REVENUE ALLOCATED									$ 7,978	

(a) Effective adjustment calculated on Sheet E-15

BALTIMORE GAS AND ELECTRIC COMPANY
PROPOSED CHANGE IN ELECTRIC SERVICE TARIFF
SCHEDULE GS - GENERAL SERVICE SMALL
Rate Year 1 - 2021

Rate Year 1

	WEATHER ADJUSTED BILLING DETERMINANTS	REVENUE AT CURRENT RATES				WEATHER ADJUSTED BILLING DETERMINANTS	PROPOSED CHANGE IN REVENUE			
		CURRENT RATES	RIDER 25 ADJ. (a)	EFFECTIVE RATES	REVENUE AT CURRENT RATES		PROPOSED RATES	REVENUE AT PROPOSED RATES	CHANGE IN BASE REVENUE: REVENUE	CHANGE IN BASE REVENUE: PERCENT
	(1)	(2)	(3)	(4) = (2) + (3)	(5) = (1) x (4)	(6)	(7)	(8) = (6) x (7)	(9) = (8) - (5)	(10) = (9) / (5)
1. CUSTOMER CHARGE	BILLS					BILLS				
Schedule GS	31,374	$ 18.60		$ 18.60	$ 583,558	31,374	$ 18.60	$ 583,558	$ -	0.0%
	kWh	$/kWh	$/kWh	$/kWh		kWh	$/kWh			
2. DELIVERY SERVICE CHARGE										
Schedule GS	237,723,833	$ 0.02937	$ 0.00236	$ 0.03173	$ 7,542,977	237,723,833	0.03173	$ 7,542,977	$ -	0.0%
3. TOTAL REVENUE					$ 8,126,535			$ 8,126,535	$ -	0.0%
4. TOTAL REVENUE ALLOCATED									$ -	
5. DIFFERENCE FROM REVENUE ALLOCATED									$ -	

BALTIMORE GAS AND ELECTRIC COMPANY
PROPOSED CHANGE IN ELECTRIC SERVICE TARIFF
SCHEDULE GS - GENERAL SERVICE SMALL
Rate Year 2 - 2022

Rate Year 2

	WEATHER ADJUSTED BILLING DETERMINANTS (1)	REVENUE AT CURRENT RATES: CURRENT RATES (2)	EFFECTIVE RIDER 25 ADJ. (a) (3)	CURRENT EFFECTIVE RATES (4) = (2) + (3)	REVENUE AT CURRENT RATES (5) = (1) x (4)	WEATHER ADJUSTED BILLING DETERMINANTS (6)	PROPOSED CHANGE IN REVENUE: PROPOSED RATES (7)	REVENUE AT PROPOSED RATES (8) = (6) x (7)	CHANGE IN BASE REVENUE: REVENUE (9) = (8) - (5)	PERCENT (10) = (9) / (5)
1. CUSTOMER CHARGE	BILLS					BILLS				
Schedule GS	31,446	$ 18.60		$ 18.60	$ 584,891	31,446	$ 18.60	$ 584,891	$ -	0.0%
	kWh	$/kWh	$/kWh	$/kWh		kWh	$/kWh			
2. DELIVERY SERVICE CHARGE										
Schedule GS	234,253,622	$ 0.03173	$ 0.00054	$ 0.03227	$ 7,559,364	234,253,622	0.03227	$ 7,559,364	$ -	0.0%
3. TOTAL REVENUE					$ 8,144,255			$ 8,144,255	$ -	0.0%
4. TOTAL REVENUE ALLOCATED									$ -	
5. DIFFERENCE FROM REVENUE ALLOCATED									$ -	

BALTIMORE GAS AND ELECTRIC COMPANY
PROPOSED CHANGE IN ELECTRIC SERVICE TARIFF
SCHEDULE GS - GENERAL SERVICE SMALL
Rate Year 3 - 2023

Rate Year 3

	WEATHER ADJUSTED BILLING DETERMINANTS (1)	REVENUE AT CURRENT RATES: CURRENT RATES (2)	EFFECTIVE RIDER 25 ADJ. (a) (3)	CURRENT EFFECTIVE RATES (4) = (2) + (3)	REVENUE AT CURRENT RATES (5) = (1) x (4)	WEATHER ADJUSTED BILLING DETERMINANTS (6)	PROPOSED CHANGE IN REVENUE: PROPOSED RATES (7)	REVENUE AT PROPOSED RATES (8) = (6) x (7)	CHANGE IN BASE REVENUE: REVENUE (9) = (8) - (5)	PERCENT (10) = (9) / (5)
1. CUSTOMER CHARGE	BILLS					BILLS				
Schedule GS	31,517	$ 18.60		$ 18.60	$ 586,225	31,517	$ 18.60	$ 586,225	$ -	0.0%
	kWh	$/kWh	$/kWh	$/kWh		kWh	$/kWh			
2. DELIVERY SERVICE CHARGE										
Schedule GS	231,636,956	$ 0.03227	$ 0.00044	$ 0.03271	$ 7,576,845	231,636,956	0.03687	$ 8,540,455	$ 963,610	12.7%
3. TOTAL REVENUE					$ 8,163,070			$ 9,126,680	$ 963,610	11.8%
4. TOTAL REVENUE ALLOCATED									$ 963,182	
5. DIFFERENCE FROM REVENUE ALLOCATED									$ 428	

(a) Effective adjustment calculated on Sheet E-15

BALTIMORE GAS AND ELECTRIC COMPANY
PROPOSED CHANGE IN ELECTRIC SERVICE TARIFF
SCHEDULE GU - GENERAL UNMETERED SERVICE
Rate Year 1 - 2021

Rate Year 1

	WEATHER ADJUSTED BILLING DETERMINANTS (1)	REVENUE AT CURRENT RATES: CURRENT RATES (2)	REVENUE AT CURRENT RATES: REVENUE AT CURRENT RATES (3) = (1) x (2)	TEST YEAR BILLING DETERMINANTS (4)	PROPOSED CHANGE IN REVENUE: PROPOSED RATES (5)	PROPOSED CHANGE IN REVENUE: REVENUE AT PROPOSED RATES (6) = (4) x (5)	CHANGE IN BASE REVENUE: REVENUE (7) = (6) - (3)	CHANGE IN BASE REVENUE: PERCENT (8) = (7) / (3)
1. CUSTOMER CHARGE	BILLS			BILLS				
Schedule GU	25,588	$ 6.00	$ 153,530	25,588	$ 6.00	$ 153,530	$ -	0.0%
	kWh	$/kWh		kWh	$/kWh			
2. DELIVERY SERVICE CHARGE								
Schedule GU	2,505,002	0.02871	$ 71,919	2,505,002	0.02871	$ 71,919	$ -	0.0%
3. TOTAL REVENUE			$ 225,449			$ 225,449	$ -	0.0%
4. TOTAL REVENUE ALLOCATED							$ -	
5. DIFFERENCE FROM REVENUE ALLOCATED							$ -	

COMPANY EXHIBIT LFK-2
SUPPLEMENT 650
SHEET E-8

BALTIMORE GAS AND ELECTRIC COMPANY
PROPOSED CHANGE IN ELECTRIC SERVICE TARIFF
SCHEDULE GU - GENERAL UNMETERED SERVICE
Rate Year 2 - 2022

Rate Year 2

	WEATHER ADJUSTED BILLING DETERMINANTS (1)	REVENUE AT CURRENT RATES: CURRENT RATES (2)	REVENUE AT CURRENT RATES: REVENUE AT CURRENT RATES (3) = (1) x (2)	TEST YEAR BILLING DETERMINANTS (4)	PROPOSED CHANGE IN REVENUE: PROPOSED RATES (5)	PROPOSED CHANGE IN REVENUE: REVENUE AT PROPOSED RATES (6) = (4) x (5)	CHANGE IN BASE REVENUE: REVENUE (7) = (6) - (3)	CHANGE IN BASE REVENUE: PERCENT (8) = (7) / (3)
1. CUSTOMER CHARGE	BILLS			BILLS				
Schedule GU	25,648	$ 6.00	$ 153,888	25,648	$ 6.00	$ 153,888	$ -	0.0%
	kWh	$/kWh		kWh	$/kWh			
2. DELIVERY SERVICE CHARGE								
Schedule GU	2,467,693	0.02871	$ 70,847	2,467,693	0.02871	$ 70,847	$ -	0.0%
3. TOTAL REVENUE			$ 224,735			$ 224,735	$ -	0.0%

4. TOTAL REVENUE ALLOCATED	$ -
5. DIFFERENCE FROM REVENUE ALLOCATED	$ -

BALTIMORE GAS AND ELECTRIC COMPANY
PROPOSED CHANGE IN ELECTRIC SERVICE TARIFF
SCHEDULE GU - GENERAL UNMETERED SERVICE
Rate Year 3 - 2023

Rate Year 3

	WEATHER ADJUSTED BILLING DETERMINANTS	REVENUE AT CURRENT RATES: CURRENT RATES	REVENUE AT CURRENT RATES: REVENUE AT CURRENT RATES	TEST YEAR BILLING DETERMINANTS	PROPOSED CHANGE IN REVENUE: PROPOSED RATES	PROPOSED CHANGE IN REVENUE: REVENUE AT PROPOSED RATES	CHANGE IN BASE REVENUE: REVENUE	CHANGE IN BASE REVENUE: PERCENT
	(1)	(2)	(3) = (1) x (2)	(4)	(5)	(6) = (4) x (5)	(7) = (6) - (3)	(8) = (7) / (3)
1. CUSTOMER CHARGE	BILLS			BILLS				
Schedule GU	25,708	$ 6.00	$ 154,246	25,708	$ 6.00	$ 154,246	$ -	0.0%
	kWh	$/kWh		kWh	$/kWh			
2. DELIVERY SERVICE CHARGE								
Schedule GU	2,440,358	0.02871	$ 70,063	2,440,358	0.03966	$ 96,785	$ 26,722	38.1%
3. TOTAL REVENUE			$ 224,309			$ 251,031	$ 26,722	11.9%
4. TOTAL REVENUE ALLOCATED							$ 26,721	
5. DIFFERENCE FROM REVENUE ALLOCATED							$ 1	

BALTIMORE GAS AND ELECTRIC COMPANY
PROPOSED CHANGE IN ELECTRIC SERVICE TARIFF
SCHEDULE GL - GENERAL SERVICE LARGE
Rate Year 1 - 2021

COMPANY EXHIBIT LFK-2
SUPPLEMENT 650
SHEET E-9

Rate Year 1

	WEATHER ADJUSTED BILLING DETERMINANTS	REVENUE AT CURRENT RATES			
		CURRENT RATES	RIDER 25 ADJ. (a)	EFFECTIVE RATES	REVENUE AT CURRENT RATES
	(1)	(2)	(3)	(4) = (2) + (3)	(5) = (1) x (4)
1. CUSTOMER CHARGE	BILLS				
Schedule GL Secondary	142,697	$ 88.00			$ 12,557,333
Schedule GL Primary	2,601	$ 88.00			$ 228,887
2. DEMAND CHARGE	kW	$/kW			
Schedule GL Secondary	19,731,077	3.81			$ 75,175,402
Schedule GL Primary	930,681	3.63			$ 3,378,372
3. DELIVERY SERVICE CHARGE	kWh	$/kWh	$/kWh	$/kWh	
Schedule GL Secondary	7,523,177,291	0.01686	0.00066	0.01752	$ 131,806,066
Schedule GL Primary	383,704,633	0.01619	0.00145	0.01764	$ 6,768,550
4. TOTAL REVENUE					$ 229,914,609

	WEATHER ADJUSTED BILLING DETERMINANTS	PROPOSED CHANGE IN REVENUE			
		PROPOSED RATES	REVENUE AT PROPOSED RATES	CHANGE IN BASE REVENUE	
				REVENUE	PERCENT
	(6)	(7)	(8) = (6) x (7)	(9) = (8) - (5)	(10) = (9) / (5)
1. CUSTOMER CHARGE	BILLS				
Schedule GL Secondary	142,697	$ 88.00	$ 12,557,333	$ -	0.0%
Schedule GL Primary	2,601	$ 88.00	$ 228,886.60	$ -	0.0%
	145,298		$ 12,786,219	$ -	
2. DEMAND CHARGE	kW	$/kW			
Schedule GL Secondary	19,731,077	3.81	$ 75,175,402	$ -	0.0%
Schedule GL Primary	930,681	3.63	$ 3,378,372	$ -	0.0%
	20,661,758		$ 78,553,774	$ -	
3. DELIVERY SERVICE CHARGE	kWh	$/kWh			
Schedule GL Secondary	7,523,177,291	0.01752	$ 131,806,066	$ -	0.0%
Schedule GL Primary	383,704,633	0.01764	$ 6,768,550	$ -	0.0%
	7,906,881,923		$ 138,574,616	$ -	
4. TOTAL REVENUE			$ 229,914,609	$ -	0.0%
5. TOTAL REVENUE ALLOCATED				$ -	
6. DIFFERENCE FROM REVENUE ALLOCATED				$ -	

BALTIMORE GAS AND ELECTRIC COMPANY
PROPOSED CHANGE IN ELECTRIC SERVICE TARIFF
SCHEDULE GL - GENERAL SERVICE LARGE
Rate Year 2 - 2022

Rate Year 2

	WEATHER ADJUSTED BILLING DETERMINANTS (1)	REVENUE AT CURRENT RATES: CURRENT RATES (2)	RIDER 25 ADJ. (a) (3)	EFFECTIVE RATES (4) = (2) + (3)	REVENUE AT CURRENT RATES (5) = (1) x (4)	WEATHER ADJUSTED BILLING DETERMINANTS (6)	PROPOSED CHANGE IN REVENUE: PROPOSED RATES (7)	REVENUE AT PROPOSED RATES (8) = (6) x (7)	CHANGE IN BASE REVENUE: REVENUE (9) = (8) - (5)	PERCENT (10) = (9) / (5)
1. CUSTOMER CHARGE	BILLS					BILLS				
Schedule GL Secondary	143,668	$ 88.00			$ 12,642,817	143,668	$ 88.00	$ 12,642,817	$ -	0.0%
Schedule GL Primary	2,619	$ 88.00			$ 230,445	2,619	$ 88.00	$ 230,444.75	$ -	0.0%
						146,287		$ 12,873,262	$ -	
2. DEMAND CHARGE	kW	$/kW				kW	$/kW			
Schedule GL Secondary	19,735,470	3.81			$ 75,192,141	19,735,470	3.81	$ 75,192,141	$ -	0.0%
Schedule GL Primary	930,129	3.63			$ 3,376,370	930,129	3.63	$ 3,376,370	$ -	0.0%
						20,665,599		$ 78,568,511	$ -	
3. DELIVERY SERVICE CHARGE	kWh	$/kWh	$/kWh	$/kWh		kWh	$/kWh			
Schedule GL Secondary	7,516,804,540	0.01752	0.00020	0.01772	$ 133,197,776	7,516,804,540	0.01772	$ 133,197,776	$ -	0.0%
Schedule GL Primary	383,399,190	0.01764	0.00020	0.01784	$ 6,839,842	383,399,190	0.01784	$ 6,839,842	$ -	0.0%
						7,900,203,730		$ 140,037,618	$ -	
4. TOTAL REVENUE					$ 231,479,391			$ 231,479,391	$ -	0.0%

5. TOTAL REVENUE ALLOCATED	$ -
6. DIFFERENCE FROM REVENUE ALLOCATED	$ -

BALTIMORE GAS AND ELECTRIC COMPANY
PROPOSED CHANGE IN ELECTRIC SERVICE TARIFF
SCHEDULE GL - GENERAL SERVICE LARGE
Rate Year 3 - 2023

Rate Year 3

	WEATHER ADJUSTED BILLING DETERMINANTS	REVENUE AT CURRENT RATES				WEATHER ADJUSTED BILLING DETERMINANTS	PROPOSED CHANGE IN REVENUE			
		CURRENT RATES	RIDER 25 ADJ. (a)	EFFECTIVE RATES	REVENUE AT CURRENT RATES		PROPOSED RATES	REVENUE AT PROPOSED RATES	CHANGE IN BASE REVENUE: REVENUE	CHANGE IN BASE REVENUE: PERCENT
	(1)	(2)	(3)	(4) = (2) + (3)	(5) = (1) x (4)	(6)	(7)	(8) = (6) x (7)	(9) = (8) - (5)	(10) = (9) / (5)
1. CUSTOMER CHARGE	BILLS					BILLS				
Schedule GL Secondary	144,640	$ 88.00			$ 12,728,302	144,640	$ 97.00	$ 14,030,060	$ 1,301,758	10.2%
Schedule GL Primary	2,636	$ 88.00			$ 232,003	2,636	$ 97.00	$ 255,730.48	$ 23,728	10.2%
						147,276		$ 14,285,791	$ 1,325,486	
2. DEMAND CHARGE	kW	$/kW				kW	$/kW			
Schedule GL Secondary	19,735,975	3.81			$ 75,194,065	19,735,975	4.50	$ 88,811,888	$ 13,617,823	18.1%
Schedule GL Primary	930,081	3.63			$ 3,376,195	930,081	4.32	$ 4,017,951	$ 641,756	19.0%
						20,666,056		$ 92,829,838	$ 14,259,579	
3. DELIVERY SERVICE CHARGE	kWh	$/kWh	$/kWh	$/kWh		kWh	$/kWh			
Schedule GL Secondary	7,516,071,931	0.01772	0.00018	0.01790	$ 134,537,688	7,516,071,931	0.01942	$ 145,962,117	$ 11,424,429	8.5%
Schedule GL Primary	383,372,434	0.01784	0.00018	0.01802	$ 6,908,371	383,372,434	0.01864	$ 7,147,289	$ 238,918	3.5%
						7,899,444,365		$ 153,109,406	$ 11,663,347	
4. TOTAL REVENUE					$ 232,976,624			$ 260,225,035	$ 27,248,411	11.7%
5. TOTAL REVENUE ALLOCATED									$ 27,250,197	
6. DIFFERENCE FROM REVENUE ALLOCATED									$ (1,786)	

(a) Effective adjustment calculated on Sheet E-15

BALTIMORE GAS AND ELECTRIC COMPANY
PROPOSED CHANGE IN ELECTRIC SERVICE TARIFF
SCHEDULE P - PRIMARY VOLTAGE SERVICE
Rate Year 1 - 2021

Rate Year 1

	WEATHER ADJUSTED BILLING DETERMINANTS (1)	REVENUE AT CURRENT RATES: CURRENT RATES (2)	REVENUE AT CURRENT RATES: REVENUE AT CURRENT RATES (3) = (1) x (2)	WEATHER ADJUSTED BILLING DETERMINANTS (4)	PROPOSED CHANGE IN REVENUE: PROPOSED RATES (5)	REVENUE AT PROPOSED RATES (6) = (4) x (5)	CHANGE IN BASE REVENUE: REVENUE (7) = (6) - (3)	CHANGE IN BASE REVENUE: PERCENT (8) = (7) / (3)
1. CUSTOMER CHARGE	BILLS			BILLS				
Schedule P	3,887	$ 600.00	$ 2,332,446	3,887	$ 600.00	$ 2,332,446	$ -	0.0%
2. DEMAND CHARGE	kW	$/kW		kW	$/kW			
Schedule P	10,745,123	2.90	$ 31,160,858	10,745,123	2.90	$ 31,160,858	$ -	0.0%
3. DELIVERY SERVICE CHARGE	kWh	$/kWh		kWh	$/kWh			
Schedule P	4,798,502,498	0.00546	$ 26,199,824	4,798,502,498	0.00546	$ 26,199,824	$ -	0.0%
4. TOTAL REVENUE			$ 59,693,128			$ 59,693,128	$ -	0.0%

5. TOTAL REVENUE ALLOCATED	$ -
6. DIFFERENCE FROM REVENUE ALLOCATED	$ -

BALTIMORE GAS AND ELECTRIC COMPANY
PROPOSED CHANGE IN ELECTRIC SERVICE TARIFF
SCHEDULE P - PRIMARY VOLTAGE SERVICE
Rate Year 2 - 2022

Rate Year 2

	WEATHER ADJUSTED BILLING DETERMINANTS (1)	REVENUE AT CURRENT RATES: CURRENT RATES (2)	REVENUE AT CURRENT RATES: REVENUE AT CURRENT RATES (3) = (1) x (2)	WEATHER ADJUSTED BILLING DETERMINANTS (4)	PROPOSED CHANGE IN REVENUE: PROPOSED RATES (5)	PROPOSED CHANGE IN REVENUE: REVENUE AT PROPOSED RATES (6) = (4) x (5)	CHANGE IN BASE REVENUE: REVENUE (7) = (6) - (3)	CHANGE IN BASE REVENUE: PERCENT (8) = (7) / (3)
1. CUSTOMER CHARGE	BILLS			BILLS				
Schedule P	3,838	$ 600.00	$ 2,302,614	3,838	$ 600.00	$ 2,302,614	$ -	0.0%
2. DEMAND CHARGE	kW	$/kW		kW	$/kW			
Schedule P	10,612,519	2.90	$ 30,776,304	10,612,519	2.90	$ 30,776,304	$ -	0.0%
3. DELIVERY SERVICE CHARGE	kWh	$/kWh		kWh	$/kWh			
Schedule P	4,734,217,945	0.00546	$ 25,848,830	4,734,217,945	0.00546	$ 25,848,830	$ -	0.0%
4. TOTAL REVENUE			$ 58,927,748			$ 58,927,748	$ -	0.0%
5. TOTAL REVENUE ALLOCATED							$ -	
6. DIFFERENCE FROM REVENUE ALLOCATED							$ -	

BALTIMORE GAS AND ELECTRIC COMPANY
PROPOSED CHANGE IN ELECTRIC SERVICE TARIFF
SCHEDULE P - PRIMARY VOLTAGE SERVICE
Rate Year 3 - 2023

Rate Year 3

	WEATHER ADJUSTED BILLING DETERMINANTS	REVENUE AT CURRENT RATES: CURRENT RATES	REVENUE AT CURRENT RATES: REVENUE AT CURRENT RATES	WEATHER ADJUSTED BILLING DETERMINANTS	PROPOSED CHANGE IN REVENUE: PROPOSED RATES	REVENUE AT PROPOSED RATES	CHANGE IN BASE REVENUE: REVENUE	CHANGE IN BASE REVENUE: PERCENT
	(1)	(2)	(3) = (1) x (2)	(4)	(5)	(6) = (4) x (5)	(7) = (6) - (3)	(8) = (7) / (3)
1. CUSTOMER CHARGE	BILLS			BILLS				
Schedule P	3,788	$ 600.00	$ 2,272,782	3,788	$ 660.00	$ 2,500,060	$ 227,278	10.0%
2. DEMAND CHARGE	kW	$/kW		kW	$/kW			
Schedule P	10,496,512	2.90	$ 30,439,885	10,496,512	3.25	$ 34,113,664	$ 3,673,779	12.1%
3. DELIVERY SERVICE CHARGE	kWh	$/kWh		kWh	$/kWh			
Schedule P	4,677,979,790	0.00546	$ 25,541,770	4,677,979,790	0.00614	$ 28,722,796	$ 3,181,026	12.5%
4. TOTAL REVENUE			$ 58,254,437			$ 65,336,520	$ 7,082,083	12.2%
				5. TOTAL REVENUE ALLOCATED			$ 7,075,016	
				6. DIFFERENCE FROM REVENUE ALLOCATED			$ 7,067	

BALTIMORE GAS AND ELECTRIC COMPANY
PROPOSED CHANGE IN ELECTRIC SERVICE TARIFF
SCHEDULE T - RESIDENTIAL SERVICE
Rate Year 1 - 2021

Rate Year 1

	WEATHER ADJUSTED BILLING DETERMINANTS (1)	REVENUE AT CURRENT RATES: CURRENT RATES (2)	REVENUE AT CURRENT RATES: REVENUE AT CURRENT RATES (3) = (1) x (2)	WEATHER ADJUSTED BILLING DETERMINANTS (4)	PROPOSED CHANGES IN REVENUE: PROPOSED RATES (5)	REVENUE AT PROPOSED RATES (6) = (4) x (5)	CHANGE IN BASE REVENUE: REVENUE (7) = (6) - (3)	CHANGE IN BASE REVENUE: PERCENT (8) = (7) / (3)
1. CUSTOMER CHARGE	BILLS			BILLS				
Schedule T	72	$ 2,400.00	$ 172,800	72	$ 2,400.00	$ 172,800	$ -	0.0%
2. DELIVERY SERVICE CHARGE	kWh	$/kWh		kWh	$/kWh			
Schedule T	690,138,004	0.00315	$ 2,173,935	690,138,004	0.00315	$ 2,173,935	$ -	0.0%
3. TOTAL REVENUE			$ 2,346,735			$ 2,346,735	$ -	0.0%
4. TOTAL REVENUE ALLOCATED							$ -	
5. DIFFERENCE FROM REVENUE ALLOCATED							$ -	

COMPANY EXHIBIT LFK-2
SUPPLEMENT 650
SHEET E-11
PAGE 2 OF 3

BALTIMORE GAS AND ELECTRIC COMPANY
PROPOSED CHANGE IN ELECTRIC SERVICE TARIFF
SCHEDULE T - RESIDENTIAL SERVICE
Rate Year 2 - 2022

Rate Year 2

	REVENUE AT CURRENT RATES			PROPOSED CHANGES IN REVENUE				
	WEATHER ADJUSTED BILLING DETERMINANTS	CURRENT RATES	REVENUE AT CURRENT RATES	WEATHER ADJUSTED BILLING DETERMINANTS	PROPOSED RATES	REVENUE AT PROPOSED RATES	CHANGE IN BASE REVENUE: REVENUE	CHANGE IN BASE REVENUE: PERCENT
	(1)	(2)	(3) = (1) x (2)	(4)	(5)	(6) = (4) x (5)	(7) = (6) - (3)	(8) = (7) / (3)
1. CUSTOMER CHARGE	BILLS			BILLS				
Schedule T	72	$ 2,400.00	$ 172,800	72	$ 2,400.00	$ 172,800	-	0.0%
2. DELIVERY SERVICE CHARGE	kWh	$/kWh		kWh	$/kWh			
Schedule T	679,567,538	0.00315	$ 2,140,638	679,567,538	0.00315	$ 2,140,638	$ -	0.0%
3. TOTAL REVENUE			$ 2,313,438			$ 2,313,438	$ -	0.0%
4. TOTAL REVENUE ALLOCATED							$ -	
5. DIFFERENCE FROM REVENUE ALLOCATED							$ -	

BALTIMORE GAS AND ELECTRIC COMPANY
PROPOSED CHANGE IN ELECTRIC SERVICE TARIFF
SCHEDULE T - RESIDENTIAL SERVICE
Rate Year 3 - 2023

COMPANY EXHIBIT LFK-2
SUPPLEMENT 650
SHEET E-11

Rate Year 3

	WEATHER ADJUSTED BILLING DETERMINANTS (1)	REVENUE AT CURRENT RATES: CURRENT RATES (2)	REVENUE AT CURRENT RATES: REVENUE AT CURRENT RATES (3) = (1) x (2)	WEATHER ADJUSTED BILLING DETERMINANTS (4)	PROPOSED CHANGES IN REVENUE: PROPOSED RATES (5)	PROPOSED CHANGES IN REVENUE: REVENUE AT PROPOSED RATES (6) = (4) x (5)	CHANGE IN BASE REVENUE: REVENUE (7) = (6) - (3)	CHANGE IN BASE REVENUE: PERCENT (8) = (7) / (3)
1. CUSTOMER CHARGE	BILLS			BILLS				
Schedule T	72	$ 2,400.00	$ 172,800	72	$ 2,400.00	$ 172,800	$ -	0.0%
2. DELIVERY SERVICE CHARGE	kWh	$/kWh		kWh	$/kWh			
Schedule T	680,401,187	0.00315	$ 2,143,264	680,401,187	0.00315	$ 2,143,264	$ -	0.0%
3. TOTAL REVENUE			$ 2,316,064			$ 2,316,064	$ -	0.0%
4. TOTAL REVENUE ALLOCATED							$ -	
5. DIFFERENCE FROM REVENUE ALLOCATED							$ -	

BALTIMORE GAS AND ELECTRIC COMPANY
PROPOSED CHANGE IN ELECTRIC SERVICE TARIFF
SCHEDULE SL - STREET LIGHTING

		REVENUE AT CURRENT RATES			PROPOSED CHANGES IN REVENUE		
	TEST YEAR BILLING DETERMINANTS	CURRENT RATES	REVENUE AT CURRENT RATES	PROPOSED RATES	REVENUE AT PROPOSED RATES	CHANGE IN BASE REVENUE: REVENUE	CHANGE IN BASE REVENUE: PERCENT
	(1)	(2)	(3) = (1) x (2)	(4)	(5) = (1) x (4)	(6) = (5) - (3)	(7) = (6) / (3)
Rate Year 1 - 2021							
		$/Lamp-Watt		$/Lamp-Watt			
1. Delivery Service Charge	464,419,356	0.00186	$ 863,820	0.00186	$ 863,820	$ -	0.0%
2. Facilities Provided by the Company							
(a) Underground Cable		$/ft. of cable		$/ft. of cable			
In Service on August 31, 1960	47,121,027	0.0268	$ 1,262,844	0.0268	$ 1,262,844	$ -	0.0%
Installed after August 31, 1960	86,284,468	0.0522	4,504,049	0.0522	$ 4,504,049	$ -	0.0%
			$ 5,766,893				
(b) Lamp Fixtures - Ornamental (underground supplied)		$/Fixture		$/Fixture			
INCANDESCENT - 250 CP AND OVER	0	2.95	$ 0	2.95	$ 0	$ -	0.0%
Mercury Vapor							
100w MV Pendant	234	5.56	1,301	5.56	$ 1,301	$ -	0.0%
100-175w MV Modern/Colonial	38,090	8.13	309,671.7	8.13	$ 309,672	$ -	0.0%
175-250w MV Pendant	6,380	7.57	48,297	7.57	$ 48,297	$ -	0.0%
250w MV Modern	12	12.53	150	12.53	$ 150	$ -	0.0%
400w MV Pendant/Flood	3,860	8.90	34,354	8.90	$ 34,354	$ -	0.0%
Sodium Vapor							
100w SV Acorn	1,153	7.61	8,774	7.61	$ 8,774	$ -	0.0%
100-150w SV Acorn ML	84	16.53	1,389	16.53	$ 1,389	$ -	0.0%
100-150w SV Colonial Premiere	1,801	8.83	15,903	8.83	$ 15,903	$ -	0.0%
100-150w SV Rectilinear/Pendant/Flood	3,426	5.94	20,350	5.94	$ 20,350	$ -	0.0%
100-150w SV Modern/Colonial/Gothic	27,452	8.29	227,577	8.29	$ 227,577	$ -	0.0%
100-150w SV Acorn HDG	110	10.13	1,114	10.13	$ 1,114	$ -	0.0%
150w SV Arlington	384	11.94	4,585	11.94	$ 4,585	$ -	0.0%
150w SV Acorn	0	7.61	0	7.61	$ 0	$ -	0.0%
150w SV Acorn-Victorian UG	0	16.82	0	16.82	$ 0	$ -	0.0%
250w SV Rectilinear/Pendant	3,665	15.87	58,164	15.87	$ 58,164	$ -	0.0%
400w SV Rectilinear/Pendant/Flood	7,312	17.63	128,911	17.63	$ 128,911	$ -	0.0%
1000w SV Rectilinier/Pendant	84	19.77	1,661	19.77	$ 1,661	$ -	0.0%
Metal Halide							
100-175w MH Post top C/P/M/G/A	177	12.35	2,186	12.35	$ 2,186	$ -	0.0%
			$ 864,387				
(c) Lamp Fixtures - Other Than Ornamental (overhead Supplied)		$/Fixture		$/Fixture			
105-205w Incandescent (in service Aug. 31, 1960)	1,260	1.14	$ 1,436	1.14	$ 1,436	$ -	0.0%
105w Incandescent (installed after 8/31/60)	40	5.06	202	5.06	$ 202	$ -	0.0%
Mercury Vapor							
100w MV Pendant	83,927	8.37	702,469	8.37	$ 702,469	$ -	0.0%
175-250w MV Pendant	35,755	9.99	357,192	9.99	$ 357,192	$ -	0.0%
400w MV Pendant/Flood	4,107	11.61	47,682	11.61	$ 47,682	$ -	0.0%
Sodium Vapor							
100-150w SV Pendant/Flood	135,747	11.67	1,584,167	11.67	$ 1,584,167	$ -	0.0%
150-250w SV Teardrop w/arm	111	46.00	5,106	46.00	$ 5,106	$ -	0.0%
250w SV Pendant	24,692	18.32	452,357	18.32	$ 452,357	$ -	0.0%
400w SV Pendant/Flood	9,240	20.21	186,740	20.21	$ 186,740	$ -	0.0%
1000w SV Pendant	30	22.70	681	22.70	$ 681	$ -	0.0%
Metal Halide							
150 - 175w MH Pendant	12	6.49	78	6.49	$ 78	$ -	0.0%
400w MH Pendant	75	8.63	647	8.63	$ 647	$ -	0.0%
400w MH Flood	24	8.26	198	8.26	$ 198	$ -	0.0%
400w MHP Flood	0	8.26	0	8.26	$ 0	$ -	0.0%
			$ 3,338,958				

BALTIMORE GAS AND ELECTRIC COMPANY
PROPOSED CHANGE IN ELECTRIC SERVICE TARIFF
SCHEDULE SL - STREET LIGHTING

	TEST YEAR BILLING DETERMINANTS (1)	REVENUE AT CURRENT RATES: CURRENT RATES (2)	REVENUE AT CURRENT RATES: REVENUE AT CURRENT RATES (3) = (1) x (2)	PROPOSED CHANGES IN REVENUE: PROPOSED RATES (4)	PROPOSED CHANGES IN REVENUE: REVENUE AT PROPOSED RATES (5) = (1) x (4)	CHANGE IN BASE REVENUE: REVENUE (6) = (5) - (3)	CHANGE IN BASE REVENUE: PERCENT (7) = (6) / (3)
(d) Lamp Fixtures - LED Fixtures		$/Fixture		$/Fixture			
70 LED Pendant	275	7.67	$ 2,109	7.67	$ 2,109	$ -	0.0%
100 LED Pendant	434,886	7.17	3,118,133	7.17	$ 3,118,133	$ -	0.0%
150 LED Pendant	178,087	7.45	1,326,748	7.45	$ 1,326,748	$ -	0.0%
200 LED Pendant	176	15.76	2,774	15.76	$ 2,774	$ -	0.0%
250 LED Pendant	86,204	10.13	873,247	10.13	$ 873,247	$ -	0.0%
400 LED Pendant	63,783	13.64	870,000	13.64	$ 870,000	$ -	0.0%
100 LED Post Top Acorn	120	22.99	2,759	22.99	$ 2,759	$ -	0.0%
150 LED Post Top Acorn	11	22.99	253	22.99	$ 253	$ -	0.0%
100 LED Post Top Decorative Acorn	0	32.05	0	32.05	$ 0	$ -	0.0%
150 LED Post Top Decorative Acorn	12	32.05	385	32.05	$ 385	$ -	0.0%
100 LED Post Top Arlington	0	26.02	0	26.02	$ 0	$ -	0.0%
100 LED Post Top Colonial	468	15.00	7,020	15.00	$ 7,020	$ -	0.0%
150 LED Post Top Arlington	0	26.02	0	26.02	$ 0	$ -	0.0%
150 LED Post Top Colonial	252	15.48	3,901	15.48	$ 3,901	$ -	0.0%
100 LED Premiere Colonial	120	16.28	1,954	16.28	$ 1,954	$ -	0.0%
150 LED Premiere Colonial	390	17.78	6,934	17.78	$ 6,934	$ -	0.0%
100 LED Post Top Modern	0	14.65	0	14.65	$ 0	$ -	0.0%
150 LED Post Top Modern	0	26.98	0	26.98	$ 0	$ -	0.0%
150 LED Tear Drop	564	30.45	17,174	30.45	$ 17,174	$ -	0.0%
250 LED Tear Drop	0	38.39	0	38.39	$ 0	$ -	0.0%
400 LED Floodlight	58	11.65	676	11.65	$ 676	$ -	0.0%
1000 LED Floodlight	24	23.32	560	23.32	$ 560	$ -	0.0%
			$ 6,234,625				
		$/Pole		$/Pole			
Arm-Longer than 4' OH	235,428	2.86	673,324	2.86	$ 673,324	$ -	0.0%
(e) Distribution Poles	112,201	3.10	347,823	3.10	$ 347,823	$ -	0.0%
(f) Underground Supplied Poles		$/Pole		$/Pole			
12-14' Wood Pole UG	2,680	4.11	$ 11,015	4.11	$ 11,015	$ -	0.0%
12' Fiberglass Pole with Shroud UG	12	15.94	191	15.94	$ 191	$ -	0.0%
12-16' aluminum/steel pole UG	9,994	4.41	44,074	4.41	$ 44,074	$ -	0.0%
12-16' Painted Metal Pole UG	922	4.89	4,509	4.89	$ 4,509	$ -	0.0%
12-14' Fiberglass Pole UG	13,116	4.89	64,137	4.89	$ 64,137	$ -	0.0%
12-14' Fluted Fiberglass Pole UG	1,756	25.89	45,463	25.89	$ 45,463	$ -	0.0%
20-30' Fiberglass Pole UG	180	12.95	2,331	12.95	$ 2,331	$ -	0.0%
UG Fed Wood Light Pole	2,486	6.54	16,258	6.54	$ 16,258	$ -	0.0%
20-25' Aluminum/Steel Pole UG	543	10.55	5,729	10.55	$ 5,729	$ -	0.0%
30' Aluminum/Steel Pole UG	1,240	11.64	14,434	11.64	$ 14,434	$ -	0.0%
25-30' Aluminum/Steel Pole - Multi-Arm UG	240	13.65	3,276	13.65	$ 3,276	$ -	0.0%
30-35' Fiberglass Pole-Arm UG	766	15.76	12,072	15.76	$ 12,072	$ -	0.0%
Arm-Longer than 4' UG	4,873	2.06	10,038	2.06	$ 10,038	$ -	0.0%
(g) 12' Concrete Pole UG (Ornamental Poles)	12	4.19	50	4.19	$ 50	$ -	0.0%
			$ 1,254,724				
Subtotal			$ 17,459,587		$ 17,459,587	$ -	0.0%

BALTIMORE GAS AND ELECTRIC COMPANY
PROPOSED CHANGE IN ELECTRIC SERVICE TARIFF
SCHEDULE SL - STREET LIGHTING

	TEST YEAR BILLING DETERMINANTS (1)	REVENUE AT CURRENT RATES: CURRENT RATES (2)	REVENUE AT CURRENT RATES: REVENUE AT CURRENT RATES (3) = (1) x (2)	PROPOSED CHANGES IN REVENUE: PROPOSED RATES (4)	REVENUE AT PROPOSED RATES (5) = (1) x (4)	CHANGE IN BASE REVENUE: REVENUE (6) = (5) - (3)	CHANGE IN BASE REVENUE: PERCENT (7) = (6) / (3)
3. Maintenance (Reactive & Preventative)							
(a) Incandescent		$/Lamp		$/Lamp			
Incandescent-Less Than 250 C.P.	1,300	1.80	$ 2,340	1.80	$ 2,340	$ -	0.0%
Incandescent-250 C.P. and over	468	2.87	$ 1,343	2.87	$ 1,343	$ -	0.0%
(b) Mercury Vapor		$/Lamp		$/Lamp			
100-400w Mercury Vapor	200,406	1.50	$ 300,609	1.50	$ 300,609	$ -	0.0%
(c) Sodium Vapor		$/Lamp		$/Lamp			
70-400w Sodium Vapor	422,165	3.22	$ 1,359,371	3.22	$ 1,359,371	$ -	0.0%
1000w Sodium Vapor	996	6.61	$ 6,584	6.61	$ 6,584	$ -	0.0%
(d) Metal Halide		$/Lamp		$/Lamp			
100-1000w Metal Halide	11,550	5.76	$ 66,528	5.76	$ 66,528	$ -	0.0%
(e) Direction Sign Fluorescent Lamps		$/Lamp		$/Lamp			
180-230w Fluorescent Lamps	0	3.77	$ 0	3.77	$ 0	$ -	0.0%
(f) Light-Emitting Diode		$/Lamp		$/Lamp			
100-400 LED	273,212	1.06	$ 289,605	1.06	$ 289,605	$ -	0.0%
Subtotal			$ 2,026,380		$ 2,026,380	$ -	0.0%
Maintenance (Reactive Only)							
(a) Incandescent		$/Lamp		$/Lamp			
Incandescent-Less Than 250 C.P. Reactive Only	7	1.66	$ 12	1.66	$ 12	$ -	0.0%
Incandescent-250 C.P. and over Reactive Only	0	2.64	$ 0	2.64	$ 0	$ -	0.0%
(b) Mercury Vapor		$/Lamp		$/Lamp			
100-400w Mercury Vapor Reactive Only	160,740	1.36	$ 218,606	1.36	$ 218,606	$ -	0.0%
(c) Sodium Vapor		$/Lamp		$/Lamp			
70-400w Sodium Vapor Reactive Only	602,616	2.95	$ 1,777,717	2.95	$ 1,777,717	$ -	0.0%
1000w Sodium Vapor Reactive Only	3,006	6.07	$ 18,246	6.07	$ 18,246	$ -	0.0%
(d) Metal Halide		$/Lamp		$/Lamp			
100-1000w Metal Halide Reactive Only	3,081	5.28	$ 16,268	5.28	$ 16,268	$ -	0.0%
(e) Direction Sign Fluorescent Lamps		$/Lamp		$/Lamp			
180-230w Fluorescent Reactive Only	0	3.46	$ 0	3.46	$ 0	$ -	0.0%
(f) Light-Emitting Diode		$/Lamp		$/Lamp			
100-400 LED	598,738	0.93	$ 556,826	0.93	$ 556,826	$ -	0.0%
Subtotal			$ 2,587,676		$ 2,587,676	$ -	0.0%
Total Revenue			$ 22,937,462		$ 22,937,462	$ -	0.0%
4. TOTAL REVENUE ALLOCATED						$ -	
5. DIFFERENCE FROM REVENUE ALLOCATED						$ -	

	TEST YEAR BILLING DETERMINANTS (1)	REVENUE AT CURRENT RATES: CURRENT RATES (2)	REVENUE AT CURRENT RATES: REVENUE AT CURRENT RATES (3) = (1) x (2)	PROPOSED CHANGES IN REVENUE: PROPOSED RATES (4)	PROPOSED CHANGES IN REVENUE: REVENUE AT PROPOSED RATES (5) = (1) x (4)	CHANGE IN BASE REVENUE: REVENUE (6) = (5) - (3)	CHANGE IN BASE REVENUE: PERCENT (7) = (6) / (3)
Rate Year 2 - 2022							
		$/Lamp-Watt		$/Lamp-Watt			
1. Delivery Service Charge	450,655,854	0.00186	$ 838,220	0.00186	$ 838,220	$ -	0.0%
2. Facilities Provided by the Company							
(a) Underground Cable		$/ft. of cable		$/ft. of cable			
In Service on August 31, 1960	47,121,027	0.0268	$ 1,262,844	0.0268	$ 1,262,844	$ -	0.0%
Installed after August 31, 1960	86,284,468	0.0522	4,504,049	0.0522	$ 4,504,049	$ -	0.0%
			$ 5,766,893				
(b) Lamp Fixtures - Ornamental (underground supplied)		$/Fixture		$/Fixture			
INCANDESCENT - 250 CP AND OVER	0	2.95	$ 0	2.95	$ 0	$ -	0.0%
Mercury Vapor							
100w MV Pendant	234	5.56	1,301	5.56	$ 1,301	$ -	0.0%
100-175w MV Modern/Colonial	38,090	8.13	309,672	8.13	$ 309,672	$ -	0.0%
175-250w MV Pendant	6,380	7.57	48,297	7.57	$ 48,297	$ -	0.0%
250w MV Modern	12	12.53	150	12.53	$ 150	$ -	0.0%
400w MV Pendant/Flood	3,860	8.90	34,354	8.90	$ 34,354	$ -	0.0%
Sodium Vapor							
100w SV Acorn	1,153	7.61	8,774	7.61	$ 8,774	$ -	0.0%
100-150w SV Acorn ML	84	16.53	1,389	16.53	$ 1,389	$ -	0.0%
100-150w SV Colonial Premiere	1,801	8.83	15,903	8.83	$ 15,903	$ -	0.0%
100-150w SV Rectilinear/Pendant/Flood	3,426	5.94	20,350	5.94	$ 20,350	$ -	0.0%
100-150w SV Modern/Colonial/Gothic	27,452	8.29	227,577	8.29	$ 227,577	$ -	0.0%
100-150w SV Acorn HDG	110	10.13	1,114	10.13	$ 1,114	$ -	0.0%
150w SV Arlington	384	11.94	4,585	11.94	$ 4,585	$ -	0.0%
150w SV Acorn	0	7.61	0	7.61	$ 0	$ -	0.0%
150w SV Acorn-Victorian UG	0	16.82	0	16.82	$ 0	$ -	0.0%
250w SV Rectilinear/Pendant	3,665	15.87	58,164	15.87	$ 58,164	$ -	0.0%
400w SV Rectilinear/Pendant/Flood	7,312	17.63	128,911	17.63	$ 128,911	$ -	0.0%
1000w SV Rectilinier/Pendant	84	19.77	1,661	19.77	$ 1,661	$ -	0.0%
Metal Halide							
100-175w MH Post top C/P/M/G/A	177	12.35	2,186	12.35	$ 2,186	$ -	0.0%
			$ 864,387				
(c) Lamp Fixtures - Other Than Ornamental (overhead Supplied)		$/Fixture		$/Fixture			
105-205w Incandescent (in service Aug. 31, 1960)	1,260	1.14	$ 1,436	1.14	$ 1,436	$ -	0.0%
105w Incandescent (installed after 8/31/60)	40	5.06	202	5.06	$ 202	$ -	0.0%
Mercury Vapor							
100w MV Pendant	83,927	8.37	702,469	8.37	$ 702,469	$ -	0.0%
175-250w MV Pendant	35,755	9.99	357,192	9.99	$ 357,192	$ -	0.0%
400w MV Pendant/Flood	4,107	11.61	47,682	11.61	$ 47,682	$ -	0.0%
Sodium Vapor							
100-150w SV Pendant/Flood	135,747	11.67	1,584,167	11.67	$ 1,584,167	$ -	0.0%
150-250w SV Teardrop w/arm	111	46.00	5,106	46.00	$ 5,106	$ -	0.0%
250w SV Pendant	24,692	18.32	452,357	18.32	$ 452,357	$ -	0.0%
400w SV Pendant/Flood	9,240	20.21	186,740	20.21	$ 186,740	$ -	0.0%
1000w SV Pendant	30	22.70	681	22.70	$ 681	$ -	0.0%
Metal Halide							
150 - 175w MH Pendant	12	6.49	78	6.49	$ 78	$ -	0.0%
400w MH Pendant	75	8.63	647	8.63	$ 647	$ -	0.0%
400w MH Flood	24	8.26	198	8.26	$ 198	$ -	0.0%
400w MHP Flood	0	8.26	0	8.26	$ 0	$ -	0.0%
			$ 3,338,958				

BALTIMORE GAS AND ELECTRIC COMPANY
PROPOSED CHANGE IN ELECTRIC SERVICE TARIFF
SCHEDULE SL - STREET LIGHTING

	TEST YEAR BILLING DETERMINANTS	REVENUE AT CURRENT RATES: CURRENT RATES	REVENUE AT CURRENT RATES: REVENUE AT CURRENT RATES	PROPOSED CHANGES IN REVENUE: PROPOSED RATES	PROPOSED CHANGES IN REVENUE: REVENUE AT PROPOSED RATES	CHANGE IN BASE REVENUE: REVENUE	CHANGE IN BASE REVENUE: PERCENT
	(1)	(2)	(3) = (1) x (2)	(4)	(5) = (1) x (4)	(6) = (5) - (3)	(7) = (6) / (3)
(d) Lamp Fixtures - LED Fixtures		$/Fixture		$/Fixture			
70 LED Pendant	275	7.67	$ 2,109	7.67	$ 2,109	$ -	0.0%
100 LED Pendant	434,886	7.17	3,118,133	7.17	$ 3,118,133	$ -	0.0%
150 LED Pendant	178,087	7.45	1,326,748	7.45	$ 1,326,748	$ -	0.0%
200 LED Pendant	176	15.76	2,774	15.76	$ 2,774	$ -	0.0%
250 LED Pendant	86,204	10.13	873,247	10.13	$ 873,247	$ -	0.0%
400 LED Pendant	63,783	13.64	870,000	13.64	$ 870,000	$ -	0.0%
100 LED Post Top Acorn	120	22.99	2,759	22.99	$ 2,759	$ -	0.0%
150 LED Post Top Acorn	11	22.99	253	22.99	$ 253	$ -	0.0%
100 LED Post Top Decorative Acorn	0	32.05	0	32.05	$ 0	$ -	0.0%
150 LED Post Top Decorative Acorn	12	32.05	385	32.05	$ 385	$ -	0.0%
100 LED Post Top Arlington	0	26.02	0	26.02	$ 0	$ -	0.0%
100 LED Post Top Colonial	468	15.00	7,020	15.00	$ 7,020	$ -	0.0%
150 LED Post Top Arlington	0	26.02	0	26.02	$ 0	$ -	0.0%
150 LED Post Top Colonial	252	15.48	3,901	15.48	$ 3,901	$ -	0.0%
100 LED Premiere Colonial	120	16.28	1,954	16.28	$ 1,954	$ -	0.0%
150 LED Premiere Colonial	390	17.78	6,934	17.78	$ 6,934	$ -	0.0%
100 LED Post Top Modern	0	14.65	0	14.65	$ 0	$ -	0.0%
150 LED Post Top Modern	0	26.98	0	26.98	$ 0	$ -	0.0%
150 LED Tear Drop	564	30.45	17,174	30.45	$ 17,174	$ -	0.0%
250 LED Tear Drop	0	38.39	0	38.39	$ 0	$ -	0.0%
400 LED Floodlight	58	11.65	676	11.65	$ 676	$ -	0.0%
1000 LED Floodlight	24	23.32	560	23.32	$ 560	$ -	0.0%
			$ 6,234,625				
		$/Pole		$/Pole			
Arm-Longer than 4' OH	235,428	2.86	673,324	2.86	$ 673,324	$ -	0.0%
(e) Distribution Poles	112,201	3.10	$ 347,823	3.10	$ 347,823	$ -	0.0%
(f) Underground Supplied Poles		$/Pole		$/Pole			
12-14' Wood Pole UG	2,680	4.11	$ 11,015	4.11	$ 11,015	$ -	0.0%
12' Fiberglass Pole with Shroud UG	12	15.94	191	15.94	$ 191	$ -	0.0%
12-16' aluminum/steel pole UG	9,994	4.41	44,074	4.41	$ 44,074	$ -	0.0%
12-16' Painted Metal Pole UG	922	4.89	4,509	4.89	$ 4,509	$ -	0.0%
12-14' Fiberglass Pole UG	13,116	4.89	64,137	4.89	$ 64,137	$ -	0.0%
12-14' Fluted Fiberglass Pole UG	1,756	25.89	45,463	25.89	$ 45,463	$ -	0.0%
20-30' Fiberglass Pole UG	180	12.95	2,331	12.95	$ 2,331	$ -	0.0%
UG Fed Wood Light Pole	2,486	6.54	16,258	6.54	$ 16,258	$ -	0.0%
20-25' Aluminum/Steel Pole UG	543	10.55	5,729	10.55	$ 5,729	$ -	0.0%
30' Aluminum/Steel Pole UG	1,240	11.64	14,434	11.64	$ 14,434	$ -	0.0%
25-30' Aluminum/Steel Pole - Multi-Arm UG	240	13.65	3,276	13.65	$ 3,276	$ -	0.0%
30-35' Fiberglass Pole-Arm UG	766	15.76	12,072	15.76	$ 12,072	$ -	0.0%
Arm-Longer than 4' UG	4,873	2.06	10,038	2.06	$ 10,038	$ -	0.0%
(g) 12' Concrete Pole UG (Ornamental Poles)	12	4.19	50	4.19	$ 50	$ -	0.0%
			$ 1,254,724				
Subtotal			$ 17,459,587		$ 17,459,587	$ -	0.0%

BALTIMORE GAS AND ELECTRIC COMPANY
PROPOSED CHANGE IN ELECTRIC SERVICE TARIFF
SCHEDULE SL - STREET LIGHTING

	TEST YEAR BILLING DETERMINANTS (1)	REVENUE AT CURRENT RATES: CURRENT RATES (2)	REVENUE AT CURRENT RATES: REVENUE AT CURRENT RATES (3) = (1) x (2)	PROPOSED CHANGES IN REVENUE: PROPOSED RATES (4)	REVENUE AT PROPOSED RATES (5) = (1) x (4)	CHANGE IN BASE REVENUE: REVENUE (6) = (5) - (3)	CHANGE IN BASE REVENUE: PERCENT (7) = (6) / (3)
3. Maintenance (Reactive & Preventative)							
(a) Incandescent		$/Lamp		$/Lamp			
Incandescent-Less Than 250 C.P.	1,300	1.80	$ 2,340	1.80	$ 2,340	$ -	0.0%
Incandescent-250 C.P. and over	468	2.87	$ 1,343	2.87	$ 1,343	$ -	0.0%
(b) Mercury Vapor		$/Lamp		$/Lamp			
100-400w Mercury Vapor	200,406	1.50	$ 300,609	1.50	$ 300,609	$ -	0.0%
(c) Sodium Vapor		$/Lamp		$/Lamp			
70-400w Sodium Vapor	422,165	3.22	$ 1,359,371	3.22	$ 1,359,371	$ -	0.0%
1000w Sodium Vapor	996	6.61	$ 6,584	6.61	$ 6,584	$ -	0.0%
(d) Metal Halide		$/Lamp		$/Lamp			
100-1000w Metal Halide	11,550	5.76	$ 66,528	5.76	$ 66,528	$ -	0.0%
(e) Direction Sign Fluorescent Lamps		$/Lamp		$/Lamp			
180-230w Fluorescent Lamps	0	3.77	$ 0	3.77	$ 0	$ -	0.0%
(f) Light-Emitting Diode		$/Lamp		$/Lamp			
100-400 LED	273,212	1.06	$ 289,605	1.06	$ 289,605	$ -	0.0%
Subtotal			$ 2,026,380		$ 2,026,380	$ -	0.0%
Maintenance (Reactive Only)							
(a) Incandescent		$/Lamp		$/Lamp			
Incandescent-Less Than 250 C.P. Reactive Only	7	1.66	$ 12	1.66	$ 12	$ -	0.0%
Incandescent-250 C.P. and over Reactive Only	0	2.64	$ 0	2.64	$ 0	$ -	0.0%
(b) Mercury Vapor		$/Lamp		$/Lamp			
100-400w Mercury Vapor Reactive Only	160,740	1.36	$ 218,606	1.36	$ 218,606	$ -	0.0%
(c) Sodium Vapor		$/Lamp		$/Lamp			
70-400w Sodium Vapor Reactive Only	602,616	2.95	$ 1,777,717	2.95	$ 1,777,717	$ -	0.0%
1000w Sodium Vapor Reactive Only	3,006	6.07	$ 18,246	6.07	$ 18,246	$ -	0.0%
(d) Metal Halide		$/Lamp		$/Lamp			
100-1000w Metal Halide Reactive Only	3,081	5.28	$ 16,268	5.28	$ 16,268	$ -	0.0%
(e) Direction Sign Fluorescent Lamps		$/Lamp		$/Lamp			
180-230w Fluorescent Reactive Only	0	3.46	$ 0	3.46	$ 0	$ -	0.0%
(f) Light-Emitting Diode		$/Lamp		$/Lamp			
100-400 LED	598,738	0.93	$ 556,826	0.93	$ 556,826	$ -	0.0%
Subtotal			$ 2,587,676		$ 2,587,676	$ -	0.0%
Total Revenue			$ 22,911,862		$ 22,911,862	$ -	0.0%
4. TOTAL REVENUE ALLOCATED						$ -	
5. DIFFERENCE FROM REVENUE ALLOCATED						$ -	

BALTIMORE GAS AND ELECTRIC COMPANY
PROPOSED CHANGE IN ELECTRIC SERVICE TARIFF
SCHEDULE SL - STREET LIGHTING

		REVENUE AT CURRENT RATES		PROPOSED CHANGES IN REVENUE			
	TEST YEAR BILLING DETERMINANTS	CURRENT RATES	REVENUE AT CURRENT RATES	PROPOSED RATES	REVENUE AT PROPOSED RATES	CHANGE IN BASE REVENUE: REVENUE	CHANGE IN BASE REVENUE: PERCENT
	(1)	(2)	(3) = (1) x (2)	(4)	(5) = (1) x (4)	(6) = (5) - (3)	(7) = (6) / (3)
Rate Year 3 - 2023							
		$/Lamp-Watt		$/Lamp-Watt			
1. Delivery Service Charge	436,892,352	0.00186	$ 812,620	0.00714	$ 3,119,411	$ 2,306,792	283.9%
2. Facilities Provided by the Company							
(a) Underground Cable		$/ft. of cable		$/ft. of cable			
In Service on August 31, 1960	47,121,027	0.0268	$ 1,262,844	0.0273	$ 1,286,404	$ 23,561	1.9%
Installed after August 31, 1960	86,284,468	0.0522	4,504,049	0.0532	$ 4,590,334	$ 86,284	1.9%
			$ 5,766,893				
(b) Lamp Fixtures - Ornamental (underground supplied)		$/Fixture		$/Fixture			
INCANDESCENT - 250 CP AND OVER	0	2.95	$ 0	3.00	$ 0	$ 0	1.8%
Mercury Vapor							
100w MV Pendant	234	5.56	1,301	5.66	$ 1,325	$ 24	1.8%
100-175w MV Modern/Colonial	38,090	8.13	309,672	8.28	$ 315,393	$ 5,721	1.8%
175-250w MV Pendant	6,380	7.57	48,297	7.71	$ 49,189	$ 892	1.8%
250w MV Modern	12	12.53	150	12.76	$ 153	$ 3	1.8%
400w MV Pendant/Flood	3,860	8.90	34,354	9.06	$ 34,989	$ 635	1.8%
Sodium Vapor							
100w SV Acorn	1,153	7.61	8,774	7.75	$ 8,936	$ 162	1.8%
100-150w SV Acorn ML	84	16.53	1,389	16.84	$ 1,414	$ 26	1.8%
100-150w SV Colonial Premiere	1,801	8.83	15,903	8.99	$ 16,197	$ 294	1.8%
100-150w SV Rectilinear/Pendant/Flood	3,426	5.94	20,350	6.05	$ 20,726	$ 376	1.8%
100-150w SV Modern/Colonial/Gothic	27,452	8.29	227,577	8.44	$ 231,783	$ 4,206	1.8%
100-150w SV Acorn HDG	110	10.13	1,114	10.32	$ 1,135	$ 21	1.8%
150w SV Arlington	384	11.94	4,585	12.16	$ 4,670	$ 85	1.8%
150w SV Acorn	0	7.61	0	7.75	$ 0	$ 0	1.8%
150w SV Acorn-Victorian UG	0	16.82	0	17.13	$ 0	$ 0	1.8%
250w SV Rectilinear/Pendant	3,665	15.87	58,164	16.16	$ 59,238	$ 1,075	1.8%
400w SV Rectilinear/Pendant/Flood	7,312	17.63	128,911	17.96	$ 131,292	$ 2,382	1.8%
1000w SV Rectilinier/Pendant	84	19.77	1,661	20.14	$ 1,691	$ 31	1.8%
Metal Halide							
100-175w MH Post top C/P/M/G/A	177	12.35	2,186	12.58	$ 2,226	$ 40	1.8%
			$ 864,387				
(c) Lamp Fixtures - Other Than Ornamental (overhead Supplied)		$/Fixture		$/Fixture			
105-205w Incandescent (in service Aug. 31, 1960)	1,260	1.14	$ 1,436	1.16	$ 1,463	$ 27	1.9%
105w Incandescent (installed after 8/31/60)	40	5.06	202	5.15	$ 206	$ 4	1.8%
Mercury Vapor							
100w MV Pendant	83,927	8.37	702,469	8.52	$ 715,444	$ 12,975	1.8%
175-250w MV Pendant	35,755	9.99	357,192	10.17	$ 363,793	$ 6,600	1.8%
400w MV Pendant/Flood	4,107	11.61	47,682	11.82	$ 48,563	$ 881	1.8%
Sodium Vapor							
100-150w SV Pendant/Flood	135,747	11.67	1,584,167	11.89	$ 1,613,435	$ 29,267	1.8%
150-250w SV Teardrop w/arm	111	46.00	5,106	46.85	$ 5,200	$ 94	1.8%
250w SV Pendant	24,692	18.32	452,357	18.66	$ 460,713	$ 8,356	1.8%
400w SV Pendant/Flood	9,240	20.21	186,740	20.58	$ 190,191	$ 3,450	1.8%
1000w SV Pendant	30	22.70	681	23.12	$ 694	$ 13	1.8%
Metal Halide							
150 - 175w MH Pendant	12	6.49	78	6.61	$ 79	$ 1	1.8%
400w MH Pendant	75	8.63	647	8.79	$ 659	$ 12	1.8%
400w MH Flood	24	8.26	198	8.41	$ 202	$ 4	1.8%
400w MHP Flood	0	8.26	0	8.41	$ 0	$ 0	1.8%
			$ 3,338,958				

BALTIMORE GAS AND ELECTRIC COMPANY
PROPOSED CHANGE IN ELECTRIC SERVICE TARIFF
SCHEDULE SL - STREET LIGHTING

	TEST YEAR BILLING DETERMINANTS	REVENUE AT CURRENT RATES: CURRENT RATES	REVENUE AT CURRENT RATES: REVENUE AT CURRENT RATES	PROPOSED CHANGES IN REVENUE: PROPOSED RATES	PROPOSED CHANGES IN REVENUE: REVENUE AT PROPOSED RATES	CHANGE IN BASE REVENUE: REVENUE	CHANGE IN BASE REVENUE: PERCENT
	(1)	(2)	(3) = (1) x (2)	(4)	(5) = (1) x (4)	(6) = (5) - (3)	(7) = (6) / (3)
(d) Lamp Fixtures - LED Fixtures		$/Fixture		$/Fixture			
70 LED Pendant	275	7.67	$ 2,109	7.81	$ 2,148	$ 39	1.8%
100 LED Pendant	434,886	7.17	3,118,133	7.30	$ 3,175,755	$ 57,622	1.8%
150 LED Pendant	178,087	7.45	1,326,748	7.59	$ 1,351,253	$ 24,505	1.8%
200 LED Pendant	176	15.76	2,774	16.05	$ 2,825	$ 51	1.8%
250 LED Pendant	86,204	10.13	873,247	10.32	$ 889,375	$ 16,129	1.8%
400 LED Pendant	63,783	13.64	870,000	13.89	$ 886,073	$ 16,073	1.8%
100 LED Post Top Acorn	120	22.99	2,759	23.41	$ 2,810	$ 51	1.8%
150 LED Post Top Acorn	11	22.99	253	23.41	$ 258	$ 5	1.8%
100 LED Post Top Decorative Acorn	0	32.05	0	32.64	$ 0	$ 0	1.8%
150 LED Post Top Decorative Acorn	12	32.05	385	32.64	$ 392	$ 7	1.8%
100 LED Post Top Arlington	0	26.02	0	26.50	$ 0	$ 0	1.8%
100 LED Post Top Colonial	468	15.00	7,020	15.28	$ 7,150	$ 130	1.8%
150 LED Post Top Arlington	0	26.02	0	26.50	$ 0	$ 0	1.8%
150 LED Post Top Colonial	252	15.48	3,901	15.77	$ 3,973	$ 72	1.8%
100 LED Premiere Colonial	120	16.28	1,954	16.58	$ 1,990	$ 36	1.8%
150 LED Premiere Colonial	390	17.78	6,934	18.11	$ 7,062	$ 128	1.8%
100 LED Post Top Modern	0	14.65	0	14.92	$ 0	$ 0	1.8%
150 LED Post Top Modern	0	26.98	0	27.48	$ 0	$ 0	1.8%
150 LED Tear Drop	564	30.45	17,174	31.01	$ 17,491	$ 317	1.8%
250 LED Tear Drop	0	38.39	0	39.10	$ 0	$ 0	1.8%
400 LED Floodlight	58	11.65	676	11.87	$ 688	$ 12	1.8%
1000 LED Floodlight	24	23.32	560	23.75	$ 570	$ 10	1.8%
			$ 6,234,625				
		$/Pole		$/Pole			
Arm-Longer than 4' OH	235,428	2.86	673,324	2.91	$ 685,755	$ 12,431	1.8%
(e) Distribution Poles	112,201	3.10	$ 347,823	3.16	$ 354,252	$ 6,429	1.8%
(f) Underground Supplied Poles		$/Pole		$/Pole			
12-14' Wood Pole UG	2,680	4.11	$ 11,015	4.19	$ 11,218	$ 203	1.8%
12' Fiberglass Pole with Shroud UG	12	15.94	191	16.23	$ 195	$ 4	1.8%
12-16' aluminum/steel pole UG	9,994	4.41	44,074	4.49	$ 44,888	$ 815	1.8%
12-16' Painted Metal Pole UG	922	4.89	4,509	4.98	$ 4,592	$ 83	1.8%
12-14' Fiberglass Pole UG	13,116	4.89	64,137	4.98	$ 65,322	$ 1,184	1.8%
12-14' Fluted Fiberglass Pole UG	1,756	25.89	45,463	26.37	$ 46,303	$ 840	1.8%
20-30' Fiberglass Pole UG	180	12.95	2,331	13.19	$ 2,374	$ 43	1.8%
UG Fed Wood Light Pole	2,486	6.54	16,258	6.66	$ 16,559	$ 300	1.8%
20-25' Aluminum/Steel Pole UG	543	10.55	5,729	10.74	$ 5,834	$ 106	1.8%
30' Aluminum/Steel Pole UG	1,240	11.64	14,434	11.86	$ 14,700	$ 267	1.8%
25-30' Aluminum/Steel Pole - Multi-Arm UG	240	13.65	3,276	13.90	$ 3,337	$ 61	1.8%
30-35' Fiberglass Pole-Arm UG	766	15.76	12,072	16.05	$ 12,295	$ 223	1.8%
Arm-Longer than 4' UG	4,873	2.06	10,038	2.10	$ 10,224	$ 186	1.8%
(g) 12' Concrete Pole UG (Ornamental Poles)	12	4.19	50	4.27	$ 51	$ 1	1.8%
			$ 1,254,724				
Subtotal			$ 17,459,587		$ 17,785,448	$ 325,862	1.9%

BALTIMORE GAS AND ELECTRIC COMPANY
PROPOSED CHANGE IN ELECTRIC SERVICE TARIFF
SCHEDULE SL - STREET LIGHTING

	TEST YEAR BILLING DETERMINANTS (1)	REVENUE AT CURRENT RATES: CURRENT RATES (2)	REVENUE AT CURRENT RATES: REVENUE AT CURRENT RATES (3) = (1) x (2)	PROPOSED CHANGES IN REVENUE: PROPOSED RATES (4)	REVENUE AT PROPOSED RATES (5) = (1) x (4)	CHANGE IN BASE REVENUE: REVENUE (6) = (5) - (3)	CHANGE IN BASE REVENUE: PERCENT (7) = (6) / (3)
3. Maintenance (Reactive & Preventative)							
(a) Incandescent		$/Lamp		$/Lamp			
Incandescent-Less Than 250 C.P.	1,300	1.80	$ 2,340	1.83	$ 2,383	$ 43	1.9%
Incandescent-250 C.P. and over	468	2.87	$ 1,343	2.92	$ 1,368	$ 25	1.8%
(b) Mercury Vapor		$/Lamp		$/Lamp			
100-400w Mercury Vapor	200,406	1.50	$ 300,609	1.53	$ 306,160	$ 5,551	1.8%
(c) Sodium Vapor		$/Lamp		$/Lamp			
70-400w Sodium Vapor	422,165	3.22	$ 1,359,371	3.28	$ 1,384,490	$ 25,119	1.8%
1000w Sodium Vapor	996	6.61	$ 6,584	6.73	$ 6,705	$ 122	1.8%
(d) Metal Halide		$/Lamp		$/Lamp			
100-1000w Metal Halide	11,550	5.76	$ 66,528	5.87	$ 67,757	$ 1,229	1.8%
(e) Direction Sign Fluorescent Lamps		$/Lamp		$/Lamp			
180-230w Fluorescent Lamps	0	3.77	$ 0	3.84	$ 0	$ 0	1.8%
(f) Light-Emitting Diode		$/Lamp		$/Lamp			
100-400 LED	273,212	1.06	$ 289,605	1.08	$ 294,960	$ 5,355	1.8%
Subtotal			$ 2,026,380		$ 2,063,823	$ 37,444	1.8%
Maintenance (Reactive Only)							
(a) Incandescent		$/Lamp		$/Lamp			
Incandescent-Less Than 250 C.P. Reactive Only	7	1.66	$ 12	1.69	$ 12	$ 0	1.8%
Incandescent-250 C.P. and over Reactive Only	0	2.64	$ 0	2.69	$ 0	$ 0	1.8%
(b) Mercury Vapor		$/Lamp		$/Lamp			
100-400w Mercury Vapor Reactive Only	160,740	1.36	$ 218,606	1.39	$ 222,641	$ 4,035	1.8%
(c) Sodium Vapor		$/Lamp		$/Lamp			
70-400w Sodium Vapor Reactive Only	602,616	2.95	$ 1,777,717	3.00	$ 1,810,560	$ 32,843	1.8%
1000w Sodium Vapor Reactive Only	3,006	6.07	$ 18,246	6.18	$ 18,583	$ 337	1.8%
(d) Metal Halide		$/Lamp		$/Lamp			
100-1000w Metal Halide Reactive Only	3,081	5.28	$ 16,268	5.38	$ 16,568	$ 300	1.8%
(e) Direction Sign Fluorescent Lamps		$/Lamp		$/Lamp			
180-230w Fluorescent Reactive Only	0	3.46	$ 0	3.52	$ 0	$ 0	1.8%
(f) Light-Emitting Diode		$/Lamp		$/Lamp			
100-400 LED	598,738	0.93	$ 556,826	0.95	$ 567,125	$ 10,298	1.8%
Subtotal			$ 2,587,676		$ 2,635,489	$ 47,813	1.8%
Total Revenue			$ 22,886,262		$ 25,604,172	$ 2,717,910	11.9%
4. TOTAL REVENUE ALLOCATED						$ 2,718,620	
5. DIFFERENCE FROM REVENUE ALLOCATED						$ (710)	

BALTIMORE GAS AND ELECTRIC COMPANY
PROPOSED CHANGE IN ELECTRIC SERVICE TARIFF
SCHEDULE PL - PRIVATE AREA LIGHTING

				REVENUE AT CURRENT RATES		PROPOSED CHANGE IN REVENUE			
	TEST YEAR BILLING DETERMINANTS	CURRENT DELIVERY RATES (a)	CURRENT TOTAL RATES	TOTAL REVENUE AT CURRENT RATES	BASE REVENUE AT CURRENT RATES	PROPOSED RATES	REVENUE AT PROPOSED RATES	CHANGE IN BASE REVENUE: REVENUE	CHANGE IN BASE REVENUE: PERCENT
	(1)	(1a)	(2)	(3) = (1) x (2)	(4) = (1) x (1a)	(5)	(6) = (1) x (5)	(7) = (6) - (3)	(8) = (7) / (4)
Rate Year 1 - 2021									
1. Overhead Fixtures	Fixtures		$/Fixture		$/Fixture	$/Fixture			
100w MV Pendant	3,528	$ 7.11	$ 9.06	$ 31,964	$ 25,084	$ 9.06	$ 31,964	$ -	0.0%
175w MV Pendant	10,069	$ 7.44	$ 10.86	109,349	$ 74,913	$ 10.86	109,349	-	0.0%
400w MV Pend/Flood	10,128	$ 8.58	$ 16.15	163,567	$ 86,898	$ 16.15	163,567	-	0.0%
1000w MV Pendant	1,111	$ 11.66	$ 29.83	33,141	$ 12,954	$ 29.83	33,141	-	0.0%
100w SV Flood	541	$ 8.60	$ 10.60	5,735	$ 4,653	$ 10.60	5,735	-	0.0%
100w SV Pendant	2,256	$ 7.07	$ 9.07	20,462	$ 15,950	$ 9.07	20,462	-	0.0%
150w SV Pendant	19,535	$ 7.68	$ 10.56	206,290	$ 150,029	$ 10.56	206,290	-	0.0%
250w SV Pendant	4,326	$ 12.64	$ 17.61	76,181	$ 54,681	$ 17.61	76,181	-	0.0%
400w SV Flood	53,814	$ 10.08	$ 17.86	961,118	$ 542,445	$ 17.86	961,118	-	0.0%
400w SV Pendant	39,899	$ 10.08	$ 17.86	712,596	$ 402,182	$ 17.86	712,596	-	0.0%
1000w SV Pendant	749	$ 28.36	$ 47.20	35,353	$ 21,242	$ 47.20	35,353	-	0.0%
150w MHP Teardrop	120	$ 22.94	$ 26.09	3,131	$ 2,753	$ 26.09	3,131	-	0.0%
150w MHP Pendant	487	$ 14.73	$ 17.88	8,708	$ 7,174	$ 17.88	8,708	-	0.0%
175w MH Pendant	898	$ 14.42	$ 17.84	16,020	$ 12,949	$ 17.84	16,020	-	0.0%
400w MH Spot	24	$ 20.26	$ 27.68	664	$ 486	$ 27.68	664	-	0.0%
400w MH Flood	15,515	$ 20.26	$ 27.68	429,455	$ 314,334	$ 27.68	429,455	-	0.0%
400w MH Pendant	4,884	$ 19.95	$ 27.37	133,675	$ 97,436	$ 27.37	133,675	-	0.0%
400w MHP Flood	4,664	$ 20.21	$ 27.68	129,100	$ 94,259	$ 27.68	129,100	-	0.0%
400w MHP Pend-Gray	2,211	$ 19.90	$ 27.37	60,515	$ 43,999	$ 27.37	60,515	-	0.0%
1000w MH Pend/Flood	15,691	$ 26.29	$ 44.46	697,622	$ 412,516	$ 44.46	697,622	-	0.0%
Arm-Longer than 4'	24,814	$ 3.68	$ 3.68	91,316	$ 91,316	$ 3.68	91,316	-	0.0%
Overhead Wire	43,434	$ 1.60	$ 1.60	69,487	$ 69,487	$ 1.60	69,487	-	0.0%
Light Only Wood Pole	43,843	$ 3.67	$ 3.67	160,834	$ 160,834	$ 3.67	160,834	-	0.0%
Subtotal	302,541			$ 4,156,281	$ 2,698,573		$ 4,156,281	$ -	0.0%

BALTIMORE GAS AND ELECTRIC COMPANY
PROPOSED CHANGE IN ELECTRIC SERVICE TARIFF
SCHEDULE PL - PRIVATE AREA LIGHTING

				REVENUE AT CURRENT RATES		PROPOSED CHANGE IN REVENUE			
								CHANGE IN BASE REVENUE	
	TEST YEAR BILLING DETERMINANTS	CURRENT DELIVERY RATES (a)	CURRENT TOTAL RATES	TOTAL REVENUE AT CURRENT RATES	BASE REVENUE AT CURRENT RATES	PROPOSED RATES	REVENUE AT PROPOSED RATES	REVENUE	PERCENT
	(1)	(1a)	(2)	(3) = (1) x (2)	(4) = (1) x (1a)	(5)	(6) = (1) x (5)	(7) = (6) - (3)	(8) = (7) / (4)
2. Underground Fixtures									
175w MV Mod/Col	23,775	$ 8.76	$ 12.18	$ 289,580	$ 208,269	$ 12.18	$ 289,580	$ -	0.0%
400w MV Pend/Flood	915	$ 6.23	$ 13.80	12,627	$ 5,700	$ 13.80	12,627	-	0.0%
100w SV Mod/Col	13,656	$ 8.64	$ 10.64	145,300	$ 117,988	$ 10.64	145,300	-	0.0%
100w SV Flood	63	$ 6.35	$ 8.35	526	$ 400	$ 8.35	526	-	0.0%
100w SV Gothic	228	$ 12.34	$ 14.34	3,270	$ 2,814	$ 14.34	3,270	-	0.0%
100w SV Acorn	1,380	$ 12.38	$ 14.38	19,844	$ 17,084	$ 14.38	19,844	-	0.0%
100w SV Acorn HDG	1,080	$ 13.79	$ 15.79	17,053	$ 14,893	$ 15.79	17,053	-	0.0%
100w SV Colonial PR	2,667	$ 12.93	$ 14.93	39,818	$ 34,484	$ 14.93	39,818	-	0.0%
100w SV Acorn ML	257	$ 15.33	$ 17.33	4,454	$ 3,940	$ 17.33	4,454	-	0.0%
100w SV Pendant	48	$ 6.35	$ 8.35	401	$ 305	$ 8.35	401	-	0.0%
150w SV Mod/Col	116,664	$ 8.80	$ 11.68	1,362,636	$ 1,026,643	$ 11.68	1,362,636	-	0.0%
150w SV Pendant	4,202	$ 5.30	$ 8.18	34,372	$ 22,271	$ 8.18	34,372	-	0.0%
150w SV Rectilinear	5,737	$ 14.44	$ 17.32	99,365	$ 82,842	$ 17.32	99,365	-	0.0%
150w SV Acorn	79,080	$ 13.03	$ 15.91	1,258,163	$ 1,030,412	$ 15.91	1,258,163	-	0.0%
150w SV Gothic	7,638	$ 13.03	$ 15.91	121,521	$ 99,523	$ 15.91	121,521	-	0.0%
150w SV Acorn Vict	432	$ 23.81	$ 26.69	11,530	$ 10,286	$ 26.69	11,530	-	0.0%
150w SV Colonial PR	10,706	$ 13.55	$ 16.43	175,900	$ 145,066	$ 16.43	175,900	-	0.0%
150w SV Acorn HDG	2,912	$ 14.45	$ 17.33	50,465	$ 42,078	$ 17.33	50,465	-	0.0%
150w SV Acorn ML	3,178	$ 16.12	$ 19.00	60,382	$ 51,229	$ 19.00	60,382	-	0.0%
150w SV Teardrop	72	$ 32.06	$ 34.94	2,516	$ 2,308	$ 34.94	2,516	-	0.0%
250w SV Pendant	5,538	$ 9.64	$ 14.61	80,910	$ 53,386	$ 14.61	80,910	-	0.0%
250w SV Teardrop	476	$ 39.80	$ 44.77	21,311	$ 18,945	$ 44.77	21,311	-	0.0%
400w SV Flood	12,860	$ 7.68	$ 15.46	198,816	$ 98,765	$ 15.46	198,816	-	0.0%
400w SV Pendant	20,454	$ 7.68	$ 15.46	316,219	$ 157,087	$ 15.46	316,219	-	0.0%
400w SV Rectilinear	12,629	$ 19.59	$ 27.37	345,656	$ 247,402	$ 27.37	345,656	-	0.0%
1000w SV Pendant	70	$ 23.46	$ 42.30	2,961	$ 1,642	$ 42.30	2,961	-	0.0%
100w MH Colonial	582	$ 12.75	$ 14.90	8,672	$ 7,421	$ 14.90	8,672	-	0.0%
100w MH Acorn ML	663	$ 20.89	$ 23.04	15,276	$ 13,850	$ 23.04	15,276	-	0.0%
100w MH Acorn HDG	836	$ 18.83	$ 20.98	17,539	$ 15,742	$ 20.98	17,539	-	0.0%
100w MH Acorn	3,479	$ 17.43	$ 19.58	68,119	$ 60,639	$ 19.58	68,119	-	0.0%
100w MH Gothic	36	$ 17.48	$ 19.63	707	$ 629	$ 19.63	707	-	0.0%
100w MH Towson Green	72	$ 20.68	$ 22.83	1,644	$ 1,489	$ 22.83	1,644	-	0.0%
175w MH Acorn ML	2,190	$ 23.86	$ 27.01	59,152	$ 52,253	$ 27.01	59,152	-	0.0%
150w MHP Modern	60	$ 15.57	$ 18.72	1,123	$ 934	$ 18.72	1,123	-	0.0%
150w MHP Pendant	96	$ 13.63	$ 16.78	1,611	$ 1,308	$ 16.78	1,611	-	0.0%

BALTIMORE GAS AND ELECTRIC COMPANY
PROPOSED CHANGE IN ELECTRIC SERVICE TARIFF
SCHEDULE PL - PRIVATE AREA LIGHTING

	TEST YEAR BILLING DETERMINANTS	CURRENT DELIVERY RATES (a)	CURRENT TOTAL RATES	REVENUE AT CURRENT RATES: TOTAL REVENUE AT CURRENT RATES	REVENUE AT CURRENT RATES: BASE REVENUE AT CURRENT RATES	PROPOSED CHANGE IN REVENUE: PROPOSED RATES	PROPOSED CHANGE IN REVENUE: REVENUE AT PROPOSED RATES	CHANGE IN BASE REVENUE: REVENUE	CHANGE IN BASE REVENUE: PERCENT
	(1)	(1a)	(2)	(3) = (1) x (2)	(4) = (1) x (1a)	(5)	(6) = (1) x (5)	(7) = (6) - (3)	(8) = (7) / (4)
150w MHP Acorn	25,648	$ 19.42	$ 22.57	578,875	$ 498,084	$ 22.57	578,875	-	0.0%
150w MHP Acorn HDG	2,428	$ 20.84	$ 23.99	58,248	$ 50,600	$ 23.99	58,248	-	0.0%
150w MHP Colonial	7,353	$ 14.26	$ 17.41	128,016	$ 104,854	$ 17.41	128,016	-	0.0%
150w MHP Gothic	2,697	$ 19.42	$ 22.57	60,871	$ 52,376	$ 22.57	60,871	-	0.0%
150w MHP Colonial PR	2,940	$ 15.99	$ 19.14	56,272	$ 47,011	$ 19.14	56,272	-	0.0%
150w MHP Rectilinear	984	$ 18.24	$ 21.39	21,048	$ 17,948	$ 21.39	21,048	-	0.0%
150w MHP Teardrop	1,466	$ 22.88	$ 26.03	38,160	$ 33,542	$ 26.03	38,160	-	0.0%
175w MH Acorn	45,699	$ 19.11	$ 22.53	1,029,598	$ 873,308	$ 22.53	1,029,598	-	0.0%
175w MH Colonial	5,130	$ 13.95	$ 17.37	89,108	$ 71,564	$ 17.37	89,108	-	0.0%
175w MH Up Lighting	642	$ 25.50	$ 28.92	18,567	$ 16,371	$ 28.92	18,567	-	0.0%
175w MH Gothic	5,891	$ 19.11	$ 22.53	132,724	$ 112,577	$ 22.53	132,724	-	0.0%
175w MH Modern	60	$ 15.25	$ 18.67	1,120	$ 915	$ 18.67	1,120	-	0.0%
175w MH Pendant	133	$ 13.32	$ 16.74	2,226	$ 1,772	$ 16.74	2,226	-	0.0%
175w MH Rectilinear	551	$ 17.96	$ 21.38	11,780	$ 9,896	$ 21.38	11,780	-	0.0%
175w MH Acorn HDG	708	$ 20.52	$ 23.94	16,950	$ 14,528	$ 23.94	16,950	-	0.0%
150w MHP Acorn ML	2,215	$ 23.54	$ 26.96	59,716	$ 52,141	$ 26.96	59,716	-	0.0%
175w MH Colonial PR	768	$ 15.67	$ 19.09	14,661	$ 12,035	$ 19.09	14,661	-	0.0%
400w MHP Rectilinear	12,390	$ 21.12	$ 28.59	354,230	$ 261,677	$ 28.59	354,230	-	0.0%
400w MHP Flood	1,602	$ 14.10	$ 21.57	34,555	$ 22,588	$ 21.57	34,555	-	0.0%
400w MHP Pend-Bronze	2,544	$ 15.97	$ 23.44	59,631	$ 40,628	$ 23.44	59,631	-	0.0%
400w MHP Pend-Gray	578	$ 16.57	$ 24.04	13,895	$ 9,577	$ 24.04	13,895	-	0.0%
400w MH Flood	4,088	$ 14.15	$ 21.57	88,178	$ 57,845	$ 21.57	88,178	-	0.0%
400w MH Pend Bronze	921	$ 16.03	$ 23.45	21,597	$ 14,764	$ 23.45	21,597	-	0.0%
400w MH Rectilinear	9,406	$ 21.19	$ 28.61	269,106	$ 199,313	$ 28.61	269,106	-	0.0%
400w MH Pend Gray	2,135	$ 16.66	$ 24.08	51,411	$ 35,569	$ 24.08	51,411	-	0.0%
1000w MH Pend/Flood	5,668	$ 22.41	$ 40.58	230,007	$ 127,020	$ 40.58	230,007	-	0.0%
1000w MH Rectilinear	2,953	$ 38.06	$ 56.23	166,047	$ 112,391	$ 56.23	166,047	-	0.0%
Arm-Longer than 4'	2,756	$ 3.65	$ 3.65	10,059	$ 10,059	$ 3.65	10,059	-	0.0%
Subtotal	485,085			$ 8,466,093	$ 6,510,981		$ 8,466,093	$ -	0.0%

BALTIMORE GAS AND ELECTRIC COMPANY
PROPOSED CHANGE IN ELECTRIC SERVICE TARIFF
SCHEDULE PL - PRIVATE AREA LIGHTING

				REVENUE AT CURRENT RATES		PROPOSED CHANGE IN REVENUE			
								CHANGE IN BASE REVENUE	
	TEST YEAR BILLING DETERMINANTS	CURRENT DELIVERY RATES (a)	CURRENT TOTAL RATES	TOTAL REVENUE AT CURRENT RATES	BASE REVENUE AT CURRENT RATES	PROPOSED RATES	REVENUE AT PROPOSED RATES	REVENUE	PERCENT
	(1)	(1a)	(2)	(3) = (1) x (2)	(4) = (1) x (1a)	(5)	(6) = (1) x (5)	(7) = (6) - (3)	(8) = (7) / (4)
3. LED Fixtures									
LED 70 Pendant - 39	34	$ 8.69	$ 9.34	$ 317.56	$ 295	$ 9.34	318	-	0.0%
LED 100 Pendant - 51	60	$ 7.20	$ 8.05	483	$ 432	$ 8.05	483	-	0.0%
LED 100 Pendant - 72	921	$ 8.69	$ 9.89	9,109	$ 8,003	$ 9.89	9,109	-	0.0%
LED 100 Post Top Acorn	597	$ 24.33	$ 25.50	15,224	$ 14,525	$ 25.50	15,224	-	0.0%
LED 100 Post Top Arlington	0	$ 27.41	$ 28.61	-	$ -	$ 28.61	-	-	
LED 100 Post Top Colonial	1,038	$ 16.17	$ 17.37	18,030	$ 16,784	$ 17.37	18,030	-	0.0%
LED 100 Post Top Modern	279	$ 15.82	$ 16.72	4,665	$ 4,414	$ 16.72	4,665	-	0.0%
LED 100 Post Top Decorative Acorn	394	$ 33.56	$ 34.73	13,684	$ 13,223	$ 34.73	13,684	-	0.0%
LED 100 Premiere Colonial	0	$ 17.48	$ 18.35	-	$ -	$ 18.35	-	-	
LED 150 Pendant - 72	986	$ 8.08	$ 9.28	9,150	$ 7,967	$ 9.28	9,150	-	0.0%
LED 150 Pendant - 88	1,072	$ 8.87	$ 10.34	11,084	$ 9,509	$ 10.34	11,084	-	0.0%
LED 150 Post Top Arlington	911	$ 27.42	$ 29.15	26,556	$ 24,980	$ 29.15	26,556	-	0.0%
LED 150 Post Top Colonial	12,848	$ 16.66	$ 18.43	236,789	$ 214,048	$ 18.43	236,789	-	0.0%
LED 150 Post Top Acorn	9,114	$ 24.32	$ 26.00	236,964	$ 221,652	$ 26.00	236,964	-	0.0%
LED 150 Post Top Decorative Acorn	386	$ 33.56	$ 35.24	13,603	$ 12,954	$ 35.24	13,603	-	0.0%
LED 150 Tear Drop	0	$ 31.93	$ 33.36	-	$ -	$ 33.36	-	-	
LED 150 Premiere Colonial	379	$ 19.01	$ 20.26	7,679	$ 7,205	$ 20.26	7,679	-	0.0%
LED 250 Pendant - 129	1,946	$ 11.18	$ 13.33	25,940	$ 21,756	$ 13.33	25,940	-	0.0%
LED 250 Pendant - 145	217	$ 11.24	$ 13.66	2,964	$ 2,439	$ 13.66	2,964	-	0.0%
LED 250 Tear Drop	30	$ 40.03	$ 42.55	1,277	$ 1,201	$ 42.55	1,277	-	0.0%
LED 400 Pendant - 157	2,878	$ 13.97	$ 16.59	47,746	$ 40,206	$ 16.59	47,746	-	0.0%
LED 400 Pendant - 273	10,013	$ 15.61	$ 20.16	201,862	$ 156,303	$ 20.16	201,862	-	0.0%
LED 400 Floodlight - 129	12,210	$ 12.77	$ 14.92	182,173	$ 155,922	$ 14.92	182,173	-	0.0%
LED 1000 Floodlight - 256	12,162	$ 24.67	$ 28.94	351,968	300,037	$ 28.94	351,968	-	0.0%
Subtotal	68,475			$ 1,417,266	$ 1,233,854		$ 1,417,266	$ -	0.0%

BALTIMORE GAS AND ELECTRIC COMPANY
PROPOSED CHANGE IN ELECTRIC SERVICE TARIFF
SCHEDULE PL - PRIVATE AREA LIGHTING

	TEST YEAR BILLING DETERMINANTS	CURRENT DELIVERY RATES (a)	CURRENT TOTAL RATES	REVENUE AT CURRENT RATES: TOTAL REVENUE AT CURRENT RATES	REVENUE AT CURRENT RATES: BASE REVENUE AT CURRENT RATES	PROPOSED CHANGE IN REVENUE: PROPOSED RATES	PROPOSED CHANGE IN REVENUE: REVENUE AT PROPOSED RATES	CHANGE IN BASE REVENUE: REVENUE	CHANGE IN BASE REVENUE: PERCENT
	(1)	(1a)	(2)	(3) = (1) x (2)	(4) = (1) x (1a)	(5)	(6) = (1) x (5)	(7) = (6) - (3)	(8) = (7) / (4)
4. Underground Supplied Poles			$/Pole			$/Pole			
12-14' Wood Pole	9,783	$ 15.66	$ 15.66	153,222	$ 153,222	$ 15.66	153,222	-	0.0%
12' Fiberglass Pole	2,324	$ 15.66	$ 15.66	36,399	$ 36,399	$ 15.66	36,399	-	0.0%
12' Fib Pole-Shroud	3,225	$ 25.70	$ 25.70	82,883	$ 82,883	$ 25.70	82,883	-	0.0%
14' Fiberglass Pole	311,525	$ 15.66	$ 15.66	4,879,114	$ 4,879,114	$ 15.66	4,879,114	-	0.0%
14' Fib Hinged Pole	36,316	$ 21.65	$ 21.65	786,378	$ 786,378	$ 21.65	786,378	-	0.0%
14' Fib Fluted Pole	27,958	$ 30.85	$ 30.85	862,504	$ 862,504	$ 30.85	862,504	-	0.0%
20' Bronze Fib Pole	6,083	$ 24.90	$ 24.90	151,467	$ 151,467	$ 24.90	151,467	-	0.0%
23' Fib Pole-Shroud	1,801	$ 32.79	$ 32.79	59,055	$ 59,055	$ 32.79	59,055	-	0.0%
25' Metal Pole	2,298	$ 25.99	$ 25.99	59,725	$ 59,725	$ 25.99	59,725	-	0.0%
30' Metal Pole	25,673	$ 22.01	$ 22.01	565,063	$ 565,063	$ 22.01	565,063	-	0.0%
30' Fib Pole	11,308	$ 26.79	$ 26.79	302,941	$ 302,941	$ 26.79	302,941	-	0.0%
30' Fib Pole-Arm	21,862	$ 29.54	$ 29.54	645,803	$ 645,803	$ 29.54	645,803	-	0.0%
30' Gray Fib Pole	0	$ 26.79	$ 26.79	-	$ -	$ 26.79	-	-	
Light Only Wood Pole	8,207	$ 18.00	$ 18.00	147,726	$ 147,726	$ 18.00	147,726	-	0.0%
35' Bronze Fib Pole	1,814	$ 27.08	$ 27.08	49,123	$ 49,123	$ 27.08	49,123	-	0.0%
32-35' Steel Pole-CB	3,858	$ 26.92	$ 26.92	103,857	$ 103,857	$ 26.92	103,857	-	0.0%
30' Bronze Alum Pole	468	$ 41.63	$ 41.63	19,483	$ 19,483	$ 41.63	19,483	-	0.0%
Subtotal	474,503			$ 8,904,742	$ 8,904,742		$ 8,904,742	$ -	0.0%
5. Miscellaneous Equipment			$/Item			$/Item			
Three or Four Way Bracket	63	$ 4.18	$ 4.18	$ 263	$ 263	$ 4.18	$ 263	$ -	0.0%
60 amp Photo Control Relay	12	$ 14.27	$ 14.27	$ 171	$ 171	$ 14.27	171	-	0.0%
100 amp Photo Control Relay UG	117	$ 22.70	$ 22.70	$ 2,656	$ 2,656	$ 22.70	2,656	-	0.0%
100 amp Photo Control Relay OH	24	$ 22.70	$ 22.70	$ 545	$ 545	$ 22.70	545	-	0.0%
Subtotal	216			$ 3,635	$ 3,635		$ 3,635	$ -	0.0%
Base Revenue				$ 22,948,017	$ 19,351,786		$ 22,948,017	$ -	0.0%
			5. TOTAL REVENUE ALLOCATED					$ -	
			6. DIFFERENCE FROM REVENUE ALLOCATED					$ -	

(a) Current Delivery rates as authorized in Case No. 9355
(b) Current Supply rates as approved in Supplement 642.

BALTIMORE GAS AND ELECTRIC COMPANY
PROPOSED CHANGE IN ELECTRIC SERVICE TARIFF
SCHEDULE PL - PRIVATE AREA LIGHTING

	TEST YEAR BILLING DETERMINANTS	CURRENT DELIVERY RATES (a)	CURRENT TOTAL RATES	REVENUE AT CURRENT RATES: TOTAL REVENUE AT CURRENT RATES	REVENUE AT CURRENT RATES: BASE REVENUE AT CURRENT RATES	PROPOSED CHANGE IN REVENUE: PROPOSED RATES	PROPOSED CHANGE IN REVENUE: REVENUE AT PROPOSED RATES	CHANGE IN BASE REVENUE: REVENUE	CHANGE IN BASE REVENUE: PERCENT
	(1)	(1a)	(2)	(3) = (1) x (2)	(4) = (1) x (1a)	(5)	(6) = (1) x (5)	(7) = (6) - (3)	(8) = (7) / (4)
Rate Year 2 - 2022									
1. Overhead Fixtures	Fixtures		$/Fixture		$/Fixture	$/Fixture			
100w MV Pendant	3,528	$ 7.11	$ 9.06	$ 31,964	$ 25,084	$ 9.06	$ 31,964	$ -	0.0%
175w MV Pendant	10,069	$ 7.44	$ 10.86	$ 109,349	$ 74,913	$ 10.86	$ 109,349	-	0.0%
400w MV Pend/Flood	10,128	$ 8.58	$ 16.15	$ 163,567	$ 86,898	$ 16.15	$ 163,567	-	0.0%
1000w MV Pendant	1,111	$ 11.66	$ 29.83	$ 33,141	$ 12,954	$ 29.83	$ 33,141	-	0.0%
100w SV Flood	541	$ 8.60	$ 10.60	$ 5,735	$ 4,653	$ 10.60	$ 5,735	-	0.0%
100w SV Pendant	2,256	$ 7.07	$ 9.07	$ 20,462	$ 15,950	$ 9.07	$ 20,462	-	0.0%
150w SV Pendant	19,535	$ 7.68	$ 10.56	$ 206,290	$ 150,029	$ 10.56	$ 206,290	-	0.0%
250w SV Pendant	4,326	$ 12.64	$ 17.61	$ 76,181	$ 54,681	$ 17.61	$ 76,181	-	0.0%
400w SV Flood	53,814	$ 10.08	$ 17.86	$ 961,118	$ 542,445	$ 17.86	$ 961,118	-	0.0%
400w SV Pendant	39,899	$ 10.08	$ 17.86	$ 712,596	$ 402,182	$ 17.86	$ 712,596	-	0.0%
1000w SV Pendant	749	$ 28.36	$ 47.20	$ 35,353	$ 21,242	$ 47.20	$ 35,353	-	0.0%
150w MHP Teardrop	120	$ 22.94	$ 26.09	$ 3,131	$ 2,753	$ 26.09	$ 3,131	-	0.0%
150w MHP Pendant	487	$ 14.73	$ 17.88	$ 8,708	$ 7,174	$ 17.88	$ 8,708	-	0.0%
175w MH Pendant	898	$ 14.42	$ 17.84	$ 16,020	$ 12,949	$ 17.84	$ 16,020	-	0.0%
400w MH Spot	24	$ 20.26	$ 27.68	$ 664	$ 486	$ 27.68	$ 664	-	0.0%
400w MH Flood	15,515	$ 20.26	$ 27.68	$ 429,455	$ 314,334	$ 27.68	$ 429,455	-	0.0%
400w MH Pendant	4,884	$ 19.95	$ 27.37	$ 133,675	$ 97,436	$ 27.37	$ 133,675	-	0.0%
400w MHP Flood	4,664	$ 20.21	$ 27.68	$ 129,100	$ 94,259	$ 27.68	$ 129,100	-	0.0%
400w MHP Pend-Gray	2,211	$ 19.90	$ 27.37	$ 60,515	$ 43,999	$ 27.37	$ 60,515	-	0.0%
1000w MH Pend/Flood	15,691	$ 26.29	$ 44.46	$ 697,622	$ 412,516	$ 44.46	$ 697,622	-	0.0%
Arm-Longer than 4'	24,814	$ 3.68	$ 3.68	$ 91,316	$ 91,316	$ 3.68	$ 91,316	-	0.0%
Overhead Wire	43,434	$ 1.60	$ 1.60	$ 69,487	$ 69,487	$ 1.60	$ 69,487	-	0.0%
Light Only Wood Pole	43,843	$ 3.67	$ 3.67	$ 160,834	$ 160,834	$ 3.67	$ 160,834	-	0.0%
Subtotal	302,541			$ 4,156,281	$ 2,698,573		$ 4,156,281	$ -	0.0%

BALTIMORE GAS AND ELECTRIC COMPANY
PROPOSED CHANGE IN ELECTRIC SERVICE TARIFF
SCHEDULE PL - PRIVATE AREA LIGHTING

	TEST YEAR BILLING DETERMINANTS	CURRENT DELIVERY RATES (a)	CURRENT TOTAL RATES	REVENUE AT CURRENT RATES: TOTAL REVENUE AT CURRENT RATES	REVENUE AT CURRENT RATES: BASE REVENUE AT CURRENT RATES	PROPOSED CHANGE IN REVENUE: PROPOSED RATES	PROPOSED CHANGE IN REVENUE: REVENUE AT PROPOSED RATES	CHANGE IN BASE REVENUE: REVENUE	CHANGE IN BASE REVENUE: PERCENT
	(1)	(1a)	(2)	(3) = (1) x (2)	(4) = (1) x (1a)	(5)	(6) = (1) x (5)	(7) = (6) - (3)	(8) = (7) / (4)
2. Underground Fixtures									
175w MV Mod/Col	23,775	$ 8.76	$ 12.18	$ 289,580	$ 208,269	$ 12.18	$ 289,580	$ -	0.0%
400w MV Pend/Flood	915	$ 6.23	$ 13.80	$ 12,627	$ 5,700	$ 13.80	$ 12,627	-	0.0%
100w SV Mod/Col	13,656	$ 8.64	$ 10.64	$ 145,300	$ 117,988	$ 10.64	$ 145,300	-	0.0%
100w SV Flood	63	$ 6.35	$ 8.35	$ 526	$ 400	$ 8.35	$ 526	-	0.0%
100w SV Gothic	228	$ 12.34	$ 14.34	$ 3,270	$ 2,814	$ 14.34	$ 3,270	-	0.0%
100w SV Acorn	1,380	$ 12.38	$ 14.38	$ 19,844	$ 17,084	$ 14.38	$ 19,844	-	0.0%
100w SV Acorn HDG	1,080	$ 13.79	$ 15.79	$ 17,053	$ 14,893	$ 15.79	$ 17,053	-	0.0%
100w SV Colonial PR	2,667	$ 12.93	$ 14.93	$ 39,818	$ 34,484	$ 14.93	$ 39,818	-	0.0%
100w SV Acorn ML	257	$ 15.33	$ 17.33	$ 4,454	$ 3,940	$ 17.33	$ 4,454	-	0.0%
100w SV Pendant	48	$ 6.35	$ 8.35	$ 401	$ 305	$ 8.35	$ 401	-	0.0%
150w SV Mod/Col	116,664	$ 8.80	$ 11.68	$ 1,362,636	$ 1,026,643	$ 11.68	$ 1,362,636	-	0.0%
150w SV Pendant	4,202	$ 5.30	$ 8.18	$ 34,372	$ 22,271	$ 8.18	$ 34,372	-	0.0%
150w SV Rectilinear	5,737	$ 14.44	$ 17.32	$ 99,365	$ 82,842	$ 17.32	$ 99,365	-	0.0%
150w SV Acorn	79,080	$ 13.03	$ 15.91	$ 1,258,163	$ 1,030,412	$ 15.91	$ 1,258,163	-	0.0%
150w SV Gothic	7,638	$ 13.03	$ 15.91	$ 121,521	$ 99,523	$ 15.91	$ 121,521	-	0.0%
150w SV Acorn Vict	432	$ 23.81	$ 26.69	$ 11,530	$ 10,286	$ 26.69	$ 11,530	-	0.0%
150w SV Colonial PR	10,706	$ 13.55	$ 16.43	$ 175,900	$ 145,066	$ 16.43	$ 175,900	-	0.0%
150w SV Acorn HDG	2,912	$ 14.45	$ 17.33	$ 50,465	$ 42,078	$ 17.33	$ 50,465	-	0.0%
150w SV Acorn ML	3,178	$ 16.12	$ 19.00	$ 60,382	$ 51,229	$ 19.00	$ 60,382	-	0.0%
150w SV Teardrop	72	$ 32.06	$ 34.94	$ 2,516	$ 2,308	$ 34.94	$ 2,516	-	0.0%
250w SV Pendant	5,538	$ 9.64	$ 14.61	$ 80,910	$ 53,386	$ 14.61	$ 80,910	-	0.0%
250w SV Teardrop	476	$ 39.80	$ 44.77	$ 21,311	$ 18,945	$ 44.77	$ 21,311	-	0.0%
400w SV Flood	12,860	$ 7.68	$ 15.46	$ 198,816	$ 98,765	$ 15.46	$ 198,816	-	0.0%
400w SV Pendant	20,454	$ 7.68	$ 15.46	$ 316,219	$ 157,087	$ 15.46	$ 316,219	-	0.0%
400w SV Rectilinear	12,629	$ 19.59	$ 27.37	$ 345,656	$ 247,402	$ 27.37	$ 345,656	-	0.0%
1000w SV Pendant	70	$ 23.46	$ 42.30	$ 2,961	$ 1,642	$ 42.30	$ 2,961	-	0.0%
100w MH Colonial	582	$ 12.75	$ 14.90	$ 8,672	$ 7,421	$ 14.90	$ 8,672	-	0.0%
100w MH Acorn ML	663	$ 20.89	$ 23.04	$ 15,276	$ 13,850	$ 23.04	$ 15,276	-	0.0%
100w MH Acorn HDG	836	$ 18.83	$ 20.98	$ 17,539	$ 15,742	$ 20.98	$ 17,539	-	0.0%
100w MH Acorn	3,479	$ 17.43	$ 19.58	$ 68,119	$ 60,639	$ 19.58	$ 68,119	-	0.0%
100w MH Gothic	36	$ 17.48	$ 19.63	$ 707	$ 629	$ 19.63	$ 707	-	0.0%
100w MH Towson Green	72	$ 20.68	$ 22.83	$ 1,644	$ 1,489	$ 22.83	$ 1,644	-	0.0%
175w MH Acorn ML	2,190	$ 23.86	$ 27.01	$ 59,152	$ 52,253	$ 27.01	$ 59,152	-	0.0%

BALTIMORE GAS AND ELECTRIC COMPANY
PROPOSED CHANGE IN ELECTRIC SERVICE TARIFF
SCHEDULE PL - PRIVATE AREA LIGHTING

	TEST YEAR BILLING DETERMINANTS	CURRENT DELIVERY RATES (a)	CURRENT TOTAL RATES	REVENUE AT CURRENT RATES: TOTAL REVENUE AT CURRENT RATES	REVENUE AT CURRENT RATES: BASE REVENUE AT CURRENT RATES	PROPOSED CHANGE IN REVENUE: PROPOSED RATES	PROPOSED CHANGE IN REVENUE: REVENUE AT PROPOSED RATES	CHANGE IN BASE REVENUE: REVENUE	CHANGE IN BASE REVENUE: PERCENT
	(1)	(1a)	(2)	(3) = (1) x (2)	(4) = (1) x (1a)	(5)	(6) = (1) x (5)	(7) = (6) - (3)	(8) = (7) / (4)
150w MHP Modern	60	$ 15.57	$ 18.72	$ 1,123	$ 934	$ 18.72	$ 1,123	-	0.0%
150w MHP Pendant	96	$ 13.63	$ 16.78	$ 1,611	$ 1,308	$ 16.78	$ 1,611	-	0.0%
150w MHP Acorn	25,648	$ 19.42	$ 22.57	$ 578,875	$ 498,084	$ 22.57	$ 578,875	-	0.0%
150w MHP Acorn HDG	2,428	$ 20.84	$ 23.99	$ 58,248	$ 50,600	$ 23.99	$ 58,248	-	0.0%
150w MHP Colonial	7,353	$ 14.26	$ 17.41	$ 128,016	$ 104,854	$ 17.41	$ 128,016	-	0.0%
150w MHP Gothic	2,697	$ 19.42	$ 22.57	$ 60,871	$ 52,376	$ 22.57	$ 60,871	-	0.0%
150w MHP Colonial PR	2,940	$ 15.99	$ 19.14	$ 56,272	$ 47,011	$ 19.14	$ 56,272	-	0.0%
150w MHP Rectilinear	984	$ 18.24	$ 21.39	$ 21,048	$ 17,948	$ 21.39	$ 21,048	-	0.0%
150w MHP Teardrop	1,466	$ 22.88	$ 26.03	$ 38,160	$ 33,542	$ 26.03	$ 38,160	-	0.0%
175w MH Acorn	45,699	$ 19.11	$ 22.53	$ 1,029,598	$ 873,308	$ 22.53	$ 1,029,598	-	0.0%
175w MH Colonial	5,130	$ 13.95	$ 17.37	$ 89,108	$ 71,564	$ 17.37	$ 89,108	-	0.0%
175w MH Up Lighting	642	$ 25.50	$ 28.92	$ 18,567	$ 16,371	$ 28.92	$ 18,567	-	0.0%
175w MH Gothic	5,891	$ 19.11	$ 22.53	$ 132,724	$ 112,577	$ 22.53	$ 132,724	-	0.0%
175w MH Modern	60	$ 15.25	$ 18.67	$ 1,120	$ 915	$ 18.67	$ 1,120	-	0.0%
175w MH Pendant	133	$ 13.32	$ 16.74	$ 2,226	$ 1,772	$ 16.74	$ 2,226	-	0.0%
175w MH Rectilinear	551	$ 17.96	$ 21.38	$ 11,780	$ 9,896	$ 21.38	$ 11,780	-	0.0%
175w MH Acorn HDG	708	$ 20.52	$ 23.94	$ 16,950	$ 14,528	$ 23.94	$ 16,950	-	0.0%
150w MHP Acorn ML	2,215	$ 23.54	$ 26.96	$ 59,716	$ 52,141	$ 26.96	$ 59,716	-	0.0%
175w MH Colonial PR	768	$ 15.67	$ 19.09	$ 14,661	$ 12,035	$ 19.09	$ 14,661	-	0.0%
400w MHP Rectilinear	12,390	$ 21.12	$ 28.59	$ 354,230	$ 261,677	$ 28.59	$ 354,230	-	0.0%
400w MHP Flood	1,602	$ 14.10	$ 21.57	$ 34,555	$ 22,588	$ 21.57	$ 34,555	-	0.0%
400w MHP Pend-Bronze	2,544	$ 15.97	$ 23.44	$ 59,631	$ 40,628	$ 23.44	$ 59,631	-	0.0%
400w MHP Pend-Gray	578	$ 16.57	$ 24.04	$ 13,895	$ 9,577	$ 24.04	$ 13,895	-	0.0%
400w MH Flood	4,088	$ 14.15	$ 21.57	$ 88,178	$ 57,845	$ 21.57	$ 88,178	-	0.0%
400w MH Pend Bronze	921	$ 16.03	$ 23.45	$ 21,597	$ 14,764	$ 23.45	$ 21,597	-	0.0%
400w MH Rectilinear	9,406	$ 21.19	$ 28.61	$ 269,106	$ 199,313	$ 28.61	$ 269,106	-	0.0%
400w MH Pend Gray	2,135	$ 16.66	$ 24.08	$ 51,411	$ 35,569	$ 24.08	$ 51,411	-	0.0%
1000w MH Pend/Flood	5,668	$ 22.41	$ 40.58	$ 230,007	$ 127,020	$ 40.58	$ 230,007	-	0.0%
1000w MH Rectilinear	2,953	$ 38.06	$ 56.23	$ 166,047	$ 112,391	$ 56.23	$ 166,047	-	0.0%
Arm-Longer than 4'	2,756	$ 3.65	$ 3.65	$ 10,059	$ 10,059	$ 3.65	$ 10,059	-	0.0%
Subtotal	485,085			$ 8,466,093	$ 6,510,981		$ 8,466,093	$ -	0.0%

BALTIMORE GAS AND ELECTRIC COMPANY
PROPOSED CHANGE IN ELECTRIC SERVICE TARIFF
SCHEDULE PL - PRIVATE AREA LIGHTING

	TEST YEAR BILLING DETERMINANTS	CURRENT DELIVERY RATES (a)	CURRENT TOTAL RATES	REVENUE AT CURRENT RATES: TOTAL REVENUE AT CURRENT RATES	REVENUE AT CURRENT RATES: BASE REVENUE AT CURRENT RATES	PROPOSED CHANGE IN REVENUE: PROPOSED RATES	PROPOSED CHANGE IN REVENUE: REVENUE AT PROPOSED RATES	CHANGE IN BASE REVENUE: REVENUE	CHANGE IN BASE REVENUE: PERCENT
	(1)	(1a)	(2)	(3) = (1) x (2)	(4) = (1) x (1a)	(5)	(6) = (1) x (5)	(7) = (6) - (3)	(8) = (7) / (4)
3. LED Fixtures									
LED 70 Pendant - 39	34	$ 8.69	$ 9.34	$ 317.56	$ 295	$ 9.34	318	-	0.0%
LED 100 Pendant - 51	60	$ 7.20	$ 8.05	$ 483.00	$ 432	$ 8.05	483	-	0.0%
LED 100 Pendant - 72	921	$ 8.69	$ 9.89	$ 9,108.69	$ 8,003	$ 9.89	9,109	-	0.0%
LED 100 Post Top Acorn	597	$ 24.33	$ 25.50	15,224	$ 14,525	$ 25.50	15,224	-	0.0%
LED 100 Post Top Arlington	0	$ 27.41	$ 28.61	-	$ -	$ 28.61	-	-	
LED 100 Post Top Colonial	1,038	$ 16.17	$ 17.37	18,030	$ 16,784	$ 17.37	18,030	-	0.0%
LED 100 Post Top Modern	279	$ 15.82	$ 16.72	4,665	$ 4,414	$ 16.72	4,665	-	0.0%
LED 100 Post Top Decorative Acorn	394	$ 33.56	$ 34.73	13,684	$ 13,223	$ 34.73	13,684	-	0.0%
LED 100 Premiere Colonial	0	$ 17.48	$ 18.35	-	$ -	$ 18.35	-	-	
LED 150 Pendant - 72	986	$ 8.08	$ 9.28	9,150	$ 7,967	$ 9.28	9,150	-	0.0%
LED 150 Pendant - 88	1,072	$ 8.87	$ 10.34	11,084	$ 9,509	$ 10.34	11,084	-	0.0%
LED 150 Post Top Arlington	911	$ 27.42	$ 29.15	26,556	$ 24,980	$ 29.15	26,556	-	0.0%
LED 150 Post Top Colonial	12,848	$ 16.66	$ 18.43	236,789	$ 214,048	$ 18.43	236,789	-	0.0%
LED 150 Post Top Acorn	9,114	$ 24.32	$ 26.00	236,964	$ 221,652	$ 26.00	236,964	-	0.0%
LED 150 Post Top Decorative Acorn	386	$ 33.56	$ 35.24	13,603	$ 12,954	$ 35.24	13,603	-	0.0%
LED 150 Tear Drop	0	$ 31.93	$ 33.36	-	$ -	$ 33.36	-	-	
LED 150 Premiere Colonial	379	$ 19.01	$ 20.26	7,679	$ 7,205	$ 20.26	7,679	-	0.0%
LED 250 Pendant - 129	1,946	$ 11.18	$ 13.33	25,940	$ 21,756	$ 13.33	25,940	-	0.0%
LED 250 Pendant - 145	217	$ 11.24	$ 13.66	2,964	$ 2,439	$ 13.66	2,964	-	0.0%
LED 250 Tear Drop	30	$ 40.03	$ 42.55	1,277	$ 1,201	$ 42.55	1,277	-	0.0%
LED 400 Pendant - 157	2,878	$ 13.97	$ 16.59	47,746	$ 40,206	$ 16.59	47,746	-	0.0%
LED 400 Pendant - 273	10,013	$ 15.61	$ 20.16	201,862	$ 156,303	$ 20.16	201,862	-	0.0%
LED 400 Floodlight - 129	12,210	$ 12.77	$ 14.92	182,173	$ 155,922	$ 14.92	182,173	-	0.0%
LED 1000 Floodlight - 256	12,162	$ 24.67	$ 28.94	351,968	300,037	$ 28.94	351,968	-	0.0%
Subtotal	68,475			$ 1,417,266	$ 1,233,854		$ 1,417,266	$ -	0.0%

BALTIMORE GAS AND ELECTRIC COMPANY
PROPOSED CHANGE IN ELECTRIC SERVICE TARIFF
SCHEDULE PL - PRIVATE AREA LIGHTING

				REVENUE AT CURRENT RATES		PROPOSED CHANGE IN REVENUE			
	TEST YEAR BILLING DETERMINANTS	CURRENT DELIVERY RATES (a)	CURRENT TOTAL RATES	TOTAL REVENUE AT CURRENT RATES	BASE REVENUE AT CURRENT RATES	PROPOSED RATES	REVENUE AT PROPOSED RATES	CHANGE IN BASE REVENUE: REVENUE	CHANGE IN BASE REVENUE: PERCENT
	(1)	(1a)	(2)	(3) = (1) x (2)	(4) = (1) x (1a)	(5)	(6) = (1) x (5)	(7) = (6) - (3)	(8) = (7) / (4)
4. Underground Supplied Poles			$/Pole			$/Pole			
12-14' Wood Pole	9,783	$ 15.66	$ 15.66	153,222	$ 153,222	$ 15.66	153,222	-	0.0%
12' Fiberglass Pole	2,324	$ 15.66	$ 15.66	36,399	$ 36,399	$ 15.66	36,399	-	0.0%
12' Fib Pole-Shroud	3,225	$ 25.70	$ 25.70	82,883	$ 82,883	$ 25.70	82,883	-	0.0%
14' Fiberglass Pole	311,525	$ 15.66	$ 15.66	4,879,114	$ 4,879,114	$ 15.66	4,879,114	-	0.0%
14' Fib Hinged Pole	36,316	$ 21.65	$ 21.65	786,378	$ 786,378	$ 21.65	786,378	-	0.0%
14' Fib Fluted Pole	27,958	$ 30.85	$ 30.85	862,504	$ 862,504	$ 30.85	862,504	-	0.0%
20' Bronze Fib Pole	6,083	$ 24.90	$ 24.90	151,467	$ 151,467	$ 24.90	151,467	-	0.0%
23' Fib Pole-Shroud	1,801	$ 32.79	$ 32.79	59,055	$ 59,055	$ 32.79	59,055	-	0.0%
25' Metal Pole	2,298	$ 25.99	$ 25.99	59,725	$ 59,725	$ 25.99	59,725	-	0.0%
30' Metal Pole	25,673	$ 22.01	$ 22.01	565,063	$ 565,063	$ 22.01	565,063	-	0.0%
30' Bronze Fib Pole	11,308	$ 26.79	$ 26.79	302,941	$ 302,941	$ 26.79	302,941	-	0.0%
30' Brz Fib Pole-Arm	21,862	$ 29.54	$ 29.54	645,803	$ 645,803	$ 29.54	645,803	-	0.0%
30' Gray Fib Pole	0	$ 26.79	$ 26.79	0	$ 0	$ 26.79	0	-	0.0%
Light Only Wood Pole	8,207	$ 18.00	$ 18.00	147,726	$ 147,726	$ 18.00	147,726	-	0.0%
35' Bronze Fib Pole	1,814	$ 27.08	$ 27.08	49,123	$ 49,123	$ 27.08	49,123	-	0.0%
32-35' Steel Pole-CB	3,858	$ 26.92	$ 26.92	103,857	$ 103,857	$ 26.92	103,857	-	0.0%
30' Bronze Alum Pole	468	$ 41.63	$ 41.63	19,483	$ 19,483	$ 41.63	19,483	-	0.0%
Subtotal	474,503			$ 8,904,742	$ 8,904,742		$ 8,904,742	$ -	0.0%
5. Miscellaneous Equipment			$/Item			$/Item			
Three or Four Way Bracket	63	$ 4.18	$ 4.18	$ 263	$ 263	$ 4.18	$ 263	$ -	0.0%
60 amp Photo Control Relay	12	$ 14.27	$ 14.27	$ 171	$ 171	$ 14.27	$ 171	-	0.0%
100 amp Photo Control Relay UG	117	$ 22.70	$ 22.70	$ 2,656	$ 2,656	$ 22.70	$ 2,656	-	0.0%
100 amp Photo Control Relay OH	24	$ 22.70	$ 22.70	$ 545	$ 545	$ 22.70	$ 545	-	0.0%
Subtotal	216			$ 3,635	$ 3,635		$ 3,635	$ -	0.0%
Base Revenue				$ 22,948,017	$ 19,351,786		$ 22,948,017	$ -	0.0%

5. TOTAL REVENUE ALLOCATED	$ -
6. DIFFERENCE FROM REVENUE ALLOCATED	$ -

(a) Current Delivery rates as authorized in Case No. 9355
(b) Current Supply rates as approved in Supplement 642.

BALTIMORE GAS AND ELECTRIC COMPANY
PROPOSED CHANGE IN ELECTRIC SERVICE TARIFF
SCHEDULE PL - PRIVATE AREA LIGHTING

				REVENUE AT CURRENT RATES		PROPOSED CHANGE IN REVENUE			
								CHANGE IN BASE REVENUE	
	TEST YEAR BILLING DETERMINANTS	CURRENT DELIVERY RATES (a)	CURRENT TOTAL RATES	TOTAL REVENUE AT CURRENT RATES	BASE REVENUE AT CURRENT RATES	PROPOSED RATES	REVENUE AT PROPOSED RATES	REVENUE	PERCENT
	(1)	(1a)	(2)	(3) = (1) x (2)	(4) = (1) x (1a)	(5)	(6) = (1) x (5)	(7) = (6) - (3)	(8) = (7) / (4)
Rate Year 3 - 2023									
1. Overhead Fixtures	Fixtures		$/Fixture		$/Fixture	$/Fixture			
100w MV Pendant	3,528	$ 7.11	$ 9.06	$ 31,964	$ 25,084	$ 9.06	$ 31,964	$ -	0.0%
175w MV Pendant	10,069	$ 7.44	$ 10.86	$ 109,349	$ 74,913	$ 10.86	$ 109,349	-	0.0%
400w MV Pend/Flood	10,128	$ 8.58	$ 16.15	$ 163,567	$ 86,898	$ 16.15	$ 163,567	-	0.0%
1000w MV Pendant	1,111	$ 11.66	$ 29.83	$ 33,141	$ 12,954	$ 29.83	$ 33,141	-	0.0%
100w SV Flood	541	$ 8.60	$ 10.60	$ 5,735	$ 4,653	$ 10.60	$ 5,735	-	0.0%
100w SV Pendant	2,256	$ 7.07	$ 9.07	$ 20,462	$ 15,950	$ 9.07	$ 20,462	-	0.0%
150w SV Pendant	19,535	$ 7.68	$ 10.56	$ 206,290	$ 150,029	$ 10.56	$ 206,290	-	0.0%
250w SV Pendant	4,326	$ 12.64	$ 17.61	$ 76,181	$ 54,681	$ 17.61	$ 76,181	-	0.0%
400w SV Flood	53,814	$ 10.08	$ 17.86	$ 961,118	$ 542,445	$ 17.86	$ 961,118	-	0.0%
400w SV Pendant	39,899	$ 10.08	$ 17.86	$ 712,596	$ 402,182	$ 17.86	$ 712,596	-	0.0%
1000w SV Pendant	749	$ 28.36	$ 47.20	$ 35,353	$ 21,242	$ 47.20	$ 35,353	-	0.0%
150w MHP Teardrop	120	$ 22.94	$ 26.09	$ 3,131	$ 2,753	$ 26.09	$ 3,131	-	0.0%
150w MHP Pendant	487	$ 14.73	$ 17.88	$ 8,708	$ 7,174	$ 17.88	$ 8,708	-	0.0%
175w MH Pendant	898	$ 14.42	$ 17.84	$ 16,020	$ 12,949	$ 17.84	$ 16,020	-	0.0%
400w MH Spot	24	$ 20.26	$ 27.68	$ 664	$ 486	$ 27.68	$ 664	-	0.0%
400w MH Flood	15,515	$ 20.26	$ 27.68	$ 429,455	$ 314,334	$ 27.68	$ 429,455	-	0.0%
400w MH Pendant	4,884	$ 19.95	$ 27.37	$ 133,675	$ 97,436	$ 27.37	$ 133,675	-	0.0%
400w MHP Flood	4,664	$ 20.21	$ 27.68	$ 129,100	$ 94,259	$ 27.68	$ 129,100	-	0.0%
400w MHP Pend-Gray	2,211	$ 19.90	$ 27.37	$ 60,515	$ 43,999	$ 27.37	$ 60,515	-	0.0%
1000w MH Pend/Flood	15,691	$ 26.29	$ 44.46	$ 697,622	$ 412,516	$ 44.46	$ 697,622	-	0.0%
Arm-Longer than 4'	24,814	$ 3.68	$ 3.68	$ 91,316	$ 91,316	$ 3.68	$ 91,316	-	0.0%
Overhead Wire	43,434	$ 1.60	$ 1.60	$ 69,487	$ 69,487	$ 1.60	$ 69,487	-	0.0%
Light Only Wood Pole	43,843	$ 3.67	$ 3.67	160,834	$ 160,834	$ 3.67	$ 160,834	-	0.0%
Subtotal	302,541			$ 4,156,281	$ 2,698,573		$ 4,156,281	$ -	0.0%

BALTIMORE GAS AND ELECTRIC COMPANY
PROPOSED CHANGE IN ELECTRIC SERVICE TARIFF
SCHEDULE PL - PRIVATE AREA LIGHTING

	TEST YEAR BILLING DETERMINANTS	CURRENT DELIVERY RATES (a)	CURRENT TOTAL RATES	REVENUE AT CURRENT RATES: TOTAL REVENUE AT CURRENT RATES	REVENUE AT CURRENT RATES: BASE REVENUE AT CURRENT RATES	PROPOSED CHANGE IN REVENUE: PROPOSED RATES	PROPOSED CHANGE IN REVENUE: REVENUE AT PROPOSED RATES	CHANGE IN BASE REVENUE: REVENUE	CHANGE IN BASE REVENUE: PERCENT
	(1)	(1a)	(2)	(3) = (1) x (2)	(4) = (1) x (1a)	(5)	(6) = (1) x (5)	(7) = (6) - (3)	(8) = (7) / (4)
2. Underground Fixtures									
175w MV Mod/Col	23,775	$ 8.76	$ 12.18	$ 289,580	$ 208,269	$ 12.18	$ 289,580	$ -	0.0%
400w MV Pend/Flood	915	$ 6.23	$ 13.80	$ 12,627	$ 5,700	$ 13.80	$ 12,627	-	0.0%
100w SV Mod/Col	13,656	$ 8.64	$ 10.64	$ 145,300	$ 117,988	$ 10.64	$ 145,300	-	0.0%
100w SV Flood	63	$ 6.35	$ 8.35	$ 526	$ 400	$ 8.35	$ 526	-	0.0%
100w SV Gothic	228	$ 12.34	$ 14.34	$ 3,270	$ 2,814	$ 14.34	$ 3,270	-	0.0%
100w SV Acorn	1,380	$ 12.38	$ 14.38	$ 19,844	$ 17,084	$ 14.38	$ 19,844	-	0.0%
100w SV Acorn HDG	1,080	$ 13.79	$ 15.79	$ 17,053	$ 14,893	$ 15.79	$ 17,053	-	0.0%
100w SV Colonial PR	2,667	$ 12.93	$ 14.93	$ 39,818	$ 34,484	$ 14.93	$ 39,818	-	0.0%
100w SV Acorn ML	257	$ 15.33	$ 17.33	$ 4,454	$ 3,940	$ 17.33	$ 4,454	-	0.0%
100w SV Pendant	48	$ 6.35	$ 8.35	$ 401	$ 305	$ 8.35	$ 401	-	0.0%
150w SV Mod/Col	116,664	$ 8.80	$ 11.68	$ 1,362,636	$ 1,026,643	$ 11.68	$ 1,362,636	-	0.0%
150w SV Pendant	4,202	$ 5.30	$ 8.18	$ 34,372	$ 22,271	$ 8.18	$ 34,372	-	0.0%
150w SV Rectilinear	5,737	$ 14.44	$ 17.32	$ 99,365	$ 82,842	$ 17.32	$ 99,365	-	0.0%
150w SV Acorn	79,080	$ 13.03	$ 15.91	$ 1,258,163	$ 1,030,412	$ 15.91	$ 1,258,163	-	0.0%
150w SV Gothic	7,638	$ 13.03	$ 15.91	$ 121,521	$ 99,523	$ 15.91	$ 121,521	-	0.0%
150w SV Acorn Vict	432	$ 23.81	$ 26.69	$ 11,530	$ 10,286	$ 26.69	$ 11,530	-	0.0%
150w SV Colonial PR	10,706	$ 13.55	$ 16.43	$ 175,900	$ 145,066	$ 16.43	$ 175,900	-	0.0%
150w SV Acorn HDG	2,912	$ 14.45	$ 17.33	$ 50,465	$ 42,078	$ 17.33	$ 50,465	-	0.0%
150w SV Acorn ML	3,178	$ 16.12	$ 19.00	$ 60,382	$ 51,229	$ 19.00	$ 60,382	-	0.0%
150w SV Teardrop	72	$ 32.06	$ 34.94	$ 2,516	$ 2,308	$ 34.94	$ 2,516	-	0.0%
250w SV Pendant	5,538	$ 9.64	$ 14.61	$ 80,910	$ 53,386	$ 14.61	$ 80,910	-	0.0%
250w SV Teardrop	476	$ 39.80	$ 44.77	$ 21,311	$ 18,945	$ 44.77	$ 21,311	-	0.0%
400w SV Flood	12,860	$ 7.68	$ 15.46	$ 198,816	$ 98,765	$ 15.46	$ 198,816	-	0.0%
400w SV Pendant	20,454	$ 7.68	$ 15.46	$ 316,219	$ 157,087	$ 15.46	$ 316,219	-	0.0%
400w SV Rectilinear	12,629	$ 19.59	$ 27.37	$ 345,656	$ 247,402	$ 27.37	$ 345,656	-	0.0%
1000w SV Pendant	70	$ 23.46	$ 42.30	$ 2,961	$ 1,642	$ 42.30	$ 2,961	-	0.0%
100w MH Colonial	582	$ 12.75	$ 14.90	$ 8,672	$ 7,421	$ 14.90	$ 8,672	-	0.0%
100w MH Acorn ML	663	$ 20.89	$ 23.04	$ 15,276	$ 13,850	$ 23.04	$ 15,276	-	0.0%
100w MH Acorn HDG	836	$ 18.83	$ 20.98	$ 17,539	$ 15,742	$ 20.98	$ 17,539	-	0.0%
100w MH Acorn	3,479	$ 17.43	$ 19.58	$ 68,119	$ 60,639	$ 19.58	$ 68,119	-	0.0%
100w MH Gothic	36	$ 17.48	$ 19.63	$ 707	$ 629	$ 19.63	$ 707	-	0.0%

BALTIMORE GAS AND ELECTRIC COMPANY
PROPOSED CHANGE IN ELECTRIC SERVICE TARIFF
SCHEDULE PL - PRIVATE AREA LIGHTING

	TEST YEAR BILLING DETERMINANTS	CURRENT DELIVERY RATES (a)	CURRENT TOTAL RATES	REVENUE AT CURRENT RATES: TOTAL REVENUE AT CURRENT RATES	REVENUE AT CURRENT RATES: BASE REVENUE AT CURRENT RATES	PROPOSED CHANGE IN REVENUE: PROPOSED RATES	PROPOSED CHANGE IN REVENUE: REVENUE AT PROPOSED RATES	CHANGE IN BASE REVENUE: REVENUE	CHANGE IN BASE REVENUE: PERCENT
	(1)	(1a)	(2)	(3) = (1) x (2)	(4) = (1) x (1a)	(5)	(6) = (1) x (5)	(7) = (6) - (3)	(8) = (7) / (4)
100w MH Towson Green	72	$ 20.68	$ 22.83	$ 1,644	$ 1,489	$ 22.83	$ 1,644	-	0.0%
175w MH Acorn ML	2,190	$ 23.86	$ 27.01	$ 59,152	$ 52,253	$ 27.01	$ 59,152	-	0.0%
150w MHP Modern	60	$ 15.57	$ 18.72	$ 1,123	$ 934	$ 18.72	$ 1,123	-	0.0%
150w MHP Pendant	96	$ 13.63	$ 16.78	$ 1,611	$ 1,308	$ 16.78	$ 1,611	-	0.0%
150w MHP Acorn	25,648	$ 19.42	$ 22.57	$ 578,875	$ 498,084	$ 22.57	$ 578,875	-	0.0%
150w MHP Acorn HDG	2,428	$ 20.84	$ 23.99	$ 58,248	$ 50,600	$ 23.99	$ 58,248	-	0.0%
150w MHP Colonial	7,353	$ 14.26	$ 17.41	$ 128,016	$ 104,854	$ 17.41	$ 128,016	-	0.0%
150w MHP Gothic	2,697	$ 19.42	$ 22.57	$ 60,871	$ 52,376	$ 22.57	$ 60,871	-	0.0%
150w MHP Colonial PR	2,940	$ 15.99	$ 19.14	$ 56,272	$ 47,011	$ 19.14	$ 56,272	-	0.0%
150w MHP Rectilinear	984	$ 18.24	$ 21.39	$ 21,048	$ 17,948	$ 21.39	$ 21,048	-	0.0%
150w MHP Teardrop	1,466	$ 22.88	$ 26.03	$ 38,160	$ 33,542	$ 26.03	$ 38,160	-	0.0%
175w MH Acorn	45,699	$ 19.11	$ 22.53	$ 1,029,598	$ 873,308	$ 22.53	$ 1,029,598	-	0.0%
175w MH Colonial	5,130	$ 13.95	$ 17.37	$ 89,108	$ 71,564	$ 17.37	$ 89,108	-	0.0%
175w MH Up Lighting	642	$ 25.50	$ 28.92	$ 18,567	$ 16,371	$ 28.92	$ 18,567	-	0.0%
175w MH Gothic	5,891	$ 19.11	$ 22.53	$ 132,724	$ 112,577	$ 22.53	$ 132,724	-	0.0%
175w MH Modern	60	$ 15.25	$ 18.67	$ 1,120	$ 915	$ 18.67	$ 1,120	-	0.0%
175w MH Pendant	133	$ 13.32	$ 16.74	$ 2,226	$ 1,772	$ 16.74	$ 2,226	-	0.0%
175w MH Rectilinear	551	$ 17.96	$ 21.38	$ 11,780	$ 9,896	$ 21.38	$ 11,780	-	0.0%
175w MH Acorn HDG	708	$ 20.52	$ 23.94	$ 16,950	$ 14,528	$ 23.94	$ 16,950	-	0.0%
150w MHP Acorn ML	2,215	$ 23.54	$ 26.96	$ 59,716	$ 52,141	$ 26.96	$ 59,716	-	0.0%
175w MH Colonial PR	768	$ 15.67	$ 19.09	$ 14,661	$ 12,035	$ 19.09	$ 14,661	-	0.0%
400w MHP Rectilinear	12,390	$ 21.12	$ 28.59	$ 354,230	$ 261,677	$ 28.59	$ 354,230	-	0.0%
400w MHP Flood	1,602	$ 14.10	$ 21.57	$ 34,555	$ 22,588	$ 21.57	$ 34,555	-	0.0%
400w MHP Pend-Bronze	2,544	$ 15.97	$ 23.44	$ 59,631	$ 40,628	$ 23.44	$ 59,631	-	0.0%
400w MHP Pend-Gray	578	$ 16.57	$ 24.04	$ 13,895	$ 9,577	$ 24.04	$ 13,895	-	0.0%
400w MH Flood	4,088	$ 14.15	$ 21.57	$ 88,178	$ 57,845	$ 21.57	$ 88,178	-	0.0%
400w MH Pend Bronze	921	$ 16.03	$ 23.45	$ 21,597	$ 14,764	$ 23.45	$ 21,597	-	0.0%
400w MH Rectilinear	9,406	$ 21.19	$ 28.61	$ 269,106	$ 199,313	$ 28.61	$ 269,106	-	0.0%
400w MH Pend Gray	2,135	$ 16.66	$ 24.08	$ 51,411	$ 35,569	$ 24.08	$ 51,411	-	0.0%
1000w MH Pend/Flood	5,668	$ 22.41	$ 40.58	$ 230,007	$ 127,020	$ 40.58	$ 230,007	-	0.0%
1000w MH Rectilinear	2,953	$ 38.06	$ 56.23	$ 166,047	$ 112,391	$ 56.23	$ 166,047	-	0.0%
Arm-Longer than 4'	2,756	$ 3.65	$ 3.65	10,059	$ 10,059	$ 3.65	$ 10,059	-	0.0%
Subtotal	485,085			$ 8,466,093	$ 6,510,981		$ 8,466,093	$ -	0.0%

COMPANY EXHIBIT LFK-2
SUPPLEMENT 650
SHEET E-13

BALTIMORE GAS AND ELECTRIC COMPANY
PROPOSED CHANGE IN ELECTRIC SERVICE TARIFF
SCHEDULE PL - PRIVATE AREA LIGHTING

	TEST YEAR BILLING DETERMINANTS	CURRENT DELIVERY RATES (a)	CURRENT TOTAL RATES	REVENUE AT CURRENT RATES: TOTAL REVENUE AT CURRENT RATES	REVENUE AT CURRENT RATES: BASE REVENUE AT CURRENT RATES	PROPOSED CHANGE IN REVENUE: PROPOSED RATES	PROPOSED CHANGE IN REVENUE: REVENUE AT PROPOSED RATES	CHANGE IN BASE REVENUE: REVENUE	CHANGE IN BASE REVENUE: PERCENT
	(1)	(1a)	(2)	(3) = (1) x (2)	(4) = (1) x (1a)	(5)	(6) = (1) x (5)	(7) = (6) - (3)	(8) = (7) / (4)
3. LED Fixtures									
LED 70 Pendant - 39	34	$ 8.69	$ 9.34	$ 318	$ 295	$ 9.34	$ 318	-	0.0%
LED 100 Pendant - 51	60	$ 7.20	$ 8.05	$ 483	$ 432	$ 8.05	$ 483	-	0.0%
LED 100 Pendant - 72	921	$ 8.69	$ 9.89	$ 9,109	$ 8,003	$ 9.89	$ 9,109	-	0.0%
LED 100 Post Top Acorn	597	$ 24.33	$ 25.50	$ 15,224	$ 14,525	$ 25.50	$ 15,224	-	0.0%
LED 100 Post Top Arlington	0	$ 27.41	$ 28.61	$ -	$ -	$ 28.61	$ -	-	
LED 100 Post Top Colonial	1,038	$ 16.17	$ 17.37	$ 18,030	$ 16,784	$ 17.37	$ 18,030	-	0.0%
LED 100 Post Top Modern	279	$ 15.82	$ 16.72	$ 4,665	$ 4,414	$ 16.72	$ 4,665	-	0.0%
LED 100 Post Top Decorative Acorn	394	$ 33.56	$ 34.73	$ 13,684	$ 13,223	$ 34.73	$ 13,684	-	0.0%
LED 100 Premiere Colonial	0	$ 17.48	$ 18.35	$ -	$ -	$ 18.35	$ -	-	
LED 150 Pendant - 72	986	$ 8.08	$ 9.28	$ 9,150	$ 7,967	$ 9.28	$ 9,150	-	0.0%
LED 150 Pendant - 88	1,072	$ 8.87	$ 10.34	$ 11,084	$ 9,509	$ 10.34	$ 11,084	-	0.0%
LED 150 Post Top Arlington	911	$ 27.42	$ 29.15	$ 26,556	$ 24,980	$ 29.15	$ 26,556	-	0.0%
LED 150 Post Top Colonial	12,848	$ 16.66	$ 18.43	$ 236,789	$ 214,048	$ 18.43	$ 236,789	-	0.0%
LED 150 Post Top Acorn	9,114	$ 24.32	$ 26.00	$ 236,964	$ 221,652	$ 26.00	$ 236,964	-	0.0%
LED 150 Post Top Decorative Acorn	386	$ 33.56	$ 35.24	$ 13,603	$ 12,954	$ 35.24	$ 13,603	-	0.0%
LED 150 Tear Drop	0	$ 31.93	$ 33.36	$ -	$ -	$ 33.36	$ -	-	
LED 150 Premiere Colonial	379	$ 19.01	$ 20.26	$ 7,679	$ 7,205	$ 20.26	$ 7,679	-	0.0%
LED 250 Pendant - 129	1,946	$ 11.18	$ 13.33	$ 25,940	$ 21,756	$ 13.33	$ 25,940	-	0.0%
LED 250 Pendant - 145	217	$ 11.24	$ 13.66	$ 2,964	$ 2,439	$ 13.66	$ 2,964	-	0.0%
LED 250 Tear Drop	30	$ 40.03	$ 42.55	$ 1,277	$ 1,201	$ 42.55	$ 1,277	-	0.0%
LED 400 Pendant - 157	2,878	$ 13.97	$ 16.59	$ 47,746	$ 40,206	$ 16.59	$ 47,746	-	0.0%
LED 400 Pendant - 273	10,013	$ 15.61	$ 20.16	$ 201,862	$ 156,303	$ 20.16	$ 201,862	-	0.0%
LED 400 Floodlight - 129	12,210	$ 12.77	$ 14.92	$ 182,173	$ 155,922	$ 14.92	$ 182,173	-	0.0%
LED 1000 Floodlight - 256	12,162	$ 24.67	$ 28.94	$ 351,968	300,037	$ 28.94	$ 351,968	-	0.0%
Subtotal	68,475			$ 1,417,266	$ 1,233,854		$ 1,417,266	$ -	0.0%

COMPANY EXHIBIT LFK-2
SUPPLEMENT 650
SHEET E-13

BALTIMORE GAS AND ELECTRIC COMPANY
PROPOSED CHANGE IN ELECTRIC SERVICE TARIFF
SCHEDULE PL - PRIVATE AREA LIGHTING

				REVENUE AT CURRENT RATES		PROPOSED CHANGE IN REVENUE			
	TEST YEAR BILLING DETERMINANTS	CURRENT DELIVERY RATES (a)	CURRENT TOTAL RATES	TOTAL REVENUE AT CURRENT RATES	BASE REVENUE AT CURRENT RATES	PROPOSED RATES	REVENUE AT PROPOSED RATES	CHANGE IN BASE REVENUE: REVENUE	CHANGE IN BASE REVENUE: PERCENT
	(1)	(1a)	(2)	(3) = (1) x (2)	(4) = (1) x (1a)	(5)	(6) = (1) x (5)	(7) = (6) - (3)	(8) = (7) / (4)
4. Underground Supplied Poles			$/Pole			$/Pole			
12-14' Wood Pole	9,783	$ 15.66	$ 15.66	153,222	$ 153,222	$ 15.66	153,222	-	0.0%
12' Fiberglass Pole	2,324	$ 15.66	$ 15.66	36,399	$ 36,399	$ 15.66	36,399	-	0.0%
12' Fib Pole-Shroud	3,225	$ 25.70	$ 25.70	82,883	$ 82,883	$ 25.70	82,883	-	0.0%
14' Fiberglass Pole	311,525	$ 15.66	$ 15.66	4,879,114	$ 4,879,114	$ 15.66	4,879,114	-	0.0%
14' Fib Hinged Pole	36,316	$ 21.65	$ 21.65	786,378	$ 786,378	$ 21.65	786,378	-	0.0%
14' Fib Fluted Pole	27,958	$ 30.85	$ 30.85	862,504	$ 862,504	$ 30.85	862,504	-	0.0%
20' Bronze Fib Pole	6,083	$ 24.90	$ 24.90	151,467	$ 151,467	$ 24.90	151,467	-	0.0%
23' Fib Pole-Shroud	1,801	$ 32.79	$ 32.79	59,055	$ 59,055	$ 32.79	59,055	-	0.0%
25' Metal Pole	2,298	$ 25.99	$ 25.99	59,725	$ 59,725	$ 25.99	59,725	-	0.0%
30' Metal Pole	25,673	$ 22.01	$ 22.01	565,063	$ 565,063	$ 22.01	565,063	-	0.0%
30' Bronze Fib Pole	11,308	$ 26.79	$ 26.79	302,941	$ 302,941	$ 26.79	302,941	-	0.0%
30' Brz Fib Pole-Arm	21,862	$ 29.54	$ 29.54	645,803	$ 645,803	$ 29.54	645,803	-	0.0%
30' Gray Fib Pole	0	$ 26.79	$ 26.79	-	$ -	$ 26.79	-	-	
Light Only Wood Pole	8,207	$ 18.00	$ 18.00	147,726	$ 147,726	$ 18.00	147,726	-	0.0%
35' Bronze Fib Pole	1,814	$ 27.08	$ 27.08	49,123	$ 49,123	$ 27.08	49,123	-	0.0%
32-35' Steel Pole-CB	3,858	$ 26.92	$ 26.92	103,857	$ 103,857	$ 26.92	103,857	-	0.0%
30' Bronze Alum Pole	468	$ 41.63	$ 41.63	19,483	$ 19,483	$ 41.63	19,483	-	0.0%
Subtotal	474,503			$ 8,904,742	$ 8,904,742		$ 8,904,742	$ -	0.0%
5. Miscellaneous Equipment			$/Item			$/Item			
Three or Four Way Bracket	63	$ 4.18	$ 4.18	$ 263	$ 263	$ 4.18	$ 263	$ -	0.0%
60 amp Photo Control Relay	12	$ 14.27	$ 14.27	$ 171	$ 171	$ 14.27	$ 171	-	0.0%
100 amp Photo Control Relay UG	117	$ 22.70	$ 22.70	$ 2,656	$ 2,656	$ 22.70	$ 2,656	-	0.0%
100 amp Photo Control Relay OH	24	$ 22.70	$ 22.70	$ 545	$ 545	$ 22.70	$ 545	-	0.0%
Subtotal	216			$ 3,635	$ 3,635		$ 3,635	$ -	0.0%
Base Revenue				$ 22,948,017	$ 19,351,786		$ 22,948,017	$ -	0.0%

5. TOTAL REVENUE ALLOCATED	$ -
6. DIFFERENCE FROM REVENUE ALLOCATED	$ -

(a) Current Delivery rates as authorized in Case No. 9355
(b) Current Supply rates as approved in Supplement 642.

BALTIMORE GAS AND ELECTRIC COMPANY
TIME-OF-USE DISTRIBUTION RATE FOR PC44 PILOT
SCHEDULE RD - RESIDENTIAL DELIVERY AND ENERGY TIME-OF-USE PILOT
Rate Year 1

	TEST YEAR BILLING DETERMINANTS	REVENUE AT PROPOSED SCHEDULE R RATES: CURRENT RATES (a)	REVENUE AT PROPOSED SCHEDULE R RATES: REVENUE AT CURRENT RATES		TEST YEAR BILLING DETERMINANTS	PROPOSED CHANGE IN REVENUE: PROPOSED RATES	PROPOSED CHANGE IN REVENUE: REVENUE AT PROPOSED RATES	CHANGE IN BASE REVENUE: REVENUE	CHANGE IN BASE REVENUE: PERCENT
	(1)	(2)	(3) = (1) x (2)		(5)	(6)	(7) = (5) x (6)	(8) = (7) - (3)	(9) = (8) / (3)
1. CUSTOMER CHARGE	BILLS				BILLS				
Schedule R	13,514,961	$ 8.00	$ 108,119,686	Schedule RD	13,514,961	$ 8.00	$ 108,119,686	$ -	0.0%
	kWh	$/kWh			kWh	$/kWh			
2. DELIVERY SERVICE CHARGE									
Schedule R - Total	11,235,369,008	0.03651	$ 410,203,322						
				Schedule RD - On Peak	1,445,991,991	0.12263	$ 177,321,998		
				Schedule RD - Off Peak	9,789,377,016	0.02379	$ 232,889,279		
				Schedule RD - Total	11,235,369,008		$ 410,211,277	$ 7,955	0.0%
3. TOTAL REVENUE			$ 518,323,008				$ 518,330,963	$ 7,955	0.0%

4. TOTAL REVENUE ALLOCATED	$ -
5. DIFFERENCE FROM REVENUE ALLOCATED	$ 7,955

BALTIMORE GAS AND ELECTRIC COMPANY
TIME-OF-USE DISTRIBUTION RATE FOR PC44 PILOT
SCHEDULE RD - RESIDENTIAL DELIVERY AND ENERGY TIME-OF-USE PILOT
Rate Year 2 (b)

	REVENUE AT PROPOSED SCHEDULE R RATES				PROPOSED CHANGE IN REVENUE				
	TEST YEAR BILLING DETERMINANTS	CURRENT RATES (a)	REVENUE AT CURRENT RATES		TEST YEAR BILLING DETERMINANTS	PROPOSED RATES	REVENUE AT PROPOSED RATES	CHANGE IN BASE REVENUE: REVENUE	CHANGE IN BASE REVENUE: PERCENT
	(1)	(2)	(3) = (1) x (2)		(5)	(6)	(7) = (5) x (6)	(8) = (7) - (3)	(9) = (8) / (3)
1. CUSTOMER CHARGE	BILLS				BILLS				
Schedule R	13,583,281	$ 8.00	$ 108,666,249	Schedule RD	13,583,281	$ 8.00	$ 108,666,249	$ -	0.0%
	kWh	$/kWh			kWh	$/kWh			
2. DELIVERY SERVICE CHARGE									
Schedule R - Total	11,352,319,553	0.03633	$ 412,429,769						
				Schedule RD - On Peak	1,461,043,526	0.12202	$ 178,276,531		
				Schedule RD - Off Peak	9,891,276,026	0.02367	$ 234,126,504		
				Schedule RD - Total	11,352,319,553		$ 412,403,035	$ (26,734)	0.0%
3. TOTAL REVENUE			$ 521,096,018				$ 521,069,284	$ (26,734)	0.0%

4. TOTAL REVENUE ALLOCATED	$ -
5. DIFFERENCE FROM REVENUE ALLOCATED	$ (26,734)

COMPANY EXHIBIT LFK-2
SUPPLEMENT 650
SHEET E-14

BALTIMORE GAS AND ELECTRIC COMPANY
TIME-OF-USE DISTRIBUTION RATE FOR PC44 PILOT
SCHEDULE RD - RESIDENTIAL DELIVERY AND ENERGY TIME-OF-USE PILOT
Rate Year 3 (b)

	TEST YEAR BILLING DETERMINANTS	REVENUE AT PROPOSED SCHEDULE R RATES: CURRENT RATES (a)	REVENUE AT PROPOSED SCHEDULE R RATES: REVENUE AT CURRENT RATES		TEST YEAR BILLING DETERMINANTS	PROPOSED CHANGE IN REVENUE: PROPOSED RATES	REVENUE AT PROPOSED RATES	CHANGE IN BASE REVENUE: REVENUE	CHANGE IN BASE REVENUE: PERCENT
	(1)	(2)	(3) = (1) x (2)		(5)	(6)	(7) = (5) x (6)	(8) = (7) - (3)	(9) = (8) / (3)
1. CUSTOMER CHARGE	BILLS				BILLS				
Schedule R	13,694,561	$ 9.00	$ 123,251,047	Schedule RD	13,694,561	$ 9.00	$ 123,251,047	$ -	0.0%
	kWh	$/kWh			kWh	$/kWh			
2. DELIVERY SERVICE CHARGE									
Schedule R - Total	11,489,373,793	0.04250	$ 488,298,386						
				Schedule RD - On Peak	1,478,682,407	0.14274	$ 211,067,127		
				Schedule RD - Off Peak	10,010,691,386	0.02769	$ 277,196,044		
				Schedule RD - Total	11,489,373,793		$ 488,263,171	$ (35,215)	0.0%
3. TOTAL REVENUE			$ 611,549,433				$ 611,514,218	$ (35,215)	0.0%
				4. TOTAL REVENUE ALLOCATED				$ -	
				5. DIFFERENCE FROM REVENUE ALLOCATED				$ (35,215)	

(a) Proposed Schedule R rates in Sheet E-4.
(b) The Time-of-Use Pilot currently will be effective through April 1, 2022 unless the Commission allows continuation of the pilot rates. Rate Year 2 and 3 will be applicable in the event that the Commission does allow continuation.

SCHEDULE - R

Rate Year 1: SCHEDULE R - RESIDENTIAL SERVICE

1. TARGET BASE REVENUE - 2021 - Rate Year 1 (a)	$	518,269,344
2. LESS: Rate Year 1 CUSTOMER CHARGE REVENUES		108,119,686
3. Rate Year 1 DELIVERY CHARGE REVENUE	$	410,149,658
4. DIVIDED BY: Rate Year 1 BILLING DETERMINANTS - KWH		11,235,369,008
5. DELIVERY CHARGE INCLUDING MONTHLY RATE ADJUSTMENT	$	0.03651
6. CURRENT DELIVERY SERVICE RATE - CASE NO. 9610		0.03507
7. Rate Year 1 RIDER 25 ADJUSTMENT	$	0.00144

Rate Year 2: SCHEDULE R - RESIDENTIAL SERVICE

1. TARGET BASE REVENUE - 2022 - Rate Year 2 (a)	$	521,083,776
2. ADD: Rate Year 1 REVENUE INCREASE	$	-
3. LESS: Rate Year 2 CUSTOMER CHARGE REVENUES		108,666,249
4. Rate Year 2 DELIVERY CHARGE REVENUE	$	412,417,527
5. DIVIDED BY: Rate Year 2 BILLING DETERMINANTS - KWH		11,352,319,553
6. DELIVERY CHARGE INCLUDING MONTHLY RATE ADJUSTMENT	$	0.03633
7. Rate Year 1 PROPOSED DELIVERY SERVICE RATE		0.03651
8. Rate Year 2 RIDER 25 ADJUSTMENT	$	(0.00018)

Rate Year 3: SCHEDULE R - RESIDENTIAL SERVICE

1. TARGET BASE REVENUE - 2023 - Rate Year 3 (a)	$	525,553,286
2. ADD: Rate Year 1 REVENUE INCREASE	$	-
3. ADD: Rate Year 2 REVENUE INCREASE	$	-
4. LESS: Rate Year 3 CUSTOMER CHARGE REVENUES		109,556,487
5. Rate Year 3 DELIVERY CHARGE REVENUE	$	415,996,800
6. DIVIDED BY: Rate Year 3 BILLING DETERMINANTS - KWH		11,489,373,793
7. DELIVERY CHARGE INCLUDING MONTHLY RATE ADJUSTMENT	$	0.03621
8. Rate Year 2 PROPOSED DELIVERY SERVICE RATE		0.03633
9. Rate Year 3 RIDER 25 ADJUSTMENT	$	(0.00012)

SCHEDULE - RL

Rate Year 1: SCHEDULE RL - RESIDENTIAL OPTIONAL TIME-OF-USE SERVICE

1. TARGET BASE REVENUE - 2021 - Rate Year 1 (a)	$	38,799,869
2. LESS: Rate Year 1 CUSTOMER CHARGE REVENUES		8,401,377
3. Rate Year 1 DELIVERY CHARGE REVENUE	$	30,398,492
4. DIVIDED BY: Rate Year 1 BILLING DETERMINANTS - KWH		826,001,760
5. DELIVERY CHARGE INCLUDING MONTHLY RATE ADJUSTMENT	$	0.03680
6. CURRENT DELIVERY SERVICE RATE - CASE NO. 9610		0.03538
7. Rate Year 1 RIDER 25 ADJUSTMENT	$	0.00142

Rate Year 2: SCHEDULE RL - RESIDENTIAL OPTIONAL TIME-OF-USE SERVICE

1. TARGET BASE REVENUE - 2022 - Rate Year 2 (a)	$	39,000,191
2. ADD: Rate Year 1 REVENUE INCREASE	$	-
3. LESS: Rate Year 2 CUSTOMER CHARGE REVENUES		8,439,618
4. Rate Year 2 DELIVERY CHARGE REVENUE	$	30,560,573
5. DIVIDED BY: Rate Year 2 BILLING DETERMINANTS - KWH		834,657,338
6. DELIVERY CHARGE INCLUDING MONTHLY RATE ADJUSTMENT	$	0.03661
7. Rate Year 1 PROPOSED DELIVERY SERVICE RATE		0.03680
8. Rate Year 2 RIDER 25 ADJUSTMENT	$	(0.00019)

Rate Year 3: SCHEDULE RL - RESIDENTIAL OPTIONAL TIME-OF-USE SERVICE

1. TARGET BASE REVENUE - 2023 - Rate Year 3 (a)	$	39,324,920
2. ADD: Rate Year 1 REVENUE INCREASE	$	-
3. ADD: Rate Year 2 REVENUE INCREASE	$	-
4. LESS: Rate Year 3 CUSTOMER CHARGE REVENUES		8,504,527
5. Rate Year 3 DELIVERY CHARGE REVENUE	$	30,820,393
6. DIVIDED BY: Rate Year 3 BILLING DETERMINANTS - KWH		845,479,981
7. DELIVERY CHARGE INCLUDING MONTHLY RATE ADJUSTMENT	$	0.03645
8. Rate Year 2 PROPOSED DELIVERY SERVICE RATE		0.03661
9. Rate Year 3 RIDER 25 ADJUSTMENT	$	(0.00016)

SCHEDULE - G

Rate Year 1: SCHEDULE G - GENERAL SERVICE

1. TARGET BASE REVENUE - 2021 - Rate Year 1 (a)	$	99,155,325
2. LESS: Rate Year 1 CUSTOMER CHARGE REVENUES		16,014,854
3. Rate Year 1 DELIVERY CHARGE REVENUE	$	83,140,471
4. DIVIDED BY: Rate Year 1 BILLING DETERMINANTS - KWH		2,446,608,171
5. DELIVERY CHARGE INCLUDING MONTHLY RATE ADJUSTMENT	$	0.03398
6. CURRENT DELIVERY SERVICE RATE - CASE NO. 9610		0.03194
7. Rate Year 1 RIDER 25 ADJUSTMENT	$	0.00204

Rate Year 2: SCHEDULE G - GENERAL SERVICE

1. TARGET BASE REVENUE - 2022 - Rate Year 2 (a)	$	99,388,271
2. ADD: Rate Year 1 REVENUE INCREASE	$	-
3. LESS: Rate Year 2 CUSTOMER CHARGE REVENUES		16,052,166
4. Rate Year 2 DELIVERY CHARGE REVENUE	$	83,336,105
5. DIVIDED BY: Rate Year 2 BILLING DETERMINANTS - KWH		2,410,169,150
6. DELIVERY CHARGE INCLUDING MONTHLY RATE ADJUSTMENT	$	0.03458
7. Rate Year 1 PROPOSED DELIVERY SERVICE RATE		0.03398
8. Rate Year 2 RIDER 25 ADJUSTMENT	$	0.00060

Rate Year 3: SCHEDULE G - GENERAL SERVICE

1. TARGET BASE REVENUE - 2023 - Rate Year 3 (a)	$	99,620,770
2. ADD: Rate Year 1 REVENUE INCREASE	$	-
3. ADD: Rate Year 2 REVENUE INCREASE	$	-
4. LESS: Rate Year 3 CUSTOMER CHARGE REVENUES		16,089,477
5. Rate Year 3 DELIVERY CHARGE REVENUE	$	83,531,293
6. DIVIDED BY: Rate Year 3 BILLING DETERMINANTS - KWH		2,383,471,793
7. DELIVERY CHARGE INCLUDING MONTHLY RATE ADJUSTMENT	$	0.03505
8. Rate Year 2 PROPOSED DELIVERY SERVICE RATE		0.03458
9. Rate Year 3 RIDER 25 ADJUSTMENT	$	0.00047

SCHEDULE - GS

Rate Year 1: SCHEDULE GS - GENERAL SMALL SERVICE

1. TARGET BASE REVENUE - 2021 - Rate Year 1 (a)	$	8,125,508
2. LESS: Rate Year 1 CUSTOMER CHARGE REVENUES		583,558
3. Rate Year 1 DELIVERY CHARGE REVENUE	$	7,541,951
4. DIVIDED BY: Rate Year 1 BILLING DETERMINANTS - KWH		237,723,833
5. DELIVERY CHARGE INCLUDING MONTHLY RATE ADJUSTMENT	$	0.03173
6. CURRENT DELIVERY SERVICE RATE - CASE NO. 9610		0.02937
7. Rate Year 1 RIDER 25 ADJUSTMENT	$	0.00236

Rate Year 2: SCHEDULE GS - GENERAL SMALL SERVICE

1. TARGET BASE REVENUE - 2022 - Rate Year 2 (a)	$	8,144,081
2. ADD: Rate Year 1 REVENUE INCREASE	$	-
3. LESS: Rate Year 2 CUSTOMER CHARGE REVENUES		584,891
4. Rate Year 2 DELIVERY CHARGE REVENUE	$	7,559,190
5. DIVIDED BY: Rate Year 2 BILLING DETERMINANTS - KWH		234,253,622
6. DELIVERY CHARGE INCLUDING MONTHLY RATE ADJUSTMENT	$	0.03227
7. Rate Year 1 PROPOSED DELIVERY SERVICE RATE		0.03173
8. Rate Year 2 RIDER 25 ADJUSTMENT	$	0.00054

Rate Year 3: SCHEDULE GS - GENERAL SMALL SERVICE

1. TARGET BASE REVENUE - 2023 - Rate Year 3 (a)	$	8,162,655
2. ADD: Rate Year 1 REVENUE INCREASE	$	-
3. ADD: Rate Year 2 REVENUE INCREASE	$	-
4. LESS: Rate Year 3 CUSTOMER CHARGE REVENUES		586,225
5. Rate Year 3 DELIVERY CHARGE REVENUE	$	7,576,429
6. DIVIDED BY: Rate Year 3 BILLING DETERMINANTS - KWH		231,636,956
7. DELIVERY CHARGE INCLUDING MONTHLY RATE ADJUSTMENT	$	0.03271
8. Rate Year 2 PROPOSED DELIVERY SERVICE RATE		0.03227
9. Rate Year 3 RIDER 25 ADJUSTMENT	$	0.00044

SCHEDULE - GL

Rate Year 1: SCHEDULE GL - GENERAL SERVICE LARGE

1. TARGET BASE REVENUE - 2021 - Rate Year 1 (a)	$	219,505,119
2. LESS: Rate Year 1 CUSTOMER CHARGE REVENUES		12,557,333
3. LESS: Rate Year 1 DEMAND CHARGE REVENUES		75,175,402
4. Rate Year 1 DELIVERY CHARGE REVENUE	$	131,772,384
5. DIVIDED BY: Rate Year 1 BILLING DETERMINANTS - KWH		7,523,177,291
6. DELIVERY CHARGE INCLUDING MONTHLY RATE ADJUSTMENT	$	0.01752
7. CURRENT DELIVERY SERVICE RATE - CASE NO. 9610		0.01686
8. Rate Year 1 RIDER 25 ADJUSTMENT	$	0.00066

Rate Year 2: SCHEDULE GL - GENERAL SERVICE LARGE

1. TARGET BASE REVENUE - 2022 - Rate Year 2 (a)	$	220,999,379
2. ADD: Rate Year 1 REVENUE INCREASE		-
3. LESS: Rate Year 2 DEMAND CHARGE REVENUES		75,192,141
4. LESS: Rate Year 2 CUSTOMER CHARGE REVENUES		12,642,817
5. Rate Year 2 DELIVERY CHARGE REVENUE	$	133,164,421
6. DIVIDED BY: Rate Year 2 BILLING DETERMINANTS - KWH		7,516,804,540
7. DELIVERY CHARGE INCLUDING MONTHLY RATE ADJUSTMENT	$	0.01772
8. Rate Year 1 PROPOSED DELIVERY SERVICE RATE		0.01752
9. Rate Year 2 RIDER 25 ADJUSTMENT	$	0.00020

Rate Year 3: SCHEDULE GL - GENERAL SERVICE LARGE

1. TARGET BASE REVENUE - 2023 - Rate Year 3 (a)	$	222,493,639
2. ADD: Rate Year 1 REVENUE INCREASE		-
3. ADD: Rate Year 2 REVENUE INCREASE		-
3. LESS: Rate Year 3 DEMAND CHARGE REVENUES		75,194,065
4. LESS: Rate Year 3 CUSTOMER CHARGE REVENUES		12,728,302
5. Rate Year 3 DELIVERY CHARGE REVENUE	$	134,571,272
6. DIVIDED BY: Rate Year 3 BILLING DETERMINANTS - KWH		7,516,071,931
7. DELIVERY CHARGE INCLUDING MONTHLY RATE ADJUSTMENT	$	0.01790
8. Rate Year 2 PROPOSED DELIVERY SERVICE RATE		0.01772
9. Rate Year 3 RIDER 25 ADJUSTMENT	$	0.00018

SCHEDULE - GLP

Rate Year 1: SCHEDULE GLP - GENERAL SERVICE LARGE PRIMARY		
1. TARGET BASE REVENUE - 2021 - Rate Year 1 (a)	$	10,375,949
2. LESS: Rate Year 1 CUSTOMER CHARGE REVENUES		228,887
3. LESS: Rate Year 1 DEMAND CHARGE REVENUES		3,378,372
4. Rate Year 1 DELIVERY CHARGE REVENUE	$	6,768,691
5. DIVIDED BY: Rate Year 1 BILLING DETERMINANTS - KWH		383,704,633
6. DELIVERY CHARGE INCLUDING MONTHLY RATE ADJUSTMENT	$	0.01764
7. CURRENT DELIVERY SERVICE RATE - CASE NO. 9610		0.01619
8. Rate Year 1 RIDER 25 ADJUSTMENT	$	0.00145
Rate Year 2: SCHEDULE GLP - GENERAL SERVICE LARGE PRIMARY		
1. TARGET BASE REVENUE - 2022 - Rate Year 2 (a)	$	10,446,583
2. ADD: Rate Year 1 REVENUE INCREASE		-
3. LESS: Rate Year 2 DEMAND CHARGE REVENUES		3,376,370
4. LESS: Rate Year 2 CUSTOMER CHARGE REVENUES		230,445
5. Rate Year 2 DELIVERY CHARGE REVENUE	$	6,839,769
6. DIVIDED BY: Rate Year 2 BILLING DETERMINANTS - KWH		383,399,190
7. DELIVERY CHARGE INCLUDING MONTHLY RATE ADJUSTMENT	$	0.01784
8. Rate Year 1 PROPOSED DELIVERY SERVICE RATE		0.01764
9. Rate Year 2 RIDER 25 ADJUSTMENT	$	0.00020
Rate Year 3: SCHEDULE GLP - GENERAL SERVICE LARGE PRIMARY		
1. TARGET BASE REVENUE - 2023 - Rate Year 3 (a)	$	10,517,218
2. ADD: Rate Year 1 REVENUE INCREASE		-
3. ADD: Rate Year 2 REVENUE INCREASE		-
3. LESS: Rate Year 3 DEMAND CHARGE REVENUES		3,376,195
4. LESS: Rate Year 3 CUSTOMER CHARGE REVENUES		232,003
5. Rate Year 3 DELIVERY CHARGE REVENUE	$	6,909,020
6. DIVIDED BY: Rate Year 3 BILLING DETERMINANTS - KWH		383,372,434
7. DELIVERY CHARGE INCLUDING MONTHLY RATE ADJUSTMENT	$	0.01802
8. Rate Year 2 PROPOSED DELIVERY SERVICE RATE		0.01784
9. Rate Year 3 RIDER 25 ADJUSTMENT	$	0.00018

(a) - Based on Rider 25 targets set in Case No. 9610.

BALTIMORE GAS AND ELECTRIC COMPANY
PERCENT INCREASE IN CUSTOMERS' BILLS

Rate Year 1 - 2021

	Distribution Revenues from Customers' BGE Bills (a)	Total Sales (kWh)	Estimated Commodity Rev (Volumes x Rate)	Customers' Total Electric Bills	Increase in Customers' BGE Bills (E-1 Sheet, Col. 1)	Percent Increase in Customers' Total Bills	Annual Number of Electric Bills	Average Monthly Bill Impact
	(1)	(2)	(3) = (2) x rate (b)	(4) = (1) + (3)	(5)	(6) = (5) / (4)	(7)	(8) = (7) / (5)
1. SCHEDULE R	$ 532,466,237	11,235,369,008	$ 828,159,050	$ 1,360,625,287	$ -	0.0%	13,514,961	$ -
2. SCHEDULE RL	$ 39,750,030	826,001,760	$ 60,884,590	$ 100,634,620	$ -	0.0%	700,115	$ -
3. SCHEDULE G	$ 105,852,158	2,447,991,586	$ 157,503,779	$ 263,355,936	$ -	0.0%	1,291,716	$ -
4. SCHEDULE GU	$ 240,572	2,505,002	$ 161,172	$ 401,744	$ -	0.0%	25,588	$ -
5. SCHEDULE GS	$ 8,689,559	237,723,833	$ 15,295,151	$ 23,984,711	$ -	0.0%	31,374	$ -
6. SCHEDULE GL	$ 242,174,936	7,906,881,923	$ 473,780,365	$ 715,955,300	$ -	0.0%	147,276	$ -
7. SCHEDULE P	$ 66,594,964	4,798,502,498	$ 287,526,270	$ 354,121,233	$ -	0.0%	3,887	$ -
8. SCHEDULE T	$ 3,185,558	690,138,004	$ 41,353,069	$ 44,538,628	$ -	0.0%	72	$ -
9. SCHEDULE SL (c)	$ 26,016,915	154,651,646	$ 7,743,408	$ 33,760,323	$ -	0.0%	n/a	n/a
10. SCHEDULE PL (c)	$ 19,410,026	66,281,001	$ 3,596,232	$ 23,006,257	$ -	0.0%	n/a	n/a
11. TOTAL	$ 1,044,380,954	28,366,046,260	$ 1,876,003,085	$ 2,920,384,039	$ -	0.0%		

(a) Total distribution revenues include base revenues as well as all other Riders and appropriate service charges.

(b) Estimated POLR Rate

Schedule R/RL	= $	0.07371	per kWh
Schedule G/GU/GS	= $	0.06434	per kWh
Schedule GL	= $	0.05992	per kWh
Schedule P/T	= $	0.05992	per kWh
Schedule SL	= $	0.05007	per kWh

(c) Schedule SL and PL billing determinants are the number of fixtures as well as lamp-watts. Therefore customer counts are not shown for the purposes of this bill impact analysis.

BALTIMORE GAS AND ELECTRIC COMPANY
PERCENT INCREASE IN CUSTOMERS' BILLS

Rate Year 2 - 2022

	Distribution Revenues from Customers' BGE Bills (a)	Total Sales (kWh)	Estimated Commodity Rev (Volumes x Rate)	Customers' Total Electric Bills	Increase in Customers' BGE Bills (E-1 Sheet, Col. 1)	Percent Increase in Customers' Total Bills	Annual Number of Electric Bills	Average Monthly Bill Impact
	(1)	(2)	(3) = (2) x rate (b)	(4) = (1) + (3)	(5)	(6) = (5) / (4)	(7)	(8) = (7) / (5)
1. SCHEDULE R	$ 535,405,197	11,352,319,553	$ 836,779,474	$ 1,372,184,671	$ -	0.0%	13,583,281	$ -
2. SCHEDULE RL	$ 39,958,971	834,657,338	$ 61,522,592	$ 101,481,563	$ -	0.0%	703,302	$ -
3. SCHEDULE G	$ 106,061,369	2,411,531,961	$ 155,157,966	$ 261,219,336	$ -	0.0%	1,294,726	$ -
4. SCHEDULE GU	$ 241,047	2,505,002	$ 161,172	$ 402,219	$ -	0.0%	25,648	$ -
5. SCHEDULE GS	$ 8,705,880	234,253,622	$ 15,071,878	$ 23,777,758	$ -	0.0%	31,446	$ -
6. SCHEDULE GL	$ 243,770,682	7,900,203,730	$ 473,380,208	$ 717,150,889	$ -	0.0%	146,287	$ -
7. SCHEDULE P	$ 65,738,129	4,734,217,945	$ 283,674,339	$ 349,412,468	$ -	0.0%	3,838	$ -
8. SCHEDULE T	$ 3,140,226	679,567,538	$ 40,719,687	$ 43,859,913	$ -	0.0%	72	$ -
9. SCHEDULE SL (c)	$ 25,987,287	150,068,399	$ 7,513,925	$ 33,501,212	$ -	0.0%	n/a	n/a
10. SCHEDULE PL (c)	$ 19,409,211	65,363,906	$ 3,596,232	$ 23,005,443	$ -	0.0%	n/a	n/a
11. TOTAL	$ 1,048,417,999	28,364,688,994	$ 1,877,577,473	$ 2,925,995,472	$ -	0.0%		

(a) Total distribution revenues include base revenues as well as all other Riders and appropriate service charges.

(b) Estimated POLR Rate

Schedule R/RL	=	$ 0.07371	per kWh
Schedule G/GU/GS	=	$ 0.06434	per kWh
Schedule GL	=	$ 0.05992	per kWh
Schedule P/T	=	$ 0.05992	per kWh
Schedule SL	=	$ 0.05007	per kWh

(c) Schedule SL and PL billing determinants are the number of fixtures as well as lamp-watts. Therefore customer counts are not shown for the purposes of this bill impact analysis.

BALTIMORE GAS AND ELECTRIC COMPANY
PERCENT INCREASE IN CUSTOMERS' BILLS

Rate Year 3 - 2023

	Distribution Revenues from Customers' BGE Bills (a)	Total Sales (kWh)	Estimated Commodity Rev (Volumes x Rate)	Customers' Total Electric Bills	Increase in Customers' BGE Bills (E-1 Sheet, Col. 1)	Percent Increase in Customers' Total Bills	Annual Number of Electric Bills	Average Monthly Bill Impact
	(1)	(2)	(3) = (2) x rate (b)	(4) = (1) + (3)	(5)	(6) = (5) / (4)	(7)	(8) = (7) / (5)
1. SCHEDULE R	$ 540,028,054	11,489,373,793	$ 846,881,742	$ 1,386,909,796	$ 85,962,722	6.2%	13,694,561	$ 6.28
2. SCHEDULE RL	$ 40,294,737	845,479,981	$ 62,320,329	$ 102,615,067	$ 4,599,411	4.5%	708,711	$ 6.49
3. SCHEDULE G	$ 106,278,835	2,384,819,508	$ 153,439,287	$ 259,718,122	$ 11,764,674	4.5%	1,297,735	$ 9.07
4. SCHEDULE GU	$ 241,541	2,467,693	$ 158,771	$ 400,313	$ 26,722	6.7%	25,708	$ 1.04
5. SCHEDULE GS	$ 8,722,919	231,636,956	$ 14,903,522	$ 23,626,441	$ 963,610	4.1%	31,517	$ 30.57
6. SCHEDULE GL	$ 245,369,592	7,899,444,365	$ 473,334,706	$ 718,704,298	$ 27,248,411	3.8%	147,276	$ 185.02
7. SCHEDULE P	$ 64,981,347	4,677,979,790	$ 280,304,549	$ 345,285,896	$ 7,082,083	2.1%	3,788	$ 1,869.63
8. SCHEDULE T	$ 3,143,630	680,401,187	$ 40,769,639	$ 43,913,269	$ -	0.0%	72	$ -
9. SCHEDULE SL (c)	$ 25,957,625	145,485,153	$ 7,284,442	$ 33,242,066	$ 2,717,910	8.2%	n/a	n/a
10. SCHEDULE PL (c)	$ 19,408,633	64,724,868	$ 3,596,232	$ 23,004,865	$ -	0.0%	n/a	n/a
11. TOTAL	$ 1,054,426,913	28,421,813,295	$ 1,882,993,220	$ 2,937,420,133	$ 140,365,543	4.8%		

(a) Total distribution revenues include base revenues as well as all other Riders and appropriate service charges.

(b) Estimated POLR Rate

Schedule R/RL	=	$	0.07371	per kWh
Schedule G/GU/GS	=	$	0.06434	per kWh
Schedule GL	=	$	0.05992	per kWh
Schedule P/T	=	$	0.05992	per kWh
Schedule SL	=	$	0.05007	per kWh

(c) Schedule SL and PL billing determinants are the number of fixtures as well as lamp-watts. Therefore customer counts are not shown for the purposes of this bill impact analysis.

Annual Average Change Over the MYP	**1.6%**

BALTIMORE GAS AND ELECTRIC COMPANY
COMPARISON OF BILLS FOR
CURRENT VERSUS PROPOSED RATES
Residential Customers (Schedule R)

Rate Year 1 - 2021

		CURRENT RATES	PROPOSED RATES	
Electric Supply		**$ 0.07371**	**$ 0.07371**	** shown on bill*
Standard Offer Service Rate	per kWh	$ 0.07220	$ 0.07220	
Energy Cost Adjustment (Rider 8)	per kWh	$ 0.00151	$ 0.00151	
Delivery				
Customer Charge (Schedule R)	per month	**$ 8.00**	**$ 8.00**	** shown on bill*
EmPOWER MD Chg	per kWh	**$ 0.00830**	**$ 0.00830**	** shown on bill*
Energy Efficiency (Rider 2)	per kWh	$ 0.00466	$ 0.00466	
Peak Time Rebates (Rider 26)	per kWh	$ 0.00019	$ 0.00019	
Demand Response (Rider 15)	per kWh	$ 0.00345	$ 0.00345	
Distribution Chg	per kWh	**$ 0.03523**	**$ 0.03523**	** shown on bill*
Base Distribution Charge (Schedule R)	per kWh	$ 0.03651	$ 0.03651	
Administrative Cost Adjustment (Rider 10)	per kWh	$ (0.00128)	$ (0.00128)	
Taxes & Surcharges				
MD Universal Service Program	per month	**$ 0.32**	**$ 0.32**	** shown on bill*
Environmental Surcharge	per kWh	**$ 0.000143**	**$ 0.000143**	** shown on bill*
Franchise Tax	per kWh	**$ 0.00062**	**$ 0.00062**	** shown on bill*

CUSTOMER PERCENTILE	MONTHLY USE (KWH)	BILL AT CURRENT RATES	BILL AT PROPOSED RATES	CHANGE IN BILL	PERCENT CHANGE IN BILL
	100	$20.12	$20.12	$0.00	0.00%
	200	$31.92	$31.92	$0.00	0.00%
	300	$43.72	$43.72	$0.00	0.00%
25th Percentile	381	$53.28	$53.28	$0.00	0.00%
	400	$55.52	$55.52	$0.00	0.00%
	600	$79.12	$79.12	$0.00	0.00%
Average (Electric Non-Heating)	609	$80.18	$80.18	$0.00	0.00%
Average (Median)	706	$91.63	$91.63	$0.00	0.00%
	800	$102.72	$102.72	$0.00	0.00%
Average (Mean)	831	$106.38	$106.38	$0.00	0.00%
	1000	$126.32	$126.32	$0.00	0.00%
	1100	$138.12	$138.12	$0.00	0.00%
75th Percentile	1140	$142.84	$142.84	$0.00	0.00%
	1300	$161.72	$161.72	$0.00	0.00%
	1500	$185.32	$185.32	$0.00	0.00%
	1750	$214.83	$214.83	$0.00	0.00%
	2000	$244.33	$244.33	$0.00	0.00%
	2500	$303.33	$303.33	$0.00	0.00%
	5000	$598.34	$598.34	$0.00	0.00%

BALTIMORE GAS AND ELECTRIC COMPANY
COMPARISON OF BILLS FOR
CURRENT VERSUS PROPOSED RATES
Residential Customers (Schedule R)

Rate Year 2 - 2022

		CURRENT RATES	PROPOSED RATES	
Electric Supply		**$ 0.07371**	**$ 0.07371**	** shown on bill*
Standard Offer Service Rate	per kWh	$ 0.07220	$ 0.07220	
Energy Cost Adjustment (Rider 8)	per kWh	$ 0.00151	$ 0.00151	
Delivery				
Customer Charge (Schedule R)	per month	**$ 8.00**	**$ 8.00**	** shown on bill*
EmPOWER MD Chg	per kWh	**$ 0.00830**	**$ 0.00830**	** shown on bill*
Energy Efficiency (Rider 2)	per kWh	$ 0.00466	$ 0.00466	
Peak Time Rebates (Rider 26)	per kWh	$ 0.00019	$ 0.00019	
Demand Response (Rider 15)	per kWh	$ 0.00345	$ 0.00345	
Distribution Chg	per kWh	**$ 0.03505**	**$ 0.03505**	** shown on bill*
Base Distribution Charge (Schedule R)	per kWh	$ 0.03633	$ 0.03633	
Administrative Cost Adjustment (Rider 10)	per kWh	$ (0.00128)	$ (0.00128)	
Taxes & Surcharges				
MD Universal Service Program	per month	**$ 0.32**	**$ 0.32**	** shown on bill*
Environmental Surcharge	per kWh	**$ 0.000143**	**$ 0.000143**	** shown on bill*
Franchise Tax	per kWh	**$ 0.00062**	**$ 0.00062**	** shown on bill*

CUSTOMER PERCENTILE	MONTHLY USE (KWH)	BILL AT CURRENT RATES	BILL AT PROPOSED RATES	CHANGE IN BILL	PERCENT CHANGE IN BILL
	100	$20.10	$20.10	$0.00	0.00%
	200	$31.88	$31.88	$0.00	0.00%
	300	$43.67	$43.67	$0.00	0.00%
25th Percentile	381	$53.21	$53.21	$0.00	0.00%
	400	$55.45	$55.45	$0.00	0.00%
	600	$79.01	$79.01	$0.00	0.00%
Average (Electric Non-Heating)	609	$80.07	$80.07	$0.00	0.00%
Average (Median)	706	$91.50	$91.50	$0.00	0.00%
	800	$102.58	$102.58	$0.00	0.00%
Average (Mean)	836	$106.82	$106.82	$0.00	0.00%
	1000	$126.14	$126.14	$0.00	0.00%
	1100	$137.93	$137.93	$0.00	0.00%
75th Percentile	1140	$142.64	$142.64	$0.00	0.00%
	1300	$161.49	$161.49	$0.00	0.00%
	1500	$185.05	$185.05	$0.00	0.00%
	1750	$214.51	$214.51	$0.00	0.00%
	2000	$243.97	$243.97	$0.00	0.00%
	2500	$302.88	$302.88	$0.00	0.00%
	5000	$597.44	$597.44	$0.00	0.00%

BALTIMORE GAS AND ELECTRIC COMPANY
COMPARISON OF BILLS FOR
CURRENT VERSUS PROPOSED RATES
Residential Customers (Schedule R)

Rate Year 3 - 2023

		CURRENT RATES	PROPOSED RATES	
Electric Supply		**$ 0.07371**	**$ 0.07371**	** shown on bill*
Standard Offer Service Rate	per kWh	$ 0.07220	$ 0.07220	
Energy Cost Adjustment (Rider 8)	per kWh	$ 0.00151	$ 0.00151	
Delivery				
Customer Charge (Schedule R)	per month	**$ 8.00**	**$ 9.00**	** shown on bill*
EmPOWER MD Chg	per kWh	**$ 0.00830**	**$ 0.00830**	** shown on bill*
Energy Efficiency (Rider 2)	per kWh	$ 0.00466	$ 0.00466	
Peak Time Rebates (Rider 26)	per kWh	$ 0.00019	$ 0.00019	
Demand Response (Rider 15)	per kWh	$ 0.00345	$ 0.00345	
Distribution Chg	per kWh	**$ 0.03493**	**$ 0.04122**	** shown on bill*
Base Distribution Charge (Schedule R)	per kWh	$ 0.03621	$ 0.04250	
Administrative Cost Adjustment (Rider 10)	per kWh	$ (0.00128)	$ (0.00128)	
Taxes & Surcharges				
MD Universal Service Program	per month	**$ 0.32**	**$ 0.32**	** shown on bill*
Environmental Surcharge	per kWh	**$ 0.000143**	**$ 0.000143**	** shown on bill*
Franchise Tax	per kWh	**$ 0.00062**	**$ 0.00062**	** shown on bill*

CUSTOMER PERCENTILE	MONTHLY USE (KWH)	BILL AT CURRENT RATES	BILL AT PROPOSED RATES	CHANGE IN BILL	PERCENT CHANGE IN BILL
	100	$20.09	$21.72	$1.63	8.11%
	200	$31.86	$34.12	$2.26	7.09%
	300	$43.63	$46.52	$2.89	6.62%
25th Percentile	381	$53.16	$56.56	$3.40	6.39%
	400	$55.40	$58.92	$3.52	6.35%
	600	$78.94	$83.72	$4.77	6.05%
Average (Electric Non-Heating)	609	$80.00	$84.83	$4.83	6.04%
Average (Median)	706	$91.42	$96.86	$5.44	5.95%
	800	$102.48	$108.51	$6.03	5.89%
Average (Mean)	839	$107.07	$113.35	$6.28	5.86%
	1000	$126.02	$133.31	$7.29	5.78%
	1100	$137.79	$145.71	$7.92	5.75%
75th Percentile	1140	$142.50	$150.67	$8.17	5.73%
	1300	$161.33	$170.51	$9.18	5.69%
	1500	$184.87	$195.31	$10.44	5.64%
	1750	$214.30	$226.31	$12.01	5.60%
	2000	$243.73	$257.31	$13.58	5.57%
	2500	$302.58	$319.30	$16.73	5.53%
	5000	$596.84	$629.29	$32.45	5.44%
Annual Average Change Over the MYP				**$ 2.09**	**2.0%**

BALTIMORE GAS AND ELECTRIC COMPANY
COMPARISON OF BILLS FOR
CURRENT VERSUS PROPOSED RATES

Rate Year 1 - 2021

GAS SCHEDULE D - RESIDENTIAL SERVICE

		CURRENT RATES	PROPOSED RATES	
Gas Supply		**$ 0.4068**	**$ 0.4068**	** shown on bill*
Monthly Commodity Rate	per therm	$ 0.3868	$ 0.3868	
Gas Administrative Charge	per therm	$ 0.0200	$ 0.0200	** included as part of the monthly commodity rate*
Delivery				
Customer Charge (Schedule D)	per month	**$ 14.25**	**$ 14.25**	** shown on bill*
EmPOWER MD Chg (Rider 1)	per therm	$ 0.0447	$ 0.0447	** shown on bill*
STRIDE Charge	per month	$ 1.03	$ 1.03	** shown on bill*
Distribution Chg		**$ 0.5952**	**$ 0.5952**	** shown on bill, excludes the effect of Rider 8 and GAC*
Base Distribution Charge (Schedule D)	per therm	$ 0.5921	$ 0.5921	
Gas Choice & Reliability Charge (Rider 7)	per therm	$ 0.0031	$ 0.0031	
Taxes & Surcharges				
Franchise Tax	per therm	**$ 0.00402**	**$ 0.00402**	** shown on bill*

ELECTRIC SCHEDULE R - RESIDENTIAL SERVICE

		CURRENT RATES	PROPOSED RATES	
Electric Supply		**$ 0.07371**	**$ 0.07371**	** shown on bill*
Delivery				
Customer Charge (Schedule R)	per month	**$ 8.00**	**$ 8.00**	** shown on bill*
EmPOWER MD Chg	per kWh	**$ 0.00830**	**$ 0.00830**	** shown on bill*
Energy Efficiency (Rider 2)	per kWh	$ 0.00466	$ 0.00466	
Peak Time Rebates (Rider 26)	per kWh	$ 0.00019	$ 0.00019	
Demand Response (Rider 15)	per kWh	$ 0.00345	$ 0.00345	
Distribution Chg	per kWh	**$ 0.03523**	**$ 0.03523**	** shown on bill*
Base Distribution Charge (Schedule R)	per kWh	$ 0.03651	$ 0.03651	
Administrative Cost Adjustment (Rider 10)	per kWh	$ (0.00128)	$ (0.00128)	
Taxes & Surcharges				
MD Universal Service Program	per month	**$ 0.32**	**$ 0.32**	** shown on bill*
Environmental Surcharge	per kWh	**$ 0.000143**	**$ 0.000143**	** shown on bill*
Franchise Tax	per kWh	**$ 0.00062**	**$ 0.00062**	** shown on bill*

	MONTHLY VOLUMES	BILL AT CURRENT RATES	BILL AT PROPOSED RATES	CHANGE IN BILL	PERCENT CHANGE IN BILL
Average Gas Customer (Therms)	56	$74.12	$74.12	$0.00	0.00%
Electric Non-Heating Customer (kWh)	609	$80.18	$80.18	$0.00	0.00%
Average Total Bill		**$154.30**	**$154.30**	**$0.00**	**0.00%**

BALTIMORE GAS AND ELECTRIC COMPANY
COMPARISON OF BILLS FOR
CURRENT VERSUS PROPOSED RATES

Rate Year 2 - 2022

GAS SCHEDULE D - RESIDENTIAL SERVICE

		CURRENT RATES	PROPOSED RATES	
Gas Supply		**$ 0.4068**	**$ 0.4068**	** shown on bill*
Monthly Commodity Rate	per therm	$ 0.3868	$ 0.3868	
Gas Administrative Charge	per therm	$ 0.0200	$ 0.0200	** included as part of the monthly commodity rate*
Delivery				
Customer Charge (Schedule D)	per month	**$ 14.25**	**$ 14.25**	** shown on bill*
EmPOWER MD Chg (Rider 1)	per therm	$ 0.0447	$ 0.0447	** shown on bill*
STRIDE Charge	per month	$ 2.00	$ 2.00	** shown on bill*
Distribution Chg		**$ 0.5935**	**$ 0.5935**	** shown on bill, excludes the effect of Rider 8 and GAC*
Base Distribution Charge (Schedule D)	per therm	$ 0.5904	$ 0.5904	
Gas Choice & Reliability Charge (Rider 7)	per therm	$ 0.0031	$ 0.0031	
Taxes & Surcharges				
Franchise Tax	per therm	**$ 0.00402**	**$ 0.00402**	** shown on bill*

ELECTRIC SCHEDULE R - RESIDENTIAL SERVICE

		CURRENT RATES	PROPOSED RATES	
Electric Supply		**$ 0.07371**	**$ 0.07371**	** shown on bill*
Delivery				
Customer Charge (Schedule R)	per month	**$ 8.00**	**$ 8.00**	** shown on bill*
EmPOWER MD Chg	per kWh	**$ 0.00830**	**$ 0.00830**	** shown on bill*
Energy Efficiency (Rider 2)	per kWh	$ 0.00466	$ 0.00466	
Peak Time Rebates (Rider 26)	per kWh	$ 0.00019	$ 0.00019	
Demand Response (Rider 15)	per kWh	$ 0.00345	$ 0.00345	
Distribution Chg	per kWh	**$ 0.03505**	**$ 0.03505**	** shown on bill*
Base Distribution Charge (Schedule R)	per kWh	$ 0.03633	$ 0.03633	
Administrative Cost Adjustment (Rider 10)	per kWh	$ (0.00128)	$ (0.00128)	
Taxes & Surcharges				
MD Universal Service Program	per month	**$ 0.32**	**$ 0.32**	** shown on bill*
Environmental Surcharge	per kWh	**$ 0.000143**	**$ 0.000143**	** shown on bill*
Franchise Tax	per kWh	**$ 0.00062**	**$ 0.00062**	** shown on bill*

	MONTHLY VOLUMES	BILL AT CURRENT RATES	BILL AT PROPOSED RATES	CHANGE IN BILL	PERCENT CHANGE IN BILL
Average Gas Customer (Therms)	56	$75.00	$75.00	$0.00	0.00%
Electric Non-Heating Customer (kWh)	609	$80.07	$80.07	$0.00	0.00%
Average Total Bill		**$155.07**	**$155.07**	**$0.00**	**0.00%**

BALTIMORE GAS AND ELECTRIC COMPANY
COMPARISON OF BILLS FOR
CURRENT VERSUS PROPOSED RATES

Rate Year 3 - 2023

GAS SCHEDULE D - RESIDENTIAL SERVICE

		CURRENT RATES	PROPOSED RATES	
Gas Supply		**$ 0.4068**	**$ 0.4068**	** shown on bill*
Monthly Commodity Rate	per therm	$ 0.3868	$ 0.3868	
Gas Administrative Charge	per therm	$ 0.0200	$ 0.0200	** included as part of the monthly commodity rate*
Delivery				
Customer Charge (Schedule D)	per month	**$ 14.25**	**$ 15.25**	** shown on bill*
EmPOWER MD Chg (Rider 1)	per therm	$ 0.0447	$ 0.0447	** shown on bill*
STRIDE Charge	per month	$ 2.00	$ 2.00	** shown on bill*
Distribution Chg		**$ 0.5929**	**$ 0.7185**	** shown on bill, excludes the effect of Rider 8 and GAC*
Base Distribution Charge (Schedule D)	per therm	$ 0.5898	$ 0.7154	
Gas Choice & Reliability Charge (Rider 7)	per therm	$ 0.0031	$ 0.0031	
Taxes & Surcharges				
Franchise Tax	per therm	**$ 0.00402**	**$ 0.00402**	** shown on bill*

ELECTRIC SCHEDULE R - RESIDENTIAL SERVICE

		CURRENT RATES	PROPOSED RATES	
Electric Supply		**$ 0.07371**	**$ 0.07371**	** shown on bill*
Delivery				
Customer Charge (Schedule R)	per month	**$ 8.00**	**$ 9.00**	** shown on bill*
EmPOWER MD Chg	per kWh	**$ 0.00830**	**$ 0.00830**	** shown on bill*
Energy Efficiency (Rider 2)	per kWh	$ 0.00466	$ 0.00466	
Peak Time Rebates (Rider 26)	per kWh	$ 0.00019	$ 0.00019	
Demand Response (Rider 15)	per kWh	$ 0.00345	$ 0.00345	
Distribution Chg	per kWh	**$ 0.03493**	**$ 0.04122**	** shown on bill*
Base Distribution Charge (Schedule R)	per kWh	$ 0.03621	$ 0.04250	
Administrative Cost Adjustment (Rider 10)	per kWh	$ (0.00128)	$ (0.00128)	
Taxes & Surcharges				
MD Universal Service Program	per month	**$ 0.32**	**$ 0.32**	** shown on bill*
Environmental Surcharge	per kWh	**$ 0.000143**	**$ 0.000143**	** shown on bill*
Franchise Tax	per kWh	**$ 0.00062**	**$ 0.00062**	** shown on bill*

	MONTHLY VOLUMES	BILL AT CURRENT RATES	BILL AT PROPOSED RATES	CHANGE IN BILL	PERCENT CHANGE IN BILL
Average Gas Customer (Therms)	56	$74.96	$83.00	$8.04	10.73%
Electric Non-Heating Customer (kWh)	609	$80.00	$84.83	$4.83	6.04%
Average Total Bill		**$154.96**	**$167.83**	**$12.87**	**8.31%**

Annual Average Change Over the MYP				**$4.29**	**2.8%**

BALTIMORE GAS AND ELECTRIC COMPANY
COMPARISON OF BILLS FOR
CURRENT VERSUS PROPOSED RATES
Small Commercial Customers (Schedule G Type I)

Rate Year 1 - 2021

		CURRENT RATES	PROPOSED RATES	
Electric Supply		**$ 0.06434**	**$ 0.06434**	** shown on bill*
Standard Offer Service Rate	per kWh	$ 0.06622	$ 0.06622	
Energy Cost Adjustment (Rider 8)	per kWh	$ (0.00188)	$ (0.00188)	
Delivery				
Customer Charge (Schedule G)	per month	**$ 12.40**	**$ 12.40**	** shown on bill*
EmPOWER MD Chg	per kWh	**$ 0.00820**	**$ 0.00820**	** shown on bill*
Energy Efficiency (Rider 2)	per kWh	$ 0.00804	$ 0.00804	
Peak Time Rebates (Rider 26)	per kWh	$ 0.00016	$ 0.00016	
Distribution Chg	per kWh	**$ 0.03306**	**$ 0.03306**	** shown on bill*
Base Distribution Charge (Schedule G)	per kWh	$ 0.03398	$ 0.03398	
Administrative Cost Adjustment (Rider 10)	per kWh	$ (0.00092)	$ (0.00092)	
Taxes & Surcharges				
MD Universal Service Program	per month	**$ 1.85**	**$ 1.85**	** shown on bill*
Environmental Surcharge	per kWh	**$ 0.000143**	**$ 0.000143**	** shown on bill*
Franchise Tax	per kWh	**$ 0.00062**	**$ 0.00062**	** shown on bill*

CUSTOMER PERCENTILE	MONTHLY USE (KWH)	BILL AT CURRENT RATES	BILL AT PROPOSED RATES	CHANGE IN BILL	PERCENT CHANGE IN BILL
	25	$16.91	$16.91	$0.00	0.00%
	75	$22.23	$22.23	$0.00	0.00%
	100	$24.89	$24.89	$0.00	0.00%
25th Percentile	184	$33.82	$33.82	$0.00	0.00%
	300	$46.16	$46.16	$0.00	0.00%
	400	$56.80	$56.80	$0.00	0.00%
Average (Median)	547	$72.43	$72.43	$0.00	0.00%
	800	$99.34	$99.34	$0.00	0.00%
	1000	$120.61	$120.61	$0.00	0.00%
75th Percentile	1414	$164.65	$164.65	$0.00	0.00%
Average (Mean)	1894	$215.70	$215.70	$0.00	0.00%
	2500	$280.16	$280.16	$0.00	0.00%
	3000	$333.34	$333.34	$0.00	0.00%
	5000	$546.07	$546.07	$0.00	0.00%
	7000	$758.79	$758.79	$0.00	0.00%
	9000	$971.52	$971.52	$0.00	0.00%
	9500	$1,024.70	$1,024.70	$0.00	0.00%
	10000	$1,077.88	$1,077.88	$0.00	0.00%

BALTIMORE GAS AND ELECTRIC COMPANY
COMPARISON OF BILLS FOR
CURRENT VERSUS PROPOSED RATES
Small Commercial Customers (Schedule G Type I)

Rate Year 2 - 2022

		CURRENT RATES	PROPOSED RATES	
Electric Supply		**$ 0.06434**	**$ 0.06434**	** shown on bill*
Standard Offer Service Rate	per kWh	$ 0.06622	$ 0.06622	
Energy Cost Adjustment (Rider 8)	per kWh	$ (0.00188)	$ (0.00188)	
Delivery				
Customer Charge (Schedule G)	per month	**$ 12.40**	**$ 12.40**	** shown on bill*
EmPOWER MD Chg	per kWh	**$ 0.00820**	**$ 0.00820**	** shown on bill*
Energy Efficiency (Rider 2)	per kWh	$ 0.00804	$ 0.00804	
Peak Time Rebates (Rider 26)	per kWh	$ 0.00016	$ 0.00016	
Distribution Chg	per kWh	**$ 0.03366**	**$ 0.03366**	** shown on bill*
Base Distribution Charge (Schedule G)	per kWh	$ 0.03458	$ 0.03458	
Administrative Cost Adjustment (Rider 10)	per kWh	$ (0.00092)	$ (0.00092)	
Taxes & Surcharges				
MD Universal Service Program	per month	**$ 1.85**	**$ 1.85**	** shown on bill*
Environmental Surcharge	per kWh	**$ 0.000143**	**$ 0.000143**	** shown on bill*
Franchise Tax	per kWh	**$ 0.00062**	**$ 0.00062**	** shown on bill*

CUSTOMER PERCENTILE	MONTHLY USE (KWH)	BILL AT CURRENT RATES	BILL AT PROPOSED RATES	CHANGE IN BILL	PERCENT CHANGE IN BILL
	25	$16.92	$16.92	$0.00	0.00%
	75	$22.27	$22.27	$0.00	0.00%
	100	$24.95	$24.95	$0.00	0.00%
25th Percentile	184	$33.93	$33.93	$0.00	0.00%
	300	$46.34	$46.34	$0.00	0.00%
	400	$57.04	$57.04	$0.00	0.00%
Average (Median)	547	$72.76	$72.76	$0.00	0.00%
	800	$99.82	$99.82	$0.00	0.00%
	1000	$121.21	$121.21	$0.00	0.00%
75th Percentile	1414	$165.50	$165.50	$0.00	0.00%
Average (Mean)	1862	$213.42	$213.42	$0.00	0.00%
	2500	$281.66	$281.66	$0.00	0.00%
	3000	$335.14	$335.14	$0.00	0.00%
	5000	$549.07	$549.07	$0.00	0.00%
	7000	$762.99	$762.99	$0.00	0.00%
	9000	$976.92	$976.92	$0.00	0.00%
	9500	$1,030.40	$1,030.40	$0.00	0.00%
	10000	$1,083.88	$1,083.88	$0.00	0.00%

BALTIMORE GAS AND ELECTRIC COMPANY
COMPARISON OF BILLS FOR
CURRENT VERSUS PROPOSED RATES
Small Commercial Customers (Schedule G Type I)

Rate Year 3 - 2023

		CURRENT RATES	PROPOSED RATES	
Electric Supply		**$ 0.06434**	**$ 0.06434**	** shown on bill*
Standard Offer Service Rate	per kWh	$ 0.06622	$ 0.06622	
Energy Cost Adjustment (Rider 8)	per kWh	$ (0.00188)	$ (0.00188)	
Delivery				
Customer Charge (Schedule G)	per month	**$ 12.40**	**$ 14.00**	** shown on bill*
EmPOWER MD Chg	per kWh	**$ 0.00820**	**$ 0.00820**	** shown on bill*
Energy Efficiency (Rider 2)	per kWh	$ 0.00804	$ 0.00804	
Peak Time Rebates (Rider 26)	per kWh	$ 0.00016	$ 0.00016	
Distribution Chg	per kWh	**$ 0.03413**	**$ 0.03819**	** shown on bill*
Base Distribution Charge (Schedule G)	per kWh	$ 0.03505	$ 0.03911	
Administrative Cost Adjustment (Rider 10)	per kWh	$ (0.00092)	$ (0.00092)	
Taxes & Surcharges				
MD Universal Service Program	per month	**$ 1.85**	**$ 1.85**	** shown on bill*
Environmental Surcharge	per kWh	**$ 0.000143**	**$ 0.000143**	** shown on bill*
Franchise Tax	per kWh	**$ 0.00062**	**$ 0.00062**	** shown on bill*

CUSTOMER PERCENTILE	MONTHLY USE (KWH)	BILL AT CURRENT RATES	BILL AT PROPOSED RATES	CHANGE IN BILL	PERCENT CHANGE IN BILL
	25	$16.94	$18.64	$1.70	10.05%
	75	$22.31	$24.21	$1.90	8.54%
	100	$24.99	$27.00	$2.01	8.03%
25th Percentile	184	$34.02	$36.36	$2.35	6.90%
	300	$46.48	$49.30	$2.82	6.06%
	400	$57.22	$60.45	$3.22	5.63%
Average (Median)	547	$73.02	$76.84	$3.82	5.23%
	800	$100.20	$105.04	$4.85	4.84%
	1000	$121.68	$127.34	$5.66	4.65%
75th Percentile	1414	$166.16	$173.50	$7.34	4.42%
Average (Mean)	1837	$211.60	$220.66	$9.06	4.28%
	2500	$282.83	$294.58	$11.75	4.15%
	3000	$336.55	$350.33	$13.78	4.09%
	5000	$551.42	$573.32	$21.90	3.97%
	7000	$766.28	$796.30	$30.02	3.92%
	9000	$981.15	$1,019.29	$38.14	3.89%
	9500	$1,034.86	$1,075.03	$40.17	3.88%
	10000	$1,088.58	$1,130.78	$42.20	3.88%
Annual Average Change Over the MYP				**$ 3.02**	**1.4%**

BALTIMORE GAS AND ELECTRIC COMPANY
COMPARISON OF BILLS FOR
CURRENT VERSUS PROPOSED RATES
Large Commercial Customers (Schedule GL)

Rate Year 1 - 2021

		CURRENT RATES	PROPOSED RATES	
Electric Supply		**$ 0.05992**	**$ 0.05992**	** shown on bill*
Standard Offer Service Rate	per kWh	$ 0.06036	$ 0.06036	
Energy Cost Adjustment (Rider 8)	per kWh	$ (0.00044)	$ (0.00044)	
Delivery				
Customer Charge (Schedule GL)	per month	**$ 88.00**	**$ 88.00**	** shown on bill*
EmPOWER MD Chg	per kWh	**$ 0.00329**	**$ 0.00329**	** shown on bill*
Energy Efficiency (Rider 2)	per kWh	$ 0.00315	$ 0.00315	
Peak Time Rebates (Rider 26)	per kWh	$ 0.00014	$ 0.00014	
Distribution Chg	per kWh	**$ 0.01719**	**$ 0.01719**	** shown on bill*
Base Distribution Charge (Schedule GL)	per kWh	$ 0.01752	$ 0.01752	
Administrative Cost Adjustment (Rider 10)	per kWh	$ (0.00033)	$ (0.00033)	
Demand				
Distribution Demand Chg	per kW	**$ 3.81**	**$ 3.81**	** shown on bill*
Transmission Demand Chg	per kW	**$ 3.03**	**$ 3.03**	** shown on bill*
Standard Offer Service Transmission Rate	per kW	$ 2.98	$ 2.98	
Energy Cost Adjustment (Rider 8)	per kW	$ 0.05	$ 0.05	
Taxes & Surcharges				
MD Universal Service Program	per month	**$ 1.85**	**$ 1.85**	** shown on bill*
Environmental Surcharge	per kWh	**$ 0.000143**	**$ 0.000143**	** shown on bill*
Franchise Tax	per kWh	**$ 0.00062**	**$ 0.00062**	** shown on bill*

CUSTOMER PERCENTILE	MONTHLY USE (KWH)	MONTHLY DEMAND (KW)	BILL AT CURRENT RATES	BILL AT PROPOSED RATES	CHANGE IN BILL	PERCENT CHANGE IN BILL
	5000	60	$906.07	$906.07	$0.00	0.00%
	7500	60	$1,108.97	$1,108.97	$0.00	0.00%
	10000	60	$1,311.88	$1,311.88	$0.00	0.00%
25th Percentile	12485	60	$1,513.57	$1,513.57	$0.00	0.00%
	17500	60	$1,920.60	$1,920.60	$0.00	0.00%
	20000	60	$2,123.51	$2,123.51	$0.00	0.00%
	25000	64	$2,556.69	$2,556.69	$0.00	0.00%
Average (Median)	25446	65	$2,599.72	$2,599.72	$0.00	0.00%
75th Percentile	51284	130	$5,141.41	$5,141.41	$0.00	0.00%
Average (Mean)	52721	134	$5,285.40	$5,285.40	$0.00	0.00%
	60000	153	$6,006.15	$6,006.15	$0.00	0.00%
	65000	165	$6,494.05	$6,494.05	$0.00	0.00%
	75000	191	$7,483.52	$7,483.52	$0.00	0.00%
	100000	254	$9,943.51	$9,943.51	$0.00	0.00%
	150000	381	$14,870.34	$14,870.34	$0.00	0.00%
	175000	445	$17,337.18	$17,337.18	$0.00	0.00%
	200000	509	$19,804.01	$19,804.01	$0.00	0.00%
	225000	572	$22,264.01	$22,264.01	$0.00	0.00%

BALTIMORE GAS AND ELECTRIC COMPANY
COMPARISON OF BILLS FOR
CURRENT VERSUS PROPOSED RATES
Large Commercial Customers (Schedule GL)

COMPANY EXHIBIT LFK-2
SUPPLEMENT 650
SHEET E-20

Rate Year 2 - 2022

		CURRENT RATES	PROPOSED RATES	
Electric Supply		**$ 0.05992**	**$ 0.05992**	** shown on bill*
Standard Offer Service Rate	per kWh	$ 0.06036	$ 0.06036	
Energy Cost Adjustment (Rider 8)	per kWh	$ (0.00044)	$ (0.00044)	
Delivery				
Customer Charge (Schedule GL)	per month	**$ 88.00**	**$ 88.00**	** shown on bill*
EmPOWER MD Chg	per kWh	**$ 0.00329**	**$ 0.00329**	** shown on bill*
Energy Efficiency (Rider 2)	per kWh	$ 0.00315	$ 0.00315	
Peak Time Rebates (Rider 26)	per kWh	$ 0.00014	$ 0.00014	
Distribution Chg	per kWh	**$ 0.01739**	**$ 0.01739**	** shown on bill*
Base Distribution Charge (Schedule GL)	per kWh	$ 0.01772	$ 0.01772	
Administrative Cost Adjustment (Rider 10)	per kWh	$ (0.00033)	$ (0.00033)	
Demand				
Distribution Demand Chg	per kW	**$ 3.81**	**$ 3.81**	** shown on bill*
Transmission Demand Chg	per kW	**$ 3.03**	**$ 3.03**	** shown on bill*
Standard Offer Service Transmission Rate	per kW	$ 2.98	$ 2.98	
Energy Cost Adjustment (Rider 8)	per kW	$ 0.05	$ 0.05	
Taxes & Surcharges				
MD Universal Service Program	per month	**$ 1.85**	**$ 1.85**	** shown on bill*
Environmental Surcharge	per kWh	**$ 0.000143**	**$ 0.000143**	** shown on bill*
Franchise Tax	per kWh	**$ 0.00062**	**$ 0.00062**	** shown on bill*

CUSTOMER PERCENTILE	MONTHLY USE (KWH)	MONTHLY DEMAND (KW)	BILL AT CURRENT RATES	BILL AT PROPOSED RATES	CHANGE IN BILL	PERCENT CHANGE IN BILL
	5000	60	$907.07	$907.07	$0.00	0.00%
	7500	60	$1,110.47	$1,110.47	$0.00	0.00%
	10000	60	$1,313.88	$1,313.88	$0.00	0.00%
25th Percentile	12485	60	$1,516.07	$1,516.07	$0.00	0.00%
	17500	60	$1,924.10	$1,924.10	$0.00	0.00%
	20000	60	$2,127.51	$2,127.51	$0.00	0.00%
	25000	64	$2,561.69	$2,561.69	$0.00	0.00%
Average (Median)	25446	65	$2,604.81	$2,604.81	$0.00	0.00%
75th Percentile	51284	130	$5,151.67	$5,151.67	$0.00	0.00%
Average (Mean)	52721	134	$5,295.95	$5,295.95	$0.00	0.00%
	60000	153	$6,018.15	$6,018.15	$0.00	0.00%
	65000	165	$6,507.05	$6,507.05	$0.00	0.00%
	75000	191	$7,498.52	$7,498.52	$0.00	0.00%
	100000	254	$9,963.51	$9,963.51	$0.00	0.00%
	150000	381	$14,900.34	$14,900.34	$0.00	0.00%
	175000	445	$17,372.18	$17,372.18	$0.00	0.00%
	200000	509	$19,844.01	$19,844.01	$0.00	0.00%
	225000	572	$22,309.01	$22,309.01	$0.00	0.00%

BALTIMORE GAS AND ELECTRIC COMPANY
COMPARISON OF BILLS FOR
CURRENT VERSUS PROPOSED RATES
Large Commercial Customers (Schedule GL)

Rate Year 3 - 2023

		CURRENT RATES	PROPOSED RATES	
Electric Supply		**$ 0.05992**	**$ 0.05992**	** shown on bill*
Standard Offer Service Rate	per kWh	$ 0.06036	$ 0.06036	
Energy Cost Adjustment (Rider 8)	per kWh	$ (0.00044)	$ (0.00044)	
Delivery				
Customer Charge (Schedule GL)	per month	**$ 88.00**	**$ 97.00**	** shown on bill*
EmPOWER MD Chg	per kWh	**$ 0.00329**	**$ 0.00329**	** shown on bill*
Energy Efficiency (Rider 2)	per kWh	$ 0.00315	$ 0.00315	
Peak Time Rebates (Rider 26)	per kWh	$ 0.00014	$ 0.00014	
Distribution Chg	per kWh	**$ 0.01757**	**$ 0.01909**	** shown on bill*
Base Distribution Charge (Schedule GL)	per kWh	$ 0.01790	$ 0.01942	
Administrative Cost Adjustment (Rider 10)	per kWh	$ (0.00033)	$ (0.00033)	
Demand				
Distribution Demand Chg	per kW	**$ 3.81**	**$ 4.50**	** shown on bill*
Transmission Demand Chg	per kW	**$ 3.03**	**$ 3.03**	** shown on bill*
Standard Offer Service Transmission Rate	per kW	$ 2.98	$ 2.98	
Energy Cost Adjustment (Rider 8)	per kW	$ 0.05	$ 0.05	
Taxes & Surcharges				
MD Universal Service Program	per month	**$ 1.85**	**$ 1.85**	** shown on bill*
Environmental Surcharge	per kWh	**$ 0.000143**	**$ 0.000143**	** shown on bill*
Franchise Tax	per kWh	**$ 0.00062**	**$ 0.00062**	** shown on bill*

CUSTOMER PERCENTILE	MONTHLY USE (KWH)	MONTHLY DEMAND (KW)	BILL AT CURRENT RATES	BILL AT PROPOSED RATES	CHANGE IN BILL	PERCENT CHANGE IN BILL
	5000	60	$907.97	$965.97	$58.00	6.39%
	7500	60	$1,111.82	$1,173.62	$61.80	5.56%
	10000	60	$1,315.68	$1,381.28	$65.60	4.99%
25th Percentile	12485	60	$1,518.31	$1,587.69	$69.38	4.57%
	17500	60	$1,927.25	$2,004.25	$77.00	4.00%
	20000	60	$2,131.11	$2,211.91	$80.80	3.79%
	25000	64	$2,566.19	$2,657.35	$91.16	3.55%
Average (Median)	25446	65	$2,609.39	$2,701.92	$92.53	3.55%
75th Percentile	51284	130	$5,160.90	$5,337.55	$176.65	3.42%
Average (Mean)	52721	134	$5,305.44	$5,487.03	$181.60	3.42%
	60000	153	$6,028.95	$6,234.72	$205.77	3.41%
	65000	165	$6,518.75	$6,740.40	$221.65	3.40%
	75000	191	$7,512.02	$7,766.81	$254.79	3.39%
	100000	254	$9,981.51	$10,317.77	$336.26	3.37%
	150000	381	$14,927.34	$15,427.23	$499.89	3.35%
	175000	445	$17,403.68	$17,985.73	$582.05	3.34%
	200000	509	$19,880.01	$20,544.22	$664.21	3.34%
	225000	572	$22,349.51	$23,095.19	$745.68	3.34%
Annual Average Change Over the MYP					**$ 60.53**	**1.1%**

Company Exhibit LKF-3
Supplement 650
Filed: May 15, 2020
Effective: June 14, 2020

Electric Service Tariff
With Revision Markings

RESIDENTIAL SERVICE–ELECTRIC

SCHEDULE R

Availability:

(a) For use for the domestic requirements of:

(1) A single private dwelling.

(2) An individually metered dwelling unit in a multiple dwelling building.

(3) One combination of two dwelling units within a building, if served through a single meter.

(4) A dwelling occupied as the dwelling place of a church divine or of religious associates engaged in church duties.

(5) A single dwelling within a building where the occupant has not more than 10 bedrooms to let or not more than 10 table boarders, or a combination of not more than ten.

(b) For use, if on one property and served through a single meter, of a combination of the occupant's domestic requirements in a dwelling and his nondomestic requirements, provided that more than 50 percent of the connected load is for domestic purposes.

(c) For use, if served through a separate meter, by appliances used in common by the occupants of not more than two dwelling units within a building.

Delivery Voltage: Service at Secondary Distribution Systems voltages.

Monthly Net Rates:

Effective with service rendered on or after 12/17/2019

Delivery Service Customer Charge: **$ 8.00 per month,**

~~**Less: Competitive Billing (where applicable)**~~ ~~**$ 0.62 per month, plus,**~~

~~**(see Section 7.7 for details)**~~

Delivery Service Charge: **0.03507 $/kWh**

	Rate Year 1 Effective January 1, 2021	**Rate Year 2 Effective January 1, 2022**	**Rate Year 3 Effective January 1, 2023**
Customer Charge (per Month)	$8.00	$8.00	$9.00
Delivery Service Charge ($/kWh)	$0.03651	$0.03633	$0.04250

- Competitive Billing (where applicable) credits $ 0.62 per month (see Section 7.7 for details)
- The Delivery Service Charge excludes Rider 10 - Administrative Cost Adjustment

~~**Energy Charges:**~~

~~Generation and Transmission Market-Priced Service Charges can be found on www.bge.com and Rider 1 – Standard Offer Service.~~

~~**Delivery Service Charge:**~~ ~~**0.03507 $/kWh**~~

~~**(Excludes Rider 10 - Administrative Cost Adjustment)**~~

Energy Charges:

Generation and Transmission Market-Priced Service Charges can be found on www.bge.com and Rider 1 – Standard Offer Service.

(Continued on Next Page)

Schedule R continued

Minimum Charge: Net Delivery Service Customer Charge.

Billing Seasons: Summer rates are billed for the four billing periods ending June through September. Non-Summer rates are billed for the eight billing periods ending October through May.

Late Payment Charge: Standard. (Sec. 7.4)

Payment Terms: Standard. (Sec. 7)

Subject to Riders applicable as listed below:

1. Standard Offer Service
2. Electric Efficiency Charge
3. Miscellaneous Taxes and Surcharges
4. Budget Billing
6. Vehicle Charging Time-Of-Use Adjustment
8. Energy Cost Adjustment
9. Customer Billing and Consumption Data Requests
10. Administrative Cost Adjustment
12. Prepaid Pilot
13. Change of Schedule
15. Demand Response Service
16. Multi-Year Plan (“MYP”) Adjustment Rider
18. Net Energy Metering
21. Billing in Event of Service Interruption
22. Minimum Charge for Short-Term Uses
23. Advanced Meter Services
25. Monthly Rate Adjustment
26. Peak Time Rebate
27. Smart Meter Opt-Out
28. Small Generator Interconnection Standards

31. Electric Reliability Investment Initiative Charge
32. Community Energy Pilot Program

RESIDENTIAL DELIVERY AND ENERGY TIME-OF-USE PILOT - ELECTRIC

SCHEDULE RD

Availability: At the Customer's request, for use, at the customer's option, for all residential purposes.

To be eligible for participation, a Customer must have a Smart Meter capable of measuring hourly time-of-use data for at least the past 1 year and cannot participate in virtual or aggregated net metering or any other Company pilot program such as, but not limited to, Rider 32 - Community Solar or Rider 12 - Prepaid.

The pilot is available to a limited number of residential customers. Additionally, a maximum of 10% of pilot participants are allowed to be net metered under Rider 18.

Delivery Voltage: Service at Secondary Distribution Systems voltages.

Monthly Net Rates:

Effective with service rendered on or after 12/17/2019

Delivery Service Customer Charge: **$ 8.00 per month,**

Delivery Service Charge: On-Peak **0.11780 $/kWh**

Off-Peak **0.02285 $/kWh**

~~**Less: Competitive Billing (where applicable) $ 0.62 per month,**~~

~~(see Section 7.7 for details)~~

	Rate Year 1 Effective January 1, 2021	**Rate Year 2 Effective January 1, 2022**	**Rate Year 3 Effective January 1, 2023**
Customer Charge (per Month)	$8.00	$8.00	$9.00
Delivery Service Charge On-Peak ($/kWh)	$0.12263	$0.12202	$0.14274
Delivery Service Charge Off-Peak ($/kWh)	$0.02379	$0.02367	$.02769

- Competitive Billing (where applicable) credits $ 0.62 per month (see Section 7.7 for details)
- The Delivery Service Charge excludes Rider 10 - Administrative Cost Adjustment

Energy Charges:

Generation and Transmission Market-Priced Service Charges can be found on www.bge.com and Rider 1 – Standard Offer Service.

~~**Delivery Service Charge: On-Peak 0.11780 $/kWh**~~

~~**Off-Peak 0.02285 $/kWh**~~

~~**(Excludes Rider 10 - Administrative Cost Adjustment)**~~

Minimum Charge: Net Delivery Service Customer Charge.

Billing Seasons: Summer rates are billed for usage from June 1 through September 30. Non-Summer rates are billed for usage from October 1 through May 31.

(Continued on Next Page)

Schedule RD continued

Rating Periods:

Summer

On-Peak - Between the hours of 2 pm and 7 pm on weekdays, excluding the National holidays listed below.

Off-Peak - All times other than those defined for the On-Peak rating period.

Non-Summer

On-Peak - Between the hours of 6 am and 9 am on weekdays, excluding the National holidays listed below.

Off-Peak - All times other than those defined for the On-Peak rating period.

The Non-Summer time periods shown above will begin and end one hour later for the period between the second Sunday in March and the first Sunday in April, and for the period between the last Sunday in October and the first Sunday in November.

Holidays

All hours on Saturdays and Sundays and the following National holidays are Off-Peak: New Year's Day, President's Day, Good Friday, Memorial Day, Independence Day, Labor Day, Thanksgiving, Christmas, and the Monday following such of these as fall on Sunday.

Late Payment Charge: Standard. (Sec. 7.4)

Payment Terms: Standard. (Sec. 7)

Term of Contract: Customers have the ability to request service under this schedule through April 1, 2021. This rate schedule will remain effective until April 1, 2022 and thereafter the Customer can choose to stay on this schedule if continued by the Maryland Public Service Commission, or return to Schedule R.

Subject to Riders applicable as listed below:

1. Standard Offer Service
2. Electric Efficiency Charge
3. Miscellaneous Taxes and Surcharges
4. Budget Billing
8. Energy Cost Adjustment
9. Customer Billing and Consumption Data Requests
10. Administrative Cost Adjustment
13. Change of Schedule
15. Demand Response Service
16. Multi-Year Plan ("MYP") Adjustment Rider
18. Net Energy Metering
21. Billing in Event of Service Interruption
22. Minimum Charge for Short-Term Uses
23. Advanced Meter Services
25. Monthly Rate Adjustment
26. Peak Time Rebate
28. Small Generator Interconnection Standards
31. Electric Reliability Investment Initiative Charge

RESIDENTIAL ELECTRIC VEHICLE TIME-OF-USE - ELECTRIC

SCHEDULE EV

Availability: At the Customer's request, for BGE Standard Offer Service residential customers who purchase or lease a plug-in electric vehicle and charge the vehicle through a connection to the BGE electric distribution system . A plug-in electric vehicle is any vehicle propelled by an engine that utilizes, at least in part, on-board electric energy from a battery charging system. Electric vehicles include plug-in hybrid-electric vehicles (PHEV), extended range electric vehicles (EREV) and battery electric vehicles (BEV). This schedule is available to residential customers who charge their electric vehicles at their primary residence on a single time-of-use meter that is also used to measure consumption at the primary residence (whole house) level. Participation requires the installation of a Smart Meter capable of measuring hourly time-of-use data.

Delivery Voltage: Service at Secondary Distribution Systems voltages.

Monthly Net Rates:

Effective with service rendered on or after 12/17/2019

Delivery Service Customer Charge: **$ 8.00 per month,**

Delivery Service Charge: **0.03507 $/kWh**

	Rate Year 1 Effective January 1, 2021	Rate Year 2 Effective January 1, 2022	Rate Year 3 Effective January 1, 2023
Customer Charge (per Month)	$8.00	$8.00	$9.00
Delivery Service Charge ($/kWh)	$0.03651	$0.03633	$0.04250

~~**Less: Competitive Billing (where applicable) $ 0.62 per month,**~~

~~(see Section 7.7 for details)~~

- Competitive Billing (where applicable) credits $ 0.62 per month (see Section 7.7 for details)
- The Delivery Service Charge excludes Rider 10 - Administrative Cost Adjustment

~~**Energy Charges:**~~

~~**Generation and Transmission Market-Priced Service Charges can be found on www.bge.com and Rider 1 – Standard Offer Service.**~~

~~**Delivery Service Charge: 0.03507 $/kWh**~~

~~**(Excludes Rider 10 - Administrative Cost Adjustment)**~~

Energy Charges:

Generation and Transmission Market-Priced Service Charges can be found on www.bge.com and Rider 1 – Standard Offer Service.

Minimum Charge: Net Delivery Service Customer Charge.

Billing Seasons: Summer rates are billed for usage from June 1 through September 30. Non-Summer rates are billed for usage from October 1 through May 31.

(Continued on Next Page)

Schedule EV continued

Rating Periods:

Summer

Peak - Between the hours of 10 am and 8 pm on weekdays, excluding the National holidays listed below.

Off-Peak - All times other than those defined for the On-Peak rating period.

Non-Summer

Peak - Between the hours of 7 am and 11 am, and the hours of 5 pm and 9 pm on weekdays, excluding the National holidays listed below.

Off-Peak - All times other than those defined for the On-Peak rating period.

The Non-Summer time periods shown above will begin and end one hour later for the period between the second Sunday in March and the first Sunday in April, and for the period between the last Sunday in October and the first Sunday in November.

Holidays

All hours on Saturdays and Sundays and the following National holidays are Off-Peak: New Year's Day, President's Day, Good Friday, Memorial Day, Independence Day, Labor Day, Thanksgiving, Christmas, and the Monday following such of these as fall on Sunday.

Late Payment Charge: Standard. (Sec. 7.4)

Payment Terms: Standard. (Sec. 7)

Subject to Riders applicable as listed below:

1. Standard Offer Service
2. Electric Efficiency Charge
3. Miscellaneous Taxes and Surcharges
4. Budget Billing
8. Energy Cost Adjustment
9. Customer Billing and Consumption Data Requests
10. Administrative Cost Adjustment
12. Prepaid Pilot
13. Change of Schedule
15. Demand Response Service
16. Multi-Year Plan ("MYP") Adjustment Rider
21. Billing in Event of Service Interruption
22. Minimum Charge for Short-Term Uses
23. Advanced Meter Services
25. Monthly Rate Adjustment
26. Peak Time Rebate
28. Small Generator Interconnection Standards
31. Electric Reliability Investment Initiative Charge
32. Community Energy Pilot Program

RESIDENTIAL OPTIONAL TIME-OF-USE - ELECTRIC

SCHEDULE RL

Availability: At the Customer's request, for use, at the customer's option, for all residential purposes for single family buildings having electric central air conditioning or electric central heating, or where otherwise requested and approved by the Company. For buildings meeting these use conditions, the Schedule is also available for a combination of domestic requirements and non-domestic requirements served through a single meter where the connected load and use are predominantly domestic.

Delivery Voltage: Service at Secondary Distribution Systems voltages.

Monthly Net Rates:

Effective with service rendered on or after 12/17/2019

Delivery Service Customer Charge: **$ 12.00 per month,**

Delivery Service Charge: **0.03538 $/kWh**

~~**Less: Competitive Billing (where applicable) $ 0.62 per month,**~~

~~(see Section 7.7 for details)~~

	Rate Year 1 Effective January 1, 2021	Rate Year 2 Effective January 1, 2022	Rate Year 3 Effective January 1, 2023
Customer Charge (per Month)	$12.00	$12.00	$12.00
Delivery Service Charge ($/kWh)	$0.03680	$0.03661	$0.04189

- Competitive Billing (where applicable) credits $ 0.62 per month (see Section 7.7 for details)
- The Delivery Service Charge excludes Rider 10 - Administrative Cost Adjustment

~~**Energy Charges:**~~

~~**Generation and Transmission Market-Priced Service Charges can be found on www.bge.com and Rider 1 – Standard Offer Service.**~~

~~**Delivery Service Charge: 0.03538 $/kWh**~~

~~**(Excludes Rider 10 - Administrative Cost Adjustment)**~~

Energy Charges:

Generation and Transmission Market-Priced Service Charges can be found on www.bge.com and Rider 1 – Standard Offer Service.

Minimum Charge: Net Delivery Service Customer Charge.

Billing Seasons: Summer rates are billed for usage from June 1 through September 30.
Non-Summer rates are billed for usage from October 1 through May 31.

(Continued on Next Page)

Schedule RL continued

Rating Periods:

Summer

Peak - Between the hours of 10 am and 8 pm on weekdays, excluding the National holidays listed below.

Intermediate - Between the hours of 7 am and 10 am, and the hours of 8 pm and 11 pm on weekdays, excluding the National holidays listed below.

Off-Peak - All times other than those defined for the On-Peak and Intermediate-Peak rating periods.

Non-Summer

Peak - Between the hours of 7 am and 11 am, and the hours of 5 pm and 9 pm on weekdays, excluding the National holidays listed below.

Intermediate - Between the hours of 11 am and 5 pm on weekdays, excluding the National holidays listed below.

Off-Peak - All times other than those defined for the On-Peak and Intermediate-Peak rating periods.

The Non-Summer time periods shown above will begin and end one hour later for the period between the second Sunday in March and the first Sunday in April, and for the period between the last Sunday in October and the first Sunday in November.

Holidays

All hours on Saturdays and Sundays and the following National holidays are Off-Peak: New Year's Day, President's Day, Good Friday, Memorial Day, Independence Day, Labor Day, Thanksgiving, Christmas, and the Monday following such of these as fall on Sunday.

Late Payment Charge: Standard. (Sec. 7.4)

Payment Terms: Standard. (Sec. 7)

Term of Contract: One year and thereafter until terminated by the Customer.

Subject to Riders applicable as listed below:

1. Standard Offer Service
2. Electric Efficiency Charge
3. Miscellaneous Taxes and Surcharges
4. Budget Billing
8. Energy Cost Adjustment
9. Customer Billing and Consumption Data Requests
10. Administrative Cost Adjustment
12. Prepaid Pilot
13. Change of Schedule
15. Demand Response Service
16. Multi-Year Plan (“MYP”) Adjustment Rider
21. Billing in Event of Service Interruption
22. Minimum Charge for Short-Term Uses
23. Advanced Meter Services
25. Monthly Rate Adjustment
26. Peak Time Rebate
28. Small Generator Interconnection Standards
31. Electric Reliability Investment Initiative Charge
32. Community Energy Pilot Program

GENERAL SERVICE – ELECTRIC

SCHEDULE G

Availability: For use for all purposes where the Customer does not qualify for any of the Company's other rate schedules.

Delivery Voltage: Service at Secondary Distribution Systems voltages. It is also available for customers receiving Primary service under this Schedule on or before January 1, 1987 or for a new customer who locates to an existing facility served at Primary Systems voltages where the customer does not qualify for other Primary service rate schedules.

Monthly Net Rates:

Effective with service rendered on or after 12/17/2019

Delivery Service Customer Charge: **$ 12.40 per month,**

~~**Less: Competitive Billing (where applicable) $ 0.47 per month, plus, (see Section 7.7 for details)**~~

~~**Energy Charges:**~~

~~**Generation and Transmission Market-Priced Service Charges can be found on www.bge.com and Rider 1 – Standard Offer Service.**~~

Delivery Service Charge (Secondary): **0.03194 $/kWh**

Delivery Service Charge (Primary): **0.02909 $/kWh**

~~**(Excludes Rider 10 – Administrative Cost Adjustment)**~~

	Rate Year 1 Effective January 1, 2021	Rate Year 2 Effective January 1, 2022	Rate Year 3 Effective January 1, 2023
Customer Charge (per Month)	$12.40	$12.40	$14.00
Delivery Service Charge (Secondary) ($/kWh)	$0.03398	$0.03458	$0.03911
Delivery Service Charge (Primary) ($/kWh)	$0.02909	$0.02909	$0.03755

- Competitive Billing (where applicable) credits $ 0.47 per month (see Section 7.7 for details)
- The Delivery Service Charge excludes Rider 10 - Administrative Cost Adjustment

Energy Charges:

Generation and Transmission Market-Priced Service Charges can be found on www.bge.com and Rider 1 – Standard Offer Service.

Minimum Charge: Net Delivery Service Customer Charge.

Billing Seasons: Summer rates are billed for the four billing periods ending June through September. Non-Summer rates are billed for the eight billing periods ending October through May.

Late Payment Charge: Standard. (Sec. 7.4)

Payment Terms: Standard. (Sec. 7)

Term of Contract: The initial term of contract is 2 years where additional main facilities are required for supply. Otherwise, the term of contract is one year. After the initial term of contract, the contract may be terminated by at least 30 days' notice from the Customer.

Schedule G continued

Subject to Riders applicable as listed below:

1. Standard Offer Service
2. Electric Efficiency Charge
3. Miscellaneous Taxes and Surcharges.
4. Budget Billing
8. Energy Cost Adjustment
9. Customer Billing and Consumption Data Request
10. Administrative Cost Adjustment
13. Change of Schedule
16. Multi-Year Plan ("MYP") Adjustment Rider
18. Net Energy Metering
19. Demonstration and Trial Installation
21. Billing in Event of Service Interruption
22. Minimum Charge for Short-Term Uses
23. Advanced Meter Services
24. Economic Development
25. Monthly Rate Adjustment
26. Peak Time Rebate
27. Smart Meter Opt-Out
28. Small Generator Interconnection Standards
31. Electric Reliability Investment Initiative Charge
32. Community Energy Pilot Program

GENERAL UNMETERED SERVICE - ELECTRIC
SCHEDULE GU

Availability: Unmetered service is available under conditions specified by the Company for the lighting and operation of electrical devices owned, operated and maintained by the Customer. Electrical devices served under this schedule include but are not limited to traffic signals, other traffic control devices, traffic speed cameras, crime cameras, and surveillance cameras. Unmetered Service is not available until the requesting Customer provides all information regarding its devices deemed necessary by the Company, and agrees to the control and audit provision selected by the Company. The kilowatt-hours applied to the Schedule's Usage Charge are predetermined average monthly uses of Company selected categories and groupings of equipment, with no allowances for outages. For traffic signals and other traffic control devices, one signalized intersection of thoroughfares is the largest category or grouping available for billing purposes.

Delivery Voltage: Service at Secondary Distribution Systems voltages.

Monthly Net Rates:

Effective with service rendered on or after 12/17/2019

Delivery Service Customer Charge: **$ 6.00 per month,**

Delivery Service Charge (Secondary): **0.02871 $/kWh**

	Rate Year 1 Effective January 1, 2021	Rate Year 2 Effective January 1, 2022	Rate Year 3 Effective January 1, 2023
Customer Charge (per Month)	$6.00	$6.00	$6.00
Delivery Service Charge ($/kWh)	$0.02871	$0.02871	$0.03966

- Competitive Billing (where applicable) credits $ 0.47 per month (see Section 7.7 for details)
- The Delivery Service Charge excludes Rider 10 - Administrative Cost Adjustment

~~**Less: Competitive Billing (where applicable) $ 0.47 per month plus,**~~
~~(see Section 7.7 for details)~~

Energy Charges:

Generation and Transmission Market-Priced Service Charges can be found on www.bge.com and Rider 1 – Standard Offer Service.

~~**Delivery Service Charge (Secondary): 0.02871 $/kWh**~~

Minimum Charge: Net Delivery Service Customer Charge.

Billing Seasons: Summer rates are billed for the four billing periods ending June through September. Non-Summer rates are billed for the eight billing periods ending October through May.

Late Payment Charge: Standard. (Sec. 7.4)

Payment Terms: Standard. (Sec. 7)

Term of Contract: The initial term of contract is 2 years where additional main facilities are required for supply. Otherwise, the term of contract is one year. After the initial term of contract, the contract may be terminated by at least 30 days' notice from the Customer.

Schedule GU continued

Subject to Riders applicable as listed below:

1. Standard Offer Service
3. Miscellaneous Taxes and Surcharges
8. Energy Cost Adjustment
9. Customer Billing and Consumption Data Request
10. Administrative Cost Adjustment
16. Multi-Year Plan ("MYP") Adjustment Rider
21. Billing in Event of Service Interruption
31. Electric Reliability Investment Initiative Charge
32. Community Energy Pilot Program

GENERAL SERVICE SMALL - ELECTRIC

SCHEDULE GS

Availability: At the Customer's request, for use for all purposes where the Customer qualifies for Schedule G, and where the Customer's consumption is 2,000 kWh or more in any month.

Delivery Voltage: Service at Secondary Distribution Systems voltages.

Monthly Net Rates:

Effective with service rendered on or after 12/17/2019

Delivery Service Customer Charge: $ 18.60 per month,

Delivery Service Charge: 0.02937 $/kWh ~~**Less:**~~

~~**Competitive Billing (where applicable) $ 0.47 per month, plus,**~~

~~**(see Section 7.7 for details)**~~

	Rate Year 1 Effective January 1, 2021	**Rate Year 2 Effective January 1, 2022**	**Rate Year 3 Effective January 1, 2023**
Customer Charge (per Month)	$18.60	$18.60	$18.60
Delivery Service Charge ($/kWh)	$0.03173	$0.03227	$0.03687

- Competitive Billing (where applicable) credits $ 0.47 per month (see Section 7.7 for details)
- The Delivery Service Charge excludes Rider 10 - Administrative Cost Adjustment

~~**Energy Charges:**~~

~~Generation and Transmission Market-Priced Service Charges can be found on www.bge.com and Rider 1 – Standard Offer Service.~~

~~Delivery Service Charge: 0.02937 $/kWh~~

~~(Excludes Rider 10 – Administrative Cost Adjustment)~~

Energy Charges:

Generation and Transmission Market-Priced Service Charges can be found on www.bge.com and Rider 1 – Standard Offer Service.

Minimum Charge: Net Delivery Service Customer Charge.

Billing Seasons: Summer rates are billed for usage from June 1 through September 30. Non-Summer rates are billed for usage from October 1 through May 31.

(Continued on Next Page)

Schedule GS continued

Rating Periods:

Summer

Peak - Between the hours of 10 am and 8 pm on weekdays, excluding the National holidays listed below.

Intermediate - Between the hours of 7 am and 10 am, and the hours of 8 pm and 11 pm on weekdays, excluding the National holidays listed below.

Off-Peak - All times other than those defined for the On-Peak and Intermediate-Peak rating periods.

Non-Summer

Peak - Between the hours of 7 am and 11 am, and the hours of 5 pm and 9 pm on weekdays, excluding the National holidays listed below.

Intermediate - Between the hours of 11 am and 5 pm on weekdays, excluding the National holidays listed below.

Off-Peak - All times other than those defined for the On-Peak and Intermediate-Peak rating periods.

The Non-Summer time periods shown above will begin and end one hour later for the period between the second Sunday in March and the first Sunday in April, and for the period between the last Sunday in October and the first Sunday in November.

Holidays:

All hours on Saturdays and Sundays and the following National holidays are Off-Peak: New Year's Day, President's Day, Good Friday, Memorial Day, Independence Day, Labor Day, Thanksgiving, Christmas, and the Monday following such of these as fall on Sunday.

Late Payment Charge: Standard. (Sec. 7.4)

Payment Terms: Standard. (Sec. 7)

Term of Contract: One year and thereafter until terminated by the Customer.

Subject to Riders applicable as listed below:

1. Standard Offer Service
2. Electric Efficiency Charge
3. Miscellaneous Taxes and Surcharges
4. Budget Billing
8. Energy Cost Adjustment
9. Customer Billing and Consumption Data Requests
10. Administrative Cost Adjustment
13. Change of Schedule
16. Multi-Year Plan (“MYP”) Adjustment Rider
18. Net Energy Metering
19. Demonstration and Trial Installations
21. Billing in Event of Service Interruption
22. Minimum Charge for Short-Term Uses
23. Advanced Meter Services
24. Economic Development
25. Monthly Rate Adjustment
26. Peak Time Rebate
28. Small Generator Interconnection Standards
31. Electric Reliability Investment Initiative Charge
32. Community Energy Pilot Program

GENERAL SERVICE LARGE–ELECTRIC

SCHEDULE GL

Availability: For use for all purposes, where the Customer has established a monthly demand of 60 kW or more. The applicable Market-Priced Standard Offer Service Type is determined as follows.

Type II- Market-Priced Service: For non-residential customers not eligible for Type 1 SOS whose PJM capacity peak load contribution is less than 600kW, unless excluded by the Phase I Settlement Agreement in Case No.8908.

Delivery Voltage: Service at Secondary Distribution Systems voltages, or at Primary Systems voltages where the Customer does not qualify for Schedule P.

Monthly Net Rates:

Effective with service rendered on or after 12/17/2019

Delivery Service Customer Charge: **$ 88.00 per month,**

~~**Less: Competitive Billing (where applicable) $ 0.47 per month, plus,**~~
~~(see Section 7.7 for details)~~

Secondary Service Customers:

Demand Charges:

Transmission Market-Priced Service Charge can be found on www.bge.com and Rider 1 – Standard Offer Service.

Delivery Service: **$ 3.81/kW**

Energy Charges:

Generation Market-Priced Service Charges can be found on www.bge.com and Rider 1 – Standard Offer Service.

Delivery Service Charge: **0.01686 $/kWh**

~~**(Excludes Rider 10 – Administrative Cost Adjustment)**~~

	Rate Year 1 Effective January 1, 2021	**Rate Year 2 Effective January 1, 2022**	**Rate Year 3 Effective January 1, 2023**
Customer Charge (per Month)	$88.00	$88.00	$97.00
Delivery Service Demand Charge ($/kW~~h~~)	$3.81	$3.81	$4.50
Delivery Service Charge ($/kWh)	$0.01752	$0.01772	$0.01942

-

- Competitive Billing (where applicable) credits $ 0.47 per month (see Section 7.7 for details)
- The Delivery Service Charge excludes Rider 10 - Administrative Cost Adjustment

Minimum Charge: Net Delivery Service Customer Charge.

Billing Seasons: Summer rates are billed for usage from June 1 through September 30. Non-Summer rates are billed for usage from October 1 through May 31.

Schedule GL continued

Rating Periods:

Summer

Peak-Between the hours of 10am and 8pm on weekdays, excluding the National holidays listed below.

Intermediate - Between the hours of 7 am and 10 am, and the hours of 8 pm and 11 pm on weekdays, excluding the National holidays listed below.

Off-Peak - All times other than those defined for the On-Peak and Intermediate-Peak rating periods.

~~(Continued on Next Page)~~

Non-Summer

Peak - Between the hours of 7 am and 11 am, and the hours of 5 pm and 9 pm on weekdays, excluding the National holidays listed below.

Intermediate - Between the hours of 11 am and 5 pm on weekdays, excluding the National holidays listed below.

Off-Peak - All times other than those defined for the On-Peak and Intermediate-Peak rating periods.

The Non-Summer time periods shown above will begin and end one hour later for the period between the second Sunday in March and the first Sunday in April, and for the period between the last Sunday in October and the first Sunday in November.

Holidays:

All hours on Saturdays and Sundays and the following National holidays are Off-Peak: New Year's Day, President's Day, Good Friday, Memorial Day, Independence Day, Labor Day, Thanksgiving, Christmas, and the Monday following such of these as fall on Sunday.

Billing Demand: The maximum 30-minute measured demand, adjusted to the nearest whole kW, in each applicable rating period for the month. Measured demand is the Customer's rate of use of electric energy as shown by or computed from readings of the Company's demand meter. Generation and Transmission Demand are billed for each kW of billing demand occurring during the Peak rating period. Delivery Service Demand is for each kW of Billing Demand recorded during any rating period.

Primary Service Customers: For Customers taking service at Primary Systems voltages, Type II Secondary Service rates apply for Generation and Transmission Services. The Delivery Service Demand and Energy Charge rates are as follows.

Effective with service rendered on or after 12/17/2019

Delivery Service Demand Charge: $ 3.63/kW

Delivery Service Energy Charge: 0.01619 $/kWh

	Rate Year 1 Effective January 1, 2021	**Rate Year 2 Effective January 1, 2022**	**Rate Year 3 Effective January 1, 2023**
Customer Charge (per Month)	$88.00	$88.00	$97.00
Delivery Service Demand Charge ($/kWh)	$3.63	$3.63	$4.32
Delivery Service Energy Charge ($/kWh)	$0.01764	$0.01784	$0.01864

- Competitive Billing (where applicable) credits $ 0.62 per month (see Section 7.7 for details)
- The Delivery Service Charge excludes Rider 10 - Administrative Cost Adjustment

~~**(Excludes Rider 10 – Administrative Cost Adjustment)**~~

Schedule GL continued

Late Payment Charge: Standard. (Sec. 7.4)

Payment Terms: Standard. (Sec. 7)

Term of Contract: The initial term of contract is 2 years where additional main facilities are required for supply. Otherwise, the term of contract is one year. After the initial term of contract, the contract may be terminated by at least 30 days' notice from the Customer.

Subject to Riders applicable as listed below:

1. Standard Offer Service
2. Electric Efficiency Charge
3. Miscellaneous Taxes and Surcharges
5. Electric Vehicle Charging Distribution Demand Credit
7. Economic Development (Closed to New Customers)
8. Energy Cost Adjustment
9. Customer Billing and Consumption Data Requests
10. Administrative Cost Adjustment
11. Measured Demand
13. Change of Schedule
16. Multi-Year Plan ("MYP") Adjustment Rider
17. Best Efforts Service
18. Net Energy Metering
19. Demonstration and Trial Installations
21. Billing in Event of Service Interruption
22. Minimum Charge for Short-Term Uses
23. Advanced Meter Services
24. Economic Development
25. Monthly Rate Adjustment
26. Peak Time Rebate
28. Small Generator Interconnection Standards
31. Electric Reliability Investment Initiative Charge
32. Community Energy Pilot Program

P R I M A R Y   V O L T A G E   S E R V I C E

SCHEDULE P

Availability: For use for all purposes, for demands of 1,500 kW or more. The applicable Market-Priced Standard Offer Service Type is determined as follows.

Type II Market-Priced Service: For non-residential customers not eligible for Type I SOS whose PJM capacity peak load contribution is less than 600kW, unless excluded by the Phase I Settlement Agreement in Case No.8908.

(Service hereunder will be continued for customers with demands of less than 1,500 kW, who originally took Schedule T service prior to February 11, 1982, but not to their successors or assigns).

Delivery Voltage: Three-phase, 13,200 Volts and over as specified by Company.

Monthly Net Rates:

Effective with service rendered on or after 12/17/2019

Delivery Service Customer Charge: $ 600.00 per month,

~~**Less: Competitive Billing (where applicable) $ 0.47 per month, plus,**~~

~~(See Section 7.7 for details)~~

Demand Charges:

Transmission Market-Priced Service Charge can be found on www.bge.com and Rider 1 – Standard Offer Service.

Delivery Service: $ 2.90/kW

Energy Charges:

Generation Market-Priced Service Charges can be found on www.bge.com and Rider 1 – Standard Offer Service.

Delivery Service Charge ($/kWh): 0.00546

~~**(Excludes Rider 10 – Administrative Cost Adjustment)**~~

	Rate Year 1 Effective January 1, 2021	**Rate Year 2 Effective January 1, 2022**	**Rate Year 3 Effective January 1, 2023**
Customer Charge (per Month)	$600.00	$600.00	$660.00
Delivery Service Demand Charge ($/kWh)	$2.90	$2.90	$3.25
Delivery Service Energy Charge ($/kWh)	$0.00546	$0.00546	$0.00614

-Competitive Billing (where applicable) credits $ 0.47 per month (see Section 7.7 for details)

-The Delivery Service Charge excludes Rider 10 - Administrative Cost Adjustment

Minimum Charge: Net Delivery Service Customer Charge plus the Demand Charges.

Transmission Service: For Customers served at 115 kV and above, the Delivery Service Demand Charge does not apply.

Schedule P continued

Billing Seasons: Summer rates are billed for usage from June 1 through September 30. Non-Summer rates are billed for usage from October 1 through May 31.

Holidays:
All hours on Saturdays and Sundays and the following National holidays are Off-Peak: New Year's Day, President's Day, Good Friday, Memorial Day, Independence Day, Labor Day, Thanksgiving, Christmas, and the Monday following such of these as fall on Sunday.

~~(Continued on Next Page)~~

Rating Periods:

Summer

Peak - Between the hours of 10 am and 8 pm on weekdays, excluding the National holidays listed below.

Intermediate - Between the hours of 7 am and 10 am, and the hours of 8 pm and 11 pm on weekdays, excluding the National holidays listed below.

Off-Peak - All times other than those defined for the On-Peak and Intermediate-Peak rating periods.

Non-Summer

Peak - Between the hours of 7 am and 11 am, and the hours of 5 pm and 9 pm on weekdays, excluding the National holidays listed below.

Intermediate - Between the hours of 11 am and 5 pm on weekdays, excluding the National holidays listed below.

Off-Peak - All times other than those defined for the On-Peak and Intermediate-Peak rating periods.

Billing Demand: The maximum 30-minute Measured Demand, adjusted to the nearest whole kW, in each applicable rating period for the month is the Billing Demand. Measured Demand is the Customer's rate of use of electric energy as shown by or computed from readings of the Company's demand meter, but in no case less than 1,500 kW. (For customers with demands of less than 1,500 kW originally taking service prior to February 11, 1982, the minimum Billing Demand is 200 kW.) Generation and Transmission Demand are billed for each kW of billing demand occurring during the Peak rating period. Delivery Service Demand is for each kW of Billing Demand recorded during any rating period. During the first 6 months of service under Schedule P, the Billing Demand may be less than 1,500 kW, but in that event is not subject to decrease. When it reaches 1,500 kW, this provision no longer applies.

Late Payment Charge: Standard. (Sec. 7.4)

Payment Terms: Standard. (Sec. 7)

Term of Contract: Five years and thereafter until terminated by at least 30 days' notice from the Customer.

Schedule P continued

Subject to Riders applicable as listed below:

1. Standard Offer Service
2. Electric Efficiency Charge
3. Miscellaneous Taxes and Surcharges
5. Electric Vehicle Charging Distribution Demand Credit
7. Economic Development (Closed to New Customers)
8. Energy Cost Adjustment
9. Customer Billing and Consumption Data Requests
10. Administrative Cost Adjustment
11. Measured Demand
13. Change of Schedule
16. Multi-Year Plan (“MYP”) Adjustment Rider
18. Net Energy Metering
19. Demonstration and Trial Installations
21. Billing in Event of Service Interruption
22. Minimum Charge for Short-Term Uses
23. Advanced Meter Services
24 Economic Development
26. Peak Time Rebate
28. Small Generator Interconnection Standards
31. Electric Reliability Investment Initiative Charge
32. Community Energy Pilot Program

TRANSMISSION VOLTAGE SERVICE

SCHEDULE T

Availability: For use for all purposes, for demands of 1,500 kW or more where service is supplied at 115,000 Volts and over. The applicable Market-Priced Standard Offer Service Type is determined as follows.

Type II Market-Priced Service: For non-residential customers not eligible for Type I SOS whose PJM capacity peak load contribution is less than 600kW, unless excluded by the Phase I Settlement Agreement in Case No.8908.

Hourly-Priced Service: Distribution customers not eligible for Type I or Type II Service whose PJM capacity peak load contribution is 600kW or greater are eligible for Hourly-Priced Service.

Delivery Voltage: Three-phase, 115,000 Volts and over as specified by the Company.

Monthly Net Rates:

Delivery Service Customer Charge: **$ 2,400.00 per month,**

~~**Less: Competitive Billing (where applicable) $ 0.47 per month, plus,**~~
~~(See Section 7.7 for details)~~

Demand Charges:

Transmission Market-Priced Service Charge can be found on www.bge.com and Rider 1 – Standard Offer Service.

Energy Charges:

Generation Market-Priced Service Charges can be found on www.bge.com and Rider 1 – Standard Offer Service.

Delivery Service Charge ($/kWh): **0.00315**

	Rate Year 1 Effective January 1, 2021	Rate Year 2 Effective January 1, 2022	Rate Year 3 Effective January 1, 2023
Customer Charge (per Month)	$2,400.00	$2,400.00	$2,400.00
Delivery Service Energy Charge ($/kWh)	$0.00315	$0.00315	$0.00315

- Competitive Billing (where applicable) credits $0.47 per month (see Section 7.7 for details)
- The Delivery Service Charge excludes Rider 10 - Administrative Cost Adjustment

~~**(Excludes Rider 10 – Administrative Cost Adjustment)**~~

Minimum Charge: Net Delivery Service Customer Charge.

Billing Seasons: Summer rates are billed for usage from June 1 through September 30. Non-Summer rates are billed for usage from October 1 through May 31.

Holidays:
All hours on Saturdays and Sundays and the following National holidays are Off-Peak: New Year's Day, President's Day, Good Friday, Memorial Day, Independence Day, Labor Day, Thanksgiving, Christmas, and the Monday following such of these as fall on Sunday.

~~(Continued on Next Page)~~

Schedule T continued

Rating Periods:

Summer

Peak - Between the hours of 10 am and 8 pm on weekdays, excluding the National holidays listed below.

Intermediate - Between the hours of 7 am and 10 am, and the hours of 8 pm and 11 pm on weekdays, excluding the National holidays listed below.

Off-Peak - All times other than those defined for the On-Peak and Intermediate-Peak rating periods.

Non-Summer

Peak - Between the hours of 7 am and 11 am, and the hours of 5 pm and 9 pm on weekdays, excluding the National holidays listed below.

Intermediate - Between the hours of 11 am and 5 pm on weekdays, excluding the National holidays listed below.

Off-Peak - All times other than those defined for the On-Peak and Intermediate-Peak rating periods.

Billing Demand: The maximum 30-minute Measured Demand, adjusted to the nearest whole kW, in each applicable rating period for the month is the Billing Demand. Measured Demand is the Customer's rate of use of electric energy as shown by or computed from readings of the Company's demand meter, but in no case less than 1,500 kW. (For customers with demands of less than 1,500 kW originally taking service prior to February 11, 1982, the minimum Billing Demand is 200 kW.) Transmission Demand is billed for each kW of billing demand occurring during the Peak rating period. During the first 6 months of service under Schedule T, the Billing Demand may be less than 1,500 kW, but in that event is not subject to decrease. When it reaches 1,500 kW, this provision no longer applies.

Late Payment Charge: Standard. (Sec. 7.4)

Payment Terms: Standard. (Sec. 7)

Term of Contract: Five years and thereafter until terminated by at least 30 days' notice from the Customer.

Schedule T continued

Subject to Riders applicable as listed below:

1.Standard Offer Service
2.Electric Efficiency Charge
3.Miscellaneous Taxes and Surcharges
7.Economic Development (Closed to New Customers)
8.Energy Cost Adjustment
9.Customer Billing and Consumption Data Requests
10. Administrative Cost Adjustment
11. Measured Demand
16. Multi-Year Plan (“MYP”) Adjustment Rider
18. Net Energy Metering
19. Demonstration and Trial Installations
21. Billing in Event of Service Interruption
22. Minimum Charge for Short-Term Uses
23. Advanced Meter Services
24. Economic Development
26. Peak Time Rebate
28. Small Generator Interconnection Standards
32. Community Energy Pilot Program

STREET LIGHTING
SCHEDULE SL

AVAILABILITY: For unmetered street lighting service (defined to include other public area lighting) supplied from overhead or underground facilities on dedicated public streets, roads, walkways and other public areas where required by City, Town, County, or other Municipal or Public Agency, or by an incorporated association of local residents.

A builder or developer may contract for street lighting service prior to the execution of a contract with the ultimate customer.

MONTHLY RATES:

		Rate Eff. 12/17/19	Rate Yr. 1 Eff. 1/1/21	Rate Yr. 2 Eff. 1/1/22	Rate Yr. 3 Eff. 1/1/23
1.	**Supply of Electricity**				
	Generation Market-Priced Service Charge can be found on **www.bge.com** and **Rider 1 – Standard Offer Service**				
	Delivery Service ($/Lamp-Watt)	$0.00186	$0.00186	$0.00186	$0.00714
2.	**Facilities Provided by the Company**				
	(a) Underground St. Ltg. Cable (per ft of cable) (includes cable rental and cable maintenance)				
	In Service on August 31, 1960	$0.0268	$0.0268	$0.0268	$0.0273
	Installed after August 31, 1960 (including replacements)	$0.0522	$0.0522	$0.0522	$0.0532
	(b) Lamp Fixtures - ornamental (underground supplied)				
Billing Watts	Description	~~Rate~~			
	Incandescent				
100	Incandescent** ~~(limited to existing installatio~~	$2.95	$2.95	$2.95	$3.00
	Mercury Vapor (limited to existing installations)				
117	100w MV Pendant	$5.56	$5.56	$5.56	$5.66
117-205	100-175w MV Modern/Colonial	$8.13	$8.13	$8.13	$8.28
205-294	175-250w MV Pendant	$7.57	$7.57	$7.57	$7.71
294	250w MV Modern	$12.53	$12.53	$12.53	$12.76
454	400w MV Pendant/Flood	$8.90	$8.90	$8.90	$9.06
	Sodium Vapor				
120	100w SV Acorn	$7.61	$7.61	$7.61	$7.75
120-173	100-150w SV Acorn ML (maple lawn)	$16.53	$16.53	$16.53	$16.84
120-173	100-150w SV Colonial Premiere	$8.83	$8.83	$8.83	$8.99
120-173	100-150w SV Rectilinear/Pendant/ Flood** ~~(limited to existing installations)~~	$5.94	$5.94	$5.94	$6.05
120	100w SV Colonial/Gothic/ Modern** ~~(limited to existing installations)~~	$8.29	$8.29	$8.29	$8.44
173	150w SV Modern/Colonial/Gothic	$8.29	$8.29	$8.29	$8.44
120-173	100-150w SV Acorn HDG	$10.13	$10.13	$10.13	$10.32
173	150w SV Arlington** ~~(limited to existing inst~~	$11.94	$11.94	$11.94	$12.16
173	150w SV Acorn	$7.61	$7.61	$7.61	$7.75
173	150w SV Acorn-Victorian** ~~(limited to existi~~	$16.82	$16.82	$16.82	$17.13
298	250w SV Rectilinear/Pendant	$15.87	$15.87	$15.87	$16.16
467	400w SV Rectilinear/Pendant/Flood	$17.63	$17.63	$17.63	$17.96
1,130	1000w SV Rectilinear/Pendant	$19.77	$19.77	$19.77	$20.14
	Metal Halide (limited to existing installations)				
129-189	100-175w MH (post top) – Colonial/Premier/Modern/Gothic/Acorn	$12.35	$12.35	$12.35	$12.58
	** (limited to existing installations)				

(Continued on Next Page~~)~~

Schedule SL Continued

(c) Lamp Fixtures-other than ornamental(overhead supplied)

Billing Watts	Description	Rate Eff. 12/17/19	Rate Yr. 1 Eff. 1/1/21	Rate Yr. 2 Eff. 1/1/22	Rate Yr. 3 Eff. 1/1/23
	Incandescent (limited to existing installations)				
	In service on August 31, 1960				
	Open-Type, less than 250 candlepower	$1.14	$1.14	$1.14	$1.16
	All fixtures installed after August 31, 1960	$5.06	$5.06	$5.06	$5.15
	Mercury Vapor (limited to existing installations)				
117	100w MV Pendant	$8.37	$8.37	$8.37	$8.52
205-294	175-250w MV Pendant	$9.99	$9.99	$9.99	$10.17
454	400w MV Pendant/Flood	$11.61	$11.61	$11.61	$11.82
	Sodium Vapor				
120-173	100-150w SV Pendant/ Flood** ~~(limited to existing inst~~	$11.67	$11.67	$11.67	$11.89
173-298	150-250w SV Tear Drop w/arm	$46.00	$46.00	$46.00	$46.85
298	250w SV Pendant	$18.32	$18.32	$18.32	$18.66
467	400w SV Pendant/Flood	$20.21	$20.21	$20.21	$20.58
1,130	1000w SV Pendant	$22.70	$22.70	$22.70	$23.12
	Metal Halide (limited to existing installations)				
189-205	150-175w MH Pendant	$6.49	$6.49	$6.49	$6.61
445	400w MH Pendant	$8.63	$8.63	$8.63	$8.79
445	400w MH/MHP Flood	$8.26	$8.26	$8.26	$8.41
	** (limited to existing installations)				

(d) Lamp Fixtures - LED fixtures

Billing Watts	Description	Rate Eff. 12/17/19	Rate Yr. 1 Eff. 1/1/21	Rate Yr. 2 Eff. 1/1/22	Rate Yr. 3 Eff. 1/1/23
	Light-Emitting Diode*#				
39	70 LED Pendant	$7.67	$7.67	$7.67	$7.81
51-73	100 LED Pendant	$7.17	$7.17	$7.17	$7.30
72-110	150 LED Pendant	$7.45	$7.45	$7.45	$7.59
135-146	200 LED Pendant** ~~(limited to existing instal~~	$15.76	$15.76	$15.76	$16.05
129-208	250 LED Pendant	$10.13	$10.13	$10.13	$10.32
157-275	400 LED Pendant	$13.64	$13.64	$13.64	$13.89
70	100 LED Post Top Acorn	$22.99	$22.99	$22.99	$23.41
101	150 LED Post Top Acorn	$22.99	$22.99	$22.99	$23.41
70	100 LED Post Top Decorative Acorn	$32.05	$32.05	$32.05	$32.64
101	150 LED Post Top Decorative Acorn	$32.05	$32.05	$32.05	$32.64
72	100 LED Post Top Arlington	$26.02	$26.02	$26.02	$26.50
72	100 LED Post Top Colonial	$15.00	$15.00	$15.00	$15.28
104	150 LED Post Top Arlington	$26.02	$26.02	$26.02	$26.50
106	150 LED Post Top Colonial	$15.48	$15.48	$15.48	$15.77
52	100 LED Premiere Colonial	$16.28	$16.28	$16.28	$16.58
75	150 LED Premiere Colonial	$17.78	$17.78	$17.78	$18.11
54	100 LED Post Top Modern	$14.65	$14.65	$14.65	$14.92
90	150 LED Post Top Modern** ~~(limited to exist~~	$26.98	$26.98	$26.98	$27.48
86	150 LED Tear Drop	$30.45	$30.45	$30.45	$31.01
151	250 LED Tear Drop	$38.39	$38.39	$38.39	$39.10
129	400 LED Floodlight	$11.65	$11.65	$11.65	$11.87
256	1000 LED Floodlight	$23.32	$23.32	$23.32	$23.75

*# LED naming based on HID equivalent lamp watts

** (limited to existing installations)

Continued on Next Page

Schedule SL Continued

(Where longer than 4-foot upsweep arms are required, add for 10- to 20-foot upsweep arms)	$2.86	$2.86	$2.86	$2.91
(e) Distribution poles supporting wires or other service facilities used only for street lighting (per pole)	$3.10	$3.10	$3.10	$3.16

(f) Underground-Supplied Lamp Poles	Rate Eff. 12/17/19	Rate Yr. 1 Eff. 1/1/21	Rate Yr. 2 Eff. 1/1/22	Rate Yr. 3 Eff. 1/1/23
12-foot embedded wood poles	$4.11	$4.11	$4.11	$4.19
12-foot fiberglass with shroud	$15.94	$15.94	$15.94	$16.23
14-foot plain embedded metal poles	$4.41	$4.41	$4.41	$4.49
14-foot embedded metal poles** ~~(limited to existing installat~~	$4.89	$4.89	$4.89	$4.98
14-foot fiberglass poles	$4.89	$4.89	$4.89	$4.98
14-foot black fluted poles	$25.89	$25.89	$25.89	$26.37
20- to 30-foot fiberglass	$12.95	$12.95	$12.95	$13.19
25- to 30-foot pre-wired wood poles*	$6.54*	$6.54*	$6.54*	$6.66
25-foot plain embedded metal poles	$10.55	$10.55	$10.55	$10.74
30-foot plain embedded metal poles	$11.64	$11.64	$11.64	$11.86
30-foot plain embedded metal poles with twin mast arms	$13.65	$13.65	$13.65	$13.90
30-foot bronze-fiberglass poles with one arm	$15.76	$15.76	$15.76	$16.05
* (Where longer than 4-foot upsweep arms are required, add for 10- to 20- foot upsweep arms)	$2.06	$2.06	$2.06	$2.10
Upsweep Arms 10- to 20- feet	$2.86	$2.86	$2.86	$2.91
(g) Ornamental lamp poles** ~~(limited to existing installation~~	$4.19	$4.19	$4.19	$4.27

** (limited to existing installations)

Note: Other than maintenance covered under Monthly Rate (3) and (5) below, fixture and pole rental includes reactive maintenance such as fixture repair, pole knockdown renewal, ballast replacement and glassware replacement. Exceptions are noted in Special Provisions.

3A. Maintenance (Bundled Reactive and Preventative~~; Reactive Only~~)

			~~Reactive &~~ Preventative	~~Reactive Only~~
	Rate Eff. 12/17/19 (per lamp)	Rate Yr. 1 Eff. 1/1/21 (per lamp)	Rate Yr. 2 Eff. 1/1/22 (per lamp)	Rate Yr. 3 Eff. 1/1/23 (per lamp)
(a) Incandescent				
Incandescent Less than 250 candlepower	$1.80	$1.80	$1.80	$1.83
Incandescent 250 candlepower and over	$2.87	$2.87	$2.87	$2.92
(b) Mercury Vapor				
100-400w Mercury Vapor	$1.50	$1.50	$1.50	$1.53
(c) Sodium Vapor				
70-400w Mercury Vapor	$3.22	$3.22	$3.22	$3.28
1000w Sodium Vapor	$6.61	$6.61	$6.61	$6.73
(d) Metal Halide				
100-1000w Metal Halide	$5.76	$5.76	$5.76	$5.87
(e) Direction Sign Fluorescent Lamps **~~(limited to existing installations)~~				
180-230w Fluorescent	$3.77	$3.77	$3.77	$3.84
(f) Light-Emitting Diode				
100-1000 LED	$1.06	$1.06	$1.06	$1.08

** limited to existing installation

3B. Maintenance (Reactive Only)

(a) Incandescent				
Incandescent Less than 250 candlepower	$1.66	$1.66	$1.66	$1.69
Incandescent 250 candlepower and over	$2.64	$2.64	$2.64	$2.69
(b) Mercury Vapor				
100-400w Mercury Vapor	$1.36	$1.36	$1.36	$1.39
(c) Sodium Vapor				
70-400w Mercury Vapor	$2.95	$2.95	$2.95	$3.00
1000w Sodium Vapor	$6.07	$6.07	$6.07	$6.18

Continued on Next Page

Schedule SL Continued

	Rate Eff. 12/17/19 (per lamp)	Rate Yr. 1 Eff. 1/1/21 (per lamp)	Rate Yr. 2 Eff. 1/1/22 (per lamp)	Rate Yr. 3 Eff. 1/1/23 (per lamp)
(d) Metal Halide				
100-1000w Metal Halide	$5.28	$5.28	$5.28	$5.38
(e) Direction Sign Fluorescent Lamps**				
180-230w Fluorescent	$3.46	$3.46	$3.46	$3.52
(f) Light-Emitting Diode				
100-1000 LED	$0.93	$0.93	$0.93	$0.95

** (limited to existing installations)

4. Municipal Duct (where provided and charged for by the Municipal or Public Agency)

(a) Duct occupied solely by St. Ltg. Cable	one-twelfth of the annual per foot duct rental charge payable by Company
(b) Duct occupied jointly with other cable	one twenty-fourth of the annual per foot duct rental charge payable by Company

5. **Light-Emitting Diode (LED) Facilities** – Customer-owned LED fixtures must be evaluated and approved by BGE prior to installation. Such review will generally take approximately 90 days. Billing Watts for LED fixtures shall be based on Illuminating Engineering Society of North America (IESNA) LM-79 Test Reports, which are provided by lighting manufacturers. Customer-owned LED fixtures shall be billed for delivery service accordingly. Please refer to the link **LED Product Listing** for the LED fixtures approved by BGE along with each fixture's Billing Watts. The LM-79 Reports for BGE-approved LED fixtures are available upon request.

6. Customized Lighting Facilities other than those listed above as requested by the Customer, to be priced on an individual contract basis. The Term of Contract for Customized Lighting Facilities may vary. BGE shall file the rates for new fixtures and equipment with the Commission at least 30 days prior to the expected installation of such facilities. To the extent that a Customer requires the installation of new fixtures and/or related equipment before a filing can be submitted, BGE is permitted to file for such rates as soon as possible, but no more than 30 days after the installation of the fixtures/equipment. In such circumstances, the rate charged during the time before Commission approval will be subject to refund if the Commission concludes that the proposed rate is too great. However, BGE shall not be permitted to retroactively bill a Customer if the Commission concludes the proposed rate is too low.

Street Lighting is subject to the following provisions:

(a) The Customer designates the size and location of the fixtures and the location of the poles for underground supplied streetlights. The determination of the type of system as to overhead or underground and location of the circuits rests solely with the Company.

(b) Under Item 1 of the Monthly Rates, the Company makes available a controlled supply of electricity for operation of the lamps from dusk to dawn each night for a total of approximately 4,000 hours per year. When at the Customer's request, and agreed to by the Company, the Company provides customized lighting control, such that the lights burn for less than the stated hours per year, no adjustment to the monthly fee will be made for reduced electricity usage, because service under the Schedule is unmetered.

(c) The Customer may choose from the following types of service as applicable, subject to approval by the Company:

1. The Company offers to provide, own and maintain all equipment as listed and as priced under Item 2 of the Schedule.

2. The Customer may request the Company to furnish, install and sell those items in Monthly Rate 2, excluding cable, at the Customer's expense. The Customer may choose to have the Company perform maintenance services provided for in Monthly Rate 3. Maintenance, not included in Monthly Rate 3, but on equipment supplied exclusively by Company circuitry (e.g., fixture changes, ballast replacement), is performed by the Company at the Customer's expense. If the Customer chooses to perform their own maintenance, a disconnect means acceptable to the Company and the local authority having jurisdiction must exist. The Customer is responsible for all costs for disconnect means above and beyond what is provided by BGE design standards.

Schedule SL Continued

3. In certain instances approved by the Company, the Company may install Customer supplied/owned equipment not included in Monthly Rate 2(b), (c), and (f). Maintenance of this equipment follows the same provisions as delineated in the preceding paragraph (c) 2.

4. In instances where the Customer desires to install, own, and maintain his own lighting equipment (e.g., traffic, sign, street), the Customer must provide a point of disconnect In this case, the Company will provide energy to this service under Monthly Rate 1. Maintenance as described in Monthly Rate 3 will provide energy to this service under Monthly Rate 1. Maintenance as described in Monthly Rate 3 is optional for street and sign lighting.

(d) Fixtures under this Tariff do not include custom shades. For select fixtures, custom shades are available and installed by the Company upon Customer request. Customer is responsible for all associated costs.

(e) The number of feet of cable, the number of distribution poles (line and guy) supporting wires or other service facilities used only for street lighting, the number of lamps and the number of feet of municipal duct occupied solely or jointly by street lighting cable, shall be as shown by the Company's records and shall, for billing purposes, be as of the end of the month preceding the billing month. All underground cable removed is considered to have been in service as of August 31, 1960. The charge under item 2(a) does not apply to underground street lighting cable installed in a development project coincident with underground main under the provisions of Sec. 8.22.

(f) For all fixtures, Monthly Rate 3, Bundled Preventive and Reactive Maintenance, is the default maintenance service for Customers renting fixtures under Provision (c)1 and for Customers owning their own fixtures under Provisions (c)2 and (c)3 and choosing to have the Company perform maintenance service under Monthly Rate 3. For Customer-owned LED lighting facilities under Item 5, the Company, upon the Customer's request, will provide reactive maintenance on a time and materials basis. The Preventive Maintenance service provided under Monthly Rate 3 includes scheduled cleaning of glassware, and lamp, photo control and fuse renewal as needed. LED Preventative Maintenance service provided under Monthly Rate 3 includes scheduled cleaning of glassware, and photo control and fuse replacement as needed.

Monthly Rate 3, Reactive Only Maintenance, is an optional service for these Customers provided upon Customer request. The Reactive Only Maintenance service involves replacement of lamps, fuses or photo control performed with reasonable promptness upon notification to the Company. LED Reactive Maintenance Service involves replacement of photo control or fuse performed with reasonable promptness upon notification to the company.

For customers who choose the Reactive Only Maintenance service or who choose to have no maintenance performed pursuant to Provision (c)4, the Company will not perform Preventive Maintenance service on any current and future fixtures installed on the Customer's behalf. For customers who choose the Bundled Reactive and Preventive Maintenance service after participating in the Reactive Only Maintenance service or after choosing to have no maintenance performed pursuant to Provision (c)4, the Customer's lights will be preventively maintained as part of the Company's normal 6 to 8 year Preventive Maintenance cycle.

Customers choosing either the Bundled Reactive and Preventive Maintenance service or the Reactive Only Maintenance service will be covered by this elected program for all lights under their bill account(s) with two exceptions: (1) customers owning their own fixtures may perform their own maintenance as provided under Provision (c)2, and (2) for Customers owning their own LED lighting facilities, the Customer may request that the Company provide reactive maintenance on a time and materials basis.

In the case of Customer-owned equipment, the Company does not inspect or maintain lamp poles, lamp pole bases or other related equipment, and nothing contained in this Schedule shall be construed to extend the Company's obligation to inspect or maintain any part of such Customer-owned lamp poles, lamp pole bases or related equipment. Additionally, replacement or repair of Customer-owned equipment, other than that which is provided under Monthly Rate 3, is the responsibility of the Customer and subject to Provision c(2) above. Glassware replaced on Customer-owned equipment installed under Provision c(2) or c(3) will be performed by the Company on an as needed basis (typically every 6-8 years) and charged to the Customer.

Schedule SL Continued

(g) The Customer, at their expense, restores improved paving on streets, sidewalks, driveways, and the like, where necessary for the installation, maintenance, relocation or renewal of street lighting cable laid other than in municipal duct, or of galva duct conduit. If an alternative construction method can be used and is selected by the Customer, the Customer is responsible for the price differential.

(h) The Customer shall pay all costs incurred as a result of relocation of Customer-owned or rented streetlights. Should the Customer request that the fixture/pole be removed and within the year request a new installation at or near the original location, the Customer will be charged at cost for this relocation.

(i) When a Customer-owned lamp pole, fixture, and/or associated equipment is damaged as a result of an accident, weather, vandalism, etc., the Company may repair/replace as necessary, under agreement with the Customer, and attempt to bill the party at fault (where applicable). But, if the Company cannot collect the damages from the responsible party, the Customer shall pay for the repair/replacement. However, Customer's agreement is not necessary for the Company to respond to damaged Customer-owned lamp pole, fixture, and/or associated equipment in order to make the equipment and area safe. Customer will be responsible for BGE's costs to respond and make safe if the costs cannot be collected from the responsible party. The rate charged to the Customer to respond and provide make safe only services is $95 per hour, which includes labor, vehicle and travel charges.
In the case of Company-owned equipment, the Company will provide vandal proof equipment for select fixtures at the Customer's request and expense. If the Company identifies vandalism on Company-owned equipment, the Company will make the Customer aware of the need for vandal proofing. If the Customer elects not to vandal proof the facilities, the Company has the option to remove the equipment for repeat cases of vandalism.

(j) Extension of supply facilities for street lighting are subject to the provisions of Sec. 8 for that portion of such facilities required up to the point of control of the electricity supply to the lamps, excluding facilities specifically designated and charged for under the Schedule.

(k) Change in pole style, fixture style, wattage, or type, at the request of the Customer, for Customer-owned equipment, is paid for by the Customer. In instances where the fixture/pole is owned by the Company, Customer requested changes are performed upon request by the Customer and a cost-based fee will be charged to the Customer on a per fixture/pole basis. Should the Customer request that the fixtures/poles be removed and within the year request a new installation, at or near the previous location, the Customer will be charged cost-based fee per fixture/pole for associated costs.

(l) Requests for removal of Company-owned LED lighting equipment prior to the completion of the initial Term of Contract will result in a charge to the Customer calculated as follows: monthly rental rate times remaining months of contract.

LATE PAYMENT CHARGE: STANDARD. (SEC. 7.4)

PAYMENT TERMS: STANDARD. (SEC. 7)

TERM OF CONTRACT: Five years for non LED fixtures and ten years for LED fixtures and thereafter from year to year until terminated at the expiration of any such year by at least 90 days' notice from the Customer.

Riders Applicable:

1. Standard Offer Service
3. Miscellaneous Taxes Surcharges
8. Energy Cost Adjustment
9. Customer Billing and Consumption Data Requests
10. Administrative Cost Adjustment
16. Multi-Year Plan ("MYP") Adjustment Rider
21. Billing in Event of Service Interruption
32. Community Energy Pilot Program

Schedule PL Continued

(h) The Customer shall pay the Company the cost of relocating its private area lighting equipment made at the Customer's request. Should the Customer request that the fixture/pole be removed and within the year request a new installation at or purposefully near the previous location, the Customer will be charged a cost-based fee for the relocation.

(i) Extension of primary-voltage facilities for the supply of private area lighting is subject to the extension provisions of Sec. 8.33.

(j) Tree trimming to enhance light distribution or to facilitate pole and fixture installation is the responsibility of the Customer.

(k) Requests for a change in pole style, fixture size, type or style is paid for at cost by the Customer.

(l) The Company reserves the right to deny the request for installation where access to the pole/fixtures is such that they could not be maintained using typical Company supplied tools and equipment or maintenance could not be done without free access to the property.

(m) Requests for removal of Company owned lighting equipment prior to the Contract Term will result in a charge to the Customer calculated as follows: For non-LED fixtures, the remaining months on the Contract is divided by 60, times the estimated current installation and removal costs of the equipment. For LED fixtures, the remaining months on the Contract is divided by 120, times the estimated current installation and removal costs of the equipment.

(n) The equipment style, size, and location are agreed upon by the Customer and the Company. The determination of the type of system as to overhead or underground and location of the circuits rests solely with the Company. In instances where the Customer requests a location or type of system that is non-standard or more costly to the Company but can be installed, the Customer may request this type of system and/or location but bear the additional expense.

LATE PAYMENT CHARGE: STANDARD. (SEC. 7.4)

PAYMENT TERMS: STANDARD. (SEC. 7)

TERM OF CONTRACT: Five years for non LED fixtures and ten years for LED fixtures, and thereafter until terminated by at least 30 days' notice from the Customer; or until terminated by at least 30 days' notice from the Company.

Subject to Riders applicable as listed below:

3. Miscellaneous Taxes and Surcharges
9. Customer Billing and Consumption Data Requests
16. Multi-Year Plan ("MYP") Adjustment Rider
21. Billing in Event of Service Interruption
32. Community Energy Pilot Program

RIDER INDEX

1. Standard Offer Service
2. Electric Efficiency Charge
3. Miscellaneous Taxes and Surcharges
4. Budget Billing
5. Electric Vehicle Charging Distribution Demand Credit
6. Vehicle Charging Time-Of-Use Adjustment
7. Economic Development (Closed to New Customers)
8. Energy Cost Adjustment
9. Customer Billing and Consumption Data Requests
10. Administrative Cost Adjustment
11. Measured Demand
12. Prepaid Pilot
13. Change of Schedule
14. Reserved for Future Use
15. Demand Response Service
16. ~~Reserved for Future Use~~Multi-Year Plan ("MYP") Adjustment Rider
17. Best Efforts Service
18. Net Energy Metering
19. Demonstration and Trial Installations
20. Reserved for Future Use
21. Billing in Event of Service Interruption
22. Minimum Charge for Short-Term Uses
23. Advanced Meter Services
24. Economic Development
25. Monthly Rate Adjustment
26. Peak Time Rebate
27. Smart Meter Opt-Out
28. Small Generator Interconnection Standards
29. Reserved for Future Use
30. Reserved for Future Use
31. Electric Reliability Investment Initiative Charge
32. Community Energy Pilot Program

Schedule		**Riders Applicable**
R	. . . .	1, 2, 3, 4, 6, 8, 9, 10, 12, 13, 15, 16, 18, 21, 22, 23, 25, 26, 27, 28, 31, 32
RD	. . . .	1, 2, 3, 4, 8, 9, 10, 13, 15, 16, 18, 21, 22, 23, 25, 26, 28, 31
EV	. . . .	1, 2, 3, 4, 8, 9, 10, 12, 13, 15, 16, 21, 22, 23, 25, 26, 28, 31, 32
RL	. . . .	1, 2, 3, 4, 8, 9, 10, 12, 13, 15, 16 18, 21, 22, 23, 25, 26, 28, 31, 32
G	. . . .	1, 2, 3, 4, 8, 9, 10, 13, 16, 18, 19, 21, 22, 23, 24, 25, 26, 27, 28, 31, 32
GU	. . . .	1, 3, 8, 9, 10, 16, 21, 31, 32
GS	. . . .	1, 2, 3, 4, 8, 9, 10, 13, 16, 18, 19, 21, 22, 23, 24, 25, 26, 28, 31, 32
GL	. . . .	1, 2, 3, 5, 7, 8, 9, 10, 11, 13, 16, 17, 18, 19, 21, 22, 23, 24, 25, 26, 28, 31, 32
P	. . . .	1, 2, 3, 5, 7, 8, 9, 10, 11, 13, 16, 18, 19, 21, 22, 23, 24, 26, 28, 31, 32
T	. . . .	1, 2, 3, 7, 8, 9, 10, 11, 16, 18, 19, 21, 22, 23, 24, 26, 28, 32
SL	. . . .	1, 3, 8, 9, 10, 16, 21, 32
PL	. . . .	3, 9, 16, 21, 32

6. Vehicle Charging Time-Of-Use Adjustment - continued

Customers will receive an adjustment for charging station usage during the On-Peak and Off-Peak periods on their monthly bill based on the data received from the Customer's EV charger. The Customer is responsible for enabling and maintaining the EV charger's smart capabilities and connection to the premise's WiFi network. If there is a delay in BGE or BGE's designated vendor receiving the EV charging data, then the Customer's total metered consumption for the premise will be charged Schedule R supply rates and the VC-TOU adjustments will be provided to the Customer on their next monthly bill as long as the delay in receiving smart Level 2 EV Charger data is less than 60 days. BGE is unable to provide Customer adjustments/credits for usage data received 60 days after the date of use.

Billing Seasons: Summer rates are billed for usage from June 1 through September 30. Non-summer rates are billed for usage from October 1 through May 31.

Rate Periods

Summer

Peak – Between the hours of 10 am and 8 pm on weekdays, excluding the National holidays listed below.

Off-Peak – All times other than those defined for the On-Peak rating period.

Non-Summer

Peak – Between the hours of 7 am and 11 am, and the hours of 5 pm and 9 pm on weekdays, excluding the National holidays listed below.

Off-Peak – All times other than those defined for the On-Peak rating period.

The Non-Summer time periods shown above will begin and end one hour later for the period between the second Sunday in March and the first Sunday in April, and for the period between the last Sunday in October and the first Sunday in November.

Holidays

All hours on Saturdays and Sundays and the following National holidays are Off-Peak: New Year's Day, President's Day, Good Friday, Memorial Day, Independence Day, Labor Day, Thanksgiving, Christmas, and the Monday following such of these as fall on Sunday.

7. Economic Development (Closed to New Customers)

This rider is closed to new customers effective August 20, 2015. Customers taking service under this rider before August 20, 2015 will continue taking service under the rider until the expiration of their contract term. Upon application by the Customer and approval by the Company, Economic Development price reductions are available on the Qualifying Load of customers served under Schedule GL, P or T (the Controlling Schedule). Qualifying Load (QL) is new or incremental load in excess of historic demand and energy use, as determined by the Company, which is associated with new employment of at least 10 full-time equivalent persons. The Company will approve applications when the price reductions (1) have been certified by a Review Panel (see below) as necessary to attract new business or encourage expansion of existing business, and (2) do not cause the total amount of Rider 7 customers' price reductions granted in a calendar year to exceed $2 million.

The Review Panel will consist of 3 representatives; one each from BGE, Maryland's Department of Business and Economic Development, and local government in the area affected by the potential new

7. Economic Development (Closed to New Customers) – continued

business. The offering of price reductions must be agreed to by all 3 representatives, and must be accompanied by an offering of governmental economic development assistance.

Rider 7 price reductions may not be used in connection with a retail establishment unless the Review Panel determines that such price reductions are necessary to accomplish the purposes of this Rider. A retail establishment is defined as an establishment which sells goods or services to ultimate users, and not for purpose of resale or business use. Discounts will not be provided where a customer merely changes names or service locations within BGE's service territory, without meeting the other criteria for price reductions under this Rider.

Two price reduction options are available to qualifying customers. Option 1 is available to customers meeting the schedule requirements; Option 2 is available to customers meeting the schedule requirements and who are certified as eligible for State-provided Enterprise Zone benefits.

Effective for agreements after July 1, 2004, price reductions for the QL are restricted to the Delivery Service charges in the Customer's Controlling Schedule. Price reductions will not be applied to Generation charges, Transmission charges, Taxes, Surcharges or the CTC in the Customer's Controlling Schedule regardless of the Customer's supply source.

The Customer credits are applied in the following manner:

		Option 1	Option 2
	Minimum QL	500 kW	200 kW
Price Reduction (%):	Year 1	10	15
	Year 2	5	10
	Year 3	5	5
	Year 4	-	5
	Year 5	-	5

The Company will recoup all rate reductions previously granted if the QL is shifted to an alternative energy source, such as Customer-owned generation, within 3 years, for Option 1, or 5 years, for Option 2, from the date of last price reduction.

8. Energy Cost Adjustment

The Standard Offer Market-Priced Service Charges for Residential, Types I, II and Hourly Service are subject to periodic adjustment to reflect the actual cost of providing energy and transmission-related services. The true-up process compares retail customer billings for energy and transmission services against payments by the Company to wholesale suppliers and the Pennsylvania-New Jersey-Maryland Interconnection (PJM). This true-up adjustment will be made in the February, June and October billing months or more frequently, if necessary. The adjustment is applied to the Customer's billed kilowatt-hours. The current Energy Cost Adjustment by SOS Type is available on the BGE website at www.bge.com.

~~16. Reserved for Future Use~~

16. Multi-Year Plan ("MYP") Adjustment Rider

This rider addresses Imbalances that may arise between the revenue requirement approved by the Commission as part of initial rates under a Multi-Year Plan ("MYP") and the actual revenue requirement filed as part of the Annual Informational Filings or Final Reconciliation, pursuant to Order No. 89482.

The Annual Informational Filings shall be filed within 90 days of the end of the first and second years of the approved MYP.

The Final Reconciliation shall be filed within 120 days of the end of the MYP. The Final Recollection shall cover investments and costs in the MRP period not previously reviewed for prudency and reconciled in the rate case.

Imbalances shall be calculated consistent with the MYP revenue requirement approved by the Commission in an order resulting from an MYP proceeding. Rate base and operating income shall use actual results from the applicable MYP period in calculating the actual revenue requirement to determine the Imbalance. If an Imbalance calculated as part of an Annual Informational Filing, as defined in Order No. 89482, represents an amount owed to customers, the MYP Adjustment Rider can be utilized to provide a credit for such amount, if determined to be appropriate by the Commission. The MYP Adjustment Rider can be utilized to recover or credit an Imbalance calculated as part of a Final Reconciliation, as determined to be appropriate by the Commission.

All Imbalances are deferred into a regulatory asset or liability until such time as the Commission determines the appropriate disposition of the Imbalance, including the appropriate period over which an Imbalance is recovered or credited to customers. Carrying costs will apply for amounts owed to customers and will continue to apply during the credit period.

Calculation of Rate

The MYP Adjustment Rider rate is determined for each Schedule by first allocating the Imbalance, as determined appropriate by the Commission, in proportion to each Schedule's amount of base distribution revenues in the final year of the MYP. The resulting amounts are then divided by the estimated billing determinants, per kilowatt-hour or per fixture, for each applicable Schedule. Details concerning the calculation of the MYP Adjustment are filed with and approved by the Commission prior to their use in billing. The MYP Adjustment shall be included in the Distribution Charge on the Customer's monthly electric bill.

Rates Effective [insert date range]

Rate Schedule	Rate
R/RD/EV	$0.00000 per kWh
RL	$0.00000 per kWh
G/GU	$0.00000 per kWh
GS	$0.00000 per kWh
GL	$0.00000 per kWh
P	$0.00000 per kWh
T	$0.00000 per kWh
SL	$0.00000 per kWh
PL	$0.00 per fixture

32. Community Energy Pilot Program - continued

On or before 30 days after the billing cycle that is complete immediately prior to the end of April each year, BGE will apply bill credits to the bill of each eligible Subscriber a true up for any excess generation up to $25. True-up credits greater than $25 may be paid by check. The Subscriber's excess generation shall be credited or paid to reasonably exclude the distribution, transmission, and non-commodity portion of the Subscriber's bill for the excess generation amount.

Subscriber Organization: Prior to applying for an Interconnection Agreement for this pilot program, a Subscriber Organization must first be granted permission to participate in this pilot from the PSC and have received a Subscriber Organization Identification Number. Once the Subscriber Organization has an Identification Number, they must apply to BGE for an Interconnection Agreement under Code of Maryland Regulations 20.50.09, indicating a request to participate in the Pilot Program. Interconnection Applications will be processed in the order in which the completed Interconnection Applications are received. Each Subscriber Organization and affiliated-ownership Subscriber Organizations are limited to 2 (two) Interconnection Applications during the initial 20 business days of the Year 2/3 interconnection queue period. Year 2/3 Interconnection Applications may be submitted no earlier than 12:00:00PM (EPT) on November 5, 2018. A Subscriber Organization is responsible for all interconnection costs.

A CSEGS is subject to all tariff provisions applicable under the schedule they are placed. Tariff Schedule and demand are determined based on the capacity of the CSEGS system. A CSEGS may not exceed 2MW in AC rated capacity. A CSEGS of 500 kW or greater may not be located on the same or contiguous parcel of property as another CSEGS of 500kW or greater owned by the same Subscriber Organization or its affiliate unless constructed on one of the following: a building rooftop or parking structure, over a parking lot or roadway, in a platted industrial park, or 2 or more projects, each of up to 2 MW in size comprising no more than 6 MW constructed on a brownfield site. A CSEGS facility with a capacity greater than 1 MW will be placed on Primary Service. Metering for a CSEGS will be divided into an input and an output channel. All usage on the input channel will be billed in accordance with the applicable tariff schedule of the CSEGS. All generation on the output channel will be used in the calculation of the Subscriber Credits. BGE reserves the right to require the CSEGS facility to be moved to a bill cycle in order to facilitate efficient credit calculation.

A Subscriber Organization must provide a partially executed Interconnection Agreement, in conjunction with a Community Energy Pilot Application. Pilot Program Applications shall be processed in the order in which they are received. BGE will notify the Subscriber Organization of receipt of the Pilot Program Application and whether the Pilot Program Application is complete within 5 business days. A Subscriber Organization receiving notice of an incomplete Pilot Program Application shall revise and resubmit within 10 days of receiving the notice. Projects that are not awarded pilot program capacity in Year 1 will have their Interconnection Application canceled and must reapply for interconnection and reapply to the pilot program in a future year and do not maintain their waiting list position for capacity in Year 2. Year 1 (including the waitlist) will end on October 26, 2018 at 5:00:00PM (EPT). In Year 2, if a Pilot Program Application exceeds the available program capacity or category and is otherwise complete, the Pilot Program Application shall be deferred to the next program year if cap space is available. Deferral of one Pilot Program Application does not preclude the company from accepting a smaller Pilot Program Application received after the deferred Pilot Program Application. Available pilot program capacity can be found on BGE.com. A CSEGS Identification Number will be assigned and capacity in the pilot program queue will be reserved for the Subscriber Organization's specific CSEGS upon a complete and accepted Pilot Program Application. If a CSEGS or Subscriber Organization raises a dispute with BGE or the Commission regarding the processing of an Interconnection Application or a Pilot Program Application, BGE will not set aside capacity for the CSEG during the pendency of the investigation of the dispute.

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Company Exhibit LKF-3
Supplement 650
Filed: May 15, 2020
Effective: June 14, 2020

Electric Service Tariff
Without Revision Markings

RESIDENTIAL SERVICE–ELECTRIC

SCHEDULE R

Availability:

(a) For use for the domestic requirements of:

(1) A single private dwelling.

(2) An individually metered dwelling unit in a multiple dwelling building.

(3) One combination of two dwelling units within a building, if served through a single meter.

(4) A dwelling occupied as the dwelling place of a church divine or of religious associates engaged in church duties.

(5) A single dwelling within a building where the occupant has not more than 10 bedrooms to let or not more than 10 table boarders, or a combination of not more than ten.

(b) For use, if on one property and served through a single meter, of a combination of the occupant's domestic requirements in a dwelling and his nondomestic requirements, provided that more than 50 percent of the connected load is for domestic purposes.

(c) For use, if served through a separate meter, by appliances used in common by the occupants of not more than two dwelling units within a building.

Delivery Voltage: Service at Secondary Distribution Systems voltages.

Monthly Net Rates:

Effective with service rendered on or after 12/17/2019

Delivery Service Customer Charge: **$ 8.00 per month,**

Delivery Service Charge: **0.03507 $/kWh**

	Rate Year 1 Effective January 1, 2021	**Rate Year 2 Effective January 1, 2022**	**Rate Year 3 Effective January 1, 2023**
Customer Charge (per Month)	$8.00	$8.00	$9.00
Delivery Service Charge ($/kWh)	$0.03651	$0.03633	$0.04250

- Competitive Billing (where applicable) credits $ 0.62 per month (see Section 7.7 for details)
- The Delivery Service Charge excludes Rider 10 - Administrative Cost Adjustment

Energy Charges:

Generation and Transmission Market-Priced Service Charges can be found on www.bge.com and Rider 1 – Standard Offer Service.

(Continued on Next Page)

Schedule R continued

Minimum Charge: Net Delivery Service Customer Charge.

Billing Seasons: Summer rates are billed for the four billing periods ending June through September. Non-Summer rates are billed for the eight billing periods ending October through May.

Late Payment Charge: Standard. (Sec. 7.4)

Payment Terms: Standard. (Sec. 7)

Subject to Riders applicable as listed below:

1. Standard Offer Service
2. Electric Efficiency Charge
3. Miscellaneous Taxes and Surcharges
4. Budget Billing
6. Vehicle Charging Time-Of-Use Adjustment
8. Energy Cost Adjustment
9. Customer Billing and Consumption Data Requests
10. Administrative Cost Adjustment
12. Prepaid Pilot
13. Change of Schedule
15. Demand Response Service
16. Multi-Year Plan (“MYP”) Adjustment Rider
18. Net Energy Metering
21. Billing in Event of Service Interruption
22. Minimum Charge for Short-Term Uses
23. Advanced Meter Services
25. Monthly Rate Adjustment
26. Peak Time Rebate
27. Smart Meter Opt-Out
28. Small Generator Interconnection Standards
31. Electric Reliability Investment Initiative Charge
32. Community Energy Pilot Program

RESIDENTIAL DELIVERY AND ENERGY TIME-OF-USE PILOT - ELECTRIC

SCHEDULE RD

Availability: At the Customer's request, for use, at the customer's option, for all residential purposes.

To be eligible for participation, a Customer must have a Smart Meter capable of measuring hourly time-of-use data for at least the past 1 year and cannot participate in virtual or aggregated net metering or any other Company pilot program such as, but not limited to, Rider 32 - Community Solar or Rider 12 - Prepaid.

The pilot is available to a limited number of residential customers. Additionally, a maximum of 10% of pilot participants are allowed to be net metered under Rider 18.

Delivery Voltage: Service at Secondary Distribution Systems voltages.

Monthly Net Rates:

Effective with service rendered on or after 12/17/2019

Delivery Service Customer Charge: **$ 8.00 per month,**
Delivery Service Charge: On-Peak **0.11780 $/kWh**
Off-Peak **0.02285 $/kWh**

	Rate Year 1 Effective January 1, 2021	Rate Year 2 Effective January 1, 2022	Rate Year 3 Effective January 1, 2023
Customer Charge (per Month)	$8.00	$8.00	$9.00
Delivery Service Charge On-Peak ($/kWh)	$0.12263	$0.12202	$0.14274
Delivery Service Charge Off-Peak ($/kWh)	$0.02379	$0.02367	$.02769

- Competitive Billing (where applicable) credits $ 0.62 per month (see Section 7.7 for details)
- The Delivery Service Charge excludes Rider 10 - Administrative Cost Adjustment

Energy Charges:

Generation and Transmission Market-Priced Service Charges can be found on www.bge.com and Rider 1 – Standard Offer Service.

Minimum Charge: Net Delivery Service Customer Charge.

Billing Seasons: Summer rates are billed for usage from June 1 through September 30.
Non-Summer rates are billed for usage from October 1 through May 31.

(Continued on Next Page)

Schedule RD continued

Rating Periods:

Summer

On-Peak - Between the hours of 2 pm and 7 pm on weekdays, excluding the National holidays listed below.

Off-Peak - All times other than those defined for the On-Peak rating period.

Non-Summer

On-Peak - Between the hours of 6 am and 9 am on weekdays, excluding the National holidays listed below.

Off-Peak - All times other than those defined for the On-Peak rating period.

The Non-Summer time periods shown above will begin and end one hour later for the period between the second Sunday in March and the first Sunday in April, and for the period between the last Sunday in October and the first Sunday in November.

Holidays

All hours on Saturdays and Sundays and the following National holidays are Off-Peak: New Year's Day, President's Day, Good Friday, Memorial Day, Independence Day, Labor Day, Thanksgiving, Christmas, and the Monday following such of these as fall on Sunday.

Late Payment Charge: Standard. (Sec. 7.4)

Payment Terms: Standard. (Sec. 7)

Term of Contract: Customers have the ability to request service under this schedule through April 1, 2021. This rate schedule will remain effective until April 1, 2022 and thereafter the Customer can choose to stay on this schedule if continued by the Maryland Public Service Commission, or return to Schedule R.

Subject to Riders applicable as listed below:

1. Standard Offer Service
2. Electric Efficiency Charge
3. Miscellaneous Taxes and Surcharges
4. Budget Billing
8. Energy Cost Adjustment
9. Customer Billing and Consumption Data Requests
10. Administrative Cost Adjustment
13. Change of Schedule
15. Demand Response Service
16. Multi-Year Plan (“MYP”) Adjustment Rider
18. Net Energy Metering
21. Billing in Event of Service Interruption
22. Minimum Charge for Short-Term Uses
23. Advanced Meter Services
25. Monthly Rate Adjustment
26. Peak Time Rebate
28. Small Generator Interconnection Standards
31. Electric Reliability Investment Initiative Charge

RESIDENTIAL ELECTRIC VEHICLE TIME-OF-USE - ELECTRIC

SCHEDULE EV

Availability: At the Customer's request, for BGE Standard Offer Service residential customers who purchase or lease a plug-in electric vehicle and charge the vehicle through a connection to the BGE electric distribution system . A plug-in electric vehicle is any vehicle propelled by an engine that utilizes, at least in part, on-board electric energy from a battery charging system. Electric vehicles include plug-in hybrid-electric vehicles (PHEV), extended range electric vehicles (EREV) and battery electric vehicles (BEV). This schedule is available to residential customers who charge their electric vehicles at their primary residence on a single time-of-use meter that is also used to measure consumption at the primary residence (whole house) level. Participation requires the installation of a Smart Meter capable of measuring hourly time-of-use data.

Delivery Voltage: Service at Secondary Distribution Systems voltages.

Monthly Net Rates:

Effective with service rendered on or after 12/17/2019

Delivery Service Customer Charge: **$ 8.00 per month,**

Delivery Service Charge: **0.03507 $/kWh**

	Rate Year 1 Effective January 1, 2021	**Rate Year 2 Effective January 1, 2022**	**Rate Year 3 Effective January 1, 2023**
Customer Charge (per Month)	$8.00	$8.00	$9.00
Delivery Service Charge ($/kWh)	$0.03651	$0.03633	$0.04250

- Competitive Billing (where applicable) credits $ 0.62 per month (see Section 7.7 for details)
- The Delivery Service Charge excludes Rider 10 - Administrative Cost Adjustment

Energy Charges:

Generation and Transmission Market-Priced Service Charges can be found on www.bge.com and Rider 1 – Standard Offer Service.

Minimum Charge: Net Delivery Service Customer Charge.

Billing Seasons: Summer rates are billed for usage from June 1 through September 30.
Non-Summer rates are billed for usage from October 1 through May 31.

(Continued on Next Page)

Schedule EV continued

Rating Periods:

Summer

Peak - Between the hours of 10 am and 8 pm on weekdays, excluding the National holidays listed below.

Off-Peak - All times other than those defined for the On-Peak rating period.

Non-Summer

Peak - Between the hours of 7 am and 11 am, and the hours of 5 pm and 9 pm on weekdays, excluding the National holidays listed below.

Off-Peak - All times other than those defined for the On-Peak rating period.

The Non-Summer time periods shown above will begin and end one hour later for the period between the second Sunday in March and the first Sunday in April, and for the period between the last Sunday in October and the first Sunday in November.

Holidays

All hours on Saturdays and Sundays and the following National holidays are Off-Peak: New Year's Day, President's Day, Good Friday, Memorial Day, Independence Day, Labor Day, Thanksgiving, Christmas, and the Monday following such of these as fall on Sunday.

Late Payment Charge: Standard. (Sec. 7.4)

Payment Terms: Standard. (Sec. 7)

Subject to Riders applicable as listed below:

1. Standard Offer Service
2. Electric Efficiency Charge
3. Miscellaneous Taxes and Surcharges
4. Budget Billing
8. Energy Cost Adjustment
9. Customer Billing and Consumption Data Requests
10. Administrative Cost Adjustment
12. Prepaid Pilot
13. Change of Schedule
15. Demand Response Service
16. Multi-Year Plan (“MYP”) Adjustment Rider
21. Billing in Event of Service Interruption
22. Minimum Charge for Short-Term Uses
23. Advanced Meter Services
25. Monthly Rate Adjustment
26. Peak Time Rebate
28. Small Generator Interconnection Standards
31. Electric Reliability Investment Initiative Charge
32. Community Energy Pilot Program

RESIDENTIAL OPTIONAL TIME-OF-USE - ELECTRIC

SCHEDULE RL

Availability: At the Customer's request, for use, at the customer's option, for all residential purposes for single family buildings having electric central air conditioning or electric central heating, or where otherwise requested and approved by the Company. For buildings meeting these use conditions, the Schedule is also available for a combination of domestic requirements and non-domestic requirements served through a single meter where the connected load and use are predominantly domestic.

Delivery Voltage: Service at Secondary Distribution Systems voltages.

Monthly Net Rates:

Effective with service rendered on or after 12/17/2019

Delivery Service Customer Charge: **$ 12.00 per month,**

Delivery Service Charge: **0.03538 $/kWh**

	Rate Year 1 Effective January 1, 2021	Rate Year 2 Effective January 1, 2022	Rate Year 3 Effective January 1, 2023
Customer Charge (per Month)	$12.00	$12.00	$12.00
Delivery Service Charge ($/kWh)	$0.03680	$0.03661	$0.04189

- Competitive Billing (where applicable) credits $ 0.62 per month (see Section 7.7 for details)
- The Delivery Service Charge excludes Rider 10 - Administrative Cost Adjustment

Energy Charges:

Generation and Transmission Market-Priced Service Charges can be found on www.bge.com and Rider 1 – Standard Offer Service.

Minimum Charge: Net Delivery Service Customer Charge.

Billing Seasons: Summer rates are billed for usage from June 1 through September 30.
Non-Summer rates are billed for usage from October 1 through May 31.

(Continued on Next Page)

Schedule RL continued

Rating Periods:

Summer

Peak - Between the hours of 10 am and 8 pm on weekdays, excluding the National holidays listed below.

Intermediate - Between the hours of 7 am and 10 am, and the hours of 8 pm and 11 pm on weekdays, excluding the National holidays listed below.

Off-Peak - All times other than those defined for the On-Peak and Intermediate-Peak rating periods.

Non-Summer

Peak - Between the hours of 7 am and 11 am, and the hours of 5 pm and 9 pm on weekdays, excluding the National holidays listed below.

Intermediate - Between the hours of 11 am and 5 pm on weekdays, excluding the National holidays listed below.

Off-Peak - All times other than those defined for the On-Peak and Intermediate-Peak rating periods.

The Non-Summer time periods shown above will begin and end one hour later for the period between the second Sunday in March and the first Sunday in April, and for the period between the last Sunday in October and the first Sunday in November.

Holidays

All hours on Saturdays and Sundays and the following National holidays are Off-Peak: New Year's Day, President's Day, Good Friday, Memorial Day, Independence Day, Labor Day, Thanksgiving, Christmas, and the Monday following such of these as fall on Sunday.

Late Payment Charge: Standard. (Sec. 7.4)

Payment Terms: Standard. (Sec. 7)

Term of Contract: One year and thereafter until terminated by the Customer.

Subject to Riders applicable as listed below:

1. Standard Offer Service
2. Electric Efficiency Charge
3. Miscellaneous Taxes and Surcharges
4. Budget Billing
8. Energy Cost Adjustment
9. Customer Billing and Consumption Data Requests
10. Administrative Cost Adjustment
12. Prepaid Pilot
13. Change of Schedule
15. Demand Response Service
16. Multi-Year Plan (“MYP”) Adjustment Rider
21. Billing in Event of Service Interruption
22. Minimum Charge for Short-Term Uses
23. Advanced Meter Services
25. Monthly Rate Adjustment
26. Peak Time Rebate
28. Small Generator Interconnection Standards
31. Electric Reliability Investment Initiative Charge
32. Community Energy Pilot Program

GENERAL SERVICE – ELECTRIC

SCHEDULE G

Availability: For use for all purposes where the Customer does not qualify for any of the Company's other rate schedules.

Delivery Voltage: Service at Secondary Distribution Systems voltages. It is also available for customers receiving Primary service under this Schedule on or before January 1, 1987 or for a new customer who locates to an existing facility served at Primary Systems voltages where the customer does not qualify for other Primary service rate schedules.

Monthly Net Rates:

Effective with service rendered on or after 12/17/2019

Delivery Service Customer Charge:	**$ 12.40 per month,**
Delivery Service Charge (Secondary):	**0.03194 $/kWh**
Delivery Service Charge (Primary):	**0.02909 $/kWh**

	Rate Year 1 Effective January 1, 2021	Rate Year 2 Effective January 1, 2022	Rate Year 3 Effective January 1, 2023
Customer Charge (per Month)	$12.40	$12.40	$14.00
Delivery Service Charge (Secondary) ($/kWh)	$0.03398	$0.03458	$0.03911
Delivery Service Charge (Primary) ($/kWh)	$0.02909	$0.02909	$0.03755

- Competitive Billing (where applicable) credits $ 0.47 per month (see Section 7.7 for details)
- The Delivery Service Charge excludes Rider 10 - Administrative Cost Adjustment

Energy Charges:

Generation and Transmission Market-Priced Service Charges can be found on www.bge.com and Rider 1 – Standard Offer Service.

Minimum Charge: Net Delivery Service Customer Charge.

Billing Seasons: Summer rates are billed for the four billing periods ending June through September. Non-Summer rates are billed for the eight billing periods ending October through May.

Late Payment Charge: Standard. (Sec. 7.4)

Payment Terms: Standard. (Sec. 7)

Term of Contract: The initial term of contract is 2 years where additional main facilities are required for supply. Otherwise, the term of contract is one year. After the initial term of contract, the contract may be terminated by at least 30 days' notice from the Customer.

Schedule G continued

Subject to Riders applicable as listed below:

1. Standard Offer Service
2. Electric Efficiency Charge
3. Miscellaneous Taxes and Surcharges.
4. Budget Billing
8. Energy Cost Adjustment
9. Customer Billing and Consumption Data Request
10. Administrative Cost Adjustment
13. Change of Schedule
16. Multi-Year Plan (“MYP”) Adjustment Rider
18. Net Energy Metering
19. Demonstration and Trial Installation
21. Billing in Event of Service Interruption
22. Minimum Charge for Short-Term Uses
23. Advanced Meter Services
24. Economic Development
25. Monthly Rate Adjustment
26. Peak Time Rebate
27. Smart Meter Opt-Out
28. Small Generator Interconnection Standards
31. Electric Reliability Investment Initiative Charge
32. Community Energy Pilot Program

GENERAL UNMETERED SERVICE - ELECTRIC
SCHEDULE GU

Availability: Unmetered service is available under conditions specified by the Company for the lighting and operation of electrical devices owned, operated and maintained by the Customer. Electrical devices served under this schedule include but are not limited to traffic signals, other traffic control devices, traffic speed cameras, crime cameras, and surveillance cameras. Unmetered Service is not available until the requesting Customer provides all information regarding its devices deemed necessary by the Company, and agrees to the control and audit provision selected by the Company. The kilowatt-hours applied to the Schedule's Usage Charge are predetermined average monthly uses of Company selected categories and groupings of equipment, with no allowances for outages. For traffic signals and other traffic control devices, one signalized intersection of thoroughfares is the largest category or grouping available for billing purposes.

Delivery Voltage: Service at Secondary Distribution Systems voltages.

Monthly Net Rates:

Effective with service rendered on or after 12/17/2019

Delivery Service Customer Charge: **$ 6.00 per month,**

Delivery Service Charge (Secondary): **0.02871 $/kWh**

	Rate Year 1 Effective January 1, 2021	Rate Year 2 Effective January 1, 2022	Rate Year 3 Effective January 1, 2023
Customer Charge (per Month)	$6.00	$6.00	$6.00
Delivery Service Charge ($/kWh)	$0.02871	$0.02871	$0.03966

- Competitive Billing (where applicable) credits $ 0.47 per month (see Section 7.7 for details)
- The Delivery Service Charge excludes Rider 10 - Administrative Cost Adjustment

Energy Charges:

Generation and Transmission Market-Priced Service Charges can be found on www.bge.com and Rider 1 – Standard Offer Service.

Minimum Charge: Net Delivery Service Customer Charge.

Billing Seasons: Summer rates are billed for the four billing periods ending June through September. Non-Summer rates are billed for the eight billing periods ending October through May.

Late Payment Charge: Standard. (Sec. 7.4)

Payment Terms: Standard. (Sec. 7)

Term of Contract: The initial term of contract is 2 years where additional main facilities are required for supply. Otherwise, the term of contract is one year. After the initial term of contract, the contract may be terminated by at least 30 days' notice from the Customer.

Schedule GU continued

Subject to Riders applicable as listed below:

1. Standard Offer Service
3. Miscellaneous Taxes and Surcharges
8. Energy Cost Adjustment
9. Customer Billing and Consumption Data Request
10. Administrative Cost Adjustment
16. Multi-Year Plan (“MYP”) Adjustment Rider
21. Billing in Event of Service Interruption
31. Electric Reliability Investment Initiative Charge
32. Community Energy Pilot Program

GENERAL SERVICE SMALL - ELECTRIC

SCHEDULE GS

Availability: At the Customer's request, for use for all purposes where the Customer qualifies for Schedule G, and where the Customer's consumption is 2,000 kWh or more in any month.

Delivery Voltage: Service at Secondary Distribution Systems voltages.

Monthly Net Rates:

Effective with service rendered on or after 12/17/2019

Delivery Service Customer Charge: **$ 18.60 per month,**

Delivery Service Charge: **0.02937 $/kWh**

	Rate Year 1 Effective January 1, 2021	Rate Year 2 Effective January 1, 2022	Rate Year 3 Effective January 1, 2023
Customer Charge (per Month)	$18.60	$18.60	$18.60
Delivery Service Charge ($/kWh)	$0.03173	$0.03227	$0.03687

- Competitive Billing (where applicable) credits $ 0.47 per month (see Section 7.7 for details)
- The Delivery Service Charge excludes Rider 10 - Administrative Cost Adjustment

Energy Charges:

Generation and Transmission Market-Priced Service Charges can be found on www.bge.com and Rider 1 – Standard Offer Service.

Minimum Charge: Net Delivery Service Customer Charge.

Billing Seasons: Summer rates are billed for usage from June 1 through September 30.
Non-Summer rates are billed for usage from October 1 through May 31.

(Continued on Next Page)

Schedule GS continued

Rating Periods:

Summer

Peak - Between the hours of 10 am and 8 pm on weekdays, excluding the National holidays listed below.

Intermediate - Between the hours of 7 am and 10 am, and the hours of 8 pm and 11 pm on weekdays, excluding the National holidays listed below.

Off-Peak - All times other than those defined for the On-Peak and Intermediate-Peak rating periods.

Non-Summer

Peak - Between the hours of 7 am and 11 am, and the hours of 5 pm and 9 pm on weekdays, excluding the National holidays listed below.

Intermediate - Between the hours of 11 am and 5 pm on weekdays, excluding the National holidays listed below.

Off-Peak - All times other than those defined for the On-Peak and Intermediate-Peak rating periods.

The Non-Summer time periods shown above will begin and end one hour later for the period between the second Sunday in March and the first Sunday in April, and for the period between the last Sunday in October and the first Sunday in November.

Holidays:

All hours on Saturdays and Sundays and the following National holidays are Off-Peak: New Year's Day, President's Day, Good Friday, Memorial Day, Independence Day, Labor Day, Thanksgiving, Christmas, and the Monday following such of these as fall on Sunday.

Late Payment Charge: Standard. (Sec. 7.4)

Payment Terms: Standard. (Sec. 7)

Term of Contract: One year and thereafter until terminated by the Customer.

Subject to Riders applicable as listed below:

1. Standard Offer Service
2. Electric Efficiency Charge
3. Miscellaneous Taxes and Surcharges
4. Budget Billing
8. Energy Cost Adjustment
9. Customer Billing and Consumption Data Requests
10. Administrative Cost Adjustment
13. Change of Schedule
16. Multi-Year Plan (“MYP”) Adjustment Rider
18. Net Energy Metering
19. Demonstration and Trial Installations
21. Billing in Event of Service Interruption
22. Minimum Charge for Short-Term Uses
23. Advanced Meter Services
24. Economic Development
25. Monthly Rate Adjustment
26. Peak Time Rebate
28. Small Generator Interconnection Standards
31. Electric Reliability Investment Initiative Charge
32. Community Energy Pilot Program

GENERAL SERVICE LARGE–ELECTRIC

SCHEDULE GL

Availability: For use for all purposes, where the Customer has established a monthly demand of 60 kW or more. The applicable Market-Priced Standard Offer Service Type is determined as follows.

Type II- Market-Priced Service: For non-residential customers not eligible for Type 1 SOS whose PJM capacity peak load contribution is less than 600kW, unless excluded by the Phase I Settlement Agreement in Case No.8908.

Delivery Voltage: Service at Secondary Distribution Systems voltages, or at Primary Systems voltages where the Customer does not qualify for Schedule P.

Monthly Net Rates:

Effective with service rendered on or after 12/17/2019

Delivery Service Customer Charge: **$ 88.00 per month,**

Secondary Service Customers:

Demand Charges:

Transmission Market-Priced Service Charge can be found on www.bge.com and Rider 1 – Standard Offer Service.

Delivery Service: **$ 3.81/kW**

Energy Charges:

Generation Market-Priced Service Charges can be found on www.bge.com and Rider 1 – Standard Offer Service.

Delivery Service Charge: **0.01686 $/kWh**

	Rate Year 1 Effective January 1, 2021	Rate Year 2 Effective January 1, 2022	Rate Year 3 Effective January 1, 2023
Customer Charge (per Month)	$88.00	$88.00	$97.00
Delivery Service Demand Charge ($/kW)	$3.81	$3.81	$4.50
Delivery Service Charge ($/kWh)	$0.01752	$0.01772	$0.01942

-

- Competitive Billing (where applicable) credits $ 0.47 per month (see Section 7.7 for details)
- The Delivery Service Charge excludes Rider 10 - Administrative Cost Adjustment

Minimum Charge: Net Delivery Service Customer Charge.

Billing Seasons: Summer rates are billed for usage from June 1 through September 30. Non-Summer rates are billed for usage from October 1 through May 31.

Schedule GL continued

Rating Periods:

Summer

Peak-Between the hours of 10am and 8pm on weekdays, excluding the National holidays listed below.

Intermediate - Between the hours of 7 am and 10 am, and the hours of 8 pm and 11 pm on weekdays, excluding the National holidays listed below.

Off-Peak - All times other than those defined for the On-Peak and Intermediate-Peak rating periods.

Non-Summer

Peak - Between the hours of 7 am and 11 am, and the hours of 5 pm and 9 pm on weekdays, excluding the National holidays listed below.

Intermediate - Between the hours of 11 am and 5 pm on weekdays, excluding the National holidays listed below.

Off-Peak - All times other than those defined for the On-Peak and Intermediate-Peak rating periods.

The Non-Summer time periods shown above will begin and end one hour later for the period between the second Sunday in March and the first Sunday in April, and for the period between the last Sunday in October and the first Sunday in November.

Holidays:

All hours on Saturdays and Sundays and the following National holidays are Off-Peak: New Year's Day, President's Day, Good Friday, Memorial Day, Independence Day, Labor Day, Thanksgiving, Christmas, and the Monday following such of these as fall on Sunday.

Billing Demand: The maximum 30-minute measured demand, adjusted to the nearest whole kW, in each applicable rating period for the month. Measured demand is the Customer's rate of use of electric energy as shown by or computed from readings of the Company's demand meter. Generation and Transmission Demand are billed for each kW of billing demand occurring during the Peak rating period. Delivery Service Demand is for each kW of Billing Demand recorded during any rating period.

Primary Service Customers: For Customers taking service at Primary Systems voltages, Type II Secondary Service rates apply for Generation and Transmission Services. The Delivery Service Demand and Energy Charge rates are as follows.

Effective with service rendered on or after 12/17/2019

Delivery Service Demand Charge: **$ 3.63/kW**

Delivery Service Energy Charge: **0.01619 $/kWh**

	Rate Year 1 Effective January 1, 2021	**Rate Year 2 Effective January 1, 2022**	**Rate Year 3 Effective January 1, 2023**
Customer Charge (per Month)	$88.00	$88.00	$97.00
Delivery Service Demand Charge ($/kWh)	$3.63	$3.63	$4.32
Delivery Service Energy Charge ($/kWh)	$0.01764	$0.01784	$0.01864

- Competitive Billing (where applicable) credits $ 0.62 per month (see Section 7.7 for details)
- The Delivery Service Charge excludes Rider 10 - Administrative Cost Adjustment

Schedule GL continued

Late Payment Charge: Standard. (Sec. 7.4)

Payment Terms: Standard. (Sec. 7)

Term of Contract: The initial term of contract is 2 years where additional main facilities are required for supply. Otherwise, the term of contract is one year. After the initial term of contract, the contract may be terminated by at least 30 days' notice from the Customer.

Subject to Riders applicable as listed below:

1. Standard Offer Service
2. Electric Efficiency Charge
3. Miscellaneous Taxes and Surcharges
5. Electric Vehicle Charging Distribution Demand Credit
7. Economic Development (Closed to New Customers)
8. Energy Cost Adjustment
9. Customer Billing and Consumption Data Requests
10. Administrative Cost Adjustment
11. Measured Demand
13. Change of Schedule
16. Multi-Year Plan ("MYP") Adjustment Rider
17. Best Efforts Service
18. Net Energy Metering
19. Demonstration and Trial Installations
21. Billing in Event of Service Interruption
22. Minimum Charge for Short-Term Uses
23. Advanced Meter Services
24. Economic Development
25. Monthly Rate Adjustment
26. Peak Time Rebate
28. Small Generator Interconnection Standards
31. Electric Reliability Investment Initiative Charge
32. Community Energy Pilot Program

PRIMARY VOLTAGE SERVICE

SCHEDULE P

Availability: For use for all purposes, for demands of 1,500 kW or more. The applicable Market-Priced Standard Offer Service Type is determined as follows.

Type II Market-Priced Service: For non-residential customers not eligible for Type I SOS whose PJM capacity peak load contribution is less than 600kW, unless excluded by the Phase I Settlement Agreement in Case No.8908.

(Service hereunder will be continued for customers with demands of less than 1,500 kW, who originally took Schedule T service prior to February 11, 1982, but not to their successors or assigns).

Delivery Voltage: Three-phase, 13,200 Volts and over as specified by Company.

Monthly Net Rates:

Effective with service rendered on or after 12/17/2019

Delivery Service Customer Charge: **$ 600.00 per month,**

Demand Charges:

Transmission Market-Priced Service Charge can be found on www.bge.com and Rider 1 – Standard Offer Service.

Delivery Service: **$ 2.90/kW**

Energy Charges:

Generation Market-Priced Service Charges can be found on www.bge.com and Rider 1 – Standard Offer Service.

Delivery Service Charge ($/kWh): **0.00546**

	Rate Year 1 Effective January 1, 2021	Rate Year 2 Effective January 1, 2022	Rate Year 3 Effective January 1, 2023
Customer Charge (per Month)	$600.00	$600.00	$660.00
Delivery Service Demand Charge ($/kWh)	$2.90	$2.90	$3.25
Delivery Service Energy Charge ($/kWh)	$0.00546	$0.00546	$0.00614

-Competitive Billing (where applicable) credits $ 0.47 per month (see Section 7.7 for details)

-The Delivery Service Charge excludes Rider 10 - Administrative Cost Adjustment

Minimum Charge: Net Delivery Service Customer Charge plus the Demand Charges.

Transmission Service: For Customers served at 115 kV and above, the Delivery Service Demand Charge does not apply.

Schedule P continued

Billing Seasons: Summer rates are billed for usage from June 1 through September 30. Non-Summer rates are billed for usage from October 1 through May 31.

Holidays:
All hours on Saturdays and Sundays and the following National holidays are Off-Peak: New Year's Day, President's Day, Good Friday, Memorial Day, Independence Day, Labor Day, Thanksgiving, Christmas, and the Monday following such of these as fall on Sunday.

Rating Periods:

Summer

Peak - Between the hours of 10 am and 8 pm on weekdays, excluding the National holidays listed below.

Intermediate - Between the hours of 7 am and 10 am, and the hours of 8 pm and 11 pm on weekdays, excluding the National holidays listed below.

Off-Peak - All times other than those defined for the On-Peak and Intermediate-Peak rating periods.

Non-Summer

Peak - Between the hours of 7 am and 11 am, and the hours of 5 pm and 9 pm on weekdays, excluding the National holidays listed below.

Intermediate - Between the hours of 11 am and 5 pm on weekdays, excluding the National holidays listed below.

Off-Peak - All times other than those defined for the On-Peak and Intermediate-Peak rating periods.

Billing Demand: The maximum 30-minute Measured Demand, adjusted to the nearest whole kW, in each applicable rating period for the month is the Billing Demand. Measured Demand is the Customer's rate of use of electric energy as shown by or computed from readings of the Company's demand meter, but in no case less than 1,500 kW. (For customers with demands of less than 1,500 kW originally taking service prior to February 11, 1982, the minimum Billing Demand is 200 kW.) Generation and Transmission Demand are billed for each kW of billing demand occurring during the Peak rating period. Delivery Service Demand is for each kW of Billing Demand recorded during any rating period. During the first 6 months of service under Schedule P, the Billing Demand may be less than 1,500 kW, but in that event is not subject to decrease. When it reaches 1,500 kW, this provision no longer applies.

Late Payment Charge: Standard. (Sec. 7.4)

Payment Terms: Standard. (Sec. 7)

Term of Contract: Five years and thereafter until terminated by at least 30 days' notice from the Customer.

Schedule P continued

Subject to Riders applicable as listed below:

1. Standard Offer Service
2. Electric Efficiency Charge
3. Miscellaneous Taxes and Surcharges
5. Electric Vehicle Charging Distribution Demand Credit
7. Economic Development (Closed to New Customers)
8. Energy Cost Adjustment
9. Customer Billing and Consumption Data Requests
10. Administrative Cost Adjustment
11. Measured Demand
13. Change of Schedule
16. Multi-Year Plan ("MYP") Adjustment Rider
18. Net Energy Metering
19. Demonstration and Trial Installations
21. Billing in Event of Service Interruption
22. Minimum Charge for Short-Term Uses
23. Advanced Meter Services
24 Economic Development
26. Peak Time Rebate
28. Small Generator Interconnection Standards
31. Electric Reliability Investment Initiative Charge
32. Community Energy Pilot Program

TRANSMISSION VOLTAGE SERVICE

SCHEDULE T

Availability: For use for all purposes, for demands of 1,500 kW or more where service is supplied at 115,000 Volts and over. The applicable Market-Priced Standard Offer Service Type is determined as follows.

Type II Market-Priced Service: For non-residential customers not eligible for Type I SOS whose PJM capacity peak load contribution is less than 600kW, unless excluded by the Phase I Settlement Agreement in Case No.8908.

Hourly-Priced Service: Distribution customers not eligible for Type I or Type II Service whose PJM capacity peak load contribution is 600kW or greater are eligible for Hourly-Priced Service.

Delivery Voltage: Three-phase, 115,000 Volts and over as specified by the Company.

Monthly Net Rates:

Delivery Service Customer Charge: **$ 2,400.00 per month,**

Demand Charges:

Transmission Market-Priced Service Charge can be found on www.bge.com and Rider 1 – Standard Offer Service.

Energy Charges:

Generation Market-Priced Service Charges can be found on www.bge.com and Rider 1 – Standard Offer Service.

Delivery Service Charge ($/kWh): **0.00315**

	Rate Year 1 Effective January 1, 2021	Rate Year 2 Effective January 1, 2022	Rate Year 3 Effective January 1, 2023
Customer Charge (per Month)	$2,400.00	$2,400.00	$2,400.00
Delivery Service Energy Charge ($/kWh)	$0.00315	$0.00315	$0.00315

- Competitive Billing (where applicable) credits $0.47 per month (see Section 7.7 for details)
- The Delivery Service Charge excludes Rider 10 - Administrative Cost Adjustment

Minimum Charge: Net Delivery Service Customer Charge.

Billing Seasons: Summer rates are billed for usage from June 1 through September 30. Non-Summer rates are billed for usage from October 1 through May 31.

Holidays:

All hours on Saturdays and Sundays and the following National holidays are Off-Peak: New Year's Day, President's Day, Good Friday, Memorial Day, Independence Day, Labor Day, Thanksgiving, Christmas, and the Monday following such of these as fall on Sunday.

Schedule T continued

Rating Periods:

Summer

Peak - Between the hours of 10 am and 8 pm on weekdays, excluding the National holidays listed below.

Intermediate - Between the hours of 7 am and 10 am, and the hours of 8 pm and 11 pm on weekdays, excluding the National holidays listed below.

Off-Peak - All times other than those defined for the On-Peak and Intermediate-Peak rating periods.

Non-Summer

Peak - Between the hours of 7 am and 11 am, and the hours of 5 pm and 9 pm on weekdays, excluding the National holidays listed below.

Intermediate - Between the hours of 11 am and 5 pm on weekdays, excluding the National holidays listed below.

Off-Peak - All times other than those defined for the On-Peak and Intermediate-Peak rating periods.

Billing Demand: The maximum 30-minute Measured Demand, adjusted to the nearest whole kW, in each applicable rating period for the month is the Billing Demand. Measured Demand is the Customer's rate of use of electric energy as shown by or computed from readings of the Company's demand meter, but in no case less than 1,500 kW. (For customers with demands of less than 1,500 kW originally taking service prior to February 11, 1982, the minimum Billing Demand is 200 kW.) Transmission Demand is billed for each kW of billing demand occurring during the Peak rating period. During the first 6 months of service under Schedule T, the Billing Demand may be less than 1,500 kW, but in that event is not subject to decrease. When it reaches 1,500 kW, this provision no longer applies.

Late Payment Charge: Standard. (Sec. 7.4)

Payment Terms: Standard. (Sec. 7)

Term of Contract: Five years and thereafter until terminated by at least 30 days' notice from the Customer.

Schedule T continued

Subject to Riders applicable as listed below:

1.Standard Offer Service
2.Electric Efficiency Charge
3.Miscellaneous Taxes and Surcharges
7.Economic Development (Closed to New Customers)
8.Energy Cost Adjustment
9.Customer Billing and Consumption Data Requests
10. Administrative Cost Adjustment
11. Measured Demand
16. Multi-Year Plan ("MYP") Adjustment Rider
18. Net Energy Metering
19. Demonstration and Trial Installations
21. Billing in Event of Service Interruption
22. Minimum Charge for Short-Term Uses
23. Advanced Meter Services
24. Economic Development
26. Peak Time Rebate
28. Small Generator Interconnection Standards
32. Community Energy Pilot Program

STREET LIGHTING
SCHEDULE SL

AVAILABILITY: For unmetered street lighting service (defined to include other public area lighting) supplied from overhead or underground facilities on dedicated public streets, roads, walkways and other public areas where required by City, Town, County, or other Municipal or Public Agency, or by an incorporated association of local residents.

A builder or developer may contract for street lighting service prior to the execution of a contract with the ultimate customer.

MONTHLY RATES:

		Rate Eff. 12/17/19	Rate Yr. 1 Eff. 1/1/21	Rate Yr. 2 Eff. 1/1/22	Rate Yr. 3 Eff. 1/1/23
1.	**Supply of Electricity**				
	Generation Market-Priced Service Charge can be found on **www.bge.com** and **Rider 1 – Standard Offer Service**				
	Delivery Service ($/Lamp-Watt)	$0.00186	$0.00186	$0.00186	$0.00714
2.	**Facilities Provided by the Company**				
	(a) Underground St. Ltg. Cable (per ft of cable) (includes cable rental and cable maintenance)				
	In Service on August 31, 1960	$0.0268	$0.0268	$0.0268	$0.0273
	Installed after August 31, 1960 (including replacements)	$0.0522	$0.0522	$0.0522	$0.0532
	(b) Lamp Fixtures - ornamental (underground supplied)				
Billing Watts	Description				
	Incandescent				
100	Incandescent**	$2.95	$2.95	$2.95	$3.00
	Mercury Vapor (limited to existing installations)				
117	100w MV Pendant	$5.56	$5.56	$5.56	$5.66
117-205	100-175w MV Modern/Colonial	$8.13	$8.13	$8.13	$8.28
205-294	175-250w MV Pendant	$7.57	$7.57	$7.57	$7.71
294	250w MV Modern	$12.53	$12.53	$12.53	$12.76
454	400w MV Pendant/Flood	$8.90	$8.90	$8.90	$9.06
	Sodium Vapor				
120	100w SV Acorn	$7.61	$7.61	$7.61	$7.75
120-173	100-150w SV Acorn ML (maple lawn)	$16.53	$16.53	$16.53	$16.84
120-173	100-150w SV Colonial Premiere	$8.83	$8.83	$8.83	$8.99
120-173	100-150w SV Rectilinear/Pendant/ Flood**	$5.94	$5.94	$5.94	$6.05
120	100w SV Colonial/Gothic/ Modern**	$8.29	$8.29	$8.29	$8.44
173	150w SV Modern/Colonial/Gothic	$8.29	$8.29	$8.29	$8.44
120-173	100-150w SV Acorn HDG	$10.13	$10.13	$10.13	$10.32
173	150w SV Arlington**	$11.94	$11.94	$11.94	$12.16
173	150w SV Acorn	$7.61	$7.61	$7.61	$7.75
173	150w SV Acorn-Victorian**	$16.82	$16.82	$16.82	$17.13
298	250w SV Rectilinear/Pendant	$15.87	$15.87	$15.87	$16.16
467	400w SV Rectilinear/Pendant/Flood	$17.63	$17.63	$17.63	$17.96
1,130	1000w SV Rectilinear/Pendant	$19.77	$19.77	$19.77	$20.14
	Metal Halide (limited to existing installations)				
129-189	100-175w MH (post top) – Colonial/Premier/Modern/Gothic/Acorn	$12.35	$12.35	$12.35	$12.58
	** (limited to existing installations)				

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Schedule SL Continued

(c) Lamp Fixtures-other than ornamental(overhead supplied)

Billing Watts	Description	Rate Eff. 12/17/19	Rate Yr. 1 Eff. 1/1/21	Rate Yr. 2 Eff. 1/1/22	Rate Yr. 3 Eff. 1/1/23
	Incandescent (limited to existing installations)				
	In service on August 31, 1960				
	Open-Type, less than 250 candlepower	$1.14	$1.14	$1.14	$1.16
	All fixtures installed after August 31, 1960	$5.06	$5.06	$5.06	$5.15
	Mercury Vapor (limited to existing installations)				
117	100w MV Pendant	$8.37	$8.37	$8.37	$8.52
205-294	175-250w MV Pendant	$9.99	$9.99	$9.99	$10.17
454	400w MV Pendant/Flood	$11.61	$11.61	$11.61	$11.82
	Sodium Vapor				
120-173	100-150w SV Pendant/ Flood**	$11.67	$11.67	$11.67	$11.89
173-298	150-250w SV Tear Drop w/arm	$46.00	$46.00	$46.00	$46.85
298	250w SV Pendant	$18.32	$18.32	$18.32	$18.66
467	400w SV Pendant/Flood	$20.21	$20.21	$20.21	$20.58
1,130	1000w SV Pendant	$22.70	$22.70	$22.70	$23.12
	Metal Halide (limited to existing installations)				
189-205	150-175w MH Pendant	$6.49	$6.49	$6.49	$6.61
445	400w MH Pendant	$8.63	$8.63	$8.63	$8.79
445	400w MH/MHP Flood	$8.26	$8.26	$8.26	$8.41

** (limited to existing installations)

(d) Lamp Fixtures - LED fixtures

Billing Watts	Description	Rate Eff. 12/17/19	Rate Yr. 1 Eff. 1/1/21	Rate Yr. 2 Eff. 1/1/22	Rate Yr. 3 Eff. 1/1/23
	Light-Emitting Diode#				
39	70 LED Pendant	$7.67	$7.67	$7.67	$7.81
51-73	100 LED Pendant	$7.17	$7.17	$7.17	$7.30
72-110	150 LED Pendant	$7.45	$7.45	$7.45	$7.59
135-146	200 LED Pendant**	$15.76	$15.76	$15.76	$16.05
129-208	250 LED Pendant	$10.13	$10.13	$10.13	$10.32
157-275	400 LED Pendant	$13.64	$13.64	$13.64	$13.89
70	100 LED Post Top Acorn	$22.99	$22.99	$22.99	$23.41
101	150 LED Post Top Acorn	$22.99	$22.99	$22.99	$23.41
70	100 LED Post Top Decorative Acorn	$32.05	$32.05	$32.05	$32.64
101	150 LED Post Top Decorative Acorn	$32.05	$32.05	$32.05	$32.64
72	100 LED Post Top Arlington	$26.02	$26.02	$26.02	$26.50
72	100 LED Post Top Colonial	$15.00	$15.00	$15.00	$15.28
104	150 LED Post Top Arlington	$26.02	$26.02	$26.02	$26.50
106	150 LED Post Top Colonial	$15.48	$15.48	$15.48	$15.77
52	100 LED Premiere Colonial	$16.28	$16.28	$16.28	$16.58
75	150 LED Premiere Colonial	$17.78	$17.78	$17.78	$18.11
54	100 LED Post Top Modern	$14.65	$14.65	$14.65	$14.92
90	150 LED Post Top Modern**	$26.98	$26.98	$26.98	$27.48
86	150 LED Tear Drop	$30.45	$30.45	$30.45	$31.01
151	250 LED Tear Drop	$38.39	$38.39	$38.39	$39.10
129	400 LED Floodlight	$11.65	$11.65	$11.65	$11.87
256	1000 LED Floodlight	$23.32	$23.32	$23.32	$23.75

LED naming based on HID equivalent lamp watts

** (limited to existing installations)

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Schedule SL Continued

(Where longer than 4-foot upsweep arms are required, add for 10- to 20-foot upsweep arms)	$2.86	$2.86	$2.86	$2.91
(e) Distribution poles supporting wires or other service facilities used only for street lighting (per pole)	$3.10	$3.10	$3.10	$3.16

(f) Underground-Supplied Lamp Poles	Rate Eff. 12/17/19	Rate Yr. 1 Eff. 1/1/21	Rate Yr. 2 Eff. 1/1/22	Rate Yr. 3 Eff. 1/1/23
12-foot embedded wood poles	$4.11	$4.11	$4.11	$4.19
12-foot fiberglass with shroud	$15.94	$15.94	$15.94	$16.23
14-foot plain embedded metal poles	$4.41	$4.41	$4.41	$4.49
14-foot embedded metal poles**	$4.89	$4.89	$4.89	$4.98
14-foot fiberglass poles	$4.89	$4.89	$4.89	$4.98
14-foot black fluted poles	$25.89	$25.89	$25.89	$26.37
20- to 30-foot fiberglass	$12.95	$12.95	$12.95	$13.19
25- to 30-foot pre-wired wood poles*	$6.54*	$6.54*	$6.54*	$6.66
25-foot plain embedded metal poles	$10.55	$10.55	$10.55	$10.74
30-foot plain embedded metal poles	$11.64	$11.64	$11.64	$11.86
30-foot plain embedded metal poles with twin mast arms	$13.65	$13.65	$13.65	$13.90
30-foot bronze-fiberglass poles with one arm	$15.76	$15.76	$15.76	$16.05
* (Where longer than 4-foot upsweep arms are required, add for 10- to 20- foot upsweep arms)	$2.06	$2.06	$2.06	$2.10
Upsweep Arms 10- to 20- feet	$2.86	$2.86	$2.86	$2.91
(g) Ornamental lamp poles**	$4.19	$4.19	$4.19	$4.27
** (limited to existing installations)				

Note: Other than maintenance covered under Monthly Rate (3) and (5) below, fixture and pole rental includes reactive maintenance such as fixture repair, pole knockdown renewal, ballast replacement and glassware replacement. Exceptions are noted in Special Provisions.

3A. Maintenance (Bundled Reactive and Preventative)

	Rate Eff. 12/17/19 (per lamp)	Rate Yr. 1 Eff. 1/1/21 (per lamp)	Rate Yr. 2 Eff. 1/1/22 (per lamp)	Rate Yr. 3 Eff. 1/1/23 (per lamp)
(a) Incandescent				
Incandescent Less than 250 candlepower	$1.80	$1.80	$1.80	$1.83
Incandescent 250 candlepower and over	$2.87	$2.87	$2.87	$2.92
(b) Mercury Vapor				
100-400w Mercury Vapor	$1.50	$1.50	$1.50	$1.53
(c) Sodium Vapor				
70-400w Mercury Vapor	$3.22	$3.22	$3.22	$3.28
1000w Sodium Vapor	$6.61	$6.61	$6.61	$6.73
(d) Metal Halide				
100-1000w Metal Halide	$5.76	$5.76	$5.76	$5.87
(e) Direction Sign Fluorescent Lamps**				
180-230w Fluorescent	$3.77	$3.77	$3.77	$3.84
(f) Light-Emitting Diode				
100-1000 LED	$1.06	$1.06	$1.06	$1.08
** limited to existing installation				

3B. Maintenance (Reactive Only)

(a) Incandescent				
Incandescent Less than 250 candlepower	$1.66	$1.66	$1.66	$1.69
Incandescent 250 candlepower and over	$2.64	$2.64	$2.64	$2.69
(b) Mercury Vapor				
100-400w Mercury Vapor	$1.36	$1.36	$1.36	$1.39
(c) Sodium Vapor				
70-400w Mercury Vapor	$2.95	$2.95	$2.95	$3.00
1000w Sodium Vapor	$6.07	$6.07	$6.07	$6.18

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Schedule SL Continued

	Rate Eff. 12/17/19 (per lamp)	Rate Yr. 1 Eff. 1/1/21 (per lamp)	Rate Yr. 2 Eff. 1/1/22 (per lamp)	Rate Yr. 3 Eff. 1/1/23 (per lamp)
(d) Metal Halide				
100-1000w Metal Halide	$5.28	$5.28	$5.28	$5.38
(e) Direction Sign Fluorescent Lamps**				
180-230w Fluorescent	$3.46	$3.46	$3.46	$3.52
(f) Light-Emitting Diode				
100-1000 LED	$0.93	$0.93	$0.93	$0.95

** (limited to existing installations)

4. Municipal Duct (where provided and charged for by the Municipal or Public Agency)

(a) Duct occupied solely by St. Ltg. Cable	one-twelfth of the annual per foot duct rental charge payable by Company
(b) Duct occupied jointly with other cable	one twenty-fourth of the annual per foot duct rental charge payable by Company

5. **Light-Emitting Diode (LED) Facilities** – Customer-owned LED fixtures must be evaluated and approved by BGE prior to installation. Such review will generally take approximately 90 days. Billing Watts for LED fixtures shall be based on Illuminating Engineering Society of North America (IESNA) LM-79 Test Reports, which are provided by lighting manufacturers. Customer-owned LED fixtures shall be billed for delivery service accordingly. Please refer to the link **LED Product Listing** for the LED fixtures approved by BGE along with each fixture's Billing Watts. The LM-79 Reports for BGE-approved LED fixtures are available upon request.

6. Customized Lighting Facilities other than those listed above as requested by the Customer, to be priced on an individual contract basis. The Term of Contract for Customized Lighting Facilities may vary. BGE shall file the rates for new fixtures and equipment with the Commission at least 30 days prior to the expected installation of such facilities. To the extent that a Customer requires the installation of new fixtures and/or related equipment before a filing can be submitted, BGE is permitted to file for such rates as soon as possible, but no more than 30 days after the installation of the fixtures/equipment. In such circumstances, the rate charged during the time before Commission approval will be subject to refund if the Commission concludes that the proposed rate is too great. However, BGE shall not be permitted to retroactively bill a Customer if the Commission concludes the proposed rate is too low.

Street Lighting is subject to the following provisions:

(a) The Customer designates the size and location of the fixtures and the location of the poles for underground supplied streetlights. The determination of the type of system as to overhead or underground and location of the circuits rests solely with the Company.

(b) Under Item 1 of the Monthly Rates, the Company makes available a controlled supply of electricity for operation of the lamps from dusk to dawn each night for a total of approximately 4,000 hours per year. When at the Customer's request, and agreed to by the Company, the Company provides customized lighting control, such that the lights burn for less than the stated hours per year, no adjustment to the monthly fee will be made for reduced electricity usage, because service under the Schedule is unmetered.

(c) The Customer may choose from the following types of service as applicable, subject to approval by the Company:
1. The Company offers to provide, own and maintain all equipment as listed and as priced under Item 2 of the Schedule.
2. The Customer may request the Company to furnish, install and sell those items in Monthly Rate 2, excluding cable, at the Customer's expense. The Customer may choose to have the Company perform maintenance services provided for in Monthly Rate 3. Maintenance, not included in Monthly Rate 3, but on equipment supplied exclusively by Company circuitry (e.g., fixture changes, ballast replacement), is performed by the Company at the Customer's expense. If the Customer chooses to perform their own maintenance, a disconnect means acceptable to the Company and the local authority having jurisdiction must exist. The Customer is responsible for all costs for disconnect means above and beyond what is provided by BGE design standards.

Schedule SL Continued

3. In certain instances approved by the Company, the Company may install Customer supplied/owned equipment not included in Monthly Rate 2(b), (c), and (f). Maintenance of this equipment follows the same provisions as delineated in the preceding paragraph (c) 2.

4. In instances where the Customer desires to install, own, and maintain his own lighting equipment (e.g., traffic, sign, street), the Customer must provide a point of disconnect In this case, the Company will provide energy to this service under Monthly Rate 1. Maintenance as described in Monthly Rate 3 will provide energy to this service under Monthly Rate 1. Maintenance as described in Monthly Rate 3 is optional for street and sign lighting.

(d) Fixtures under this Tariff do not include custom shades. For select fixtures, custom shades are available and installed by the Company upon Customer request. Customer is responsible for all associated costs.

(e) The number of feet of cable, the number of distribution poles (line and guy) supporting wires or other service facilities used only for street lighting, the number of lamps and the number of feet of municipal duct occupied solely or jointly by street lighting cable, shall be as shown by the Company's records and shall, for billing purposes, be as of the end of the month preceding the billing month. All underground cable removed is considered to have been in service as of August 31, 1960. The charge under item 2(a) does not apply to underground street lighting cable installed in a development project coincident with underground main under the provisions of Sec. 8.22.

(f) For all fixtures, Monthly Rate 3, Bundled Preventive and Reactive Maintenance, is the default maintenance service for Customers renting fixtures under Provision (c)1 and for Customers owning their own fixtures under Provisions (c)2 and (c)3 and choosing to have the Company perform maintenance service under Monthly Rate 3. For Customer-owned LED lighting facilities under Item 5, the Company, upon the Customer’s request, will provide reactive maintenance on a time and materials basis. The Preventive Maintenance service provided under Monthly Rate 3 includes scheduled cleaning of glassware, and lamp, photo control and fuse renewal as needed. LED Preventative Maintenance service provided under Monthly Rate 3 includes scheduled cleaning of glassware, and photo control and fuse replacement as needed.

Monthly Rate 3, Reactive Only Maintenance, is an optional service for these Customers provided upon Customer request. The Reactive Only Maintenance service involves replacement of lamps, fuses or photo control performed with reasonable promptness upon notification to the Company. LED Reactive Maintenance Service involves replacement of photo control or fuse performed with reasonable promptness upon notification to the company. For customers who choose the Reactive Only Maintenance service or who choose to have no maintenance performed pursuant to Provision (c)4, the Company will not perform Preventive Maintenance service on any current and future fixtures installed on the Customer’s behalf. For customers who choose the Bundled Reactive and Preventive Maintenance service after participating in the Reactive Only Maintenance service or after choosing to have no maintenance performed pursuant to Provision (c)4, the Customer’s lights will be preventively maintained as part of the Company’s normal 6 to 8 year Preventive Maintenance cycle.

Customers choosing either the Bundled Reactive and Preventive Maintenance service or the Reactive Only Maintenance service will be covered by this elected program for all lights under their bill account(s) with two exceptions: (1) customers owning their own fixtures may perform their own maintenance as provided under Provision (c)2, and (2) for Customers owning their own LED lighting facilities, the Customer may request that the Company provide reactive maintenance on a time and materials basis.

In the case of Customer-owned equipment, the Company does not inspect or maintain lamp poles, lamp pole bases or other related equipment, and nothing contained in this Schedule shall be construed to extend the Company’s obligation to inspect or maintain any part of such Customer-owned lamp poles, lamp pole bases or related equipment. Additionally, replacement or repair of Customer-owned equipment, other than that which is provided under Monthly Rate 3, is the responsibility of the Customer and subject to Provision c(2) above. Glassware replaced on Customer-owned equipment installed under Provision c(2) or c(3) will be performed by the Company on an as needed basis (typically every 6-8 years) and charged to the Customer.

Schedule SL Continued

(g) The Customer, at their expense, restores improved paving on streets, sidewalks, driveways, and the like, where necessary for the installation, maintenance, relocation or renewal of street lighting cable laid other than in municipal duct, or of galva duct conduit. If an alternative construction method can be used and is selected by the Customer, the Customer is responsible for the price differential.

(h) The Customer shall pay all costs incurred as a result of relocation of Customer-owned or rented streetlights. Should the Customer request that the fixture/pole be removed and within the year request a new installation at or near the original location, the Customer will be charged at cost for this relocation.

(i) When a Customer-owned lamp pole, fixture, and/or associated equipment is damaged as a result of an accident, weather, vandalism, etc., the Company may repair/replace as necessary, under agreement with the Customer, and attempt to bill the party at fault (where applicable). But, if the Company cannot collect the damages from the responsible party, the Customer shall pay for the repair/replacement. However, Customer's agreement is not necessary for the Company to respond to damaged Customer-owned lamp pole, fixture, and/or associated equipment in order to make the equipment and area safe. Customer will be responsible for BGE's costs to respond and make safe if the costs cannot be collected from the responsible party. The rate charged to the Customer to respond and provide make safe only services is $95 per hour, which includes labor, vehicle and travel charges.
In the case of Company-owned equipment, the Company will provide vandal proof equipment for select fixtures at the Customer's request and expense. If the Company identifies vandalism on Company-owned equipment, the Company will make the Customer aware of the need for vandal proofing. If the Customer elects not to vandal proof the facilities, the Company has the option to remove the equipment for repeat cases of vandalism.

(j) Extension of supply facilities for street lighting are subject to the provisions of Sec. 8 for that portion of such facilities required up to the point of control of the electricity supply to the lamps, excluding facilities specifically designated and charged for under the Schedule.

(k) Change in pole style, fixture style, wattage, or type, at the request of the Customer, for Customer-owned equipment, is paid for by the Customer. In instances where the fixture/pole is owned by the Company, Customer requested changes are performed upon request by the Customer and a cost-based fee will be charged to the Customer on a per fixture/pole basis. Should the Customer request that the fixtures/poles be removed and within the year request a new installation, at or near the previous location, the Customer will be charged cost-based fee per fixture/pole for associated costs.

(l) Requests for removal of Company-owned LED lighting equipment prior to the completion of the initial Term of Contract will result in a charge to the Customer calculated as follows: monthly rental rate times remaining months of contract.

LATE PAYMENT CHARGE: STANDARD. (SEC. 7.4)

PAYMENT TERMS: STANDARD. (SEC. 7)

TERM OF CONTRACT: Five years for non LED fixtures and ten years for LED fixtures and thereafter from year to year until terminated at the expiration of any such year by at least 90 days' notice from the Customer.

Riders Applicable:

1. Standard Offer Service
3. Miscellaneous Taxes Surcharges
8. Energy Cost Adjustment
9. Customer Billing and Consumption Data Requests
10. Administrative Cost Adjustment
16. Multi-Year Plan ("MYP") Adjustment Rider
21. Billing in Event of Service Interruption
32. Community Energy Pilot Program

Schedule PL Continued

(h) The Customer shall pay the Company the cost of relocating its private area lighting equipment made at the Customer's request. Should the Customer request that the fixture/pole be removed and within the year request a new installation at or purposefully near the previous location, the Customer will be charged a cost-based fee for the relocation.

(i) Extension of primary-voltage facilities for the supply of private area lighting is subject to the extension provisions of Sec. 8.33.

(j) Tree trimming to enhance light distribution or to facilitate pole and fixture installation is the responsibility of the Customer.

(k) Requests for a change in pole style, fixture size, type or style is paid for at cost by the Customer.

(l) The Company reserves the right to deny the request for installation where access to the pole/fixtures is such that they could not be maintained using typical Company supplied tools and equipment or maintenance could not be done without free access to the property.

(m) Requests for removal of Company owned lighting equipment prior to the Contract Term will result in a charge to the Customer calculated as follows: For non-LED fixtures, the remaining months on the Contract is divided by 60, times the estimated current installation and removal costs of the equipment. For LED fixtures, the remaining months on the Contract is divided by 120, times the estimated current installation and removal costs of the equipment.

(n) The equipment style, size, and location are agreed upon by the Customer and the Company. The determination of the type of system as to overhead or underground and location of the circuits rests solely with the Company. In instances where the Customer requests a location or type of system that is non-standard or more costly to the Company but can be installed, the Customer may request this type of system and/or location but bear the additional expense.

LATE PAYMENT CHARGE: STANDARD. (SEC. 7.4)

PAYMENT TERMS: STANDARD. (SEC. 7)

TERM OF CONTRACT: Five years for non LED fixtures and ten years for LED fixtures, and thereafter until terminated by at least 30 days' notice from the Customer; or until terminated by at least 30 days' notice from the Company.

Subject to Riders applicable as listed below:

3. Miscellaneous Taxes and Surcharges
9. Customer Billing and Consumption Data Requests
16. Multi-Year Plan (“MYP”) Adjustment Rider
21. Billing in Event of Service Interruption
32. Community Energy Pilot Program

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6. Vehicle Charging Time-Of-Use Adjustment - continued

Customers will receive an adjustment for charging station usage during the On-Peak and Off-Peak periods on their monthly bill based on the data received from the Customer's EV charger. The Customer is responsible for enabling and maintaining the EV charger's smart capabilities and connection to the premise's WiFi network. If there is a delay in BGE or BGE's designated vendor receiving the EV charging data, then the Customer's total metered consumption for the premise will be charged Schedule R supply rates and the VC-TOU adjustments will be provided to the Customer on their next monthly bill as long as the delay in receiving smart Level 2 EV Charger data is less than 60 days. BGE is unable to provide Customer adjustments/credits for usage data received 60 days after the date of use.

Billing Seasons: Summer rates are billed for usage from June 1 through September 30. Non-summer rates are billed for usage from October 1 through May 31.

Rate Periods

Summer

Peak – Between the hours of 10 am and 8 pm on weekdays, excluding the National holidays listed below.

Off-Peak – All times other than those defined for the On-Peak rating period.

Non-Summer

Peak – Between the hours of 7 am and 11 am, and the hours of 5 pm and 9 pm on weekdays, excluding the National holidays listed below.

Off-Peak – All times other than those defined for the On-Peak rating period.

The Non-Summer time periods shown above will begin and end one hour later for the period between the second Sunday in March and the first Sunday in April, and for the period between the last Sunday in October and the first Sunday in November.

Holidays

All hours on Saturdays and Sundays and the following National holidays are Off-Peak: New Year's Day, President's Day, Good Friday, Memorial Day, Independence Day, Labor Day, Thanksgiving, Christmas, and the Monday following such of these as fall on Sunday.

7. Economic Development (Closed to New Customers)

This rider is closed to new customers effective August 20, 2015. Customers taking service under this rider before August 20, 2015 will continue taking service under the rider until the expiration of their contract term. Upon application by the Customer and approval by the Company, Economic Development price reductions are available on the Qualifying Load of customers served under Schedule GL, P or T (the Controlling Schedule). Qualifying Load (QL) is new or incremental load in excess of historic demand and energy use, as determined by the Company, which is associated with new employment of at least 10 full-time equivalent persons. The Company will approve applications when the price reductions (1) have been certified by a Review Panel (see below) as necessary to attract new business or encourage expansion of existing business, and (2) do not cause the total amount of Rider 7 customers' price reductions granted in a calendar year to exceed $2 million.

The Review Panel will consist of 3 representatives; one each from BGE, Maryland's Department of Business and Economic Development, and local government in the area affected by the potential new

7. Economic Development (Closed to New Customers) – continued

business. The offering of price reductions must be agreed to by all 3 representatives, and must be accompanied by an offering of governmental economic development assistance.

Rider 7 price reductions may not be used in connection with a retail establishment unless the Review Panel determines that such price reductions are necessary to accomplish the purposes of this Rider. A retail establishment is defined as an establishment which sells goods or services to ultimate users, and not for purpose of resale or business use. Discounts will not be provided where a customer merely changes names or service locations within BGE's service territory, without meeting the other criteria for price reductions under this Rider.

Two price reduction options are available to qualifying customers. Option 1 is available to customers meeting the schedule requirements; Option 2 is available to customers meeting the schedule requirements and who are certified as eligible for State-provided Enterprise Zone benefits.

Effective for agreements after July 1, 2004, price reductions for the QL are restricted to the Delivery Service charges in the Customer's Controlling Schedule. Price reductions will not be applied to Generation charges, Transmission charges, Taxes, Surcharges or the CTC in the Customer's Controlling Schedule regardless of the Customer's supply source.

The Customer credits are applied in the following manner:

		Option 1	Option 2
	Minimum QL	500 kW	200 kW
Price Reduction (%):	Year 1	10	15
	Year 2	5	10
	Year 3	5	5
	Year 4	-	5
	Year 5	-	5

The Company will recoup all rate reductions previously granted if the QL is shifted to an alternative energy source, such as Customer-owned generation, within 3 years, for Option 1, or 5 years, for Option 2, from the date of last price reduction.

8. Energy Cost Adjustment

The Standard Offer Market-Priced Service Charges for Residential, Types I, II and Hourly Service are subject to periodic adjustment to reflect the actual cost of providing energy and transmission-related services. The true-up process compares retail customer billings for energy and transmission services against payments by the Company to wholesale suppliers and the Pennsylvania-New Jersey-Maryland Interconnection (PJM). This true-up adjustment will be made in the February, June and October billing months or more frequently, if necessary. The adjustment is applied to the Customer's billed kilowatt-hours. The current Energy Cost Adjustment by SOS Type is available on the BGE website at www.bge.com.

16. Multi-Year Plan ("MYP") Adjustment Rider

This rider addresses Imbalances that may arise between the revenue requirement approved by the Commission as part of initial rates under a Multi-Year Plan ("MYP") and the actual revenue requirement filed as part of the Annual Informational Filings or Final Reconciliation, pursuant to Order No. 89482.

The Annual Informational Filings shall be filed within 90 days of the end of the first and second years of the approved MYP.

The Final Reconciliation shall be filed within 120 days of the end of the MYP. The Final Recollection shall cover investments and costs in the MRP period not previously reviewed for prudency and reconciled in the rate case.

Imbalances shall be calculated consistent with the MYP revenue requirement approved by the Commission in an order resulting from an MYP proceeding. Rate base and operating income shall use actual results from the applicable MYP period in calculating the actual revenue requirement to determine the Imbalance. If an Imbalance calculated as part of an Annual Informational Filing, as defined in Order No. 89482, represents an amount owed to customers, the MYP Adjustment Rider can be utilized to provide a credit for such amount, if determined to be appropriate by the Commission. The MYP Adjustment Rider can be utilized to recover or credit an Imbalance calculated as part of a Final Reconciliation, as determined to be appropriate by the Commission.

All Imbalances are deferred into a regulatory asset or liability until such time as the Commission determines the appropriate disposition of the Imbalance, including the appropriate period over which an Imbalance is recovered or credited to customers. Carrying costs will apply for amounts owed to customers and will continue to apply during the credit period.

Calculation of Rate

The MYP Adjustment Rider rate is determined for each Schedule by first allocating the Imbalance, as determined appropriate by the Commission, in proportion to each Schedule's amount of base distribution revenues in the final year of the MYP. The resulting amounts are then divided by the estimated billing determinants, per kilowatt-hour or per fixture, for each applicable Schedule. Details concerning the calculation of the MYP Adjustment are filed with and approved by the Commission prior to their use in billing. The MYP Adjustment shall be included in the Distribution Charge on the Customer's monthly electric bill.

Rates Effective [insert date range]

Rate Schedule	Rate
R/RD/EV	$0.00000 per kWh
RL	$0.00000 per kWh
G/GU	$0.00000 per kWh
GS	$0.00000 per kWh
GL	$0.00000 per kWh
P	$0.00000 per kWh
T	$0.00000 per kWh
SL	$0.00000 per kWh
PL	$0.00 per fixture

32. Community Energy Pilot Program - continued

On or before 30 days after the billing cycle that is complete immediately prior to the end of April each year, BGE will apply bill credits to the bill of each eligible Subscriber a true up for any excess generation up to $25. True-up credits greater than $25 may be paid by check. The Subscriber's excess generation shall be credited or paid to reasonably exclude the distribution, transmission, and non-commodity portion of the Subscriber's bill for the excess generation amount.

Subscriber Organization: Prior to applying for an Interconnection Agreement for this pilot program, a Subscriber Organization must first be granted permission to participate in this pilot from the PSC and have received a Subscriber Organization Identification Number. Once the Subscriber Organization has an Identification Number, they must apply to BGE for an Interconnection Agreement under Code of Maryland Regulations 20.50.09, indicating a request to participate in the Pilot Program. Interconnection Applications will be processed in the order in which the completed Interconnection Applications are received. Each Subscriber Organization and affiliated-ownership Subscriber Organizations are limited to 2 (two) Interconnection Applications during the initial 20 business days of the Year 2/3 interconnection queue period. Year 2/3 Interconnection Applications may be submitted no earlier than 12:00:00PM (EPT) on November 5, 2018. A Subscriber Organization is responsible for all interconnection costs.

A CSEGS is subject to all tariff provisions applicable under the schedule they are placed. Tariff Schedule and demand are determined based on the capacity of the CSEGS system. A CSEGS may not exceed 2MW in AC rated capacity. A CSEGS of 500 kW or greater may not be located on the same or contiguous parcel of property as another CSEGS of 500kW or greater owned by the same Subscriber Organization or its affiliate unless constructed on one of the following: a building rooftop or parking structure, over a parking lot or roadway, in a platted industrial park, or 2 or more projects, each of up to 2 MW in size comprising no more than 6 MW constructed on a brownfield site. A CSEGS facility with a capacity greater than 1 MW will be placed on Primary Service. Metering for a CSEGS will be divided into an input and an output channel. All usage on the input channel will be billed in accordance with the applicable tariff schedule of the CSEGS. All generation on the output channel will be used in the calculation of the Subscriber Credits. BGE reserves the right to require the CSEGS facility to be moved to a bill cycle in order to facilitate efficient credit calculation.

A Subscriber Organization must provide a partially executed Interconnection Agreement, in conjunction with a Community Energy Pilot Application. Pilot Program Applications shall be processed in the order in which they are received. BGE will notify the Subscriber Organization of receipt of the Pilot Program Application and whether the Pilot Program Application is complete within 5 business days. A Subscriber Organization receiving notice of an incomplete Pilot Program Application shall revise and resubmit within 10 days of receiving the notice. Projects that are not awarded pilot program capacity in Year 1 will have their Interconnection Application canceled and must reapply for interconnection and reapply to the pilot program in a future year and do not maintain their waiting list position for capacity in Year 2. Year 1 (including the waitlist) will end on October 26, 2018 at 5:00:00PM (EPT). In Year 2, if a Pilot Program Application exceeds the available program capacity or category and is otherwise complete, the Pilot Program Application shall be deferred to the next program year if cap space is available. Deferral of one Pilot Program Application does not preclude the company from accepting a smaller Pilot Program Application received after the deferred Pilot Program Application. Available pilot program capacity can be found on BGE.com. A CSEGS Identification Number will be assigned and capacity in the pilot program queue will be reserved for the Subscriber Organization's specific CSEGS upon a complete and accepted Pilot Program Application. If a CSEGS or Subscriber Organization raises a dispute with BGE or the Commission regarding the processing of an Interconnection Application or a Pilot Program Application, BGE will not set aside capacity for the CSEG during the pendency of the investigation of the dispute.

BALTIMORE GAS AND ELECTRIC COMPANY
APPORTIONMENT OF PROPOSED GAS BASE RATE
REVENUE CHANGE TO CLASSES OF SERVICE
RATE YEAR 1

RATE SCHEDULE	REFERENCE	ADDITIONAL REVENUE REQUIREMENT (1)	PERCENT INCREASE IN CUSTOMERS' TOTAL GAS BILLS (2)	PERCENT INCREASE IN TOTAL GAS DISTRIBUTION REVENUE (3)
1. SCHEDULE D	*(SHEET G-4)*	$ -	0.0%	0.0%
2. SCHEDULE C	*(SHEET G-5)*	$ -	0.0%	0.0%
3. SCHEDULE IS	*(SHEET G-6)*	$ -	0.0%	0.0%
4. SCHEDULE ISS	*(SHEET G-7)*	$ -	0.0%	0.0%
5. SCHEDULE EG	*(SHEET G-8)*	$ -	0.0%	0.0%
6. SCHEDULE PLG	*(SHEET G-9)*	$ -	0.0%	0.0%
7. TOTAL		$ -	0.0%	0.0%
8. TOTAL REQUIRED CHANGE IN BASE REVENUE		$ -		
9. DIFFERENCE FROM REVENUE REQUIRED		$ -		

BALTIMORE GAS AND ELECTRIC COMPANY
APPORTIONMENT OF PROPOSED GAS BASE RATE
REVENUE CHANGE TO CLASSES OF SERVICE
RATE YEAR 2

RATE SCHEDULE	REFERENCE	ADDITIONAL REVENUE REQUIREMENT (1)	PERCENT INCREASE IN CUSTOMERS' TOTAL GAS BILLS (2)	PERCENT INCREASE IN TOTAL GAS DISTRIBUTION REVENUE (3)
1. SCHEDULE D	*(SHEET G-4)*	$ -	0.0%	0.0%
2. SCHEDULE C	*(SHEET G-5)*	$ -	0.0%	0.0%
3. SCHEDULE IS	*(SHEET G-6)*	$ -	0.0%	0.0%
4. SCHEDULE ISS	*(SHEET G-7)*	$ -	0.0%	0.0%
5. SCHEDULE EG	*(SHEET G-8)*	$ -	0.0%	0.0%
6. SCHEDULE PLG	*(SHEET G-9)*	$ -	0.0%	0.0%
7. TOTAL		$ -	0.0%	0.0%
8. TOTAL REQUIRED CHANGE IN BASE REVENUE		$ -		
9. DIFFERENCE FROM REVENUE REQUIRED		$ -		

BALTIMORE GAS AND ELECTRIC COMPANY
APPORTIONMENT OF PROPOSED GAS BASE RATE
REVENUE CHANGE TO CLASSES OF SERVICE
RATE YEAR 3

RATE SCHEDULE	REFERENCE	ADDITIONAL REVENUE REQUIREMENT (1)	PERCENT INCREASE IN CUSTOMERS' TOTAL GAS BILLS (2)	PERCENT INCREASE IN TOTAL GAS DISTRIBUTION REVENUE (3)
1. SCHEDULE D	*(SHEET G-4)*	$ 63,791,813	10.8%	15.5%
2. SCHEDULE C	*(SHEET G-5)*	$ 25,258,407	9.2%	16.5%
3. SCHEDULE IS	*(SHEET G-6)*	$ 5,438,557	5.4%	21.0%
4. SCHEDULE ISS	*(SHEET G-7)*	$ 395,363	6.5%	16.4%
5. SCHEDULE EG	*(SHEET G-8)*	$ -	0.0%	0.0%
6. SCHEDULE PLG	*(SHEET G-9)*	$ -	0.0%	0.0%
7. TOTAL		$ 94,884,140	9.5%	15.9%
8. TOTAL REQUIRED CHANGE IN BASE REVENUE		$ 94,885,000		
9. DIFFERENCE FROM REVENUE REQUIRED		$ (860)		

BALTIMORE GAS AND ELECTRIC COMPANY
ALLOCATION OF PROPOSED 2023 GAS BASE RATE
REVENUE CHANGE TO CLASSES OF SERVICE

STEP 1 - ALLOCATION OF REVENUE INCREASE

RATE SCHEDULE		BASE RATE REVENUE AT CURRENT RATES	RELATIVE ROR		STEP 1 REVENUE ALLOCATION		BASE REVENUE AFTER STEP 1
		(1)	(2)		(3)[a]		(4) = (1) + (3)
1. SCHEDULE D	$	368,939,958	1.02	$	-	$	368,939,958
2. SCHEDULE C	$	146,086,218	0.92	$	-	$	146,086,218
3. SCHEDULE PLG	$	24,435	8.09	$	-	$	24,435
4. SCHEDULES IS	$	24,742,573	0.81	$	989,333	$	25,731,906
5. SCHEDULE ISS	$	2,286,532	1.04	$	-	$	2,286,532
5. SCHEDULE EG	$	6,090,093	4.62	$	-	$	6,090,093
6. TOTAL	$	548,169,809		$	989,333	$	549,159,142

STEP 2 - ALLOCATION OF REMAINING REVENUE INCREASE TO ALL RATE SCHEDULES, EXCLUDING EG AND PLG

		REVENUE INCREASE
		(5)
7. REQUIRED CHANGE IN BASE RATE REVENUE TO BE ALLOCATED	$	94,885,000

RATE SCHEDULE		BASE REVENUE AFTER STEP 1	PERCENT OF TOTAL		STEP 2 REVENUE ALLOCATION		TOTAL BASE REVENUE ALLOCATION		TOTAL BASE REVENUE AT PROPOSED RATES	PERCENT OF TOTAL DISTRIBUTION INCREASE
		(6) = (4)	(7)[b]		(8) = ((5) - (3)) * (7)		(9) = (3) + (8)		(10) = (1) + (9)	(11)
8. SCHEDULE D	$	368,939,958	67.94%	$	63,791,929	$	63,791,929	$	432,731,887	67.23%
9. SCHEDULE C	$	146,086,218	26.90%	$	25,259,182	$	25,259,182	$	171,345,400	26.62%
10. SCHEDULE PLG	$	24,435	-	$	-	$	-	$	24,435	-
11. SCHEDULE IS	$	25,731,906	4.74%	$	4,449,201	$	5,438,534	$	30,181,107	5.73%
12. SCHEDULE ISS	$	2,286,532	0.42%	$	395,355	$	395,355	$	2,681,887	0.42%
13. SCHEDULE EG	$	6,090,093	-	$	-	$	-	$	6,090,093	-
14. TOTAL	$	549,159,142	100.00%	$	93,895,667	$	94,885,000	$	643,054,809	100.00%
15. TOTAL REVENUE INCREASE						$	94,885,000			

(a) Sch. IS Step 1 Allocation from proposed GCOSS
(b) Excluding PLG and EG

BALTIMORE GAS AND ELECTRIC COMPANY
SUMMARY OF PROPOSED GAS MYP BASE RATE REVENUE
CHANGE BY RATE SCHEDULES OVER MYP PERIOD

(1)	(2)	(3)	(4)	(5)	(6)
				Total Revenue Increase	
	Rate Year 1	Rate Year 2	Rate Year 3	($)	(%)
1. MYP REVENUE REQUIREMENT	$ -	$ -	$ 94,885,000	$ 94,885,000	
RATE SCHEDULE					
2. 1. SCHEDULE D	$ -	$ -	$ 63,791,929	$ 63,791,929	67.2%
3. 2. SCHEDULE C	$ -	$ -	$ 25,259,182	$ 25,259,182	26.6%
4. 3. SCHEDULE PLG	$ -	$ -	$ -	$ -	-
5. 4. SCHEDULE IS	$ -	$ -	$ 5,438,534	$ 5,438,534	5.7%
6. 5. SCHEDULE ISS	$ -	$ -	$ 395,355	$ 395,355	0.4%
7. 6. SCHEDULE EG	$ -	$ -	$ -	$ -	-
12. TOTAL	$ -	$ -	$ 94,885,000	$ 94,885,000	100.0%

BALTIMORE GAS AND ELECTRIC COMPANY
PROPOSED CHANGE IN GAS SERVICE TARIFF
SCHEDULE D - RESIDENTIAL SERVICE
RATE YEAR 1 - 2021

RATE YEAR 1	WEATHER ADJUSTED BILLING DETERMINANTS	REVENUE AT CURRENT RATES: CURRENT RATES	EFFECTIVE RIDER 8 & GAC ADJ	CURRENT EFFECTIVE RATES	REVENUE AT CURRENT RATES	WEATHER ADJUSTED BILLING DETERMINANTS	PROPOSED CHANGE IN REVENUE: PROPOSED RATES	REVENUE AT PROPOSED RATES	CHANGE IN BASE REVENUE: REVENUE	PERCENT
	(1)	(2)	(3)	(4) = (2) + (3)	(5) = (1) x (4)	(6)	(7)	(8) = (6) x (7)	(9) = (8) - (5)	(10) = (9) / (5)
	BILLS					BILLS				
1. CUSTOMER CHARGE	7,760,672	$ 14.25		$ 14.25	$ 110,589,572	7,760,672	$ 14.25	$ 110,589,572	$ -	0.0%
	THERMS	$/TH	$/TH	$/TH		THERMS	$/TH			
2. DELIVERY PRICE	436,328,974	0.5960	-0.0039	0.5921	$ 258,350,386	436,328,974	0.5921	$ 258,350,386	$ -	0.0%
3. TOTAL REVENUE					$ 368,939,958			$ 368,939,958	$ -	0.0%
4. TOTAL REVENUE ALLOCATED									$ -	
5. DIFFERENCE FROM REVENUE ALLOCATED									$ -	

BALTIMORE GAS AND ELECTRIC COMPANY
PROPOSED CHANGE IN GAS SERVICE TARIFF
SCHEDULE D - RESIDENTIAL SERVICE
RATE YEAR 2 - 2022

RATE YEAR 2

	WEATHER ADJUSTED BILLING DETERMINANTS	REVENUE AT CURRENT RATES: CURRENT RATES	EFFECTIVE RIDER 8 & GAC ADJ	CURRENT EFFECTIVE RATES	REVENUE AT CURRENT RATES
	(1)	(2)	(3)	(4) = (2) + (3)	(5) = (1) x (4)
	BILLS				
1. CUSTOMER CHARGE	7,823,810	$ 14.25		$ 14.25	$ 111,489,286
	THERMS	$/TH	$/TH	$/TH	
2. DELIVERY PRICE	441,185,498	0.5921	-0.0017	0.5904	$ 260,475,918
3. TOTAL REVENUE					$ 371,965,204

	WEATHER ADJUSTED BILLING DETERMINANTS	PROPOSED CHANGE IN REVENUE: PROPOSED RATES	REVENUE AT PROPOSED RATES	CHANGE IN BASE REVENUE: REVENUE	PERCENT
	(6)	(7)	(8) = (6) x (7)	(9) = (8) - (5)	(10) = (9) / (5)
	BILLS				
1. CUSTOMER CHARGE	7,823,810	$ 14.25	$ 111,489,286	$ -	0.0%
	THERMS	$/TH			
2. DELIVERY PRICE	441,185,498	0.5904	$ 260,475,918	$ -	0.0%
3. TOTAL REVENUE			$ 371,965,204	$ -	0.0%
4. TOTAL REVENUE ALLOCATED				$ -	
5. DIFFERENCE FROM REVENUE ALLOCATED				$ -	

BALTIMORE GAS AND ELECTRIC COMPANY
PROPOSED CHANGE IN GAS SERVICE TARIFF
SCHEDULE D - RESIDENTIAL SERVICE
RATE YEAR 3 - 2023

RATE YEAR 3

	WEATHER ADJUSTED BILLING DETERMINANTS	REVENUE AT CURRENT RATES: CURRENT RATES	REVENUE AT CURRENT RATES: EFFECTIVE RIDER 8 & GAC ADJ	REVENUE AT CURRENT RATES: CURRENT EFFECTIVE RATES	REVENUE AT CURRENT RATES: REVENUE AT CURRENT RATES
	(1)	(2)	(3)	(4) = (2) + (3)	(5) = (1) x (4)
	BILLS				
1. CUSTOMER CHARGE	7,886,947	$ 14.25		$ 14.25	$ 112,389,000
	THERMS	$/TH	$/TH	$/TH	
2. DELIVERY PRICE	445,102,435	0.5904	-0.0006	0.5898	$ 262,521,416
3. TOTAL REVENUE					$ 374,910,416

	WEATHER ADJUSTED BILLING DETERMINANTS	PROPOSED CHANGE IN REVENUE: PROPOSED RATES	PROPOSED CHANGE IN REVENUE: REVENUE AT PROPOSED RATES	CHANGE IN BASE REVENUE: REVENUE	CHANGE IN BASE REVENUE: PERCENT
	(6)	(7)	(8) = (6) x (7)	(9) = (8) - (5)	(10) = (9) / (5)
	BILLS				
1. CUSTOMER CHARGE	7,886,947	$ 15.25	$ 120,275,947	$ 7,886,947	7.0%
	THERMS	$/TH			
2. DELIVERY PRICE	445,102,435	0.7154	$ 318,426,282	$ 55,904,866	21.3%
3. TOTAL REVENUE			$ 438,702,229	$ 63,791,813	17.0%
4. TOTAL REVENUE ALLOCATED				$ 63,791,929	
5. DIFFERENCE FROM REVENUE ALLOCATED				$ (116)	

BALTIMORE GAS AND ELECTRIC COMPANY
PROPOSED CHANGE IN GAS SERVICE TARIFF
SCHEDULE C - GENERAL SERVICE
RATE YEAR 1 - 2021

RATE YEAR 1	WEATHER ADJUSTED BILLING DETERMINANTS	REVENUE AT CURRENT RATES: CURRENT RATES	EFFECTIVE RIDER 8 & GAC ADJ	CURRENT EFFECTIVE RATES	REVENUE AT CURRENT RATES
	(1)	(2)	(3)	(4) = (2) + (3)	(5) = (1) x (4)
	BILLS				
1. CUSTOMER CHARGE	532,736	$ 36.30		$ 36.30	$ 19,338,313
2. INFORMATION FEE	3,432	$ 65.00		$ 65.00	$ 223,105
DELIVERY PRICE	THERMS	$/TH	$/TH	$/TH	
3. FIRST 10,000 THERMS	235,858,360	0.4541	0.0140	0.4681	$ 110,405,298
4. ALL OVER 10,000 THERMS	65,955,409	0.2304	0.0140	0.2444	$ 16,119,502
					$ 126,524,800
5. TOTAL THERMS	301,813,768				
6. TOTAL REVENUE					$ 146,086,218

	WEATHER ADJUSTED BILLING DETERMINANTS	PROPOSED CHANGE IN REVENUE: PROPOSED RATES	REVENUE AT PROPOSED RATES	CHANGE IN BASE REVENUE: REVENUE	PERCENT
	(6)	(7)	(8) = (6) x (7)	(9) = (8) - (5)	(10) = (9) / (5)
	BILLS				
1. CUSTOMER CHARGE	532,736	$ 36.30	$ 19,338,313	$ -	0.0%
2. INFORMATION FEE	3,432	$ 65.00	$ 223,105	$ -	0.0%
DELIVERY PRICE	THERMS	$/TH			
3. FIRST 10,000 THERMS	235,858,360	0.4681	$ 110,405,298	$ -	
4. ALL OVER 10,000 THERMS	65,955,409	0.2444	$ 16,119,502	$ -	
			$ 126,524,800	$ -	0.0%
5. TOTAL THERMS	301,813,768				
6. TOTAL REVENUE			$ 146,086,218	$ -	0.0%
7. TOTAL REVENUE ALLOCATED				$ -	
8. DIFFERENCE FROM REVENUE ALLOCATED				$ -	

BALTIMORE GAS AND ELECTRIC COMPANY
PROPOSED CHANGE IN GAS SERVICE TARIFF
SCHEDULE C - GENERAL SERVICE
RATE YEAR 2 - 2022

RATE YEAR 2	WEATHER ADJUSTED BILLING DETERMINANTS	REVENUE AT CURRENT RATES: CURRENT RATES	REVENUE AT CURRENT RATES: EFFECTIVE RIDER 8 & GAC ADJ	REVENUE AT CURRENT RATES: CURRENT EFFECTIVE RATES	REVENUE AT CURRENT RATES: REVENUE AT CURRENT RATES	WEATHER ADJUSTED BILLING DETERMINANTS	PROPOSED CHANGE IN REVENUE: PROPOSED RATES	PROPOSED CHANGE IN REVENUE: REVENUE AT PROPOSED RATES	CHANGE IN BASE REVENUE: REVENUE	CHANGE IN BASE REVENUE: PERCENT
	(1)	(2)	(3)	(4) = (2) + (3)	(5) = (1) x (4)	(6)	(7)	(8) = (6) x (7)	(9) = (8) - (5)	(10) = (9) / (5)
	BILLS					BILLS				
1. CUSTOMER CHARGE	534,518	$ 36.30		$ 36.30	$ 19,402,997	534,518	$ 36.30	$ 19,402,997	$ -	0.0%
2. INFORMATION FEE	3,432	$ 65.00		$ 65.00	$ 223,105	3,432	$ 65.00	$ 223,105	$ -	0.0%
DELIVERY PRICE	THERMS	$/TH	$/TH	$/TH		THERMS	$/TH			
3. FIRST 10,000 THERMS	235,721,694	0.4681	0.0008	0.4689	$ 110,529,902	235,721,694	0.4689	$ 110,529,902	$ -	
4. ALL OVER 10,000 THERMS	65,974,177	0.2444	0.0008	0.2452	$ 16,176,868	65,974,177	0.2452	$ 16,176,868	$ -	
					$ 126,706,770			$ 126,706,770	$ -	0.0%
5. TOTAL THERMS	301,695,871					301,695,871				
6. TOTAL REVENUE					$ 146,332,872			$ 146,332,872	$ -	0.0%

7. TOTAL REVENUE ALLOCATED	$ -
8. DIFFERENCE FROM REVENUE ALLOCATED	$ -

BALTIMORE GAS AND ELECTRIC COMPANY
PROPOSED CHANGE IN GAS SERVICE TARIFF
SCHEDULE C - GENERAL SERVICE
RATE YEAR 3

RATE YEAR 3

	WEATHER ADJUSTED BILLING DETERMINANTS	REVENUE AT CURRENT RATES: CURRENT RATES	REVENUE AT CURRENT RATES: EFFECTIVE RIDER 8 & GAC ADJ	REVENUE AT CURRENT RATES: CURRENT EFFECTIVE RATES	REVENUE AT CURRENT RATES: REVENUE AT CURRENT RATES
	(1)	(2)	(3)	(4) = (2) + (3)	(5) = (1) x (4)
	BILLS				
1. CUSTOMER CHARGE	536,300	$ 36.300		$ 36.30	$ 19,467,681
2. INFORMATION FEE	3,432	$ 65.00		$ 65.00	$ 223,105
DELIVERY PRICE	THERMS	$/TH	$/TH	$/TH	
3. FIRST 10,000 THERMS	235,237,335	0.4689	0.0014	0.4703	$ 110,632,118
4. ALL OVER 10,000 THERMS	65,720,379	0.2452	0.0014	0.2466	$ 16,206,646
					$ 126,838,764
5. TOTAL THERMS	300,957,714				
6. TOTAL REVENUE					$ 146,529,550

	WEATHER ADJUSTED BILLING DETERMINANTS	PROPOSED CHANGE IN REVENUE: PROPOSED RATES	PROPOSED CHANGE IN REVENUE: REVENUE AT PROPOSED RATES	CHANGE IN BASE REVENUE: REVENUE	CHANGE IN BASE REVENUE: PERCENT
	(6)	(7)	(8) = (6) x (7)	(9) = (8) - (5)	(10) = (9) / (5)
	BILLS				
1. CUSTOMER CHARGE	536,300	$ 38.00	$ 20,379,390	$ 911,709	4.7%
2. INFORMATION FEE	3,432	$ 65.00	$ 223,105	$ -	0.0%
DELIVERY PRICE	THERMS	$/TH			
3. FIRST 10,000 THERMS	235,237,335	0.5605	$ 131,850,526	$ 21,218,408	
4. ALL OVER 10,000 THERMS	65,720,379	0.2942	$ 19,334,936	$ 3,128,290	
			$ 151,185,462	$ 24,346,698	19.2%
5. TOTAL THERMS	300,957,714				
6. TOTAL REVENUE			$ 171,787,957	$ 25,258,407	17.2%

7. TOTAL REVENUE ALLOCATED $ 25,259,182

8. DIFFERENCE FROM REVENUE ALLOCATED $ (775)

BALTIMORE GAS AND ELECTRIC COMPANY
PROPOSED CHANGE IN GAS SERVICE TARIFF
SCHEDULE IS - INTERRUPTIBLE SERVICE
RATE YEAR 1 - 2021

RATE YEAR 1	WEATHER ADJUSTED BILLING DETERMINANTS (1)	REVENUE AT CURRENT RATES: CURRENT RATES (2)	REVENUE AT CURRENT RATES: REVENUE AT CURRENT RATES (3) = (1) x (2)	WEATHER ADJUSTED BILLING DETERMINANTS (4)	PROPOSED CHANGE IN REVENUE: PROPOSED RATES (5)	PROPOSED CHANGE IN REVENUE: REVENUE AT PROPOSED RATES (6) = (4) x (5)	CHANGE IN BASE REVENUE: REVENUE (7) = (6) - (3)	CHANGE IN BASE REVENUE: PERCENT (8) = (7) / (3)
	BILLS			BILLS				
1. CUSTOMER CHARGE	1,013	$ 1,250.00	$ 1,266,772	1,013	$ 1,250.00	$ 1,266,772	$ -	0.0%
2. INFORMATION FEE	1,013	$ 65.00	$ 65,872	1,013	$ 65.00	$ 65,872	$ -	0.0%
	TH/DAY	$/TH		TH/DAY	$/TH			
3. DEMAND PRICE	12,018,098	0.8323	$ 10,002,663	12,018,098	0.8323	$ 10,002,663	$ -	0.0%
	THERMS	$/TH		THERMS	$/TH			
4. DELIVERY PRICE	184,479,827	0.0712	$ 13,134,964	184,479,827	0.0712	$ 13,134,964	$ -	0.0%
Optional Firm Delivery Service	THERMS	$/TH		THERMS	$/TH			
5. FIRST 10,000 THERMS	717,120	0.3299	$ 236,578	717,120	0.3299	$ 236,578	$ -	
6. ALL OVER 10,000 THERMS	336,384	0.1062	$ 35,724	336,384	0.1062	$ 35,724	$ -	
			$ 272,302			$ 272,302	$ -	0.0%
7. TOTAL REVENUE			$ 24,742,573			$ 24,742,573	$ -	0.0%
8. TOTAL REVENUE ALLOCATED							$ -	
9. DIFFERENCE FROM REVENUE ALLOCATED							$ -	

BALTIMORE GAS AND ELECTRIC COMPANY
PROPOSED CHANGE IN GAS SERVICE TARIFF
SCHEDULE IS - INTERRUPTIBLE SERVICE
RATE YEAR 2 - 2022

RATE YEAR 2	WEATHER ADJUSTED BILLING DETERMINANTS	REVENUE AT CURRENT RATES: CURRENT RATES	REVENUE AT CURRENT RATES: REVENUE AT CURRENT RATES	WEATHER ADJUSTED BILLING DETERMINANTS	PROPOSED CHANGE IN REVENUE: PROPOSED RATES	PROPOSED CHANGE IN REVENUE: REVENUE AT PROPOSED RATES	CHANGE IN BASE REVENUE: REVENUE	CHANGE IN BASE REVENUE: PERCENT
	(1)	(2)	(3) = (1) x (2)	(4)	(5)	(6) = (4) x (5)	(7) = (6) - (3)	(8) = (7) / (3)
	BILLS			BILLS				
1. CUSTOMER CHARGE	1,013	$ 1,250.00	$ 1,266,772	1,013	$ 1,250.00	$ 1,266,772	$ -	0.0%
2. INFORMATION FEE	1,013	$ 65.00	$ 65,872	1,013	$ 65.00	$ 65,872	$ -	0.0%
	TH/DAY	$/TH		TH/DAY	$/TH			
3. DEMAND PRICE	12,018,098	0.8323	$ 10,002,663	12,018,098	0.8323	$ 10,002,663	$ -	0.0%
	THERMS	$/TH		THERMS	$/TH			
4. DELIVERY PRICE	184,096,942	0.0712	$ 13,107,702	184,096,942	0.0712	$ 13,107,702	$ -	0.0%
Optional Firm Delivery Service	THERMS	$/TH		THERMS	$/TH			
5. FIRST 10,000 THERMS	717,120	0.3299	$ 236,578	717,120	0.3299	$ 236,578	$ -	
6. ALL OVER 10,000 THERMS	336,384	0.1062	$ 35,724	336,384	0.1062	$ 35,724	$ -	
			$ 272,302			$ 272,302	$ -	0.0%
7. TOTAL REVENUE			$ 24,715,311			$ 24,715,311	$ -	0.0%
8. TOTAL REVENUE ALLOCATED							$ -	
9. DIFFERENCE FROM REVENUE ALLOCATED							$ -	

BALTIMORE GAS AND ELECTRIC COMPANY
PROPOSED CHANGE IN GAS SERVICE TARIFF
SCHEDULE IS - INTERRUPTIBLE SERVICE
RATE YEAR 3 - 2023

RATE YEAR 3	WEATHER ADJUSTED BILLING DETERMINANTS	REVENUE AT CURRENT RATES: CURRENT RATES	REVENUE AT CURRENT RATES: REVENUE AT CURRENT RATES	WEATHER ADJUSTED BILLING DETERMINANTS	PROPOSED CHANGE IN REVENUE: PROPOSED RATES	PROPOSED CHANGE IN REVENUE: REVENUE AT PROPOSED RATES	CHANGE IN BASE REVENUE: REVENUE	CHANGE IN BASE REVENUE: PERCENT
	(1)	(2)	(3) = (1) x (2)	(4)	(5)	(6) = (4) x (5)	(7) = (6) - (3)	(8) = (7) / (3)
	BILLS			BILLS				
1. CUSTOMER CHARGE	1,013	$ 1,250.00	$ 1,266,772	1,013	$ 1,250.00	$ 1,266,772	$ -	0.0%
2. INFORMATION FEE	1,013	$ 65.00	$ 65,872	1,013	$ 65.00	$ 65,872	$ -	0.0%
	TH/DAY	$/TH		TH/DAY	$/TH			
3. DEMAND PRICE	12,018,098	0.8323	$ 10,002,663	12,018,098	1.1314	$ 13,597,276	$ 3,594,613	35.9%
	THERMS	$/TH		THERMS	$/TH			
4. DELIVERY PRICE	185,186,010	0.0712	$ 13,185,244	185,186,010	0.0808	$ 14,963,030	$ 1,777,786	13.5%
Optional Firm Delivery Service	THERMS	$/TH		THERMS	$/TH			
5. FIRST 10,000 THERMS	717,120	0.3299	$ 236,578	717,120	0.4063	$ 291,366	$ 54,788	
6. ALL OVER 10,000 THERMS	336,384	0.1062	$ 35,724	336,384	0.1400	$ 47,094	$ 11,370	
			$ 272,302			$ 338,460	$ 66,158	24.3%
7. TOTAL REVENUE			$ 24,792,853			$ 30,231,410	$ 5,438,557	21.9%

8. TOTAL REVENUE ALLOCATED	$ 5,438,534
9. DIFFERENCE FROM REVENUE ALLOCATED	$ 23

BALTIMORE GAS AND ELECTRIC COMPANY
PROPOSED CHANGE IN GAS SERVICE TARIFF
SCHEDULE ISS - INTERRUPTIBLE SERVICE SMALL
RATE YEAR 1 - 2021

RATE YEAR 1	WEATHER ADJUSTED BILLING DETERMINANTS	REVENUE AT CURRENT RATES: CURRENT RATES	REVENUE AT CURRENT RATES: REVENUE AT CURRENT RATES	WEATHER ADJUSTED BILLING DETERMINANTS	PROPOSED CHANGE IN REVENUE: PROPOSED RATES	PROPOSED CHANGE IN REVENUE: REVENUE AT PROPOSED RATES	CHANGE IN BASE REVENUE: REVENUE	CHANGE IN BASE REVENUE: PERCENT
	(1)	(2)	(3) = (1) x (2)	(4)	(5)	(6) = (4) x (5)	(7) = (6) - (3)	(8) = (7) / (3)
	BILLS			BILLS				
1. CUSTOMER CHARGE	593	$ 363.50	$ 215,598	593	$ 363.50	$ 215,598	$ -	0.0%
2. INFORMATION FEE	593	$ 65.00	$ 38,553	593	$ 65.00	$ 38,553	$ -	0.0%
	TH/DAY	$/TH		TH/DAY	$/TH			
3. DEMAND PRICE	808,271	1.0538	$ 851,755	808,271	1.0538	$ 851,755	$ -	0.0%
	THERMS	$/TH		THERMS	$/TH			
4. DELIVERY PRICE	8,891,230	0.1190	$ 1,058,056	8,891,230	0.1190	$ 1,058,056	$ -	0.0%
Optional Firm Delivery Ser	THERMS	$/TH		THERMS	$/TH			
5. FIRST 10,000 THERMS	494,976	0.2438	$ 120,675	494,976	0.2438	$ 120,675	$ -	0.0%
6. ALL OVER 10,000 THE	94,272	0.0201	$ 1,895	94,272	0.0201	$ 1,895	$ -	
			$ 122,570			$ 122,570	$ -	
7. TOTAL REVENUE			$ 2,286,532			$ 2,286,532	$ -	0.0%
8. TOTAL REVENUE ALLOCATED							$ -	
9. DIFFERENCE FROM REVENUE ALLOCATED							$ -	

BALTIMORE GAS AND ELECTRIC COMPANY
PROPOSED CHANGE IN GAS SERVICE TARIFF
SCHEDULE ISS - INTERRUPTIBLE SERVICE SMALL
RATE YEAR 2 - 2022

RATE YEAR 2

	WEATHER ADJUSTED BILLING DETERMINANTS	REVENUE AT CURRENT RATES: CURRENT RATES	REVENUE AT CURRENT RATES: REVENUE AT CURRENT RATES	WEATHER ADJUSTED BILLING DETERMINANTS	PROPOSED CHANGE IN REVENUE: PROPOSED RATES	REVENUE AT PROPOSED RATES	CHANGE IN BASE REVENUE: REVENUE	CHANGE IN BASE REVENUE: PERCENT
	(1)	(2)	(3) = (1) x (2)	(4)	(5)	(6) = (4) x (5)	(7) = (6) - (3)	(8) = (7) / (3)
	BILLS			BILLS				
1. CUSTOMER CHARGE	593	$ 363.50	$ 215,598	593	$ 363.50	$ 215,598	$ -	0.0%
2. INFORMATION FEE	593	$ 65.00	$ 38,553	593	$ 65.00	$ 38,553	$ -	0.0%
	TH/DAY	$/TH		TH/DAY	$/TH			
3. DEMAND PRICE	808,271	1.0538	$ 851,755	808,271	1.0538	$ 851,755	$ -	0.0%
	THERMS	$/TH		THERMS	$/TH			
4. DELIVERY PRICE	8,900,913	0.1190	$ 1,059,209	8,900,913	0.1190	$ 1,059,209	$ -	0.0%
Optional Firm Delivery Ser	THERMS	$/TH		THERMS	$/TH			
5. FIRST 10,000 THERMS	494,976	0.2438	$ 120,675	494,976	0.2438	$ 120,675	$ -	0.0%
6. ALL OVER 10,000 THE	94,272	0.0201	$ 1,895	94,272	0.0201	$ 1,895	$ -	
			$ 122,570			$ 122,570	$ -	
7. TOTAL REVENUE			$ 2,287,685			$ 2,287,685	$ -	0.0%

8. TOTAL REVENUE ALLOCATED	$ -
9. DIFFERENCE FROM REVENUE ALLOCATED	$ -

BALTIMORE GAS AND ELECTRIC COMPANY
PROPOSED CHANGE IN GAS SERVICE TARIFF
SCHEDULE ISS - INTERRUPTIBLE SERVICE SMALL
RATE YEAR 3 - 2023

RATE YEAR 3	WEATHER ADJUSTED BILLING DETERMINANTS	REVENUE AT CURRENT RATES: CURRENT RATES	REVENUE AT CURRENT RATES: REVENUE AT CURRENT RATES	WEATHER ADJUSTED BILLING DETERMINANTS	PROPOSED CHANGE IN REVENUE: PROPOSED RATES	PROPOSED CHANGE IN REVENUE: REVENUE AT PROPOSED RATES	CHANGE IN BASE REVENUE: REVENUE	CHANGE IN BASE REVENUE: PERCENT
	(1)	(2)	(3) = (1) x (2)	(4)	(5)	(6) = (4) x (5)	(7) = (6) - (3)	(8) = (7) / (3)
	BILLS			BILLS				
1. CUSTOMER CHARGE	593	$ 363.50	$ 215,598	593	$ 375.00	$ 222,419	$ 6,821	3.2%
2. INFORMATION FEE	593	$ 65.00	$ 38,553	593	$ 65.00	$ 38,553	$ -	0.0%
	TH/DAY	$/TH		TH/DAY	$/TH			
3. DEMAND PRICE	808,271	1.0538	$ 851,755	808,271	1.2513	$ 1,011,389	$ 159,634	18.7%
	THERMS	$/TH		THERMS	$/TH			
4. DELIVERY PRICE	9,063,190	0.1190	$ 1,078,520	9,063,190	0.1405	$ 1,273,378	$ 194,858	18.1%
Optional Firm Delivery Ser	THERMS	$/TH		THERMS	$/TH			
5. FIRST 10,000 THERMS	494,976	0.2438	$ 120,675	494,976	0.3084	$ 152,651	$ 31,976	26.5%
6. ALL OVER 10,000 THE	94,272	0.0201	$ 1,895	94,272	0.0421	$ 3,969	$ 2,074	
			$ 122,570			$ 156,620	$ 34,050	
7. TOTAL REVENUE			$ 2,306,996			$ 2,702,359	$ 395,363	17.1%

8. TOTAL REVENUE ALLOCATED	$ 395,355
9. DIFFERENCE FROM REVENUE ALLOCATED	$ 8

BALTIMORE GAS AND ELECTRIC COMPANY
PROPOSED CHANGE IN GAS SERVICE TARIFF
SCHEDULE EG - ELECTRIC GENERATION
RATE YEAR 1 - 2021

RATE YEAR 1

	WEATHER ADJUSTED BILLING DETERMINANTS	REVENUE AT CURRENT RATES: CURRENT RATES	REVENUE AT CURRENT RATES: REVENUE AT CURRENT RATES	WEATHER ADJUSTED BILLING DETERMINANTS	PROPOSED CHANGE IN REVENUE: PROPOSED RATES	PROPOSED CHANGE IN REVENUE: REVENUE AT PROPOSED RATES	CHANGE IN BASE REVENUE: REVENUE	CHANGE IN BASE REVENUE: PERCENT
	(1)	(2)	(3) = (1) x (2)	(4)	(5)	(6) = (4) x (5)	(7) = (6) - (3)	(8) = (7) / (3)
	BILLS			BILLS				
1. CUSTOMER CHARGE	48	$ 3,000.00	$ 144,000	48	$ 3,000.00	$ 144,000	$ -	0.0%
2. INFORMATION FEE	48	$ 65.00	$ 3,120	48	$ 65.00	$ 3,120	$ -	0.0%
	TH/DAY	$/TH		TH/DAY	$/TH			
3. DEMAND PRICE	7,758,268	0.3546	$ 2,751,082	7,758,268	0.3546	$ 2,751,082	$ -	0.0%
	THERMS	$/TH		THERMS	$/TH			
4. DELIVERY PRICE	37,863,470	0.0843	$ 3,191,891	37,863,470	0.0843	$ 3,191,891	$ -	0.0%
Optional Firm Delivery Service	THERMS	$/TH		THERMS	$/TH			
5. FIRST 10,000 THERMS	0	0.3299	$ -	0	0.3299	$ -	$ -	
6. ALL OVER 10,000 THERMS	0	0.1062	$ -	0	0.1062	$ -	$ -	
			$ -			$ -	$ -	0.0%
7. TOTAL REVENUE			$ 6,090,093			$ 6,090,093	$ -	0.0%

8. TOTAL REVENUE ALLOCATED	$ -
9. DIFFERENCE FROM REVENUE ALLOCATED	$ -

BALTIMORE GAS AND ELECTRIC COMPANY
PROPOSED CHANGE IN GAS SERVICE TARIFF
SCHEDULE EG - ELECTRIC GENERATION
RATE YEAR 2 - 2022

RATE YEAR 2

	WEATHER ADJUSTED BILLING DETERMINANTS	REVENUE AT CURRENT RATES: CURRENT RATES	REVENUE AT CURRENT RATES: REVENUE AT CURRENT RATES	WEATHER ADJUSTED BILLING DETERMINANTS	PROPOSED CHANGE IN REVENUE: PROPOSED RATES	PROPOSED CHANGE IN REVENUE: REVENUE AT PROPOSED RATES	CHANGE IN BASE REVENUE: REVENUE	CHANGE IN BASE REVENUE: PERCENT
	(1)	(2)	(3) = (1) x (2)	(4)	(5)	(6) = (4) x (5)	(7) = (6) - (3)	(8) = (7) / (3)
	BILLS			BILLS				
1. CUSTOMER CHARGE	48	$ 3,000.00	$ 144,000	48	$ 3,000.00	$ 144,000	$ -	0.0%
2. INFORMATION FEE	48	$ 65.00	$ 3,120	48	$ 65.00	$ 3,120	$ -	0.0%
	TH/DAY	$/TH		TH/DAY	$/TH			
3. DEMAND PRICE	7,758,268	0.3546	$ 2,751,082	7,758,268	0.3546	$ 2,751,082	$ -	0.0%
	THERMS	$/TH		THERMS	$/TH			
4. DELIVERY PRICE	37,837,903	0.0843	$ 3,189,735	37,837,903	0.0843	$ 3,189,735	$ -	0.0%
Optional Firm Delivery Service	THERMS	$/TH		THERMS	$/TH			
5. FIRST 10,000 THERMS	0	0.3299	$ -	0	0.3299	$ -	$ -	
6. ALL OVER 10,000 THERMS	0	0.1062	$ -	0	0.1062	$ -	$ -	
			$ -			$ -	$ -	0.0%
7. TOTAL REVENUE			$ 6,087,937			$ 6,087,937	$ -	0.0%

8. TOTAL REVENUE ALLOCATED $ -
9. DIFFERENCE FROM REVENUE ALLOCATED $ -

BALTIMORE GAS AND ELECTRIC COMPANY
PROPOSED CHANGE IN GAS SERVICE TARIFF
SCHEDULE EG - ELECTRIC GENERATION
RATE YEAR 3 - 2023

RATE YEAR 3	WEATHER ADJUSTED BILLING DETERMINANTS	REVENUE AT CURRENT RATES: CURRENT RATES	REVENUE AT CURRENT RATES: REVENUE AT CURRENT RATES	WEATHER ADJUSTED BILLING DETERMINANTS	PROPOSED CHANGE IN REVENUE: PROPOSED RATES	PROPOSED CHANGE IN REVENUE: REVENUE AT PROPOSED RATES	CHANGE IN BASE REVENUE: REVENUE	CHANGE IN BASE REVENUE: PERCENT
	(1)	(2)	(3) = (1) x (2)	(4)	(5)	(6) = (4) x (5)	(7) = (6) - (3)	(8) = (7) / (3)
	BILLS			BILLS				
1. CUSTOMER CHARGE	48	$ 3,000.00	$ 144,000	48	$ 3,000.00	$ 144,000	$ -	0.0%
2. INFORMATION FEE	48	$ 65.00	$ 3,120	48	$ 65.00	$ 3,120	$ -	0.0%
	TH/DAY	$/TH		TH/DAY	$/TH			
3. DEMAND PRICE	7,758,268	0.3546	$ 2,751,082	7,758,268	0.3546	$ 2,751,082	$ -	0.0%
	THERMS	$/TH		THERMS	$/TH			
4. DELIVERY PRICE	37,769,921	0.0843	$ 3,184,004	37,769,921	0.0843	$ 3,184,004	$ -	0.0%
Optional Firm Delivery Service	THERMS	$/TH		THERMS	$/TH			
5. FIRST 10,000 THERMS	0	0.3299	$ -	0	0.4034	$ -	$ -	
6. ALL OVER 10,000 THERMS	0	0.1062	$ -	0	0.1371	$ -	$ -	
			$ -			$ -	$ -	0.0%
7. TOTAL REVENUE			$ 6,082,206			$ 6,082,206	$ -	0.0%
8. TOTAL REVENUE ALLOCATED							$ -	
9. DIFFERENCE FROM REVENUE ALLOCATED							$ -	

Exhibit LKF-4
SHEET G-9

BALTIMORE GAS AND ELECTRIC COMPANY
PROPOSED CHANGE IN GAS SERVICE TARIFF
SCHEDULE PLG - PRIVATE AREA LIGHTING
RATE YEAR 1 - 2021

RATE YEAR 1		REVENUE AT CURRENT RATES			PROPOSED CHANGE IN REVENUE			CHANGE IN BASE REVENUE	
		TEST YEAR BILLING DETERMINANTS	CURRENT	REVENUE AT CURRENT	TEST YEAR BILLING DETERMINANTS	PROPOSED	REVENUE AT PROPOSED		
LAMP RATE		(LAMPS)	RATES	RATES	(LAMPS)	RATES	RATES	REVENUE	PERCENT
SOLAR VALUE		(1)	(2)	(3) = (1) x (2)	(4)	(5)	(6) = (4) x (5)	(7) = (6) - (3)	(8) = (7) / (3)
1. 2.5 CU-FT/HR		12	$ 6.20	$ 74	12	$ 6.20	$ 74	$ -	0.0%
UNCONTROLLED LAMP									
2. 2.5 CU-FT/HR		1,845	$ 6.20	$ 11,439	1,845	$ 6.20	$ 11,439	$ -	0.0%
3. 3.0 CU-FT/HR		-	$ 6.20	$ -	-	$ 6.20	$ -	$ -	0.0%
4. 3.5 CU-FT/HR		660	$ 6.20	$ 4,092	660	$ 6.20	$ 4,092	$ -	0.0%
5. TOTAL LAMP RATE REVENUE				$ 15,605			$ 15,605	$ -	0.0%
BURNER CAPACITY	BURNER								
SOLAR VALUE	CAPACITY								
6. 2.5 CU-FT/HR	2.5	12	$ 1.27	$ 38	12	$ 1.27	$ 38	$ -	0.0%
UNCONTROLLED LAMP									
7. 2.5 CU-FT/HR	2.5	1,845	$ 1.27	$ 5,858	1,845	$ 1.27	$ 5,858	$ -	0.0%
8. 3.0 CU-FT/HR	3.0	-	$ 1.27	$ -	-	$ 1.27	$ -	$ -	0.0%
9. 3.5 CU-FT/HR	3.5	660	$ 1.27	$ 2,934	660	$ 1.27	$ 2,934	$ -	0.0%
10. TOTAL BURNER CAPACITY REVENUE				$ 8,830			$ 8,830	$ -	0.0%
11. TOTAL REVENUE				$ 24,435			$ 24,435	$ -	0.0%
12. TOTAL REVENUE ALLOCATED								$ -	
13. DIFFERENCE FROM REVENUE ALLOC.								$ -	

BALTIMORE GAS AND ELECTRIC COMPANY
PROPOSED CHANGE IN GAS SERVICE TARIFF
SCHEDULE PLG - PRIVATE AREA LIGHTING
RATE YEAR 2- 2022

RATE YEAR 2

		REVENUE AT CURRENT RATES			PROPOSED CHANGE IN REVENUE				
LAMP RATE		TEST YEAR BILLING DETERMINANTS (LAMPS)	CURRENT RATES	REVENUE AT CURRENT RATES	TEST YEAR BILLING DETERMINANTS (LAMPS)	PROPOSED RATES	REVENUE AT PROPOSED RATES	CHANGE IN BASE REVENUE: REVENUE	CHANGE IN BASE REVENUE: PERCENT
SOLAR VALUE		(1)	(2)	(3) = (1) x (2)	(4)	(5)	(6) = (4) x (5)	(7) = (6) - (3)	(8) = (7) / (3)
1. 2.5 CU-FT/HR		12	$ 6.20	$ 74	12	$ 6.20	$ 74	$ -	0.0%
UNCONTROLLED LAMP									
2. 2.5 CU-FT/HR		1,845	$ 6.20	$ 11,439	1,845	$ 6.20	$ 11,439	$ -	0.0%
3. 3.0 CU-FT/HR		-	$ 6.20	$ -	-	$ 6.20	$ -	$ -	0.0%
4. 3.5 CU-FT/HR		660	$ 6.20	$ 4,092	660	$ 6.20	$ 4,092	$ -	0.0%
5. TOTAL LAMP RATE REVENUE				$ 15,605			$ 15,605	$ -	0.0%
BURNER CAPACITY	BURNER								
SOLAR VALUE	CAPACITY								
6. 2.5 CU-FT/HR	2.5	12	$ 1.27	$ 38	12	$ 1.27	$ 38	$ -	0.0%
UNCONTROLLED LAMP									
7. 2.5 CU-FT/HR	2.5	1,845	$ 1.27	$ 5,858	1,845	$ 1.27	$ 5,858	$ -	0.0%
8. 3.0 CU-FT/HR	3.0	-	$ 1.27	$ -	-	$ 1.27	$ -	$ -	0.0%
9. 3.5 CU-FT/HR	3.5	660	$ 1.27	$ 2,934	660	$ 1.27	$ 2,934	$ -	0.0%
10. TOTAL BURNER CAPACITY REVENUE				$ 8,830			$ 8,830	$ -	0.0%
11. TOTAL REVENUE				$ 24,435			$ 24,435	$ -	0.0%

12. TOTAL REVENUE ALLOCATED	$ -
13. DIFFERENCE FROM REVENUE ALLOC.	$ -

BALTIMORE GAS AND ELECTRIC COMPANY
PROPOSED CHANGE IN GAS SERVICE TARIFF
SCHEDULE PLG - PRIVATE AREA LIGHTING
RATE YEAR 3 - 2023

RATE YEAR 3

		REVENUE AT CURRENT RATES				PROPOSED CHANGE IN REVENUE			
		TEST YEAR BILLING DETERMINANTS (LAMPS)	CURRENT RATES	REVENUE AT CURRENT RATES	TEST YEAR BILLING DETERMINANTS (LAMPS)	PROPOSED RATES	REVENUE AT PROPOSED RATES	CHANGE IN BASE REVENUE: REVENUE	PERCENT
LAMP RATE *SOLAR VALUE*		(1)	(2)	(3) = (1) x (2)	(4)	(5)	(6) = (4) x (5)	(7) = (6) - (3)	(8) = (7) / (3)
1. 2.5 CU-FT/HR		12	$ 6.20	$ 74	12	$ 6.20	$ 74	$ -	0.0%
UNCONTROLLED LAMP									
2. 2.5 CU-FT/HR		1,845	$ 6.20	$ 11,439	1,845	$ 6.20	$ 11,439	$ -	0.0%
3. 3.0 CU-FT/HR		-	$ 6.20	$ -	-	$ 6.20	$ -	$ -	0.0%
4. 3.5 CU-FT/HR		660	$ 6.20	$ 4,092	660	$ 6.20	$ 4,092	$ -	0.0%
5. TOTAL LAMP RATE REVENUE				$ 15,605			$ 15,605	$ -	0.0%
BURNER CAPACITY *SOLAR VALUE*	BURNER CAPACITY								
6. 2.5 CU-FT/HR	2.5	12	$ 1.27	$ 38	12	$ 1.27	$ 38	$ -	0.0%
UNCONTROLLED LAMP									
7. 2.5 CU-FT/HR	2.5	1,845	$ 1.27	$ 5,858	1,845	$ 1.27	$ 5,858	$ -	0.0%
8. 3.0 CU-FT/HR	3.0	-	$ 1.27	$ -	-	$ 1.27	$ -	$ -	0.0%
9. 3.5 CU-FT/HR	3.5	660	$ 1.27	$ 2,934	660	$ 1.27	$ 2,934	$ -	0.0%
10. TOTAL BURNER CAPACITY REVENUE				$ 8,830			$ 8,830	$ -	0.0%
11. TOTAL REVENUE				$ 24,435			$ 24,435	$ -	0.0%

12. TOTAL REVENUE ALLOCATED	$ -
13. DIFFERENCE FROM REVENUE ALLOC.	$ -

BALTIMORE GAS AND ELECTRIC COMPANY

RIDER 8 - MONTHLY RATE ADJUSTMENT &
GAS ADMINISTRATIVE CHARGE

	Rider 8 (1)		GAC Adjustment (2)	Total (3) = (1) + (2)
SCHEDULE D - RESIDENTIAL SERVICE				
RATE YEAR 1				
1. TARGET BASE REVENUE - 2021 - RATE YEAR 1 (a)	$ 362,514,377			
2. LESS: RATE YEAR 1 CUSTOMER CHARGE REVENUES	110,589,572			
3. RATE YEAR 1 DELIVERY CHARGE REVENUE	$ 251,924,805	GAC REVENUE	$ 6,425,038	
4. DIVIDED BY: RATE YEAR 1 BILLING DETERMINANTS - THERMS	436,328,974	THERMS	436,328,974	
5. DELIVERY CHARGE INCLUDING MONTHLY RATE ADJUSTMENT	$ 0.5774	AVG RATE	$ 0.0147	
6. CURRENT DELIVERY RATE - CASE NO. 9610	$ 0.5960			
7. RATE YEAR 1 RIDER 8 ADJUSTMENT	$ (0.0186)			
8. $ PER THERM	$ (0.0186)		$ 0.0147	$ (0.0039)
RATE YEAR 2				
1. TARGET BASE REVENUE - 2022 - RATE YEAR 2 (a)	$ 365,517,355			
2. ADD: RATE YEAR 1 REVENUE INCREASE	-			
3. LESS: RATE YEAR 2 CUSTOMER CHARGE REVENUES	111,489,286			
4. RATE YEAR 2 DELIVERY CHARGE REVENUE	$ 254,028,069	GAC REVENUE	$ 6,425,038	
5. DIVIDED BY: RATE YEAR 2 BILLING DETERMINANTS - THERMS	441,185,498	THERMS	441,185,498	
6. DELIVERY CHARGE INCLUDING MONTHLY RATE ADJUSTMENT	$ 0.5758	AVG RATE	$ 0.0146	
7. RATE YEAR 1 DELIVERY RATE	$ 0.5921			
8. RATE YEAR 2 RIDER 8 ADJUSTMENT	$ (0.0163)			
9. $ PER THERM	$ (0.0163)		$ 0.0146	$ (0.0017)
RATE YEAR 3				
1. TARGET BASE REVENUE - 2023 - RATE YEAR 3 (a)	$ 368,520,338			
2. ADD: RATE YEAR 1 REVENUE INCREASE	$ -			
3. ADD: RATE YEAR 2 REVENUE INCREASE	$ -			
4. LESS: RATE YEAR 3 CUSTOMER CHARGE REVENUES	112,389,000			
5. RATE YEAR 3 DELIVERY CHARGE REVENUE	$ 256,131,338	GAC REVENUE	$ 6,425,038	
6. DIVIDED BY: RATE YEAR 3 BILLING DETERMINANTS - THERMS	445,102,435	THERMS	445,102,435	
7. DELIVERY CHARGE INCLUDING MONTHLY RATE ADJUSTMENT	$ 0.5754	AVG RATE	$ 0.0144	
8. RATE YEAR 2 DELIVERY RATE	$ 0.5904			
9. RATE YEAR 3 RIDER 8 ADJUSTMENT	$ (0.0150)			
10. $ PER THERM	$ (0.0150)		$ 0.0144	$ (0.0006)

SCHEDULE C - GENERAL SERVICE

RATE YEAR 1

1. TARGET BASE REVENUE - 2021 - RATE YEAR 1 (a)	$ 144,612,492			
2. LESS: RATE YEAR 1 CUSTOMER CHARGE REVENUE & INFO FEES	19,561,418			
3. RATE YEAR 1 DELIVERY CHARGE REVENUE	$ 125,051,074	GAC REVENUE	$ 1,476,506	
4. DIVIDED BY: RATE YEAR 1 BILLING DETERMINANTS - THERMS	301,813,768	THERMS	301,813,768	
5. DELIVERY CHARGE INCLUDING MONTHLY RATE ADJUSTMENT	$ 0.4143	AVG RATE	$ 0.0049	
6. DELIVERY RATE EXCLUDING MONTHLY RATE ADJUSTMENT	$ 0.4052			
7. RIDER 8 EFFECTIVE RATE	$ 0.0091			
8. $ PER THERM	$ 0.0091		$ 0.0049	$ 0.0140

FIRST 10,000 THERMS	235,858,360	$ 0.4541	$ 107,103,281
ALL OVER 10,000 THERMS	65,955,409	$ 0.2304	$ 15,196,126
	301,813,768	$ 0.4052	$ 122,299,407

RATE YEAR 2

1. TARGET BASE REVENUE - 2022 - RATE YEAR 2 (a)	$ 144,846,980			
2. ADD: RATE YEAR 1 REVENUE INCREASE	-			
3. LESS: RATE YEAR 2 CUSTOMER CHARGE REVENUE & INFO FEES	19,626,102			
4. RATE YEAR 2 DELIVERY CHARGE REVENUE	$ 125,220,878	GAC REVENUE	$ 1,476,506	
5. DIVIDED BY: RATE YEAR 2 BILLING DETERMINANTS - THERMS	301,695,871	THERMS	301,695,871	
6. DELIVERY CHARGE INCLUDING MONTHLY RATE ADJUSTMENT	$ 0.4151	AVG RATE	$ 0.0049	
7. DELIVERY RATE EXCLUDING MONTHLY RATE ADJUSTMENT	$ 0.4192			
8. RIDER 8 EFFECTIVE RATE	$ (0.0041)			
9. $ PER THERM	$ (0.0041)		$ 0.0049	$ 0.0008

FIRST 10,000 THERMS	235,721,694	$ 0.4681	$ 110,341,325
ALL OVER 10,000 THERMS	65,974,177	$ 0.2444	$ 16,124,089
	301,695,871	$ 0.4192	$ 126,465,414

RATE YEAR 3

1. TARGET BASE REVENUE - 2023 - RATE YEAR 3 (a)	$ 145,081,468			
2. ADD: RATE YEAR 1 REVENUE INCREASE	-			
2. ADD: RATE YEAR 2 REVENUE INCREASE	$ -			
3. LESS: RATE YEAR 3 CUSTOMER CHARGE REVENUE & INFO FEES	19,690,786			
4. RATE YEAR 3 DELIVERY CHARGE REVENUE	$ 125,390,682	GAC REVENUE	$ 1,476,506	
5. DIVIDED BY: RATE YEAR 3 BILLING DETERMINANTS - THERMS	300,957,714	THERMS	300,957,714	
6. DELIVERY CHARGE INCLUDING MONTHLY RATE ADJUSTMENT	$ 0.4166	AVG RATE	$ 0.0049	
7. DELIVERY RATE EXCLUDING MONTHLY RATE ADJUSTMENT	$ 0.4201			
8. RIDER 8 EFFECTIVE RATE	$ (0.0035)			
9. $ PER THERM	$ (0.0035)		$ 0.0049	$ 0.0014

FIRST 10,000 THERMS	235,237,335	$ 0.4689	$ 110,302,786
ALL OVER 10,000 THERMS	65,720,379	$ 0.2452	$ 16,114,637
	300,957,714	$ 0.4201	$ 126,417,423

(a) Based on Case No. 9610 Rider 8 targets.

BALTIMORE GAS AND ELECTRIC COMPANY

CALCULATION OF OPTIONAL FIRM DELIVERY SERVICE PRICE (OFDS) AND INTERRUPTION PENALTY PRICE WHEN A CUSTOMER USES GAS DURING AN INTERRUPTION

RATE YEAR 3 - 2023

	Schedule IS	Schedule ISS	Schedule EG
1. Total Class Demand Revenue (a)	$ 13,597,276	$ 1,011,389	$ 2,751,082
2. Divided By Total Class Volume (a)	185,186,010	9,063,190	37,769,921
3. Effective Demand Rate per therm	$ 0.0734	$ 0.1116	$ 0.0728
4. Schedule C First Block Rate (b)	$ 0.5605	$ 0.5605	$ 0.5605
5. Less Delivery Price (a)	$ 0.0808	$ 0.1405	$ 0.0843
6. Less Effective Demand Rate	$ 0.0734	$ 0.1116	$ 0.0728
7. First Block OFDS Rate per therm	$ 0.4063	$ 0.3084	$ 0.4034
8. Schedule C Second Block Rate (b)	$ 0.2942	$ 0.2942	$ 0.2942
9. Less Delivery Price (a)	$ 0.0808	$ 0.1405	$ 0.0843
10. Less Effective Demand Rate	$ 0.0734	$ 0.1116	$ 0.0728
11. Second Block OFDS Rate per therm	$ 0.1400	$ 0.0421	$ 0.1371
12. Interruption Penalty Price per therm (Line 7 x 1.5)	$ 0.6095	$ 0.4626	$ 0.6051
13. Excessive Use Interruption Penalty Price per therm (Line 7 x 2)	$ 0.8126	$ 0.6168	$ 0.8068

(a) Data from G-6, G-7 and G-8 for Schedules IS, ISS, and EG respectively
(b) Data from G-5 - Schedule C

BALTIMORE GAS AND ELECTRIC COMPANY
COMPARISON OF BILLS FOR
CURRENT VERSUS PROPOSED RATES
SCHEDULE D - RESIDENTIAL SERVICE
RATE YEAR 1 - 2021

		CURRENT RATES	PROPOSED RATE YEAR 1 RATES	
Gas Supply		**$ 0.4068**	**$ 0.4068**	** shown on bill*
Monthly Commodity Rate	per therm	$ 0.3868	$ 0.3868	
Gas Administrative Charge	per therm	$ 0.0200	$ 0.0200	** included as part of the monthly commodity rate*
Delivery				
Customer Charge (Schedule D)	per month	**$ 14.25**	**$ 14.25**	** shown on bill*
EmPOWER MD Chg (Rider 1)	per therm	**$ 0.0447**	**$ 0.0447**	** shown on bill*
STRIDE Charge	per month	**$ 1.03**	**$ 1.03**	** shown on bill*
Distribution Chg		**$ 0.5952**	**$ 0.5952**	** shown on bill*
Base Distribution Charge (Schedule D)	per therm	$ 0.5921	$ 0.5921	
Gas Choice & Reliability Charge (Rider 7)	per therm	$ 0.0031	$ 0.0031	
Taxes & Surcharges				
Franchise Tax	per therm	**$ 0.00402**	**$ 0.00402**	** shown on bill*

CUSTOMER PERCENTILE	MONTHLY THERMS	BILL AT CURRENT RATES	BILL AT PROPOSED RATES	CHANGE IN BILL	PERCENT CHANGE IN BILL
	10	$25.79	$25.79	$0.00	0.00%
	15	$31.04	$31.04	$0.00	0.00%
25th Percentile	20	$36.29	$36.29	$0.00	0.00%
	25	$41.55	$41.55	$0.00	0.00%
	30	$46.80	$46.80	$0.00	0.00%
	35	$52.06	$52.06	$0.00	0.00%
	40	$57.31	$57.31	$0.00	0.00%
50th Percentile	45	$62.56	$62.56	$0.00	0.00%
Average (Mean)	56	$74.12	$74.12	$0.00	0.00%
	60	$78.32	$78.32	$0.00	0.00%
75th Percentile	69	$87.78	$87.78	$0.00	0.00%
	70	$88.83	$88.83	$0.00	0.00%
	80	$99.34	$99.34	$0.00	0.00%
	90	$109.84	$109.84	$0.00	0.00%
	100	$120.35	$120.35	$0.00	0.00%
	150	$172.89	$172.89	$0.00	0.00%
	200	$225.42	$225.42	$0.00	0.00%
	250	$277.96	$277.96	$0.00	0.00%
	300	$330.50	$330.50	$0.00	0.00%
	350	$383.03	$383.03	$0.00	0.00%
	400	$435.57	$435.57	$0.00	0.00%
	450	$488.10	$488.10	$0.00	0.00%
	500	$540.64	$540.64	$0.00	0.00%
	550	$593.18	$593.18	$0.00	0.00%
	600	$645.71	$645.71	$0.00	0.00%

BALTIMORE GAS AND ELECTRIC COMPANY
COMPARISON OF BILLS FOR
CURRENT VERSUS PROPOSED RATES
SCHEDULE D - RESIDENTIAL SERVICE
RATE YEAR 2 - 2022

		CURRENT RATES	PROPOSED RATE YEAR 2 RATES	
Gas Supply		**$ 0.4068**	**$ 0.4068**	** shown on bill*
Monthly Commodity Rate	per therm	$ 0.3868	$ 0.3868	
Gas Administrative Charge	per therm	$ 0.0200	$ 0.0200	** included as part of the monthly commodity rate*
Delivery				
Customer Charge (Schedule D)	per month	**$ 14.25**	**$ 14.25**	** shown on bill*
EmPOWER MD Chg (Rider 1)	per therm	**$ 0.0447**	**$ 0.0447**	** shown on bill*
STRIDE Charge	per month	**$ 2.00**	**$ 2.00**	** shown on bill*
Distribution Chg		**$ 0.5935**	**$ 0.5935**	** shown on bill*
Base Distribution Charge (Schedule D)	per therm	$ 0.5904	$ 0.5904	
Gas Choice & Reliability Charge (Rider 7)	per therm	$ 0.0031	$ 0.0031	
Taxes & Surcharges				
Franchise Tax	per therm	**$ 0.00402**	**$ 0.00402**	** shown on bill*

CUSTOMER PERCENTILE	MONTHLY THERMS	BILL AT CURRENT RATES	BILL AT PROPOSED RATES	CHANGE IN BILL	PERCENT CHANGE IN BILL
	10	$26.74	$26.74	$0.00	0.00%
	15	$31.99	$31.99	$0.00	0.00%
25th Percentile	20	$37.23	$37.23	$0.00	0.00%
	25	$42.48	$42.48	$0.00	0.00%
	30	$47.72	$47.72	$0.00	0.00%
	35	$52.97	$52.97	$0.00	0.00%
	40	$58.21	$58.21	$0.00	0.00%
50th Percentile	45	$63.46	$63.46	$0.00	0.00%
Average (Mean)	56	$75.00	$75.00	$0.00	0.00%
	60	$79.19	$79.19	$0.00	0.00%
75th Percentile	69	$88.63	$88.63	$0.00	0.00%
	70	$89.68	$89.68	$0.00	0.00%
	80	$100.17	$100.17	$0.00	0.00%
	90	$110.66	$110.66	$0.00	0.00%
	100	$121.15	$121.15	$0.00	0.00%
	150	$173.60	$173.60	$0.00	0.00%
	200	$226.05	$226.05	$0.00	0.00%
	250	$278.51	$278.51	$0.00	0.00%
	300	$330.96	$330.96	$0.00	0.00%
	350	$383.41	$383.41	$0.00	0.00%
	400	$435.86	$435.86	$0.00	0.00%
	450	$488.31	$488.31	$0.00	0.00%
	500	$540.76	$540.76	$0.00	0.00%
	550	$593.21	$593.21	$0.00	0.00%
	600	$645.66	$645.66	$0.00	0.00%

BALTIMORE GAS AND ELECTRIC COMPANY
COMPARISON OF BILLS FOR
CURRENT VERSUS PROPOSED RATES
SCHEDULE D - RESIDENTIAL SERVICE
RATE YEAR 3 - 2023

		CURRENT RATES	PROPOSED RATE YEAR 3 RATES	
Gas Supply		**$ 0.4068**	**$ 0.4068**	** shown on bill*
Monthly Commodity Rate	per therm	$ 0.3868	$ 0.3868	
Gas Administrative Charge	per therm	$ 0.0200	$ 0.0200	** included as part of the monthly commodity rate*
Delivery				
Customer Charge (Schedule D)	per month	**$ 14.25**	**$ 15.25**	** shown on bill*
EmPOWER MD Chg (Rider 1)	per therm	**$ 0.0447**	**$ 0.0447**	** shown on bill*
STRIDE Charge	per month	**$ 2.00**	**$ 2.00**	** shown on bill*
Distribution Chg		**$ 0.5929**	**$ 0.7185**	** shown on bill*
Base Distribution Charge (Schedule D)	per therm	$ 0.5898	$ 0.7154	
Gas Choice & Reliability Charge (Rider 7)	per therm	$ 0.0031	$ 0.0031	
Taxes & Surcharges				
Franchise Tax	per therm	**$ 0.00402**	**$ 0.00402**	** shown on bill*

CUSTOMER PERCENTILE	MONTHLY THERMS	BILL AT CURRENT RATES	BILL AT PROPOSED RATES	CHANGE IN BILL	PERCENT CHANGE IN BILL
	10	$26.73	$28.99	$2.26	8.45%
	15	$31.98	$34.86	$2.88	9.01%
25th Percentile	20	$37.22	$40.73	$3.51	9.43%
	25	$42.46	$46.60	$4.14	9.75%
	30	$47.70	$52.47	$4.77	10.00%
	35	$52.94	$58.34	$5.40	10.20%
	40	$58.19	$64.21	$6.02	10.35%
50th Percentile	45	$63.43	$70.08	$6.65	10.48%
Average (Mean)	56	$74.96	$83.00	$8.04	10.73%
	60	$79.16	$87.69	$8.53	10.78%
75th Percentile	69	$88.59	$98.26	$9.67	10.92%
	70	$89.64	$99.43	$9.79	10.92%
	80	$100.12	$111.17	$11.05	11.04%
	90	$110.61	$122.91	$12.30	11.12%
	100	$121.09	$134.65	$13.56	11.20%
	150	$173.51	$193.35	$19.84	11.43%
	200	$225.93	$252.05	$26.12	11.56%
	250	$278.36	$310.76	$32.40	11.64%
	300	$330.78	$369.46	$38.68	11.69%
	350	$383.20	$428.16	$44.96	11.73%
	400	$435.62	$486.86	$51.24	11.76%
	450	$488.04	$545.56	$57.52	11.79%
	500	$540.46	$604.26	$63.80	11.80%
	550	$592.88	$662.96	$70.08	11.82%
	600	$645.30	$721.66	$76.36	11.83%
Annual Average Change Over MYP				**$ 2.68**	**3.6%**

BALTIMORE GAS AND ELECTRIC COMPANY
COMPARISON OF BILLS FOR
CURRENT VERSUS PROPOSED RATES
SCHEDULE C - GENERAL SERVICE
RATE YEAR 1- 2021

		CURRENT RATES	PROPOSED RATES	
Gas Supply		**$ 0.4068**	**$ 0.4068**	** shown on bill*
Monthly Commodity Rate	per therm	$ 0.3868	$ 0.3868	
Gas Administrative Charge	per therm	$ 0.0200	$ 0.0200	** included as part of the monthly commodity rate*
Delivery				
Customer Charge (Schedule C)	per month	**$ 36.30**	**$ 36.30**	** shown on bill*
STRIDE Charge	per therm	**$ 6.12**	**$ 6.12**	** shown on bill*
Distribution Charge 1st 10,000 therms		**$ 0.4752**	**$ 0.4752**	** shown on bill*
Distribution Charge > 10,000 therms		**$ 0.2515**	**$ 0.2515**	** shown on bill*
Base Distribution Charge 1st 10,000 therms	per therm	$ 0.4681	$ 0.4681	
Base Distribution Charge > 10,000 therms	per therm	$ 0.2444	$ 0.2444	
Gas Choice & Reliability Charge (Rider 7)	per therm	$ 0.0031	$ 0.0031	
Taxes & Surcharges				
Franchise Tax	per therm	**$ 0.00402**	**$ 0.00402**	** shown on bill*

	MONTHLY USE (THERMS)	BILL AT CURRENT RATES	BILL AT PROPOSED RATES	CHANGE IN BILL	PERCENT CHANGE IN BILL
	100	$131.02	$131.02	$0.00	0.00%
	200	$219.63	$219.63	$0.00	0.00%
	300	$308.23	$308.23	$0.00	0.00%
	400	$396.84	$396.84	$0.00	0.00%
	500	$485.44	$485.44	$0.00	0.00%
Average (Mean)	567	$544.80	$544.80	$0.00	0.00%
	750	$706.95	$706.95	$0.00	0.00%
	1,000	$928.46	$928.46	$0.00	0.00%
	4,000	$3,586.58	$3,586.58	$0.00	0.00%
	7,500	$6,687.72	$6,687.72	$0.00	0.00%
	10,000	$8,902.82	$8,902.82	$0.00	0.00%
	14,000	$11,552.18	$11,552.18	$0.00	0.00%
	25,000	$18,837.92	$18,837.92	$0.00	0.00%
	50,000	$35,396.42	$35,396.42	$0.00	0.00%
	75,000	$51,954.92	$51,954.92	$0.00	0.00%
	100,000	$68,513.42	$68,513.42	$0.00	0.00%
	125,000	$85,071.92	$85,071.92	$0.00	0.00%
	150,000	$101,630.42	$101,630.42	$0.00	0.00%
	160,000	$108,253.82	$108,253.82	$0.00	0.00%

BALTIMORE GAS AND ELECTRIC COMPANY
COMPARISON OF BILLS FOR
CURRENT VERSUS PROPOSED RATES
SCHEDULE C - GENERAL SERVICE
RATE YEAR 2- 2022

		CURRENT RATES	PROPOSED RATES	
Gas Supply		**$ 0.4068**	**$ 0.4068**	** shown on bill*
Monthly Commodity Rate	per therm	$ 0.3868	$ 0.3868	
Gas Administrative Charge	per therm	$ 0.0200	$ 0.0200	** included as part of the monthly commodity rate*
Delivery				
Customer Charge (Schedule C)	per month	**$ 36.30**	**$ 36.30**	** shown on bill*
STRIDE Charge	per therm	**$ 11.61**	**$ 11.61**	** shown on bill*
Distribution Charge 1st 10,000 therms		**$ 0.4760**	**$ 0.4760**	** shown on bill*
Distribution Charge > 10,000 therms		**$ 0.2523**	**$ 0.2523**	** shown on bill*
Base Distribution Charge 1st 10,000 therms	per therm	$ 0.4689	$ 0.4689	
Base Distribution Charge > 10,000 therms	per therm	$ 0.2452	$ 0.2452	
Gas Choice & Reliability Charge (Rider 7)	per therm	$ 0.0031	$ 0.0031	
Taxes & Surcharges				
Franchise Tax	per therm	**$ 0.00402**	**$ 0.00402**	** shown on bill*

	MONTHLY USE (THERMS)	BILL AT CURRENT RATES	BILL AT PROPOSED RATES	CHANGE IN BILL	PERCENT CHANGE IN BILL
	100	$136.59	$136.59	$0.00	0.00%
	200	$225.28	$225.28	$0.00	0.00%
	300	$313.96	$313.96	$0.00	0.00%
	400	$402.65	$402.65	$0.00	0.00%
	500	$491.33	$491.33	$0.00	0.00%
Average (Mean)	564	$548.09	$548.09	$0.00	0.00%
	750	$713.04	$713.04	$0.00	0.00%
	1,000	$934.75	$934.75	$0.00	0.00%
	4,000	$3,595.27	$3,595.27	$0.00	0.00%
	7,500	$6,699.21	$6,699.21	$0.00	0.00%
	10,000	$8,916.31	$8,916.31	$0.00	0.00%
	14,000	$11,568.87	$11,568.87	$0.00	0.00%
	25,000	$18,863.41	$18,863.41	$0.00	0.00%
	50,000	$35,441.91	$35,441.91	$0.00	0.00%
	75,000	$52,020.41	$52,020.41	$0.00	0.00%
	100,000	$68,598.91	$68,598.91	$0.00	0.00%
	125,000	$85,177.41	$85,177.41	$0.00	0.00%
	150,000	$101,755.91	$101,755.91	$0.00	0.00%
	160,000	$108,387.31	$108,387.31	$0.00	0.00%

BALTIMORE GAS AND ELECTRIC COMPANY
COMPARISON OF BILLS FOR
CURRENT VERSUS PROPOSED RATES
SCHEDULE C - GENERAL SERVICE
RATE YEAR 3- 2023

		CURRENT RATES	PROPOSED RATES	
Gas Supply		**$ 0.4068**	**$ 0.4068**	** shown on bill*
Monthly Commodity Rate	per therm	$ 0.3868	$ 0.3868	
Gas Administrative Charge	per therm	$ 0.0200	$ 0.0200	** included as part of the monthly commodity rate*
Delivery				
Customer Charge (Schedule C)	per month	**$ 36.30**	**$ 38.00**	** shown on bill*
STRIDE Charge	per therm	**$ 11.61**	**$ 11.61**	** shown on bill*
Distribution Charge 1st 10,000 therms		**$ 0.4775**	**$ 0.5676**	** shown on bill*
Distribution Charge > 10,000 therms		**$ 0.2538**	**$ 0.3013**	** shown on bill*
Base Distribution Charge 1st 10,000 therms	per therm	$ 0.4704	$ 0.5605	
Base Distribution Charge > 10,000 therms	per therm	$ 0.2467	$ 0.2942	
Gas Choice & Reliability Charge (Rider 7)	per therm	$ 0.0031	$ 0.0031	
Taxes & Surcharges				
Franchise Tax	per therm	**$ 0.00402**	**$ 0.00402**	** shown on bill*

	MONTHLY USE (THERMS)	BILL AT CURRENT RATES	BILL AT PROPOSED RATES	CHANGE IN BILL	PERCENT CHANGE IN BILL
	100	$136.74	$147.45	$10.71	7.83%
	200	$225.58	$245.30	$19.72	8.74%
	300	$314.41	$343.14	$28.73	9.14%
	400	$403.25	$440.99	$37.74	9.36%
	500	$492.08	$538.83	$46.75	9.50%
Average (Mean)	561	$546.27	$598.51	$52.24	9.56%
	750	$714.17	$783.44	$69.27	9.70%
	1,000	$936.25	$1,028.05	$91.80	9.81%
	4,000	$3,601.27	$3,963.37	$362.10	10.05%
	7,500	$6,710.46	$7,387.91	$677.45	10.10%
	10,000	$8,931.31	$9,834.01	$902.70	10.11%
	14,000	$11,589.87	$12,682.57	$1,092.70	9.43%
	25,000	$18,900.91	$20,516.11	$1,615.20	8.55%
	50,000	$35,516.91	$38,319.61	$2,802.70	7.89%
	75,000	$52,132.91	$56,123.11	$3,990.20	7.65%
	100,000	$68,748.91	$73,926.61	$5,177.70	7.53%
	125,000	$85,364.91	$91,730.11	$6,365.20	7.46%
	150,000	$101,980.91	$109,533.61	$7,552.70	7.41%
	160,000	$108,627.31	$116,655.01	$8,027.70	7.39%
Annual Average Change Over MYP				**$17.41**	**3.2%**

BALTIMORE GAS AND ELECTRIC COMPANY
COMPARISON OF BILLS FOR
RATE YEAR 1 - 2021

GAS SCHEDULE D - RESIDENTIAL SERVICE

		CURRENT RATES	PROPOSED RATES	
Gas Supply		**$ 0.4068**	**$ 0.4068**	** shown on bill*
Monthly Commodity Rate	per therm	$ 0.3868	$ 0.3868	
Gas Administrative Charge	per therm	$ 0.0200	$ 0.0200	** included as part of the monthly commodity rate*
Delivery				
Customer Charge (Schedule D)	per month	**$ 14.25**	**$ 14.25**	** shown on bill*
EmPOWER MD Chg (Rider 1)	per therm	**$ 0.0447**	**$ 0.0447**	** shown on bill*
STRIDE Charge	per month	**$ 1.03**	**$ 1.03**	** shown on bill*
Distribution Chg		**$ 0.5952**	**$ 0.5952**	** shown on bill*
Base Distribution Charge (Schedule D)	per therm	$ 0.5921	$ 0.5921	
Gas Choice & Reliability Charge (Rider 7)	per therm	$ 0.0031	$ 0.0031	
Taxes & Surcharges				
Franchise Tax	per therm	**$ 0.00402**	**$ 0.00402**	** shown on bill*

ELECTRIC SCHEDULE R - RESIDENTIAL SERVICE

		CURRENT RATES	PROPOSED RATES	
Electric Supply		**$ 0.07371**	**$ 0.07371**	** shown on bill*
Delivery				
Customer Charge (Schedule R)	per month	**$ 8.00**	**$ 8.00**	** shown on bill*
EmPOWER MD Chg	per kWh	**$ 0.00830**	**$ 0.00830**	** shown on bill*
Energy Efficiency (Rider 2)	per kWh	$ 0.00466	$ 0.00466	
Peak Time Rebates (Rider 26)	per kWh	$ 0.00019	$ 0.00019	
Demand Response (Rider 15)	per kWh	$ 0.00345	$ 0.00345	
Distribution Chg	per kWh	**$ 0.03523**	**$ 0.03523**	** shown on bill*
Base Distribution Charge (Schedule R)	per kWh	$ 0.03651	$ 0.03651	
Administrative Cost Adjustment (Rider 10)	per kWh	$ (0.00128)	$ (0.00128)	
Taxes & Surcharges				
MD Universal Service Program	per month	**$ 0.32**	**$ 0.32**	** shown on bill*
Environmental Surcharge	per kWh	**#########**	**$ 0.000143**	** shown on bill*
Franchise Tax	per kWh	**$ 0.00062**	**$ 0.00062**	** shown on bill*

	MONTHLY VOLUMES	BILL AT CURRENT RATES	BILL AT PROPOSED RATES	CHANGE IN BILL	PERCENT CHANGE IN BILL
Average Gas Customer (Therms)	56	$74.12	$74.12	$0.00	0.00%
Electric Non-Heating Customer (kWh)	609	$80.18	$80.18	$0.00	0.00%
Average Total Bill		**$154.30**	**$154.30**	**$0.00**	**0.00%**

BALTIMORE GAS AND ELECTRIC COMPANY
COMPARISON OF BILLS FOR
RATE YEAR 2 - 2022

GAS SCHEDULE D - RESIDENTIAL SERVICE

		CURRENT RATES	PROPOSED RATES	
Gas Supply		**$ 0.4068**	**$ 0.4068**	** shown on bill*
Monthly Commodity Rate	per therm	$ 0.3868	$ 0.3868	
Gas Administrative Charge	per therm	$ 0.0200	$ 0.0200	** included as part of the monthly commodity rate*
Delivery				
Customer Charge (Schedule D)	per month	**$ 14.25**	**$ 14.25**	** shown on bill*
EmPOWER MD Chg (Rider 1)	per therm	**$ 0.0447**	**$ 0.0447**	** shown on bill*
STRIDE Charge	per month	**$ 2.00**	**$ 2.00**	** shown on bill*
Distribution Chg		**$ 0.5935**	**$ 0.5935**	** shown on bill*
Base Distribution Charge (Schedule D)	per therm	$ 0.5904	$ 0.5904	
Gas Choice & Reliability Charge (Rider 7)	per therm	$ 0.0031	$ 0.0031	
Taxes & Surcharges				
Franchise Tax	per therm	**$ 0.00402**	**$ 0.00402**	** shown on bill*

ELECTRIC SCHEDULE R - RESIDENTIAL SERVICE

		CURRENT RATES	PROPOSED RATES	
Electric Supply		**$ 0.07371**	**$ 0.07371**	** shown on bill*
Delivery				
Customer Charge (Schedule R)	per month	**$ 8.00**	**$ 8.00**	** shown on bill*
EmPOWER MD Chg	per kWh	**$ 0.00830**	**$ 0.00830**	** shown on bill*
Energy Efficiency (Rider 2)	per kWh	$ 0.00466	$ 0.00466	
Peak Time Rebates (Rider 26)	per kWh	$ 0.00019	$ 0.00019	
Demand Response (Rider 15)	per kWh	$ 0.00345	$ 0.00345	
Distribution Chg	per kWh	**$ 0.03505**	**$ 0.03505**	** shown on bill*
Base Distribution Charge (Schedule R)	per kWh	$ 0.03633	$ 0.03633	
Administrative Cost Adjustment (Rider 10)	per kWh	$ (0.00128)	$ (0.00128)	
Taxes & Surcharges				
MD Universal Service Program	per month	**$ 0.32**	**$ 0.32**	** shown on bill*
Environmental Surcharge	per kWh	**$ 0.00014**	**$ 0.00014**	** shown on bill*
Franchise Tax	per kWh	**$ 0.00062**	**$ 0.00062**	** shown on bill*

	MONTHLY VOLUMES	BILL AT CURRENT RATES	BILL AT PROPOSED RATES	CHANGE IN BILL	PERCENT CHANGE IN BILL
Average Gas Customer (Therms)	56	$75.00	$75.00	$0.00	0.00%
Electric Non-Heating Customer (kWh)	609	$80.07	$80.07	$0.00	0.00%
Average Total Bill		**$155.07**	**$155.07**	**$0.00**	**0.00%**

BALTIMORE GAS AND ELECTRIC COMPANY
COMPARISON OF BILLS FOR
RATE YEAR 3 - 2023

GAS SCHEDULE D - RESIDENTIAL SERVICE

		CURRENT RATES	PROPOSED RATES	
Gas Supply		**$ 0.4068**	**$ 0.4068**	** shown on bill*
Monthly Commodity Rate	per therm	$ 0.3868	$ 0.3868	
Gas Administrative Charge	per therm	$ 0.0200	$ 0.0200	** included as part of the monthly commodity rate*
Delivery				
Customer Charge (Schedule D)	per month	**$ 14.25**	**$ 15.25**	** shown on bill*
EmPOWER MD Chg (Rider 1)	per therm	**$ 0.0447**	**$ 0.0447**	** shown on bill*
STRIDE Charge	per month	**$ 2.00**	**$ 2.00**	** shown on bill*
Distribution Chg		**$ 0.5929**	**$ 0.7185**	** shown on bill*
Base Distribution Charge (Schedule D)	per therm	$ 0.5898	$ 0.7154	
Gas Choice & Reliability Charge (Rider 7)	per therm	$ 0.0031	$ 0.0031	
Taxes & Surcharges				
Franchise Tax	per therm	**$ 0.00402**	**$ 0.00402**	** shown on bill*

ELECTRIC SCHEDULE R - RESIDENTIAL SERVICE

		CURRENT RATES	PROPOSED RATES	
Electric Supply		**$ 0.07371**	**$ 0.07371**	** shown on bill*
Delivery				
Customer Charge (Schedule R)	per month	**$ 8.00**	**$ 9.00**	** shown on bill*
EmPOWER MD Chg	per kWh	**$ 0.00830**	**$ 0.00830**	** shown on bill*
Energy Efficiency (Rider 2)	per kWh	$ 0.00466	$ 0.00466	
Peak Time Rebates (Rider 26)	per kWh	$ 0.00019	$ 0.00019	
Demand Response (Rider 15)	per kWh	$ 0.00345	$ 0.00345	
Distribution Chg	per kWh	**$ 0.03493**	**$ 0.04122**	** shown on bill*
Base Distribution Charge (Schedule R)	per kWh	$ 0.03651	$ 0.04250	
Administrative Cost Adjustment (Rider 10)	per kWh	$ (0.00128)	$ (0.00128)	
Taxes & Surcharges				
MD Universal Service Program	per month	**$ 0.32**	**$ 0.32**	** shown on bill*
Environmental Surcharge	per kWh	**$ 0.00014**	**$ 0.00014**	** shown on bill*
Franchise Tax	per kWh	**$ 0.00062**	**$ 0.00062**	** shown on bill*

	MONTHLY VOLUMES	BILL AT CURRENT RATES	BILL AT PROPOSED RATES	CHANGE IN BILL	PERCENT CHANGE IN BILL
Average Gas Customer (Therms)	56	$74.96	$83.00	$8.04	10.73%
Electric Non-Heating Customer (kWh)	609	$80.00	$84.83	$4.83	6.04%
Average Total Bill		**$154.96**	**$167.83**	**$12.87**	**8.31%**

Annual Average Change Over MYP				**$4.29**	**2.8%**

BALTIMORE GAS AND ELECTRIC COMPANY
PERCENT INCREASE IN CUSTOMERS' GAS BILLS
RATE YEAR 1 - 2021

	Total Gas Distribution Revenues from Customers' Gas Bills (a)	Total Sales Volumes (DTH) (b)	Total Estimated Gas Supply Charges (Volumes x Rate)	Customers' Total Gas Bills	Change in Gas Base Rate Revenues (Sheet G-1, Col. 1)	Percent Change in Customers' Gas Bills	Annual Number of Gas Bills	Average Monthly Bill Impact
	(1)	(2)	(3) = (2) x (rate (c))	(4) =(1) + (3)	(5)	(6) = (5) / (4)	(7)	(8) = (5) / (7)
1. SCHEDULE D	$ 396,437,355	43,632,897	$ 177,498,627	$ 573,935,982	$ -	0.0%	7,760,672	$ -
2. SCHEDULE C	$ 149,346,562	30,181,377	$ 122,777,841	$ 272,124,403	$ -	0.0%	532,736	$ -
3. SCHEDULE PLG	$ 24,435	-	$ -	$ 24,435	$ -	0.0%	2,517	$ -
4. SCHEDULE IS	$ 25,302,608	18,447,983	$ 75,046,394	$ 100,349,002	$ -	0.0%	1,013	$ -
5. SCHEDULE ISS	$ 2,337,534	889,123	$ 3,616,952	$ 5,954,486	$ -	0.0%	593	$ -
6. SCHEDULE EG	$ 6,197,644	3,786,347	$ 15,402,860	$ 21,600,504	$ -	0.0%	48	$ -
7. TOTAL	$ 579,646,137	$ 96,937,727	$ 394,342,674	$ 973,988,811	$ -	0.0%		

(a) Total gas distribution revenues include total gas base rate revenues, STRIDE surcharge revenues, and Gas Efficiency Charge revenues.

(b) Total sales volumes is equal to each schedule's Rate Year 1 delivery billing determinants.

(c) Total Estimated Gas Supply Charges: Schedule D, C, IS, ISS, and EG = Weighted Average of BGE Commodity Costs for Calendar Year 2019
$0.4068 per therm

BALTIMORE GAS AND ELECTRIC COMPANY
PERCENT INCREASE IN CUSTOMERS' GAS BILLS
RATE YEAR 2 - 2022

	Total Gas Distribution Revenues from Customers' Gas Bills (a)	Total Sales Volumes (DTH) (b)	Total Estimated Gas Supply Charges (Volumes x Rate)	Customers' Total Gas Bills	Change in Gas Base Rate Revenues (Sheet G-1, Col. 1)	Percent Change in Customers' Gas Bills	Annual Number of Gas Bills	Average Monthly Bill Impact
	(1)	(2)	(3) = (2) x (rate (c))	(4) =(1) + (3)	(5)	(6) = (5) / (4)	(7)	(8) = (5) / (7)
1. SCHEDULE D	$ 407,333,814.85	44,118,550	$ 179,474,261	$ 586,808,076	$ -	0.0%	7,823,810	$ -
2. SCHEDULE C	$ 152,538,624	30,169,587	$ 122,729,880	$ 275,268,504	$ -	0.0%	534,518	$ -
3. SCHEDULE PLG	$ 24,435	-	$ -	$ 24,435	$ -	0.0%	2,517	$ -
4. SCHEDULE IS	$ 25,783,281	18,409,694	$ 74,890,636	$ 100,673,917	$ -	0.0%	1,013	$ -
5. SCHEDULE ISS	$ 2,388,396	890,091	$ 3,620,891	$ 6,009,287	$ -	0.0%	593	$ -
6. SCHEDULE EG	$ 6,293,034.76	3,783,790	$ 15,392,459	$ 21,685,494	$ -	0.0%	48	$ -
7. TOTAL	$ 594,361,586	$ 97,371,713	$ 396,108,127	$ 990,469,713	$ -	0.0%		

(a) Total gas distribution revenues include total gas base rate revenues, STRIDE surcharge revenues, and Gas Efficiency Charge revenues.

(b) Total sales volumes is equal to each schedule's Rate Year 2 delivery billing determinants.

(c) Total Estimated Gas Supply Charges: Schedule D, C, IS, ISS, and EG = Weighted Average of BGE Commodity Costs for Calendar Year 2019
$0.4068 per therm

BALTIMORE GAS AND ELECTRIC COMPANY
PERCENT INCREASE IN CUSTOMERS' GAS BILLS
RATE YEAR 3 - 2023

	Total Gas Distribution Revenues from Customers' Gas Bills (a)	Total Sales Volumes (DTH) (b)	Total Estimated Gas Supply Charges (Volumes x Rate)	Customers' Total Gas Bills	Change in Gas Base Rate Revenues (Sheet G-1, Col. 1)	Percent Change in Customers' Gas Bills	Annual Number of Gas Bills	Average Monthly Bill Impact
	(1)	(2)	(3) = (2) x (rate (c))	(4) =(1) + (3)	(5)	(6) = (5) / (4)	(7)	(8) = (5) / (7)
1. SCHEDULE D	$ 410,580,390	44,510,244	$ 181,067,671	$ 591,648,061	$ 63,791,813	10.8%	7,886,947	$ 8.09
2. SCHEDULE C	$ 152,755,990	30,095,771	$ 122,429,598	$ 275,185,588	$ 25,258,407	9.2%	536,300	$ 47.10
3. SCHEDULE PLG	$ 24,435	-	$ -	$ 24,435	$ -	0.0%	2,517	$ -
4. SCHEDULE IS	$ 25,860,823	18,518,601	$ 75,333,669	$ 101,194,492	$ 5,438,557	5.4%	1,013	$ 5,366.55
5. SCHEDULE ISS	$ 2,407,707	906,319	$ 3,686,906	$ 6,094,613	$ 395,363	6.5%	593	$ 666.58
6. SCHEDULE EG	$ 6,287,304	3,776,992	$ 15,364,804	$ 21,652,108	$ -	0.0%	48	$ -
7. TOTAL	$ 597,916,649	$ 97,807,927	$ 397,882,648	$ 995,799,297	$ 94,884,140	9.5%		

(a) Total gas distribution revenues include total gas base rate revenues, STRIDE surcharge revenues, and Gas Efficiency Charge revenues.

(b) Total sales volumes is equal to each schedule's Rate Year 3 delivery billing determinants.

(c) Total Estimated Gas Supply Charges: Schedule D, C, IS, ISS, and EG = Weighted Average of BGE Commodity Costs for Calendar Year 2019
$0.4068 per therm

Annual Average Change Over MYP	**3.2%**

Company Exhibit LKF-5
Supplement 467
Filed: May 15, 2020
Effective: June 14, 2020

Gas Service Tariff
With Revision Markings

RESIDENTIAL SERVICE – GAS

SCHEDULE D

1. AVAILABILITY:

(a) For use for the domestic requirements of:
1. A single private dwelling.
2. An individually metered dwelling unit in a multiple dwelling building.
3. One combination of two dwelling units within a building, if served through a single meter.
4. A dwelling occupied as the dwelling place of a church divine or of religious associates engaged in church duties.
5. A single dwelling within a building where the occupant has not more than 10 bedrooms to let or not more than 10 table boarders, or a combination of not more than ten.

(b) For use, if on one property and served through a single meter, of a combination of the occupant's domestic requirements in a dwelling and his nondomestic requirements, provided that more than 50 percent of the connected load is for domestic purposes.

(c) For use, if served through a separate meter, by appliances used in common by the occupants of not more than two dwelling units within a building.

2. RATE TABLE:

Effective with service rendered on or after 12/17/2019
Customer Charge . . . .$14.25 per month, plus
Delivery Price (For all gas used) . . . . ~~.~~. . . .$0.5960 per therm

	Rate Year 1 Effective January 1, 2021	**Rate Year 2 Effective January 1, 2022**	**Rate Year 3 Effective January 1, 2023**
Customer Charge (per Month)	$14.25	$14.25	$15.25
Delivery Price ($/therm)	$0.5921	$0.5904	$0.7154

3. DELIVERY SERVICE:

Firm service transportation of gas through the Company's distribution system for all customers served under this Schedule.

Schedule D continued

5. GENERAL TERMS

5.1 Minimum Charge: Customer Charge

5.2 Late Payment Charge: Standard (Part 2, Sec. 7.5)

5.3 Payment Terms: Standard (Part 2, Sec. 7)

5.4 Term of Contract with BGE: The Customer's initial term of contract with BGE for Delivery Service is 1 year, and thereafter until terminated by at least 30 days notice from the Customer to BGE.

6. RIDERS APPLICABLE: This Schedule is subject to Riders applicable as listed below:

1. Gas Efficiency Charge
2. Gas Commodity Price
4. Budget Billing
5. Smart Meter Opt-Out
7. Gas Choice and Reliability Charges
8. Monthly Rate Adjustment
10. Billing in Event of Service Interruption
11. Unaccounted – For Gas Factor
12. Gas Administrative Charge
15. Multi-Year Plan ("MYP") Adjustment Rider
16. STRIDE (Strategic Infrastructure Development and Enhancement) Surcharge
17. Prepaid Pilot

GENERAL SERVICE – GAS

SCHEDULE C

1. AVAILABILITY:

For use for 3 or more dwelling units served within a building through a single meter and all other non-domestic firm service.

2. RATE TABLE:

Effective with service rendered on or after 12/17/2019

Customer Charge . . . .$ 36.30 per month, plus

Delivery Price:

First 10,000 therms . . . .$ 0.4541 per therm, plus

All Over . . . . $ 0.2304 per therm

	Rate Year 1 Effective January 1, 2021	**Rate Year 2 Effective January 1, 2022**	**Rate Year 3 Effective January 1, 2023**
Customer Charge (per Month)	$36.30	$36.30	$38.00
Delivery Price First 10,000 therms ($/therm)	$0.4681	$0.4689	$0.5605
Delivery Price All Over ($/therm)	$0.2444	$0.2452	$0.2942

For Daily-Metered customers

AMR Required . . . . .Estimated Installed Cost

Information Fee . . . . $65 per month, plus

Balancing Service Options:

Comprehensive Balancing Service ……………………… $0.0006 per therm

Self Balancing Option*:* The following Imbalance Prices apply*:*

Percent of Imbalance	Imbalance Price
0 to 3%	No Charge
Greater than 3% to 6%	$0.00393 per therm
Greater than 6% to 10%	$0.00524 per therm
Greater than 10% to 15%	$0.01048 per therm
Greater than 15%	$0.02096 per therm

3. DELIVERY SERVICE:

Firm service transportation of gas through the Company's distribution system for all customers served under this Schedule.

Schedule C continued

4. GAS COMMODITY SERVICE:

4.1 BGE Gas Commodity Service The sale of gas by BGE is provided under the provisions of Riders 2 and 12 – Gas Commodity Price and Gas Administrative Charge.

4.2 Supplier Gas Commodity Service: The Customer may elect to obtain Gas Commodity Service from a third party gas supplier subject to the following Terms and Conditions:

4.21 Terms and Conditions

(a) the Customer arranges for the transport and delivery of gas into the Company's distribution system at its interstate pipeline gate station(s); and

(b) the Customer may only contract with a gas supplier that has obtained a license from the Public Service Commission of Maryland and has separately contracted with the Company under the Gas Supplier Tariff. A Daily Metered Customer may elect to act as its own supplier under the provisions of the Gas Supplier Tariff. Service under this Schedule is provided only so long as the Customer's gas supplier remains a qualified gas supplier under the Gas Supplier Tariff. In the event that the Customer's gas supplier becomes disqualified, the Customer must obtain Gas Commodity Service from another qualified gas supplier or return to BGE Gas Commodity Service, if eligible; and

(c) the Customer shall select only one gas supplier for any period; and

(d) the Customer takes title to the gas at or before the Company's City Gate; and

(e) the transported gas is for the Customer's burner tip use and shall not be resold, except as an Accumulated Imbalance Corrective Measure as provided for in Section 4.254(d)(1) of this Schedule; and

(f) the Customer shall be responsible for the payment of any tax or assessment levied by any jurisdiction related to the acquisition, transportation or use of Transportation Gas.

4.22 Definitions:

(a) Daily-Metered Customer: A Supplier Gas Commodity Service Customer with annual use of 120,000 therms or greater, or with annual use greater than 90,000 therms but less than 120,000 therms who elects to have an AMR device installed.

(b) Transportation Gas: All gas to which the Customer takes title at or before the Company's City Gate.

(c) Daily Imbalance: The difference between the Customer's daily use and daily delivery of gas to the Company's City Gate.

(d) AMR: – an automated meter reading device suitable for daily interface between a Daily-Metered Customer and the Company's data collection and processing system.

(e) Gas Production Day: A Gas Day when the Company anticipates engaging in peak shaving activities. The Company will endeavor to notify the Non-Standby Service Customer of expected peak shaving activity.

(f) Gas Day: A 24-hour period beginning at 10:00 a.m. Eastern Time.

Schedule C continued

4.23 Telephone Line Responsibility*:* All customers not classified as Daily-Metered with annual use of 15,000 therms or greater are required to install and maintain a non-dedicated telephone line to the meter location. The Customer is required to maintain this telephone line in working order and is subject to the terms of Part 2, Sec. 4.11

4.24 Termination of Supplier Gas Commodity Service*:* Upon termination of Supplier Gas Commodity Service for any reason, the Customer is subject to Sec. 4.254(d) Accumulated Imbalance Corrective Measures of this Schedule and to the requirements of Sec. 4.255 – Standby Service and Non-Standby Service for Daily Metered Customers.

4.25 For Daily-Metered Customers:

4.251 Metering Equipment: An AMR owned and maintained by the Company suitable for daily interface with the Company's data collection and processing system is required. The Customer pays the estimated installed cost of the AMR, plus any additional facilities necessary, under the provisions of Part 2, Sec. 8.5. Sixty (60) days notice is required for installation of the AMR. Service under this Option will commence upon installation of the AMR.

4.252 Information Fee: All Customers with an AMR installed shall pay a monthly Information Fee of $65.

4.253 Failure of the Customer's Transportation Gas to arrive at the City Gate: Where all or part of the Customer's Transportation Gas fails to arrive at the Company's City Gate, the Customer is subject to Sec. 4.254(d) – Accumulated Imbalance Corrective Measures of this Schedule.

4.254 City Gate Balancing Services: The Company balances daily gas deliveries at the City Gate with unaccounted-for gas adjusted, burner tip use. Daily-Metered customers must select one of the Balancing Service Options. The prices for the components of Balancing Service are in addition to the monthly rates for Delivery Service and apply to the Customer's metered use.

(a) Balancing Service Options:

1. Comprehensive Balancing Service: Balancing of the gas delivered to the Company's City Gate on behalf of the Customer with the Customer's use of gas on a daily basis is performed by the Company. A Comprehensive Balancing Service Price is applied to all therms of gas used by the Customer adjusted to the Company's City Gate. The Customer also pays a pro rata share of any interstate gas pipeline penalties incurred based on the Customer's Daily Imbalance in the same direction as the Imbalance for which the penalty was incurred, unless the Customer is part of a Selective Group, and that Group is in balance.

Schedule C continued

6. RIDERS APPLICABLE: This Schedule is subject to Riders applicable as listed below:

2. Gas Commodity Price
3. Standby Service Price
4. Even Monthly Payment Plan
5. Smart Meter Opt-Out
7. Gas Choice and Reliability Charges
8. Monthly Rate Adjustment
9. Demonstration and Trial Installations
10. Billing in Event of Service Interruption
11. Unaccounted - For Gas Factor
12. Gas Administrative Charge
14. Economic Development
15. Multi Year Plan ("MYP") Adjustment Rider
16. STRIDE (Strategic Infrastructure Development and Enhancement) Surcharge

INTERRUPTIBLE LARGE VOLUME SERVICE -- GAS SCHEDULE IS

1. AVAILABILITY:

(a) Where the connected capacity of the Customer's gas-fired equipment is 250 therms per hour or greater, and

(b) where the Customer must interrupt their use of gas within 6 hours, or sooner if possible, following receipt of notice by the Company at any time of the day, and during any time of the year, and

(c) where "interrupt their use of gas" means that the Customer must reduce gas consumption to zero or to contracted Optional Firm Delivery Service (OFDS) levels, if any.

2. RATE TABLE:

~~Effective with service rendered on or after 12/17/2019~~

~~Customer Charge . . . . $1,250 per month, plus~~
~~Demand Price . . . . $ 0.8323 per therm~~
~~Delivery Price . . . . $ 0.0712 per therm~~

~~Distribution Interruption Penalty Price………………………..…….$0.4212 per therm~~
~~Excessive Use Distribution Interruption Penalty Price……………..…$0.5616 per therm~~

~~AMR Required…………………………………..Estimated Installed Cost~~
~~Information Fee………………………………….$65 per month~~

Optional Firm Delivery Service …OFDS Hourly Volume x 24 hours x Number of Days in Month x Optional Firm Delivery Price. The following rates will apply to OFDS volumes:

~~First 10,000 therms per month……………………………………..$0.3299 per therm~~
~~Over 10,000 therms per month……………………………………$0.1062 per therm~~

	Rate Year 1 Effective January 1, 2021	Rate Year 2 Effective January 1, 2022	Rate Year 3 Effective January 1, 2023
Customer Charge (per Month)	$1,250.00	$1,250.00	$1,250.00
Demand Price ($/therm)	$0.8323	$0.8323	$1.1314
Delivery Price ($/therm)	$0.0712	$0.0712	$0.0808
Distribution Interruption Penalty Price ($/therm)	$0.4212	$0.4212	$0.6095
Excessive Use Distribution Interruption Penalty Price ($/therm)	$0.5616	$0.5616	$0.8126
OFDS – First 10,000 ($/therm)	$0.3299	$0.3299	$0.4063
OFDS – Over 10,000 ($/therm)	$0.1062	$0.1062	$0.1400

AMR Required…………………………………..Estimated Installed Cost
Information Fee………………………………….$65 per month

Schedule IS continued

Comprehensive Balancing Option. . . . . $0.0006 per therm

Self Balancing Option: The following Imbalance Prices apply:

Percent of Imbalance	Imbalance Price
0 to 3%	No Charge
Greater than 3% to 6%	$0.00393 per therm
Greater than 6% to 10%	$0.00524 per therm
Greater than 10% to 15%	$0.01048 per therm
Greater than 15%	$0.02096 per therm

3. DELIVERY SERVICE:
Interruptible Service transportation of gas through the Company's distribution system for all Customers served under this Schedule.

3.1 Billing Demand:
The Customer's Billing Demand is the maximum winter day measured demand during the latest 12 month period adjusted to the nearest whole Dth. Measured demand is the Customer's total metered use of gas during the Gas Day beginning at 10:00 a.m. Eastern time. The winter period is the 5 months of November through March, inclusive.

3.2 Demand Free Day:
For a Customer taking service hereunder, the Company may at its option designate any Gas Day as "demand free." The designation, if any, will be made no later than 2 p.m., Eastern Time, of the day immediately preceding the Demand Free day. Any gas used during a Demand Free day will not be considered when determining a Customer's Billing Demand.

3.3 Optional Firm Delivery Service

(a) The Customer may contract for Optional Firm Delivery Service through meters served under this Schedule. This option allows the Customer to contract for a specific amount of firm distribution service available to interruptible customers during a distribution system interruption. The Company will not maintain interstate gas pipeline capacity to supply the Customer's OFDS requirements. The Customer must contract for a specific volume of OFDS on an hourly basis. The Company reserves the right to decline a request for new or an increase to OFDS should capacity not be available on the gas distribution system. However, the Customer may request a distribution system upgrade under the terms of Part 2, Section 8 to receive OFDS.
The OFDS rates are incremental to all existing IS tariff rates. The OFDS rates represent the effective difference between the existing IS rates and the Schedule C delivery prices.

(b) An existing Schedule IS Customer desiring OFDS volumes must contract for a specific hourly amount, at a specified meter, with the Company, and revise their request no later than July 31 to be effective November 1 through October 31. The initial term of contract for OFDS is 2 years. During the first year of the initial term, and before July 31, the Customer may revise their OFDS contract volume to no less than 50% of the original contract amount, or as high as needed, providing sufficient distribution capacity is available, to be effective November 1. Upon completion of the initial 2 year contract period, the contract will continue to automatically renew for 1

Schedule IS continued

year unless notified by the Customer by July 31. Following the first initial enrollment period, subsequent enrollment periods will have no limitations on the OFDS volumes, provided there is available distribution system capacity.

(c) A new Customer to Schedule IS may contract for OFDS upon commencement of interruptible service or at the next Enrollment Period. The 2 year initial contract timeframe will be determined to place the Customer on the November 1 to October 31 contract schedule.

(d) A Customer who fails two physical interruption tests may also contract for OFDS as described in Section 3.5.

(e) Schedule IS remains the controlling Schedule when a Customer contracts for OFDS.

3.4 Use of Gas During an Interruption:

(a) If a Customer does not contract for OFDS, the Customer must reduce their gas usage to zero during a distribution system interruption. OFDS, subject to Section 3.3 of this Schedule, is available during an interruption for distribution system reasons. Except as described below, if a Customer fails to reduce to zero usage or to OFDS levels during an interruption for distribution system reasons, the monthly Distribution Interruption Penalty will be assessed as follows: the average of the hourly non-compliant therms x 24 hours x number of days in the month x Distribution Interruption Penalty Price. The monthly Distribution Interruption Penalty will begin billing in May for a total of 12 months.

Customer's non-compliant usage is considered Excessive Use if, during any hour of a distribution system interruption, non-compliant usage exceeds 575 therms. The monthly Excessive Use Distribution Interruption Penalty will be assessed as follows: all non-compliant therms for that event x the number of days in the month x the Excessive Use Distribution Interruption Penalty Price. However, in the event a distribution system interruption is less than 24 hours, and the Customer's non-compliant usage is Excessive Use, the monthly Excessive Use Distribution Interruption Penalty will be calculated as the higher of:

(The average hourly non-compliant therms) x (24 hours) x (the number of days in the month) x (the Excessive Use Distribution Interruption Penalty Price)

Or

(All non-compliant therms) x (the number of days in the month) x (the Excessive Use Distribution Interruption Penalty Price).

The monthly Excessive Use Interruption Penalty will begin billing in May for a total of 12 months. Each interruption will be evaluated individually.

When multiple distribution interruptions occur during the 12 month period from May to April, the average hourly non-compliant therms from each interruption are billed cumulatively over the 12 months beginning in May. All revenue collected from the application of the Distribution Interruption Penalty Price and Excessive Use Distribution Interruption Penalty Price will be applied as a credit in the determination of the Rider 8 Monthly Rate Adjustment.

Schedule IS continued

(b) The Public Service Commission, upon the request of BGE or a Customer served under this Schedule, may choose to reduce or waive entirely the duration of the Distribution Interruption Penalty or the Excessive Use Distribution Interruption Penalty in Paragraph 3.4(a) for a Customer who demonstrates that a good faith effort was made to interrupt its gas usage as required under this Schedule and substantially reduced its usage during an interruption. The demonstration of a good faith effort shall include (1) efforts made prior to the interruption to be fully compliant; (2) the reason why full compliance was not attained, such as sudden failure of alternative fuel equipment; (3) efforts to correct non-compliance during the interruption; and (4) customer actions after the interruption to be fully compliant in the future. Usage above hourly OFDS levels during an interruption of more than 5% of the Customer's billing demand, for the specified meter, effective during the month of the interruption shall be prima facie evidence that the Customer did not make a good faith effort to comply with the interruption. However, any waiver or reduction of the Distribution Interruption Penalty or the Excessive Use Distribution Interruption Penalty shall consider the Customer's good faith efforts to interrupt its gas usage and may not be based solely on the extent to which the Customer actually reduced its gas usage. Any credits granted to Customers through the waiver process will also result in similar debits to Rider 8 – Monthly Rate Adjustment.

(c) All OFDS gas used by the Customer during an interruption for distribution system reasons, without a Gas Production Day, except the Customer's Transportation Gas, is billed at the higher of the Gas Commodity Price , or 110% of the highest Transco Zone 6 (non-New York) price for the current month. All OFDS gas used by the Customer during an interruption for distribution system reasons and a Gas Production Day, except the Customer's Transportation Gas, a $0.50 per therm penalty is added to the higher of the Gas Commodity Price, or 110% of the highest Transco Zone 6 (non-New York) price for the current month. Any penalty revenue will be treated as gas commodity revenue. For all gas used by the Customer, during an interruption, in excess of the OFDS volumes, even if the Customer's Transportation Gas arrives at BGE's City Gate, a $1.50 per therm penalty is added to the higher of the Gas Commodity Price or 110% of the highest Transco Zone 6 (non-New York) price for the current month. This penalty revenue will be allocated as follows: One-third of the penalty revenue will be treated as gas commodity revenue while the remaining two-thirds of the penalty will be applied as a credit in the determination of the Rider 8 – Monthly Rate Adjustment.

(d) If a Customer fails to interrupt its use of gas, and the Customer is unable to demonstrate items (1)-(4) as described in Paragraph 3.4(b), the Company, at its discretion, may take actions to ensure the future reliability of its distribution system. However, the Company may also take such actions if a Customer fails to interrupt its use of gas during two or more interruption events which are initiated within a period of 36 months. Such actions may include, but are not limited to, the termination of service to the Customer under this Schedule. Prior to the termination of service to the Customer under this Schedule becoming effective, BGE shall provide at least thirty (30) calendar days written notice to both the Customer and the Commission. In addition, the Company has the right to deny the Customer's request for interruptible service under any other schedule.

Schedule IS continued

This provision is not applicable during an actual gas interruption event during which a Customer has failed to interrupt as required under this Schedule. BGE may employ any actions necessary to address such failure to interrupt to ensure the continued reliability of the distribution system (see Paragraph 3.4(e)).

(e) Failure to interrupt may result in the immediate discontinuance of service without notice, under Part 2, Section 2.4 (k). If the Customer is disconnected from the distribution system, reconnection will be made when the cause for the interruption no

(f) In the event that a curtailment of supply is implemented under Part 2, Section 2.3, all gas used will be billed in accordance with Appendix A – Natural Gas Curtailment Plan, even if the Customer's Transportation Gas arrives at BGE's City Gate.

Schedule IS continued

thereto is not less than 50 therms per hour at any such location. Additional metering installations used for less than 1 year are subject to charges for installation and removal, less salvage, upon removal by the Company.

5.6 DEFINITIONS:

(a) Transportation Gas: All gas to which the Customer takes title at or before the Company's City Gate.
(b) Daily Imbalance: The difference between the Customer's daily use and daily delivery of Gas to the Company's City Gate.
(c) AMR: – an automated meter reading device suitable for daily interface between a Customer and the Company's data collection and processing system.
(d) Gas Production Day: A Gas Day when the Company anticipates engaging in peak shaving activities. The Company will endeavor to notify the Customer of expected peak shaving activity.
(e) Gas Day: A 24-hour period beginning at 10:00 a.m. Eastern Time.
(f) Non-Compliant Therms: Gas usage above contracted hourly OFDS volumes, if any, or all gas usage during a distribution system interruption if no contracted OFDS.
(g) Enrollment Period: The timeframe when a Customer may request an hourly volume for OFDS or cancel existing OFDS, which always ends on July 31.

5.7 METERING EQUIPMENT:

An AMR owned and maintained by the Company suitable for daily interface with the Company's data collection and processing system is required. The Customer pays the estimated installed cost of the AMR, plus any additional facilities necessary, under the provisions of Part 2, Sec. 8.5. Sixty (60) days notice is required for installation of the AMR. Service under this Option will commence upon installation of the AMR.

5.8 INFORMATION FEE:

All Customers served under this Schedule shall pay a monthly Information Fee of $65.

6. RIDERS APPLICABLE:

This Schedule is subject to Riders applicable as listed below:

9. Demonstration and Trial Installations
10. Billing in Event of Service Interruption
11. Unaccounted - For Gas Factor
14. Economic Development
15. Multi-Year Plan ("MYP") Adjustment Rider
16. STRIDE (Strategic Infrastructure Development and Enhancement) Surcharge

INTERRUPTIBLE SMALL VOLUME SERVICE -- GAS SCHEDULE ISS

1. AVAILABILITY:

(a) Where the connected capacity of the Customer's gas-fired equipment is at least 50 therms per hour and less than 250 therms per hour,

(b) where the Customer must interrupt their use of gas within 2 hours, or sooner if possible, following receipt of notice by the Company at any time of the day, and during any time of the year, and

(c) where "interrupt their use of gas" means that the Customer must reduce gas consumption to zero or to contracted Optional Firm Delivery Service (OFDS) levels, if any.

2. RATE TABLE:

Effective with service rendered on or after 12/17/2019

Customer Charge . . . . $363.50 per month, plus
Demand Price . . . . $ 1.0538 per therm
Delivery Price . . . . $ 0.1190 per therm

Distribution Interruption Penalty Price…………………………..…….$0.3026 per therm
Excessive Use Distribution Interruption Penalty Price……………..…$0.4034 per therm

~~AMR Required for Delivery Service. . . . . .Estimated Installed Cost~~
~~Information Fee if AMR installed. . . . . $65 per month~~

Optional Firm Delivery Service …OFDS Hourly Volume x 24 hours x Number of Days in Month x Optional Firm Delivery Price. The following rates will apply to OFDS volumes:

First 10,000 therms per month……………………………………..$0.2438 per therm
Over 10,000 therms per month…………………………………….$0.0201 per therm

	Rate Year 1 Effective January 1, 2021	Rate Year 2 Effective January 1, 2022	Rate Year 3 Effective January 1, 2023
Customer Charge (per Month)	$363.50	$363.50	$375.00
Demand Price ($/therm)	$1.0538	$1.0538	$1.2513
Delivery Price ($/therm)	$0.1190	$0.1190	$0.1405
Distribution Interruption Penalty Price ($/therm)	$0.3026	$0.3026	$0.4626
Excessive Use Distribution Interruption Penalty Price ($/therm)	$0.4034	$0.4034	$0.6168
OFDS – First 10,000 ($/therm)	$0.2438	$0.2438	$0.3084
OFDS – Over 10,000 ($/therm)	$0.0201	$0.0201	$0.0421

AMR Required for Delivery Service. . . . . .Estimated Installed Cost
Information Fee if AMR installed. . . . . $65 per month

Schedule ISS continued

Comprehensive Balancing Option. . . . .$0.0006 per therm

Self Balancing Option: The following Imbalance Prices apply:

Percent of Imbalance	Imbalance Price
0 to 3%	No Charge
Greater than 3% to 6%	$0.00393 per therm
Greater than 6% to 10%	$0.00524 per therm
Greater than 10% to 15%	$0.01048 per therm
Greater than 15%	$0.02096 per therm

3. DELIVERY SERVICE: Interruptible Service transportation of gas through the Company's distribution system for all Customers served under this Schedule.

3.1 Billing Demand: The Customer's Billing Demand is the maximum winter day measured demand during the latest 12 month period adjusted to the nearest whole Dth. Measured demand is the Customer's total metered use of gas during the Gas Day beginning at 10:00 a.m. Eastern time. The winter period is the 5 months of November through March, inclusive.

3.2 Demand Free Day: For a Customer taking service hereunder, the Company may at its option designate any Gas Day as "demand free". The designation, if any, will be made no later than 2 p.m., Eastern Time, of the day immediately preceding the Demand Free day. Any gas used during a Demand Free day will not be considered when determining a Customer's Billing Demand.

3.3 Optional Firm Delivery Service

(a) The Customer may contract for Optional Firm Delivery Service through meters served under this Schedule. This option allows the Customer to contract for a specific amount of firm distribution service available to interruptible customers during a distribution system interruption. The Company will not maintain interstate gas pipeline capacity to supply the Customer's OFDS requirements. The Customer must contract for a specific volume of OFDS on an hourly basis. The Company reserves the right to decline a request for new or an increase to OFDS should capacity not be available on the gas distribution system. However, the Customer may request a distribution system upgrade under the terms of Part 2, Section 8 to receive OFDS. The OFDS rates are incremental to all existing ISS tariff rates. The OFDS rates represent the effective difference between the existing ISS rates and the Schedule C delivery prices.

(b) An existing Schedule ISS Customer desiring OFDS volumes must contract for a specific hourly amount, at a specified meter, with the Company, and revise their request no later than July 31 to be effective November 1 through October 31. The initial term of contract for OFDS is 2 years. During the first year of the initial term, and before July 31, the Customer may revise their OFDS contract volume to no less than 50% of the original contract amount, or as high as needed, providing sufficient distribution capacity is available, to be effective November 1. Upon completion of the initial 2 year contract period, the contract will continue to automatically renew for 1 year unless notified by the Customer by July 31. Following the first initial enrollment period, subsequent enrollment periods will have no limitations on the OFDS volumes, provided there is available distribution system capacity.

Schedule ISS continued

(c) A new Customer to Schedule ISS may contract for OFDS upon commencement of interruptible service or at the next Enrollment Period. The 2 year initial contract timeframe will be determined to place the Customer on the November 1 to October 31 contract schedule.

(d) A Customer who fails two physical interruption tests may also contract for OFDS as described in Section 3.5.

(e) Schedule ISS remains the controlling Schedule when a Customer contracts for OFDS.

3.4 Use of Gas During an Interruption:

(a) If a Customer does not contract for OFDS, the Customer must reduce their gas usage to zero during a distribution system interruption. OFDS subject to Section 3.3 of this Schedule is available during an interruption for distribution system reasons. Except as described below, if a Customer fails to reduce to zero usage or to OFDS levels during an interruption for distribution system reasons, the monthly Distribution Interruption Penalty will be assessed as follows: the average of the hourly non-compliant therms x 24 hours x number of days in the month x Distribution Interruption Penalty Price . The monthly Distribution Interruption Penalty will begin billing in May for a total of 12 months.

Customer's non-compliant usage is considered Excessive Use if, during any hour of a distribution system interruption, non-compliant usage exceeds 575 therms. The monthly Excessive Use Distribution Interruption Penalty will be assessed as follows: all non-compliant therms for that event x the number of days in the month x the Excessive Use Distribution Interruption Penalty Price. However, in the event a distribution system interruption is less than 24 hours, and the Customer's non-compliant usage is Excessive Use, the monthly Excessive Use Distribution Interruption Penalty will be calculated as the higher of:

(The average hourly non-compliant therms) x (24 hours) x (the number of days in the month) x (the Excessive Use Distribution Interruption Penalty Price)

Or

(All non-compliant therms) x (the number of days in the month) x (the Excessive Use Distribution Interruption Penalty Price).

The monthly Excessive Use Interruption Penalty will begin billing in May for a total of 12 months. Each interruption will be evaluated individually.

When multiple distribution interruptions occur during the 12 month period from May to April, the average hourly non-compliant therms from each interruption are billed cumulatively over the 12 months beginning in May. All revenue collected from the application of the Distribution Interruption Penalty Price and the Excessive Use Distribution Interruption Penalty Price will be applied as a credit in the determination of the Rider 8 Monthly Rate Adjustment.

Schedule ISS continued

(b) The Public Service Commission, upon the request of BGE or a Customer served under this Schedule, may choose to reduce or waive entirely the duration of the Distribution Interruption Penalty or the Excessive Use Distribution Interruption Penalty in Paragraph 3.4(a) for a Customer who demonstrates that a good faith effort was made to interrupt its gas usage as required under this Schedule and substantially reduced its usage during an interruption. The demonstration of a good faith effort shall include (1) efforts made prior to the interruption to be fully compliant; (2) the reason why full compliance was not attained, such as sudden failure of alternative fuel equipment; (3) efforts to correct non-compliance during the interruption; and (4) customer actions after the interruption to be fully compliant in the future. Usage above hourly OFDS levels during an interruption of more than 5% of the Customer's billing demand, for the specified meter, effective during the month of the interruption shall be prima facie evidence that the Customer did not make a good faith effort to comply with the interruption. However, any waiver or reduction of the Distribution Interruption Penalty or the Excessive Use Distribution Interruption Penalty shall consider the Customer's good faith efforts to interrupt its gas usage and may not be based solely on the extent to which the Customer actually reduced its gas usage. Any credits granted to Customers through the waiver process will also result in similar debits to Rider 8 – Monthly Rate Adjustment.

(c) All OFDS gas used by the Customer during an interruption for distribution system reasons, without a Gas Production Day, except the Customer's Transportation Gas, is billed at the higher of the Gas Commodity Price , or 110% of the highest Transco Zone 6 (non-New York) price for the current month. All OFDS gas used by the Customer during an interruption for distribution system reasons and a Gas Production Day, except the Customer's Transportation Gas, a $0.50 per therm penalty is added to the higher of the Gas Commodity Price, or 110% of the highest Transco Zone 6 (non-New York) price for the current month. Any penalty revenue will be treated as gas commodity revenue. For all gas used by the Customer, during an interruption, in excess of the OFDS volumes, even if the Customer's Transportation Gas arrives at BGE's City Gate, a $1.50 per therm penalty is added to the higher of the Gas

Commodity Price or 110% of the highest Transco Zone 6 (non-New York) price for the current month. This penalty revenue will be allocated as follows: One-third of the penalty revenue will be treated as gas commodity revenue while the remaining two-thirds of the penalty will be applied as a credit in the determination of the Rider 8 – Monthly Rate Adjustment.

(d) If a Customer fails to interrupt its use of gas, and the Customer is unable to demonstrate items (1)-(4) as described in Paragraph 3.4(b), the Company, at its discretion, may take actions to ensure the future reliability of its distribution system.

However, the Company may also take such actions if a Customer fails to interrupt its use of gas during two or more interruption events which are initiated within a period of 36 months. Such actions may include, but are not limited to, the termination of service to the Customer under this Schedule. Prior to the termination of service to the Customer under this Schedule becoming effective, BGE shall provide at least thirty (30) calendar days written notice to both the Customer and the Commission. In addition, the Company has the right to deny the Customer's request for interruptible service under any other schedule.

Schedule ISS continued

This provision is not applicable during an actual gas interruption event during which a Customer has failed to interrupt as required under this Schedule. BGE may employ any actions necessary to address such failure to interrupt to ensure the continued reliability of the distribution system (see Paragraph 3.4(e)).

(e) Failure to interrupt may result in the immediate discontinuance of service without notice, under Part 2, Section 2.4 (k). If the Customer is disconnected from the distribution system, reconnection will be made when the cause for the interruption no longer exists subject to the Customer satisfying all requirements of the Gas Service Tariff.

(f) In the event that a curtailment of supply is implemented under Part 2, Section 2.3, all gas used will be billed in accordance with Appendix A – Natural Gas Curtailment Plan, even if the Customer's Transportation Gas arrives at BGE's City Gate.

Schedule ISS continued

(c) AMR: – an automated meter reading device suitable for daily interface between a Customer and the Company's data collection and processing system.

(d) Gas Production Day: A Gas Day when the Company anticipates engaging in peak shaving activities. The Company will endeavor to notify the Customer of expected peak shaving activity.

(e) Gas Day: A 24-hour period beginning at 10:00 a.m. Eastern Time.

(f) Non-Compliant Therms: Gas usage above contracted hourly OFDS volumes, if any, or all gas usage during a distribution system interruption if no contracted OFDS.

(g) Enrollment Period: The timeframe when a Customer may request an hourly volume for OFDS or cancel existing OFDS, which always ends on July 31.

5.7 METERING EQUIPMENT:

An AMR owned and maintained by the Company suitable for daily interface with the Company's data collection and processing system is required. The Customer pays the estimated installed cost of the AMR, plus any additional facilities necessary, under the provisions of Part 2, Sec. 8.5. Sixty (60) days notice is required for installation of the AMR. Service under this Option will commence upon installation of the AMR.

5.8 INFORMATION FEE:

All Customers served under this Schedule shall pay a monthly Information Fee of $65.

6. RIDERS APPLICABLE:

This Schedule is subject to Riders applicable as listed below:

9. Demonstration and Trial Installations
10. Billing in Event of Service Interruption
11. Unaccounted - For Gas Factor
14. Economic Development
15. Multi-Year Plan ("MYP") Adjustment Rate
16. STRIDE (Strategic Infrastructure Development and Enhancement) Surcharge

INTERRUPTIBLE GAS-FIRED ELECTRIC GENERATION SERVICE – GAS SCHEDULE EG

1. Availability:

1.1 Where the combined connected capacity of all Customer gas-fired generation equipment at the Customer's premise is 2,500 therms per hour or greater;

1.2 Where the Customer must comply with the Operational Availability and Communication requirements of Section 3.4 of this Schedule and the Distribution System Interruption Requirements of Section 3.5 of this Schedule;

1.3 Where the Customer must interrupt their use of gas immediately or within the timeframe indicated by the Company following receipt of notice by the Company at any time of the day, and during any time of the year, and

1.4 Where "interrupt their use of gas" means that the Customer must reduce gas consumption to zero or contracted Optional Firm Delivery Service (OFDS) levels, if any.

2. Rate Table

Effective with service rendered on or after 12/17/2019
Customer Charge . . . . $3,000 per month, plus
Demand Price . . . . $ 0.3546 per therm
Delivery Price . . . . $ 0.0843 per therm

Distribution Interruption Penalty Price……………………………..…….$0.4359 per therm
Excessive Use Distribution Interruption Penalty Price……………..…$0.5812 per therm

~~AMR Required…………………………………..Estimated Installed Cost~~
~~Information Fee…………………………………..$65 per month~~

Optional Firm Delivery Service …OFDS Hourly Volume x 24 hours x Number of Days in Month x Optional Firm Delivery Price. The following rates will apply to OFDS volumes:

First 10,000 therms per month…………………………………..$0.3299 per therm
Over 10,000 therms per month…………………………………..$0.1062 per therm

	Rate Year 1 Effective January 1, 2021	Rate Year 2 Effective January 1, 2022	Rate Year 3 Effective January 1, 2023
Customer Charge (per Month)	$3,000.00	$3,000.00	$3,000.00
Demand Price ($/therm)	$0.3546	$0.3546	$0.3546
Delivery Price ($/therm)	$0.0843	$0.0843	$0.0843
Distribution Interruption Penalty Price ($/therm)	$0.4359	$0.4359	$0.6051
Excessive Use Distribution Interruption Penalty Price ($/therm)	$0.5812	$0.5812	$0.8068
OFDS – First 10,000 ($/therm)	$0.3299	$0.3299	$0.4034
OFDS – Over 10,000 ($/therm)	$0.1062	$0.1062	$0.1371

AMR Required…………………………………..Estimated Installed Cost
Information Fee………………………………….$65 per month

Schedule EG continued

Comprehensive Balancing Option. . . . .$0.0006 per therm

Self-Balancing Option: The following Imbalance Prices apply:

Percent of Imbalance	Imbalance Price
0 to 3%	No Charge
Greater than 3% to 6%	$0.00393 per therm
Greater than 6% to 10%	$0.00524 per therm
Greater than 10% to 15%	$0.01048 per therm
Greater than 15%	$0.02096 per therm

3. Delivery Service: Interruptible Service transportation of gas through the Company's distribution system for all Customers served under this Schedule.

3.1 Billing Demand: The Customer's Billing Demand is the maximum winter day measured demand during the latest 12-month period adjusted to the nearest whole Dth. Measured demand is the Customer's total metered use of gas during the Gas Day beginning at 10:00 a.m. Eastern Prevailing Time. The winter period is the 5 months of November through March, inclusive.

3.3 Optional Firm Delivery Service

3.3.1 The Customer may contract for Optional Firm Delivery Service through meters served under this Schedule. This option allows the Customer to contract for a specific amount of firm distribution service available to interruptible gas-fired electric generation customers throughout the year and during a distribution system interruption. The Company will not maintain interstate gas pipeline capacity to supply the Customer's OFDS requirements. The Customer must contract for a specific volume of OFDS on an hourly basis. The Company reserves the right to decline a request, whether new or a requested increase to existing OFDS, should the Company determine capacity is not available on the gas distribution system. However, the Customer may request a distribution system upgrade under the terms of Part 2, Section 8 to receive OFDS.

The OFDS rates are incremental to all existing EG tariff rates. The OFDS rates represent the effective difference between the existing EG rates and the Schedule C delivery prices.

3.3.2 An existing Schedule EG Customer desiring OFDS volumes must contract for a specific hourly amount, at a specified meter, with the Company, and revise their request no later than July 31 to be effective November 1 through October 31. The initial term of contract for OFDS is 2 years. During the first year of the initial term, and before July 31, the Customer may revise their OFDS contract volume to no less than 50% of the original contract amount, or as high as needed, providing sufficient distribution capacity is available, to be effective November 1. Upon completion of the initial 2-year contract period, the contract will continue to automatically renew for 1 year unless notified by the Customer by July 31. Following the first initial enrollment period, subsequent enrollment periods will have no limitations on the OFDS volumes, provided there is available distribution system capacity.

Schedule EG continued

3.3.3 A new Customer to Schedule EG may contract for OFDS upon commencement of interruptible gas-fired electric generation service or at the next Enrollment Period. The 2 year initial contract timeframe will be determined in a manner such that the Customer is placed on the November 1 to October 31 contract schedule after the end of the initial 2 year contract timeframe.

3.3.4 A Customer who fails two physical interruption tests may contract for OFDS as described in Section 3.6.

3.3.5 Schedule EG remains the controlling Schedule when a Customer contracts for OFDS.

3.4 Operational Availability and Communication Requirements

3.4.1 The ability of a Customer to use gas at any time is dependent on operating conditions and system constraints. If a Customer's metered usage exceeds 20,000 therms per gas day or 2,500 therms in any given hour, the Customer is subject to comply with the Operational Availability and Communication Requirements outlined in this section.

3.4.2 Approval to operate electric generation equipment means that the Customer has conditional approval to use capacity in the Company's distribution system. The use of gas is subject to the Provisions in Section 4.2 of this Schedule. The Company may, at any time, rescind approval for the Customer to use gas.

The Customer must receive explicit approval from the Company before using gas. The lack of response from the Company is not an approval under any of the requests outlined in this section.

3.4.3 Operational Availability and Communication requirements are established on a seasonal basis. The winter period is November through March and the non-winter period is April through October.

3.4.4 Winter Period Requirements

3.4.4.1 Morning Day-Ahead Request - During the winter period, the Customer is required to submit an email request by 8:00 AM Eastern Prevailing Time to run for the following calendar day. The Company will provide a response by email to the Customer as soon as practical following reception of the request that confirms the receipt of the request. In addition, the Company will provide a substantive response by email to the Customer by 9:30 AM Eastern Prevailing Time and shall either conditionally approve the request to operate or deny the request to operate. Conditional approval may be in the form of approval of the original request, approval to use a reduced amount for the same or a reduced duration or approval to use the requested amount at a reduced duration, and may require delivery on a specified city gate/pipeline.

Schedule EG continued

The Customer shall provide the following information in the email requesting approval to operate:

(a) Gas-fired electric generating unit(s) that will run,

(b) Start time,

(c) Run time (duration),

(d) Usage by hour,

(e) Total gas usage,

(f) Interstate gas pipeline of gas delivery to the Company, and

(g) Any other information requested by the Company to evaluate the Customer's request for approval in order to maintain gas distribution system safety and reliability.

3.4.4.2 Afternoon Day-Ahead Confirmation – During the winter period, the Customer is also required to provide, to a Company prescribed email address by 3:00 PM Eastern Prevailing Time, an email confirming the original approved request or indicating requested changes to operate the following calendar day. The submission of an Afternoon Day-Ahead Confirmation that differs from the Morning Day-Ahead Request that will not be subject to penalty. The Company will provide a response by email to the Customer as soon as practical following reception of the request that confirms the receipt of the request. In addition, the Company will provide a substantive response by email to the Customer by 4:00 PM Eastern Prevailing Time and shall either conditionally confirm the original request, conditionally approve the modified request or deny the request to operate. Conditional approval may be in the form of approval of the original request, approval to use a reduced amount for the same or a reduced duration or approval to use the requested amount at a reduced duration, and may require delivery on a specified city gate/pipeline.

3.4.4.3 During the winter period, on the current gas or calendar day the Customer may submit a request to operate, via an email to the Company prescribed email address, even if conditional approval was not requested the prior day. The Customer shall provide as much notice as possible when making "day of" requests, but no less than thirty minutes prior to their planned start. The Customer shall provide in the email the same information required under Section 3.4.4.1 above. Within 15 minutes of the Customer's request, the Company will respond to the Customer approving, denying or stating that the Company requires additional time to evaluate the request and provide a time estimate thereof. Conditional approval may be in the form of approval of the original request, approval to use a reduced amount for the same or a reduced duration or approval to use the requested amount at a reduced duration.

Schedule EG continued

3.4.4.4 During the winter period, Customers who received conditional "day ahead" approval to operate shall make a confirming telephone call to the Company at least thirty minutes before and no more than two hours before beginning to use gas. When conditional approval is granted on the same day, and conditional approval is more than two hours in advance of beginning operations, the Customer shall make a confirming telephone call to the Company at least thirty minutes before beginning to use gas.

3.4.5 **Non-Winter Period Requirements**: During the non-winter period, the Customer shall provide, via email, a request to operate, with as much notice as possible, prior to starting to use gas and shall provide the same information as required under Section 3.4.4.1 when requesting approval to use gas, except that a Customer may request a range of usage by hour. The Company will respond by email within 15 minutes of the Customer's request approving, denying, or stating that the Company requires additional time to evaluate and provide a time estimate thereof. When conditional approval is granted more than two hours in advance, the Customer shall make a confirming telephone call to the Company at least thirty minutes before and no more than two hours before beginning to use gas.

3.4.6 For "day ahead" requests, if the Company determines there is not enough distribution system capacity available to approve every Customer request to operate under this Schedule, the Company will determine conditional approval based on gas system conditions and the Customer's position on the Daily priority list. The Daily priority list will be set by October 1st of each year by the Company. Capacity availability may be determined on a system-wide basis or specific to certain parts of the gas system. The Daily priority list will set the Customer's position for each day of the upcoming Winter season. The Daily priority list is only used to determine priority when there is not enough distribution system capacity available to serve all requests and does not imply approval to operate on any day. Conditional approval will be granted as described in paragraph 3.4.4.1.

"Day of" requests will be handled on a "first-come, first-served" basis when two or more customers request usage and all requests cannot be approved by the Company. "Day-of" requests will be made independent of the Daily priority list.

3.4.7 If there is a change that exceeds 2,500 therms per hour of the original approved usage in any given hour, the Customer is required to notify the Company first by phone followed by a confirming email. This excludes any changes during ramp up to full load at start-up or ramp down to shut-down within the times originally conditionally approved by the Company.

If a Customer's unit has ceased operation part-way through the original run time, the Customer shall immediately inform the Company by phone of the status of the gas-fired electric generating unit. If the Customer's unit plans to re-start outside the originally approved operating time frame, extend beyond the originally approved time frame, or there are changes to any of the other conditions approved by the Company, then the Customer shall email the information required under Section 3.4.4.1 and the request shall be treated as a new request to operate.

Schedule EG continued

3.4.8 Failure to comply with the Operational Availability and Communication requirements of Section 3.4 will result in a penalty to the Customer (incremental to any penalty assessed under Section 3.4.9). Instances of non-compliance within a rolling 24-month period will result in the following penalties being assessed:

First instance	$25,000 penalty
Second instance	$50,000 penalty,
Three or more instances	$100,000 penalty per instance.

With the third instance of non-compliance within a rolling 36-month period, the Company reserves the right to terminate service under this Schedule. Prior to termination of service to the Customer under this Schedule becoming effective, BGE shall provide at least thirty (30) calendar days written notice to both the Customer and the Public Service Commission. In addition, the Company has the right to deny the Customer's request for interruptible service under any other schedule. All revenue collected from the application of this penalty shall be applied as a credit in the determination of the Rider 8 Monthly Rate Adjustment.

3.4.9 If the Customer uses gas outside of a distribution system interruption in a manner that is not approved by the Company, the Excessive Use Distribution Interruption Penalty Price will be applied to all non-compliant gas used in addition to the Accumulated Imbalance Corrective Measures in Section 4.2.3.4. Additionally, BGE may employ any actions necessary to address a failure to comply with the provisions of this schedule to ensure the continued reliability of the distribution system. The monthly penalty will begin billing immediately for a total of 3 months. Each instance of noncompliance will be evaluated individually. All revenue collected from the application of this penalty shall be applied as a credit in the determination of the Rider 8 Monthly Adjustment. This penalty is also eligible for the waiver provisions outlined in Section 3.5.2 below. If such usage occurs during a distribution system interruption, the Excessive Use Distribution Penalty Price provisions described in Section 3.5.1 shall be applied once per event.

3.4.10 In addition to the certification requirement outlined in Section 3.6 below, the Customer's Authorized Facility Manager shall annually certify in writing that the Customer is familiar with all operational requirements for Schedule EG as described herein and all penalties associated with non-compliance. The Facility Manager shall also certify that each of their facilities/plants have procedures and policies in place to meet all requirements of this Schedule.

3.5 Use of Gas During an Interruption:

3.5.1 If a Customer does not contract for OFDS, the Customer must reduce their gas usage to zero during a distribution system interruption. OFDS, subject to Section 3.3 of this Schedule, is available during an interruption for distribution system reasons. Except as described below, if a Customer fails to reduce to zero usage or to OFDS levels during an interruption for distribution system reasons, the monthly Distribution Interruption Penalty will be assessed as follows: the average of the hourly non-compliant therms x 24 hours x number of days in the month x Distribution Interruption Penalty Price. The monthly Distribution Interruption Penalty will begin billing in May for a total of 12 months.

Schedule EG continued

Customer's non-compliant usage is considered Excessive Use if, during any hour of a distribution system interruption, non-compliant usage exceeds 575 therms. The monthly Excessive Use Distribution Interruption Penalty will be assessed as follows: all non-compliant therms for that event x the number of days in the month x the Excessive Use Distribution Interruption Penalty Price. However, in the event a distribution system interruption is less than 24 hours, and the Customer's non-compliant usage is Excessive Use, the monthly Excessive Use Distribution Interruption Penalty will be calculated as the higher of:

(The average hourly non-compliant therms) x (24 hours) x (the number of days in the month) x (the Excessive Use Distribution Interruption Penalty Price)

Or

(All non-compliant therms) x (the number of days in the month) x (the Excessive Use Distribution Interruption Penalty Price).

The monthly Excessive Use Interruption Penalty will begin billing in May for a total of 12 months. Each interruption will be evaluated individually.

When multiple distribution interruptions occur during the 12-month period from May to April, the average hourly non-compliant therms from each interruption are billed cumulatively over the 12 months beginning in May. All revenue collected from the application of the Distribution Interruption Penalty Price and Excessive Use Distribution Interruption Penalty Price will be applied as a credit in the determination of the Rider 8 Monthly Rate Adjustment.

3.5.2 The Public Service Commission, upon the request of BGE or a Customer served under this Schedule, may choose to reduce or waive entirely the duration of the Distribution Interruption Penalty or the Excessive Use Distribution Interruption Penalty in Section 3.5 for a Customer who demonstrates that a good faith effort was made to interrupt its gas usage as required under this Schedule and substantially reduced its usage during an interruption. The demonstration of a good faith effort shall include (1) efforts made prior to the interruption to be fully compliant; (2) the reason why full compliance was not attained, such as sudden failure of alternative fuel equipment; (3) efforts to correct non-compliance during the interruption; and (4) customer actions after the interruption to be fully compliant in the future. Usage above hourly OFDS levels during an interruption of more than 5% of the Customer's billing demand, for the specified meter, effective during the month of the interruption shall be prima facie evidence that the Customer did not make a good faith effort to comply with the interruption. However, any waiver or reduction of the Distribution Interruption Penalty or the Excessive Use Distribution Interruption Penalty shall consider the Customer's good faith efforts to interrupt its gas usage and may not be based solely on the extent to which the Customer actually reduced its gas usage. Any credits granted to Customers through the waiver process will also result in similar debits to Rider 8 Monthly Rate Adjustment.

Schedule EG continued

3.5.3 All OFDS gas used by the Customer during an interruption for distribution system reasons, without a Gas Production Day, except the Customer's Transportation Gas, is billed at the higher of the Gas Commodity Price , or 110% of the highest Transco Zone 6 (non-New York) price for the current month. All OFDS gas used by the Customer during an interruption for distribution system reasons and a Gas Production Day, except the Customer's Transportation Gas, a $0.50 per therm penalty is added to the higher of the Gas Commodity Price, or 110% of the highest Transco Zone 6 (non-New York) price for the current month. Any penalty revenue will be treated as gas commodity revenue. For all gas used by the Customer, during an interruption, in excess of the OFDS volumes, even if the Customer's Transportation Gas arrives at BGE's City Gate, a $1.50 per therm penalty is added to the higher of the Gas Commodity Price or 110% of the highest Transco Zone 6 (non-New York) price for the current month. This penalty revenue will be allocated as follows: One-third of the penalty revenue will be treated as gas commodity revenue while the remaining two-thirds of the penalty will be applied as a credit in the determination of the Rider 8 – Monthly Rate Adjustment.

3.5.4 If a Customer fails to interrupt its use of gas, and the Customer is unable to demonstrate items (1)-(4) as described in Section 3.5.2, the Company, at its discretion, may take actions to ensure the future reliability of its distribution system.

However, the Company may also take such actions if a Customer fails to interrupt its use of gas during two or more interruption events which are initiated within a period of 36 months. Such actions may include, but are not limited to, the termination of service to the Customer under this Schedule. Prior to the termination of service to the Customer under this Schedule becoming effective, BGE shall provide at least thirty (30) calendar days written notice to both the Customer and the Commission. In addition, the Company has the right to deny the Customer's request for interruptible service under any other schedule. This provision is not applicable during an actual gas interruption event during which a Customer has failed to interrupt as required under this Schedule. BGE may employ any actions necessary to address such failure to interrupt to ensure the continued reliability of the distribution system (see Section 3.5.5).

3.5.5 Failure to interrupt may result in the immediate discontinuance of service without notice, under Part 2, Section 2.4 (k). If the Customer is disconnected from the distribution system, reconnection will be made when the cause for the interruption no longer exists subject to the Customer satisfying all requirements of the Gas Service Tariff.

3.5.6 In the event that a curtailment of supply is implemented under Part 2, Section 2.3, all gas used will be billed in accordance with Appendix A – Natural Gas Curtailment Plan, even if the Customer's Transportation Gas arrives at BGE's City Gate.

Schedule EG continued

3.5 **Interruption Capability Verification Program:** BGE will test the Customer's ability to interrupt. The test will consist of two parts. Part one will test the Customer's communication systems. BGE will perform this portion of the test annually. Part two will test the ability of the Customer to interrupt with at least six hours notice for at least four hours. The Customer can satisfy this portion of the test by either 1) enlisting the services of a licensed Professional Engineer to certify that the equipment and/or procedures are in place to reduce gas usage to zero, or to contracted hourly OFDS volumes; or 2) actively participate in a physical test interruption. The Physical Interruption Test and/or Professional Engineer certification will be required every year. Should BGE call a Distribution System Interruption, any customer that complies with the interruption will not be required to participate in the Physical Interruption Test or provide a Professional Engineer certification for the next 12 months from the date of the interruption. Customers must instead provide certification from the Authorized Facility Manager indicating that no material changes and/or additions have been made to the equipment or production process, and that the Customer would comply with the requirements of an interruption. A Customer who fails to provide an annual Authorized Facility Manager Certificate will be required to complete a Physical Interruption Test early in the next winter heating season. If a Customer fails to reduce to zero usage or to contracted OFDS amounts during an interruption for distribution reasons, the Customer will be required to participate in a Physical Interruption Test.

A new Customer will be required to complete a Physical Interruption Test early in the next winter heating season. In addition, a new Customer will also be required to complete Part one of the Interruption Capability Verification Program.

Penalties associated with the Use of Gas During an Interruption provisions of this rate schedule will be waived the first time the Customer fails the Physical Interruption Test. If the Customer fails the Physical Interruption Test a second time, all penalties under Section 3.5 of this Schedule will apply until such time that the Customer becomes compliant. A Customer who fails a second Physical Interruption Test has the option of immediately contracting for 2 years of OFDS, if available, effective November 1 of the current heating season. 12 months of penalty billing for a second failed Physical Interruption Test will commence immediately unless the Customer contracts for OFDS. In addition, the Customer will be subject to disconnection from the gas distribution system under Section 2.4(k), and may be reconnected after they have demonstrated, to BGE's satisfaction, that they have made the necessary improvements and can complete the Physical Interruption Test.

3.7 Extension Provision:

3.7.1 The Customer pays the Company in advance, or at the completion of installation upon credit approval, the estimated installed cost of additional Main and Service Line facilities required to provide service under this Schedule.

3.7.2 Upon request by the Customer, the contribution required from the Customer will be determined under the provisions of Part 2, Sec 8.

Schedule EG continued

4. Gas Commodity Service

4.1 BGE Gas Commodity Service: The Company does not offer Gas Commodity Service under this Schedule. However, gas may be provided from month-to-month on a best efforts basis provided the Customer makes a request for such gas prior to the first day of the delivery month. This gas is priced at the Gas Commodity Price (Riders 2 and 12).

Even if the Company approves the Customer's request for gas supply, the Gas Commodity Price is not applicable for any gas used during a Gas Production Day, a Distribution System Interruption or a curtailment under Appendix A. During a Gas Production Day, a Distribution System Interruption or a curtailment under Appendix A, the pricing provisions governing those situations will apply.

4.2 Supplier Gas Commodity Service: The Customer must obtain Gas Commodity Service from a third party gas supplier subject to the following Terms and Conditions

4.2.1 Terms and Conditions

4.2.1.1 the Customer must arrange for the transport and delivery of gas into the Company's distribution system at its interstate pipeline gate station(s); and

4.2.1.2 the Customer may only contract with a gas supplier that has separately contracted with the Company under the provisions of the Gas Supplier Tariff. In the event that the Customer's gas supplier becomes disqualified under the Gas Supplier Tariff, the Customer must obtain Gas Commodity Service from another qualified gas supplier. The Customer shall select only one gas supplier for any period; and

4.2.1.3 the Customer takes title to the gas at or before the Company's City Gate; and

4.2.1.4 the transported gas must be for the Customer's burner tip use and shall not be resold except as an Accumulated Imbalance Corrective Measure as provided for in this Schedule; and

4.2.1.5 the Customer shall be responsible for the payment of any tax or assessment levied by any jurisdiction related to the acquisition, transportation or use of Transportation Gas.

4.2.2 Failure of the Customer's Transportation Gas to arrive at the City Gate: Where all or part of the Customer's Transportation Gas fails to arrive at the Company's City Gate the Customer is subject to Section 4.2.3.4 - Accumulated Imbalance Corrective Measures of this Schedule.

4.2.3 City Gate Balancing Service: The Company balances daily gas deliveries at the City Gate with unaccounted-for gas adjusted, burner tip use. The Customer must select one of the Balancing Service Options. The prices for the components of Balancing Service are in addition to the monthly rates for Delivery Service and apply to the Customer's metered use.

Schedule EG continued

4.2.3.1 Balancing Service Options:

(a) **Comprehensive Balancing Service:** Balancing of the gas delivered to the Company's City Gate on behalf of the Customer with the Customer's use of gas on a daily basis is performed by the Company. A Comprehensive Balancing Service Price is applied to all therms of gas used by the Customer adjusted to the Company's City Gate. The Customer also pays a pro rata share of any interstate gas pipeline penalties incurred based on the Customer's Daily Imbalance in the same direction as the Imbalance for which the penalty was incurred, unless the Customer is part of a Selective Group, and that Group is in balance.

At any time that the Customer's accumulated imbalance exceeds 2 times the Customer's average daily nomination for the 5 highest of the preceding 7 days nominations or 1,000 Dth, whichever is smaller, the Accumulated Imbalance Corrective Measures of Section 4.2.3.4 may be required.

(b) **Self Balancing Option:** Balancing of gas delivered to the Company's City Gate on behalf of the Customer with the Customer's use of gas on a daily basis is the responsibility of the Customer. An Imbalance Price based on the percentage of the Daily Imbalance to the Customer's average daily nomination is applied to the Daily Imbalance. The Customer also pays a pro rata share of any interstate gas pipeline penalties incurred based on the Customer's Daily Imbalance in the same direction as the Imbalance for which the penalty was incurred, unless the Customer is part of a Selective Group, and that Group is in balance.

The Imbalance Prices are determined as a percentage of the weighted average cost for the Company to correct an imbalance. The resultant Imbalance Prices are revised when the calculated weighted average cost of correcting an imbalance changes by more than 5 percent from the currently effective cost of correcting an imbalance. Details of the calculation of the weighted average cost of correcting an imbalance and the resultant Imbalance Prices are filed with the Public Service Commission.

At any time that the Customer's accumulated imbalance exceeds 20 percent of the Customer's average daily nomination for the 5 highest of the preceding 7 days nominations, the Accumulated Imbalance Corrective Measures of Section 4.2.3.4 may be required.

Schedule EG continued

4.2.3.2 Selective Grouping: Under either the Comprehensive Balancing Service or the Self Balancing Option, the Customer may join other customers in forming a Group for Daily Balancing purposes only. Where the Customer participates in a Group under the Self Balancing Option, a Group Administrator is required. The Group Administrator shall separately contract with the Company under the Gas Supplier Tariff and shall be responsible for payment of all Imbalance Prices and penalties. A Group Administrator is permitted for Groups under the Comprehensive Balancing Service. The Customer may revise their selection of Group membership on a monthly basis.

4.2.3.3 Daily Balancing Revenue: The revenue collected through the application of the Comprehensive Balancing Service Price and the Imbalance Price is recorded as Gas Commodity Price revenue.

4.2.3.4 Accumulated Imbalance Corrective Measures:

(a) **Over-Tendered Accumulated Imbalance:** When the Customer's accumulated imbalance exceeds the applicable limit, the Company will purchase the total accumulated over-tendered imbalance at the lower of the Gas Commodity Price, or 90% of the lowest Transcontinental Gas Pipeline Corporation (Transco) Zone 6 (non-New York) price for the current month. On Gas Production Days, Balancing Service provisions are suspended. When Gas Production Days cease, the Company will provide a period of time for the Customer to reduce the amount of any over-tendered imbalance.

(b) At the conclusion of this time period, if the accumulated imbalance exceeds the applicable limit, the Company will purchase the total accumulated imbalance at the above stated price.

(c) **Under-Tendered Accumulated Imbalance:** When the Customer's accumulated imbalance exceeds the applicable limit, the Customer will purchase all gas used in excess of delivered Transportation Gas at the following rates:

(i) During periods other than an interruption for system distribution reasons or Gas Production Days, all gas used will be billed at the higher of the Gas Commodity Price or 110% of the highest Transco Zone 6 (non-New York) price for the current month.

Schedule EG continued

(ii) On Gas Production Days, Balancing Service provisions are suspended. A tolerance of 3% is permitted on under-deliveries. When the 3% tolerance is exceeded, the following corrective measures become effective. For all gas used in excess of the Customer's Transportation Gas arriving at the Company's City Gate, including the 3% tolerance, a $0.50 per therm penalty will be added to the higher of the Gas Commodity Price or 110% of the highest Transco Zone 6 (Non-New York) price for the current month. Any penalty revenue will be treated as gas commodity revenue.

(iii) During periods of an interruption for system distribution reasons, the Use of Gas During an Interruption provisions of this Schedule apply.

4.2.3.5 Interruption of Transportation Gas for Distribution System Reasons: Where the Company interrupts the Customer's Transportation Gas for Distribution System reasons, the Imbalance Fees will not apply during the period of the interruption.

Schedule EG continued

5. General Terms:

5.1 Minimum Charge: Customer Charge

5.2 Late Payment Charge: Standard (Part 2, Sec 7.5)

5.3 Payment Terms: Standard (Part 2, Sec 7.5)

5.4 Term of Contract with BGE: The initial term of contract is 1 year or as required for allowance under the Extension Provisions above. The contract continues thereafter from year to year until terminated at the expiration of any such term by at least 30 days notice from either party to the other.

5.5 General

5.5.1 The supply of both interruptible service under this Schedule and firm service under Schedule C is permitted upon separation of facilities by the Customer.

5.5.2 The supply of interruptible service to a Customer under this Schedule for the Customer's requirements at two or more locations on property comprising single or contiguous land parcels, as defined in Part 2, Sec. 2.2, may be combined in billing on a single application of this Schedule where the Customer installs, operates and maintains at the Customer's expense, all additional Service Line installations required for supply at other than the initial location, provided the capacity of specific gas-fired equipment connected thereto is not less than 50 therms per hour at any such location. Additional metering installations used for less than 1 year are subject to charges for installation and removal, less salvage, upon removal by the Company.

5.6 Definitions

5.6.1 Connected capacity: As used in this Schedule is the therms estimated to be used when the gas-fired equipment is operated for 1 hour under optimum load conditions.

5.6.2 Transportation Gas: All gas to which the Customer takes title at or before the Company's City Gate.

5.6.3 Daily Imbalance: The difference between the Customer's daily use and daily delivery of Gas to the Company's City Gate.

5.6.4 AMR: An automated meter reading device suitable for daily interface between a Customer and the Company's data collection and processing system.

Schedule EG continued

5.6.5 Gas Production Day: A Gas Day when the Company anticipates engaging in peak shaving activities. The Company will endeavor to notify the Customer of expected peak shaving activity.

5.6.6 Gas Day: A 24-hour period beginning at 10:00 a.m. Eastern Prevailing Time.

5.6.7 Non-Compliant Therms: Gas usage above contracted hourly OFDS volumes, if any, or all gas usage during a distribution system interruption if no contracted OFDS or any unapproved gas usage.

5.6.8 Enrollment Period: The timeframe when a Customer may request an hourly volume for OFDS or cancel existing OFDS, which always ends on July 31.

5.7 Metering Equipment: An AMR owned and maintained by the Company suitable for daily interface with the Company's data collection and processing system is required. The Customer pays the estimated installed cost of the AMR, plus any additional facilities necessary, under the provisions of Part 2, Sec. 8.5. Sixty (60) days notice is required for installation of the AMR. Service under this Option will commence upon installation of the AMR

5.8 Information Fee All Customers served under this Schedule shall pay a monthly Information Fee of $65.

6. Riders Applicable: This schedule is subject to Riders applicable as listed below:

9. Demonstration and Trial Installations
10. Billing in Event of Service Interruption
11. Unaccounted - For Gas Factor
14. Economic Development
15. Multi-Year Plan ("MYP") Adjustment Rider
16. STRIDE (Strategic Infrastructure Development and Enhancement) Surcharge

(c) The Customer agrees to notify the Company promptly of any escape of gas or of unused gas at the lamp because of extinguished flame so that it can proceed to correct the condition and restore service.

(d) The Company is not liable for any loss, cost, damage or expense to any party resulting from the use or presence of gas in the Customer's facilities.

6. GENERAL TERMS

6.1 Minimum Charge:
Customer Charge

6.2 Late Payment Charge:
Standard. (Part 2, Sec. 7.5)

6.3 Payment Terms:
Standard. (Part 2, Sec. 7)

7. RIDERS APPLICABLE:
This Schedule is subject to Riders applicable as listed below:

2. Gas Commodity Price
10. Billing in Event of Service Interruption
11. Unaccounted for Gas Factor
15. Multi-Year Plan ("MYP") Adjustment Rider

GAS SERVICE TO GRANTORS OF RIGHTS-OF-WAY TO THE MARYLAND GAS TRANSMISSION CORPORATION

1. AVAILABILITY:

(a) Gas for domestic use is sold direct from the transmission line to grantors of rights-of-way for the natural gas transmission line granted to and exercised by The Maryland Gas Transmission Corporation, its successors and assigns, in Baltimore, Harford and Howard Counties, Maryland, subject to the consent and agreement of that Corporation, under the Company's Gas Service Tariff, and only to such successors and assigns of such grantors as are residents as of the date service is supplied, of property on which the transmission line is located.

2. RATE TABLE

Effective with service rendered on or after 12/17/2019
Customer Charge:……………………………………………$ 14.25 per month
Delivery Price (For all gas used)…………………………….. $0.5960 per therm

	Rate Year 1 Effective January 1, 2021	**Rate Year 2 Effective January 1, 2022**	**Rate Year 3 Effective January 1, 2023**
Customer Charge (per Month)	$14.25	$14.25	$15.25
Delivery Price ($/therm)	$0.5921	$0.5904	$0.7154

3. DELIVERY SERVICE:

Firm service of gas sold directly from the transmission line for all customers served under this Schedule.

4. TERMS AND CONDITIONS

A. Under Part 2

4.1. The following does not apply:

(a) Section 3.5 Use for Less Than Initial Term of Contract;
(b) In Section 4.1 – Service Equipment Furnished by the Customer – the fourth sentence of the second paragraph only;
(c) In Section 5.1 – Service Equipment Furnished by the Company, paragraphs (a) & (c) only;
(d) In Section 6.1 - Location of Service Equipment – General – the second and third paragraphs only;
(e) Section 8.15 – Grading of Property;
(f) Section 8.2 – Charges for Extensions; and
(g) Section 8.5 – Payment Plans.

4.2. Customer's Installation: That part of the service from a point within 3 feet of the transmission line to a point within the building to be supplied is designated

"Excess Service", is installed by the Company at the Customer's expense and is owned and maintained by him. The route shall be the shortest practicable route lying entirely within the property of the Customer.

5. GENERAL TERMS:

5.1 The Customer assumes the responsibility for the detection of any defect or leak on his premises, and agrees in the event of any failure of the service due to irregular supply, leakage, high or low pressure, to notify the Company immediately.

5.2 Minimum Charge: .... Customer Charge

5.3 Late Payment Charge: .... Standard. (Part 2, Sec. 7.5)

5.4 Payment Terms....................................... Standard (Part 2, Sec. 7)

5.5 Term of Contract: One year; thereafter until terminated by at least 10 days notice from the Customer. The Customer shall pay all costs of connection and disconnection, if service is used less than 1 year.

6. RIDERS APPLICABLE: This Schedule is subject to Riders applicable as listed below:

1. Gas Efficiency Charge
2. Gas Commodity Price
4. Budget Billing
5. Smart Meter Opt-Out
7. Gas Choice and Reliability Charge
8. Monthly Rate Adjustment
10. Billing in Event of Service Interruption
11. Unaccounted – For Gas Factor
12. Gas Administrative Charge
15. Multi-Year Plan ("MYP") Adjustment Rider
16. STRIDE (Strategic Infrastructure Development and Enhancement) Surcharge

RIDER INDEX

1. Gas Efficiency Charge
2. Gas Commodity Price
3. Standby Service Price
4. Budget Billing
5. Smart Meter Opt-Out
6. (Reserved for Future Use)
7. Gas Choice and Reliability Charges
8. Monthly Rate Adjustment
9. Demonstration and Trial Installations
10. Billing in Event of Service Interruption
11. Unaccounted - For Gas Factor
12. Gas Administrative Charge
13. (Reserved for future use)
14. Economic Development
15. ~~(Reserved for Future Use)~~Multi-Year Plan ("MYP") Adjustment Rider
16. STRIDE (Strategic Infrastructure Development and Enhancement) Surcharge
17. Prepaid Pilot

Schedule		Riders Applicable
D	. . . .	**1, 2, 4, 5, 7, 8, 10, 11, 12, 15, 16, 17**
C	. . . .	**2, 3, 4, 5, 7, 8, 9, 10, 11, 12, 14, 15, 16**
IS	. . . .	**9, 10, 11, 14, 15, 16**
ISS	. . . .	**9, 10, 11, 14, 15, 16**
EG	. . . .	**9, 10, 11, 14, 15, 16**
PLG	. . . .	**2, 10, 11, 15**
GRANTORS	. . . .	**1, 2, 4, 5, 7, 8, 10, 11, 12, 15, 16**

Rider 14. Economic Development (continued)

Incentives

Location	Rate Reductions	Discount Length	Extension Charge Discount
Non-Enterprise Zone	25%	3 years	None
Enterprise Zone	25%	5 years	75%

Price reductions are applied only to the Customer Charge, Delivery Service Charge (exclusive of all riders), and Demand Charge (if applicable). Price reductions will not be applied to any other charges, taxes, etc. Only the Qualifying Load is eligible for these price reductions. The combined total price reductions for all Customers under this Rider are limited to $2 million per calendar year. New applicants are not eligible for these price reductions in years where this limit is exceeded.

For Enterprise Zone customers the Company will provide a 75% discount to the extension charge requirements set forth in Section 8 of this tariff. The Customer's contribution is subject to gross-up for taxes. For each Customer, the discount is limited up to a maximum of $2.5 million per signed contract where the total amount of extension charge price reductions granted in a calendar year under this Rider does not exceed $5 million.

Failure to meet the requirements of the Rider will result in termination of ongoing price reductions and extension charge discounts and may require the Customer to reimburse Company for any price reductions and extension charge discounts previously granted. The Company will report to Commission Staff on the use of this Rider annually by September 1st of each year.

~~**Rider 15. Reserved For Future Use**~~

15. Multi-Year Plan ("MYP") Adjustment Rider

This rider addresses Imbalances that may arise between the revenue requirement approved by the Commission as part of initial rates under a Multi-Year Plan ("MYP") and the actual revenue requirement filed as part of the Annual Informational Filings or Final Reconciliation, pursuant to Order No. 89482.

The Annual Informational Filings shall be filed within 90 days of the end of the first and second years of the approved MYP.

The Final Reconciliation shall be filed within 120 days of the end of the MYP. The Final Recollection shall cover investments and costs in the MRP period not previously reviewed for prudency and reconciled in the rate case.

Imbalances shall be calculated consistent with the MYP revenue requirement approved by the Commission in an order resulting from an MYP proceeding. Rate base and operating income shall use actual results from the applicable MYP period in calculating the actual revenue requirement to determine the Imbalance. If an Imbalance calculated as part of an Annual Informational Filing, as defined in Order No. 89482, represents an amount owed to customers, the MYP Adjustment Rider can be utilized to provide a credit for such amount, if determined to be appropriate by the Commission. The MYP

15. Multi-Year Plan ("MYP") Adjustment Rider (continued)

Adjustment Rider can be utilized to recover or credit an Imbalance calculated as part of a Final Reconciliation, as determined to be appropriate by the Commission.

All Imbalances are deferred into a regulatory asset or liability until such time as the Commission determines the appropriate disposition of the Imbalance, including the appropriate period over which an Imbalance is recovered or credited to customers. Carrying costs will apply for amounts owed to customers and will continue to apply during the credit period.

Calculation of Rate

The MYP Adjustment Rider rate is determined for each Schedule by first allocating the Imbalance, as determined appropriate by the Commission, in proportion to each Schedule's amount of base distribution revenues in the final year of the MYP. The resulting amounts are then divided by the estimated billing determinants, per kilowatt-hour or per fixture, for each applicable Schedule. Details concerning the calculation of the MYP Adjustment are filed with and approved by the Commission prior to their use in billing. The MYP Adjustment shall be included in the Distribution Charge on the Customer's monthly gas bill.

Rates Effective [insert date range]

Rate Schedule	Rate
Schedule D	$0.0000 per therm
Schedule C	$0.0000 per therm
Schedule IS	$0.0000 per therm
Schedule ISS	$0.0000 per therm
Schedule EG	$0.0000 per therm
Schedule PLG	$0.0000 per therm
GRANTORS	$0.0000 per therm

16. STRIDE (Strategic Infrastructure Development and Enhancement) Surcharge

The Strategic Infrastructure Development and Enhancement ("STRIDE") surcharge recovers certain expenditures related to the execution of the Company's STRIDE plan, which addresses accelerated natural gas infrastructure replacements, as approved by the Public Service Commission. The Company will file a gas base rate case within five years of the implementation of its Commission-approved STRIDE plan.

Calculation of Charge

The STRIDE surcharge consists of a Current Rate and Reconciliation Rate. The Current Rate represents the recovery of the expected STRIDE revenue requirement for the upcoming calendar year. The Current Rate is calculated annually for a 12-month period (or for the remainder of the calendar year when a new surcharge becomes effective after January 1) for residential (Schedule D and Grantors-of-Rights-of-Way customers), Schedule C, Schedule IS, Schedule ISS, and Schedule EG customers by first allocating the revenue requirement (which is based on Eligible Costs as defined below) based on the proportion of base distribution revenues that these customers bear in the Company's most recently approved gas base rate case. The Current Rate revenue requirement is then divided by the forecasted number of bills for residential and non-residential customers for the prospective billing period, yielding a separate monthly Current Rate on a per customer basis for residential, Schedule C, Schedule IS, Schedule ISS, and Schedule EG customers.

16. STRIDE (Strategic Infrastructure Development and Enhancement) Surcharge (continued)

The Reconciliation Rate is based on the Imbalance between actual STRIDE surcharge revenue and the actual revenue requirement for the 12 months ended December 31 of the prior year and is separately determined for residential, Schedule C, Schedule IS, Schedule ISS, and Schedule EG customers. The Reconciliation Rate is in effect for the period of May though December each year and is determined by dividing the Imbalance by the forecasted number of bills for residential and non-residential customers for this period. The Imbalance is debited or credited against the costs eligible for recovery during the 12-month rate effective period. When the Imbalance represents an over-collection of costs at year end, Carrying Costs are applied to the Imbalance using the Company's most recent Gas authorized rate of return in the calculation of the Reconciliation Rate. In the event the Imbalance for a customer class represents an over-collection of costs and the Current Rate plus the Reconciliation Rate for that customer class is capped at the maximum monthly charge (defined below), the Company will hold the Imbalance amount above the cap until the STRIDE surcharge is less than the maximum monthly charge (i.e., is uncapped) at which point this Imbalance amount (including carrying costs) will be applied against the costs eligible for recovery during that future period.

The STRIDE surcharge is subject to a maximum monthly charge of $2.00 per month for residential customers. For Schedule C customers the maximum monthly charge is $11.61; for Schedule IS customers the maximum monthly charge is $1,053.83; for Schedule ISS customers the maximum monthly charge is $169.80; for Schedule EG customers the maximum monthly charge is $4,272.87. The maximum monthly charge is capped based on the proportion of total non-residential base distribution per customer revenues to total residential base distribution per customer revenues, as determined in the most recently approved base rate case, multiplied by the $2.00 residential monthly cap.

Eligible Costs

The revenue requirement for the STRIDE surcharge is based on eligible costs as defined in the STRIDE legislation, incurred by the Company associated solely with its STRIDE plan, and as approved by the Commission each year. They include the following categories:

a) Depreciation and amortization,
b) Earnings on the net investment as determined by applying the Company's most recent gas authorized rate of return, adjusted for taxes and bad debt expense, to the average investment balance net of deferred taxes, and
c) Property and other applicable taxes.

Future Rate Proceedings

Upon a Commission Order in a gas distribution rate proceeding that occurs while the STRIDE plan is in effect, the STRIDE surcharges will be reset due to the following:

a) The revenue requirement associated with the STRIDE surcharge will be reduced to remove the investments reflected in the new base rates,
b) The revenue requirement for STRIDE costs that are not included in the new base rates is updated to reflect the new rate of return approved in the new rate case,
c) The percentages used to allocate the STRIDE revenue requirement to residential and non-residential customers are updated to reflect the new base distribution revenues authorized, and
d) The Schedule C, IS ISS, and EG caps are reset by calculating the new base distribution per customer revenues as a proportion to the new residential base distribution per customer revenues, and then multiplied by the $2.00 residential monthly cap.

Company Exhibit LKF-5
Supplement 467
Filed: May 15, 2020
Effective: June 14, 2020

Gas Service Tariff
Without Revision Markings

RESIDENTIAL SERVICE – GAS

SCHEDULE D

1. AVAILABILITY:

(a) For use for the domestic requirements of:
1. A single private dwelling.
2. An individually metered dwelling unit in a multiple dwelling building.
3. One combination of two dwelling units within a building, if served through a single meter.
4. A dwelling occupied as the dwelling place of a church divine or of religious associates engaged in church duties.
5. A single dwelling within a building where the occupant has not more than 10 bedrooms to let or not more than 10 table boarders, or a combination of not more than ten.

(b) For use, if on one property and served through a single meter, of a combination of the occupant's domestic requirements in a dwelling and his nondomestic requirements, provided that more than 50 percent of the connected load is for domestic purposes.

(c) For use, if served through a separate meter, by appliances used in common by the occupants of not more than two dwelling units within a building.

2. RATE TABLE:

Effective with service rendered on or after 12/17/2019
Customer Charge . . . . ….$14.25 per month, plus
Delivery Price (For all gas used) . . . . ….$0.5960 per therm

	Rate Year 1 **Effective January 1, 2021**	**Rate Year 2** **Effective January 1, 2022**	**Rate Year 3** **Effective January 1, 2023**
Customer Charge (per Month)	$14.25	$14.25	$15.25
Delivery Price ($/therm)	$0.5921	$0.5904	$0.7154

3. DELIVERY SERVICE:

Firm service transportation of gas through the Company's distribution system for all customers served under this Schedule.

Schedule D continued

5. GENERAL TERMS

5.1 Minimum Charge: Customer Charge

5.2 Late Payment Charge: Standard (Part 2, Sec. 7.5)

5.3 Payment Terms: Standard (Part 2, Sec. 7)

5.4 Term of Contract with BGE: The Customer's initial term of contract with BGE for Delivery Service is 1 year, and thereafter until terminated by at least 30 days notice from the Customer to BGE.

6. RIDERS APPLICABLE:

This Schedule is subject to Riders applicable as listed below:

1. Gas Efficiency Charge
2. Gas Commodity Price
4. Budget Billing
5. Smart Meter Opt-Out
7. Gas Choice and Reliability Charges
8. Monthly Rate Adjustment
10. Billing in Event of Service Interruption
11. Unaccounted – For Gas Factor
12. Gas Administrative Charge
15. Multi-Year Plan ("MYP") Adjustment Rider
16. STRIDE (Strategic Infrastructure Development and Enhancement) Surcharge
17. Prepaid Pilot

GENERAL SERVICE – GAS

SCHEDULE C

1. AVAILABILITY:

For use for 3 or more dwelling units served within a building through a single meter and all other non-domestic firm service.

2. RATE TABLE:

Effective with service rendered on or after 12/17/2019
Customer Charge . . . .$ 36.30 per month, plus
Delivery Price:
First 10,000 therms . . . .$ 0.4541 per therm, plus
All Over . . . . $ 0.2304 per therm

	Rate Year 1 Effective January 1, 2021	Rate Year 2 Effective January 1, 2022	Rate Year 3 Effective January 1, 2023
Customer Charge (per Month)	$36.30	$36.30	$38.00
Delivery Price First 10,000 therms ($/therm)	$0.4681	$0.4689	$0.5605
Delivery Price All Over ($/therm)	$0.2444	$0.2452	$0.2942

For Daily-Metered customers
AMR Required . . . . .Estimated Installed Cost
Information Fee . . . . $65 per month, plus

Balancing Service Options:
Comprehensive Balancing Service ……………………… $0.0006 per therm
Self Balancing Option*:* The following Imbalance Prices apply*:*

Percent of Imbalance	Imbalance Price
0 to 3%	No Charge
Greater than 3% to 6%	$0.00393 per therm
Greater than 6% to 10%	$0.00524 per therm
Greater than 10% to 15%	$0.01048 per therm
Greater than 15%	$0.02096 per therm

3. DELIVERY SERVICE:

Firm service transportation of gas through the Company's distribution system for all customers served under this Schedule.

Schedule C continued

4. GAS COMMODITY SERVICE:

4.1 BGE Gas Commodity Service The sale of gas by BGE is provided under the provisions of Riders 2 and 12 – Gas Commodity Price and Gas Administrative Charge.

4.2 Supplier Gas Commodity Service: The Customer may elect to obtain Gas Commodity Service from a third party gas supplier subject to the following Terms and Conditions:

4.21 Terms and Conditions

(a) the Customer arranges for the transport and delivery of gas into the Company's distribution system at its interstate pipeline gate station(s); and

(b) the Customer may only contract with a gas supplier that has obtained a license from the Public Service Commission of Maryland and has separately contracted with the Company under the Gas Supplier Tariff. A Daily Metered Customer may elect to act as its own supplier under the provisions of the Gas Supplier Tariff. Service under this Schedule is provided only so long as the Customer's gas supplier remains a qualified gas supplier under the Gas Supplier Tariff. In the event that the Customer's gas supplier becomes disqualified, the Customer must obtain Gas Commodity Service from another qualified gas supplier or return to BGE Gas Commodity Service, if eligible; and

(c) the Customer shall select only one gas supplier for any period; and

(d) the Customer takes title to the gas at or before the Company's City Gate; and

(e) the transported gas is for the Customer's burner tip use and shall not be resold, except as an Accumulated Imbalance Corrective Measure as provided for in Section 4.254(d)(1) of this Schedule; and

(f) the Customer shall be responsible for the payment of any tax or assessment levied by any jurisdiction related to the acquisition, transportation or use of Transportation Gas.

4.22 Definitions:

(a) Daily-Metered Customer: A Supplier Gas Commodity Service Customer with annual use of 120,000 therms or greater, or with annual use greater than 90,000 therms but less than 120,000 therms who elects to have an AMR device installed.

(b) Transportation Gas: All gas to which the Customer takes title at or before the Company's City Gate.

(c) Daily Imbalance: The difference between the Customer's daily use and daily delivery of gas to the Company's City Gate.

(d) AMR: – an automated meter reading device suitable for daily interface between a Daily-Metered Customer and the Company's data collection and processing system.

(e) Gas Production Day: A Gas Day when the Company anticipates engaging in peak shaving activities. The Company will endeavor to notify the Non-Standby Service Customer of expected peak shaving activity.

(f) Gas Day: A 24-hour period beginning at 10:00 a.m. Eastern Time.

Schedule C continued

4.23 Telephone Line Responsibility*:* All customers not classified as Daily-Metered with annual use of 15,000 therms or greater are required to install and maintain a non-dedicated telephone line to the meter location. The Customer is required to maintain this telephone line in working order and is subject to the terms of Part 2, Sec. 4.11

4.24 Termination of Supplier Gas Commodity Service*:* Upon termination of Supplier Gas Commodity Service for any reason, the Customer is subject to Sec. 4.254(d) Accumulated Imbalance Corrective Measures of this Schedule and to the requirements of Sec. 4.255 – Standby Service and Non-Standby Service for Daily Metered Customers.

4.25 For Daily-Metered Customers:

4.251 Metering Equipment: An AMR owned and maintained by the Company suitable for daily interface with the Company's data collection and processing system is required. The Customer pays the estimated installed cost of the AMR, plus any additional facilities necessary, under the provisions of Part 2, Sec. 8.5. Sixty (60) days notice is required for installation of the AMR. Service under this Option will commence upon installation of the AMR.

4.252 Information Fee: All Customers with an AMR installed shall pay a monthly Information Fee of $65.

4.253 Failure of the Customer's Transportation Gas to arrive at the City Gate: Where all or part of the Customer's Transportation Gas fails to arrive at the Company's City Gate, the Customer is subject to Sec. 4.254(d) – Accumulated Imbalance Corrective Measures of this Schedule.

4.254 City Gate Balancing Services: The Company balances daily gas deliveries at the City Gate with unaccounted-for gas adjusted, burner tip use. Daily-Metered customers must select one of the Balancing Service Options. The prices for the components of Balancing Service are in addition to the monthly rates for Delivery Service and apply to the Customer's metered use.

(a) Balancing Service Options:

1. Comprehensive Balancing Service: Balancing of the gas delivered to the Company's City Gate on behalf of the Customer with the Customer's use of gas on a daily basis is performed by the Company. A Comprehensive Balancing Service Price is applied to all therms of gas used by the Customer adjusted to the Company's City Gate. The Customer also pays a pro rata share of any interstate gas pipeline penalties incurred based on the Customer's Daily Imbalance in the same direction as the Imbalance for which the penalty was incurred, unless the Customer is part of a Selective Group, and that Group is in balance.

Schedule C continued

6. RIDERS APPLICABLE: This Schedule is subject to Riders applicable as listed below:

2. Gas Commodity Price
3. Standby Service Price
4. Even Monthly Payment Plan
5. Smart Meter Opt-Out
7. Gas Choice and Reliability Charges
8. Monthly Rate Adjustment
9. Demonstration and Trial Installations
10. Billing in Event of Service Interruption
11. Unaccounted - For Gas Factor
12. Gas Administrative Charge
14. Economic Development
15. Multi Year Plan (“MYP”) Adjustment Rider
16. STRIDE (Strategic Infrastructure Development and Enhancement) Surcharge

INTERRUPTIBLE LARGE VOLUME SERVICE -- GAS SCHEDULE IS

1. AVAILABILITY:

(a) Where the connected capacity of the Customer's gas-fired equipment is 250 therms per hour or greater, and

(b) where the Customer must interrupt their use of gas within 6 hours, or sooner if possible, following receipt of notice by the Company at any time of the day, and during any time of the year, and

(c) where "interrupt their use of gas" means that the Customer must reduce gas consumption to zero or to contracted Optional Firm Delivery Service (OFDS) levels, if any.

2. RATE TABLE:

Effective with service rendered on or after 12/17/2019
Customer Charge . . . . $1,250 per month, plus
Demand Price . . . . $ 0.8323 per therm
Delivery Price . . . . $ 0.0712 per therm

Distribution Interruption Penalty Price…………………………..…….$0.4212 per therm
Excessive Use Distribution Interruption Penalty Price……………..…$0.5616 per therm

Optional Firm Delivery Service …OFDS Hourly Volume x 24 hours x Number of Days in Month x Optional Firm Delivery Price. The following rates will apply to OFDS volumes:

First 10,000 therms per month……………………………………..$0.3299 per therm
Over 10,000 therms per month…………………………………….$0.1062 per therm

	Rate Year 1 Effective January 1, 2021	Rate Year 2 Effective January 1, 2022	Rate Year 3 Effective January 1, 2023
Customer Charge (per Month)	$1,250.00	$1,250.00	$1,250.00
Demand Price ($/therm)	$0.8323	$0.8323	$1.1314
Delivery Price ($/therm)	$0.0712	$0.0712	$0.0808
Distribution Interruption Penalty Price ($/therm)	$0.4212	$0.4212	$0.6095
Excessive Use Distribution Interruption Penalty Price ($/therm)	$0.5616	$0.5616	$0.8126
OFDS – First 10,000 ($/therm)	$0.3299	$0.3299	$0.4063
OFDS – Over 10,000 ($/therm)	$0.1062	$0.1062	$0.1400

AMR Required…………………………………..Estimated Installed Cost
Information Fee………………………………….$65 per month

Schedule IS continued

Comprehensive Balancing Option. . . . . $0.0006 per therm

Self Balancing Option: The following Imbalance Prices apply:

Percent of Imbalance	Imbalance Price
0 to 3%	No Charge
Greater than 3% to 6%	$0.00393 per therm
Greater than 6% to 10%	$0.00524 per therm
Greater than 10% to 15%	$0.01048 per therm
Greater than 15%	$0.02096 per therm

3. DELIVERY SERVICE: Interruptible Service transportation of gas through the Company's distribution system for all Customers served under this Schedule.

3.1 Billing Demand: The Customer's Billing Demand is the maximum winter day measured demand during the latest 12 month period adjusted to the nearest whole Dth. Measured demand is the Customer's total metered use of gas during the Gas Day beginning at 10:00 a.m. Eastern time. The winter period is the 5 months of November through March, inclusive.

3.2 Demand Free Day: For a Customer taking service hereunder, the Company may at its option designate any Gas Day as "demand free." The designation, if any, will be made no later than 2 p.m., Eastern Time, of the day immediately preceding the Demand Free day. Any gas used during a Demand Free day will not be considered when determining a Customer's Billing Demand.

3.3 Optional Firm Delivery Service

(a) The Customer may contract for Optional Firm Delivery Service through meters served under this Schedule. This option allows the Customer to contract for a specific amount of firm distribution service available to interruptible customers during a distribution system interruption. The Company will not maintain interstate gas pipeline capacity to supply the Customer's OFDS requirements. The Customer must contract for a specific volume of OFDS on an hourly basis. The Company reserves the right to decline a request for new or an increase to OFDS should capacity not be available on the gas distribution system. However, the Customer may request a distribution system upgrade under the terms of Part 2, Section 8 to receive OFDS.
The OFDS rates are incremental to all existing IS tariff rates. The OFDS rates represent the effective difference between the existing IS rates and the Schedule C delivery prices.

(b) An existing Schedule IS Customer desiring OFDS volumes must contract for a specific hourly amount, at a specified meter, with the Company, and revise their request no later than July 31 to be effective November 1 through October 31. The initial term of contract for OFDS is 2 years. During the first year of the initial term, and before July 31, the Customer may revise their OFDS contract volume to no less than 50% of the original contract amount, or as high as needed, providing sufficient distribution capacity is available, to be effective November 1. Upon completion of the initial 2 year contract period, the contract will continue to automatically renew for 1

Schedule IS continued

year unless notified by the Customer by July 31. Following the first initial enrollment period, subsequent enrollment periods will have no limitations on the OFDS volumes, provided there is available distribution system capacity.

(c) A new Customer to Schedule IS may contract for OFDS upon commencement of interruptible service or at the next Enrollment Period. The 2 year initial contract timeframe will be determined to place the Customer on the November 1 to October 31 contract schedule.

(d) A Customer who fails two physical interruption tests may also contract for OFDS as described in Section 3.5.

(e) Schedule IS remains the controlling Schedule when a Customer contracts for OFDS.

3.4 Use of Gas During an Interruption:

(a) If a Customer does not contract for OFDS, the Customer must reduce their gas usage to zero during a distribution system interruption. OFDS, subject to Section 3.3 of this Schedule, is available during an interruption for distribution system reasons. Except as described below, if a Customer fails to reduce to zero usage or to OFDS levels during an interruption for distribution system reasons, the monthly Distribution Interruption Penalty will be assessed as follows: the average of the hourly non-compliant therms x 24 hours x number of days in the month x Distribution Interruption Penalty Price. The monthly Distribution Interruption Penalty will begin billing in May for a total of 12 months.

Customer's non-compliant usage is considered Excessive Use if, during any hour of a distribution system interruption, non-compliant usage exceeds 575 therms. The monthly Excessive Use Distribution Interruption Penalty will be assessed as follows: all non-compliant therms for that event x the number of days in the month x the Excessive Use Distribution Interruption Penalty Price. However, in the event a distribution system interruption is less than 24 hours, and the Customer's non-compliant usage is Excessive Use, the monthly Excessive Use Distribution Interruption Penalty will be calculated as the higher of:

(The average hourly non-compliant therms) x (24 hours) x (the number of days in the month) x (the Excessive Use Distribution Interruption Penalty Price)

Or

(All non-compliant therms) x (the number of days in the month) x (the Excessive Use Distribution Interruption Penalty Price).

The monthly Excessive Use Interruption Penalty will begin billing in May for a total of 12 months. Each interruption will be evaluated individually.

When multiple distribution interruptions occur during the 12 month period from May to April, the average hourly non-compliant therms from each interruption are billed cumulatively over the 12 months beginning in May. All revenue collected from the application of the Distribution Interruption Penalty Price and Excessive Use Distribution Interruption Penalty Price will be applied as a credit in the determination of the Rider 8 Monthly Rate Adjustment.

Schedule IS continued

(b) The Public Service Commission, upon the request of BGE or a Customer served under this Schedule, may choose to reduce or waive entirely the duration of the Distribution Interruption Penalty or the Excessive Use Distribution Interruption Penalty in Paragraph 3.4(a) for a Customer who demonstrates that a good faith effort was made to interrupt its gas usage as required under this Schedule and substantially reduced its usage during an interruption. The demonstration of a good faith effort shall include (1) efforts made prior to the interruption to be fully compliant; (2) the reason why full compliance was not attained, such as sudden failure of alternative fuel equipment; (3) efforts to correct non-compliance during the interruption; and (4) customer actions after the interruption to be fully compliant in the future. Usage above hourly OFDS levels during an interruption of more than 5% of the Customer's billing demand, for the specified meter, effective during the month of the interruption shall be prima facie evidence that the Customer did not make a good faith effort to comply with the interruption. However, any waiver or reduction of the Distribution Interruption Penalty or the Excessive Use Distribution Interruption Penalty shall consider the Customer's good faith efforts to interrupt its gas usage and may not be based solely on the extent to which the Customer actually reduced its gas usage. Any credits granted to Customers through the waiver process will also result in similar debits to Rider 8 – Monthly Rate Adjustment.

(c) All OFDS gas used by the Customer during an interruption for distribution system reasons, without a Gas Production Day, except the Customer's Transportation Gas, is billed at the higher of the Gas Commodity Price , or 110% of the highest Transco Zone 6 (non-New York) price for the current month. All OFDS gas used by the Customer during an interruption for distribution system reasons and a Gas Production Day, except the Customer's Transportation Gas, a $0.50 per therm penalty is added to the higher of the Gas Commodity Price, or 110% of the highest Transco Zone 6 (non-New York) price for the current month. Any penalty revenue will be treated as gas commodity revenue. For all gas used by the Customer, during an interruption, in excess of the OFDS volumes, even if the Customer's Transportation Gas arrives at BGE's City Gate, a $1.50 per therm penalty is added to the higher of the Gas Commodity Price or 110% of the highest Transco Zone 6 (non-New York) price for the current month. This penalty revenue will be allocated as follows: One-third of the penalty revenue will be treated as gas commodity revenue while the remaining two-thirds of the penalty will be applied as a credit in the determination of the Rider 8 – Monthly Rate Adjustment.

(d) If a Customer fails to interrupt its use of gas, and the Customer is unable to demonstrate items (1)-(4) as described in Paragraph 3.4(b), the Company, at its discretion, may take actions to ensure the future reliability of its distribution system. However, the Company may also take such actions if a Customer fails to interrupt its use of gas during two or more interruption events which are initiated within a period of 36 months. Such actions may include, but are not limited to, the termination of service to the Customer under this Schedule. Prior to the termination of service to the Customer under this Schedule becoming effective, BGE shall provide at least thirty (30) calendar days written notice to both the Customer and the Commission. In addition, the Company has the right to deny the Customer's request for interruptible service under any other schedule.

Schedule IS continued

This provision is not applicable during an actual gas interruption event during which a Customer has failed to interrupt as required under this Schedule. BGE may employ any actions necessary to address such failure to interrupt to ensure the continued reliability of the distribution system (see Paragraph 3.4(e)).

(e) Failure to interrupt may result in the immediate discontinuance of service without notice, under Part 2, Section 2.4 (k). If the Customer is disconnected from the distribution system, reconnection will be made when the cause for the interruption no

(f) In the event that a curtailment of supply is implemented under Part 2, Section 2.3, all gas used will be billed in accordance with Appendix A – Natural Gas Curtailment Plan, even if the Customer's Transportation Gas arrives at BGE's City Gate.

Schedule IS continued

thereto is not less than 50 therms per hour at any such location. Additional metering installations used for less than 1 year are subject to charges for installation and removal, less salvage, upon removal by the Company.

5.6 DEFINITIONS:

(a) Transportation Gas: All gas to which the Customer takes title at or before the Company's City Gate.
(b) Daily Imbalance: The difference between the Customer's daily use and daily delivery of Gas to the Company's City Gate.
(c) AMR: – an automated meter reading device suitable for daily interface between a Customer and the Company's data collection and processing system.
(d) Gas Production Day: A Gas Day when the Company anticipates engaging in peak shaving activities. The Company will endeavor to notify the Customer of expected peak shaving activity.
(e) Gas Day: A 24-hour period beginning at 10:00 a.m. Eastern Time.
(f) Non-Compliant Therms: Gas usage above contracted hourly OFDS volumes, if any, or all gas usage during a distribution system interruption if no contracted OFDS.
(g) Enrollment Period: The timeframe when a Customer may request an hourly volume for OFDS or cancel existing OFDS, which always ends on July 31.

5.7 METERING EQUIPMENT:

An AMR owned and maintained by the Company suitable for daily interface with the Company's data collection and processing system is required. The Customer pays the estimated installed cost of the AMR, plus any additional facilities necessary, under the provisions of Part 2, Sec. 8.5. Sixty (60) days notice is required for installation of the AMR. Service under this Option will commence upon installation of the AMR.

5.8 INFORMATION FEE:

All Customers served under this Schedule shall pay a monthly Information Fee of $65.

6. RIDERS APPLICABLE: This Schedule is subject to Riders applicable as listed below:

9. Demonstration and Trial Installations
10. Billing in Event of Service Interruption
11. Unaccounted - For Gas Factor
14. Economic Development
15. Multi-Year Plan ("MYP") Adjustment Rider
16. STRIDE (Strategic Infrastructure Development and Enhancement) Surcharge

INTERRUPTIBLE SMALL VOLUME SERVICE -- GAS SCHEDULE ISS

1. AVAILABILITY:

(a) Where the connected capacity of the Customer's gas-fired equipment is at least 50 therms per hour and less than 250 therms per hour,

(b) where the Customer must interrupt their use of gas within 2 hours, or sooner if possible, following receipt of notice by the Company at any time of the day, and during any time of the year, and

(c) where "interrupt their use of gas" means that the Customer must reduce gas consumption to zero or to contracted Optional Firm Delivery Service (OFDS) levels, if any.

2. RATE TABLE:

Effective with service rendered on or after 12/17/2019
Customer Charge . . . . $363.50 per month, plus
Demand Price . . . . $ 1.0538 per therm
Delivery Price . . . . $ 0.1190 per therm

Distribution Interruption Penalty Price……………………………..…….$0.3026 per therm
Excessive Use Distribution Interruption Penalty Price……………..…$0.4034 per therm

Optional Firm Delivery Service …OFDS Hourly Volume x 24 hours x Number of Days in Month x Optional Firm Delivery Price. The following rates will apply to OFDS volumes:

First 10,000 therms per month……………………………………..$0.2438 per therm
Over 10,000 therms per month…………………………………….$0.0201 per therm

	Rate Year 1 Effective January 1, 2021	Rate Year 2 Effective January 1, 2022	Rate Year 3 Effective January 1, 2023
Customer Charge (per Month)	$363.50	$363.50	$375.00
Demand Price ($/therm)	$1.0538	$1.0538	$1.2513
Delivery Price ($/therm)	$0.1190	$0.1190	$0.1405
Distribution Interruption Penalty Price ($/therm)	$0.3026	$0.3026	$0.4626
Excessive Use Distribution Interruption Penalty Price ($/therm)	$0.4034	$0.4034	$0.6168
OFDS – First 10,000 ($/therm)	$0.2438	$0.2438	$0.3084
OFDS – Over 10,000 ($/therm)	$0.0201	$0.0201	$0.0421

AMR Required for Delivery Service. . . . . .Estimated Installed Cost
Information Fee if AMR installed. . . . . $65 per month

Schedule ISS continued

Comprehensive Balancing Option. . . . .$0.0006 per therm

Self Balancing Option: The following Imbalance Prices apply:

Percent of Imbalance	Imbalance Price
0 to 3%	No Charge
Greater than 3% to 6%	$0.00393 per therm
Greater than 6% to 10%	$0.00524 per therm
Greater than 10% to 15%	$0.01048 per therm
Greater than 15%	$0.02096 per therm

3. DELIVERY SERVICE:

Interruptible Service transportation of gas through the Company's distribution system for all Customers served under this Schedule.

3.1 Billing Demand: The Customer's Billing Demand is the maximum winter day measured demand during the latest 12 month period adjusted to the nearest whole Dth. Measured demand is the Customer's total metered use of gas during the Gas Day beginning at 10:00 a.m. Eastern time. The winter period is the 5 months of November through March, inclusive.

3.2 Demand Free Day: For a Customer taking service hereunder, the Company may at its option designate any Gas Day as "demand free". The designation, if any, will be made no later than 2 p.m., Eastern Time, of the day immediately preceding the Demand Free day. Any gas used during a Demand Free day will not be considered when determining a Customer's Billing Demand.

3.3 Optional Firm Delivery Service

(a) The Customer may contract for Optional Firm Delivery Service through meters served under this Schedule. This option allows the Customer to contract for a specific amount of firm distribution service available to interruptible customers during a distribution system interruption. The Company will not maintain interstate gas pipeline capacity to supply the Customer's OFDS requirements. The Customer must contract for a specific volume of OFDS on an hourly basis. The Company reserves the right to decline a request for new or an increase to OFDS should capacity not be available on the gas distribution system. However, the Customer may request a distribution system upgrade under the terms of Part 2, Section 8 to receive OFDS. The OFDS rates are incremental to all existing ISS tariff rates. The OFDS rates represent the effective difference between the existing ISS rates and the Schedule C delivery prices.

(b) An existing Schedule ISS Customer desiring OFDS volumes must contract for a specific hourly amount, at a specified meter, with the Company, and revise their request no later than July 31 to be effective November 1 through October 31. The initial term of contract for OFDS is 2 years. During the first year of the initial term, and before July 31, the Customer may revise their OFDS contract volume to no less than 50% of the original contract amount, or as high as needed, providing sufficient distribution capacity is available, to be effective November 1. Upon completion of the initial 2 year contract period, the contract will continue to automatically renew for 1 year unless notified by the Customer by July 31. Following the first initial enrollment period, subsequent enrollment periods will have no limitations on the OFDS volumes, provided there is available distribution system capacity.

Schedule ISS continued

(c) A new Customer to Schedule ISS may contract for OFDS upon commencement of interruptible service or at the next Enrollment Period. The 2 year initial contract timeframe will be determined to place the Customer on the November 1 to October 31 contract schedule.

(d) A Customer who fails two physical interruption tests may also contract for OFDS as described in Section 3.5.

(e) Schedule ISS remains the controlling Schedule when a Customer contracts for OFDS.

3.4 Use of Gas During an Interruption:

(a) If a Customer does not contract for OFDS, the Customer must reduce their gas usage to zero during a distribution system interruption. OFDS subject to Section 3.3 of this Schedule is available during an interruption for distribution system reasons. Except as described below, if a Customer fails to reduce to zero usage or to OFDS levels during an interruption for distribution system reasons, the monthly Distribution Interruption Penalty will be assessed as follows: the average of the hourly non-compliant therms x 24 hours x number of days in the month x Distribution Interruption Penalty Price . The monthly Distribution Interruption Penalty will begin billing in May for a total of 12 months.

Customer's non-compliant usage is considered Excessive Use if, during any hour of a distribution system interruption, non-compliant usage exceeds 575 therms. The monthly Excessive Use Distribution Interruption Penalty will be assessed as follows: all non-compliant therms for that event x the number of days in the month x the Excessive Use Distribution Interruption Penalty Price. However, in the event a distribution system interruption is less than 24 hours, and the Customer's non-compliant usage is Excessive Use, the monthly Excessive Use Distribution Interruption Penalty will be calculated as the higher of:

(The average hourly non-compliant therms) x (24 hours) x (the number of days in the month) x (the Excessive Use Distribution Interruption Penalty Price)

Or

(All non-compliant therms) x (the number of days in the month) x (the Excessive Use Distribution Interruption Penalty Price).

The monthly Excessive Use Interruption Penalty will begin billing in May for a total of 12 months. Each interruption will be evaluated individually.

When multiple distribution interruptions occur during the 12 month period from May to April, the average hourly non-compliant therms from each interruption are billed cumulatively over the 12 months beginning in May. All revenue collected from the application of the Distribution Interruption Penalty Price and the Excessive Use Distribution Interruption Penalty Price will be applied as a credit in the determination of the Rider 8 Monthly Rate Adjustment.

Schedule ISS continued

(b) The Public Service Commission, upon the request of BGE or a Customer served under this Schedule, may choose to reduce or waive entirely the duration of the Distribution Interruption Penalty or the Excessive Use Distribution Interruption Penalty in Paragraph 3.4(a) for a Customer who demonstrates that a good faith effort was made to interrupt its gas usage as required under this Schedule and substantially reduced its usage during an interruption. The demonstration of a good faith effort shall include (1) efforts made prior to the interruption to be fully compliant; (2) the reason why full compliance was not attained, such as sudden failure of alternative fuel equipment; (3) efforts to correct non-compliance during the interruption; and (4) customer actions after the interruption to be fully compliant in the future. Usage above hourly OFDS levels during an interruption of more than 5% of the Customer's billing demand, for the specified meter, effective during the month of the interruption shall be prima facie evidence that the Customer did not make a good faith effort to comply with the interruption. However, any waiver or reduction of the Distribution Interruption Penalty or the Excessive Use Distribution Interruption Penalty shall consider the Customer's good faith efforts to interrupt its gas usage and may not be based solely on the extent to which the Customer actually reduced its gas usage. Any credits granted to Customers through the waiver process will also result in similar debits to Rider 8 – Monthly Rate Adjustment.

(c) All OFDS gas used by the Customer during an interruption for distribution system reasons, without a Gas Production Day, except the Customer's Transportation Gas, is billed at the higher of the Gas Commodity Price , or 110% of the highest Transco Zone 6 (non-New York) price for the current month. All OFDS gas used by the Customer during an interruption for distribution system reasons and a Gas Production Day, except the Customer's Transportation Gas, a $0.50 per therm penalty is added to the higher of the Gas Commodity Price, or 110% of the highest Transco Zone 6 (non-New York) price for the current month. Any penalty revenue will be treated as gas commodity revenue. For all gas used by the Customer, during an interruption, in excess of the OFDS volumes, even if the Customer's Transportation Gas arrives at BGE's City Gate, a $1.50 per therm penalty is added to the higher of the Gas

Commodity Price or 110% of the highest Transco Zone 6 (non-New York) price for the current month. This penalty revenue will be allocated as follows: One-third of the penalty revenue will be treated as gas commodity revenue while the remaining two-thirds of the penalty will be applied as a credit in the determination of the Rider 8 – Monthly Rate Adjustment.

(d) If a Customer fails to interrupt its use of gas, and the Customer is unable to demonstrate items (1)-(4) as described in Paragraph 3.4(b), the Company, at its discretion, may take actions to ensure the future reliability of its distribution system.

However, the Company may also take such actions if a Customer fails to interrupt its use of gas during two or more interruption events which are initiated within a period of 36 months. Such actions may include, but are not limited to, the termination of service to the Customer under this Schedule. Prior to the termination of service to the Customer under this Schedule becoming effective, BGE shall provide at least thirty (30) calendar days written notice to both the Customer and the Commission. In addition, the Company has the right to deny the Customer's request for interruptible service under any other schedule.

Schedule ISS continued

This provision is not applicable during an actual gas interruption event during which a Customer has failed to interrupt as required under this Schedule. BGE may employ any actions necessary to address such failure to interrupt to ensure the continued reliability of the distribution system (see Paragraph 3.4(e)).

(e) Failure to interrupt may result in the immediate discontinuance of service without notice, under Part 2, Section 2.4 (k). If the Customer is disconnected from the distribution system, reconnection will be made when the cause for the interruption no longer exists subject to the Customer satisfying all requirements of the Gas Service Tariff.

(f) In the event that a curtailment of supply is implemented under Part 2, Section 2.3, all gas used will be billed in accordance with Appendix A – Natural Gas Curtailment Plan, even if the Customer's Transportation Gas arrives at BGE's City Gate.

Schedule ISS continued

(c) AMR: – an automated meter reading device suitable for daily interface between a Customer and the Company's data collection and processing system.

(d) Gas Production Day: A Gas Day when the Company anticipates engaging in peak shaving activities. The Company will endeavor to notify the Customer of expected peak shaving activity.

(e) Gas Day: A 24-hour period beginning at 10:00 a.m. Eastern Time.

(f) Non-Compliant Therms: Gas usage above contracted hourly OFDS volumes, if any, or all gas usage during a distribution system interruption if no contracted OFDS.

(g) Enrollment Period: The timeframe when a Customer may request an hourly volume for OFDS or cancel existing OFDS, which always ends on July 31.

5.7 METERING EQUIPMENT:

An AMR owned and maintained by the Company suitable for daily interface with the Company's data collection and processing system is required. The Customer pays the estimated installed cost of the AMR, plus any additional facilities necessary, under the provisions of Part 2, Sec. 8.5. Sixty (60) days notice is required for installation of the AMR. Service under this Option will commence upon installation of the AMR.

5.8 INFORMATION FEE:

All Customers served under this Schedule shall pay a monthly Information Fee of $65.

6. RIDERS APPLICABLE: This Schedule is subject to Riders applicable as listed below:

9. Demonstration and Trial Installations
10. Billing in Event of Service Interruption
11. Unaccounted - For Gas Factor
14. Economic Development
15. Multi-Year Plan ("MYP") Adjustment Rate
16. STRIDE (Strategic Infrastructure Development and Enhancement) Surcharge

INTERRUPTIBLE GAS-FIRED ELECTRIC GENERATION SERVICE – GAS SCHEDULE EG

1. Availability:

1.1 Where the combined connected capacity of all Customer gas-fired generation equipment at the Customer's premise is 2,500 therms per hour or greater;

1.2 Where the Customer must comply with the Operational Availability and Communication requirements of Section 3.4 of this Schedule and the Distribution System Interruption Requirements of Section 3.5 of this Schedule;

1.3 Where the Customer must interrupt their use of gas immediately or within the timeframe indicated by the Company following receipt of notice by the Company at any time of the day, and during any time of the year, and

1.4 Where "interrupt their use of gas" means that the Customer must reduce gas consumption to zero or contracted Optional Firm Delivery Service (OFDS) levels, if any.

2. Rate Table

Effective with service rendered on or after 12/17/2019
Customer Charge . . . . $3,000 per month, plus
Demand Price . . . . $ 0.3546 per therm
Delivery Price . . . . $ 0.0843 per therm

Distribution Interruption Penalty Price…………………………..…….$0.4359 per therm
Excessive Use Distribution Interruption Penalty Price……………..…$0.5812 per therm

Optional Firm Delivery Service …OFDS Hourly Volume x 24 hours x Number of Days in Month x Optional Firm Delivery Price. The following rates will apply to OFDS volumes:

First 10,000 therms per month……………………………………..$0.3299 per therm
Over 10,000 therms per month…………………………………….$0.1062 per therm

	Rate Year 1 Effective January 1, 2021	Rate Year 2 Effective January 1, 2022	Rate Year 3 Effective January 1, 2023
Customer Charge (per Month)	$3,000.00	$3,000.00	$3,000.00
Demand Price ($/therm)	$0.3546	$0.3546	$0.3546
Delivery Price ($/therm)	$0.0843	$0.0843	$0.0843
Distribution Interruption Penalty Price ($/therm)	$0.4359	$0.4359	$0.6051
Excessive Use Distribution Interruption Penalty Price ($/therm)	$0.5812	$0.5812	$0.8068
OFDS – First 10,000 ($/therm)	$0.3299	$0.3299	$0.4034
OFDS – Over 10,000 ($/therm)	$0.1062	$0.1062	$0.1371

AMR Required…………………………………..Estimated Installed Cost
Information Fee…………………………………$65 per month

Schedule EG continued

Comprehensive Balancing Option. . . . .$0.0006 per therm

Self-Balancing Option: The following Imbalance Prices apply:

Percent of Imbalance	Imbalance Price
0 to 3%	No Charge
Greater than 3% to 6%	$0.00393 per therm
Greater than 6% to 10%	$0.00524 per therm
Greater than 10% to 15%	$0.01048 per therm
Greater than 15%	$0.02096 per therm

3. Delivery Service:

Interruptible Service transportation of gas through the Company's distribution system for all Customers served under this Schedule.

3.1 Billing Demand: The Customer's Billing Demand is the maximum winter day measured demand during the latest 12-month period adjusted to the nearest whole Dth. Measured demand is the Customer's total metered use of gas during the Gas Day beginning at 10:00 a.m. Eastern Prevailing Time. The winter period is the 5 months of November through March, inclusive.

3.3 Optional Firm Delivery Service

3.3.1 The Customer may contract for Optional Firm Delivery Service through meters served under this Schedule. This option allows the Customer to contract for a specific amount of firm distribution service available to interruptible gas-fired electric generation customers throughout the year and during a distribution system interruption. The Company will not maintain interstate gas pipeline capacity to supply the Customer's OFDS requirements. The Customer must contract for a specific volume of OFDS on an hourly basis. The Company reserves the right to decline a request, whether new or a requested increase to existing OFDS, should the Company determine capacity is not available on the gas distribution system. However, the Customer may request a distribution system upgrade under the terms of Part 2, Section 8 to receive OFDS.

The OFDS rates are incremental to all existing EG tariff rates. The OFDS rates represent the effective difference between the existing EG rates and the Schedule C delivery prices.

3.3.2 An existing Schedule EG Customer desiring OFDS volumes must contract for a specific hourly amount, at a specified meter, with the Company, and revise their request no later than July 31 to be effective November 1 through October 31. The initial term of contract for OFDS is 2 years. During the first year of the initial term, and before July 31, the Customer may revise their OFDS contract volume to no less than 50% of the original contract amount, or as high as needed, providing sufficient distribution capacity is available, to be effective November 1. Upon completion of the initial 2-year contract period, the contract will continue to automatically renew for 1 year unless notified by the Customer by July 31. Following the first initial enrollment period, subsequent enrollment periods will have no limitations on the OFDS volumes, provided there is available distribution system capacity.

Schedule EG continued

3.3.3 A new Customer to Schedule EG may contract for OFDS upon commencement of interruptible gas-fired electric generation service or at the next Enrollment Period. The 2 year initial contract timeframe will be determined in a manner such that the Customer is placed on the November 1 to October 31 contract schedule after the end of the initial 2 year contract timeframe.

3.3.4 A Customer who fails two physical interruption tests may contract for OFDS as described in Section 3.6.

3.3.5 Schedule EG remains the controlling Schedule when a Customer contracts for OFDS.

3.4 Operational Availability and Communication Requirements

3.4.1 The ability of a Customer to use gas at any time is dependent on operating conditions and system constraints. If a Customer's metered usage exceeds 20,000 therms per gas day or 2,500 therms in any given hour, the Customer is subject to comply with the Operational Availability and Communication Requirements outlined in this section.

3.4.2 Approval to operate electric generation equipment means that the Customer has conditional approval to use capacity in the Company's distribution system. The use of gas is subject to the Provisions in Section 4.2 of this Schedule. The Company may, at any time, rescind approval for the Customer to use gas.

The Customer must receive explicit approval from the Company before using gas. The lack of response from the Company is not an approval under any of the requests outlined in this section.

3.4.3 Operational Availability and Communication requirements are established on a seasonal basis. The winter period is November through March and the non-winter period is April through October.

3.4.4 Winter Period Requirements

3.4.4.1 Morning Day-Ahead Request - During the winter period, the Customer is required to submit an email request by 8:00 AM Eastern Prevailing Time to run for the following calendar day. The Company will provide a response by email to the Customer as soon as practical following reception of the request that confirms the receipt of the request. In addition, the Company will provide a substantive response by email to the Customer by 9:30 AM Eastern Prevailing Time and shall either conditionally approve the request to operate or deny the request to operate. Conditional approval may be in the form of approval of the original request, approval to use a reduced amount for the same or a reduced duration or approval to use the requested amount at a reduced duration, and may require delivery on a specified city gate/pipeline.

Schedule EG continued

The Customer shall provide the following information in the email requesting approval to operate:

(a) Gas-fired electric generating unit(s) that will run,

(b) Start time,

(c) Run time (duration),

(d) Usage by hour,

(e) Total gas usage,

(f) Interstate gas pipeline of gas delivery to the Company, and

(g) Any other information requested by the Company to evaluate the Customer's request for approval in order to maintain gas distribution system safety and reliability.

3.4.4.2 Afternoon Day-Ahead Confirmation – During the winter period, the Customer is also required to provide, to a Company prescribed email address by 3:00 PM Eastern Prevailing Time, an email confirming the original approved request or indicating requested changes to operate the following calendar day. The submission of an Afternoon Day-Ahead Confirmation that differs from the Morning Day-Ahead Request that will not be subject to penalty. The Company will provide a response by email to the Customer as soon as practical following reception of the request that confirms the receipt of the request. In addition, the Company will provide a substantive response by email to the Customer by 4:00 PM Eastern Prevailing Time and shall either conditionally confirm the original request, conditionally approve the modified request or deny the request to operate. Conditional approval may be in the form of approval of the original request, approval to use a reduced amount for the same or a reduced duration or approval to use the requested amount at a reduced duration, and may require delivery on a specified city gate/pipeline.

3.4.4.3 During the winter period, on the current gas or calendar day the Customer may submit a request to operate, via an email to the Company prescribed email address, even if conditional approval was not requested the prior day. The Customer shall provide as much notice as possible when making "day of" requests, but no less than thirty minutes prior to their planned start. The Customer shall provide in the email the same information required under Section 3.4.4.1 above. Within 15 minutes of the Customer's request, the Company will respond to the Customer approving, denying or stating that the Company requires additional time to evaluate the request and provide a time estimate thereof. Conditional approval may be in the form of approval of the original request, approval to use a reduced amount for the same or a reduced duration or approval to use the requested amount at a reduced duration.

Schedule EG continued

3.4.4.4 During the winter period, Customers who received conditional "day ahead" approval to operate shall make a confirming telephone call to the Company at least thirty minutes before and no more than two hours before beginning to use gas. When conditional approval is granted on the same day, and conditional approval is more than two hours in advance of beginning operations, the Customer shall make a confirming telephone call to the Company at least thirty minutes before beginning to use gas.

3.4.5 **Non-Winter Period Requirements**: During the non-winter period, the Customer shall provide, via email, a request to operate, with as much notice as possible, prior to starting to use gas and shall provide the same information as required under Section 3.4.4.1 when requesting approval to use gas, except that a Customer may request a range of usage by hour. The Company will respond by email within 15 minutes of the Customer's request approving, denying, or stating that the Company requires additional time to evaluate and provide a time estimate thereof. When conditional approval is granted more than two hours in advance, the Customer shall make a confirming telephone call to the Company at least thirty minutes before and no more than two hours before beginning to use gas.

3.4.6 For "day ahead" requests, if the Company determines there is not enough distribution system capacity available to approve every Customer request to operate under this Schedule, the Company will determine conditional approval based on gas system conditions and the Customer's position on the Daily priority list. The Daily priority list will be set by October 1st of each year by the Company. Capacity availability may be determined on a system-wide basis or specific to certain parts of the gas system. The Daily priority list will set the Customer's position for each day of the upcoming Winter season. The Daily priority list is only used to determine priority when there is not enough distribution system capacity available to serve all requests and does not imply approval to operate on any day. Conditional approval will be granted as described in paragraph 3.4.4.1.

"Day of" requests will be handled on a "first-come, first-served" basis when two or more customers request usage and all requests cannot be approved by the Company. "Day-of" requests will be made independent of the Daily priority list.

3.4.7 If there is a change that exceeds 2,500 therms per hour of the original approved usage in any given hour, the Customer is required to notify the Company first by phone followed by a confirming email. This excludes any changes during ramp up to full load at start-up or ramp down to shut-down within the times originally conditionally approved by the Company.

If a Customer's unit has ceased operation part-way through the original run time, the Customer shall immediately inform the Company by phone of the status of the gas-fired electric generating unit. If the Customer's unit plans to re-start outside the originally approved operating time frame, extend beyond the originally approved time frame, or there are changes to any of the other conditions approved by the Company, then the Customer shall email the information required under Section 3.4.4.1 and the request shall be treated as a new request to operate.

Schedule EG continued

3.4.8 Failure to comply with the Operational Availability and Communication requirements of Section 3.4 will result in a penalty to the Customer (incremental to any penalty assessed under Section 3.4.9). Instances of non-compliance within a rolling 24-month period will result in the following penalties being assessed:

First instance	$25,000 penalty
Second instance	$50,000 penalty,
Three or more instances	$100,000 penalty per instance.

With the third instance of non-compliance within a rolling 36-month period, the Company reserves the right to terminate service under this Schedule. Prior to termination of service to the Customer under this Schedule becoming effective, BGE shall provide at least thirty (30) calendar days written notice to both the Customer and the Public Service Commission. In addition, the Company has the right to deny the Customer's request for interruptible service under any other schedule. All revenue collected from the application of this penalty shall be applied as a credit in the determination of the Rider 8 Monthly Rate Adjustment.

3.4.9 If the Customer uses gas outside of a distribution system interruption in a manner that is not approved by the Company, the Excessive Use Distribution Interruption Penalty Price will be applied to all non-compliant gas used in addition to the Accumulated Imbalance Corrective Measures in Section 4.2.3.4. Additionally, BGE may employ any actions necessary to address a failure to comply with the provisions of this schedule to ensure the continued reliability of the distribution system. The monthly penalty will begin billing immediately for a total of 3 months. Each instance of noncompliance will be evaluated individually. All revenue collected from the application of this penalty shall be applied as a credit in the determination of the Rider 8 Monthly Adjustment. This penalty is also eligible for the waiver provisions outlined in Section 3.5.2 below. If such usage occurs during a distribution system interruption, the Excessive Use Distribution Penalty Price provisions described in Section 3.5.1 shall be applied once per event.

3.4.10 In addition to the certification requirement outlined in Section 3.6 below, the Customer's Authorized Facility Manager shall annually certify in writing that the Customer is familiar with all operational requirements for Schedule EG as described herein and all penalties associated with non-compliance. The Facility Manager shall also certify that each of their facilities/plants have procedures and policies in place to meet all requirements of this Schedule.

3.5 Use of Gas During an Interruption:

3.5.1 If a Customer does not contract for OFDS, the Customer must reduce their gas usage to zero during a distribution system interruption. OFDS, subject to Section 3.3 of this Schedule, is available during an interruption for distribution system reasons. Except as described below, if a Customer fails to reduce to zero usage or to OFDS levels during an interruption for distribution system reasons, the monthly Distribution Interruption Penalty will be assessed as follows: the average of the hourly non-compliant therms x 24 hours x number of days in the month x Distribution Interruption Penalty Price. The monthly Distribution Interruption Penalty will begin billing in May for a total of 12 months.

Schedule EG continued

Customer's non-compliant usage is considered Excessive Use if, during any hour of a distribution system interruption, non-compliant usage exceeds 575 therms. The monthly Excessive Use Distribution Interruption Penalty will be assessed as follows: all non-compliant therms for that event x the number of days in the month x the Excessive Use Distribution Interruption Penalty Price. However, in the event a distribution system interruption is less than 24 hours, and the Customer's non-compliant usage is Excessive Use, the monthly Excessive Use Distribution Interruption Penalty will be calculated as the higher of:

(The average hourly non-compliant therms) x (24 hours) x (the number of days in the month) x (the Excessive Use Distribution Interruption Penalty Price)

Or

(All non-compliant therms) x (the number of days in the month) x (the Excessive Use Distribution Interruption Penalty Price).

The monthly Excessive Use Interruption Penalty will begin billing in May for a total of 12 months. Each interruption will be evaluated individually.

When multiple distribution interruptions occur during the 12-month period from May to April, the average hourly non-compliant therms from each interruption are billed cumulatively over the 12 months beginning in May. All revenue collected from the application of the Distribution Interruption Penalty Price and Excessive Use Distribution Interruption Penalty Price will be applied as a credit in the determination of the Rider 8 Monthly Rate Adjustment.

3.5.2 The Public Service Commission, upon the request of BGE or a Customer served under this Schedule, may choose to reduce or waive entirely the duration of the Distribution Interruption Penalty or the Excessive Use Distribution Interruption Penalty in Section 3.5 for a Customer who demonstrates that a good faith effort was made to interrupt its gas usage as required under this Schedule and substantially reduced its usage during an interruption. The demonstration of a good faith effort shall include (1) efforts made prior to the interruption to be fully compliant; (2) the reason why full compliance was not attained, such as sudden failure of alternative fuel equipment; (3) efforts to correct non-compliance during the interruption; and (4) customer actions after the interruption to be fully compliant in the future. Usage above hourly OFDS levels during an interruption of more than 5% of the Customer's billing demand, for the specified meter, effective during the month of the interruption shall be prima facie evidence that the Customer did not make a good faith effort to comply with the interruption. However, any waiver or reduction of the Distribution Interruption Penalty or the Excessive Use Distribution Interruption Penalty shall consider the Customer's good faith efforts to interrupt its gas usage and may not be based solely on the extent to which the Customer actually reduced its gas usage. Any credits granted to Customers through the waiver process will also result in similar debits to Rider 8 Monthly Rate Adjustment.

Schedule EG continued

3.5.3 All OFDS gas used by the Customer during an interruption for distribution system reasons, without a Gas Production Day, except the Customer's Transportation Gas, is billed at the higher of the Gas Commodity Price , or 110% of the highest Transco Zone 6 (non-New York) price for the current month. All OFDS gas used by the Customer during an interruption for distribution system reasons and a Gas Production Day, except the Customer's Transportation Gas, a $0.50 per therm penalty is added to the higher of the Gas Commodity Price, or 110% of the highest Transco Zone 6 (non-New York) price for the current month. Any penalty revenue will be treated as gas commodity revenue. For all gas used by the Customer, during an interruption, in excess of the OFDS volumes, even if the Customer's Transportation Gas arrives at BGE's City Gate, a $1.50 per therm penalty is added to the higher of the Gas Commodity Price or 110% of the highest Transco Zone 6 (non-New York) price for the current month. This penalty revenue will be allocated as follows: One-third of the penalty revenue will be treated as gas commodity revenue while the remaining two-thirds of the penalty will be applied as a credit in the determination of the Rider 8 – Monthly Rate Adjustment.

3.5.4 If a Customer fails to interrupt its use of gas, and the Customer is unable to demonstrate items (1)-(4) as described in Section 3.5.2, the Company, at its discretion, may take actions to ensure the future reliability of its distribution system.

However, the Company may also take such actions if a Customer fails to interrupt its use of gas during two or more interruption events which are initiated within a period of 36 months. Such actions may include, but are not limited to, the termination of service to the Customer under this Schedule. Prior to the termination of service to the Customer under this Schedule becoming effective, BGE shall provide at least thirty (30) calendar days written notice to both the Customer and the Commission. In addition, the Company has the right to deny the Customer's request for interruptible service under any other schedule. This provision is not applicable during an actual gas interruption event during which a Customer has failed to interrupt as required under this Schedule. BGE may employ any actions necessary to address such failure to interrupt to ensure the continued reliability of the distribution system (see Section 3.5.5).

3.5.5 Failure to interrupt may result in the immediate discontinuance of service without notice, under Part 2, Section 2.4 (k). If the Customer is disconnected from the distribution system, reconnection will be made when the cause for the interruption no longer exists subject to the Customer satisfying all requirements of the Gas Service Tariff.

3.5.6 In the event that a curtailment of supply is implemented under Part 2, Section 2.3, all gas used will be billed in accordance with Appendix A – Natural Gas Curtailment Plan, even if the Customer's Transportation Gas arrives at BGE's City Gate.

3.5 **Interruption Capability Verification Program:** BGE will test the Customer's ability to interrupt. The test will consist of two parts. Part one will test the Customer's communication systems. BGE will perform this portion of the test annually. Part two will test the ability of the Customer to interrupt with at least six hours notice for at least four hours. The Customer can satisfy this portion of the test by either 1) enlisting the services of a licensed Professional Engineer to certify that the equipment and/or procedures are in place to reduce gas usage to zero, or to contracted hourly OFDS volumes; or 2) actively participate in a physical test interruption. The Physical Interruption Test and/or Professional Engineer certification will be required every year. Should BGE call a Distribution System Interruption, any customer that complies with the interruption will not be required to participate in the Physical Interruption Test or provide a Professional Engineer certification for the next 12 months from the date of the interruption. Customers must instead provide certification from the Authorized Facility Manager indicating that no material changes and/or additions have been made to the equipment or production process, and that the Customer would comply with the requirements of an interruption. A Customer who fails to provide an annual Authorized Facility Manager Certificate will be required to complete a Physical Interruption Test early in the next winter heating season. If a Customer fails to reduce to zero usage or to contracted OFDS amounts during an interruption for distribution reasons, the Customer will be required to participate in a Physical Interruption Test.

A new Customer will be required to complete a Physical Interruption Test early in the next winter heating season. In addition, a new Customer will also be required to complete Part one of the Interruption Capability Verification Program.

Penalties associated with the Use of Gas During an Interruption provisions of this rate schedule will be waived the first time the Customer fails the Physical Interruption Test. If the Customer fails the Physical Interruption Test a second time, all penalties under Section 3.5 of this Schedule will apply until such time that the Customer becomes compliant. A Customer who fails a second Physical Interruption Test has the option of immediately contracting for 2 years of OFDS, if available, effective November 1 of the current heating season. 12 months of penalty billing for a second failed Physical Interruption Test will commence immediately unless the Customer contracts for OFDS. In addition, the Customer will be subject to disconnection from the gas distribution system under Section 2.4(k), and may be reconnected after they have demonstrated, to BGE's satisfaction, that they have made the necessary improvements and can complete the Physical Interruption Test.

3.7 Extension Provision:

3.7.1 The Customer pays the Company in advance, or at the completion of installation upon credit approval, the estimated installed cost of additional Main and Service Line facilities required to provide service under this Schedule.

3.7.2 Upon request by the Customer, the contribution required from the Customer will be determined under the provisions of Part 2, Sec 8.

Schedule EG continued

4. Gas Commodity Service

4.1 BGE Gas Commodity Service: The Company does not offer Gas Commodity Service under this Schedule. However, gas may be provided from month-to-month on a best efforts basis provided the Customer makes a request for such gas prior to the first day of the delivery month. This gas is priced at the Gas Commodity Price (Riders 2 and 12).

Even if the Company approves the Customer's request for gas supply, the Gas Commodity Price is not applicable for any gas used during a Gas Production Day, a Distribution System Interruption or a curtailment under Appendix A. During a Gas Production Day, a Distribution System Interruption or a curtailment under Appendix A, the pricing provisions governing those situations will apply.

4.2 Supplier Gas Commodity Service: The Customer must obtain Gas Commodity Service from a third party gas supplier subject to the following Terms and Conditions

4.2.1 Terms and Conditions

4.2.1.1 the Customer must arrange for the transport and delivery of gas into the Company's distribution system at its interstate pipeline gate station(s); and

4.2.1.2 the Customer may only contract with a gas supplier that has separately contracted with the Company under the provisions of the Gas Supplier Tariff. In the event that the Customer's gas supplier becomes disqualified under the Gas Supplier Tariff, the Customer must obtain Gas Commodity Service from another qualified gas supplier. The Customer shall select only one gas supplier for any period; and

4.2.1.3 the Customer takes title to the gas at or before the Company's City Gate; and

4.2.1.4 the transported gas must be for the Customer's burner tip use and shall not be resold except as an Accumulated Imbalance Corrective Measure as provided for in this Schedule; and

4.2.1.5 the Customer shall be responsible for the payment of any tax or assessment levied by any jurisdiction related to the acquisition, transportation or use of Transportation Gas.

4.2.2 Failure of the Customer's Transportation Gas to arrive at the City Gate: Where all or part of the Customer's Transportation Gas fails to arrive at the Company's City Gate the Customer is subject to Section 4.2.3.4 - Accumulated Imbalance Corrective Measures of this Schedule.

4.2.3 City Gate Balancing Service: The Company balances daily gas deliveries at the City Gate with unaccounted-for gas adjusted, burner tip use. The Customer must select one of the Balancing Service Options. The prices for the components of Balancing Service are in addition to the monthly rates for Delivery Service and apply to the Customer's metered use.

Schedule EG continued

4.2.3.1 Balancing Service Options:

(a) **Comprehensive Balancing Service:** Balancing of the gas delivered to the Company's City Gate on behalf of the Customer with the Customer's use of gas on a daily basis is performed by the Company. A Comprehensive Balancing Service Price is applied to all therms of gas used by the Customer adjusted to the Company's City Gate. The Customer also pays a pro rata share of any interstate gas pipeline penalties incurred based on the Customer's Daily Imbalance in the same direction as the Imbalance for which the penalty was incurred, unless the Customer is part of a Selective Group, and that Group is in balance.

At any time that the Customer's accumulated imbalance exceeds 2 times the Customer's average daily nomination for the 5 highest of the preceding 7 days nominations or 1,000 Dth, whichever is smaller, the Accumulated Imbalance Corrective Measures of Section 4.2.3.4 may be required.

(b) **Self Balancing Option:** Balancing of gas delivered to the Company's City Gate on behalf of the Customer with the Customer's use of gas on a daily basis is the responsibility of the Customer. An Imbalance Price based on the percentage of the Daily Imbalance to the Customer's average daily nomination is applied to the Daily Imbalance. The Customer also pays a pro rata share of any interstate gas pipeline penalties incurred based on the Customer's Daily Imbalance in the same direction as the Imbalance for which the penalty was incurred, unless the Customer is part of a Selective Group, and that Group is in balance.

The Imbalance Prices are determined as a percentage of the weighted average cost for the Company to correct an imbalance. The resultant Imbalance Prices are revised when the calculated weighted average cost of correcting an imbalance changes by more than 5 percent from the currently effective cost of correcting an imbalance. Details of the calculation of the weighted average cost of correcting an imbalance and the resultant Imbalance Prices are filed with the Public Service Commission.

At any time that the Customer's accumulated imbalance exceeds 20 percent of the Customer's average daily nomination for the 5 highest of the preceding 7 days nominations, the Accumulated Imbalance Corrective Measures of Section 4.2.3.4 may be required.

Schedule EG continued

4.2.3.2 Selective Grouping: Under either the Comprehensive Balancing Service or the Self Balancing Option, the Customer may join other customers in forming a Group for Daily Balancing purposes only. Where the Customer participates in a Group under the Self Balancing Option, a Group Administrator is required. The Group Administrator shall separately contract with the Company under the Gas Supplier Tariff and shall be responsible for payment of all Imbalance Prices and penalties. A Group Administrator is permitted for Groups under the Comprehensive Balancing Service. The Customer may revise their selection of Group membership on a monthly basis.

4.2.3.3 Daily Balancing Revenue: The revenue collected through the application of the Comprehensive Balancing Service Price and the Imbalance Price is recorded as Gas Commodity Price revenue.

4.2.3.4 Accumulated Imbalance Corrective Measures:

(a) **Over-Tendered Accumulated Imbalance:** When the Customer's accumulated imbalance exceeds the applicable limit, the Company will purchase the total accumulated over-tendered imbalance at the lower of the Gas Commodity Price, or 90% of the lowest Transcontinental Gas Pipeline Corporation (Transco) Zone 6 (non-New York) price for the current month. On Gas Production Days, Balancing Service provisions are suspended. When Gas Production Days cease, the Company will provide a period of time for the Customer to reduce the amount of any over-tendered imbalance.

(b) At the conclusion of this time period, if the accumulated imbalance exceeds the applicable limit, the Company will purchase the total accumulated imbalance at the above stated price.

(c) **Under-Tendered Accumulated Imbalance:** When the Customer's accumulated imbalance exceeds the applicable limit, the Customer will purchase all gas used in excess of delivered Transportation Gas at the following rates:

(i) During periods other than an interruption for system distribution reasons or Gas Production Days, all gas used will be billed at the higher of the Gas Commodity Price or 110% of the highest Transco Zone 6 (non-New York) price for the current month.

Schedule EG continued

(ii) On Gas Production Days, Balancing Service provisions are suspended. A tolerance of 3% is permitted on under-deliveries. When the 3% tolerance is exceeded, the following corrective measures become effective. For all gas used in excess of the Customer's Transportation Gas arriving at the Company's City Gate, including the 3% tolerance, a $0.50 per therm penalty will be added to the higher of the Gas Commodity Price or 110% of the highest Transco Zone 6 (Non-New York) price for the current month. Any penalty revenue will be treated as gas commodity revenue.

(iii) During periods of an interruption for system distribution reasons, the Use of Gas During an Interruption provisions of this Schedule apply.

4.2.3.5 Interruption of Transportation Gas for Distribution System Reasons: Where the Company interrupts the Customer's Transportation Gas for Distribution System reasons, the Imbalance Fees will not apply during the period of the interruption.

Schedule EG continued

5. General Terms:

5.1 Minimum Charge: Customer Charge

5.2 Late Payment Charge: Standard (Part 2, Sec 7.5)

5.3 Payment Terms: Standard (Part 2, Sec 7.5)

5.4 Term of Contract with BGE: The initial term of contract is 1 year or as required for allowance under the Extension Provisions above. The contract continues thereafter from year to year until terminated at the expiration of any such term by at least 30 days notice from either party to the other.

5.5 General

5.5.1 The supply of both interruptible service under this Schedule and firm service under Schedule C is permitted upon separation of facilities by the Customer.

5.5.2 The supply of interruptible service to a Customer under this Schedule for the Customer's requirements at two or more locations on property comprising single or contiguous land parcels, as defined in Part 2, Sec. 2.2, may be combined in billing on a single application of this Schedule where the Customer installs, operates and maintains at the Customer's expense, all additional Service Line installations required for supply at other than the initial location, provided the capacity of specific gas-fired equipment connected thereto is not less than 50 therms per hour at any such location. Additional metering installations used for less than 1 year are subject to charges for installation and removal, less salvage, upon removal by the Company.

5.6 Definitions

5.6.1 Connected capacity: As used in this Schedule is the therms estimated to be used when the gas-fired equipment is operated for 1 hour under optimum load conditions.

5.6.2 Transportation Gas: All gas to which the Customer takes title at or before the Company's City Gate.

5.6.3 Daily Imbalance: The difference between the Customer's daily use and daily delivery of Gas to the Company's City Gate.

5.6.4 AMR: An automated meter reading device suitable for daily interface between a Customer and the Company's data collection and processing system.

Schedule EG continued

5.6.5 Gas Production Day: A Gas Day when the Company anticipates engaging in peak shaving activities. The Company will endeavor to notify the Customer of expected peak shaving activity.

5.6.6 Gas Day: A 24-hour period beginning at 10:00 a.m. Eastern Prevailing Time.

5.6.7 Non-Compliant Therms: Gas usage above contracted hourly OFDS volumes, if any, or all gas usage during a distribution system interruption if no contracted OFDS or any unapproved gas usage.

5.6.8 Enrollment Period: The timeframe when a Customer may request an hourly volume for OFDS or cancel existing OFDS, which always ends on July 31.

5.7 Metering Equipment: An AMR owned and maintained by the Company suitable for daily interface with the Company's data collection and processing system is required. The Customer pays the estimated installed cost of the AMR, plus any additional facilities necessary, under the provisions of Part 2, Sec. 8.5. Sixty (60) days notice is required for installation of the AMR. Service under this Option will commence upon installation of the AMR

5.8 Information Fee All Customers served under this Schedule shall pay a monthly Information Fee of $65.

6. Riders Applicable: This schedule is subject to Riders applicable as listed below:

9. Demonstration and Trial Installations
10. Billing in Event of Service Interruption
11. Unaccounted - For Gas Factor
14. Economic Development
15. Multi-Year Plan ("MYP") Adjustment Rider
16. STRIDE (Strategic Infrastructure Development and Enhancement) Surcharge

(c) The Customer agrees to notify the Company promptly of any escape of gas or of unused gas at the lamp because of extinguished flame so that it can proceed to correct the condition and restore service.

(d) The Company is not liable for any loss, cost, damage or expense to any party resulting from the use or presence of gas in the Customer's facilities.

6. GENERAL TERMS

6.1 Minimum Charge: Customer Charge

6.2 Late Payment Charge: Standard. (Part 2, Sec. 7.5)

6.3 Payment Terms: Standard. (Part 2, Sec. 7)

7. RIDERS APPLICABLE: This Schedule is subject to Riders applicable as listed below:

2. Gas Commodity Price
10. Billing in Event of Service Interruption
11. Unaccounted for Gas Factor
15. Multi-Year Plan (“MYP”) Adjustment Rider

GAS SERVICE TO GRANTORS OF RIGHTS-OF-WAY TO THE MARYLAND GAS TRANSMISSION CORPORATION

1. AVAILABILITY:

(a) Gas for domestic use is sold direct from the transmission line to grantors of rights-of-way for the natural gas transmission line granted to and exercised by The Maryland Gas Transmission Corporation, its successors and assigns, in Baltimore, Harford and Howard Counties, Maryland, subject to the consent and agreement of that Corporation, under the Company's Gas Service Tariff, and only to such successors and assigns of such grantors as are residents as of the date service is supplied, of property on which the transmission line is located.

2. RATE TABLE

Effective with service rendered on or after 12/17/2019
Customer Charge:…………………………………………….$ 14.25 per month
Delivery Price (For all gas used)……………………………... $0.5960 per therm

	Rate Year 1 Effective January 1, 2021	**Rate Year 2 Effective January 1, 2022**	**Rate Year 3 Effective January 1, 2023**
Customer Charge (per Month)	$14.25	$14.25	$15.25
Delivery Price ($/therm)	$0.5921	$0.5904	$0.7154

3. DELIVERY SERVICE: Firm service of gas sold directly from the transmission line for all customers served under this Schedule.

4. TERMS AND CONDITIONS

A. Under Part 2

4.1. The following does not apply:

(a) Section 3.5 Use for Less Than Initial Term of Contract;
(b) In Section 4.1 – Service Equipment Furnished by the Customer – the fourth sentence of the second paragraph only;
(c) In Section 5.1 – Service Equipment Furnished by the Company, paragraphs (a) & (c) only;
(d) In Section 6.1 - Location of Service Equipment – General – the second and third paragraphs only;
(e) Section 8.15 – Grading of Property;
(f) Section 8.2 – Charges for Extensions; and
(g) Section 8.5 – Payment Plans.

4.2. Customer's Installation: That part of the service from a point within 3 feet of the transmission line to a point within the building to be supplied is designated

"Excess Service", is installed by the Company at the Customer's expense and is owned and maintained by him. The route shall be the shortest practicable route lying entirely within the property of the Customer.

5. GENERAL TERMS:

5.1 The Customer assumes the responsibility for the detection of any defect or leak on his premises, and agrees in the event of any failure of the service due to irregular supply, leakage, high or low pressure, to notify the Company immediately.

5.2 Minimum Charge: .... Customer Charge

5.3 Late Payment Charge: ....Standard. (Part 2, Sec. 7.5)

5.4 Payment Terms...................................... Standard (Part 2, Sec. 7)

5.5 Term of Contract: One year; thereafter until terminated by at least 10 days notice from the Customer. The Customer shall pay all costs of connection and disconnection, if service is used less than 1 year.

6. RIDERS APPLICABLE: This Schedule is subject to Riders applicable as listed below:

1. Gas Efficiency Charge
2. Gas Commodity Price
4. Budget Billing
5. Smart Meter Opt-Out
7. Gas Choice and Reliability Charge
8. Monthly Rate Adjustment
10. Billing in Event of Service Interruption
11. Unaccounted – For Gas Factor
12. Gas Administrative Charge
15. Multi-Year Plan ("MYP") Adjustment Rider
16. STRIDE (Strategic Infrastructure Development and Enhancement) Surcharge

RIDER INDEX

1. Gas Efficiency Charge
2. Gas Commodity Price
3. Standby Service Price
4. Budget Billing
5. Smart Meter Opt-Out
6. (Reserved for Future Use)
7. Gas Choice and Reliability Charges
8. Monthly Rate Adjustment
9. Demonstration and Trial Installations
10. Billing in Event of Service Interruption
11. Unaccounted - For Gas Factor
12. Gas Administrative Charge
13. (Reserved for future use)
14. Economic Development
15. Multi-Year Plan (“MYP”) Adjustment Rider
16. STRIDE (Strategic Infrastructure Development and Enhancement) Surcharge
17. Prepaid Pilot

Schedule		Riders Applicable
D	. . . .	**1, 2, 4, 5, 7, 8, 10, 11, 12, 15, 16, 17**
C	. . . .	**2, 3, 4, 5, 7, 8, 9, 10, 11, 12, 14, 15, 16**
IS	. . . .	**9, 10, 11, 14, 15, 16**
ISS	. . . .	**9, 10, 11, 14, 15, 16**
EG	. . . .	**9, 10, 11, 14, 15, 16**
PLG	. . . .	**2, 10, 11, 15**
GRANTORS	. . . .	**1, 2, 4, 5, 7, 8, 10, 11, 12, 15, 16**

Rider 14. Economic Development (continued)

Incentives

Location	Rate Reductions	Discount Length	Extension Charge Discount
Non-Enterprise Zone	25%	3 years	None
Enterprise Zone	25%	5 years	75%

Price reductions are applied only to the Customer Charge, Delivery Service Charge (exclusive of all riders), and Demand Charge (if applicable). Price reductions will not be applied to any other charges, taxes, etc. Only the Qualifying Load is eligible for these price reductions. The combined total price reductions for all Customers under this Rider are limited to $2 million per calendar year. New applicants are not eligible for these price reductions in years where this limit is exceeded.

For Enterprise Zone customers the Company will provide a 75% discount to the extension charge requirements set forth in Section 8 of this tariff. The Customer's contribution is subject to gross-up for taxes. For each Customer, the discount is limited up to a maximum of $2.5 million per signed contract where the total amount of extension charge price reductions granted in a calendar year under this Rider does not exceed $5 million.

Failure to meet the requirements of the Rider will result in termination of ongoing price reductions and extension charge discounts and may require the Customer to reimburse Company for any price reductions and extension charge discounts previously granted. The Company will report to Commission Staff on the use of this Rider annually by September 1st of each year.

15. Multi-Year Plan ("MYP") Adjustment Rider

This rider addresses Imbalances that may arise between the revenue requirement approved by the Commission as part of initial rates under a Multi-Year Plan ("MYP") and the actual revenue requirement filed as part of the Annual Informational Filings or Final Reconciliation, pursuant to Order No. 89482.

The Annual Informational Filings shall be filed within 90 days of the end of the first and second years of the approved MYP.

The Final Reconciliation shall be filed within 120 days of the end of the MYP. The Final Recollection shall cover investments and costs in the MRP period not previously reviewed for prudency and reconciled in the rate case.

Imbalances shall be calculated consistent with the MYP revenue requirement approved by the Commission in an order resulting from an MYP proceeding. Rate base and operating income shall use actual results from the applicable MYP period in calculating the actual revenue requirement to determine the Imbalance. If an Imbalance calculated as part of an Annual Informational Filing, as defined in Order No. 89482, represents an amount owed to customers, the MYP Adjustment Rider can be utilized to provide a credit for such amount, if determined to be appropriate by the Commission. The MYP

15. Multi-Year Plan ("MYP") Adjustment Rider (continued)

Adjustment Rider can be utilized to recover or credit an Imbalance calculated as part of a Final Reconciliation, as determined to be appropriate by the Commission.

All Imbalances are deferred into a regulatory asset or liability until such time as the Commission determines the appropriate disposition of the Imbalance, including the appropriate period over which an Imbalance is recovered or credited to customers. Carrying costs will apply for amounts owed to customers and will continue to apply during the credit period.

Calculation of Rate
The MYP Adjustment Rider rate is determined for each Schedule by first allocating the Imbalance, as determined appropriate by the Commission, in proportion to each Schedule's amount of base distribution revenues in the final year of the MYP. The resulting amounts are then divided by the estimated billing determinants, per kilowatt-hour or per fixture, for each applicable Schedule. Details concerning the calculation of the MYP Adjustment are filed with and approved by the Commission prior to their use in billing. The MYP Adjustment shall be included in the Distribution Charge on the Customer's monthly gas bill.

Rates Effective [insert date range]

Rate Schedule	Rate
Schedule D	$0.0000 per therm
Schedule C	$0.0000 per therm
Schedule IS	$0.0000 per therm
Schedule ISS	$0.0000 per therm
Schedule EG	$0.0000 per therm
Schedule PLG	$0.0000 per therm
GRANTORS	**$0.0000 per therm**

16. STRIDE (Strategic Infrastructure Development and Enhancement) Surcharge

The Strategic Infrastructure Development and Enhancement ("STRIDE") surcharge recovers certain expenditures related to the execution of the Company's STRIDE plan, which addresses accelerated natural gas infrastructure replacements, as approved by the Public Service Commission. The Company will file a gas base rate case within five years of the implementation of its Commission-approved STRIDE plan.

Calculation of Charge

The STRIDE surcharge consists of a Current Rate and Reconciliation Rate. The Current Rate represents the recovery of the expected STRIDE revenue requirement for the upcoming calendar year. The Current Rate is calculated annually for a 12-month period (or for the remainder of the calendar year when a new surcharge becomes effective after January 1) for residential (Schedule D and Grantors-of-Rights-of-Way customers), Schedule C, Schedule IS, Schedule ISS, and Schedule EG customers by first allocating the revenue requirement (which is based on Eligible Costs as defined below) based on the proportion of base distribution revenues that these customers bear in the Company's most recently approved gas base rate case. The Current Rate revenue requirement is then divided by the forecasted number of bills for residential and non-residential customers for the prospective billing period, yielding a separate monthly Current Rate on a per customer basis for residential, Schedule C, Schedule IS, Schedule ISS, and Schedule EG customers.

16. STRIDE (Strategic Infrastructure Development and Enhancement) Surcharge (continued)

The Reconciliation Rate is based on the Imbalance between actual STRIDE surcharge revenue and the actual revenue requirement for the 12 months ended December 31 of the prior year and is separately determined for residential, Schedule C, Schedule IS, Schedule ISS, and Schedule EG customers. The Reconciliation Rate is in effect for the period of May though December each year and is determined by dividing the Imbalance by the forecasted number of bills for residential and non-residential customers for this period. The Imbalance is debited or credited against the costs eligible for recovery during the 12-month rate effective period. When the Imbalance represents an over-collection of costs at year end, Carrying Costs are applied to the Imbalance using the Company's most recent Gas authorized rate of return in the calculation of the Reconciliation Rate. In the event the Imbalance for a customer class represents an over-collection of costs and the Current Rate plus the Reconciliation Rate for that customer class is capped at the maximum monthly charge (defined below), the Company will hold the Imbalance amount above the cap until the STRIDE surcharge is less than the maximum monthly charge (i.e., is uncapped) at which point this Imbalance amount (including carrying costs) will be applied against the costs eligible for recovery during that future period.

The STRIDE surcharge is subject to a maximum monthly charge of $2.00 per month for residential customers. For Schedule C customers the maximum monthly charge is $11.61; for Schedule IS customers the maximum monthly charge is $1,053.83; for Schedule ISS customers the maximum monthly charge is $169.80; for Schedule EG customers the maximum monthly charge is $4,272.87. The maximum monthly charge is capped based on the proportion of total non-residential base distribution per customer revenues to total residential base distribution per customer revenues, as determined in the most recently approved base rate case, multiplied by the $2.00 residential monthly cap.

Eligible Costs

The revenue requirement for the STRIDE surcharge is based on eligible costs as defined in the STRIDE legislation, incurred by the Company associated solely with its STRIDE plan, and as approved by the Commission each year. They include the following categories:

a) Depreciation and amortization,
b) Earnings on the net investment as determined by applying the Company's most recent gas authorized rate of return, adjusted for taxes and bad debt expense, to the average investment balance net of deferred taxes, and
c) Property and other applicable taxes.

Future Rate Proceedings

Upon a Commission Order in a gas distribution rate proceeding that occurs while the STRIDE plan is in effect, the STRIDE surcharges will be reset due to the following:

a) The revenue requirement associated with the STRIDE surcharge will be reduced to remove the investments reflected in the new base rates,

b) The revenue requirement for STRIDE costs that are not included in the new base rates is updated to reflect the new rate of return approved in the new rate case,

c) The percentages used to allocate the STRIDE revenue requirement to residential and non-residential customers are updated to reflect the new base distribution revenues authorized, and

d) The Schedule C, IS ISS, and EG caps are reset by calculating the new base distribution per customer revenues as a proportion to the new residential base distribution per customer revenues, and then multiplied by the $2.00 residential monthly cap.