BEFORE THE PUBLIC SERVICE COMMISSION

OF MARYLAND

IN THE MATTER OF THE		
APPLICATION OF BALTIMORE	)	
GAS AND ELECTRIC COMPANY	)	Case No. 9888
FOR AUTHORITY TO INCREASE	)	
EXISTING RATES AND CHARGES	)	
FOR ELECTRIC SERVICE	)	

DIRECT TESTIMONY AND EXHIBITS

OF RON NELSON

ON BEHALF OF

THE MARYLAND OFFICE OF PEOPLE'S COUNSEL

SEPTEMBER 22, 2026

Table of Contents

LIST OF ATTACHMENTS

Attachment RN-1 - DRs cited

Attachment RN-2 - Maryland Utility Rates and Charges

Attachment RN-3 - Why is my BGE Bill so High?

1. Introduction & Purpose of Testimony

Q. Please state your name, occupation, and business address.

A. My name is Ron Nelson. I am a Founding Partner at Current Energy Group LLC ("CEG"). My business address is 4764 E Sunrise Drive #508, Tucson, Arizona 85718.

Q. On whose behalf are you testifying in this proceeding?

A. I am testifying on behalf of the Maryland Office of People's Counsel.

Q. Have you previously testified in proceedings before the Maryland Public Service Commission?

A. Yes. I have testified in several Maryland proceedings.[1] I have also been involved with the interconnection and electric system planning work groups for several years.

Q. Have you testified in other regulatory jurisdictions before?

A. Yes. I have testified in over 100 proceedings in Alaska, Arizona, Connecticut, Colorado, Georgia, Florida, Illinois, Indiana, Maine, Maryland, Massachusetts, Michigan, Minnesota, Missouri, Nevada, New Hampshire, New York, North Carolina, North Dakota, Ohio, Oklahoma, Pennsylvania, South Carolina, Utah, Virginia, Wisconsin, and Vermont. Among the issues covered in these proceedings were marginal and embedded cost of service studies ("COSS"), revenue allocation, rate design, load management, renewable program design, fuel clause adjustments, formula rates, decoupling, performance-based regulation, multi-year

[1] See Appendix A.

rate plans, performance metrics, Distributed Energy Resource ("DER") interconnection, flexible interconnection, pre-emptive DER and load upgrades, DER compensation, DER integration, EV infrastructure investments, pilot frameworks, automated metering infrastructure, prudence review, distribution system planning, capital investment plan review, and smart inverter integration, among other topics.

I have also advised the Connecticut, Colorado, Georgia, Hawaii, and Kentucky state utility commissions and have testified and supported clients at the Federal Energy Regulatory Commission ("FERC").

Q. Please summarize your professional and educational background.

A. I have worked with numerous consumer advocates, nongovernmental organizations, utilities, and public utility commissions on issues related to cost-of-service modeling, rate design, grid modernization, distributed energy resource valuation and integration, and performance-based regulation. CEG specializes in providing clients regulatory services in the areas of cost-of-service modeling, regulatory innovation, performance-based regulation, distributed energy resources ("DER"), rate design, renewable program development, grid modernization, new grid technologies, integrated resource planning, and electric vehicles. Prior to founding CEG, I briefly worked for my own sole proprietorship and at a consulting firm in various roles for six years, including as a Senior Director.

Prior to 2018, I worked for the Minnesota Attorney General's Office for almost five years, where I led that office's work on cost of service, rate design, renewable energy program design, performance-based regulation, and utility business model issues. Before that, I worked for two universities and the United States Geological Survey as an economic researcher. I have a Master of Science from Colorado State University in Agriculture and Resource Economics, and a Bachelor of Arts in Environmental Economics from Western Washington University, where I also minored in Mathematics. My curriculum vitae is attached as Exhibit RN-1.

Q. What is the purpose of your direct testimony?

A. The purpose of this testimony is to review the company's proposals related to cost-of-service modeling, class revenue apportionment, residential rate design, and review certain Information Technology (IT) investments.

Q. How is the rest of your testimony organized?

A. My testimony begins with a summary of my recommendations. Section 3 provides an analysis of the residential bill impacts and affordability implications. In Section 4, I provide analysis and recommendations related to IT and customer service expenditures. In Section 5, I review the company's proposed cost of service model and its assumptions. In Section 6, I provide recommendations related to revenue apportionment. In Section 7, I analyze the company's residential rate design proposals. In Section 8, I review and provide recommendations related to rate riders.

2. Recommendations

Q. Please provide a summary of your recommendations.

A. Regarding IT and customer service expenditures, I recommend the Commission:

- Reject $8,065,282 in capital expenses associated with Project 78077 (DERMS Implementation) because it was not required to meet the objectives of the energy storage pilot, is limited to control and operations for two existing utility-owned BESS projects, and BGE has failed to quantify system cost reductions stemming from the current investment levels and failed to identify and quantify future grid service use cases as part of a consistent DER integration roadmap.
- Require Exelon to re-categorize the $3,311,496 of costs under Project 79404 "Exelon Utilities (EU) Customer Flight Path: Large Customer Services (LCS) Program" under a distinct category for tracking costs associated with large loads. If this is not a cost item particular to large loads as defined by the company, but to large customers more broadly, then re-allocate to the appropriate cost of service class and remove costs from other customer customers.

Regarding the cost of service study, I recommend the Commission direct the company to classify FERC account 923 as demand-related and use the total distribution plant cost allocator for allocation to customer classes. I recommend the Commission, adopt my revenue apportionment modifications in Section 6, and reject the Company's proposed customer charge increase. Finally, I recommend that the Commission reject the company's proposed storm rider.

3. Residential Bill Impacts and Affordability

Q. Please summarize how the company presents the residential bill impact of its proposed rate increase.

A. BGE requests an increase in electric base distribution revenues of $156.1 million, which the company states would produce an overall increase of 2.8 percent in total electric bills across all customer classes.[2] For the residential class specifically, company witness Karas testifies that a Schedule R customer with an average monthly consumption of 851 kWh would see a bill increase of $8.18 per month, or approximately 4.4 percent.[3]

Q. Does the 4.4 percent reflect the full picture of how this case would change a residential customer's bill?

A. No. That figure blends together three components of a customer's bill that behave very differently: the supply charge, distribution charges, and various taxes and surcharges.[4] The supply charge, riders, and surcharges are held constant in the company's bill-impact exhibits, diluting the apparent size of the distribution rate increase actually being requested in this proceeding with the other components of a customer's bill.

Q. What is the increase when the analysis is limited to the distribution portion of the bill?

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[2] Direct Testimony of John C. Frain at 12.
[3] Direct Testimony of Jennifer A. Karas at 23; 32.
[4] Frain Direct at 14–15 & Figure 1.

A. It is far larger than 4.4 percent. Company Exhibit JAK-1 shows that, for the average residential (Schedule R) customer, current distribution charges are $62.29 per month; under the company's proposed rates, including the associated customer charge increase, distribution charges would rise to $70.47 per month, a 13.1 percent increase in the delivery portion of the bill alone for an average residential customer.[5]

Q. Why does this distinction matter for the Commission's evaluation of the company's proposal?

A. The "4.4 percent" figure is the number most likely to be repeated and relied upon in evaluating whether this increase is reasonable. Yet this obscures the fact that magnitude of the distribution rate increase the Commission is being asked to approve is three to four times larger. A distribution rate increase of this magnitude warrants significant Commission scrutiny.

Q. Is this proposed increase occurring in isolation, or does it come on top of a longer trend of rising BGE bills?

A. This proposed increase comes on top of a sustained, multi-year trend. BGE's electric distribution rates have already climbed 58 percent since 2020, and 129 percent since Exelon acquired BGE in 2012.[6] The residential bill impacts at issue

[5] Direct Testimony of Jennifer A. Karas, Exhibit JAK-1.

[6] Maryland Office of People's Council, *Consumer's Guide to: BGE's Proposed Electric Rate Increase,* August 2026, *See* https://opc.maryland.gov/Portals/0/Files/Publications/BGE%20Consumer%27s%20Guide%20-%202026%20-%20FINAL%20VERSION.pdf.

in this case should be evaluated against that cumulative trend, and not simply as an isolated, one-time 13.1 percent adjustment.

Q. Separate from the distribution rate increase requested in this case, have other portions of customers' electric bills also been rising?

A. Yes. Company Witness Frain testifies that "[r]ecent increases in electric supply costs (driven primarily by capacity and generation prices) have been much greater than increases in distribution costs."[7] As documented by OPC, when combined, the average BGE customer has seen its total annual electricity bill increase by almost $900 per year from 2020-2025, an increase of almost 75%.[8] The increase from this proceeding, will further compound these previous increases in residential bills and strain BGE's ratepayers.

Q. What is "energy burden," and why is it a relevant lens for evaluating this bill impact?

A. Energy burden is a standard affordability metric, defined as the percentage of a household's gross income spent on home energy costs.[9]

Q. What does the record show about energy burden for BGE's low-income customers specifically?

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[7] Frain Direct at 16.

[8] Maryland Office of People's Counsel, Baltimore Gas and Electric Rate information. *See* https://opc.maryland.gov/Consumer-Learning/Utility-Rates-and-Basics/BGE.

[9] Maryland Office of People's Counsel, Maryland Low-Income Market Characterization, at 3 (Sept. 2022). See https://opc.maryland.gov/Portals/0/Files/Publications/Reports/Maryland%20Low-Income%20Market%20Characterization_September%202022%20final.pdf?ver=ne_Hpk3YK-ryXO8f-C9cyw%3d%3d.

A. BGE states that it "does not maintain data on all customers' income levels"[10] or track energy burden.[11] The most comprehensive available study of energy burden for this population is OPC's 2022 Low-Income Market Characterization, which found that OHEP-eligible households statewide carry an average gross energy burden of 14 percent of income.[12] The burden is materially worse within BGE's service territory: Baltimore City's OHEP-eligible households carry the highest gross energy burden of any region in the state, at 17 percent.[13] By comparison, the Commission has identified six percent of income as a reasonable energy affordability standard.[14] BGE's lowest-income Baltimore customers are therefore already carrying an energy burden roughly three times that benchmark, before any increase approved in this case takes effect. The company's proposed rate increase in this proceeding, in tandem with increases in energy supply will increase the energy burden for customers who are already facing affordability challenges. As such, the Commission should fully scrutinize the company's proposal in this proceeding.

4. IT and Customer Service Expenditures

Q. What is the purpose of this section of your testimony?

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[10] BGE Response to OPC DR07.
[11] BGE Response to Staff DR19-01.
[12] Maryland Low-Income Market Characterization, supra, at 6, Table 2.2.
[13] Maryland Low-Income Market Characterization, supra, at 6, Table 2.2.
[14] Order No. 92190 at 9-10; 45; *see also* Maryland Low-Income Market Characterization, supra, at 4.

A. In this section I review certain of BGE's IT expenditures and customer service expenditures. In particular, this section focuses on BGE's Distributed Energy Resource Management System ("DERMS") investment and related IT investments in light of BGE's current capabilities around DER management and control.

Q. Describe the DERMS costs BGE includes in this rate request.

A. BGE includes $8,065,282 in capital expenses for Project 78077 (DERMS Implementation). BGE states that the purpose of the DERMS investments relate to various use cases to improve visibility, monitoring, and control of DERs and to lay the foundation for future increased DER integration. In response to discovery, BGE stated that Project 78077 was specifically deployed for the following use cases:[15]

- Monitoring and control of Fairhaven and Chesapeake Beach BESS (3.5 MW total)
- Short-term load and DER forecasting
- Estimated output of unmetered DER
- DER alarms
- DER telemetry
- DER measurement and verification ("M&V")

Q. Do you have any concerns with BGE's DERMS investments covered in this rate request?

[15] See BGE Response to MEA DR03-17 subpart b and subpart c.

A. Yes, I am concerned that while BGE has explained the use cases for Project 78077 as listed above, BGE has not quantified any customer cost savings that will result from implementing the DERMS, which calls into question the usefulness of the investment if the only benefits are qualitative.[16] At its base, a DERMS is a tool for managing and coordinating DER for grid benefits. As such, the system cost reductions from deploying this technology should be clearly documented so that stakeholders can evaluate whether the resource is delivering the expected benefits.

Q. If there are no quantified benefits of Project 78077, was there a definite need for this investment to support the Fairhaven and Chesapeake Beach BESS that justified the investment?

A. No. The DERMS investment reflected in Project 78077 was chosen to replace the custom scripting[17] that BGE had developed to communicate dispatch requirements between its distribution supervisory control and data acquisition ("DSCADA") system, the BESS, and related protective equipment located within the substation. Adding incremental costs to the already approved amounts in the initial Energy Storage Pilot approvals has not been adequately justified in terms of providing needed reliability improvements or increasing the project benefits, and should therefore be rejected because the remaining use case is forward-looking and unsupported with cost-benefit analysis.

Q. What was the purpose of the initial energy storage pilot?

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[16] See BGE Response to OPC DR18-01 and BGE Response to OPC Data Request 18-02.

[17] A script is a specific software code created for a BESS or other application. In this case, the scripts developed by BGE to manage the utility-owned BESS would send dispatch commands to the units to achieve certain objectives.

A. The Commission approved BGE's Energy Storage Pilots for both Fairhaven and Chesapeake Beach BESS in Case No. 9619.[18] The Commission stated that, '…this pilot program's value to both ratepayers and the public will come primarily from the lessons learned by utilities, stakeholders, and the Commission, and which will later be relied on in making future investment decisions."[19] While the primary objective of the storage pilot program was to develop and generate these learnings, BGE did provide a benefit cost analysis of the expected electric system benefits from operating the storage. The two system values were avoided distribution capacity investments valued at $12,631,000 and expected PJM market revenues of $2,387,000 for regulation services, both on a present value basis.

Q. Was BGE able to meet the purpose of the pilot program without investing in further costs for the utility DERMS?

A. Yes. The initial installation and configuration of the BESS, as it was designed and scoped at the outset of the pilot, was able to provide lessons learned and meet these core objectives without a utility DERMS. BGE stated as early as 2022 that it had "gleaned important learnings" from its experience about the various processes for constructing and operationalizing batteries.[20] Further, BGE's 2024 annual

[18] Md. Pub. Serv. Comm'n, Order No. 89664, In the Matter of the Maryland Energy Storage Pilot Program (Case No. 9619, Nov. 6, 2020).

[19] Order No. 89664, at 23, ordering paragraph 76.

[20] See Case No. 9619, BGE's Further Request for Extension of the Operational Deadlines of the Chesapeake and Fairhaven Energy Storage Projects (Sep. 27, 2022) at 6, "Importantly, BGE has gleaned important learnings from the Fairhaven project process that will inform and improve any future utility energy storage project endeavors."

metrics report that the BESS had achieved multiple dispatch use cases without a DERMS in place.[21]

Q. Was the DERMS investment in Project 78077 required for any legislative or regulatory requirements under the Energy Storage Pilot?

A. No.[22]

Q. Did Project 78077 provide material benefit to Exelon Corporation?

A. Yes, there was substantial benefit to Exelon resulting from early and accelerated implementation of Project 78077 in terms of "gaining operational experience with DERMS capabilities, integration approaches, and DER management processes through deployment of a commercial DERMS platform in BGE's operating environment."[23] Despite this recognition, BGE nevertheless argues in response to discovery that the Project 78077 was, "justified based on BGE's operational needs and anticipated DER management requirements."[24]

It is helpful here to separate BGE's two claims. First, regarding the justification for the project to meet BGE's operational needs, BGE states that "prior to Project 78077, BGE utilized a custom DER management approach within its ADMS/DSCADA environment to monitor and control utility-scale battery assets. *While that approach was capable of supporting existing battery resources*,

[21] Baltimore Gas and Electric Company, *BGE Annual Storage Project Metrics Report 2024*, ML# 309423 (Case No. 9619, May 1, 2024). Metric Number 72. The two grid use cases achieved were utility controlled peak shaving and PJM market participation.
[22] BGE Response to OPC DR18-01 subpart a.
[23] BGE Response to OPC DR18-02 subpart h.
[24] BGE Response to OPC DR18-02 subpart h.

Project 78077 implemented a dedicated DERMS platform designed to provide a more scalable solution for future DER management needs."[25] The Fairhaven BESS pilot project was designed with the full communications and control necessary to achieve the objectives of the pilot, including realization of the expected benefits the BESS was forecasted to achieve by means of PJM market participation and provision of distribution reliability, as well as provide essential learnings that could inform future storage procurements and processes.[26]

Second, with respect to the "anticipated DER management requirements", BGE states that "Project 78077 was authorized in 2023 when implementation of FERC Order No. 2222 was anticipated on a significantly earlier timeline and BGE expected DERMS capabilities could play an important role in supporting future DER participation models and related compliance activities."[27]

Q. Above you characterize the Project 78077 deployment as "early and accelerated." Why do you say that?

A. I say this for several reasons. First, project 78077 was authorized in May 2023, and yet the Fairhaven BESS did not achieve commercial service until November

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[25] BGE Response to OPCDR18-01 subpart a (emphasis added to the original).

[26] BGE stated in the initial application for the pilot that "[T]he BESS would include a Lithium Ion battery system with 7.1 MWhs of usable capacity stored in two (2) 48' x 8' battery containers, four (4) inverters, two (2) step-up transformers, *controls and communication necessary to operate the BESS*." *See* Case No. 9619, Application of Joint Exelon Utilities for Approval of Energy Storage Pilot Projects, at 15 (Apr. 15, 2020), emphasis added to the original. And further, BGE stated that it would communicate with the BESS for charge and discharge needs and would install a remote terminal unit ("RTU") "to enable communication between BGE's operations systems and the BESS controller." *Id.,* at 15-16.

[27] BGE Response to OPC DR18-01 subpart a.

2023, six months after BGE had approved Project 78077 and began developing the DERMS. This indicates that BGE and Exelon were pursuing the DERMS for other means beyond simply meeting the actual project requirements. By comparison, the disadvantages listed for "do nothing" approach (i.e., continue with the BESS communication and controls configurations that were scoped and funded pursuant to the requirements of the energy storage pilot) were stated as "[N]o additional business learnings to inform [Exelon's] DERMS north star design."[28] In other words, as it currently stands, Project 78077 amounts to an Exelon pilot investment that will provide significant Exelon learnings and benefits with no clearly identified quantitative benefits to BGE customers.

Finally, BGE describes Project 78077 as a "foundational platform investment" that will enable future DER growth, and yet it has not quantified the number of future DERs that it can handle with the given investment level. Because BGE has failed to do this, stakeholders are left to take it on faith that the investment will lead to cost reductions at some future date and deliver on the promises of investing in a DERMS. Consequently, the Commission cannot adequately gauge whether the platform investment was prudently incurred.

Q. Can you elaborate on the risks of implementing an enterprise DERMS platform without further vetting the use cases and expected costs and benefits prior to investment?

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[28] BGE Response to OPC DR18-02 subpart h.

A. Yes. BGE mentioned that its decision to adopt OSI Integra as a standalone DERMS solution outside of the Exelon Utilities' roadmap was to reduce reliance on custom-calculated scripts to manage its utility-owned BESS, and also to enable future scaling for greater DER integration. However, based on BGE's responses to data requests, I am concerned that Project 78077 is insufficiently limited in scope and functionality and not appropriately configured to scale with the level of DERs that BGE expects to see on its system in the coming years.

For instance, BGE expects to see an increase of approximately 850 MW of distributed solar and 87 MW of energy storage on its system over the next five years.[29] And yet, BGE's decision to implement the stand-alone OSI Integra DERMS system was made prior to any kind of public or transparent DERMS roadmap being discussed with stakeholders. In particular, BGE has not provided a comprehensive DER integration roadmap that demonstrates how BGE expects to use these investments for various grid outcomes.[30]

This is despite the fact that the Company has invested research and development dollars with the Electric Power Research Institute for a two-year project completed in December 2025 titled, "Distribution System Operator Capabilities to Enable DER Services." The benefits described for this project include, "produc[ing] a strategic roadmap and implementation plans to support

[29] BGE Response to OPC DR07-03 subpart c.
[30] BGE Response to MEA DR03-22.

DER integration and identify[ing] needed systems, data exchanges, capabilities, and operational improvements."[31] This lack of a coordinated approach can translate to a future path-dependence in which BGE is required to continue investing in more add-on integrations and implementations with OSI Integra in order to integrate more DER types and greater MW of DER.

Q. Do you have any concerns about specific IT-related projects based on your review?

A. Yes. Project 79404 "Exelon Utilities (EU) Customer Flight Path: Large Customer Services (LCS) Program" for a total of $3,311,496 is inappropriately being socialized to all customer classes despite the fact that it solely benefits large customers. BGE states that it categorizes costs for this program under the FERC Account 303-Miscellaneous category and therefore it is justified in including the costs under the typical class allocation process.[32] BGE also states that if costs are tracked such that they can be separately identified as applying to certain customers, those costs are directly assigned in the cost of service study.[33] More simply, this project appears clearly related to a specific customer or customer class, and should therefore be directly assigned to said customer or large load class, not socialized to all customers. Assigning the costs to the causing customer or class better aligns with cost causation.

[31] BGE Response to Staff DR28-23, Attachment 2, page 1 of 3.
[32] BGE Response to OPC DR07-02 subpart a.
[33] BGE Response to OPC DR07-02 subpart b.

Q. What are your recommendations to the Commission?

A. I recommend that the Commission:

- Reject $8,065,282 in capital expenses associated with Project 78077 (DERMS Implementation) because it was not required to meet the objectives of the energy storage pilot, is limited to control and operations for two existing utility-owned BESS projects, and BGE has failed to quantify system cost reductions stemming from the current investment levels and failed to identify and quantify future grid service use cases as part of a consistent DER integration roadmap.
    - I recognize that in its recent report on the energy storage pilot, Staff recommends that the Commission continue investment in DERMS capabilities, but, importantly, also clarifies that any such future storage proposals should identify DERMS and other related telemetry, control, and communications requirements "necessary to support each intended value stream."[34] Given the shortcomings identified in my above testimony, I recommend that the Commission require BGE to provide a transparent explanation regarding how the foundational platform investment it made in the stand-alone OSI Integra DERMS system will lead to lower system costs compared to

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[34] Md. Pub. Serv. Comm'n Technical Staff, *Energy Storage Pilot Program Final Report,* ML# 332550 (Case No. 9619, Jul. 27, 2026), at 171.

alternative methods. This kind of showing may be more appropriate for BGE's upcoming Preliminary Electric System Plan due in 2027. If the Commission does not disallow the investment outright, the Commission might defer prudency until such time as more complete details about the expected costs and benefits of scaling the DERMS to additional resources are available.

- Require Exelon to re-categorize the $3,311,496 of costs under Project 79404 "Exelon Utilities (EU) Customer Flight Path: Large Customer Services (LCS) Program" under a distinct category for tracking costs associated with large loads. If this is not a cost item particular to large loads as defined by the company, but to large customers more broadly, then re-allocate to the appropriate cost of service class and remove costs from other customer customers.

5. Electric Cost of Service Study

Q. What is a Cost of Service Study ("COSS") and why is it important to the rate case?

A. A COSS refers to the process by which the utility divides its revenue requirement into cost categories and assigns or allocates these categories of costs to different jurisdictions and customer classes. The costs allocated to a customer class are used to inform how much revenue is collected from that class, and therefore, how high the rates for that class will be set.

Q. Is there a single standard method by which every utility conducts a COSS?

A. No. While the core steps of a COSS are generally consistent across utilities, the methodologies used can depart substantially. Importantly, the philosophical decisions about which methodologies are used for a COSS significantly impact the results and must be evaluated in-depth to ensure the methodologies continue to reflect cost causation as system dynamics change.

Because COSS methods and the corresponding results can vary significantly based on assumptions and preferences, the Commission should exercise caution when assessing the results of a COSS. Every cost analyst makes numerous subjective determinations that will dramatically impact the results of the study.

Q. What is the purpose of a COSS?

A. As discussed by company witness Jason Manuel, the purpose of a COSS is to align the total cost incurred by BGE in the test year with the customer classes responsible for those costs.

Q. How accurate is a COSS in determining cost causation?

A. While it is impossible to determine cost causation with perfect accuracy, a well-conducted COSS will rely on as much detail and accuracy as possible to determine which customer class caused the utility's various embedded costs to inform class revenue allocation and rate design.

Q. How is a traditional COSS performed?

A. A COSS has three steps:

1. Functionalize costs into various categories.
2. Classify costs related to energy/commodity, demand/capacity, or customers.
3. Allocate costs to the various jurisdictions and customer classes using allocators related to energy, demand, or customer characteristics or through direct assignment.

Q. Are there standard principles used in a COSS to inform these three steps?

A. Yes. The principles of "cost causation" and "beneficiary pays" are used throughout the COSS to determine the most appropriate functionalization, classification, and allocation of costs. "Cost causation" dictates that the user(s) who incurred, or caused, a cost must pay for it. Conversely, "beneficiary pays" dictates that all of those who benefit from an investment must pay for its costs – in other words, "costs follow benefits." Incorporating the beneficiary pays principle at the retail level is a more modern concept but is reflected in some traditional cost classification and allocation approaches. However, this approach is widely used and accepted by the Federal Energy Regulatory Commission ("FERC") for transmission cost allocation and is becoming more widely used in allocation rates at the retail level.

Q. Explain how costs are functionalized in the first step of a COSS.

A. Functionalization is the process of grouping utility cost by function. For example, generation, transmission and distribution are different functional cost categories.

Public utilities are required to maintain records in accordance with the Uniform System of Accounts as designated by the FERC. These accounts divide costs by various functions, such as generation, transmission, and distribution. The purpose of functionalizing costs is to aid in determining which customers are jointly or solely responsible for various costs or which customers benefit from those costs. Many utilities, including BGE, also sub-functionalize costs, which often aligns with different voltage levels. For example, distribution costs can be sub-functionalized into primary and secondary voltages. The purpose of sub-functionalization is to reflect cost causation or beneficiaries more granularly.

Q. How are costs then classified in step 2 of a COSS?

A. Cost causation is used to classify whether each cost is an energy-, demand-, or customer-related cost. Energy costs relate to a customer class's energy usage, measured in kilowatt-hours (kWh). Demand costs relate to a customer class's contribution to peak demand within the system, measured in kilowatts (kW) and are also referred to as capacity costs. Finally, customer costs are those required to provide service to customers, regardless of whether the customers consume electricity. Specifically, the National Association of Regulatory Utility Commissioners Electric Utility Cost Allocation Manual ("NARUC Manual") defines customer costs as "costs that are directly related to the number of customers served." In other words, the utility incurs customer costs based on the number of customers on its system, rather than based on the amount of energy they consume or when they consume it.

Q. How are costs allocated once they have been classified?

A. Costs are allocated to customer classes based on each class's contribution to each classified cost. For customer-related costs, if a utility's costs are caused equally by each customer on the system, regardless of energy and demand requirements, these costs would be allocated based on the number of customers. For demand-related costs, customer classes have historically been allocated costs based on their contribution to system peaks or non-coincident peak demands. As for energy-related costs, the utility costs are allocated based on kWh consumption levels or a similar energy-related characteristics.

Q. You indicated earlier that cost-of-service studies are fundamentally based on the philosophical decisions of a utility or analyst. What do you mean?

A. Each decision in a cost-of-service study has an implication, sometimes quite profound, on how costs are divided amongst customers – i.e. who will bear the costs of the utility – and the price signals sent to those customers, if any. Many decisions about how costs are functionalized, classified, and allocated are inherently subjective, and can be tuned to achieve different objectives. Thus, Commissions must thoroughly vet and consider the implications of COSS methodologies.

Q. Has the company selected appropriate classification and allocation approaches in this proceeding?

A. No. In the section that follows, I recommend revisions to the company's allocation of demand-related distribution system costs.

i. BGE's use of a four-year average NCP for distribution system cost allocation is not supported.

Q. How does BGE propose to allocate demand-related distribution investments?

A. BGE proposes to use each class's contribution to the NCP as the primary method to allocate demand-related distribution investments.[35]

Q. Does the company propose to use the test year NCP for this calculation?

A. No, it does not. Consistent with previous rate cases, the company proposes to use four-year average demand allocators as the basis to calculate NCP for all metered customer classes.[36] For non-metered customer classes, the company proposes to use data from the 2024 test year only.

Q. Do you have any concerns with the company's proposed methodology for NCP allocators?

A. Yes, I do. First, I am concerned about using different time periods to develop the allocators for metered and non-metered customer classes. Second, I have concerns with the use of a four-year average to develop the NCP. Finally, I have concerns with the use of the NCP to assess cost causation.

Q. What are the problems with using different time periods to calculate NCP for metered and unmetered customer classes?

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[35] Direct Testimony of Jason Manuel at 11:15-21.
[36] Direct Testimony of Jason Manuel at 13:21-14:1.

A. By using two different time periods for the calculation of NCP, the company is comparing two different metrics in calculating NCP allocators. While one would expect less year-to-year variability in the unmetered lighting customer classes, it is not appropriate to use the four-year average for all other customer classes and only one year of data for the two unmetered customer classes. If the company maintains the use of a four-year average for calculating NCP, it should use that same four-year average for all customer classes to ensure an apples-to-apples comparison across all customer classes.

Q. What are the problems with the company's use of a four-year average to calculate NCP?

A. Typically, a new COSS is conducted in each rate case to provide an up-to-date snapshot of each class's contribution to system costs. A COSS is intended to allocate historic system costs based on the recent test year's billing determinants to ensure cost reflectiveness. By using data as far back as 2021, the company risks allocating costs based on demand patterns that do not reflect current usage, due to potential economic or technological changes.

Q. What are the flaws with the company's use of NCP allocators for demand-related distribution costs?

A. For demand-related distribution costs, the company calculates demand allocators based on class NCP demand at different voltages that correspond to the system levels. The choice of an NCP allocator incorrectly assumes that peak loads during a single hour of the year drive the sizing for primary distribution system costs such as circuits and substation transformers. This assumption drives the volatility that causes the company to use a multi-year average for NCP. A single class NCP hour can change dramatically from one year to the next in a way that does not reflect actual volatility in system costs. For example, if the Residential customer class's share of NCP demands increases by 5 percent in a given year, that does not mean that the company increased the size and/or cost of distribution assets by 5 percent. The premise that a single class NCP hour drives demand costs is an oversimplified assumption that should be updated. In other words, the system is planned and built to meet the diversity of demand at all times and over specific durations, not just during the single hour of a given class's peak.

The company's use of the NCP allocator is particularly problematic for primary distribution system and substation transformer costs. While class NCP demand allocators assume primary circuit requirements are driven by one hour in a year, primary circuits typically peak at different hours across a service territory, contradicting this foundational assumption. Similarly, substation costs are not driven by a single hour of the year; substations peak at different times of day and in different months throughout the year. In addition, substation costs are driven not only by peak demand, but by energy requirements throughout the year, with performance ratings related to sustained heating overloads rather than to a single hour of peak demand. According to the Regulatory Assistance Project:

> A transformer that is very heavily loaded for a couple of hours a year and lightly loaded in other hours may last 40 years or more until the enclosure rusts away. A similar transformer subjected to the same annual peaks, but also to many smaller overloads in each year, may burn out in 20 years.[37]

Finally, electric distribution companies ("EDCs") are increasingly connecting feeders and substations to build resiliency within their grids. These connections and transfers make any one substation less influenced by the needs of one hour by increasing operational flexibility and the potential to switch loads to other substations and feeders. These realities show that the NCP demand allocator for primary distribution system and substation transformer costs is imprecise and should be updated.

Furthermore, the proliferation of distribution sited storage further impacts historical notions of cost causation. Energy storage systems are used to import energy during off-peak periods, and discharge during peaks to serve local peaks. Using energy storage systems in this way results in sizing distribution system assets less strictly on peaks and more toward average loads (i.e., energy allocators). For example, if energy storage was a least-cost option and distributed throughout the distribution system, the distribution system would largely be sized to meet average demands due to storage's ability to balance out the system and

[37] Jim Lazar et. al., Regulatory Assistance Project, Electric Cost Allocation for a New Era: A Manual (January 2, 2020) at 148, *See* https://www.raponline.org/knowledge-center/electric-cost-allocation-new-era/.

flatten load curves. While this is not a near-term outcome, the point is that distribution system sizing is likely to trend more towards energy-related usage in the future than it did historically, given our ability to store energy more cost-effectively.

Q. How do you recommend updating the company's demand allocators?

A. Rather than using one non-coincident peak, it may be more reflective of cost causation to conduct a temporal analysis to evaluate how class loads contribute to peak immediately before, during, and after circuit or asset peaks, including the time-of-day information, differentiated by season/month and asset type (e.g., substation). This analysis is a valuable use case for leveraging advanced metering infrastructure ("AMI") data. While the described analysis will enable stakeholders to develop an embedded cost-of-service demand allocator, efficient pricing is informed by forward-looking (rather than historic) marginal costs. Amid the energy transition, analysis of how costs were caused historically may provide little insight into how they will be caused in the future.

Q. Will such an analysis be available for this proceeding?

A. It's unlikely that such a detailed analysis can be conducted as part of this rate proceeding. However, it may be possible to assess class NCPs across the system during the hours adjacent to NCP and not just one hour during the year. OPC has asked for discovery to collect data to conduct such an analysis and may present the analysis in its surrebuttal testimony, if appropriate.

Q. Given the current lack of sufficient data, what is your NCP demand allocator recommendation at this time?

A. I recommend that the Commission direct the company to use a four-year average NCP data for all customer classes, though I reserve the right to modify this recommendation in surrebuttal testimony.

ii. FERC Account 923

Q. What costs are normally recorded under FERC account 923?

A. According to the FERC accounting guidelines, FERC account 923 should include:

> fees and expenses of professional consultants and others for general services which are not applicable to a particular operating function or to other accounts. It shall include also the pay and expenses of persons engaged for a special or temporary administrative or general purpose in circumstances where the person so engaged is not considered as an employee of the utility.[38]

Specific items referenced by FERC guidelines are as follows:

> 1. Fees, pay and expenses of accountants and auditors, actuaries, appraisers, attorneys, engineering consultants, management consultants, negotiators, public relations counsel, tax consultants, etc.
> 2. Supervision fees and expenses paid under contracts for general management services.

Q. What costs does the company record under FERC account 923?

[38] 18 C.F.R. pt. 101, Acct. 101 (2026), *See* https://www.ecfr.gov/current/title-18/chapter-I/subchapter-C/part-101.

A. The company records several Exelon costs allocated to the company , including executive services, financial services, HR services, legal services, and IT services.[39]

Q. How does the company classify and allocate the FERC account 923 costs?

A. The company classifies these costs as customer related and allocates them using a labor allocator.

Q. Do you have concerns with the company's classification and allocation of costs within FERC account 923?

A. Yes. These costs are more appropriately classified as demand-related costs. Financial, IT, HR, and executive-related costs are not directly related to the number of customers. The issue with the company's misclassification of these costs stems from two issues. First, there is simply a cost causation argument that these costs are more related to demand than customers. The second issue is a structural one. If the company was not part of a holding company, some of these costs would likely be recorded in other FERC accounts that would be classified and allocated differently.

IT service costs are a good example. Many software and hardware-related IT costs are recorded in the 300 level (i.e., within the distribution system plant cost function) FERC accounts. These other 300 level FERC accounts are classified and allocated differently than how the company classifies and allocates FERC account

[39] See BGE Response to OPC DR01-09, Attachment 1.

923. The result of the differential classification and allocation is two-fold. First, misclassifying these costs inflates customer-related costs. The inflated customer costs are then used to argue for higher customer charges by approximately $8/month per residential customer. Second, the misallocation of these costs results in over-allocating costs to residential customers.

Q. What is your recommendation related to FERC account 923?

A. I recommend the Commission direct the company to classify FERC account 923 as demand-related and use the total distribution plant cost allocator for allocation to customer classes.

iii. FERC Account 903

Q. What is FERC account 903?

A. FERC account 903 records customer records and collection expenses.

Q. Do you have any concerns with FERC account 903?

A. Yes. FERC account costs are approximately $4/month per customer for the residential class. This is high compared to similarly situated utilities in my experience. I have issued discovery to obtain the subaccounts and preserve the right to provide additional testimony on the account in rebuttal or surrebuttal, if necessary.

iv. Costs to Interconnect Large Loads

Q. Has the company included any costs to interconnect data centers in this proceeding?

A. Yes. The company had at least $2.8 million in distribution for new business expenditures to interconnect data centers.[40]

Q. Would these new customers qualify for the large load tariff recently filed by the company?

A. It's not clear. In discovery, the company claimed it currently has 12 customers who would qualify for the large load tariff with an aggregate demand over 25 MW, and four customers with demand of 25 MW or more at one site.[41] The record is not clear on whether any of these three projects would qualify for the large load tariff if it had been in effect.

Q. Why is this an issue?

A. The Next Generation Energy Act requires that new large load customers be subject to forthcoming tariffs and be required to pay for all incremental costs to interconnect, with no costs shifted to other customers. While that tariff has yet to take effect, it is therefore still important to understand whether any costs in this rate case were incurred solely for the interconnection of large loads.

Q. Could there be other costs in this proceeding incurred to interconnect large loads?

A. Yes, there could. In addition to the identified new business costs, there could also be additional distribution system upgrades driven by the interconnection of these data center customers.

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[40] BGE Response to Staff DR01-01, Att. 1.
[41] BGE Response to OPC DR 05-11 (Revised), Att.1.

Q. What is your recommendation regarding costs to interconnection data centers and other large loads?

A. With the passage of the Next Generation Energy Act, the legislature has indicated that no costs associated with the interconnection of large loads should be socialized to other customers.[42] While the tariff implementing this legislation has yet to take effect, the problem it sought to address has already emerged and is squarely within the Commission's power and responsibilities in a ratesetting proceeding. I recommend that the company provide additional detail on the new business costs in this proceeding related to the interconnection of large load customers, including the date of interconnection, the nature of the investments, facility contracted demand, and rate schedule the customer is taking service under. In addition, the company should detail if any additional investments were required to interconnect these facilities. This information will help the Commission understand the nature of the investments and the appropriate treatment of any costs.

6. Revenue Apportionment

Q. What is the purpose of this section of your testimony?

A. In this section, I will explain how BGE proposes to apportion the proposed electric revenue increase being requested among customer classes. I will recommend

[42] Md. Code Ann., Pub. Util. § 4-212(b) states that "It is the intent of the General Assembly that residential retail electric customers in the State should not bear the financial risks associated with large load customers interconnecting to the electric system serving the State.".

against excluding Schedule PL customers in the apportionment of this revenue increase and highlight the importance of gradualism and accordingly recommend a slight tweak to the methodology the company proposes to use to assess the class responsibility of the Residential class.

Q. Please summarize the company's approach for revenue apportionment by class in this rate case.

A. The company, as detailed by Witness Karas in her direct testimony, aims to apportion the revenue increase such that each customer class's rate of return moves toward the system average rate of return. They propose a two-step process to accomplish this. In the first step, any classes that have a relative rate of return ("RROR") below 0.90 are assigned revenue to more closely align their RROR with the system average. For Schedule R, this means a revenue apportionment adjustment to move 50% of the way to the desired +/- 10% of the system average, resulting in the RROR moving from 0.65 to 0.77. In step two, the remaining revenue increase is allocated across existing rate classes in proportion to base distribution revenues. Schedules PL, T, and EVP do not receive any revenue adjustment.[43]

Q. Why are Schedules EVP, PL, and T excluded from the revenue apportionment approach?

A. Schedule EVP is the Utility Owned Electric Vehicle Public Charging rate class. The company uses its market-based rates as a reason to exclude Schedule EVP

43 Karas Direct at 10-11.

from the revenue allocation, as it claims that these rates can only be changed in a focused proceeding. Schedules PL and T have RRORs that are greater than the system average, 2.70 and 20.46 respectively, and the company uses this as justification for not assigning any additional revenue to these classes as it claims they are already significantly overcontributed according to the company's COSS.[44]

Q. Is this a valid justification?

A. Partially. Schedule EVP is unique and excluding it from revenue allocation makes sense. Schedule T has a RROR of 20.46, making it an extreme outlier from the rest of the classes, so it also makes sense to exclude it from revenue allocation at this time. However, Schedule PL has a RROR of 2.70 in the company's COSS, which is not distinct enough from other classes to justify removing it from revenue apportionment. While it is higher than other classes, the company provides no affirmative justification for its exclusion. Nor is there a clear sign that this class is a dramatic outlier from other classes. The two-step approach proposed by the company will also help reduce the RROR of Schedule PL (and all classes with a RROR above the system average).

Q. Do you recommend excluding any Schedules from the revenue apportionment?

A. I am supportive of excluding Schedule EVP and Schedule T from the revenue apportionment, but recommend including Schedule PL.

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44 Karas Direct at 11.

Q. Has the company's specific two-step methodology been adopted by other Maryland electric utilities?

A. Not to my knowledge. In BGE's last rate case, Case No. 9692, Commission Staff proposed an alternative four-step allocation methodology and cited, as precedent for that alternative, four-step methods used in recent Pepco and Delmarva settlements, not BGE's own two-step formula.[45] I am not aware of any other Maryland electric utility that uses the methodology that the company proposes here - moving an under-earning class by a fixed percentage of the distance to a target RROR.

Q. What has been the Commission's preferred method of revenue apportionment in the past?

A. In the past, the Commission has considered and rejected the company's proposed gap-closing formula in favor of a methodology that the Commission describes as a historic approach.[46]

The Commission's approach is also a two-step methodology, but it differs from the company's proposal in how step one is sized. Rather than closing a fixed proportion of the RROR gap between the current and target, the Commission allocates a fixed percentage of the total system-wide revenue increase in step one to classes earning below a certain threshold. In the last two BGE rate cases, the Commission has chosen to assign 20% of the total revenue increase to classes

[45] Maryland PSC Case No. 9692, Direct Testimony of David Hoppock, at 2 and 68.
[46] Md. Pub. Serv. Comm'n, Order No. 89678, Application of Baltimore Gas and Electric Company for an Electric and Gas Multi-Year Plan. (Case No. 9645, Dec. 16, 2020), at 214-215.

earning below the system-wide average.[47] Step two is then the same as the company's, which involves allocating the remainder of the revenue increase based on each class's share of current base distribution revenue.

Q. What are the implications of the company's proposed approach on the Residential class?

A. As indicated in Table 2 of Karas Direct, the company's proposal would result in a step 1 allocation of $32 million to the Residential class, and a $68 million allocation in step 2, resulting in a total of $100.1 million being allocated to the Residential class. This corresponds to 64.1% of the total distribution revenue increase. Notably, the $32 million step 1 allocation represents approximately 20.5% of the total $156 million revenue increase, meaning that BGE's proposed methodology is similar in outcomes to the methodology approved by the Commission in BGE's last rate case.

Q. Has the company evaluated the resulting RROR of classes other than Schedule R under its proposed revenue apportionment?

A. No. Staff Data Request 30, Item 03 asked the company to provide the "updated RRORs for each customer class based on BGE's proposed rate design." In response, the company indicates it "has not performed a relative rate of return analysis after applying the proposed rate increase." Thus, the company has not analyzed the impact on eight classes of its proposed revenue apportionment methodology.

[47] Order No. 89678, Case No. 9645, at 214-215, and Order No. 90948, Case No 9692, at 259-260.

Q. Do you support BGE's approach for revenue apportionment?

A. I support the general two-step framework, but I propose a change to the specific methodology. The company's proposal results in the vast majority of the revenue increase going towards the Residential class, violating the concept of gradualism and allocating the majority of costs to a single class that already faces affordability concerns.

Q. What is your recommended approach for revenue apportionment?

A. I recommend the Commission continue to apply its historic two-step methodology, as established in Order No. 89678[48] and affirmed in Order No. 90948,[49] rather than adopt BGE's gap-closing formula. However, I recommend the Commission set the step one percentage at 10% rather than 20% of the total revenue increase, due to gradualism.

In practice, this means step one would involve allocating 10% of the company's total requested base distribution revenue increase - $15,611,500 in the company's direct case - to Schedule R. Step two would allocate the remaining $140,503,500 to schedule R and the other non-excluded classes (RL, G, GU, GS, GL, P, PL, and SL) in proportion to each class's share of current base distribution revenue. Notably, this includes Schedule PL in the adjustment, as I recommended previously.

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[48] Md. Pub. Serv. Comm'n, Order No. 89678, Application of Baltimore Gas and Electric Company for an Electric and Gas Multi-Year Plan (Case No. 9645, December 16, 2020).

[49] Md. Pub. Serv. Comm'n, Order No. 90948, Application of Baltimore Gas and Electric Company for an Electric and Gas Multi-Year Plan (Case No. 9692, December 14, 2023).

Q. Why do you recommend 10% rather than the 20% the Commission has applied previously?

A. A 10% step one adjustment would result in a reduction in the dollar increase borne by residential customers this cycle, aligning with principles of gradualism and affordability.

Q. What would Schedule R receive in total under your recommended approach?

A. The table below details the resulting allocation to each class under my recommended ten percent step one, calculated using the same current revenue and current RROR figures reflected in company Exhibit JAK-2, Sheet E-2.

Table 1. Revenue Apportionment Under Proposed Allocation Methodology

Rate Schedule	Current RROR	Step 1 ($M)	Step 2 ($M)	Total ($M)	% of Total
Schedule R	0.65	$15.61	$75.83	$91.44	58.6%
Schedule RL	0.91	--	$5.05	$5.05	3.2%
Schedule G	1.41	--	$13.87	$13.87	8.9%
Schedule GU	1.41	--	$0.03	$0.03	0.0%
Schedule GS	1.85	--	$1.13	$1.13	0.7%
Schedule GL	1.63	--	$31.91	$31.91	20.4%
Schedule P	1.27	--	$7.66	$7.66	4.9%
Schedule T	20.46	--	--	$0.00	0.0%
Schedule SL	1.06	--	$2.80	$2.80	1.8%
Schedule PL	2.70	--	$2.23	$2.23	1.4%
Total		**$15.61**	**$140.50**	**$156.12**	**100.0%**

Q. How does this outcome compare to what BGE proposed?

A. BGE's proposal results in $100.08 million being allocated to Schedule R, and my approach detailed above results in $91.44 being allocated to Schedule R. This means $8.6 million fewer dollars would be allocated to residential customers under my proposal.

Q. What is your conclusion about the reasonableness of this approach?

A. My recommendation is a modest adjustment to the Commission's own historic methodology. It provides meaningful bill relief to residential customers without sacrificing the gradual change to Schedule R's relative earnings position. I recommend the Commission adopt this approach.

7. Residential Rate Design

v. The Commission should reject BGE's proposal to increase the residential customer charge.

Q. What is the purpose of this section of your testimony?

A. This section provides an overview of the company's approach to rate design in the Residential class, with a focus on changes made in this rate case. I explain the concerns I have about its proposal to increase the customer fixed charge and propose that the current fixed charge remain constant.

Q. What change to the residential customer charge is the company proposing?

A. Witness Karas details the proposal to increase the residential customer charge by $1.00 per month, from a value of $10.00 to $11.00. There is no change proposed for Schedule RL customers, who are on the residential time-of-use rate schedule.[50]

Q. Does the company provide any further justification for this proposal?

[50] Karas Direct at 17.

A. The company claims that this update would move the fixed cost recovery closer to the level supported by the COSS in this proceeding of $19.55. It would also reduce the difference in distribution rates between Schedule R and RL. The company claims the change would adhere to the principle of gradualism and avoid rate shock while more closely aligning rates with their cost of service.

Q. Do you agree with the company's justification?

A. No. Cost causation is only a starting point in designing rates. It must be balanced against state policy goals and equity considerations, and the company's proposal does not do so.

Q. What other considerations should be considered when considering changes to fixed charges?

A. While rate stability and cost causation are elements of rate design, these elements must be balanced with state policy goals and equity considerations. These considerations are important because increases in fixed charges may (i) conflict with state policy goals that encourage energy efficiency and (ii) burden customers who hope to reduce their utility bills through energy conservation. Cost causation is also highly dependent on a utility's method of allocating costs.

Q. Why is increasing the fixed monthly customer charge problematic considering the state's energy efficiency programs?

A. Increases to the customer charge can undermine the progress achieved through energy efficiency programs because customers have less of an incentive to conserve energy. Because the company's rates are set to recover a specific revenue requirement, any increase in customer charges is offset by a decrease in the volumetric charge, and vice versa. Increasing the fixed charge limits customers' ability to control their bill through reducing consumption, thus weakening incentives to conserve energy or invest in energy efficiency.

Q. Why does increasing the fixed monthly customer charge burden customers who hope to reduce their utility bills through energy conservation?

A. The proposed increase in the customer charge disproportionately impacts low-consumption customers because the customer charge, as a fixed component, represents a larger share of the total bill for low consumption customers. As the charge increases, these customers see a greater percentage impact on their bills relative to higher-consumption customers, for whom the fixed charge is a smaller portion of total costs. The bill impacts are particularly pronounced for low-income and energy efficient customers, who generally consume less electricity and are more sensitive to increases in fixed costs. For low-income customers, a higher customer charge reduces their ability to manage overall costs through reduced usage, while energy-efficient customers, who have already invested in lowering their consumption, see diminished benefits as more of the bill becomes fixed.

Q. Will the company have the opportunity to recover its revenue requirement if the proposed customer charge increase is rejected?

A. Yes. Rates are designed to recover the company's revenue requirement in a rate case. If the Commission rejects the proposed increase in its residential customer charge, then an offsetting amount is collected through the volumetric rate and can then be collected from customers based on how much electricity each customer consumes. Moving cost recovery from fixed charges into volumetric charges will be revenue neutral for the company.

Q. What is your recommendation for the Schedule R customer charge?

A. I recommend the Commission reject the Schedule R customer charge proposal to increase from $10.00 to $11.00, and instead keep the customer charge the same. Keeping the customer charge at $10.00 will still allow the company to recover its revenue requirement while prioritizing a signal for customers to invest in energy efficiency.

vi. BGE's residential time-of-use ("TOU") rate proposal is not substantiated.

Q. What is Schedule RD?

A. Schedule RD is a residential TOU rate that includes both a distribution and commodity TOU portion.[51] The company states that the distribution rates in this proceeding were designed to be revenue neutral to Schedule R and that its overall rate shaping methodology is consistent with Commission Order No. 91917[52] and the Commission's recent Letter Order.[53]

Q. Please summarize the Commission's recent requirements regarding BGE's Schedule RD?

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[51] Karas Direct at 21:13-16.

[52] Md. Pub. Serv. Comm'n, Order No. 91917, DRIVE Act Implementation (Case No. 9761, October 12, 2025.

[53] Karas Direct at 21:20-22:3.

A. In a recent Letter Order,[54] the Commission approved the company's proposal to shift to the recovery of 60% of primary distribution costs through the on-peak period rates and the remaining 40% through off-peak rates. The company stated that at the time, this change reduced the peak-to-off-peak price ratio from 3.1 to 2.8.[55]

Q. Is the company maintaining the same peak-to-off-peak price ratio in this proceeding?

A. It's not clear. While the company states that it is maintaining the methodology regarding distribution system costs, it does not provide any information on the resulting peak-to-off-peak price ratio for review in its testimony in this proceeding. This makes it difficult to fully assess this rate design methodology at the proposed rates in this proceeding.

Q. Is it likely that the peak-to-off-peak price ratio for Schedule RD will change as a result of this proceeding?

A. Yes. The peak-to-off-peak price ratio for the distribution portion of Schedule RD previously approved by the Commission is 2.3, while peak-to-off-peak price ratio contained in Schedule RD E-13 is 2.5. Thus, the result of this proceeding could increase the overall peak-to-off-peak price ratio of Schedule RD.

Q. Why is the Schedule RD peak-to-off-peak price ratio important?

[54] See No. 9761 Supplement 749 to Md. E-6 Residential Delivery and Energy Time-of-Use – Electric – Schedule RD. Filed April 16, 2026.
[55] May 20, 2025, Letter Order approving Mail Log No. 329078

A. The Company recently changed the methodology of allocating costs to peak and off-peak periods in Schedule RD to lower the peak-to-off-peak price ratio in order to make the rate more appealing to residential customers.[56] It appears that if the methodology previously approved by the Commission to separate costs into peak and off-peak time periods is maintained in this proceeding, much of the lower peak-to-off-peak price ratio change could be lost before the company has had any opportunity to increase enrollment in Schedule RD. Such a result would not be in the best interest of ratepayers, who could benefit from such a rate.

Q. What is your recommendation regarding Schedule RD?

A. I recommend that the company provide the peak-to-off-peak price ratio that will result for Schedule RD for its proposal as part of its rebuttal testimony. This will allow the Commission to understand how this rate proceeding is impacting the rate and allow the Commission to adjust the company's method, if appropriate.

8. Ratemaking Mechanisms, Riders, and Trackers

Q. What is the purpose of this section of your testimony?

A. This section discusses the company's existing ratemaking mechanisms, riders, and trackers, as well as the new riders and regulatory assets proposed by BGE in this proceeding. My testimony urges caution around approving riders in the future for the sake of consumer protection and recommends rejection of the Storm Rider proposal.

[56] Karas Direct at 21:20-22:3

Q. Please summarize the existing riders that BGE operates for the Residential class.

A. Twenty four riders are listed as applicable to Schedule R.[57] They are: Standard Offer Service; Electric Efficiency Charge; Miscellaneous Taxes and Surcharges; Budget Billing; Vehicle Charging Time-of-Use Adjustment; Energy Cost Adjustment; Customer Billing and Consumption Data Requests; Administrative Cost Adjustment; Change of Schedule; Demand Response Service; Multi-Year Plan Adjustment Rider; Net Energy Metering; Billing in Event of Service Interruption; Minimum Charge for Short-Term Uses; Advanced Meter Services; Monthly Rate Adjustment; Peak Time Rebate; Smart Meter Opt-Out; Small Generator Interconnection Standards; Maryland Cost Allocation Method; Storm Restoration Expense; Community Energy Pilot Program; Electric Vehicle Charging Rider; and Base Distribution Revenue Offset Rider.

Q. How would you characterize each of these riders in terms of their intended function?

A. The riders fall into five general categories: energy supply charges, statutorily mandated public policy programs, taxes and government-imposed charges, administrative terms and conditions, and mechanisms that adjust distribution revenues between rate cases. I will focus on this final category in my testimony as those riders are at issue in this proceeding.

Q. Please summarize BGE's riders that adjust distribution revenue between rate cases.

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[57] Karas Direct, Exhibit JAK-3, Schedule R-Residential Service

A. Rider 10, the Administrative Cost Adjustment, Rider 16, the Multi-Year Plan Adjustment Rider, Rider 25, the Monthly Rate Adjustment, and Rider 34, the Base Distribution Revenue Offset Rider all adjust distribution revenues between rate cases. The proposed Storm Restoration Expense Rider, discussed below, would join this category.

Q. How much of the residential delivery bill is recovered through these mechanisms?

A. Using BGE's proposed rates and its stated average residential usage of 851 kWh per month, the delivery portion of the average residential bill is $71.44.[58] Of that amount, $59.50 is recovered through base distribution rates, consisting of the $11.00 customer charge and the volumetric base distribution charge. Approximately $0.97 comes from taxes and surcharges. The remaining $10.97, or 15.4% of the delivery portion of a customer's bill, is recovered through rider mechanisms.

Q. What is your perspective on the riders that BGE currently employs?

A. I am concerned about the number of mechanisms currently used to recover costs outside a general rate case.

First, each rider is a mechanism through which a category of cost can be adjusted without the comprehensive review a base rate case provides. While the

[58] Karas Direct, Exhibit JAK-2, Sheet E-16 (Comparison of Bills, Residential Customers, Schedule R).

significance of one such mechanism is limited, the cumulative significance of two dozen of these riders is not.

Second, there is a risk of riders not being reevaluated sufficiently frequently to assess whether the conditions that justified the establishment of each of them still hold. Riders are added more often than they are retired.

Third, review capacity is limited. Each standing rider requires Staff attention, and as the number of mechanisms grows, the amount of attention and review that each gets may get thinner. There is a risk that the review of costs recovered through such mechanisms may be more informal and less rigorous than the in-depth review conducted in a full rate case.

Despite my concerns, I am not opposed to the usage of public policy riders categorically. The EmPOWER Maryland surcharges implement a statutory mandate, and deliver measurable benefits to customers. The Universal Service Program supports low-income customers who depend on it. Other programs similarly drive positive outcomes for Maryland residents. Nothing in my testimony should be read as a criticism of those programs or of recovering costs through a dedicated mechanism.

Q. Has the Commission previously ruled on riders in general as a method to maintain costs made by the company?

A. Yes. In its Order on alternative forms of rate regulation, the Commission acknowledged that surcharges are vulnerable to "duplication or conflict" with mechanisms already in place, and that the Commission must "stay vigilant to avoid double recovery."[59] That risk is a direct function of how many mechanisms operate simultaneously. The Commission also noted that rate mechanisms increasing fixed cost recovery "reduce the customers' control over their bills."[60]

Q. Are there standards for when a rider may be deemed appropriate?

A. Yes. The AARP published a paper in 2012 titled, *Increasing Use of Surcharges on Consumer Utility Bills*, which focused on illustrating the risks for customers posed by excessive surcharges on utility bills. AARP's review of utility surcharge practices details three criteria under which surcharge treatment was traditionally reserved: costs "largely outside the control of the utility," costs that are "unpredictable and volatile," and costs that are "substantial and reoccurring."[61] AARP also recommends that regulators restrict the number of simultaneous surcharges in order to reduce the burden on the regulator and establish time limits with defined expiration dates on riders. The Regulatory Assistance Project ("RAP"), in a 2026 blog titled *Rate Adjustment Clauses: A Hidden Utility Business Model Problem*, similarly uses the significance, potential volatility, and independence from utility management as key criteria for approving adjustment clauses. RAP also observes that the central problem with adjustment clauses is

59 Case No. 9618, Order No. 89226, at 19.
60 *Id*.
61 Prepared by Larkin & Associates, PPLC for AARP, Increasing Use of Surcharges on Consumer Utility Bills (2012).

"their tendency to make utilities indifferent to managing a cost that ratepayers are rightly concerned about."[62]

The National Regulatory Research Institute ("NRRI") also discusses how far current practice around riders has drifted from best practice in their 2014 report, Alternative Rate Mechanisms and Their Compatibility with State Utility Commission Objectives. NRRI describes the "extraordinary circumstances" that have historically justified tracker recovery as costs that are "largely outside the control of a utility," "unpredictable and volatile," and "substantial and recurring," and states that "until the last several years, commissions required that all three conditions exist if a utility hoped to have costs recovered through a tracker." NRRI finds that "many of the new cost trackers fail the 'extraordinary circumstances' test," and notes that some utilities have accumulated more than 20 such mechanisms. NRRI also identifies the same cost-management concern RAP raises: trackers "undercut the positive effects of regulatory lag" and dilute "the frequency and quality" of the retrospective reviews that give a utility its incentive to control costs.[63]

Q. What is your recommendation for proposed riders that arise in future rate cases?

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[62] Lebel, Mark, Regulatory Assistance Project, *Rate Adjustment Clauses: A Hidden Utility Business Model Problem.* See https://www.raponline.org/blog/rate-adjustment-clauses-hidden-utility-business-model-problem/.

[63] Ken Costello, *Alternative Rate Mechanisms and Their Compatibility with State Utility Commission Objectives*, NRRI Report No. 14-03, April 2014. See https://pubs.naruc.org/pub/FA86C519-AF31-D926-BE12-2AC7AE0CD8D6.

A. I recommend the Commission adopt explicit criteria governing when a new rider mechanism may be established. The cost should be substantial, genuinely volatile and unpredictable, outside the utility's ability to manage through prudent operational decisions, or required by statute or Commission rule. A utility proposing a new rider should bear the burden of demonstrating each of these elements.

I further recommend that the Commission consider including a sunset period of no more than five years for approved riders, so that continuation requires an affirmative showing that the justifying conditions persist and that the Commission can periodically review whether existing mechanisms remain warranted.

Q. Please summarize the Storm Restoration Expense Rider that is proposed by the company.

A. The company is proposing a Storm Restoration Expense Rider ("Storm Rider") to recover or refund the difference between incremental storm restoration expense and the amount of incremental storm restoration expense in rates. The company would normalize the level of storm costs in its base distribution rates to a five-year weighted average for both major and non-major storm events. The company states that the proposal provides more appropriate funding to adequately respond to storms and ensures that the company is spending more accurately on incremental storm costs, and ensuring gradualism and customer benefit.[64]

[64] Direct Testimony of Laura A. Wright at 31-32.

Q. What is the current approach for reconciling incremental storm costs?

A. Currently, storm restoration costs are recovered through two different mechanisms, depending on the classification of the event. The classification is set by regulation. Under COMAR 20.50.01.03.B(32)(b), an event constitutes a Major Outage Event when "(i) More than 10 percent or 100,000, whichever is less, of the electric utility's Maryland customers experience a sustained interruption of electric service; and (ii) Restoration of electric service to any of these customers takes more than 24 hours."[65] An event that does not satisfy both conditions is a non-major outage event. Those two categories are exhaustive: every storm falls into one or the other.

Incremental costs from non-major (i.e., minor) storm costs are recovered through base rates. In Order No. 90948, the Commission directed BGE to use the five-year average of all non-major outage events from 2018 through 2022 as the basis for the level of non-major storm costs included in base rates.[66] That amount is collected from customers every year. If actual non-major costs come in above it, BGE absorbs the difference; if below, BGE retains the difference. The variance stays with the utility until the next base rate case resets the amount in base rates.

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[65] COMAR 20.50.01.03.B(32)(b), as quoted in BGE Response to OPC Data Request 5, Item 05. Under COMAR 20.50.12.13, a utility must submit a Major Outage Event report to the Commission within 35 days of the end of the event.

[66] Md. Pub. Serv. Comm'n, Order No. 90948, Application of Baltimore Gas and Electric Company for an Electric and Gas Multi-Year Plan (Case No. 9692, Dec. 14, 2023), at 32.

Major storm costs are recovered using the mechanism approved by the Commission in Order No. 89678 in Case No. 9645. The company is permitted to defer incremental major outage event O&M expenses to a regulatory asset, subject to prudency review, with the unamortized balance included in rate base in the next rate case.

Q. Has the Commission previously addressed proposals similar to what BGE is proposing?

A. Yes. The Commission has fielded similar requests in the past and rejected proposals with similar terms to what the company is proposing in this docket. Specifically, the Commission rejected previous requests for regulatory asset treatment of minor storm costs.

First, in Case No. 9692, Order No. 90948, the Commission rejected regulatory asset and tracker treatment for non-major outage events. It found that "the O&M costs of non-major outage events do not vary significantly enough to justify establishing a regulatory asset," and directed BGE instead to use a five-year historical average embedded in base rates.[67]

Second, in Case No. 9645, Order No. 92106, the Commission characterized regulatory asset treatment of minor storm costs as "disfavored." It approved such treatment in that instance only as a narrow exception to reduce rate shock given

[67] Order No. 90948 at 31.

the exceptionally high dollar amounts at issue, and denied carrying costs on the resulting balance.[68]

Q. What is your recommendation for the Storm Restoration Expense Rider?

A. I recommend the Commission reject the Storm Rider and maintain the current method for reconciling incremental major and minor storm costs, which can be accomplished without risking the ability to adequately respond to storms and recover associated costs. Specifically, minor storm cost recovery should remain in base rates and major storm cost recovery can be treated with regulatory asset treatment where appropriate in future rate cases.

Q. Why should minor storm costs remain in base rates?

A. First and foremost, adding a tracking mechanism for minor storm costs would remove any incentive for the company to manage costs, while also shifting all risks related to the costs of major storms to customers. Additionally, any departure from this approach should require evidence that normalization has become inadequate, which the company has failed to do in this filing. The Commission has repeatedly affirmed a consistent policy of addressing minor storm-related cost variability through normalization embedded in base rates, not through deferral or tracking mechanisms.

Q. Are you suggesting that the current embedded baseline should remain unchanged?

[68] Order No. 92106 at 26.

A. No. The baseline can be updated in this proceeding. The five-year average adopted in Order No. 90948 covered 2018-2022 and results in approximately $52 million annually in minor storm costs. This figure is now out of date. Actual non-major storm costs were approximately $96 million in 2023, $123 million in 2024, and $97 million in 2025, roughly double the embedded level in each of these three years.[69] This gap does not indicate a failure of normalization as a method, but rather a need to update the baseline as, while increasing, these costs remaining relatively stable from year-to-year.

Q. If the Commission were to consider regulatory asset treatment for minor storm costs in the future, what do you recommend?

A. Any such treatment should be accompanied by an explicit Commission directive prohibiting carrying costs on the resulting balance, consistent with the treatment of the minor storm regulatory asset approved in Order No. 92106. Further, I recommend that the Commission prohibit carrying costs of any kind, whether framed as interest or as a return on an unamortized balance in rate base, or otherwise, on any under-collected balance arising under the proposed rider, for either major or minor storm costs.

Q. How are major storm costs recovered today?

A. Major storm costs are recovered using the mechanism approved by the Commission in Order No. 89678 in Case No. 9645. The company is permitted to

[69] BGE Response to OPC DR05-07, Att. 1.

defer incremental major outage event O&M expenses to a regulatory asset, subject to prudency review, with the unamortized balance included in rate base in the next rate case.

Q. Does BGE earn a return on this balance today?

A. Yes. The company's existing major storm regulatory asset is included in the company's rate base with the weighted average cost of capital applied. The company cites Order No. 89678 as justification for applying the same carrying-cost treatment to the proposed rider as to the existing regulatory asset.[70]

Q. Has BGE shown that this mechanism is inadequate?

A. No. BGE has not identified any deficiency in the existing mechanism. BGE has also not demonstrated that this mechanism has failed to provide adequate or timely cost recovery, nor has the company explained why a tracking mechanism is needed.

Q. What regulatory oversight mechanism would be enacted under BGE's proposal?

A. BGE has confirmed that the rider's annual true-up would proceed as an annual filing reviewed at a Commission Administrative Meeting following a discovery period, comparable to the process used for BGE's existing EmPOWER Maryland filings. A Commission order would be required before new rates take effect.[71]

Q. Is this sufficient?

[70] BGE Response to OPC DR05-03.
[71] BGE Response to OPC DR05-01.

A. No. This process is much less rigorous than the review that those significant costs receive today in a contested rate proceeding. Moving an entire category of cost recovery from full evidentiary review to an annual administrative filing reduces the oversight to which those costs are subject.

Q. Please summarize your recommendation.

A. I recommend that the Commission reject the Storm Rider and maintain the current method for reconciling incremental storm costs, which can be accomplished without risking the ability to adequately respond to storms and recover associated costs. Any future effort to include incremental storm costs as regulatory assets should come with a commitment to not include carrying costs on the resulting balance.

9. Conclusion

Q. Does this conclude your direct testimony?

A. Yes.

CURRENT
ENERGY GROUP

Ron Nelson

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Education

MS, Agricultural and Resource Economics
Colorado State University, 2013

BA, Environmental Economics
Western Washington University, 2006

Work Experience

Founding Partner, Current Energy Group (May 2024 – Present)

- Subject matter and testimony expert in advanced rate design, embedded and marginal cost of service modeling, performance-based regulation, gas decarbonization, and DER integration and compensation.
- Designing and implementing policies and programs to decarbonize energy systems including deployment of distributed energy resources, demand-side management programs, energy storage and grid integration.

Founder, Volt-Watt Consulting LLC (2024 – Present)

Senior Director, Strategen Consulting, (2018 –February 2024)

- Expert witness and advisor that has testified across 20 states in over 80 proceedings and supported multiple state commissions in various proceedings

Economist, Minnesota Attorney General's Office (2013-2017)

- Provided expert testimony on cost of service modeling, rate design, grid modernization and utility business models.
- Analyzing issues related to conservation incentive programs, value of solar, grid modernization, performance-based regulation, renewable energy program design, and MISO.
- Reviewed and made recommendation to improve gas company pipeline replacement programs, demand response tariffs, performance metrics, and rate designs

Graduate Research Associate, Colorado State University (2011-2013)

Select Publications

DER Integration Framework: Regulatory Innovation for DER Compensation and Cost Allocation. McDonnell, Nelson, and Mims Frick. January 2025. Lawrence Berkeley National Laboratory.
Report

Demand Charges in the Electricity Sector. Speetles, LeBel, Nelson, Zimny-Schmitt, Stright, and McLaren. Funded by the DOE: Office of Electricity. Forthcoming

"A Regulator's Blueprint for 21st Century Has Utility Planning," A Report for Advanced Energy United (2023)
Report
Led the development of a report that provided a blueprint for state public utility commissions that are interested in developing gas utility planning requirements to improve transparency into gas utility resource and capital investment plans.

Nonpipeline Alternative Analysis Framework for the Colorado Public Utilities Commission on Behalf of Lawrence Berkeley National Laboratory (2023)
Report, Report
Through a collaboration with Lawrence Berkeley National Laboratory and the Colorado Public Utilities Commission, led the development of two reports that first examined the existing regulatory approaches for non-pipeline alternatives, and then proposed a regulatory framework.

Consumers Energy Gas Bill Impact Analysis: A Case Study of the Effects of Planned Capital Expenditures and Electrification Trends on Behalf of Advanced Energy United (2023)
White Paper
Quantified the impact of gas utility capital improvement projects on customer rates Consumers Energy gas in Michigan. The paper found that Michigan residential customers with Consumers Energy can expect to see their gas bills steadily increase over the next decade – up to 49% over 2021 levels – due to projected utility capital expenditures and electrification trends.

Select Projects

Worked with Green Mountain Power to develop their Embedded Cost of Service Model. Case No. 25-1955-PET.

Represent Maryland OPC in PC44 DSP and Interconnection Working Groups. 2022-Present. The DSP has been working on a process for stakeholder engagement and review of Maryland utilities distribution system planning processes. The interconnection has designed and implemented a new DER cost allocation approach called the Maryland Cost Allocation Mechanism (MCAM). The ultimately adopted MCAM was designed by Ron and prices hosting capacity by location and scarcity.

GridLab CHARGED Initiative - Flexible Connections, DER Planning, and Advance Rate Design Working Groups – Represent clients in Minnesota, Massachusetts, and Illinois in interconnection, flexible interconnection, interagency rates working group, long term system planning processes, and proactive planning processes. 2021-Present

Maine's Governor's Energy Office: Working in collaboration with Central Maine Power to design and implement non-firm import and export tariffs. 2024

Puerto Rico Energy Bureau – Facilitator and presenter for the Smart Inverter Implementation Working Group. Case No. NEPR-MI-2019-0009. 2024-Present

Puerto Rico Energy Bureau – Support on various regulatory matters. 2024-Present

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Hawaii Public Utilities Commission: Advanced Rate Design Proceeding. Docket No. 201-90323. 2020-2021. Documents available here.

Hawaii Public Utilities Commission -Consulted on PBR, rate design, community solar gardens program design, and DER integration. 2018-2024

Kentucky Public Service Commission – Trained staff on cost of service, rate design, distribution system planning, and DER integration. Supported the Commission on all Net Energy Metering Dockets from 2020-2024.

Minnesota Valley Electric Cooperative. Supported on power supply and advanced rate design roadmap. 2023

Xcel C&I Rate Design. Ron used the cost duration model and other embedded cost results to inform a C&I critical peak pricing rate proposal on behalf of Fresh Energy. The MN PUC eventually required Xcel to pilot Ron's proposal across 100s of its customers.
MPUC Docket No. E002/M-20-86

California Energy Storage Alliance. Supported CESA in the SCE Wholesale Distribution Access Tariff Proceeding at FERC. 2019

Expert Testimony

103. IN THE MATTER OF ADVICE NO. 2018 – ELECTRIC FILED BY PUBLIC SERVICE COMPANY OF COLORADO TO REVISE COLORADO P.U.C. NO. 8 – ELECTRIC TARIFF TO ADDRESS LARGE LOADS AND ADD TRANSMISSION LARGE (SCHEDULE TL) AND CLEAN TRANSITION TARIFF (SCHEDULE CTT) AND IMPLEMENT CHANGES TO THE TRANSMISSION LINE EXTENSION POLICY. Proceeding No. 26AL-0137E. On Behalf of NRDC and Sierra Club
Large Load Flexibility

102. MidAmerican Energy Company Proposed General Increase in Electric Rates. Docket No. 26-0331. On behalf of Citizens Utility Board.
Cost of Service, Rate Design

101. Evergy Metro, INC. Case No. ER-2026-0143. On Behalf of the Office of Public Counsel.
Cost of Service, Large Load Cost Allocation, and Rate Design

100. In re: Petition for a limited proceeding to approve large load tariff by Duke Energy Florida, LLC. Docket No. 20260064-EI. On Behalf of the Florida Office of Public Counsel.
Large Load Tariffs, Flexible Connection, and Cost Allocation

99. Maryland Office of People's Counsel, Complainant, V. PJM Interconnection, LLC and Transmission Owners Designated Under Attachment A to the Consolidated Transmission Owneres Agreement, Respondents. Docket No. EL26-63-000. Before the FERC. On behalf of Maryland OPC.

98. Application of Virginia Electric and Power Company For Approval of a Rate Adjustment Clause Rider T-1. Docket No. PUR-2026-00056

Large Load Cost Allocation
Direct

97. Application of Virginia Electric and Power Company For Approval of its Large-Load Connection Queue Process Standards. Docket No. PUR-2026-00011. On Behalf of Sierra Club.
Large Load Queue Process
Direct

96. Maryland Office of People's Counsel v. PJM Interconnection, LLC. On Behalf of Maryland OPC.
PJM Large Load Cost Allocation
Affidavit

95. ComEd's Petition for Approval of Multi-Year Integrated Grid Plan pursuant to 220 ILCS 5/16-105.17. Docket No. 26-0047. On Behalf of Illinois Citizens Utility Board.
Large Investments and Cost Allocation, Hosting Capacity and Interconnection Investments
Direct

94. Illinois-American Water Company. Proposed Rate Increase for Water and Sewer Services. Docket No. 26-0127. On Behalf of Illinois Citizens Utility Board.
Cost of Service, Rate Design, and Rate Riders
Direct

93. In the matter of the application of Arizona Public Service Commission for a hearing to determine the fair value of the utility property of the company for ratemaking purposes, to fix a just and reasonable rate of return thereon, and to approve rate schedules designed to develop such return. Docket No. E-01345A-25-0105. On Behalf of Western Resource Advocates.
Formula Rates
Direct

92. In re: Petition for a limited proceeding to approve large load tariff by Duke Energy Florida, LLC. Docket No. 20250113-EI. On Behalf of the Florida Office of Public Counsel.
Large Load Tariffs, Flexible Connection, and Cost Allocation

91. Application of Wisconsin Electric Power Company for Approval of its Very Large Customer and Bespoke Resources Tariffs. Docket No. 6630-TE-113. On Behalf of Walnut Way Conservation Corp.
Large Load Tariffs, Flexible Connection, and Cost Allocation
Direct

90. Pennsylvania Public Utility Commission v. PPL Electric Utilities Corporation. Docket No. R-2025-3057164. On Behalf of Environmental Intervenors.
Large Load Tariffs, Flexible Connection, and Cost Allocation

89. In the Matter of Application of Duke Energy Carolinas, LLC Authority to Adjust and Increase its Electric Rates and Charges. Docket No. 2025-172-E. On Behalf of Sierra Club.
Large Load Tariffs, Flexible Connection, and Cost Allocation
Direct Surrebuttal

88. In the Matter of Application of Duke Energy Progress, LLC for Authority to Adjust and Increase its Electric Rates and Charges. Docket No. 2025-154-E. On Behalf of Sierra Club.
Large Load Tariffs, Flexible Connection, and Cost Allocation

Direct Surrebuttal

87. Application of Appalachian Power Company for approval of Revisions to the Terms and Conditions of Rate Schedules L.P.S.. Case No. PUR-2025-00057. On Behalf of Sierra Club.
Large Load Tariffs, Flexible Connection, and Cost Allocation
Direct

86. Commonwealth Edison Company. Petition for Establishment of Performance Metrics Under Section 16-108.18(e) of the Public Utilities Act. Docket No. 25-0514. On Behalf of the Joint Non-Governmental Organizations.
Performance Metrics
Direct Rebuttal

85. Application of Virginia Electric & Power Company for a 2025 biennial review of the rates, terms, and conditions for the provision of generation, distribution, and transmission services pursuant to Virginia Code 56-585.1. Case No. PUR-2025-00058. On Behalf of Sierra Club.
Large Load Tariffs, Flexible Connection, and Cost Allocation
Direct

85. Petition of Massachusetts Electric Company and Nantucket Electric Company, each d/b/a National Grid, for approval by the Department of Public Utilities of the Company's Monson-Palmer-Longmeadow (Northwest) Capital Investment Project proposal under the Provisional Program established by the Department in Provisional System Planning Program, D.P.U. 20-75-B (2021). Case No. D.P.U 25-31. On Behalf of The Office of the Attorney General.
Distribution System Planning, Interconnection, DER Integration
Direct

84. Application of Nevada Power Company d/b/a NV Energy for authority to adjust its annual revenue requirement for general rates charged to all classes of electric customers and for relief properly related thereto, Docket No. 25-02016. On Behalf of Western Resource Advocates.
Embedded and Marginal Cost of Service, Large Load Line Extensions and Cost Allocation
Direct

83. Proceeding on Motion of the Commission as to the Rates, Charges, Rules and Regulations of Consolidated Edison Company of New York, Inc. for Electric Service, Case 25-E-0072. On behalf of the Environmental Defense Fund.
Rate Design
Direct

83. Petition of PPL Electric Utilities Corporation for Approval of its Second Distributed Energy Resources Management Plan. Docket No. P-2024-3049223. On Behalf of the Pennsylvania Office of Consumer Advocate.
DERMS, DER Cost Allocation, DERMS Alternatives, Cost-Benefit Analysis

82, In the Matter of the Application of the Yankee Gas Services Company d/b/a Eversource Energy to Amend Its Rate Schedules. Docket No. 24-12-01. On Behalf of the Connecticut State Office of Consumer Advocate.
Rate Design and Cost of Service
Direct Surrebuttal

81. Petition of NSTAR Electric Company d/b/a Eversource Energy for Approval to Offer Optional Electric Vehicle Time-of-Use Rates. Petition of Massachusetts Electric Company and Nantucket Electric Company each

d/b/a National Grid for Approval to offer Optional Electric Vehicle Time-of-Use Rates. On Behalf of the Massachusetts AGO (with Andy Eiden).
EV TOU Rate Design, Submetering
Direct

80. In the Matter of the Application of Rocky Mountain Power for Authority to Increase its Retail Electric Utility Rates in Utah and for Approval of its Proposed Electric Service Schedules and Electric Service Regulations. On Behalf of the Utah Office of Consumer Services.
Embedded Cost of Service Study, Flexible Connections, Rate Design
Direct Surrebuttal

79. In the Matter of the Applications of The Dayton Power and Light Company for Approval of Phase 2 of Its Smart Grid Plan and for Approval of Certain Accounting Methods. Case No. 24-0112-EL-GRD. On Behalf of Office of Consumer Counsel.
Grid Modernization Rider Proposal
Direct

78. Petition of PPL Electric Utilities Corporation for Approval of its Second Distributed Energy Resources Management Plan. Docket No. R-2024 -3049223. On Behalf of PA OCA.
DERMS Implementation, Flexible Interconnection, Export Tariffs, Smart Inverters
Direct

77. Pennsylvania Public Utility Commission v. PECO Gas Company – Electric Division. Docket No. R-2024-03046932. On Behalf of PA OCA.
Weather Normalization Adjustment

76. Pennsylvania Public Utility Commission v. PECO Energy Company – Electric Division. Docket No. R-2024-3046931. On Behalf of PA OCA.
EV Program Design and Load Management

75. Southern Maryland Electric Cooperative, INC's Application for adjustment to Its retail rates and changes for electric distribution service and other tariff revisions. On Behalf of Maryland OPC.
Cost of Service, Rate Design
Direct Rebuttal

74. Order Requiring Ameren Illinois Company to Refile an Initial Multi-Year Integrated Grid Plan and Initiating Proceeding to Determine Whether the Plan is Reasonable and Complies with the Public Utilities Act. May 13, 2024. Docket No. 22-0487. On Behalf of Environmental Law and Policy Center, Natural Resources Defense Council, Union of Concerned Scientists, and Vote Solar.
Marginal Cost of Service, Proactive Hosting Capacity
Direct

73. Order Requiring Commonwealth Edison Company to Refile an Initial Multi-Year Integrated Grid Plan and Initiating Proceeding to Determine Whether the Plan is Reasonable and Complies with the Public Utilities Act. May 22, 2023. Docket No. 22-0486. On Behalf of Environmental Law and Policy Center, Natural Resources Defense Council, Union of Concerned Scientists, and Vote Solar.
Marginal Cost of Service, Proactive Hosting Capacity, Peak Load Reduction Programs
Direct Rebuttal

CURRENT ENERGY GROUP

72. PJM Interconnection, L.L.C., Revisions to Incorporate Cost Responsibility Assignments for Regional Transmission Expansion Plan Baseline Upgrades (Jan. 10, 2024), Docket No. ER24-843, Accession No. 20240110-5117. Affidavit on behalf of Maryland OPC
Transmission Planning and Cost Allocation
Affidavit

71. Petition of Massachusetts Electric Company and Nantucket Electric Company, each d/b/a National Grid, pursuant to F.L. c. 164 for approval of a General Increase in Base Distribution Rates for Electric Service and a Performance-based Ratemaking Plan. DPU 23-150.
Cost of service and Rate Design
Direct

70. Easton Utilities Commission's Application for Authority to Increase Its Rates and Charges for Electric Service and Gas Service. On behalf of Maryland OPC. Case No. 9719.
Cost of service and Rate Design
Direct

69. In the Matter of the Tariff Revisions Designated as TA544-8 Filed by Chugach Electric Association, INC. U-23-047. On behalf of AARP.
Cost of service and Rate Design
Direct

68. Petition of Fitchburg Gas and Electric Light Company d/b/a Unitil, pursuant to G.L. c. 164, § 92B, for approval by the Department of Public Utilities of its Electric Sector Modernization Plan. D.P.U. 24-12, Petition of Massachusetts Electric Company and Nantucket Electric Company d/b/a National Grid, pursuant to G.L. c. 164, § 92B, for approval by the Department of Public Utilities of its Electric Sector Modernization Plan. D.P.U. 24-11, Petition of NSTAR Electric Company d/b/a Eversource Energy, pursuant to G.L. c. 164, § 92B, for approval by the Department of Public Utilities of its Electric Sector Modernization Plan. D.P.U. 24-10. On behalf of the MA AGO
Grid Planning and DER Integration
Direct

67. In the Matter of the Application of Potomac Electric Power Company for and Electric Multi-Year Plan for the Distribution of Electric Energy Case No. 9702. On behalf of Maryland OPC.
Electric Rate Design and Forecasting
Direct

66. In the Matter of the Application of Nevada Power Company, d/b/a NV Energy, files pursuant to NRS 704.110 (3) and (4), addressing its annual revenue requirement for general rates charged to all classes of customers. On behalf of SWEEP.
Electric TOU Rate Design
Testimony

65. In the Matter of Advice No. 1923 – Electric of Public Service Company of Colorado to Revise its Colorado P.U.C. No. 8 – Electric Tariff to Reset the General Rate Schedule Adjustments, to Place into Effect Revised Base Rates, and to Implement Other Phase II Tariff Proposals to Become Effective June 15, 2023. On behalf of WRA.
Electric TOU Rate Design
Testimony

64. Application of Baltimore Gas and Electric Company for a Second Electric and Gas Multi-Year Plan Case No. 9692. On behalf of Maryland OPC
Electric and Gas Rate Design, Gas Transition, Bill Impacts
Direct

63. Massachusetts Electric Company Nantucket Electric Company d/b/a National Grid, Capital Investment Project Filing: D.P.U. 22-170, 23-06, 23-09, and 23-12 On Behalf of the MA AGO w/ Panelists Jorge Camacho and Eli Asher
DER Integration, Interconnection and Cost Allocation
Direct | Surrebuttal

62. Order Requiring Commonwealth Edison Company to file an Initial Multi-Year Integrated Grid Plan and Initiating Proceeding to Determine Whether the Plan is Reasonable and Complies with the Public Utilities Act. Docket No. 22-0486. On Behalf of Environmental Law and Policy Center, Natural Resources Defense Council, Union of Concerned Scientists, and Vote Solar.
Hosting Capacity, Value of DER, Peak Load Reduction, Flexible Interconnection, DERMS
Direct

61. Ameren Illinois Company. Proposed General Increase in Rates and Revisions to Other Terms and Conditions of Service. Docket No. 23-0067. On Behalf of Environmental Law and Policy Center, Environmental Defense Fund, Natural Resources Defense Council, Illinois State Public Interest Research Group, Inc.
Gas Transition, Capital Planning, Line Extensions, Non-Pipeline Alternatives, Bill Impacts, Gas System Planning, PBR, Rate Design
Direct Rebuttal

60. Pennsylvania Public Utility Commission V. Philadelphia Gas Works. Docket No. P-2022-3034264. On Behalf of The Office of Consumer Advocate
Weather Normalization Adjustment and Decoupling

59. DEP and DEC EVSE Program. Docket No. 2022-158-E. On Behalf of The South Carolina Office of Regulatory Staff
EV Program Design
Direct | Surrebuttal

58. Petition of Philadelphia Gas Works for Approval on Less than Statutory Notice of Tariff Supplement Revising Weather Normalization Adjustment. Docket No. 2022-3034264. On Behalf of the Office of the Consumer Advocate
Weather Normalization Adjustment

57. In the Matter of Application of Duke Energy Progress, LLC, for Adjustment of Rates and Charges Applicable to Electric Service in North Carolina and for Performance Based Regulation. Docket No. E-2, Sub 1300. On Behalf of the North Carolina Attorney General's Office
Cost of Service, Rate Design, Performance-Based Regulation
Direct

56. Application of Public Service Company of Oklahoma, an Oklahoma Corporation, for an Adjustment in its Rates and Charges and the Electric Service Rules, Regulations, and Conditions of Service for Electric Service in the State of Oklahoma and to Approve a Formula Based Rate Proposal . On Behalf of AARP
Cost of Service and Rate Design
Responsive Testimony

55. Montana-Dakota Utilities Co. 2022 Electric Rate Increase Application. On Behalf of AARP
Cost of Service and Rate Design
Direct | Surrebuttal

54. Northern Indiana Public Service Company Rate Case. On Behalf of Citizens Action Coalition
Cost of Service and Rate Design
Direct

53. Central Maine Power Company: Request for Approval of Distribution Rate Increase and Rate Design Changes Pursuant to 35-A M.R.S. Section 307, Docket 2022-00152, On Behalf of the Governor's Energy Office w/Panelists Caroline Palmer and Nikhil Balakumar. On Behalf of the Governor's Energy Office
Marginal Cost of Service, Performance-Based Regulation, Distribution System Planning
Direct

52. Georgia Power Company's 2022 Rate Case. DOCKET NO.: 44280. On Behalf of Americans for Affordable and Clean Energy
Electric Vehicle Rate Design
Direct

51. In the Matter of the Application of Northern States Power Company for Authority to Increase Rates for Electric Service in Minnesota (Docket No 21-630), On Behalf of the Citizen's Utility Board of Minnesota
Rate Riders, Fuel Clause Risk Sharing, and MYRP Structure
Direct | Rebuttal

50. In the Matter of the Application of Northern States Power Company for Authority to Increase Rates for Electric Service in Minnesota (Docket No 21-630), On Behalf of the Clean Energy Organizations
Advanced Rate Design, Regulatory Sandbox, TOU Rate Design
Direct | Surrebuttal

49. NSTAR Electric Company d/b/a Eversource Energy, Capital Investment Project Filing: D.P.U. 22-51 through 55 On Behalf of the MA AGO w/ Panelists Jorge Camacho and Eli Asher
DER Integration, Interconnection and Cost Allocation
Direct | Surrebuttal

48. Massachusetts Electric Company Nantucket Electric Company d/b/a National Grid, Capital Investment Project Filing: Shutesbury (D.P.U. 22-61) On Behalf of the MA AGO w/ Panelists Jorge Camacho and Eli Asher
DER Integration, Interconnection and Cost Allocation
Direct

47. In the Matter of Delmarva Power and Light Company's Application for an Electric Multi-Year Plan (Case No. 9681) On Behalf of the Office of People's Counsel w/ Panelist Jorge Camacho
Distribution System Planning, Capital Investment Plan, Multi-Year Rate Plan Structure, Revenue Decoupling
Direct (No. 21) | Rebuttal (No. 23)

46. Petition of NSTAR Electric Company d/b/a Eversource Energy for approval by the Department of Public Utilities of the Company's Marion-Fairhaven capital project proposal under the Provisional Program established by the Department in Provisional System Planning Program, D.P.U 20-75-B (2021) (D.P.U. 22-47) On Behalf of the MA AGO w/ Panelists Jorge Camacho, Eli Asher, and Fred Schaefer
DER Integration, Interconnection and Cost Allocation

Direct | Surrebuttal

45. Petition for Approval of Beneficial Electrification Plan under the Electric Vehicle Act, 20 ILCS 627/45 and New EV Charging Delivery Classes under the Public Utilities Act, Article IX. (Docket No. 22-0432 and 22-0442) On Behalf of NRDC, Sierra Club, EDF, RHA and Little Village Environmental Justice Organization (LVEJO)
Electric Vehicle Rate Design and Energy Management Systems

44. Petition for Approval of Beneficial Electrification Plan pursuant to Section 45 of the Electric Vehicle Act (Docket No. 22-0431 and 22-0443) On Behalf of NRDC, Sierra Club, EDF, and RHA
Electric Vehicle Rate Design and Energy Management Systems

43. In the Matter of the Application of a Gas & Electric Company for an Order of the Commission Authorizing Applicant to Modify Its Rates, Charges, and Tariffs for Retail Electric Service in Oklahoma
Cost of service, rate design, formula rate plan
Direct | Stipulation

42. Petition for Establishment of Performance Metrics Under Section 16-108.18(e) of the Public Utilities Act, Commonwealth Edison Company, Docket No. 22-0067 On Behalf of NRDC
Demand Response and Electric Vehicle Performance Metrics
Direct | Rebuttal

41. Petition for Establishment of Performance Metrics Under Section 16-108.18(e) of the Public Utilities Act, Ameren Illinois Company, Docket No. 22-0063 On Behalf of NRDC
Demand Response and Electric Vehicle Performance Metrics
Direct | Rebuttal

40. In the matter of the application of CONSUMERS ENERGY COMPANY for authority to increase its rates for the distribution of natural gas and for other relief. U-21148. On Behalf of NRDC
Performance-based regulation and gas decarbonization
Direct

39. Petition of NSTAR Electric Company d/b/a Eversource Energy for approval by the Department of Public Utilities of the Company's Marion-Fairhaven capital project proposal under the Provisional Program established by the Department in Provisional System Planning Program, D.P.U 20-75-B (2021)
DER integration, Flexible interconnection, Capital Investment Project
Direct | Surrebuttal

38. In the Matter of the Application of Oklahoma Gas & Electric Company for an Order of the Commission Authorizing Applicant to Modify Its Rates, Charges, and Tariffs for Retail Electric Service in Oklahoma
Cost of service, rate design, formula rate plan
Direct | Stipulation

37. In the Matter of the Application of Minnesota Power for Authority to Increase Rates for Electric Utility Service in Minnesota. Docket No. E-015/GR-21-335. On Behalf of CUB Minnesota
Cost recovery, cost of service, and revenue apportionment
Direct | Surrebuttal

36. In the matter of the application of CONSUMERS ENERGY COMPANY for authority to increase its rates for the distribution of natural gas and for other relief. U-21148. On Behalf of NRDC
Performance-based regulation and gas decarbonization

Direct

35. Phase 2: Petition of Fitchburg Gas and Electric Light Company d/b/a Unitil for approval of its Electric Vehicle Infrastructure Program, Electric Vehicle Demand Charge Alternative Proposal, and Residential Electric Vehicle Time-of-Use Rate Proposal (D.P.U 21-92) On Behalf of the Attorney General's Office
EV Program Design and Load Management
Direct

34. Phase 2: Petition of Massachusetts Electric Company and Nantucket Electric Company, each d/b/a National Grid, for approval of its Phase III Electric Vehicle Market Development Program and Electric Vehicle Demand Charge Alternative Proposal (D.P.U 21-91) On Behalf of the Attorney General's Office
EV Program Design and Load Management
Direct

33. Phase 2: Petition of NSTAR Electric Company d/b/a Eversource Energy for approval of its Phase II Electric Vehicle Infrastructure Program and Electric Vehicle Demand Charge Alternative Proposal (D.P.U 21-90) On Behalf of the Attorney General's Office
EV Program Design and Load Management
Direct

32. Phase 1: Petition of Fitchburg Gas and Electric Light Company d/b/a Unitil for approval of its Electric Vehicle Infrastructure Program, Electric Vehicle Demand Charge Alternative Proposal, and Residential Electric Vehicle Time-of-Use Rate Proposal (D.P.U 21-92) On Behalf of the Attorney General's Office
EV Program Design and Load Management
Direct

31. Phase 1: Petition of Massachusetts Electric Company and Nantucket Electric Company, each d/b/a National Grid, for approval of its Phase III Electric Vehicle Market Development Program and Electric Vehicle Demand Charge Alternative Proposal (D.P.U 21-91) On Behalf of the Attorney General's Office
EV Program Design and Load Management
Direct

30. Phase 1: Petition of NSTAR Electric Company d/b/a Eversource Energy for approval of its Phase II Electric Vehicle Infrastructure Program and Electric Vehicle Demand Charge Alternative Proposal (D.P.U 21-90) On Behalf of the Attorney General's Office
EV Program Design and Load Management
Direct

29. In the Matter of the Petitions for Recovery of Certain Gas Costs (DKT: 21-138, 21-235, 21-610, 21-611) On Behalf of The Citizens Utility Board of Minnesota
Prudency Review
Direct

28. In the Matter of the Application of CenterPoint Energy Resources Corp. d/b/a CenterPoint Energy Minnesota Gas for Authority to Increase Rates for Natural Gas Utility Service in Minnesota (Docket No. 21-435) On Behalf of the Clean Energy Organizations
Rate Design and Line Extension Policy
Direct

27. In the Matter of the Petitions for Recovery of Certain Gas Costs (DKT: 21-138, 21-235, 21-610, 21-611) On Behalf of The Citizens Utility Board of Minnesota
Prudency Review
Direct

26. Green Mountain Power (DKT: 2021-3707-PET) On Behalf of Green Mountain Power
Multi-Year Rate Plan
Prefiled Direct Testimony

25. Public Service of Oklahoma (DKT: 202100055) On Behalf of AARP
ECOSS and Rate Design
Responsive Testimony

24. Duquesne Light Company (DKT: R-2021-3024750) On Behalf of the PA OCA
Transportation Electrification, Load Control
Direct | Surrebuttal (note: please type in the docket number, the testimony cannot be directly referenced)

23. PECO (DKT: R-2021-3024601) On Behalf of the PA OCA
Transportation Electrification, Load Control
Direct (note: please type in the docket number, the testimony cannot be directly referenced)

22. Mountain Power (DKT: 20-035-04) On Behalf of the Utah Office of Consumer Services
Embedded COS, Rate Design, and AMI Rollout
Direct

21. Minnesota Power* On Behalf of the MN CUB
ECOSS and low-income rate design

20. Pennsylvania Power and Light: DER Management Petition (DKT: P-2019-3010128) On Behalf of the PA OCA
DER integration
Direct | Surrebuttal (note: please type in the docket number, the testimony cannot be directly referenced)

19. Public Service of New Hampshire (dba Eversource Energy) (DKT: DE 19-057) On Behalf of the NH OCA
Embedded and marginal COS, Rate Design, and PBR
Direct

18. Liberty Utilities (DKT: DE 19-064) On Behalf of the NH OCA
Marginal COS, Rate Design, decoupling and PBR
Direct *Settled before direct was filed

17. Oklahoma Gas and Electric (DKT: 201800140) On Behalf of AARP
Rate Design and CCOSS
Direct

16. Vectren Energy Delivery of Ohio (DKT: 18-0298-GA-AIR) On Behalf of the Environmental Law and Policy Center
CCOSS and Rate Design
Direct | Supplemental | Case link

15. Commonwealth Edison (DKT: 18-0753) On Behalf of the IL AG

Distributed Generation Rebates and Smart Inverter Specifications
Direct | Rebuttal | Case link

14. Ameren Illinois Company (DKT: 18-0537) On Behalf of the IL AG
Distributed Generation Rebates and Smart Inverter Specifications
Direct | Rebuttal | Case file

13. Public Service Company of Oklahoma (DKT: 201800096) On Behalf of AARP
Formula Rates, Performance Metrics, Rate Design, and CCOSS
Direct

12. Oklahoma Gas and Electric (DKT: 201700496) On Behalf of AARP
CCOSS and Revenue Apportionment
Responsive | Case link

11. Minnesota Power (DKT: E-002/GR-16-664) On Behalf of the MN OAG
CCOSS, Rate Design, and the Utility Business Model
Surrebuttal | Rebuttal: | Testimony | Case Link

10. Minnesota Power (DKT: E-002/GR-16-664) On Behalf of the MN OAG
CCOSS, Rate Design, and the Utility Business Model
Surrebuttal | Rebuttal: | Testimony | Case Link

9. Otter Tail Power (DKT: E-002/GR-15-1033) On Behalf of the MN OAG
Marginal and Embedded CCOSS and Rate Design
Opening Statement | Direct | Rebuttal | Case link

8. Xcel Energy (DKT: E-002/GR-15-826) On Behalf of the MN OAG
CCOSS, Rate Design, and Performance-Based Regulation
Direct | Rebuttal | Surrebuttal | Case link

7. Minnesota Energy Resources Corp. (DKT: G-011/GR-15-736) On Behalf of the MN OAG
CCOSS and Rate Design
Direct : | Rebuttal | Surrebuttal | Case link

6. CenterPoint Energy (DKT: E-002/GR-15-424) On Behalf of the MN OAG
CCOSS and Rate Design
Opening Statement | Direct | Rebuttal | Surrebuttal | Case link

5. Dakota Energy Association (DKT: E-002/GR-14-482) On Behalf of the MN OAG
CCOSS and Rate Design
Direct | Rebuttal | Surrebuttal | Case link

4. Xcel Energy (DKT: E-002/GR-13-868) On Behalf of the MN OAG
CCOSS and Rate Design
Direct | Rebuttal | Surrebuttal: Case Link

3. Xcel Energy, Minnesota Energy Resources Corp, CenterPoint Energy (DKT: 21-138)
Natural Gas Prudence Testimony
Case Details | Direct

2. Minnesota Energy Resources Corp. (DKT: G-011/GR-13-617) On Behalf of the MN OAG
CCOSS
Direct | Surrebuttal | Case Link

1. CenterPoint Energy (DKT: G-008/GR-13-316) On Behalf of the MN OAG
CCOSS
Direct | Surrebuttal | Case Link

Baltimore Gas and Electric Company's Application for Adjustments to Its Electric Base Rate

Case No. 9888

Data Responses Cited in the Direct Testimony of Ron Nelson

BGE Response to MEA DR03-17(b, c)

BGE Response to MEA DR03-22

BGE Response to OPC DR01-09, including Attachment 1

BGE Response to OPC DR05-01

BGE Response to OPC DR05-03

BGE Response to OPC DR05-07, including Attachment 1

BGE Response to OPC DR05-11-REVISED, including Attachment 1

BGE Response to OPC DR07-02(a, b)

BGE Response to OPC DR07-03(b, c)

BGE Response to OPC DR07-11

BGE Response to OPC DR18-01(a)

BGE Response to OPC DR18-02(h)

BGE Response to Staff DR01-01, including Attachment 1

BGE Response to Staff DR19-01

BGE Response to Staff DR28-23, including Attachment 1 & 2

Case No. 9888
Baltimore Gas and Electric Co.
Response to MEA Data Request 3
Request Received: August 25, 2026
Response Date: September 10, 2026
Sponsor(s): Laura A. Wright; Michael J. Cloyd

Item No.: MEADR03-17

Refer to Exhibit JCF-7. For Project 78077 (DERMS Implementation, $8,065,282), please provide:

The current deployment status and schedule, including the schedule for GIS integration with ADMS;

b. The DER-enabling capabilities in production today versus planned (e.g., DER modeling, hosting-capacity analysis, flexible interconnection, BESS management, VPP dispatch, FERC Order 2222 participation), with dates of current and future implementation;

c. Quantified utilization to date, including the number and aggregate MW of DERs and battery storage systems managed through DERMS, enrolled demand response capacity (MW) by program for 2024 and 2025, and sensor deployment counts and locations by planning area;

d. The allocation of project costs among Exelon operating companies, and the allocation methodology;

e. For DERMS, the vendor selection analysis supporting the choice of the OSI Integra "out of box standalone solution," including all alternatives evaluated and their costs and capabilities, and any customizations made or planned with their costs; and

f. State whether capabilities funded through these projects have been used in distribution planning to support reliance on flexible load or DER dispatch instead of a traditional distribution investment.

RESPONSE:

a. Project 78077 was placed in service in November 2025 and is currently operational.

   Project 78077 did not include GIS integration with ADMS as part of its approved scope. To the extent this request seeks schedules or implementation details associated with future DERMS enhancements, future GIS integrations, or projects not placed in service prior to March 31, 2026, BGE objects because such information is outside the scope of the investments reflected in CN9888.

b. The following capabilities were placed into service through Project 78077 and are currently in production:
   - Monitoring and control of BGE's Fairhaven and Chesapeake Beach BESS resources
   - Short-term load and DER forecasting
   - Estimated output of unmetered DER

- DER alarms
- DER telemetry
- DER M&V

Project 78077 did not place into service hosting-capacity analysis, flexible interconnection, Virtual Power Plant ("VPP") dispatch, or FERC Order 2222 participation functionality. As described in Company Exhibit JCF-7, Project 78077 established a foundational DERMS platform intended to support future DER capabilities as operational, regulatory, and business requirements evolve.

To the extent this request seeks implementation schedules or future deployment details associated with projects not placed in service prior to March 31, 2026, BGE objects because such information is outside the scope of this proceeding. BGE further notes that future deployment and plans for these technologies are being evaluated in other regulatory proceedings such as the DRIVE Act (Case No. 9761).

c. Project 78077 is being utilized to monitor and control BGE's Fairhaven and Chesapeake Beach Battery Energy Storage Systems, representing 3.5 MW of battery storage resources.

   Project 78077 does not administer demand response programs and does not track enrolled demand response capacity by program. Similarly, Project 78077 did not include deployment of line sensors or planning-area sensor infrastructure as part of its approved scope.

d. Project 78077 was a BGE-specific project. Project costs associated with Project 78077 were allocated to BGE and were not shared among multiple Exelon operating companies.

e. As described in the Project 78077 authorization materials, BGE considered multiple alternatives before selecting the standalone OSI Integra DERMS platform, including:
   - Standalone OSI Integra DERMS (selected option);
   - Standalone non-OSI DERMS products;
   - Implementation of DERMS functionality within the Enterprise Utility ADMS program; and
   - Deferral pending future Enterprise Utility DERMS deployment.

   BGE selected the standalone OSI Integra DERMS solution because it represented the lowest implementation risk and most practical approach for establishing near-term DER management capabilities while preserving flexibility for future DER growth and regulatory requirements.

   Project 78077 was specifically scoped to leverage the base OSI Integra DERMS product as much as possible and minimize custom development. The project authorization materials previously made available in this proceeding describe the alternatives considered and the rationale supporting the selected solution.

f. Project 78077 was not implemented for the purpose of supporting distribution planning decisions that rely on flexible load or DER dispatch in lieu of traditional distribution investments. Rather, the project deployed a foundational Utility DERMS platform focused on operational monitoring and control of BGE's battery energy storage resources and establishing a scalable DER management capability.

Case No. 9888
Baltimore Gas and Electric Co.
Response to MEA Data Request 3
Request Received: August 25, 2026
Response Date: September 10, 2026
Sponsor(s): Laura A. Wright; Michael J. Cloyd

Item No.: MEADR03-22

Refer to Projects 64741 (Core GIS Implementation, $16,904,224), 78077 (DERMS Implementation, $8,065,282), 64601 (Line Sensors Deployment Support, $3,061,997), 60975 (Load Management Capital, $7,792,074), 77112 (Grid Communications and Connectivity, $12,283,341), and 262092 (GCC Fiber Route - Howard, $6,534,146) described in Exhibit JCF-7, totalling more than $54 million. Please state whether BGE maintains a comprehensive DER integration and utilization roadmap that coordinates these investments toward defined DER-enablement outcomes (e.g., flexible interconnection availability, hosting-capacity targets, VPP enrollment).

a. If yes, please provide such roadmap.
b. If no, please explain how BGE ensures these investments deliver coordinated and timely DER integration capability.

RESPONSE:

BGE is currently developing a more comprehensive DER integration roadmap and will continue to evaluate future DER integration capabilities and associated investments. BGE does not currently maintain a comprehensive DER integration and utilization roadmap that coordinates investments toward specific DER-enablement outcomes such as flexible interconnection availability, hosting-capacity targets, or VPP enrollment.

Not all of the projects identified in this request were undertaken specifically for DER integration or utilization purposes. Rather, these projects support a range of business, operational, communications, data management, grid modernization, and reliability objectives, some of which may also support DER integration.

Project 78077 established foundational DERMS capabilities that support BGE's ability to accommodate increasing DER adoption over time. In response to the evolving DER regulatory and technology landscape, BGE is currently developing a more comprehensive DER integration roadmap and will continue to evaluate future DER integration capabilities and associated investments.

Case No. 9888
Baltimore Gas and Electric Co.
Response to OPC Data Request 1
Request Received: July 29, 2026
Response Date: August 12, 2026
Sponsor(s): John C. Frain; Nancy McCart

Item No.: OPCDR01-09

For the historic test year period, provide an itemized list of expenses incurred and charged to FERC Account 923, Outside Services Employed. Expenses made to the same recipient for the same purpose may be aggregated. Expenses made to the same recipient but for different purposes should be reported as separate lines. If such information cannot be provided for the historic test year period, provide such information for the calendar year ending on Dec. 31, 2025.

(a) In column (a), report the recipient.
(b) In column (b), report the unredacted billing amount.
(c) In column (c), report the billing date.
(d) In column (d), provide an explanation of each expenditure in detail sufficient to describe the purpose of the expense. The purpose should contain more detail than simply repeating that the expense is for an outside service employed.

RESPONSE:

(a) – (d) Data is not available in the format requested. Please refer to *OPCDR01-09-Attachment 1* for an itemized list of activity recorded to FERC Account 923.

Case No. 9888
OPCDR01-09-Attachment 1

BALTIMORE GAS AND ELECTRIC COMPANY
FERC 923-Outside Services Employed
Twelve Months Ended March 31, 2026

Recipient	Services	Amount
EBSC	BSC Exelon Utilities	$ 4,243,915
EBSC	BSC Interest	188,691
EBSC	BSC Operations Services	189,595
EBSC	BSC Other	5,468,651
EBSC	BSC Real Estate	1,363,993
EBSC	Communication Services	2,293,513
EBSC	Executive Services	6,143,284
EBSC	Financial Services	19,361,231
EBSC	HR Services	6,451,161
EBSC	IT Services	57,264,602
EBSC	Legal Governance Services	6,074,057
EBSC	Regulatory and Government Affairs	1,844,376
EBSC	Security Services	1,960,893
EBSC	Supply Services	937,653
		$ 113,785,615
GREENCASTLE ASSOCIATES CONSULTING LLC	BGE Customer Operations	$ 12,641
PONTOON SOLUTIONS INC	BGE Customer Operations	7,143
		$ 19,784
GLOBAL FACILITY SOLUTIONS LLC	BGE Project Management	$ 65,379
GUARDIAN CSC	BGE Project Management	43,467
ELECTRICAL AUTOMATION SERVICES INC	BGE Project Management	11,036
BOBBYS PORTABLE RESTROOMS	BGE Project Management	822
AECOM TECHNICAL SERVICES INC	BGE Project Management	18,765
		$ 139,470
EASI SERVICES INC	BGE Project Mgmt VP Office	$ 16,446
ITRON INC	Field Operations	$ 396,740
ENERGY AND ENVIRONMENTAL ECONOMICS INC	BGE Strategy & Regulatory	$ 135,073
BAKER TILLY ADVISORY GROUP PARENT LP	BGE Strategy & Regulatory	23,824
		$ 158,897
ZONES LLC	BGE Technical Services	$ 97
CONXX INC	BGE Transmission & Substation	$ 1,926
COMMUNICATIONS TEST DESIGN INC	BGE Transmission & Substation	44,105
		$ 46,031
ZONES LLC	IT Licensing & Maintenance	$ 10,016
ALLEGIS GROUP HOLDINGS INC	Security	$ (827)
SEA LTD	Facilities	$ 4,813
Other JE (Primarily due to accounting allocation)		$ 1,824,008
Total FERC 923		$ 116,401,090

Case No. 9888
Baltimore Gas and Electric Co.
Response to OPC Data Request 5
Request Received: August 19, 2026
Response Date: September 02, 2026
Sponsor(s): John C. Frain; Jennifer A. Karas

Item No.: OPCDR05-01

Please see the direct testimony of John Frain ("Frain Direct") at page 45. Mr. Frain states that each annual filing provides "an opportunity for regulatory review of the prudency" of the incremental storm O&M. Describe the specific procedural process the Company expects to use for the annual Storm Rider filing. Would it be a compliance filing effective on a specific date, absent objection, or would it require an affirmative Commission order before new rates can take effect?

RESPONSE:

As noted on page 46 of the Direct Testimony of Company Witness Frain, "The first rate filing, including prudency review support for incremental storm O&M expenses, would be filed by the end of May 2028 proposing a charge or refund rate effective for July 2028 – June 2029 billings. Future year filings will use actual storm restoration expense for a calendar year and set the Storm Rider rate to change annually with July billings."[1] As noted in the proposed tariff included as Company Exhibit JAK-3 in the Direct Testimony of Company Witness Karas, "Details concerning the calculation of the Storm Restoration Expense Rider are filed with and approved by the Commission prior to their use in billing."[2] This procedural process is consistent with other rider rate filings submitted by the Company, such as the annual EmPOWER Maryland filings. The process for these filings allows for discovery before Commission review at an Administrative Meeting and requires an affirmative Commission order before new rates may be implemented.

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[1] Frain Direct at 46:6-10.
[2] Company Exhibit JAK-3 p. 111a.

Case No. 9888
Baltimore Gas and Electric Co.
Response to OPC Data Request 5
Request Received: August 19, 2026
Response Date: September 02, 2026
Sponsor(s): John C. Frain

Item No.: OPCDR05-03

Please see Frain Direct at page 45 which indicates that the storm imbalance will be collected with interest "using the Company's most recent authorized rate of return."

a) Please explain why the Company proposes to apply its full authorized rate of return, rather than a lower short-term borrowing rate, cost of debt, or otherwise, to the unrecovered Storm Rider balance.
b) Please identify if there are other Maryland riders or reconciliation mechanisms where BGE earns/pays interest at the full authorized rate of return on an over- or under-collection, rather than a lower rate as mentioned above.
c) Given that the EmPOWER Maryland regulatory asset's return is capped at cost of debt only under HB 864 and Order No. 91175, explain why the storm regulatory assets are entitled to a return that includes the equity component rather than a debt-only or other reduced carrying rate, and identify any Commission precedent specifically addressing the appropriate carrying cost for storm-related regulatory assets.

RESPONSE:

a. In the proposed Storm Restoration Expense Rider, the Company is proposing to apply the weighted average cost of capital symmetrically whether incremental storm expenses are higher or lower than the baseline. Utility companies, including BGE, do not finance their operations solely with debt. Rather, the operations are financed with both debt and equity – and cost recovery should reflect that by recovering at the weighted average cost of capital. The Company is financing the incremental storm restoration expenses using the same mix of debt and equity as the rest of the Company's operations. Not only is this consistent with the Company's current Major Storm regulatory asset, as discussed in subpart (c), below, but it is also consistent with other regulatory assets and liabilities included in rate base.

b. BGE previously had Rider 31 for the Electric Reliability Initiative (ERI), which recovered costs at the weighted average cost of capital.

c. HB 864 and Order No. 91175 are specifically applicable to a previous EmPOWER MD regulatory asset balance that had accumulated over a number of years, not to general over- or under-collections from a given year. Additionally, as noted on page 42 in the Direct Testimony of Company Witness Frain, the Commission granted BGE's proposal that a regulatory asset be utilized to track incremental major outage event restoration expenses in Order No. 89678.[1] This regulatory asset is included in the Company's rate base with the weighted average cost of capital applied.

[1] Case No. 9645, Order No. 89678, pp. 13-14.

Case No. 9888
Baltimore Gas and Electric Co.
Response to OPC Data Request 5
Request Received: August 19, 2026
Response Date: September 02, 2026
Sponsor(s): John C. Frain; Laura A. Wright

Item No.: OPCDR05-07

Provide the underlying data from attachment Staff DR 21-20, Attachment 1, in a live, unlocked Excel format, with all formulas and links attached, and extend the historical period to 15 years to the extent possible.

RESPONSE:

StaffDR21-20 Attachment 1 did not include any formulas or links, it was a table compiling data previously submitted in informational filings. However, please see *OPCDR05-07 Attachment 1* for an Excel file with no locked formulas that includes storm costs since 2013. Each year includes the total O&M and Capital costs for non-major and major storms broken down by categories of spend, where available. The amounts in OPCDR05-07 Attachment 1 reconcile with the amounts shared in StaffDR21-20 Attachment 1.

Non-Major Storm	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	Jan-Mar 2026
Capital	**$2,215,318**	**$7,011,878**	**$4,460,785**	**$6,236,775**	**$4,241,782**	**$7,301,284**	**$9,998,311**	**$9,556,088**	**$20,795,210**	**$22,451,334**	**$40,290,128**	**$53,552,248**	**$49,592,927**	**$8,603,688**
Labor									$4,307,484	$3,665,332	$5,921,736	$9,322,671	$11,415,354	$3,656,201
Contractor									$7,245,329	$9,798,922	$17,204,964	$23,542,832	$19,425,392	$2,136,494
Materials									$2,379,519	$2,411,808	$2,832,814	$3,805,816	$4,836,816	$868,717
Other									$6,862,878	$6,575,273	$14,330,613	$16,880,929	$13,915,365	$1,942,276
Expense	**$13,711,837**	**$23,843,173**	**$9,629,504**	**$12,563,732**	**$12,289,071**	**$24,726,956**	**$41,480,872**	**$38,279,886**	**$52,083,170**	**$33,560,100**	**$55,736,715**	**$69,641,942**	**$47,360,479**	**$16,972,680**
Labor									$11,177,357	$10,192,047	$12,730,514	$20,074,785	$17,112,272	$6,866,752
Contractor									$19,451,190	$10,784,784	$21,331,369	$23,362,255	$11,224,523	$2,574,297
Materials									$606,313	-$3,839	$682,104	$950,518	$1,589,009	$286,852
Other									$20,848,309	$12,587,109	$20,992,728	$25,254,384	$17,434,675	$7,244,779
Total Non-Major Storm Cost	**$15,927,155**	**$30,855,051**	**$14,090,289**	**$18,800,507**	**$16,530,853**	**$32,028,240**	**$51,479,183**	**$47,835,974**	**$72,878,380**	**$56,011,434**	**$96,026,843**	**$123,194,190**	**$96,953,406**	**$25,576,368**

Major Storm	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	Jan-Mar 2026
Capital	**$0**	**$0**	**$0**	**$0**	**$0**	**$17,136,734**	**$0**	**$0**	**$0**	**$72,374,486**	**$27,172,098**	**$0**	**$21,122,467**	**$0**
Labor						$1,670,745				$3,797,687	$2,092,228		$2,478,830	
Contractor						$13,049,152				$64,589,564	$22,746,906		$16,053,456	
Materials						$641,570				$1,551,082	$848,454		$1,016,611	
Other						$1,775,267				$2,436,153	$1,484,510		$1,573,571	
Expense	**$0**	**$0**	**$0**	**$0**	**$0**	**$36,455,768**	**$0**	**$0**	**$0**	**$12,694,659**	**$10,058,059**	**$0**	**$8,550,470**	**$0**
Labor						$6,867,626				$5,063,411	$3,893,548		$4,239,766	
Contractor						$14,879,914				$67,596	$0		$1,584	
Materials						$742,269				$0	$50		$0	
Other						$13,965,959				$7,563,652	$6,164,461		$4,309,121	
Regulatory Asset	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$57,112,055**	**$27,045,584**	**$0**	**$19,393,435**	**$0**
Labor										$7,294,564	$2,542,575		$1,723,915	
Contractor										$42,815,732	$21,804,048		$15,458,653	
Materials										$1,223,620	$663,740		$905,331	
Other										$5,778,139	$2,035,221		$1,305,536	
Total Major Storm Cost	**$0**	**$0**	**$0**	**$0**	**$0**	**$53,592,502**	**$0**	**$0**	**$0**	**$142,181,200**	**$64,275,741**	**$0**	**$49,066,373**	**$0**

*Category breakdown shown for non-major storms in 2021 through 2026 is not available for non-major storms prior to 2021.

Case No. 9888
Baltimore Gas and Electric Co.
Response to OPC Data Request 5
Request Received: August 19, 2026
Response Date: September 08, 2026
Sponsor(s): Jennifer A. Karas

Item No.: OPCDR05-11-REVISED

Refer to the Direct Testimony of Jennifer Karas at page 31, lines 2-15, which discusses large load tariffs.
(a) Does the Company currently serve any customers that meet the definition of "large load customer" set forth in PUA § 7-232(e). If yes, for each customer provide their maximum contracted demand and date of interconnection.
(b) Withdrawn
(c) Are any investments included in the Company's test year rate base (1) placed into service after January 1, 2024 and (2) associated with serving existing or potential customers that meet the definition of "large load customer" set forth in PUA § 7-232(e)? If yes, provide the date of the investment, dollar amount included in rate base, and a description of the investment need.

RESPONSE:

BGE continues to object to OPCDR05-11, even as revised, to the extent it seeks information that is not relevant to this proceeding and is premature. BGE has not proposed a large load tariff in this case, nor has the Commission approved such a tariff. The issues identified in this data request, including potential eligibility requirements, the identification of customers that may qualify for any future large load tariff, and the consideration of costs associated with serving such customers, are matters that will be addressed in the Commission's ongoing large load customer proceeding, Public Conference 72. Because no large load tariff is before the Commission in this proceeding, and the Commission has established a separate process to evaluate such issues, OPC's request seeks information outside the scope of this rate case and is premature. Subject to and without waiving the foregoing objections, BGE provides the following response.

a. The Company does not believe that this can be fully evaluated solely by reference to the definition of "large load customer" in PUA § 4-232(e). As reflected in PUA § 4-232 (c)(2)(iii), which governs service under an approved Large load rate schedule, the large load rate schedule

   > does not apply to the facility of an existing large load customer that has signed a service agreement before the effective date of the schedule if:
   > 1. the large load customer's existing load does not expand by more than 25 megawatts at that facility under the existing service agreement; or

2. the large load customer does not sign a new service agreement to expand the facility's load by more than 25 megawatts above the contract capacity of the existing service agreement.

Accordingly, existing customers with demands that meet those described in PUA § 4-232(e) do not, by itself, establish that the customer would be considered under a large load rate schedule. Therefore, prior to the effective date of an approved large load tariff, the Company does not currently serve any large load customers as defined by the PUA.

To the extent the question seeks identification of existing customers that may potentially meet demand thresholds in the future, such a determination would be premature because the Commission has not yet approved a Large Load tariff, established any exemption process contemplated by PUA § 7-232(e)(2), or determined how the statutory eligibility criteria will be applied to existing customers.

Please refer to *OPCDR05-11-Attachment 1* which provides customers who currently have demands greater than 25 MW, including those whose demand is greater than 25 MW on an aggregate basis. The Company has excluded customers whose primary purpose is to operate as a water company or sewage disposal company, a manufacturing facility, a hospital, a district energy system, or an agricultural facility, to the best of the Company's knowledge.

For those customers who meet the 25 MW threshold on an aggregate basis, there are multiple interconnection dates as individual service agreements were signed at varying times.

b. Withdrawn

c. No. As described in response to subpart (a), above, a large load rate schedule will only apply if a customer increases their load by more than 25 megawatts. As provided in response to sub-part (a), there are only 4 single service agreements that meet the 25 megawatt threshold on their own and their service agreement start dates are all prior to January 1, 2024. Additionally, the Company does not track investments for individual customers.

Customers With 25 MW or Greater Demands
On An Aggregate Basis
(Excluding Those Contemplated In PUA 7-232)

DESCRIPTION OF CUSTOMER:	MAX Billed KW 12 ME AUG 2025
Federal Government Agency	106,866
Federal Government Agency	99,438
Federal Government Agency	73,688
Public University System	73,464
Private University	57,202
City Government	46,654
Private Corporation	43,966
Federal Government Agency	28,973
Corporate Real Estate	28,229
Private Corporation	25,993
State Agency	25,300
Corporate Real Estate	25,300

Service Agreement Start Dates for
Customers Identified as 25 MW or Greater

Federal Government Agency	Federal Government Agency	Federal Government Agency	Public University System	Private University	City Government	Private Corporation	Federal Government Agency	Corporate Real Estate	Private Corporation	State Agency	Corporate Real Estate
3/14/1989	5/5/1955	4/10/1944	7/28/1961	1/30/1945	11/9/1959	3/29/1967	7/3/1964	6/16/1959	9/29/2014	7/3/1991	6/29/1972
4/1/1998	8/22/1955	9/11/1944	12/12/1973	9/15/1967	3/1/1960	7/20/1967	9/27/1974	10/2/1969	11/1/2014	3/27/1992	6/2/1976
4/1/1998	8/23/1956	1/14/1953	5/20/1975	12/29/1967	12/18/1961	3/29/1976	2/1/1979	9/25/1975	12/2/2014	6/5/1997	11/22/1989
4/1/1998	5/8/1985	8/1/1955	8/6/1975	4/22/1971	12/14/1963	12/9/1983	3/29/1984	7/27/1976	4/23/2018	8/5/2019	11/22/1989
5/27/1998	12/22/1985	9/24/1959	12/6/1982	6/21/1971	6/27/1966	12/22/1985	9/12/1984	11/8/1976	11/17/2018	3/29/2024	1/20/1992
6/15/1998	12/30/1985	12/2/1969	1/6/1986	6/21/1971	5/2/1967	12/22/1985	1/6/1986	2/28/1979	6/20/2019		12/31/1998
12/4/2008	4/17/1991	10/13/1972	1/17/1986	6/22/1971	8/1/1967	12/22/1985	1/9/1986	11/16/1981	6/24/2019		8/27/1999
12/4/2008	7/1/1993	7/7/1981	1/22/1986	1/24/1975	1/8/1969	12/28/1985	3/30/1989	3/8/1988	9/13/2019		4/16/2009
12/4/2008	7/1/1994	12/26/1985	3/8/1988	7/11/1978	2/24/1969	1/8/1986	10/26/1989	5/5/1988	9/13/2019		4/16/2009
12/4/2008	11/23/2003	1/15/1986	5/10/1989	1/16/1979	7/14/1969	2/1/1992	11/1/1990	1/31/1992	1/21/2020		4/16/2009
12/4/2008	12/13/2003	12/30/1986	5/10/1989	2/7/1979	8/12/1969	9/27/1993	11/27/1990	5/13/1996	2/29/2020		4/22/2009
1/2/2009	2/23/2004	7/16/1987	5/10/1989	6/4/1979	8/20/1969	3/18/1998	10/20/1993	11/26/1997	3/10/2020		4/22/2009
1/2/2009	9/23/2004	3/19/1990	5/10/1989	6/13/1984	7/19/1972	5/6/1998	12/13/1993	1/9/1998	3/10/2020		4/22/2009
1/2/2009	9/13/2005	4/28/1990	5/10/1989	6/25/1985	4/6/1977	7/13/2000	4/1/1994	7/31/1998	3/10/2020		4/22/2009
9/5/2014	10/29/2005	11/16/1990	5/15/1989	12/26/1985	11/14/1977	9/20/2002	4/22/1994	9/9/1998	3/12/2020		4/22/2009
3/20/2015	11/11/2005	10/23/1991	5/31/1991	1/3/1986	11/21/1977	1/3/2005	3/2/1995	12/7/1998	4/1/2020		4/22/2009
6/5/2015	11/11/2005	11/3/1993	7/12/1991	1/8/1986	2/1/1978	10/27/2009	5/9/1995	2/16/1999	4/1/2020		4/22/2009
6/16/2015	11/17/2005	9/13/1996	7/31/1991	4/14/1987	2/8/1978	4/30/2010	6/27/1995	3/8/1999	4/7/2020		4/22/2009
6/17/2015	11/17/2005	12/23/1996	1/8/1992	7/9/1987	6/3/1978	1/16/2012	5/1/1997	3/3/2000	4/17/2020		4/22/2009
7/1/2015	11/23/2005	2/5/1997	6/16/1992	7/29/1987	7/5/1978	1/16/2012	1/26/1999	10/20/2000	5/1/2020		6/21/2011
9/28/2017	12/13/2005	3/10/1998	2/28/1994	9/24/1987	7/17/1978	12/30/2013	7/7/1999	10/26/2000	5/26/2020		8/1/2013
4/29/2019	12/30/2005	4/1/1998	4/14/1994	9/24/1987	6/4/1979	12/10/2014	7/28/1999	11/3/2000	5/26/2020		8/23/2013
10/7/2022	12/30/2005	4/1/1998	6/8/1994	9/24/1987	8/1/1979	4/23/2019	5/13/2000	11/12/2000	6/1/2020		12/20/2013
10/13/2022	12/30/2005	4/1/1998	6/9/1994	9/24/1987	1/30/1981	4/24/2019	3/27/2001	7/17/2001	6/1/2020		12/20/2013
	1/10/2006	5/13/1998	7/11/1994	9/24/1987	3/26/1981	10/30/2019	12/10/2001	9/28/2001	6/19/2020		12/20/2013
	1/10/2006	10/27/1999	7/11/1994	9/24/1987	8/10/1982	1/18/2020	5/9/2002	10/30/2001	6/19/2020		12/20/2013
	1/10/2006	5/30/2000	10/1/1994	9/24/1987	11/23/1982	7/31/2020	7/10/2003	12/19/2001	8/29/2020		12/20/2013
	1/16/2006	9/29/2000	6/30/1995	1/29/1988	10/28/1983	7/31/2020	8/4/2003	2/5/2002	9/2/2020		12/20/2013
	2/6/2006	7/1/2003	6/30/1995	6/8/1988	12/25/1985	1/7/2021	3/11/2004	4/30/2002	9/2/2020		12/20/2013
	2/6/2006	8/22/2003	8/31/1995	11/14/1988	12/30/1985	3/3/2021	6/7/2005	10/17/2002	9/18/2020		12/20/2013
	2/7/2006	8/22/2003	10/18/1996	1/4/1989	12/31/1985	5/16/2023	8/12/2005	10/25/2002	10/16/2020		12/20/2013
	2/8/2006	8/22/2003	10/18/1996	3/27/1989	1/9/1986	11/1/2024	3/20/2006	7/15/2003	11/18/2020		12/20/2013
	2/17/2006	12/1/2003	5/12/1997	6/30/1989	1/10/1986		12/19/2008	7/17/2003	11/18/2020		1/3/2014
	2/17/2006	12/12/2003	10/1/1997	2/16/1990	1/14/1986		10/24/2012	8/7/2003	11/18/2020		1/13/2014
	2/17/2006	3/1/2004	2/17/1998	2/8/1991	1/15/1986		11/29/2012	9/15/2003	11/18/2020		5/21/2014
	2/20/2006	8/28/2004	3/6/1998	3/8/1991	1/21/1986		12/26/2018	9/29/2003	4/2/2021		10/23/2014
	2/20/2006	10/27/2004	6/30/1998	3/8/1991	1/21/1986		5/22/2020	10/7/2003	6/22/2021		7/2/2015

2/20/2006	2/23/2005	2/9/2001	1/10/1992	10/13/1986	5/22/2020	11/22/2003	10/11/2021	6/28/2017
2/22/2006	6/13/2005	11/21/2001	4/9/1992	4/26/1989	2/13/2021	11/10/2004	10/14/2021	7/26/2017
2/22/2006	10/28/2005	5/6/2002	10/21/1992	12/21/1989	3/19/2021	3/8/2005	10/14/2021	4/25/2018
3/1/2006	11/1/2005	8/6/2002	12/9/1992	5/30/1990	9/18/2021	6/13/2006	10/14/2021	8/22/2019
3/1/2006	11/4/2005	1/31/2003	9/22/1993	8/19/1991	3/2/2022	7/13/2006	10/20/2021	8/22/2019
3/8/2006	11/4/2005	3/28/2003	5/2/1994	12/12/1992	11/3/2022	2/26/2008	10/20/2021	11/27/2019
3/8/2006	5/22/2006	7/21/2005	7/8/1994	12/12/1992	11/6/2022	3/9/2009	10/21/2021	12/26/2019
3/24/2006	5/23/2006	4/4/2006	8/8/1994	12/12/1992	11/28/2023	10/20/2009	11/16/2021	1/7/2020
3/24/2006	6/16/2006	4/13/2007	10/27/1994	7/6/1993	11/28/2023	3/22/2010	11/16/2021	5/1/2020
3/27/2006	4/2/2007	7/18/2007	1/4/1995	12/28/1994		6/23/2010	1/7/2022	5/1/2020
4/1/2006	12/26/2007	9/28/2007	4/21/1995	3/20/1996		9/13/2010	2/9/2023	5/21/2020
4/21/2006	1/18/2008	10/11/2007	4/25/1995	5/1/1996		1/6/2011	5/10/2023	5/21/2020
4/21/2006	1/18/2008	11/5/2007	4/4/1997	4/4/1997		2/17/2011	8/1/2023	8/3/2020
4/25/2006	2/17/2008	1/22/2008	6/19/1997	11/10/1997		4/25/2012	8/1/2023	9/25/2020
4/25/2006	7/3/2008	6/5/2008	8/6/1997	11/17/1997		9/24/2013	9/2/2023	12/21/2020
5/3/2006	6/5/2009	7/12/2008	9/1/1997	12/18/1997		11/12/2013	9/14/2023	1/25/2021
5/9/2006	6/15/2009	11/14/2008	9/22/1997	2/25/1998		12/5/2014	3/1/2024	1/25/2021
6/22/2006	9/15/2009	11/25/2008	11/6/1997	4/6/1998		12/1/2015	4/17/2024	2/17/2021
6/24/2006	10/5/2009	6/23/2009	2/18/1998	9/18/1998		4/22/2016	7/8/2024	3/24/2021
8/15/2006	10/5/2009	10/7/2009	3/5/1998	3/11/1999		9/18/2017	9/13/2024	4/22/2021
8/31/2006	1/27/2010	1/12/2011	6/24/1998	3/11/1999		12/6/2018	10/3/2024	2/1/2022
8/31/2006	1/14/2011	1/12/2011	2/23/1999	10/19/1999		2/27/2019		3/20/2022
8/31/2006	1/26/2011	4/13/2011	11/12/1999	6/20/2000		9/7/2019		11/4/2022
11/21/2006	2/8/2011	7/27/2011	4/7/2000	10/17/2000		10/3/2019		12/12/2022
12/5/2006	9/13/2011	11/9/2011	3/1/2001	3/1/2001		11/26/2019		11/5/2024
12/6/2006	9/21/2011	2/2/2012	3/1/2001	3/15/2001		12/2/2019		1/1/2025
12/6/2006	11/14/2011	5/19/2012	3/1/2001	6/7/2001		12/5/2019		
12/12/2006	12/2/2011	5/22/2012	3/1/2001	6/15/2001		12/6/2019		
12/13/2006	5/14/2013	8/13/2012	3/1/2001	6/29/2001		12/9/2019		
12/19/2006	5/14/2013	12/14/2012	3/1/2001	9/5/2001		12/23/2019		
5/24/2007	5/19/2014	8/20/2013	3/1/2001	3/1/2002		1/10/2020		
7/10/2007	6/12/2014	9/27/2013	3/1/2001	12/11/2002		1/10/2020		
9/6/2007	6/12/2014	3/31/2014	6/8/2001	12/11/2002		1/18/2020		
9/18/2007	3/1/2015	8/4/2014	6/19/2001	12/18/2002		1/25/2020		
9/27/2007	6/15/2015	5/20/2015	8/9/2001	12/31/2002		1/25/2020		
10/2/2007	7/6/2015	10/8/2015	9/1/2001	5/3/2004		1/31/2020		
10/2/2007	9/15/2015	2/12/2016	11/7/2001	9/1/2004		5/28/2020		
10/2/2007	2/1/2016	2/12/2016	11/30/2001	1/6/2005		8/15/2020		
10/2/2007	2/10/2016	2/19/2016	12/10/2001	8/26/2005		8/22/2020		
10/2/2007	3/15/2016	3/1/2016	12/21/2001	9/15/2005		3/6/2021		
10/4/2007	7/29/2016	3/24/2016	6/10/2002	2/21/2006		4/20/2021		
10/8/2007	11/16/2016	1/27/2017	8/7/2002	4/9/2006		7/13/2022		
10/23/2007	12/21/2016	8/2/2018	8/14/2002	12/27/2006		9/20/2022		

10/29/2007	8/17/2017	2/18/2019	9/5/2002	1/22/2007	5/17/2024
11/2/2007	9/14/2017	2/19/2019	9/7/2002	3/1/2007	
11/12/2007	12/11/2017	3/1/2019	9/7/2002	4/29/2008	
11/13/2007	12/19/2017	3/1/2019	9/7/2002	5/28/2008	
11/20/2007	8/30/2018	5/2/2019	12/20/2002	7/17/2008	
12/18/2007	10/10/2018	7/11/2019	4/30/2003	11/11/2009	
12/18/2007	8/23/2019	8/23/2019	4/30/2003	6/4/2010	
1/16/2008	1/3/2020	12/18/2019	4/30/2003	1/11/2011	
1/21/2008	1/16/2020	1/27/2020	7/1/2003	4/29/2011	
2/9/2008	2/1/2020	5/20/2020	8/30/2003	11/16/2012	
2/15/2008	2/12/2020	5/20/2020	9/1/2003	4/16/2013	
2/19/2008	3/17/2020	9/3/2020	9/8/2003	5/10/2013	
5/14/2008	3/18/2020	9/3/2020	10/31/2003	2/17/2014	
5/19/2008	6/8/2020	9/9/2020	12/8/2003	4/13/2015	
5/21/2008	4/6/2021	10/29/2020	8/25/2004	2/26/2016	
5/21/2008	5/7/2021	1/1/2021	3/21/2005	7/11/2016	
6/25/2008	6/29/2022	3/9/2021	3/21/2005	12/23/2016	
2/9/2009	9/12/2022	3/16/2021	3/21/2005	2/7/2018	
2/10/2009	10/13/2022	7/19/2021	3/21/2005	10/31/2018	
2/11/2009	11/17/2022	9/1/2024	8/29/2005	12/20/2018	
2/12/2009	5/7/2024		8/31/2005	9/26/2019	
2/12/2009	10/1/2024		9/1/2005	12/2/2019	
2/18/2009			12/1/2005	12/8/2020	
2/18/2009			12/2/2005	2/1/2021	
2/18/2009			12/8/2005	8/25/2022	
3/23/2009			12/16/2005		
4/3/2009			2/20/2006		
4/7/2009			9/1/2006		
5/4/2009			10/20/2006		
5/4/2009			10/23/2006		
5/4/2009			1/9/2007		
5/22/2009			1/9/2007		
6/16/2009			1/9/2007		
6/30/2009			4/3/2007		
7/1/2009			2/29/2008		
7/9/2009			2/29/2008		
7/13/2009			4/1/2008		
7/13/2009			9/17/2008		
7/21/2009			11/5/2008		
7/30/2009			11/5/2008		
9/2/2009			11/22/2008		
9/4/2009			12/10/2008		
9/4/2009			12/19/2008		

9/5/2009	1/15/2009
9/10/2009	4/13/2009
9/11/2009	7/21/2009
9/18/2009	3/3/2010
10/9/2009	3/3/2010
10/12/2009	3/3/2010
10/13/2009	3/3/2010
10/13/2009	3/3/2010
10/14/2009	3/3/2010
10/14/2009	3/3/2010
11/10/2009	3/3/2010
11/10/2009	3/4/2010
11/17/2009	3/11/2010
11/17/2009	3/31/2010
11/19/2009	5/7/2010
12/9/2009	6/8/2010
12/9/2009	6/14/2010
12/17/2009	7/3/2010
12/23/2009	1/10/2011
1/26/2010	2/15/2012
1/27/2010	2/27/2012
1/28/2010	5/17/2012
1/29/2010	1/29/2013
1/29/2010	7/23/2013
2/2/2010	7/23/2013
2/2/2010	7/23/2013
3/3/2010	7/23/2013
3/3/2010	7/23/2013
4/8/2010	7/23/2013
4/8/2010	2/1/2014
4/10/2010	8/29/2014
4/10/2010	1/29/2015
4/10/2010	6/1/2015
5/4/2010	6/29/2015
5/17/2010	10/14/2015
5/17/2010	5/10/2016
6/7/2010	5/14/2016
7/7/2010	6/28/2016
7/7/2010	7/6/2016
7/14/2010	8/6/2016
7/14/2010	8/6/2016
7/24/2010	8/9/2016
8/21/2010	8/19/2016

8/23/2010	9/1/2016
8/31/2010	9/1/2016
9/22/2010	11/3/2016
9/26/2010	12/14/2016
10/28/2010	12/29/2016
11/4/2010	2/1/2017
11/6/2010	3/7/2017
11/6/2010	3/28/2017
11/10/2010	5/11/2017
11/18/2010	6/27/2017
11/23/2010	7/1/2017
12/22/2010	7/1/2017
1/1/2011	7/10/2017
2/6/2011	7/18/2017
2/10/2011	7/18/2017
2/15/2011	8/11/2017
3/24/2011	11/1/2017
4/1/2011	1/8/2018
4/29/2011	1/8/2018
5/11/2011	1/8/2018
5/20/2011	1/8/2018
6/9/2011	2/1/2018
7/14/2011	4/24/2018
7/15/2011	9/29/2018
7/26/2011	10/12/2018
8/15/2011	2/15/2019
9/21/2011	4/12/2019
9/22/2011	7/17/2019
10/10/2011	12/6/2019
10/26/2011	2/3/2020
11/5/2011	2/23/2020
12/2/2011	2/24/2020
12/5/2011	6/16/2020
1/19/2012	9/4/2020
1/28/2012	10/3/2020
2/9/2012	11/17/2020
2/22/2012	11/22/2020
4/14/2012	12/29/2020
5/17/2012	3/31/2021
7/26/2012	4/8/2021
8/3/2012	4/8/2021
8/23/2012	9/21/2021
9/14/2012	11/15/2021

9/21/2012	2/15/2022
9/28/2012	6/20/2022
10/9/2012	2/14/2023
10/9/2012	2/14/2023
10/10/2012	1/6/2024
10/10/2012	4/25/2025
10/23/2012	6/1/2025
10/27/2012	
11/15/2012	
11/28/2012	
12/5/2012	
12/19/2012	
1/31/2013	
5/8/2013	
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1/27/2020
2/12/2020
4/21/2020
6/12/2020
9/2/2020
3/23/2021
7/26/2022
10/30/2024

Case No. 9888
Baltimore Gas and Electric Co.
Response to OPC Data Request 7
Request Received: August 21, 2026
Response Date: September 04, 2026
Sponsor(s): Jason M.B. Manuel; John C. Frain; Jennifer A. Karas

Item No.: OPCDR07-02

Frain
Please see Company Exhibit JCF-7 attached to the Frain Direct. Page 20 of Ex. JCF-7 lists a $3,311,496 plant addition for Project 79404: Exelon Utilities (EU) Customer Flight Path: Large Customer Services (LCS) Program. The benefits statement states that the "investment creates dedicated digital experiences for BGE's medium and large commercial customers, allowing them to self-serve for billing, usage, outage information, and program enrollment."

a. How is the cost of the LCS Program being allocated to BGE's various customer rate classes? Please explain how this allocation is shown in the documents provided by BGE or provide documentation showing the allocation.
b. What is BGE's policy regarding allocating the costs of programs that may benefit only certain customer classes? Please provide documentation of this policy to the extent it exists.

RESPONSE:

a. The Customer Flight Path: Large Customer Services ("LCS") program expenses are software related. As such, these costs are included in FERC Account 303-Miscellaneous Intangible Plant. This FERC account in the Company's electric cost of service study ("ECOSS") is allocated across all customer classes using the PLANTLAB allocator, as directed by the Commission in Order No. 90948. For further discussion of the PLANTLAB allocator, please see the Direct Testimony of Company Witness Manuel, page 15, lines 14-18. Please refer to StaffDR05-01 Attachment 1 for a working Excel model of the ECOSS. Please see the "Cost of Service" tab, Excel row 1093 for the PLANTLAB allocation factors for each electric distribution customer class.

   The results of the cost of service study are not exclusively relied upon but rather it is used as a guide to inform the rate design process. (See Company Witness Manuel's Direct Testimony, page 5, line 3, and page 14, footnote 3). In this proceeding, the Company proposes to apportion the resulting revenue requirement, as provided in the Direct Testimony of Company Witnesses Frain and McCart, to each rate schedule in proportion to its respective total base distribution revenue. Because individual program costs are not separately identifiable within the overall revenue requirement, they are not directly assigned to customer classes for rate design purposes. Please refer to the Direct Testimony of Company Witness Karas, Company Exhibit JAK-2 E-Sheets, Sheet E-2 which provides the Company's proposed revenue allocation.

b. In instances where FERC accounts or FERC subaccounts are separately maintained in the accounting general ledger and can be identified as applying only to certain customers, those items are directly assigned in the cost of service study to the rate schedules in which the costs are incurred.

Case No. 9888
Baltimore Gas and Electric Co.
Response to OPC Data Request 7
Request Received: August 21, 2026
Response Date: September 04, 2026
Sponsor(s): Laura A. Wright; Michael J. Cloyd; John C. Frain

Item No.: OPCDR07-03

Frain
Please see Company Exhibit JCF-7 attached to Frain Direct. Page 17 of Ex. JCF-7 lists an $8,065,282 plant addition for 78077: Distributed Energy Resource Management System (DERMS) Implementation. BGE describes that the Company is replacing the Distribution Supervisory Control and Data Acquisition (DSCADA) system with Open Systems International (OSI) Intergra DERMS.

a. What is the total capacity of DER assets that are currently monitored and controlled by the DSCADA system?
b. BGE states that the DSCADA system is not scalable to meet the DER growth expected in the near future. How much DER capacity does the Company expect to be added to its system over the next five years?
c. BGE states that the OSI Integra solution will enable BGE to scale up DER assets over the next several years. What capacity of DER assets does BGE expect the OSI Integra solution to be capable of scaling with? In other words, does BGE expect the OSI Integra solution to scale only in the short-term with the amount of expected DER growth over the next several years, or is it also a solution that can scale with larger potential long-term growth?
d. Does BGE consider the OSI Integra solution to be a Grid-edge DERMS, a Utility DERMS, or both?
e. How does the OSI Integra solution fit into BGE's overall DERMS roadmap and system architecture?

RESPONSE:

a. Total capacity of DER assets that are currently monitored and controlled by ADMS is 4 MW.

b. Company Exhibit JCF-7 does not indicate that the DSCADA system itself lacks scalability. Rather, the identified limitation relates to BGE's existing DER management approach, which relies on a custom real-time calculation within DSCADA to monitor and control DER assets. While suitable for managing current DER resources, this manually maintained approach was not designed to scale efficiently as DER adoption increases. Project 78077 addresses this limitation by implementing a dedicated DERMS platform to support future DER growth.

c. BGE expects approximately 850 MW of solar generation interconnections over the next five years, as well as approximately 87 MW associated battery energy storage systems with projects developed under Maryland's Next Generation Energy Act.

d. BGE believes the platform is appropriately scaled to meet current operational needs and to accommodate the expected expansion of distributed energy resources within its service territory as DER adoption increases over time. The OSI Integra solution has the ability to scale for both expected near-term DER growth and larger long-term growth, providing a sustainable platform for future operational and business needs.

e. BGE OSI Integra DERMS solution is a Utility DERMS.

f. The OSI Integra Distributed Energy Resource Management System (DERMS) serves as a foundational component of BGE's Distributed Energy Resource Management (DERM) roadmap, providing the platform upon which all current and future DER capabilities are built.

Case No. 9888
Baltimore Gas and Electric Co.
Response to OPC Data Request 7
Request Received: August 21, 2026
Response Date: September 04, 2026
Sponsor(s): Jennifer A. Karas

Item No.: OPCDR07-11

Karas
Refer to JAK-2, Sheet E-16

a. Provide all studies or analyses in the Company's position that identify average monthly usage for the residential customer class for different income levels in the Company's service territory.

RESPONSE:

The Company does not maintain data on all customers' income levels. Please refer to *OPCDR07-11 Attachment 1* which provides average usage based on Office of Home Energy Programs ("OHEP") Benefit Level.

Case No. 9888
OPCDR07-11-Attachment 1

			2025	2025	2025	2025	2025	2026	2026	2026	2026	2026	2026	2026
			Aug	Sep	Oct	Nov	Dec	Jan	Feb	Mar	Apr	May	Jun	Jul
Income_Category	Heat_Source	Count	Average kWh	Average kWh	Average kWh	Average kWh	Average kWh	Average kWh	Average kWh	Average kWh	Average kWh	Average kWh	Average kWh	Average kWh
LEVEL1	Elect	3,375	909	779	722	843	1,424	1,727	1,869	1,210	842	696	768	922
LEVEL1	Non-Elec	11,023	934	712	581	520	718	820	825	634	547	516	688	946
LEVEL2	Elect	1,306	983	863	797	911	1,496	1,825	1,979	1,297	911	767	862	1,030
LEVEL2	Non-Elec	4,255	1,014	781	640	571	784	892	891	690	605	575	769	1,039
LEVEL3	Elect	4,300	856	724	684	812	1,374	1,675	1,842	1,202	843	694	747	889
LEVEL3	Non-Elec	13,679	928	710	592	549	762	873	874	675	574	532	694	953
LEVEL4	Elect	4,469	849	729	688	814	1,396	1,701	1,859	1,201	840	688	736	878
LEVEL4	Non-Elec	14,051	914	690	573	527	728	833	832	646	550	513	673	928
LEVEL5	Elect	3,164	903	770	725	867	1,475	1,775	1,941	1,256	881	724	778	931
LEVEL5	Non-Elec	9,057	952	719	597	542	750	858	856	662	567	532	703	974
LEVEL6	Elect	6,617	713	619	583	672	1,116	1,380	1,494	1,016	721	598	630	746
LEVEL6	Non-Elec	11,527	854	664	553	477	629	716	711	573	525	505	661	909
LEVEL7	Elect	526	918	766	717	838	1,449	1,739	1,955	1,245	851	699	750	923
LEVEL7	Non-Elec	1,437	974	726	607	535	726	840	846	652	580	540	728	1,016

Case No. 9888
Baltimore Gas and Electric Co.
Response to OPC Data Request 18
Request Received: September 03, 2026
Response Date: September 18, 2026
Sponsor(s): Laura A. Wright; Michael J. Cloyd

Item No.: OPCDR18-01

Please refer to the Project 78077 Authorization Presentation (78077_CONFIDENTIAL.pdf). Slide 4 states that approval was sought for "implementation of the BGE DERMS that will deliver a platform to monitor, control, and operate the Chesapeake Beach and Fairhaven Battery Energy Storage Systems (BESS)." Slide 4 also states that the need for a DERMS "to monitor, manage, and operate the increasing numbers of DER to be connected to the system" was driven by the "2022 Maryland Climate Solution Now Act (CSNA), the 2023 Maryland Energy Storage Targets/Program legislation, 2030 and 2040 Maryland RPS targets, [and] 02/02/2026 FERC Order No. 2222."

a. Explain why a DERMS was necessary to comply with the referenced state policy and FERC Order No. 2222 and how the BESS without the OSI Integra DERMS would not comply with these policies.
b. Does BGE have a plan for adding more DERs, outside of the utility-owned BESS use cases at the Chesapeake Beach and Fairhaven BESS locations, to the OSI Integra DERMS?
    i. If so, provide BGE's plan. If no formal written materials exist documenting the plan, state which DER types BGE plans to include in the OSI DERMS platform and provide a timeline for each. Include whether the planned integration for each DER type is limited to utility-owned, third-party owned, or open to either, and whether each DER type is limited to behind-the-meter, front-of-the-meter, or open to either.
c. Please identify the minimum DERMS functionality required to interconnect and operate the Chesapeake Beach and Fairhaven BESS in compliance with the 2022 Maryland Climate Solution Now Act, the 2023 Maryland Energy Storage Targets/Program legislation, the 2030 and 2040 Maryland RPS targets, and FERC Order No. 2222.
d. To the extent the OSI Integra DERMS includes functionality beyond what is identified in response to subpart c, please identify that functionality and the incremental cost associated with it.
e. Please identify the specific capabilities, if any, that a fully integrated enterprise DERMS solution would provide that the OSI Integra DERMS as implemented does not, and describe any plan and associated cost estimate for integrating or reconciling the OSI Integra DERMS with the enterprise ADMS roadmap referenced on Slide 7.
f. Please identify any alternatives to the OSI Integra DERMS solution that BGE considered for the purpose specifically of monitoring, controlling, and operating the Chesapeake Beach and Fairhaven BESS, including but not limited to a continued reliance on the existing DSCADA system. For each alternative identified in response to this, please explain why it was not selected.
g. What portion of the total spend on Project 78077 is related to processes and

components (hardware and software) that specifically support operations of the Chesapeake Beach and Fairhaven BESS, versus meant to enable broader future expansion of the OSI Integra Platform to integrate other DERs?

RESPONSE:

a. Project 78077 was not implemented because operation of the Chesapeake Beach and Fairhaven BESS required a DERMS to comply with the identified legislative or regulatory requirements. Rather, Project 78077 was implemented to establish a foundational DERMS platform that supports BGE's ability to manage existing and future DER growth in response to evolving policy, market, and operational requirements, including requirements associated with the Maryland Climate Solutions Now Act, Maryland energy storage initiatives, renewable portfolio standard targets, and anticipated DER participation models under FERC Order No. 2222.

   Prior to Project 78077, BGE utilized a custom DER management approach within its ADMS/DSCADA environment to monitor and control utility-scale battery assets. While that approach was capable of supporting existing battery resources, Project 78077 implemented a dedicated DERMS platform designed to provide a more scalable solution for future DER management needs.

b. Yes. While Project 78077 initially focused on monitoring and control of the Chesapeake Beach and Fairhaven Battery Energy Storage Systems ("BESS"), BGE anticipates that additional DER resources will be integrated with DERMS over time as business needs, regulatory requirements, and DER adoption evolve.

   Although BGE has not developed a comprehensive DERMS deployment plan identifying all future DER resources and implementation timelines, as future priorities will be influenced by evolving regulatory requirements and business needs, BGE expects to integrate additional utility-owned battery resources deployed pursuant to the Maryland Energy Storage Program ("MESP"). BGE also anticipates evaluating future integration of third-party BESS resources and Virtual Power Plant ("VPP") programs as DER participation models mature and as the DRIVE Act pilot programs and related regulatory initiatives progress.

c. The minimum DERMS functionality implemented through Project 78077 includes visibility, monitoring, telemetry, alarms, forecasting, and operational control of the Chesapeake Beach and Fairhaven BESS resources. These capabilities support safe and reliable operation of the battery systems and establish foundational DER management capabilities for future DER integration and coordination activities.

d. BGE objects to this question on the basis of relevance as additional functionality not implemented through Project 78077 would be addressed in the joint BGE/PHI DERMS project which is not yet in service, is not likely to be in service until 2028 (if approved), and therefore is well out of the scope this proceeding. Without waving such objection, BGE responds to the question as follows.

No other functionality was implemented in addition to as stated as part C for the minimum DERMS functionality.

e. BGE objects to this request to the extent it seeks information regarding hypothetical future DERMS deployment strategies, future technology decisions, or projects that have not been authorized or placed into service.

   Subject to and without waiving this objection, BGE states that Project 78077 was implemented as a foundational DERMS platform designed to provide scalable DER management capabilities that can support additional DER resources and use cases over time. The specific scope, timing, and implementation approach for any future DERMS enhancements will depend on business needs, regulatory requirements, and technology development.

f. For Project 78077, BGE evaluated multiple alternatives prior to selecting a standalone OSI Integra DERMS architecture, including:
   - Standalone OSI Integra DERMS (selected option)
   - Standalone non-OSI DERMS products
   - Implementation of DERMS as part of the Enterprise Utility ADMS program
   - Deferral pending future Enterprise Utility DERMS deployment

   As described in the Project 78077 Project Authorization materials, BGE selected the standalone OSI Integra DERMS architecture because it represented the lowest implementation risk and most practical approach to establishing near-term DER management capabilities while preserving flexibility for future regulatory and operational requirements. The Project Authorization Presentations for this project can be accessed via the SharePoint site that BGE has set up for this matter in the "Project Authorization Presentations – CONFIDENTIAL" subfolder.

g. BGE does not categorize Project 78077 spending between costs specifically supporting operation of the Chesapeake Beach and Fairhaven BESS and costs associated with enabling future expansion or integration of the OSI Integra Platform. Project 78077 was authorized, budgeted, and implemented as a DERMS platform deployment, and project costs were not tracked or recorded according to individual use cases or future functionality categories.

Case No. 9888
Baltimore Gas and Electric Co.
Response to OPC Data Request 18
Request Received: September 03, 2026
Response Date: September 18, 2026
Sponsor(s): Laura A. Wright; Michael J. Cloyd

Item No.: OPCDR18-02

Please refer to the Project 78077 Authorization Presentation (78077_CONFIDENTIAL.pdf). Slide 7 states that Alternative #1 "Install BGE stand-alone OSI Integra DERMS system" is recommended. The presentation also states that Alternative #1 has the disadvantage that it is "not fully integrated with EU ADMS roadmap."

a. Explain what is meant by the term "stand-alone" in the above quoted context.
b. Explain why the "stand-alone OSI Integra DERMS" is not fully integrated with the EU ADMS roadmap.
c. Did BGE evaluate the risks associated with implementing a stand-alone DERMS that is not fully integrated with EU ADMS roadmap? Please explain.
d. Please describe the risks associated with Project 78077 if Exelon determines that the future strategic enterprise DERMS solution roadmap does not include the OSI Integra DERMS solution. For example, would this potential outcome impact the level of expected costs of maintaining the OSI Integra DERMS solution for BGE's use case in the event that EU does not support broader deployments of it?
e. Has any other Exelon distribution utility made a capital investment in a stand-alone DERMS platform ahead of completion of the Exelon enterprise ADMS/DERMS roadmap evaluation.
    i. If so, please identify the specific operating company and the investment.
    ii. If no other Exelon distribution utility has made a comparable investment, please explain why BGE's circumstances required it to proceed on a stand-alone basis while other Exelon distribution utilities did not.
f. Are any costs associated with Project 78077 shared with BGE shareholders? If so, explain how and provide the amount.
g. Are any costs associated with Project 78077 shared with Exelon Corporation? If so, explain how and provide the amount.
h. Slide 7 states that BGE evaluated the alternative #4 "Do Nothing - Wait for Exelon ADMS Project to implement DERMS for all OpCo's", and listed a disadvantage of "[N]o additional business learnings to inform DERMS north star design." Confirm or deny that this means there is business value to Exelon Corporation of a field-deployment of BGE's standalone DERMS.
    i. If confirm, has BGE or Exelon Corporation attempted to quantify the value of BGE generating these business learnings through a field pilot outside of the EU ADMS roadmap?

RESPONSE:

a. The term "stand-alone" refers to deployment of the OSI Integra DERMS as a separate application rather than as a native component of the Exelon Utilities ("EU") ADMS platform. Although implemented as an independent platform, the DERMS exchanges data with other operational technology systems, including ADMS, through established integration mechanisms.

b. At the time Project 78077 was authorized, DERMS capabilities were still under evaluation as part of the broader EU ADMS roadmap. Accordingly, BGE elected to deploy a standalone OSI Integra DERMS. The standalone deployment allowed BGE to implement foundational DERMS capabilities while maintaining interoperability with ADMS through established integration mechanisms.

c. Yes. As reflected in the Project 78077 project authorization materials, BGE evaluated project risks as part of the normal capital project authorization process. These evaluations considered implementation risks, operational requirements, schedule constraints, technology readiness, project dependencies, and future enterprise roadmap uncertainty. BGE ultimately selected the standalone OSI Integra DERMS solution because it represented the lowest implementation risk and most practical approach for establishing near-term DER management capabilities while preserving flexibility for future DERMS evolution.

d. BGE objects to this request to the extent it seeks information regarding hypothetical future enterprise technology strategies, system selections, deployment decisions, or cost assumptions that have not been determined. Without waving such objection, BGE states that implementation of any new technology carries inherent risks. BGE considered those risks during evaluation and authorization of Project 78077 and intentionally leveraged existing operational technology architecture, including ADMS infrastructure components, SCADA design standards, and ICCP-based communications, to minimize implementation and integration risk while establishing foundational DERMS capabilities.

e. Yes, ComEd has published their DERMS and Flexible Interconnection Workshop Report as of April 22, 2025 which is publicly available (link: Workshop Series | ComEd - An Exelon Company). Further additional details regarding cost to ComEd, BGE objects as detailed other utility costs within Exelon are out of scope of BGE's pending rate adjustment filing.

f. No.

g. No.

h. Confirm, with clarification. The reference in the Project 78077 project authorization materials to "business learnings to inform DERMS north star design" reflects the value of gaining operational experience with DERMS capabilities, integration approaches, and DER management processes through deployment of a commercial DERMS platform in BGE's operating environment.

   However, Project 78077 was justified based on BGE's operational needs and anticipated DER management requirements. Project 78077 was not implemented as a pilot project performed on behalf of Exelon Corporation.

i. BGE is not aware of any separate quantified valuation developed specifically for the business learnings referenced in the Project 78077 project authorization materials.

Case No. 9888
Baltimore Gas and Electric Co.
Response to Staff Data Request 1
Request Received: July 14, 2026
Response Date: July 28, 2026
Sponsor(s): John C. Frain; Michael J. Cloyd; Laura A. Wright

Item No.: StaffDR01-01

RE: Company Exhibit JCF-7. Please provide a spreadsheet that identifies each project that falls under the line items "Total Project < Threshold" by Category, Project Name, and Project ID Number and provide the Total In-Service Addition for each project.

RESPONSE:

BGE objects to StaffDR01-01 to the extent it is intended to lead to further inquiries that would impose an undue burden on the Company and would be disproportionate to any potential benefit. The Company believes that the threshold it has established in this case (at least 80% of its electric distribution in-service additions *and* 25% of projects) provides a more than reasonable amount of information on the projects placed into service during the extended period of January 2024 through March 2026.[1] .

Notwithstanding the foregoing objection, given that Staff's request is limited to the list of projects that falls under line items "Total Project < Threshold" and their associated Total In-Service Addition amounts, please refer to *StaffDR01-01 Attachment 1* for the requested information.

[1] The January 2024 through March 2026 period shown on Company Exhibit JCF-7 shows the capital ("plant") additions to electric distribution rate base since the Company's last prudency review in the 2023 Final Reconciliation in Case No. 9645.

Electric Distribution Plant Additions - Projects Below Threshold by Category[1,2]

Category	Project	Jan 2024-Mar 2026 Total In-Service Additions
Wright		
Capacity Planning and Management - Distribution	57427: Transmission Plannig Unit (TPU) Scoping Work	303
Capacity Planning and Management - Distribution	59216: Feeder 33721 Extension for Shadyside Substation	10,154
Capacity Planning and Management - Distribution	60159: Distribution Reinforcement Forecasting Program	128,658
Capacity Planning and Management - Distribution	60169: Distribution Substation Capacitor Program	1,123,991
Capacity Planning and Management - Distribution	60258: Erdman Substation 7019 Feeder Installation	266,558
Capacity Planning and Management - Distribution	60276: Rock Avenue Substation 8873 Express Feeder Installation	32,328
Capacity Planning and Management - Distribution	60277: Queen Anne Substation Feeder 8849 Installation	26,961
Capacity Planning and Management - Distribution	60293: Erdman Substation Feeder 7020 Installation	1,360,107
Capacity Planning and Management - Distribution	60417: Key Crossing Overhead Transmission	47,191
Capacity Planning and Management - Distribution	60440: Northwest 110574 Reconductor	(6,107)
Capacity Planning and Management - Distribution	60445: Fitzell Transmission Supply	209
Capacity Planning and Management - Distribution	60756: Conservation Voltage Reduction (CVR) Capacitor Bank Controllers	2,100,423
Capacity Planning and Management - Distribution	61146: Conservation Voltage Reduction (CVR) Program	158,854
Capacity Planning and Management - Distribution	62903: Fairhaven Substation Battery	726,015
Capacity Planning and Management - Distribution	63447: Rock Avenue Substation Feeder 8873 Breaker Bay Construction	106,928
Capacity Planning and Management - Distribution	65604: Distributed Energy Resource (DER) Hosting Capacity/Power Flow - Capital	(218)
Capacity Planning and Management - Distribution	65855: Central Avenue Substation Feeder 8854 Extension to Feeder 7445	715,237
Capacity Planning and Management - Distribution	68735: Hazelwood Substation 7518 Feeder Installation	3
Capacity Planning and Management - Distribution	69651: Wheelabrator Substation Remote End - Relay and Protection Upgrades	95,074
Capacity Planning and Management - Distribution	69654: Gould Street Substation Remote End - Relay and Protection Upgrades	93,137
Capacity Planning and Management - Distribution	69656: Carroll Substation Remote End - Relay and Protection Upgrades	85,614
Capacity Planning and Management - Distribution	74785: Crystal Springs Substation Feeder 34053 Installation	(10,424)
Capacity Planning and Management - Distribution	74967: Mt. Washington Substation 8104 Feeder	3,039,775
Capacity Planning and Management - Distribution	75550: Shipley Substation New Feeder 33769 Installation	4,201
Capacity Planning and Management - Distribution	76979: Fitzell Substation Feeder 6025 Extension	100,330
Capacity Planning and Management - Distribution	77184: Rock Avenue Substation Feeder 8869 Extension	2,740,709
Capacity Planning and Management - Distribution	81078: New Center Substation Feeder 7017 Installation	2,345,413
Capacity Planning and Management - Distribution	87969: Erdman Substation 7019 Feeder Installation	330,856
Capacity Planning and Management - Distribution	87971: Erdman Substation 7020 Feeder Installation	168,236
Capacity Planning and Management - Distribution	88032: Riverside Substation Feeders 7582-7584 Extension	325,044
Capacity Planning and Management - Distribution	**Total Projects < Threshold[2]**	**16,115,561**
Corrective Maintenance - Distribution	60474: Buried Secondary Cable Industrial and Commercial Faults	2,508,635
Corrective Maintenance - Distribution	60478: Proactive Line Transformer Replacement	1,139,137

Corrective Maintenance - Distribution	60480: Pole Reinforcements	135,400
Corrective Maintenance - Distribution	60482: Underground Equipment Replacement - Emergent	832,099
Corrective Maintenance - Distribution	60483: PSC Targeted Reliability	2,590,173
Corrective Maintenance - Distribution	60485: AC Network Replacement	564,489
Corrective Maintenance - Distribution	60506: Overhead Equipment Replacement - Planned	611,458
Corrective Maintenance - Distribution	60508: Distribution Line Capacitor Replacements - Planned	2,589,955
Corrective Maintenance - Distribution	61133: Buried Secondary Cable Replacement – Emergent	1,497,755
Corrective Maintenance - Distribution	69328: Overhead (OH) Line Crossing Water - Capital	175,149
Corrective Maintenance - Distribution	**Total Projects < Threshold[2]**	**12,644,250**
Corrective Maintenance - Outdoor Lighting	60502: Contact Voltage Program	398,706
Corrective Maintenance - Outdoor Lighting	**Total Projects < Threshold[2]**	**398,706**
Corrective Maintenance - Substation	60045: Distribution Substation Fencing	435,432
Corrective Maintenance - Substation	60046: Distribution Substation HVAC Replacements	496,290
Corrective Maintenance - Substation	60047: Distribution Substation Roof Replacements	713,494
Corrective Maintenance - Substation	60082: Distribution System Land Erosion	970,051
Corrective Maintenance - Substation	60085: Transmission Substation - Fencing	245,127
Corrective Maintenance - Substation	60531: Substation Capital Corrective Maintenance Tasks - Transmission Other Equipment	179,283
Corrective Maintenance - Substation	62774: Distribution Substation Generator Replacements	245,831
Corrective Maintenance - Substation	75017: Electric Transmission & Substation Corrective Maintenance Capital	1,230,059
Corrective Maintenance - Substation	**Total Projects < Threshold[2]**	**4,515,567**
Customer Operations	56574: Customer Care Call Center Capital	90,709
Customer Operations	60551: Meters Capital Planned	355
Customer Operations	60592: Energy Metering Center Electric	50,648
Customer Operations	60601: Meter Cost	188,997
Customer Operations	60602: Capital Meter Work Electric	3,709
Customer Operations	61068: Smart Grid Software/Hardware Maintenance Costs Capital	46,452
Customer Operations	66593: Cut In/Cut Out Capital Electric	501,176
Customer Operations	66602: Corrective Maintenance Electric Meter Capital	2,721,455
Customer Operations	66606: Field & Meter Services Other Capital Electric	54,132
Customer Operations	66610: Regulatory Capital Electric	1,574
Customer Operations	67867: Special Project Capital Electric	1,040
Customer Operations	**Total Projects < Threshold[2]**	**3,660,249**
Facilities Relocation - Distribution	261893: Electric Public Relocations Construction Orders *	52,267
Facilities Relocation - Distribution	64465: Baltimore & Potomac (B&P) Tunnel Electric Relocation *	6,142
Facilities Relocation - Distribution	**Total Projects < Threshold[2]**	**58,410**
New Business - Distribution	55451: Distributed Energy Interconnection/Solar *	2,255,559
New Business - Distribution	58509: New Business Electric Development Phase *	2,869,110
New Business - Distribution	60754: New Business Electric Privatization	(41,326)
New Business - Distribution	60765: New Business Electric Co-Generation	(28,791)
New Business - Distribution	61437: Connected Communities *	46,357
New Business - Distribution	61461: New Business Net Metering	1,211,147

New Business - Distribution	75272: New Business Electric Data Center *	2,053,115
New Business - Distribution	75273: New Business Electric Data Center *	10,511
New Business - Distribution	75275: New Business Electric Data Center *	762,230
New Business - Distribution	80375: New Business 34kV Underground Residential Distribution (URD) Feeders Installation - Elkrid	87,346
New Business - Distribution	81206: Calvary Road Solar Farm: 30MW Project *	382,628
New Business - Distribution	88418: Green Power Connect IT	2,632,424
New Business - Distribution	**Total Projects < Threshold[(2)]**	**12,240,310**
New Business - Outdoor Lighting	261938: Purple Light Change-Outs *	185,822
New Business - Outdoor Lighting	60798: Street Lighting Installs - Utility Owned *	537,396
New Business - Outdoor Lighting	60800: Street Lighting Changes - Utility Owned *	353,975
New Business - Outdoor Lighting	**Total Projects < Threshold[(2)]**	**1,077,193**
Preventative Maintenance - Distribution	61020: Contact Voltage Preventative Maintenance	3,316
Preventative Maintenance - Distribution	**Total Projects < Threshold[(2)]**	**3,316**
System Performance - Distribution	262205: Manual Drones Initiative	312,048
System Performance - Distribution	262203: Advanced Drone Technology	2,460
System Performance - Distribution	262385: Solley Road Distribution Relocation	900,835
System Performance - Distribution	262796: Customer Voltage Remediation	2,346,194
System Performance - Distribution	263032: Outage Reporting & Analytics	141,366
System Performance - Distribution	54905: Exposed Cable Program	193,886
System Performance - Distribution	55783: Clifton Park Substation 4827 4kV Conversion	(1,606)
System Performance - Distribution	56545: Diverse Routing - Substation Common Right of Way Exposure Reduction	93,753
System Performance - Distribution	60709: Center Substation Feeder 4269 4kV Conversion	93
System Performance - Distribution	61134: Cable Replacement Planned Secondary	2,693,778
System Performance - Distribution	61135: Multiple Pole Hits Program	60,556
System Performance - Distribution	61136: Reliability Process Initiative	3,084
System Performance - Distribution	61139: Overhead Conductor Replacement	1,400,553
System Performance - Distribution	61140: MOSCAD Remote Terminal Unit (RTU) Replacement Program	(10,149)
System Performance - Distribution	61148: AC Network Protector Replacement Program	151,480
System Performance - Distribution	61152: Targeted Transformer Replacement Program	1,938,435
System Performance - Distribution	61156: Customer Average Interruption Duration Index (CAIDI) Improvement - Capital	73,314
System Performance - Distribution	61164: Customer Reliability Support Low Voltage Mitigation	851,870
System Performance - Distribution	61165: Cedar Park Substation Feeder Swap	227,845
System Performance - Distribution	61383: Distribution Substation Relocations	81,458
System Performance - Distribution	61436: TripSaver Tap Performance Program	2,114,101
System Performance - Distribution	61524: Vacuum Breaker Mechanism Replacement Program	(10,991)
System Performance - Distribution	61525: 4C / Form 5 Remote Terminal Unit (RTU) Replacement Program	8
System Performance - Distribution	62641: Sentient Underground Fault Indicators	484
System Performance - Distribution	62644: Sentient Overhead Fault Indicators	625,821
System Performance - Distribution	65212: Clifton Park Substation Feeder 4830 4kV Conversion	1,529,380
System Performance - Distribution	67342: Transformer Protection Program	277,804
System Performance - Distribution	67760: Westport Substation Feeder 33851 Reconductoring	1,824,423

System Performance - Distribution	68155: Common Trench Enhancement Electric	1,857,917
System Performance - Distribution	68178: Field Spun Cable Remediation - Capital	670,626
System Performance - Distribution	68245: AC Network Monitoring	2,421,096
System Performance - Distribution	68928: Spring Gardens Liquified Natural Gas (LNG) Electric Upgrades	2,197,724
System Performance - Distribution	78022: Pumphrey Substation Feeder 34082 Extension and Tie with Feeder 33642	164,046
System Performance - Distribution	82928: 34KV Transformer Neutral Connection Program	114,892
System Performance - Distribution	82952: Customer-Owned Substation Switch Remediation Program	1,197,738
System Performance - Distribution	84528: Distribution Sensors	1,421,244
System Performance - Distribution	88753: Customers Experiencing Multiple Interruptions (CEMI) - Safety	853,805
System Performance - Distribution	**Total Projects < Threshold(2)**	**28,721,372**
System Performance - Relay and Protection	55684: Protection & Control Supplemental Transmission - Relay	(95,658)
System Performance - Relay and Protection	61224: Substation Remote Terminal Unit (RTU) Replacements - Distribution	1,046,314
System Performance - Relay and Protection	61228: Disturbance Monitoring Equipment (DME) Replacement Program	296,829
System Performance - Relay and Protection	61229: NERC Standards Compliance Automation and Technology (A&T)	42,555
System Performance - Relay and Protection	61231: Remote Terminal Unit (RTU) Replacements - Transmission	42,370
System Performance - Relay and Protection	61236: Circuit Interrupting Switch Reclosing Control 34/13kV Substation Transformer Upgrades	489,950
System Performance - Relay and Protection	61237: Replace Electromechanical (EM) Relays - 34kV	22,597
System Performance - Relay and Protection	61240: Substation Protective Relay Replacements - Distribution	546,812
System Performance - Relay and Protection	61281: Monument Street 4kV Supervisory Control and Data Acquisition (SCADA)	(626)
System Performance - Relay and Protection	66688: Operational Technology (OT) Security Governance Capital	1,082,883
System Performance - Relay and Protection	82710: Substation Protection & Control (P&C) Supplemental Distribution Remote Terminal Unit (RT	1,269,114
System Performance - Relay and Protection	88256: Remote Terminal Unit (RTU) Replacements	834,615
System Performance - Relay and Protection	**Total Projects < Threshold(2)**	**5,577,755**
System Performance - Substation	262387: Hampstead Aging Infrastructure Replacement	1,131,396
System Performance - Substation	55945: Bush River Crossing Rebuild - Capital	(572)
System Performance - Substation	58923: Substation Capital - Grounding Upgrades	296,384
System Performance - Substation	61347: Distribution Substation Control Battery Replacements	1,533,988
System Performance - Substation	61348: Transmission Substation Control Battery Replacements	245,697
System Performance - Substation	61368: Transmission Substation Monitoring Equipment	1,224,610
System Performance - Substation	61369: Proactive Replacement Distribution Substation Equipment	81,578
System Performance - Substation	61376: Transmission Substation Security	15,043
System Performance - Substation	62509: Notch Cliff Propane Plant Substation Replacement Phase 1	19,714
System Performance - Substation	63195: High Pressure Fluid Filled (HPFF) Pumphouse Modernization	626,836
System Performance - Substation	78455: Notch Cliff Propane Plant Substation Rebuild Phase 2	(1,414,735)
System Performance - Substation	87030: Copperleaf Asset Transmission & Substation (T&S)	2,892,097
System Performance - Substation	88878: BGE Intelligent Computer-Aided Design (CAD) Implementation - Capital	1,188,938
System Performance - Substation	**Total Projects < Threshold(2)**	**7,840,972**
Back Office - Fleet	59820: Fleet Lease Buyout	99,203
Back Office - Fleet	60088: Fleet Projects	894,897
Back Office - Fleet	78802: Fleet Procurement-Battery Electric Vehicle (BEV) Heavy Duty	289,197
Back Office - Fleet	**Total Projects < Threshold(2)**	**1,283,297**

Back Office - Training	60127: Budget Utility Training Capital	1,209,089
Back Office - Training	**Total Projects < Threshold[(2)]**	**1,209,089**
Back Office - Tools	262255: Smart Tool Calibration and Tracking	1,536,851
Back Office - Tools	58853: Utility Training Tools Capital	(30,058)
Back Office - Tools	60095: Underground Tools Capital	1,487,875
Back Office - Tools	60099: Substation Tools Capital	2,162,101
Back Office - Tools	60101: Customer Operations Tools Capital	148,414
Back Office - Tools	**Total Projects < Threshold[(2)]**	**5,305,182**
Cloyd		
Business Services Company	78903: Separation Capital Costs to Achieve (CTA) Costs	290,139
Business Services Company	**Total Projects < Threshold[(2)]**	**290,139**
Information Technology	261763: Demand Response Program Required Modifications 2024	359,039
Information Technology	261766: Demand Response Program Required Modifications 2025	725,221
Information Technology	261781: Community Solar Modifications 2024	651,285
Information Technology	261795: Transmission & Substation (T&S) Material Ordering System (MOS) Software Migration	299,894
Information Technology	261799: Advanced Metering Infrastucture (AMI) Analytics ITRON Software License Renewal 2024	105,778
Information Technology	261801: Smart Charge Management (SCM) IT Enhancements - Capital	1,020,193
Information Technology	261813: Net Metering Flexibility Project	1,965,595
Information Technology	261826: Manage Energy Use Pull Ahead - Capital	1,543
Information Technology	261865: Outage Restoration Customer Communications Improvement - Capital	770,976
Information Technology	261908: Refresh Hardware for Security and Platform Management Applications	1,108,284
Information Technology	261925: Distributed Energy Resources (DER) Interconnection e-Payment	654,455
Information Technology	261946: Exelon Utilities (EU) Infrastructure Update - Enterprise Asset Management (EAM)	305,667
Information Technology	262023: Analytics Digital Adoption Platform (DAP) Exadata Refresh	1,086,913
Information Technology	262068: Exelon Utilities (EU) Middleware Stabilization - The Information Bus Company (TIBCO) Re	1,560,530
Information Technology	262211: Outage Management System (OMS) Upgrade 2024	391,475
Information Technology	262216: Benchmarking Tool Enhancements	1,129,522
Information Technology	262267: Exelon Utilities (EU) Work Force Management (WFM) Upgrade	199,210
Information Technology	262362: Automation Enablement	538,168
Information Technology	262368: Connected Rewards Participation Indicator	267,804
Information Technology	262371: Automation Enablement	276,541
Information Technology	262378: Property Management Online Service (PMOS) Enhancements	1,940,015
Information Technology	262402: Smart Energy Hall Video Conferencing Upgrade	681,720
Information Technology	262431: Customer Information Access	1,094,750
Information Technology	262435: Meter Accessibility Process (MAP) Day 2 Enhancements	961,243
Information Technology	262442: Integration Services Architecture (IVA) Update - The Information Bus Company (TIBCO) to	219,679
Information Technology	262473: Connected Rewards - Application Programing Interface (API) Connection with Resideo	1,519,471
Information Technology	262555: Exelon Utilities (EU) Middleware Stabilization - Informatica Upgrade	2,990
Information Technology	262558: Exelon Utilities (EU) Generative Artificial Intelligene (AI) & Corporate Functional Releases	264,147
Information Technology	262590: Geospatial Data Visualization and Analytics (GDVA) Disaster Recovery (DR) Environment U	18,345
Information Technology	262641: Agency Portal Enhancements	358,428

Information Technology	262683: BGE Maryland Senate Bill 1 (2024) Implementation	780,324
Information Technology	262702: Environmental Systems Research Institute (ESRI) Geospatial Data Visualization and Analytic	224,392
Information Technology	262705: Root Cause Investigation (RCI) Device Remediation - Phase 2	(218)
Information Technology	262728: Exelon Utilities (EU) Vehicle Radio Extender (VRX) Solution	401
Information Technology	262732: Large Customer Services (LCS) Smart Energy Data Analytics Platform (DAP) Integration	250,464
Information Technology	262746: Digital Accessibility Enhancements 2025	11,083
Information Technology	263002: Customer Experience (CX) Wrapper Adoption-Related Enhancements	2,932
Information Technology	263033: BGE My Distributed Energy Resources (MyDER) - EV Customer Experience	274,904
Information Technology	54732: BGE Facility Enhancement Program	659,871
Information Technology	55144: Project and Portfolio Management (PPM)/Oracle Tool Implementation - Capital	628,923
Information Technology	59960: Transmission & Substation (T&S) Document Management System Upgrade	(666,558)
Information Technology	61401: Advanced Distribution Management System (ADMS) Implementation	(2,625)
Information Technology	61616: Mobile Mapping Solution for Mobile Dispatch Implementation	86,516
Information Technology	64713: Exelon Utilities (EU) Digital Program	2,725,218
Information Technology	64824: Exelon Utilities (EU) Analytics - Grid Functional Release	970,295
Information Technology	64847: Exelon Utilities (EU) Digital System Hardening	1,004,301
Information Technology	66135: Exelon Utilities (EU) Analytics Customer Functional Releases	498,457
Information Technology	66365: Exelon Utilities (EU) Geographic Information System (GIS) Data Quality	1,657,470
Information Technology	69380: Communication Tower Infrastructure	249,632
Information Technology	69561: Architecture - Smart Streetlights	16,628
Information Technology	75368: Microwave Federal Communications Commission (FCC) Transformation	2,293,069
Information Technology	75493: Electric Vehicle (EV) Smart Charging Rate Consolidation Phase 3 - Capital	2,188,017
Information Technology	75524: Smart Energy Services - Uplight Energy Data Platform Replacement	(34,544)
Information Technology	75606: Exelon Utilities (EU) Geographic Information System (GIS) Geospatial Data Visualization and	479,027
Information Technology	77575: Maryland Battery Energy Storage System (BESS)	43
Information Technology	77752: Exelon Utilities (EU) Geographic Information System (GIS) Data Remediation	675,197
Information Technology	78021: Customer Care & Billing (CC&B) System Hardening	902,639
Information Technology	78024: Exelon Utilities (EU) Customer Hardening & Resiliency	757,578
Information Technology	78037: Advanced Metering Infrastructure (AMI) Head End Application Upgrade 2023	178,382
Information Technology	78046: Avolin Saratoga Customer Relationship Manager (CRM) System Replacement - Capital	(1,081)
Information Technology	78053: Exelon Utilities (EU) Next Generation Digital Platform	1,104,515
Information Technology	78096: Smart Grid Core Router Refresh	429,192
Information Technology	78272: Transmission - Golden Image & Bare Metal Restoration	(386)
Information Technology	78280: Exelon Utilities (EU) Outage Reporting & Analytics (ORA) Advanced Distribution Manageme	382,569
Information Technology	78317: Exelon Utilities (EU) Analytics Cloud Strategy Data Analytics Program (DAP) Migration	434,411
Information Technology	78323: Exelon Utilities (EU) Land Mobile Radio (LMR) East Core Upgrade	78
Information Technology	79391: Exelon Utilities (EU) Reliability Monitoring & Self Healing - Capital	433,979
Information Technology	79393: Exelon Utilities (EU) Artificial Intelligence (AI) Chat Enhancements	1,432,301
Information Technology	79408: Exelon Utilities (EU) Customer Flight Path: Outage	1,713,480
Information Technology	79410: Exelon Utilities (EU) Customer Flight Path: Low/Medium Income (LMI)	764,677
Information Technology	84803: Exelon Utilities (EU) Mainframe Decommission	349,660

Information Technology	84819: Digital & Self-Service Platform Enhancements	680,663
Information Technology	84871: Exelon Utilities (EU) Storm Critical Systems - IT Hardening and Remediation Phase 2	603,213
Information Technology	84875: Exelon Utilties (EU) NERC Critical Infrastruction Protection (CIP) Multi-Factor Authenticatio	4,309
Information Technology	84894: Exelon Utilities (EU) Call Center Cloud Transformation	69,558
Information Technology	84931: Distributed Energy Resource (DER) and Load Forecasting System	2,466,861
Information Technology	84960: oneMDS 2 (Exelon Utilities (EU) Mobile Dispatch and Mobile Mapping Enhancement)	18,893
Information Technology	84986: BGE Customer Care & Billing (CC&B) Platform Enhancement	1,267,834
Information Technology	85036: BGE Environment Strategy	1,699,226
Information Technology	85063: Exelon Utilities (EU) Analytics Advanced Metering Infrastructure Functional Release	513,863
Information Technology	85124: Exelon Utilities (EU) Analytics Data Quality Implementation & Monitoring	359,582
Information Technology	85295: Exelon Utilities Network (EUN) Hardware Refresh	1,674,450
Information Technology	86559: Exelon Utilities (EU) New Business Portal IntellioConnect Stand Up - Capital	1,024,916
Information Technology	86608: Exelon Utilities (EU) New Business Portal - Capital	1,531,857
Information Technology	86823: Advanced Distribution Management System (ADMS) Splunk License Renewal	337,533
Information Technology	87476: Windows Server Licenses - Capital	17,788
Information Technology	88153: Exelon Utilties (EU) Energy Based Observations Platform Installation - Capital	518,965
Information Technology	88494: Exelon Utilities (EU) Nexidia Application Update	131,972
Information Technology	88562: Exelon Utilities (EU) GEOMANT Wallboard Network Upgrade - Capital	(67)
Information Technology	**Total Projects < Threshold(2)**	**57,255,506**
Real Estate and Facilities Management	261884: White Marsh Service Center Roof Replacement	1,168,900
Real Estate and Facilities Management	261885: Gas & Electric Building (GEB) Fire Panel Replacement	1,837,436
Real Estate and Facilities Management	261932: Electric Operations Building (EOB) Simulator Upgrade	114,275
Real Estate and Facilities Management	262118: Lord Baltimore Building (LBB) Renovations - Capital	90,696
Real Estate and Facilities Management	262122: Perry Hall Service Center Renovation	1,082,343
Real Estate and Facilities Management	262154: Gas & Electric Building (GEB) Garage Elevator Replacement	(2,579)
Real Estate and Facilities Management	263035: White Marsh Training Center Trailer	476,124
Real Estate and Facilities Management	263089: Spring Gardens (SPG) Underground Lines (UGL) Bathrooms	109,221
Real Estate and Facilities Management	54693: Miscellaneous Requests - Furniture	272,074
Real Estate and Facilities Management	54696: Miscellaneous Requests - Branding	118,226
Real Estate and Facilities Management	57775: Third Party Pole Attachments *	1,545,319
Real Estate and Facilities Management	58006: Front Street and Monument Street Warehouse Elevators Repair	499,259
Real Estate and Facilities Management	60810: Pole Attachments - Antenna Split *	(25,726)
Real Estate and Facilities Management	60820: Infrastructure - Capital Infrastructure Management Projects	1,907,465
Real Estate and Facilities Management	65300: Piney Orchard Outdoor Lighting Replacement	59
Real Estate and Facilities Management	68212: Electric Operations Building (EOB) Data Center Infrastructure Upgrades	906,453
Real Estate and Facilities Management	68282: Gas & Electric Building (GEB) - 15th Floor Renovations	12,110
Real Estate and Facilities Management	68283: Gas & Electric Building (GEB) - 16th Floor Renovation	317,193
Real Estate and Facilities Management	68284: Spring Gardens Electric Vehicle (EV) Charging Stations	150,297
Real Estate and Facilities Management	76018: Electric Vehicle (EV) Chargers at Cockeysville	1,218,172
Real Estate and Facilities Management	76957: Fire System Upgrades	17,065
Real Estate and Facilities Management	76959: Building Automation System (BAS) Controller System Program	24,824

Real Estate and Facilities Management	77045: Electrical Upgrades	247,769
Real Estate and Facilities Management	77050: Building Facility Replacements and Emergent Work	1,217,907
Real Estate and Facilities Management	77052: Mechanical System Replacments and Emergent Work	1,120,769
Real Estate and Facilities Management	77055: Outdoor Replacments and Emergent Work	478,032
Real Estate and Facilities Management	77057: Information Technology (IT) Equipment	10,324
Real Estate and Facilities Management	77058: Cockeysville Gate (Construction)	987,126
Real Estate and Facilities Management	77082: Energy Efficiency Initiative	901,516
Real Estate and Facilities Management	81052: Forrest Street Garage Restoration	2,484,998
Real Estate and Facilities Management	81204: Spring Gardens Oil Recovery Facility	982,286
Real Estate and Facilities Management	82142: Rutherford Business Complex (RBC) Fleet Building HVAC Unit Replacement	1,209
Real Estate and Facilities Management	82411: Spring Gardens (SPG) Historic Valve House Restoration	76,732
Real Estate and Facilities Management	82412: Roof Replacement - Hillen Steet Fleet Shop	223,616
Real Estate and Facilities Management	82413: Roof Replacement - Front Street Service Center	1,232,267
Real Estate and Facilities Management	86002: Piney Orchard Service Center Pole Barn	813,285
Real Estate and Facilities Management	86474: Spring Gardens Operations Storage Facility (OSF) Building Second Floor Renovation	2,343,968
Real Estate and Facilities Management	86476: Lord Baltimore Building (LBB)-Building A Support Space	1,897,589
Real Estate and Facilities Management	86477: Westminster Service Center Renovation	522,438
Real Estate and Facilities Management	86588: Facilities Solar Projects	1,074,111
Real Estate and Facilities Management	87022: Gas & Electric Building (GEB) Building Duct Work	(317,193)
Real Estate and Facilities Management	87770: Electric Operations Building (EOB) Audio/Visual (A/V) Video Wall Upgrades	10
Real Estate and Facilities Management	87922: Electric Operations Building (EOB) Power Distribution Unit Replacements	597,038
Real Estate and Facilities Management	**Total Projects < Threshold[(2)]**	**28,735,001**
Other	262081: BGE Grid Communication and Connectivity (GCC) Fiber Route - Laurel Laterals	500,030
Other	262082: BGE Grid Communication and Connectivity (GCC) Fiber Route – Laurel	837,423
Other	262110: BGE Grid Communication and Connectivity (GCC) Fiber Route - Howard Laterals	1,643,398
Other	53369: Back Office Allocation	(292,251)
Other	60953: Strategy & Regulatory Affairs (SRA) Electric Vehicle Supply Equipment (EVSE) Cap-Workpl	567,962
Other	60988: Security Capital	183,692
Other	61076: Meter Engineering & Standards Capital	5,723
Other	61446: Strategy & Regulatory Affairs (SRA) Regulatory Information Technology (IT) - Capital	31,953
Other	61568: Innovation Initiative - Capital	1,917,225
Other	62791: Electric Vehicle Station Equipment Program Capital - BGE Public	1,183,150
Other	63246: Advanced Metering Infrastructure (AMI) Lab Remodel	41,878
Other	63996: Strategy & Regulatory Affairs (SRA) Connected Communities Capital	264,895
Other	67010: Electric Transmission & Substation (ET&S) Capital Hardware	63,054
Other	76922: Strategy & Regulatory Affairs (SRA) Electric Vehicle (EV) Department of Energy (DOE) Ride	9,279
Other	77420: BGE Permit Tracking Tool	(45,012)
Other	79567: Fiber Demonstration Project Use Case(s)	1,700,591
Other	80175: Office and Equipment Purchases	(474)
Other	88434: Advanced Metering Infrastructure (AMI) Wide Area Network (WAN) Equipment Installation/I	296,844
Other	**Total Projects < Threshold[(2)]**	**8,909,359**

(1) Co-Sponsored by Company Witnesses Wright and Cloyd

(2) Threshold is at least 80% of electric distribution in-service additions and 25% of projects

** Project has a customer contribution in aid of construction (“CIAC”) component*

Case No. 9888
Baltimore Gas and Electric Co.
Response to Staff Data Request 19
Request Received: July 31, 2026
Response Date: August 14, 2026
Sponsor(s): John C. Frain

Item No.: StaffDR19-01

Following up on the response to SDR 2-3, is BGE willing to provide reporting metrics on;

a. participation by low income customers vs non-low income customers?
   i. It is Staff's understanding that as part of the enrollment process, customers will be asked to provide their estimated household income. If this is not correct, please explain why.

b. the number of customers receiving assistance?

RESPONSE:

BGE does not oppose including certain metrics that were previously tracked or are readily available. However, household income information provided by customers during enrollment would not be used to classify customers as low income or non-low income because such information is self-reported and is not independently verified by BGE. Accordingly, if BGE were to report metrics by income segment, the Company would use participation in Maryland's Office of Home Energy Programs (OHEP) as the classifying factor. Customers identified as having received OHEP assistance would be classified as low income, while customers without an OHEP indicator would be classified as non-low income. OHEP participation provides an established and verifiable measure of low-income status.

Household income information was collected during the Prepaid Pilot to support APPRISE's independent evaluation of the pilot. Because the information is self-reported and not verified by BGE, it would not be collected as part of the full BGE FlexPay program.

Case No. 9888
Baltimore Gas and Electric Co.
Response to Staff Data Request 28
Request Received: August 12, 2026
Response Date: August 26, 2026
Sponsor(s): John C. Frain; Nancy McCart

Item No.: StaffDR28-23

Research and Development ("R&D") costs. Address the following regarding R&D costs.

a. Provide the amount of R&D costs expensed and capitalized by account number (and account description) for TYE March 31, 2026, 2025, and 2024, and explain the reason for changes in these costs from year-to-year.
b. Identify all adjustments made to R&D costs in this rate case by account number, and explain the reason for the adjustment.
c. Provide a list and description of all R&D projects (and related costs) for TYE March 31, 2025, 2024, and 2023, and explain when each R&D project began and will end. Identify and explain all expense and capital cost savings by year (for each type of account) for each R&D project, or explain why costs will increase for these R&D projects.
d. Explain if the R&D projects are being performed in conjunction with, or as a result of recommendations or prior research by Edison Electric Institute (or some other entity), and provide supporting documentation for the research project by outside entities.

RESPONSE:

a. Please see *StaffDR28-23-Attachment 1*. The Company has not prepared a variance analysis.

b. No adjustments to R&D expense are proposed in the current rate proceeding.

c. BGE incurs R&D costs through participation in collaborative utility research programs and related project activities administered by the Electric Power Research Institute ("EPRI"), Center for Energy Advancement through Technological Innovation International ("CEATI"), the National Electric Energy Testing and Research Applications Center ("NEETRAC"), and the Utility Health Sciences Group ("UHSG"). For accounting purposes, NEETRAC costs are reflected through Georgia Tech Research Corporation and UHSG costs are reflected through Watson & Renner. These organizations support research related to utility reliability, safety, asset management, distributed energy resources ("DER"), system planning, power quality, equipment performance, and emerging utility technologies.

   Quantifiable project-specific expense savings and capital savings are not tracked. Many projects involve research, testing, technology evaluation, pilot demonstrations, benchmarking, planning activities, and technology-transfer efforts. Benefits associated with these projects are generally realized through improved reliability, safety, operational efficiency, asset-management practices, technology validation, and implementation of research findings. Please see *StaffDR28-23-Attachment 2* for information detailing BGE's portfolio of R&D projects over the period 2023-2026.

d. BGE's R&D projects are generally not performed as a result of recommendations from Edison Electric Institute ("EEI"). Rather, BGE participates in collaborative utility research programs administered by EPRI, CEATI International, NEETRAC, and UHSG. These organizations perform and coordinate research, testing, pilot projects, technology demonstrations, benchmarking activities, and technical studies that support participating utilities.

   Please see the StaffDR28-23-Attachment 2 which includes the organizations with which BGE is partnering on research and development projects.

BALTIMORE GAS AND ELECTRIC

SUMMARY OF R&D EXPENSE

Years: 2024 and 2024 & Test Year Ending March 31, 2026

Year	Vendor	Account Charged	Amount
2024	EPRI	588	$312,980
2024	GEORGIA TECH RESEARCH CORP.	588	15,986
2024	WATSON AND RENNER	588	7,832
			$336,798
2025	CEATI INTERNATIONAL INC	588	$25,691
2025	EPRI	588	280,769
2025	GEORGIA TECH RESEARCH CORP.	588	16,112
2025	WATSON AND RENNER	588	8,130
			$330,703
Test Year	EPRI	588	$281,278
Test Year	WATSON AND RENNER	588	8,130
Test Year	CEATI INTERNATIONAL INC	588	8,311
Test Year	GEORGIA TECH RESEARCH CORP.	588	15,929
			$313,649

BALTIMORE GAS AND ELECTRIC
SUMMARY OF RESEARCH AND DEVELOPMENT PROJECTS

Project	**Description**	**Involved Organization**	**Benefit / Savings Explanation**	**Start Date**	**End Date**
SF6 Alternatives Lab Assessments of Handling Practices and Chemical Analysis	Laboratory assessment of the handling, analysis, maintenance, storage, treatment, and disposal of alternatives to SF6.	EPRI	Supports evaluation of alternative technologies and provides technical information relevant to equipment operation, maintenance, and worker safety.	Oct-23	Dec-26
Distribution System Operator Capabilities to Enable DER Services	Development of roadmaps and implementation plans identifying the systems, processes, tools, and data needed to enable DER services.	EPRI	Produced a strategic roadmap and implementation plans to support DER integration and identify needed systems, data exchanges, capabilities, and operational improvements.	Jan-24	Dec-25
Model-Based Analysis of DER Functions and Settings, Phase 2	Evaluation of DER functions and settings through distribution-feeder modeling and analysis.	EPRI	Supports selection of appropriate DER functions and settings, validation of feeder-analysis methods, and evaluation of DER impacts at increasing penetration levels.	Jan-24	Mar-26
Evaluation of Robotic Field Application of the E3X Conductor Coating	Evaluation of robotic application of a high-emissivity conductor coating and monitoring of field performance.	EPRI	Confirmed that E3X coating could be robotically applied to conductors and provided information concerning performance limitations, sensor reliability, and potential applications.	Sep-23	Dec-25

Project	Description	Involved Organization	Benefit / Savings Explanation	Start Date	End Date
Assessment and Mitigation of Intentional Electromagnetic Interference	Research assessing intentional electromagnetic interference threats and mitigation approaches for utility infrastructure.	EPRI	Provides technical guidance concerning potential impacts, mitigation options, shielding, physical separation, access controls, and cable-design best practices.	2023	Dec-25
Insulative Coating Performance Testing	Evaluation of commercially available spray-on insulating coatings and utility applications.	EPRI	Supports evaluation of coatings that may improve equipment reliability and reduce faults associated with contact between wildlife and energized distribution equipment.	2024	2025
EPRI BGE Contact and Stray Voltage	Development and qualification of a vehicle-mounted system used to detect contact and stray voltage on publicly accessible equipment.	EPRI	The Company estimates approximately $1 million in annual savings, primarily from bringing previously contracted contact and stray voltage inspection work in-house.	2025	Jan-26
PREMS II User Group and Related Research	Mobile radio-emissions monitoring and user collaboration supporting identification of anomalous emissions associated with utility equipment and customer power-quality issues, as well as software, hardware, and waveform-database enhancements.	EPRI	Supports faster identification and resolution of equipment or interference issues, improved investigation techniques, targeted inspections, proactive maintenance, and shared learning among participating utilities.	Jan-25	Dec-25

Project	Description	Involved Organization	Benefit / Savings Explanation	Start Date	End Date
Conductor Burndowns and Wildfire Mitigation Using Compact Single-Phase Reclosers	Evaluation of compact single-phase reclosers, including TripSaver applications, wire sizing, reclosing behavior, and protection coordination.	EPRI	Findings supported updated TripSaver applications, settings, fuse selection, and protection practices. The records identify improved coordination, reduced conductor-burndown and wildfire exposure, and a positive but unquantified SAIFI impact. The project also identified opportunities to use lower cost reclosures in some situations higher cost reclosers with lower cost units.	Sep-24	Jan-26

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Maryland's Utility Rates and Charges

Explanation and data on utility bills, rates, and charges, and how—and why—they have changed over time.

June 2024

(updates for 2025-26 rate increases to pp. 6, 9, 12, March 2025)

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Table of Contents

About This Report

- This report has information about current and historic rates and charges of the major Maryland electric and gas utilities. It includes dozens of figures illustrating and comparing rates and charges and how they have changed over time.
- The report appendix has current and historic rate and charge information organized alphabetically by utility. The information is also available on OPC's website and will be periodically updated.
- All figures and charts in this report show only rates and charges under the standard tariffs for residential customers. Rates and charges for other customer classes or non-standard options (such as time-of-use rates) for residential customers will be different.
- Rates shown in this report are intended to illustrate general rate trends. The rates are based on standard residential rate schedules. Reported rates may vary slightly from rates as they appear or appeared on customer bills because they reflect an annual weighted average, do not incorporate certain surcharges or reconciliations, or because they are not adjusted for temporary riders, including changes for tax benefits from the Tax Cuts and Jobs Act of 2017 and related credits being passed through to customers ahead of schedule.
- Rates shown for Pepco reflect the Public Service Commission's June 10, 2024, order, and Baltimore Gas and Electric rates for 2024-2026 are based on a Commission order that is subject to a rehearing request.

Glossary

- ***Capital expenditure:*** Dollars a utility spends on projects and equipment that replace or expand the utility's infrastructure. Capital expenditures go into the utility's "rate base" (see below) with the Public Service Commission's approval.
- ***Delivery charges:*** The charges for delivering gas or electricity to your home, including the monthly customer charge and the distribution rate charge that depends on energy usage. Sometimes referred to as "distribution" charges.
- ***Distribution rate:*** The rate that is multiplied by the amount of gas or electricity the customer consumes each month to determine the volumetric component of the delivery charges.
- ***Monthly customer charge:*** A monthly fixed charge on customer bills that makes up the other main portion of the delivery charges.
- ***Rate base:*** The total dollar amount of the utility's capital investments that have not yet been paid for by customers. Utilities receive a return, including profit, that is based on rate base size and that is recovered from customers in their delivery charges.
- ***Supply charge:*** A charge for the physical energy the customer consumes, measured in therms for gas and kilowatt-hours for electricity. Also called the "commodity" charge.
- ***Utility infrastructure:*** The pipes, towers, wires, computers, and other equipment and infrastructure that the utility needs to deliver gas or electricity to customers.

Key Findings

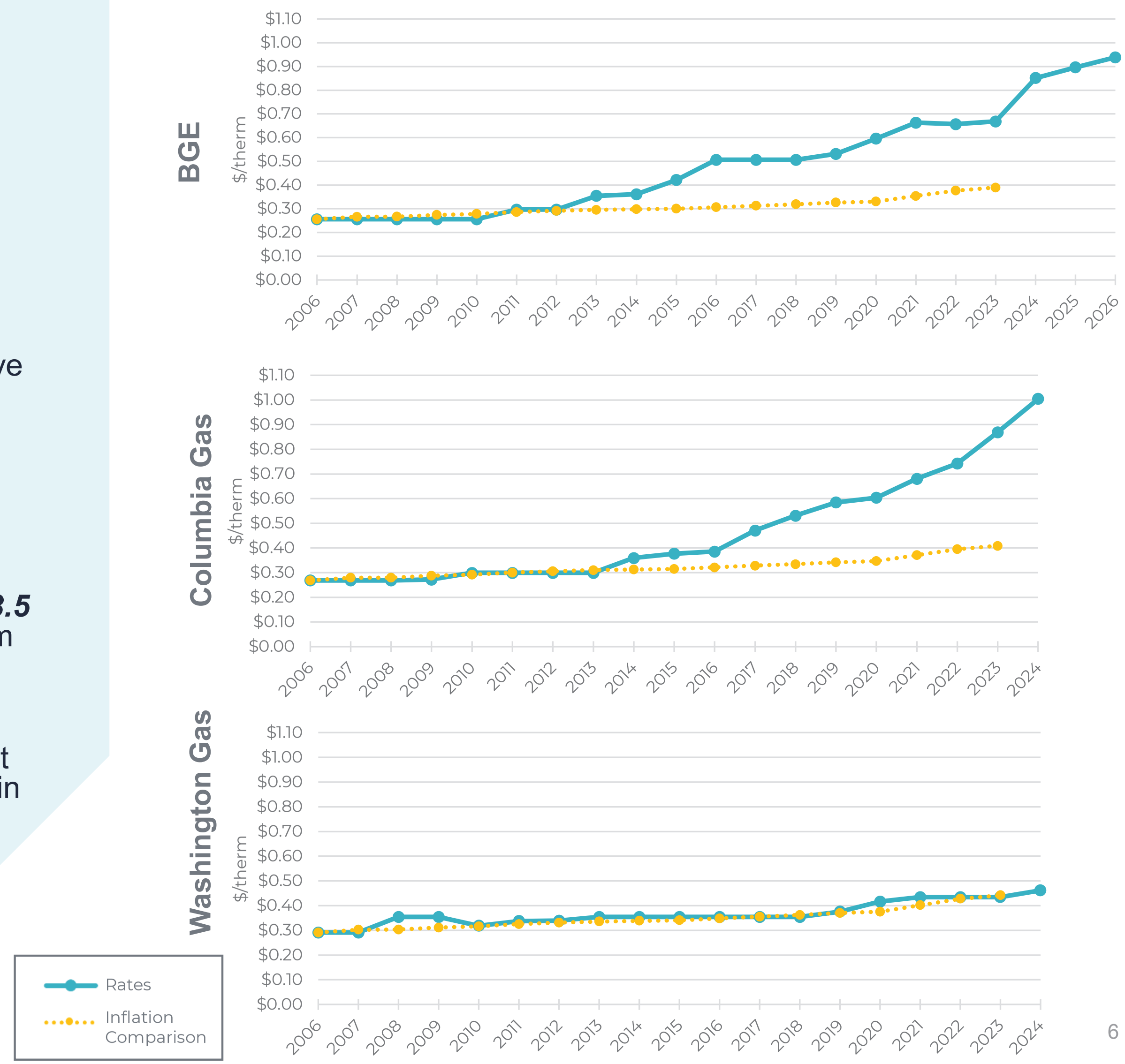
GAS UTILITY FINDINGS

Current and Historic Distribution Rates

Baltimore Gas & Electric (BGE) rates have more than ***tripled*** since 2010, increasing from 26 cents/therm to 85 cents/therm in 2024, exceeding the rate of inflation by a factor of nearly three. Under a recent Commission order, rates will rise to 94 cents/therm in 2026.

Columbia Gas rates increased at about ***3.5 times*** the rate of inflation, increasing from 30 cents/therm in 2010 to $1.00/therm in 2024.

Washington Gas rates increased at about the rate of inflation, from 32 cents/therm in 2010 to 46 cents/therm in 2024.



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GAS UTILITY FINDINGS

Reductions in Gas Supply Costs Have Masked the Effect of BGE and Columbia Gas Delivery Cost Increases

Absent substantial increases in delivery costs after 2010, declining gas supply (commodity) costs would have lowered overall customer gas bills.

BGE

Columbia Gas

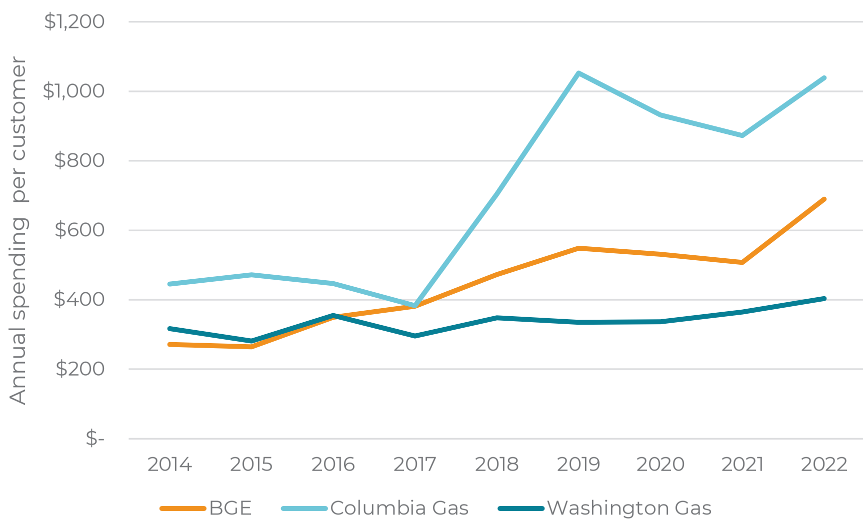
Calculations are based on gas usage of 940 therms per year.

GAS UTILITY FINDINGS

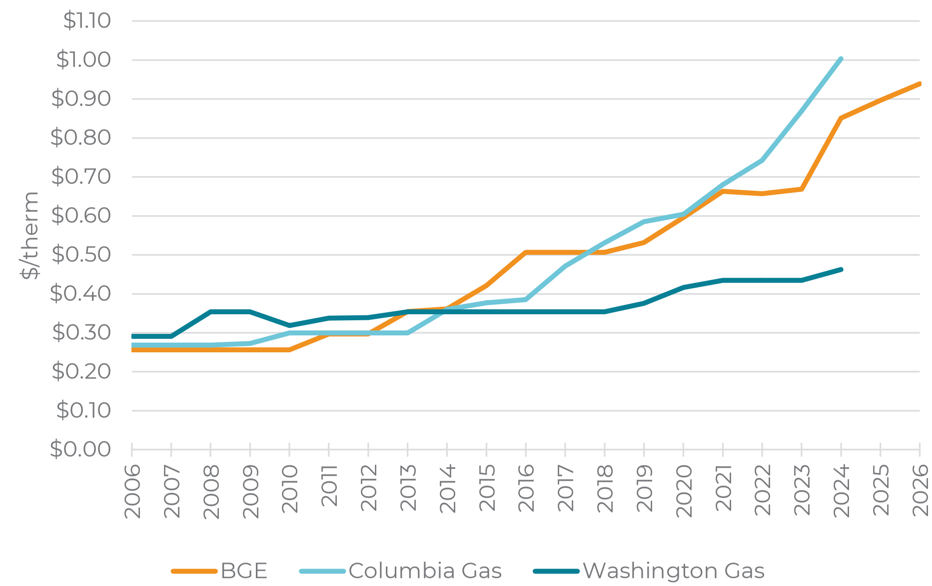
Washington Gas' distribution rates are about half of BGE's and Columbia Gas' rates due to its slower pace of infrastructure spending

Washington Gas' pace of spending on capital gas infrastructure has been much slower than BGE and Columbia Gas. From 2019 to 2022, on average Washington Gas annually spent $360/customer on gas infrastructure, while BGE spent $570/customer and Columbia Gas spent $974/customer.

Annual Gas Utility Infrastructure Spending Per Customer



Gas Utility Distribution Rates



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GAS UTILITY FINDINGS

Summary comparison of current distribution rates

Utility	Fixed Monthly Charge		Distribution Rate ($ per therm)		
	2010	**2025**	**2010**	**2025**	**Yearly Average % Increase**
Washington Gas	$10.20	$11.85	$0.39	$0.46	**1.8%**
BGE	$13.00	$15.55	$0.26	$0.90*	**8.5%**
Columbia Gas	$10.97	$16.25	$0.30	$1.00	**8.7%**

*Possible additional rate increase from BGE MYP 1 reconciliation to be determined
In 2026, BGE's rates increase to 94 cents.

Columbia Gas's rates are likely to increase in May 2025, as it is in the middle of a rate case which is scheduled to be decided on 4/22/25.

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ELECTRIC UTILITY FINDINGS

Distribution Rate Increase Highlights, 2010-2024

The three Exelon utilities' rates have increased substantially and well above inflation rates:

Pepco rates have increased from 2.6 cents/kWh to 6.2 cents/kWh.

Delmarva Power rates have increased from 3.2 cents/kWh to 7.0 cents/kWh.

BGE electric rates have increased from 2.5 cents/kWh to 4.6 cents/kWh.

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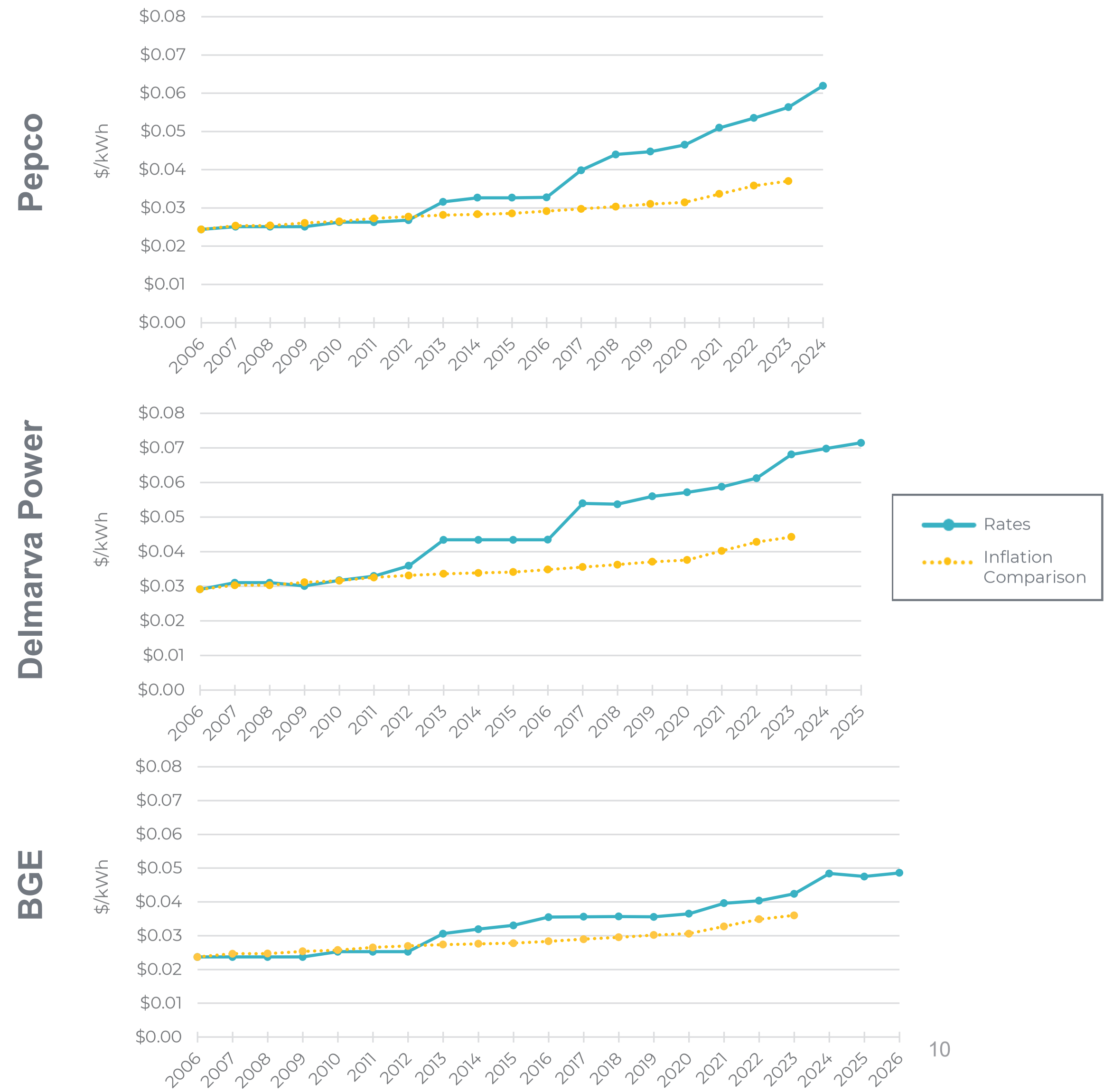
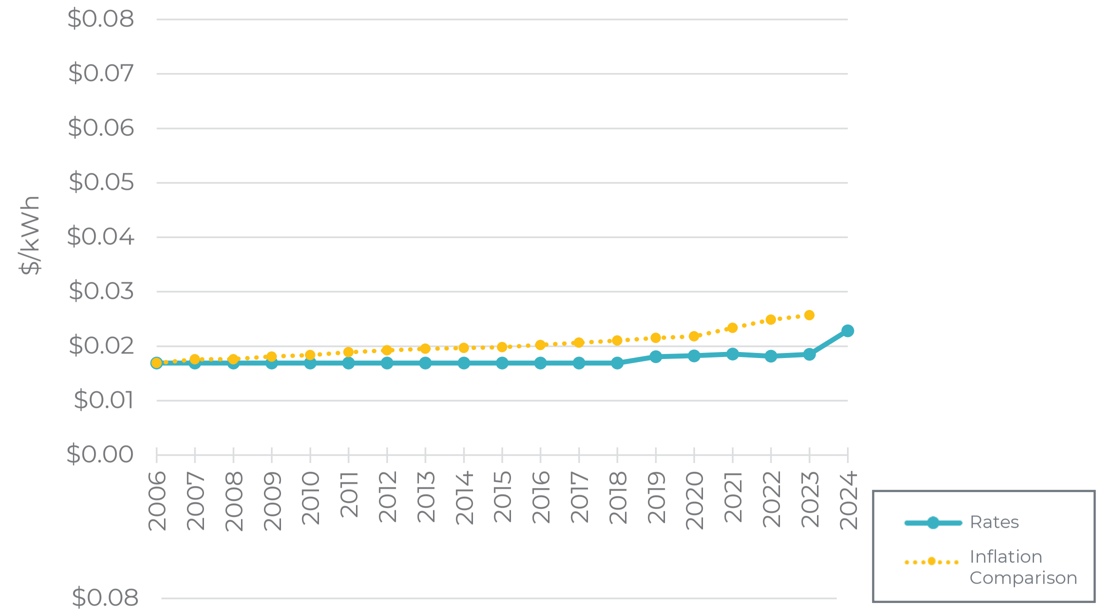


ELECTRIC UTILITY FINDINGS
Distribution Rate Increase Highlights, 2010-2024

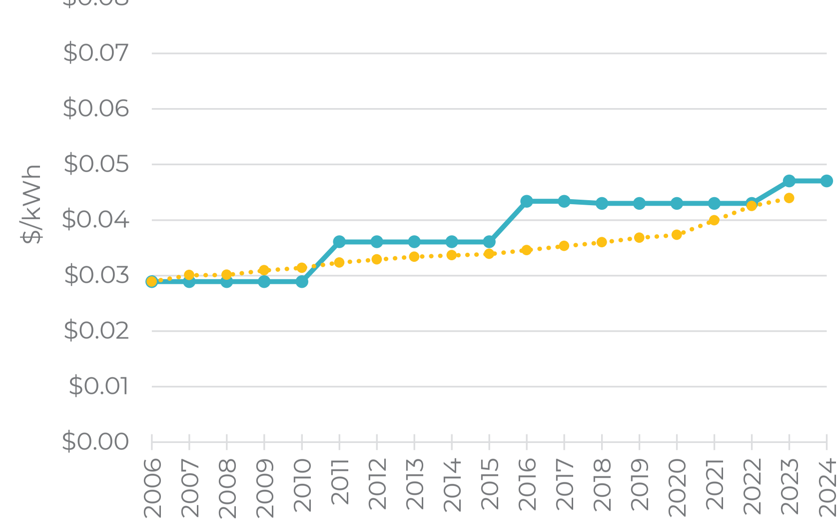
Potomac Edison's distribution rates have stayed stable and are currently substantially less than BGE, Pepco, and Delmarva Power.

Distribution rates for SMECO, a cooperative and the State's fourth largest electric utility, have increased slightly faster than the rate of inflation.

Potomac Edison



SMECO



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ELECTRIC UTILITY FINDINGS

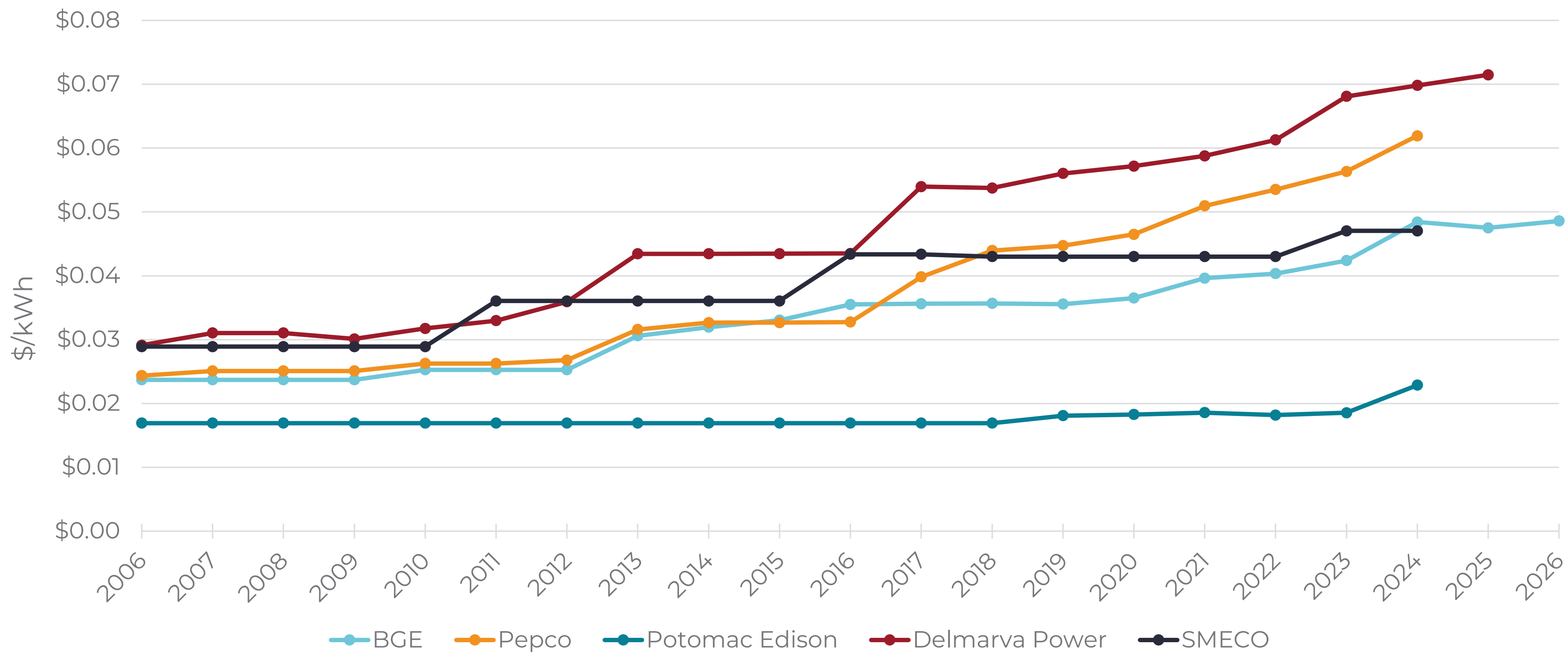
Summary comparison of current distribution rates

Utility	Fixed Monthly Charge		Distribution Rate (cents per kilowatt hour)		
	2010	**2025**	**2010**	**2025**	**Yearly Average % Increase**
Potomac Edison	$5.00	$6.00	1.7 ¢	2.3 ¢	**2.1%**
SMECO	$8.60	$9.75	2.9 ¢	5.4 ¢	**4.3%**
BGE	$7.50	$9.65	2.5 ¢	4.8 ¢*	**4.6%**
Delmarva Power	$6.00	$9.43	3.2 ¢	7.2 ¢	**5.8%**
Pepco	$6.65	$8.44	2.6 ¢	6.2 ¢	**6.0%**

*Possible additional rate increase from BGE MYP 1 reconciliation to be determined.
BGE's base rates increase to 4.9 cents in 2026; Delmarva Power's increase to 7.2 cents.

ELECTRIC UTILITY FINDINGS

Summary comparison of distribution rates



Accelerated cost recovery helps drive rate increases

Maryland has in place two forms of accelerated cost recovery mechanisms

Strategic Infrastructure Development and Enhancement Plan (STRIDE) law

Enacted in 2013, covering the costs of gas pipe replacement work

Multi-Year Rate Plans

Adopted by the Public Service Commission in 2020, covering all utility costs

Accelerated cost recovery helps drive rate increases

STRIDE

- BGE, Washington Gas, and Columbia Gas—Maryland's largest gas utilities—have taken advantage of the STRIDE program.
- Washington Gas has made the least progress in its STRIDE program and has consistently not accomplished the work it has planned to complete.*
- STRIDE program costs are recovered through the STRIDE surcharge until they are moved into regular rates at the time of a rate case, helping to drive up distribution rates.
- BGE performed gas pipe replacement work under STRIDE until 2024. Under a recent PSC order, the company now is performing its gas pipe replacement work under its multi-year rate plan, which provides the same accelerated cost recovery benefit to the utility as the STRIDE law.

* *See* Public Service Commission Order No. 90099 (March 2, 2022) (stating that "the company has overpromised and under delivered" on its STRIDE plans).

Accelerated cost recovery helps drive rate increases

Multi-Year Rate Plans

- The term "multi-year rate plan" is shorthand for an approved schedule of rate changes (typically increases) that provide accelerated cost recovery for projected utility spending.
- Multi-year rate plans cover future years, usually three years, while standard ratemaking under rate cases can occur frequently or many years apart. (Maryland utility Potomac Edison went almost 25 years—from 1994 to 2018—without a rate increase.)
- Maryland's three utility subsidiaries of the Chicago-based Exelon Corporation—BGE, Pepco, and Delmarva—have had multi-year rate plans.
- BGE's current multi-year plan runs through 2026, and Delmarva Power's runs through 2025. In a recent order, the Public Service Commission rejected the second two years of Pepco's proposed three-year multi-year rate plan.

Accelerated cost recovery helps drive rate increases

The STRIDE and multi-year alternative rate mechanisms have shifted the risks of utility overspending to customers and increased customer rates.

Standard rate case

- Rates are based on the utility's actual spending in a past year that is close in time to the filing of the rate case.
- By using actual costs to set rates, the Public Service Commission (PSC) can assess how reasonable the company's spending was when determining rates.
- Recovery for capital investments generally starts after the capital projects are used and useful—i.e., placed into service—for customers and the utility has filed a rate case.
- Utilities are free to file rate cases as frequently or infrequently as they want based on their assessment of how their investors are faring from current rates.

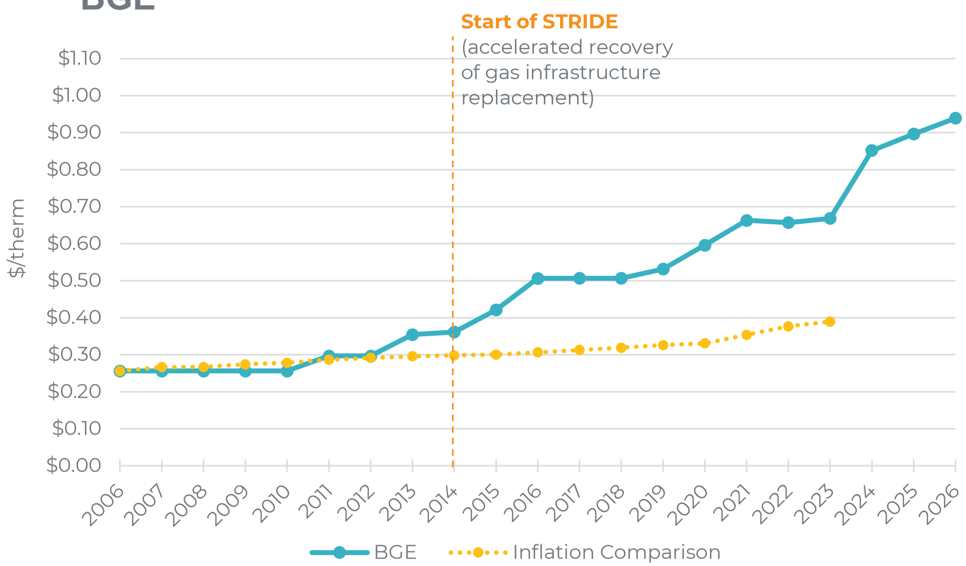
Alternative "multi-year" ratemaking

- Rates are based on projected utility capital investment spending over a future period, with the utility retaining flexibility to change its capital investment plans.
- Utilities charge customers for project costs *before* those projects are used to serve customers.
- Allows utilities to recover any overspending from customers, thereby shifting the utility's risk from its investors to its customers.
- The faster rate recovery and lowering of utility risk promotes higher levels of spending.

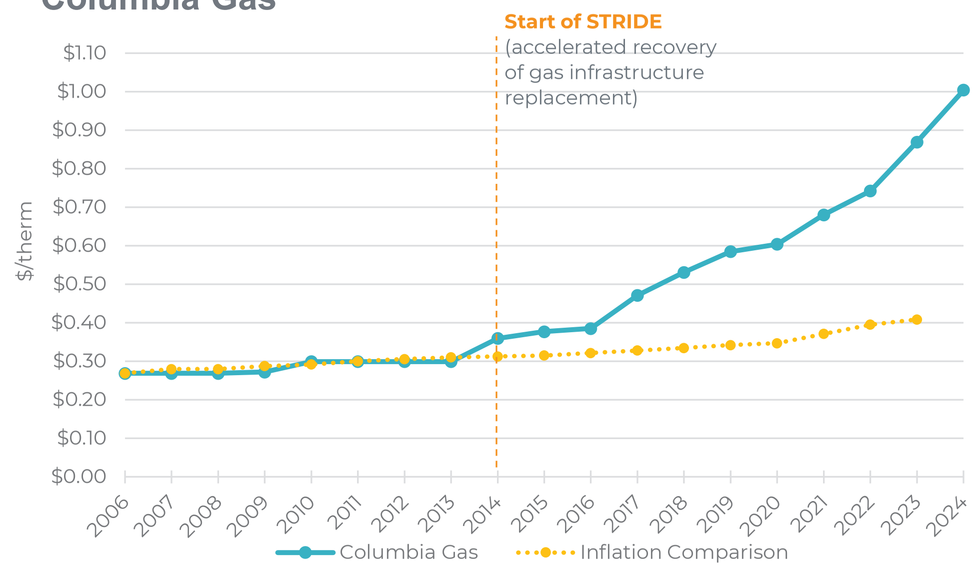
Accelerated cost recovery helps drive rate increases

STRIDE programs went into effect in 2014, leading to immediate rate increases for BGE and Columbia Gas customers.

BGE



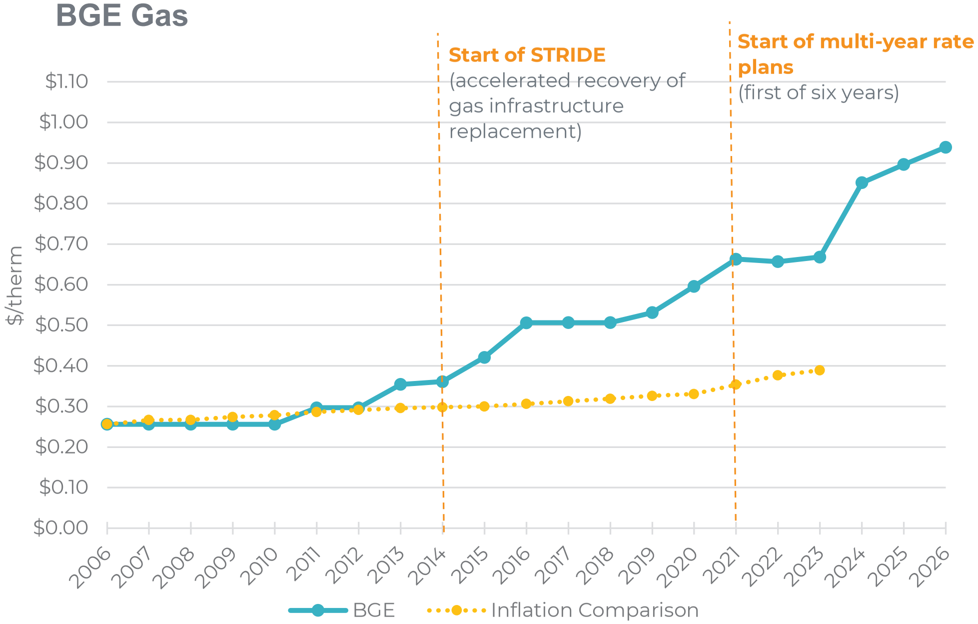
Columbia Gas



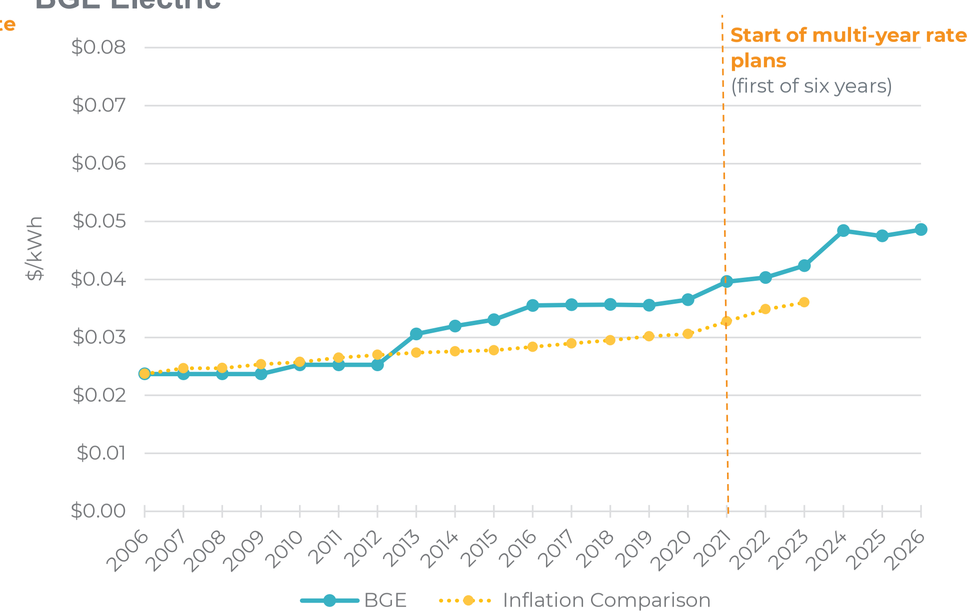
Accelerated cost recovery helps drive rate increases

Each of the Exelon utilities' rates increases following PSC approval of their **multi-year rate plans**.

BGE Gas



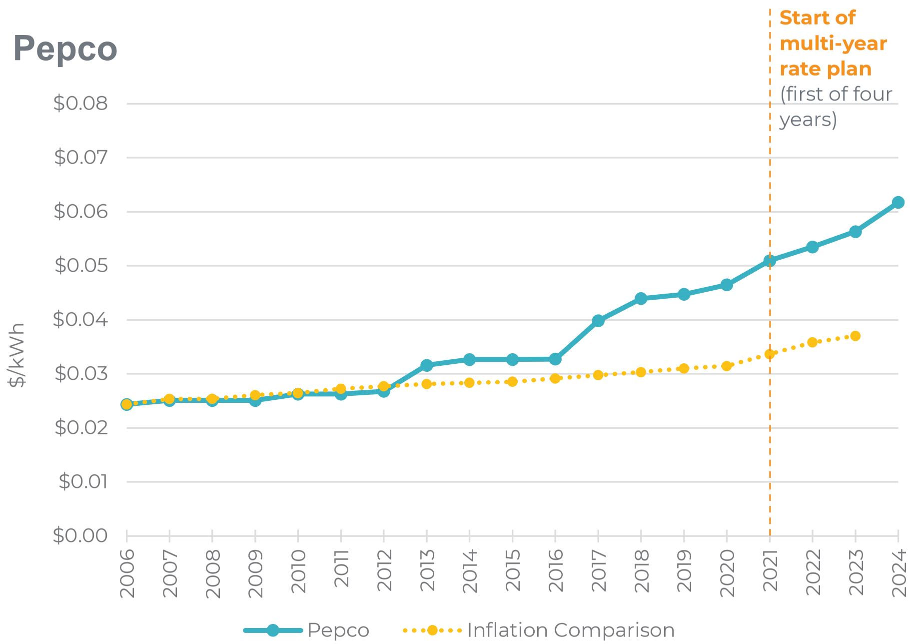
BGE Electric



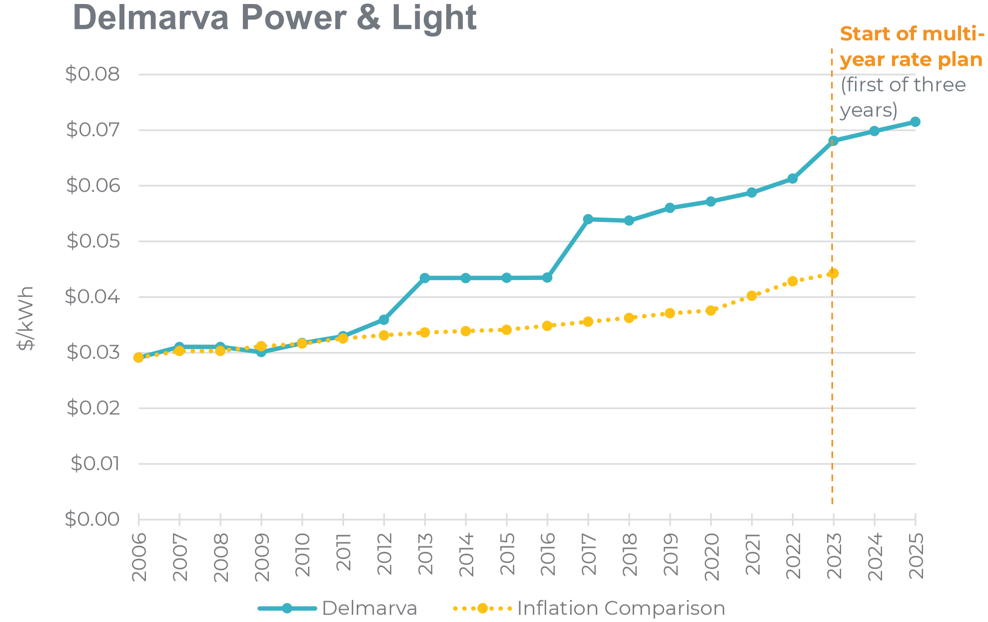
Accelerated cost recovery helps drive rate increases

Each of the Exelon utilities rates increases following PSC approval of their **multi-year rate plans**.

Pepco



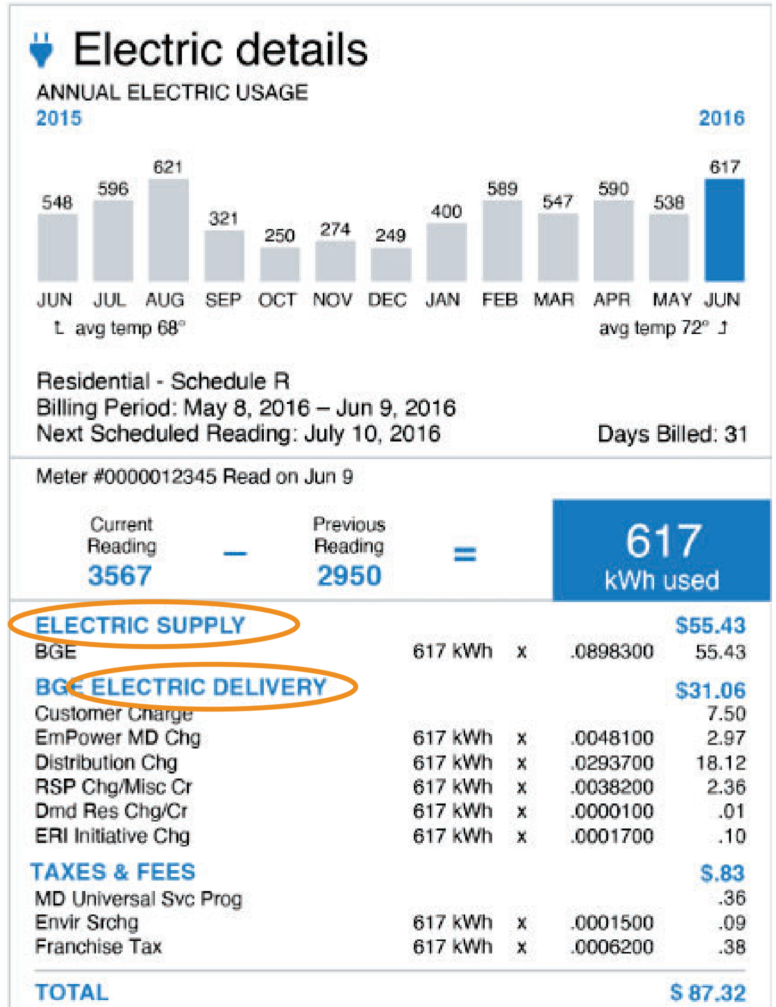
Delmarva Power & Light



Utility bill basics: rates and charges

Electric and gas utility bills include charges for two primary categories of services:

DELIVERY SERVICE
(or distribution service)
&
SUPPLY SERVICE
(or commodity service)



Electric details

ANNUAL ELECTRIC USAGE

Residential - Schedule R
Billing Period: May 8, 2016 – Jun 9, 2016
Next Scheduled Reading: July 10, 2016 Days Billed: 31

Meter #0000012345 Read on Jun 9

Current Reading 3567 – Previous Reading 2950 = 617 kWh used

ELECTRIC SUPPLY				$55.43
BGE	617 kWh	x	.0898300	55.43
BGE ELECTRIC DELIVERY				$31.06
Customer Charge				7.50
EmPower MD Chg	617 kWh	x	.0048100	2.97
Distribution Chg	617 kWh	x	.0293700	18.12
RSP Chg/Misc Cr	617 kWh	x	.0038200	2.36
Dmd Res Chg/Cr	617 kWh	x	.0000100	.01
ERI Initiative Chg	617 kWh	x	.0001700	.10
TAXES & FEES				$.83
MD Universal Svc Prog				.36
Envir Srchg	617 kWh	x	.0001500	.09
Franchise Tax	617 kWh	x	.0006200	.38
TOTAL				$ 87.32

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Delivery Service Charges

The delivery charges on customer bills include costs of the utility's "rate base"	The "rate base" comprises the utility's outstanding (not yet fully paid for) capital expenditures.
The utility's profit largely depends on the size of its rate base	The rate base grows with additional capital spending and shrinks as capital assets are depreciated. The larger the rate base, the larger the utility's profits.
Customers also pay operational costs in the utility's distribution charges	Operational costs include most of the utility's personnel costs and the utility's tax responsibility for the profit component of its rate of return, and any local taxes.
Delivery charges include the utility's profit and cost of debt—in combination often called the utility's "rate of return" or "weighted average cost of capital"	The "rate of return" or "weighted average cost of capital" is a percentage that is multiplied by the rate base to determine an annual level of return.

Supply Service Charges

- The utility's supply charge—sometimes called standard offer service, a fuel charge, or commodity charge—is for the cost of the gas or electricity you use.
  - The amount of gas used (the gas molecules) is measured in therms.
  - The amount of electricity used is measured in kilowatt hours (kWhs).
  - Utilities procure gas and electricity through competitive procurements regulated by the Public Service Commission, and the costs are passed through to customers with a small administrative fee.
    - Click to learn more about gas supply procurement.
    - Click to learn more about electricity supply procurement.
  - Commodity costs can go up and down with the market, lowering or raising your overall bill.

Other surcharges

Your utility bill also includes surcharges that add to your bill.

Here are explanations of some of those surcharges:

STRIDE surcharge

- Gas companies may have a “STRIDE” surcharge. The STRIDE surcharge is an additional charge for distribution service related to replacement of old infrastructure. What you pay in the STRIDE surcharge is eventually added into the overall delivery service charges.
- Click to learn more about STRIDE.

EmPOWER surcharge

- This surcharge supports programs to promote energy efficiency, such as rebates for energy-efficient appliances, home energy audits, and related programs.
- Click to learn more about programs through EmPOWER that can benefit you.

Local taxes

- While distribution charges cover the utilities’ tax obligation related to their profits, local taxes may be included as a separate line item on your bill.

Delivery Service

This report primarily focuses on the costs of delivery service.

Utility delivery service charges are set by the Public Service Commission in rate cases.

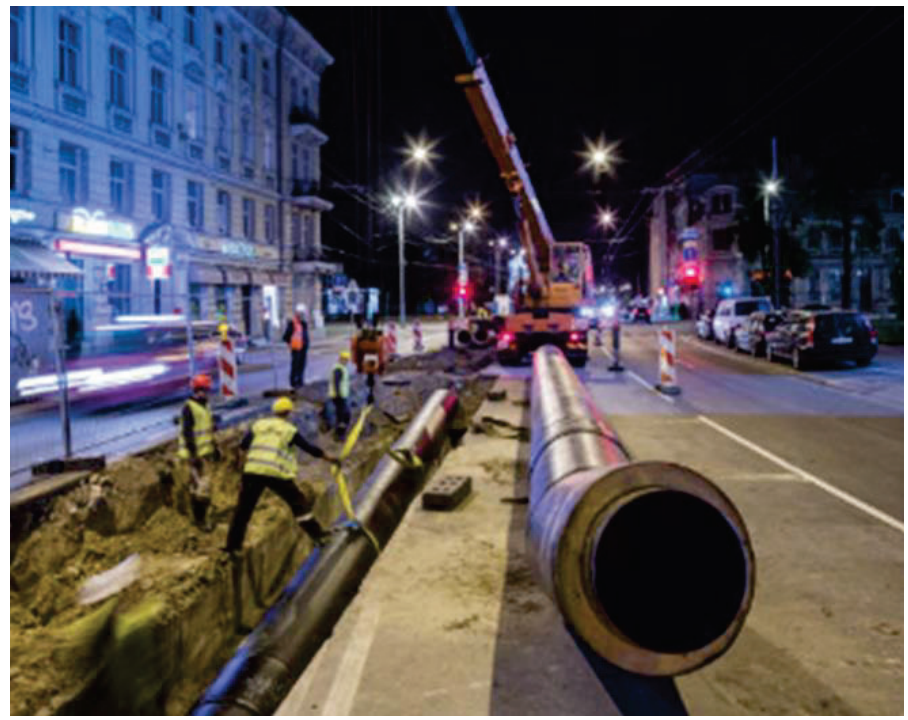
Rate cases are months-long litigated proceedings where parties put on evidence and make legal arguments about the justness and reasonableness of proposed rate changes.

OPC represents the interests of residential customers in utility rate cases.

Delivery costs

Delivery costs are recovered with two different charges on customer bills

1. A **distribution rate,** which is a volumetric charge that is calculated based on how much gas or electricity the customer uses; and
2. A fixed **monthly customer charge**, which is a flat monthly fee each residential customer pays regardless of how much gas or electricity the customer uses.



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Gas Utility Rates and Charges

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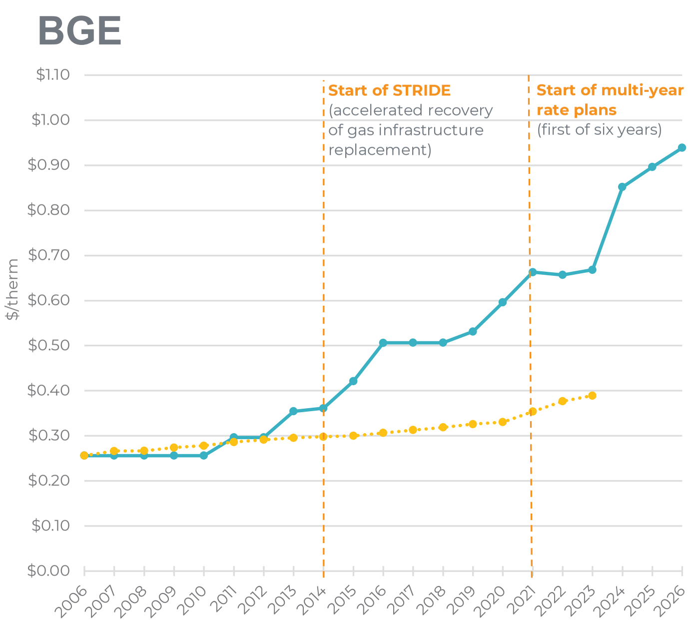
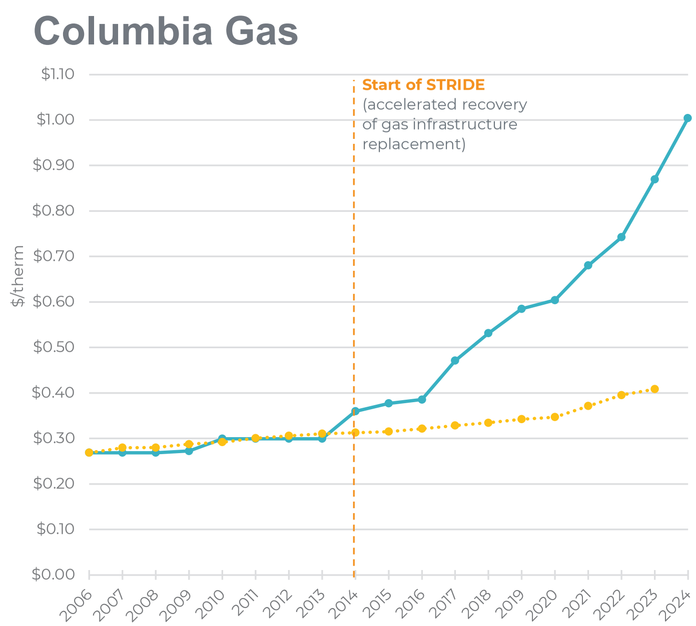
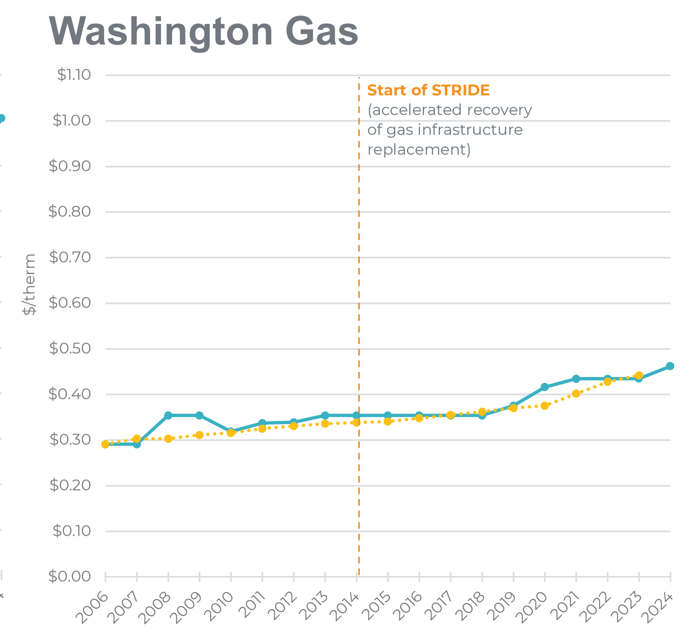
GAS UTILITIES

Distribution Rate Changes, Compared to Inflation







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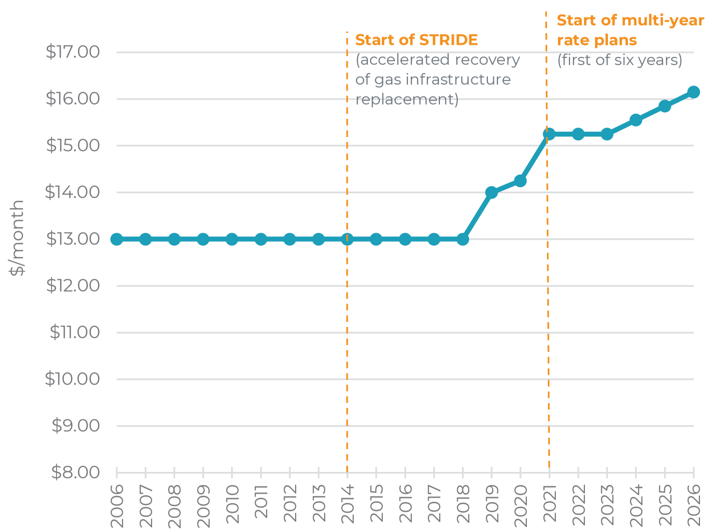
Distribution Rate Change   Inflation Comparison

BGE's figures for 2024-2026 are pending a request for rehearing of its most recent rate case.

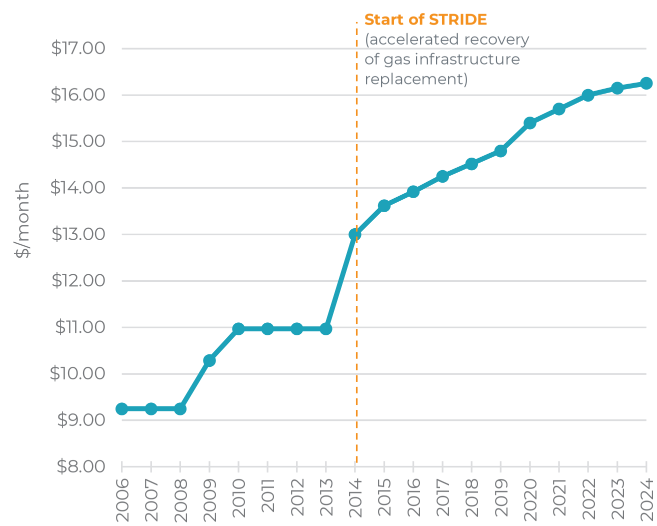
GAS UTILITIES

Monthly Customer Charge

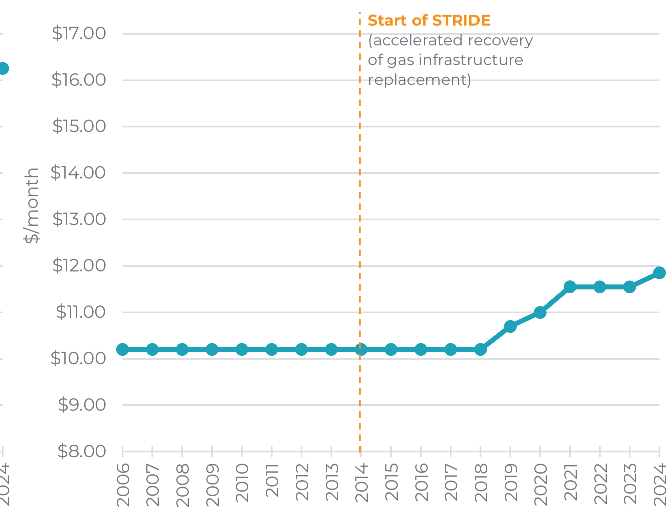
BGE



Columbia Gas



Washington Gas

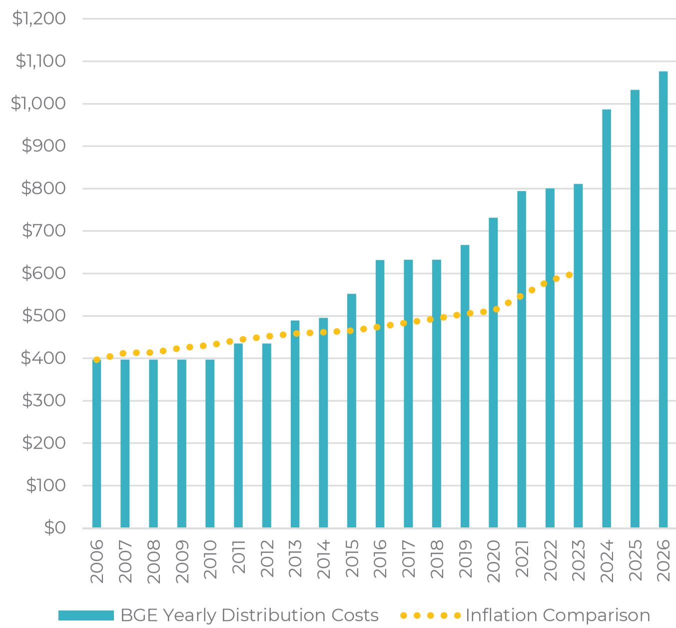


The STRIDE surcharge is not included in any of the charts in this report. In rate cases, prudently incurred STRIDE costs included in the surcharge are incorporated into utility base rates and are reflected in the distribution rate and customer charges. BGE's figures for 2024-2026 are pending a request for rehearing of its most recent rate case.

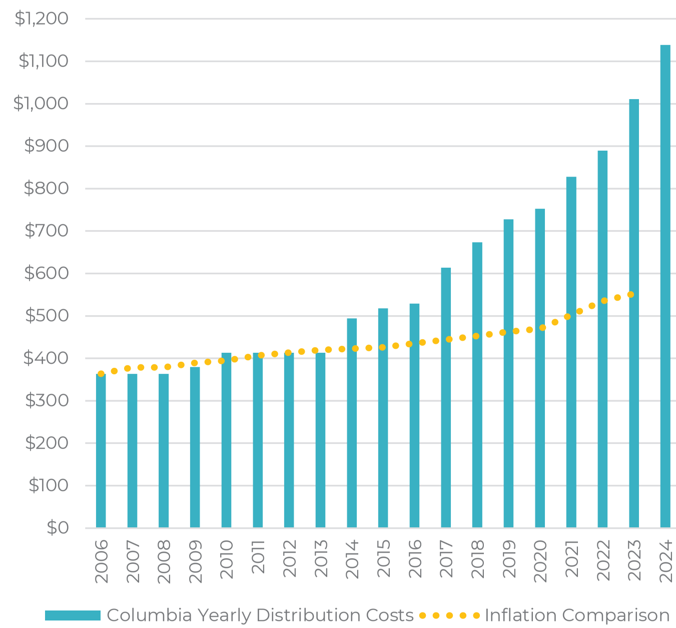
GAS UTILITIES

Total Delivery Charges

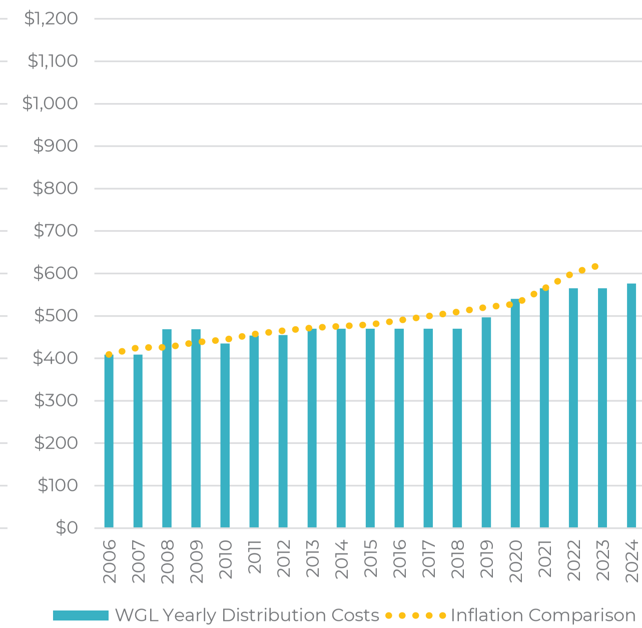
BGE



Columbia Gas



Washington Gas



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Delivery charges are based on a customer using 940 therms/year. BGE's figures for 2024-2026 are pending a request for rehearing of its most recent rate case.

GAS UTILITIES

Total Bill: Delivery Plus Supply Charges

BGE

Columbia Gas

Washington Gas

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*Delivery charges are based on a customer using 940 therms/year.

Electric Utility Rates and Charges

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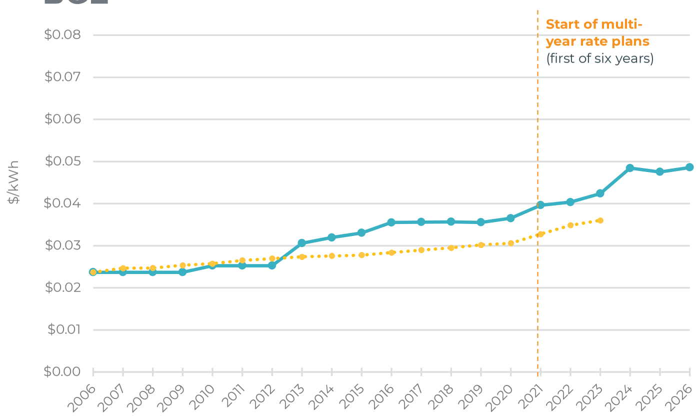
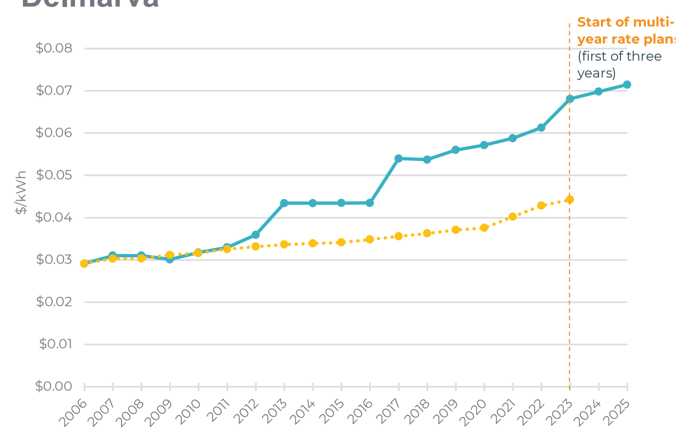
ELECTRIC UTILITIES

Distribution Rate Changes Compared to Inflation

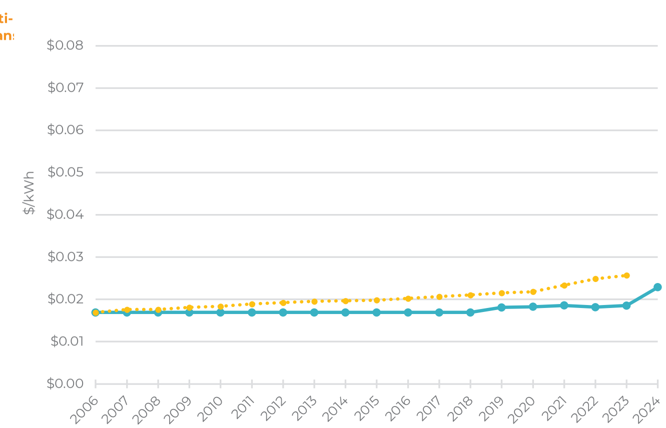
BGE



Delmarva



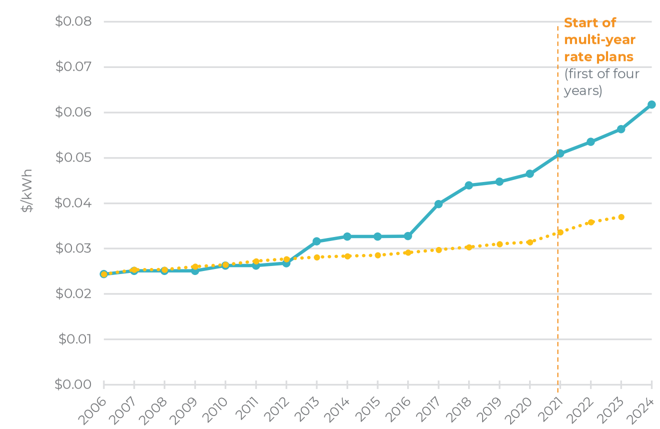
Potomac Edison



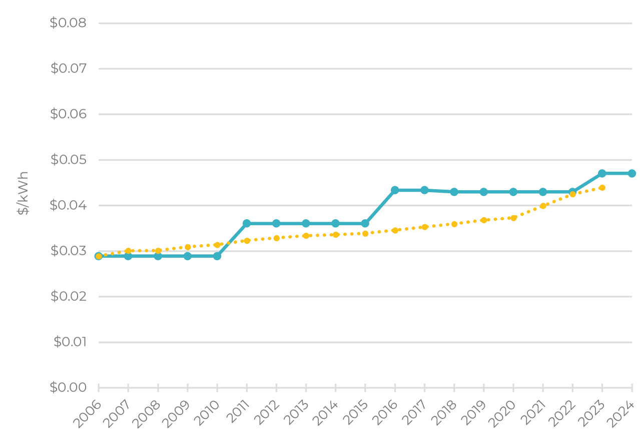
BGE's calculations for 2024-2026 are pending a request for rehearing of its most recent rate case.

Distribution Rate Change
Inflation Comparison

Pepco



SMECO



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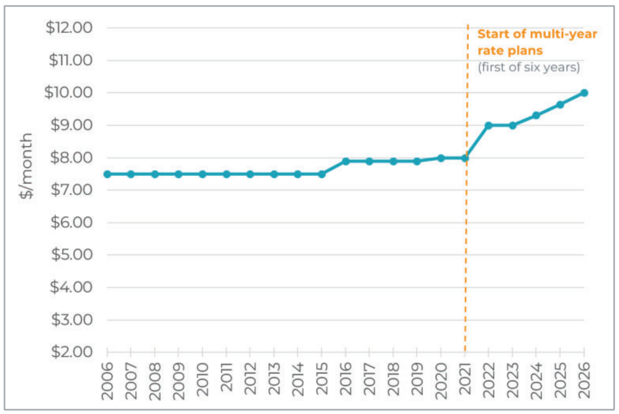
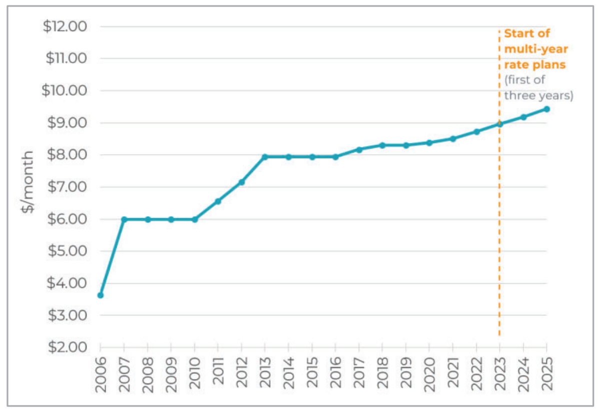
ELECTRIC UTILITIES

Monthly Customer Charge

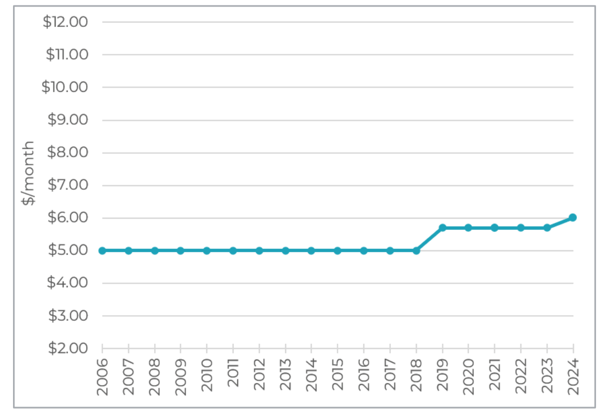
BGE



Delmarva

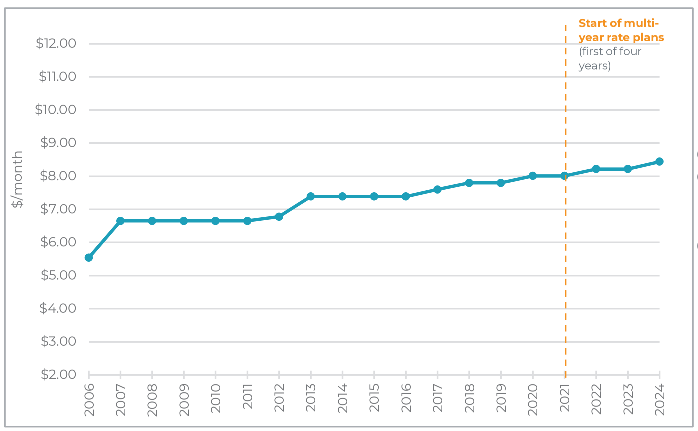


Potomac Edison

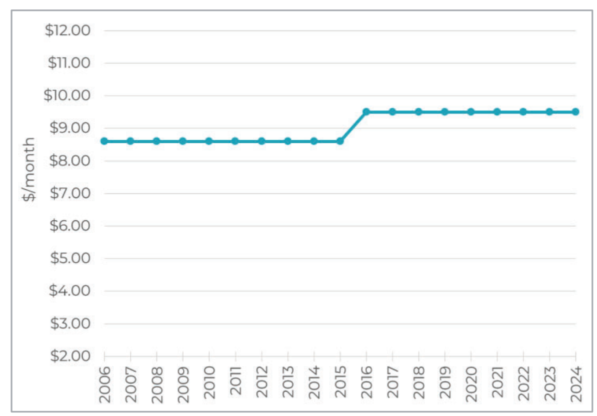


BGE's figures for 2024-2026 are pending a request for rehearing of its most recent rate case.

Pepco



SMECO



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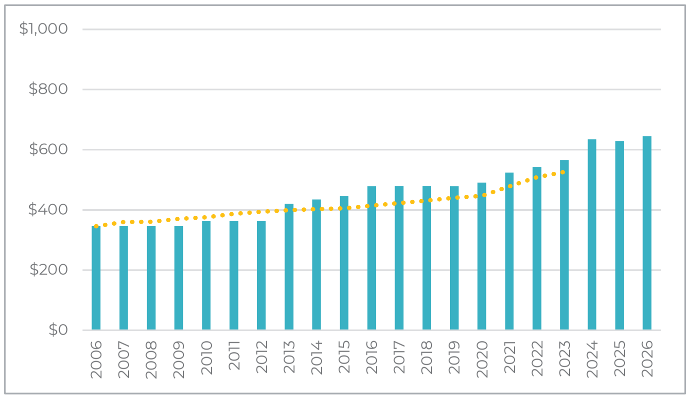
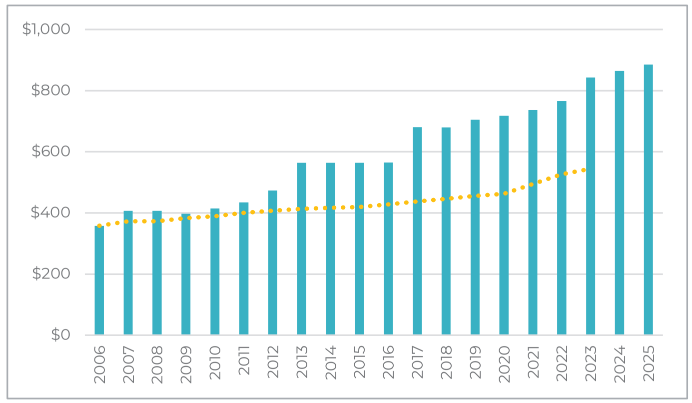
ELECTRIC UTILITIES

Total Delivery Charges

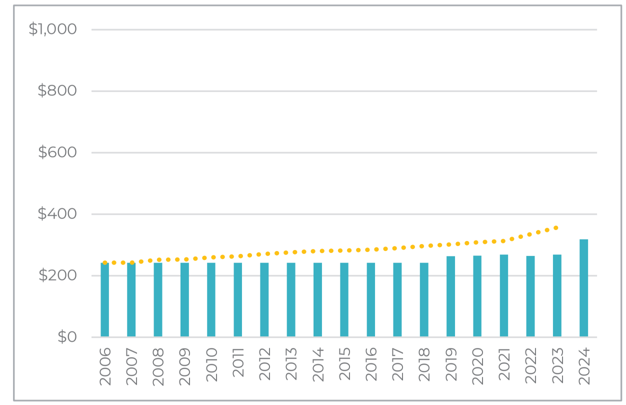
BGE



Delmarva



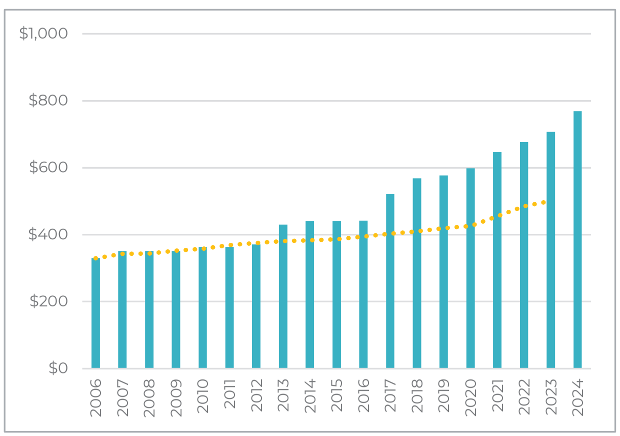
Potomac Edison



Distribution Costs
Inflation Comparison

Based on 900 kWh/month usage. BGE's figures for 2024-2026 are pending a request for rehearing of its most recent rate case.

Pepco



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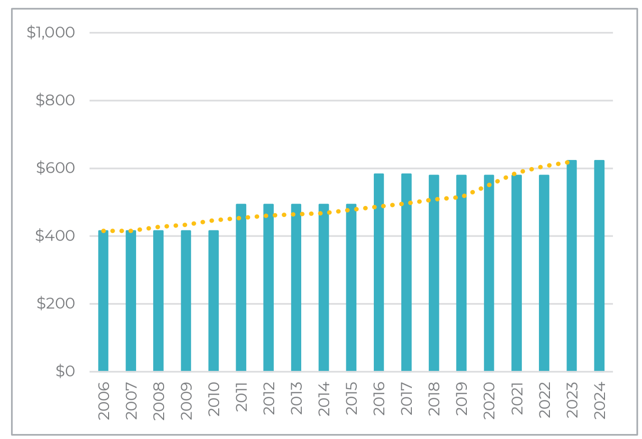

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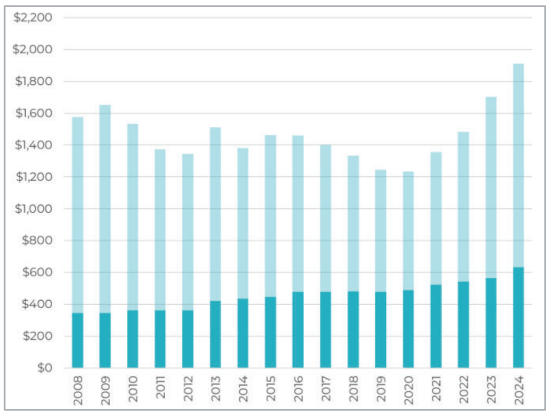
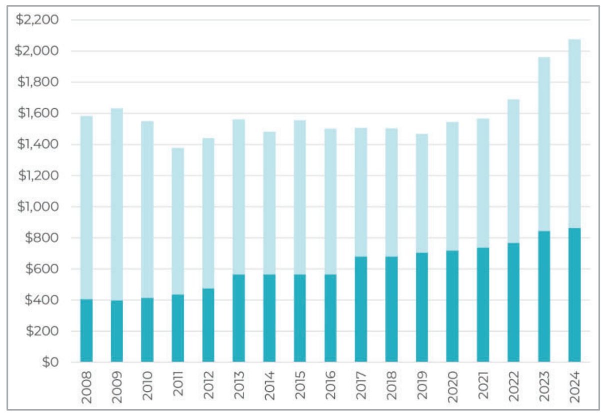
ELECTRIC UTILITIES

Total Bill: Delivery Plus Supply Charges

BGE



Delmarva

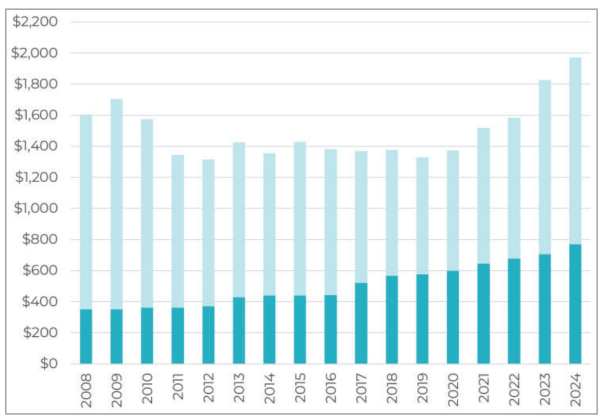


Potomac Edison

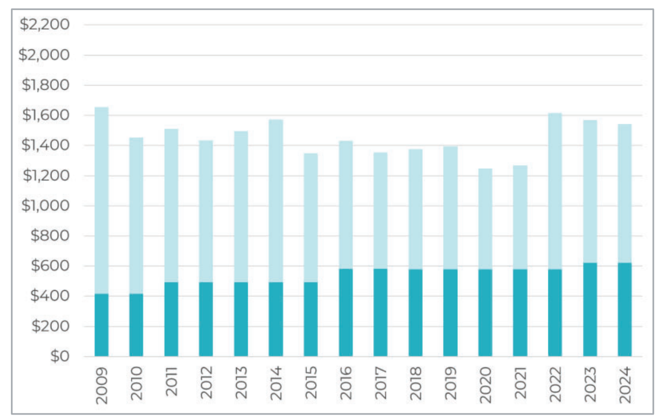
Delivery
Supply

Based on 900 kWh/month usage. BGE's figures for 2024-2026 are pending a request for rehearing of its most recent rate case.

Pepco



SMECO



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Recommendations

The Public Service Commission should permanently end its 2020 multi-year rate plan pilot program as inconsistent with the public interest.

The Maryland General Assembly should repeal the STRIDE law or, at the very least, substantially modify the law consistent with the Maryland Commission on Climate Change's recommendations, as in the proposed Ratepayer Protection Act of 2024 (SB 548/HB 731).

The Public Service Commission should require utilities to provide uniform disclosures—understandable to the public—of historic and existing rates and proposed rate changes.

Appendix

Rates in appendix reflect those in effect in 2024; updated rates are available on OPC's website here.

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Baltimore Gas and Electric

Baltimore Gas and Electric

BGE, a subsidiary of Illinois-based Exelon Corporation, is a combined electric and gas utility. BGE serves approximately 1.3 million electric customers and 700,000 gas customers in Baltimore City, Baltimore County, and Anne Arundel County, most of Howard, Carroll and Harford Counties, and parts of Prince George's, Montgomery and Calvert Counties.

BGE's last rate case was in 2023 and was a multi-year rate case. The Public Service Commission order in the case was issued on Dec 14, 2023. You can access the order and the case here. As of the beginning of May 2024, OPC's request for rehearing of the Commission's order—its request for the Commission to change certain aspects of its Dec. 14, 2023, order—remains pending before the Commission.

BGE

Current rates

Electric and gas bills include two primary categories of charges: *distribution charges* and *supply charges*. These categories of charges and additional charges are explained here. The distribution rate covers most of the average customer's distribution costs. In 2024, the volumetric rate makes up 81 percent of distribution costs for the average BGE gas customer and 82 percent of distribution costs for the average BGE electric customer.

Gas Service

Volumetric distribution rate: $0.8963/therm

Customer charge: $15.85/month

Supply cost: $0.6015/therm (February 2025)

EmPOWER surcharge (gas): $0.1087/kWh

Electric Service

Volumetric distribution rate: $0.04751/kWh

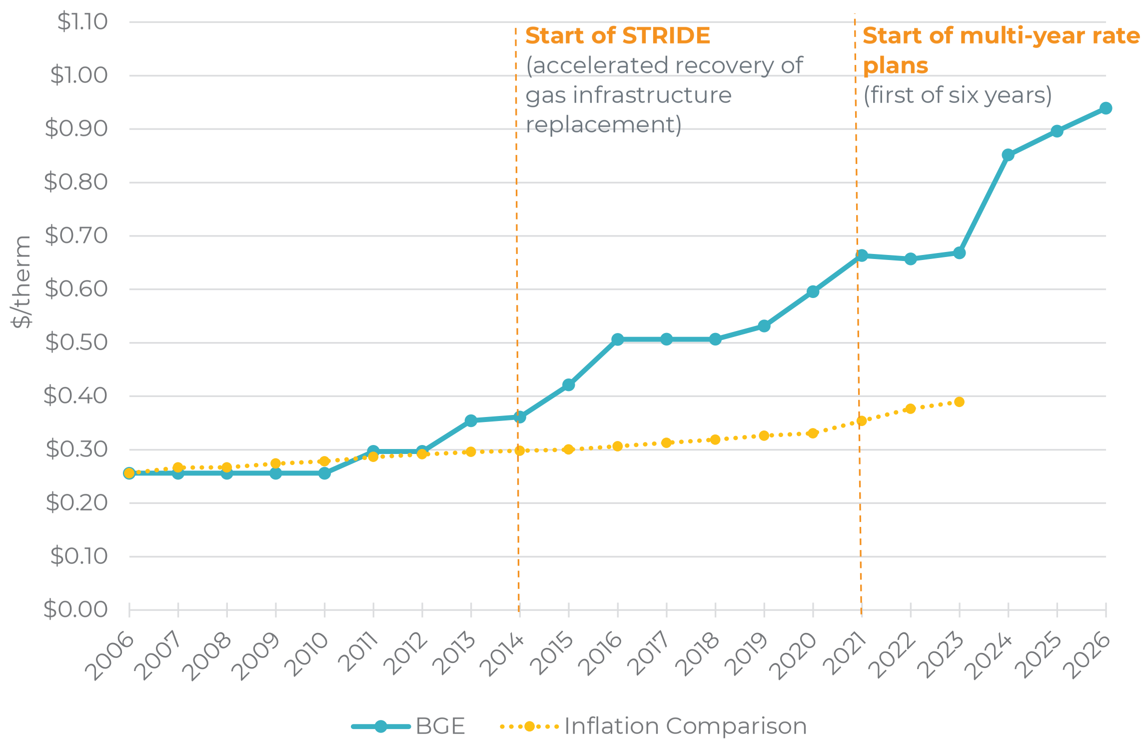
Customer charge: $9.65/month

Supply cost: $0.10397/kWh (February 2025)

EmPOWER surcharge (electric): $0.01028/kWh

BGE

Gas Delivery Costs: Distribution Rate

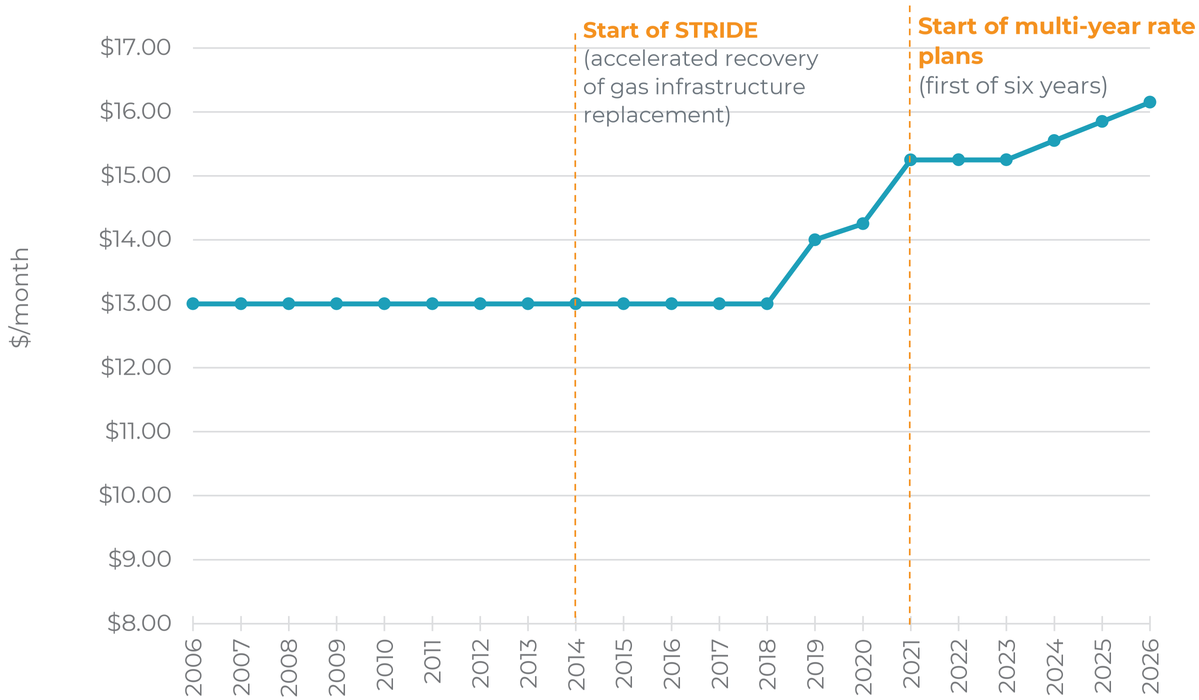


BGE's figures for 2024-2026 were approved as part of BGE's second multi-year rate plan, which is pending OPC's request for rehearing.

The STRIDE surcharge is not included in this chart. In rate cases, prudently incurred STRIDE costs included in the surcharge are incorporated into utility base rates and reflected in the volumetric and customer charges. Click here for more information about STRIDE.

BGE

Gas Monthly Customer Charge



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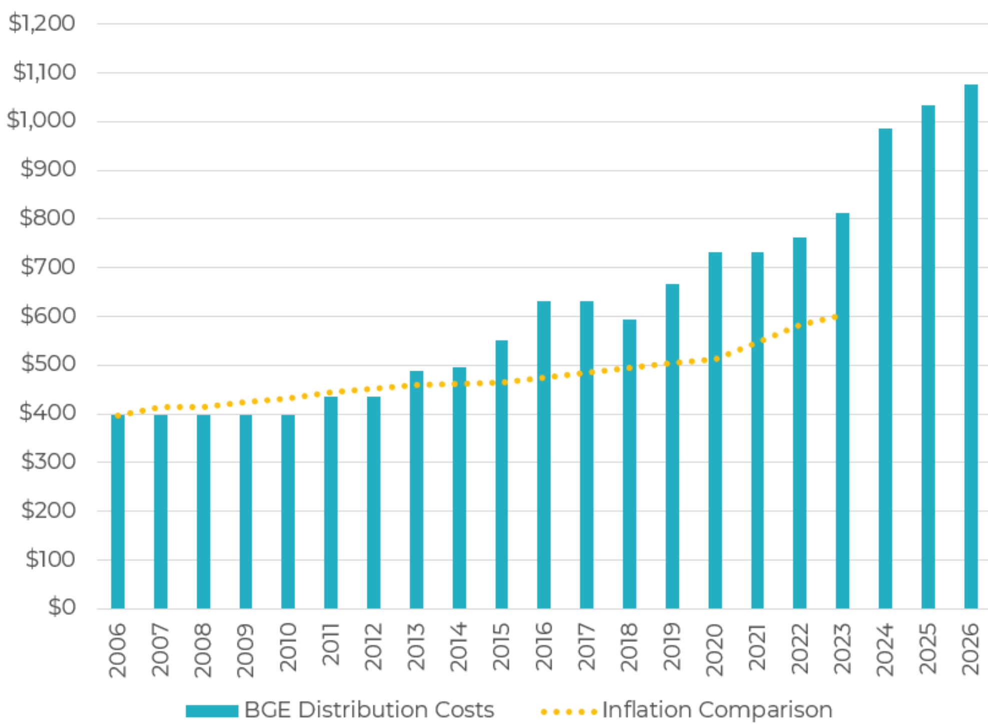
The STRIDE surcharge is not included in this chart. In rate cases, prudently incurred STRIDE costs included in the surcharge are incorporated into utility base rates and reflected in the volumetric and customer charges. Click here for more information about STRIDE.

BGE

Gas Total Annual Delivery Charges



BGE's figures for 2024-2026 were approved as part of BGE's second multi-year rate plan, which is pending OPC's request for rehearing.

Charges based on annual consumption of 940 therms.

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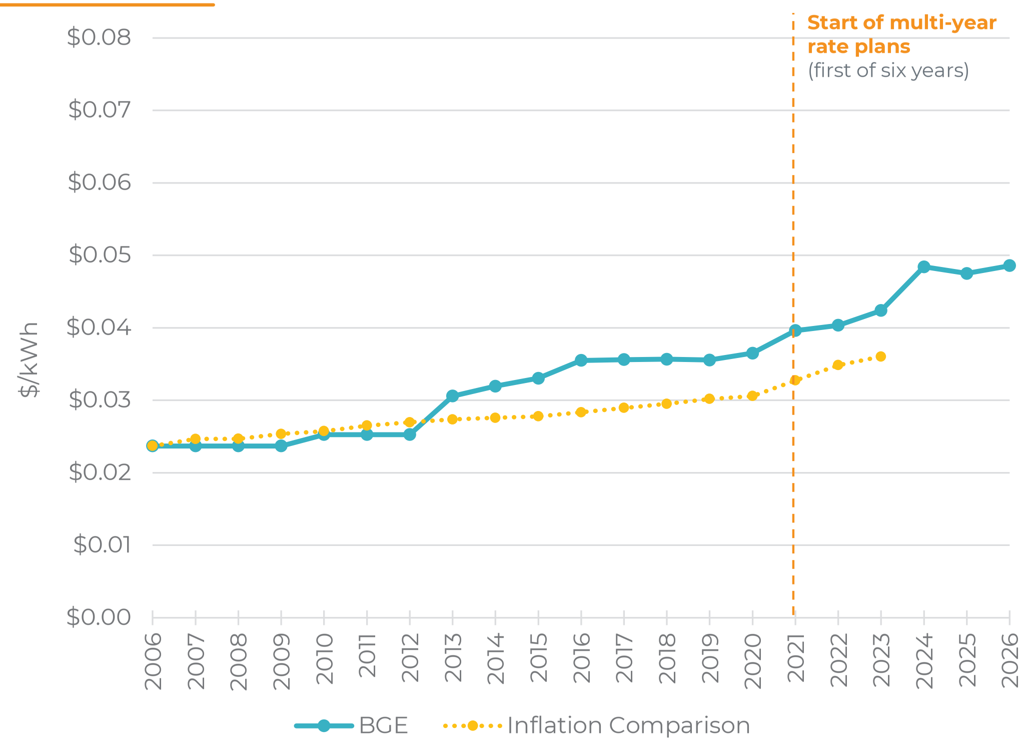
BGE

Gas Total Annual Bill: Delivery Plus Supply Charges

Charges based on annual consumption of 940 therms.

BGE

Electric Distribution Rate



BGE's figures for 2024-2026 were approved as part of BGE's second multi-year rate plan, which is pending OPC's request for rehearing.

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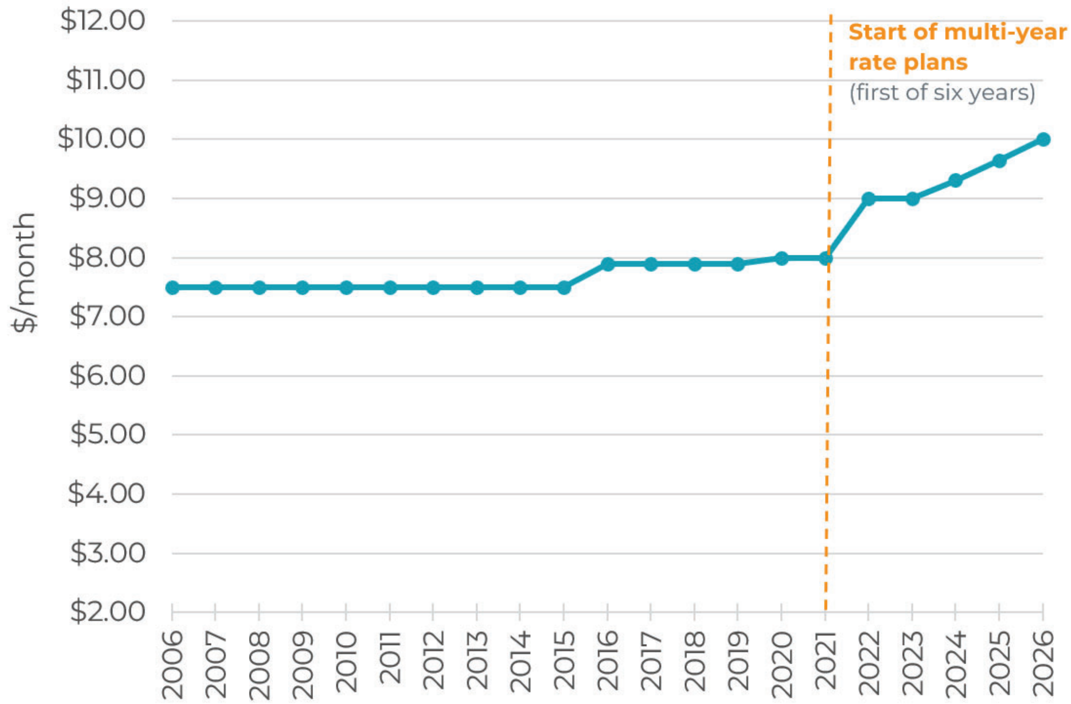
BGE

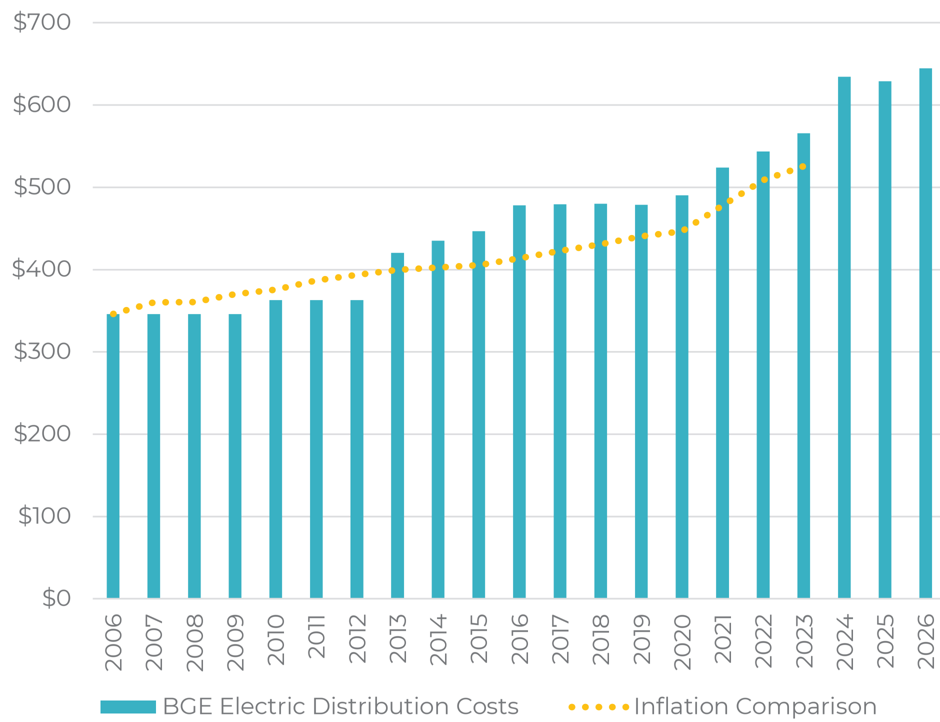
Electric Monthly Customer Charge



BGE's figures for 2024-2026 were approved as part of BGE's second multi-year rate plan, which is pending OPC's request for rehearing.

BGE

Electric Total Annual Delivery Charges



BGE's figures for 2024-2026 were approved as part of BGE's second multi-year rate plan, which is pending OPC's request for rehearing.

Charges based on monthly consumption of 900 kWhs.

BGE

Electric Total Annual Bill: Delivery Plus Supply Charges

Charges based on monthly consumption of 900 kWhs.

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Columbia Gas

Columbia Gas

Columbia Gas is an affiliate of Indiana-based NiSource, Inc., a large gas utility with operations extending to areas of the Midwest as well as its Maryland service territory. Columbia Gas serves approximately 34,000 customers in a service territory within the Western Maryland counties of Washington, Allegany, and Garrett.

Columbia's last rate case was in 2023. The final PSC ruling was issued on October 26, 2023. You can access the case here.

Columbia Gas

Current rates

Gas bills include two primary categories of charges: *distribution charges* and *supply charges*. These categories of charges and additional charges are explained here. The distribution rate covers most of the average customer's distribution costs. For the average Columbia Gas customer in 2024, the volumetric rate makes up 82 percent of distribution costs.

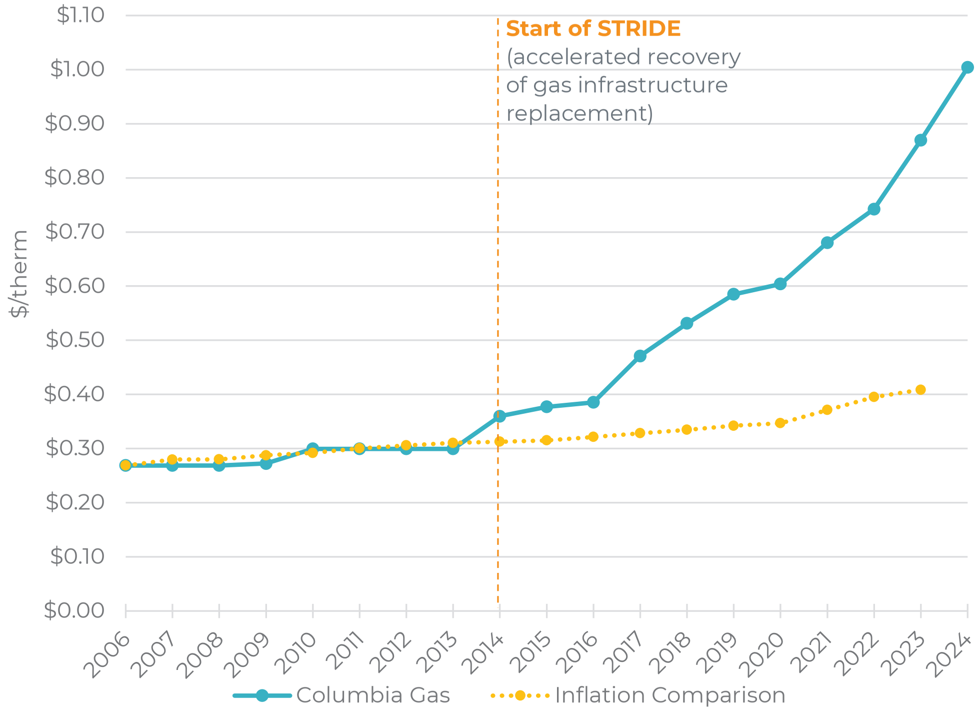
Volumetric distribution rate: $1.00385/therm

Customer charge: $16.25/month

Supply cost: $0.3309/therm (June 2024)

COLUMBIA GAS

Distribution Rate



The STRIDE surcharge is not included in this chart. In rate cases, prudently incurred STRIDE costs included in the surcharge are incorporated into utility base rates and reflected in the volumetric and customer charges. Click here for more information about STRIDE.

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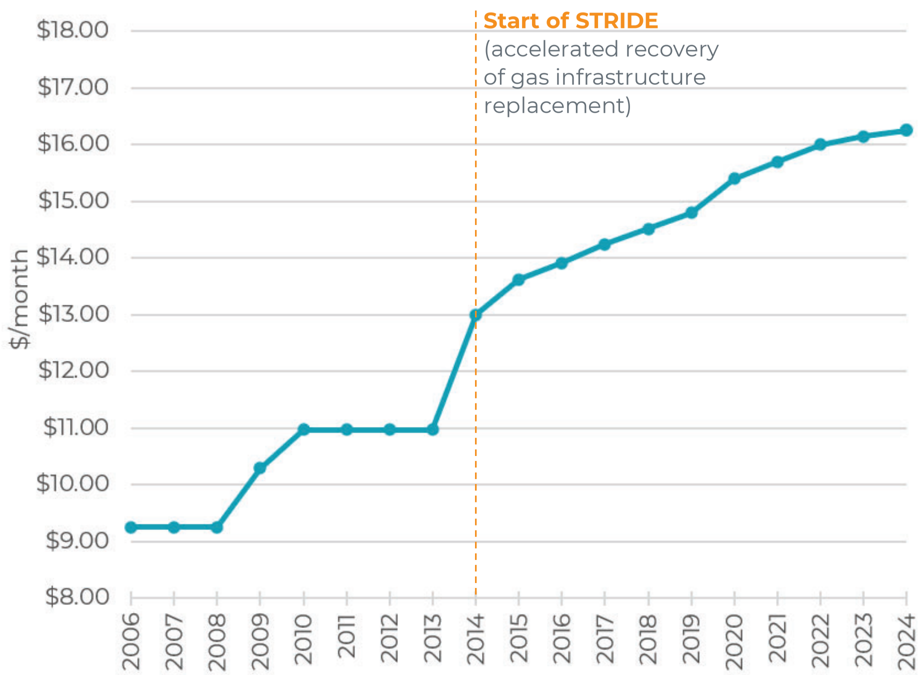
COLUMBIA GAS

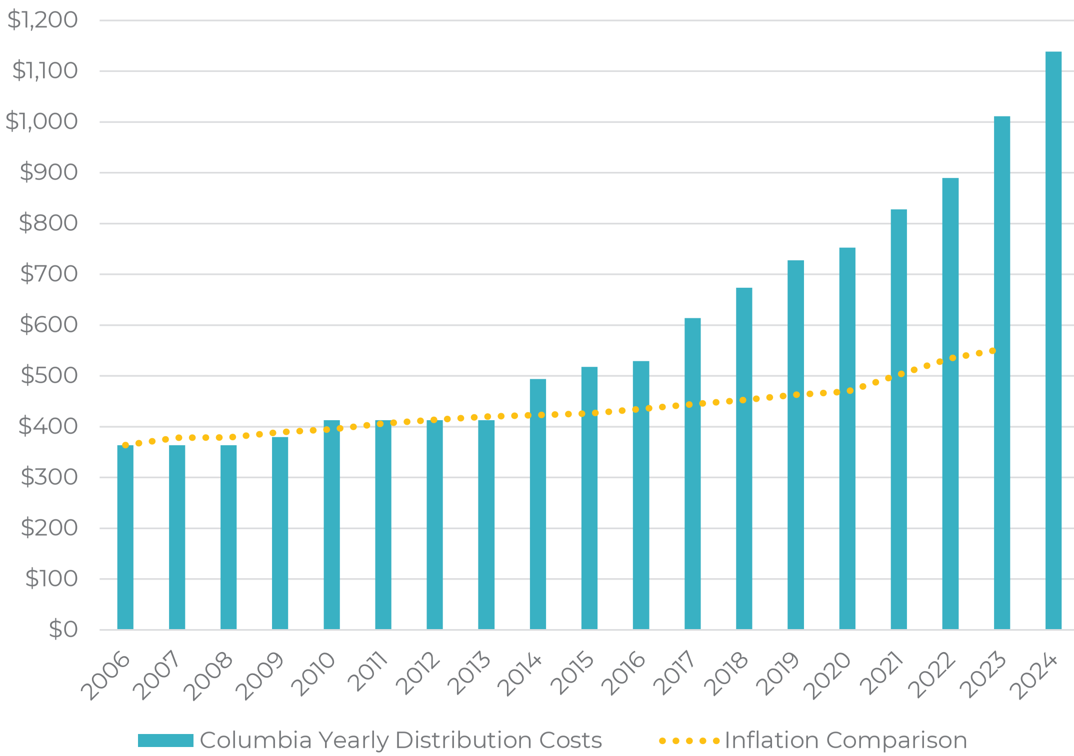
Monthly Customer Charge



The STRIDE surcharge is not included in this chart. In rate cases, prudently incurred STRIDE costs included in the surcharge are incorporated into utility base rates and reflected in the volumetric and customer charges. Click here for more information about STRIDE.

COLUMBIA GAS

Total Annual Delivery Charges



Based on annual consumption of 940 therms.

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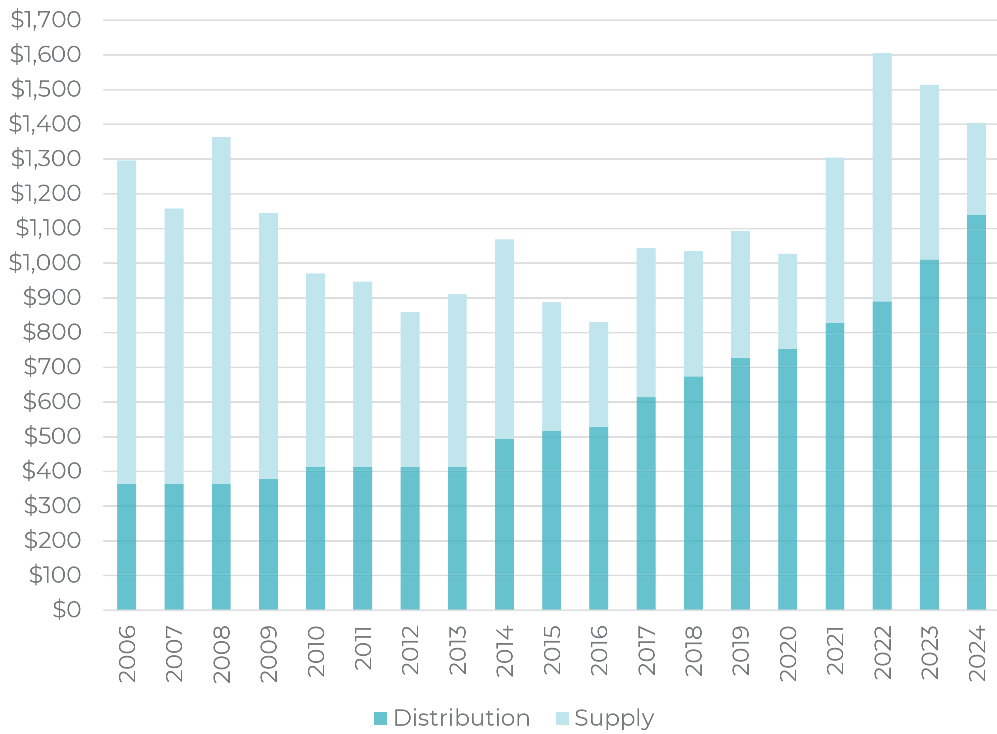
COLUMBIA GAS

Total Annual Bill: Delivery Plus Supply Charges



Based on annual consumption of 940 therms.

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Delmarva Power

Delmarva Power

Delmarva Power is a subsidiary of Illinois-based Exelon Corporation. Delmarva Power provides electric service throughout the Upper and Lower Eastern Shore of Maryland, and in Delaware. Delmarva Power serves 208,000 Maryland electric customers.

Delmarva Power's last rate case was in 2022 and was a multi-year rate case. The Public Service Commission order in the case was issued on Dec 14, 2022. You can access the order and the case here.

Delmarva Power

Current rates

Electric bills include two primary categories of charges: *distribution charges* and *supply charges*. These categories of charges and additional charges are explained here. The distribution rate covers most of the average customer's distribution costs. For the average Delmarva Power customer in 2024, the volumetric rate makes up 87 percent of distribution costs.

Distribution rate: $0.071482/kWh

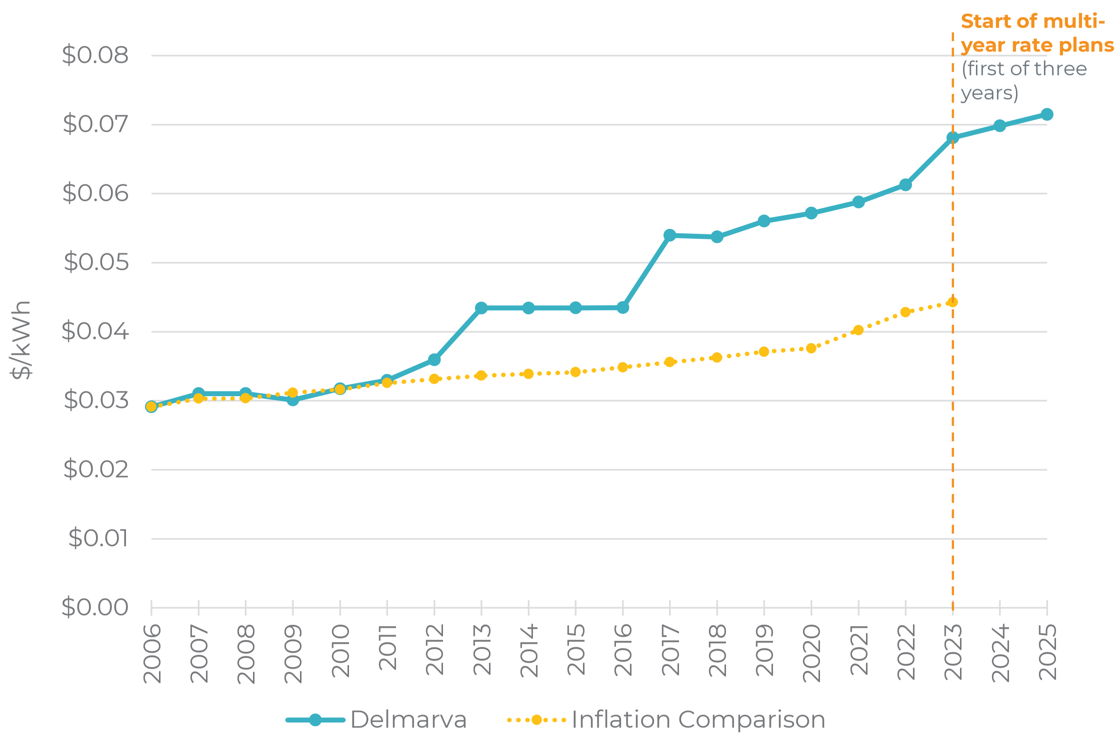
Monthly customer charge: $9.43/month

Supply cost: $0.10057/kWh (February 2025)

EmPOWER surcharge: $0.012649/kWh

DELMARVA POWER

Distribution Rate



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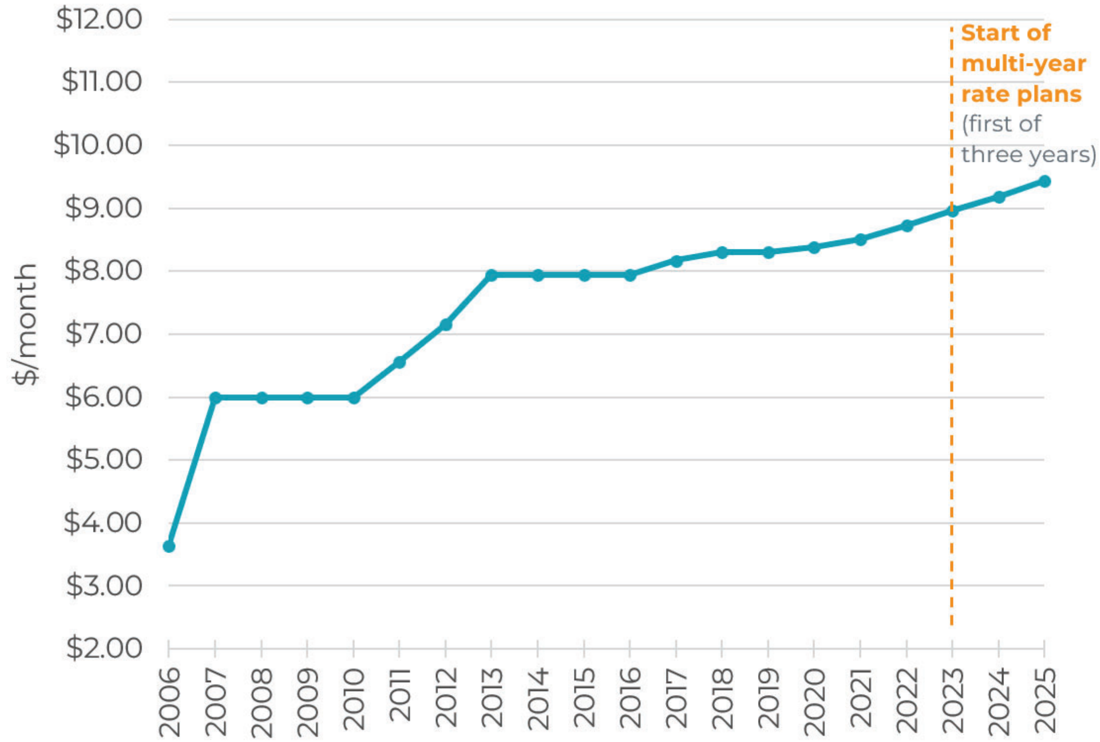
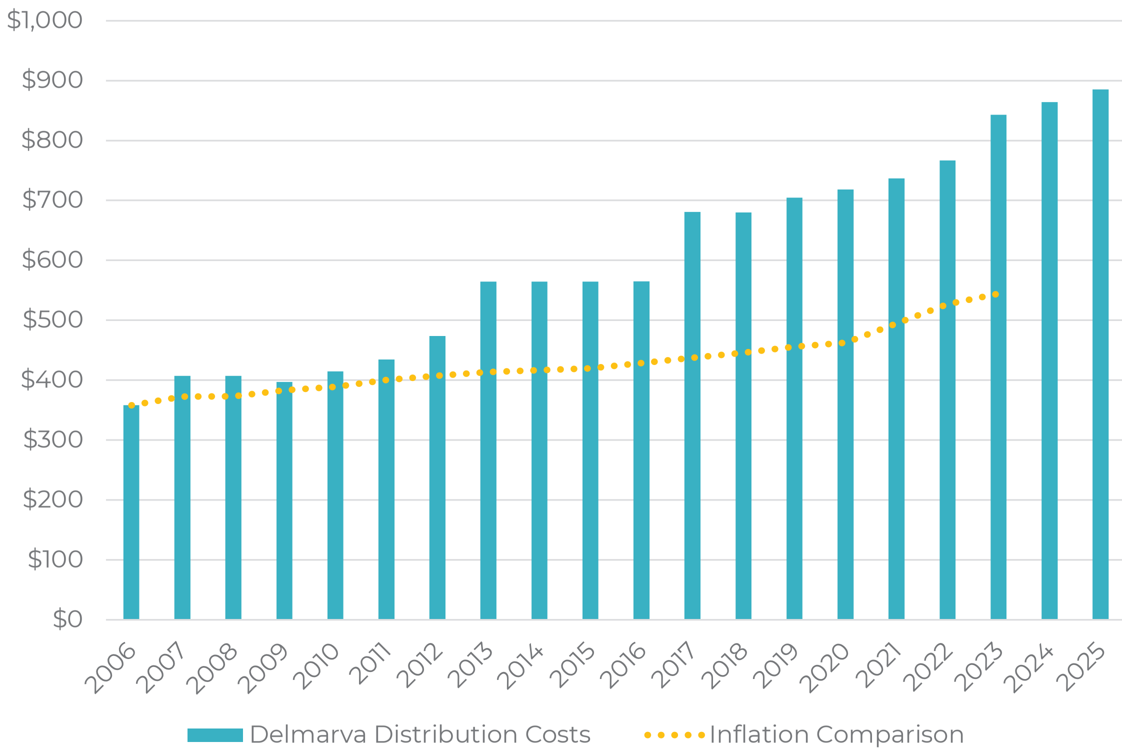
DELMARVA POWER

Monthly Customer Charge



DELMARVA POWER

Total Annual Delivery Charges



Charges based on monthly consumption of 900 kWhs.

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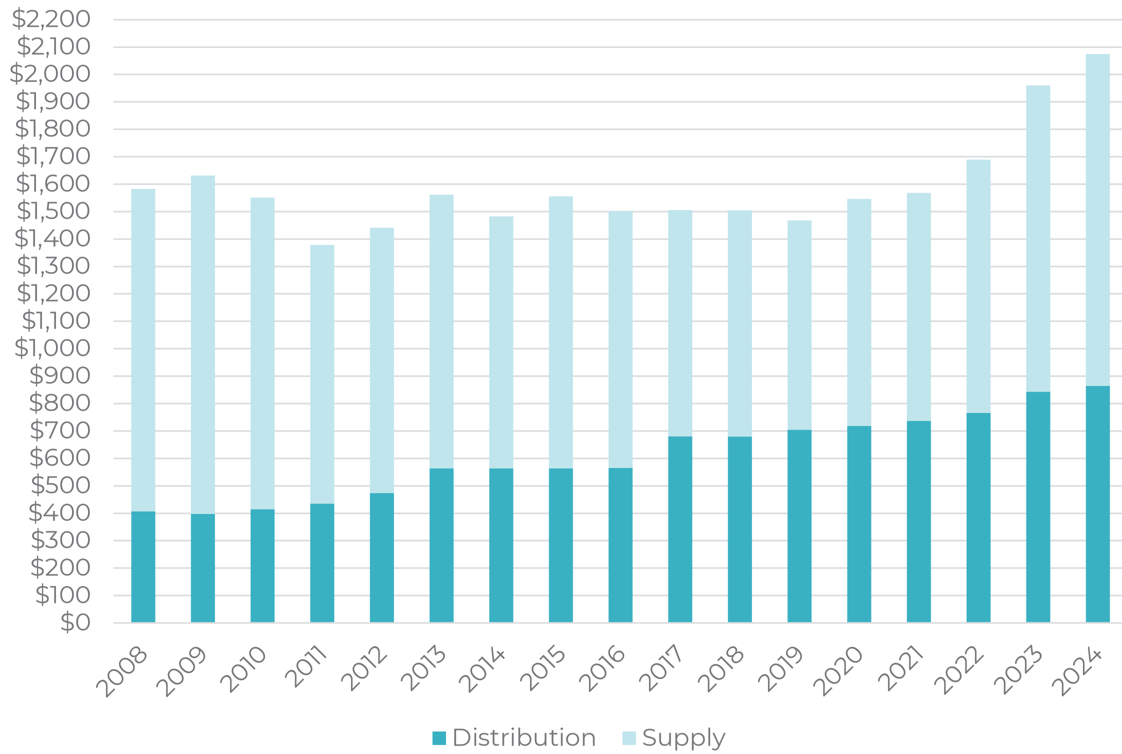
DELMARVA POWER

Total Annual Bill: Delivery Plus Supply Charges



Charges based on monthly consumption of 900 kWhs.

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Potomac Electric Power Company (Pepco)

Pepco

Potomac Electric Power Company (Pepco) is a subsidiary of Illinois-based Exelon Corporation. Pepco provides service in most of Montgomery County and Prince George's County as well as service in the District of Columbia. Pepco serves 582,000 Maryland customers.

Pepco filed its latest rate case in 2023 as a multi-year plan for rates extending into 2027. In a June 2024 decision, the Commission granted Pepco a single rate increase of $44.6 million, denying Pepco's request for a multi-year rate plan and stating its intent to evaluate how customers are faring under multi-year plans in a general "lessons learned" proceeding.

Pepco

Current rates

Electric bills include two primary categories of charges: *distribution charges* and *supply charges*. These categories of charges and additional charges are explained here. The distribution rate covers most of the average customer's distribution costs. For the average Pepco customer in 2024, the volumetric rate makes up 86 percent of distribution costs.

Volumetric distribution rate: $0.06175/kWh

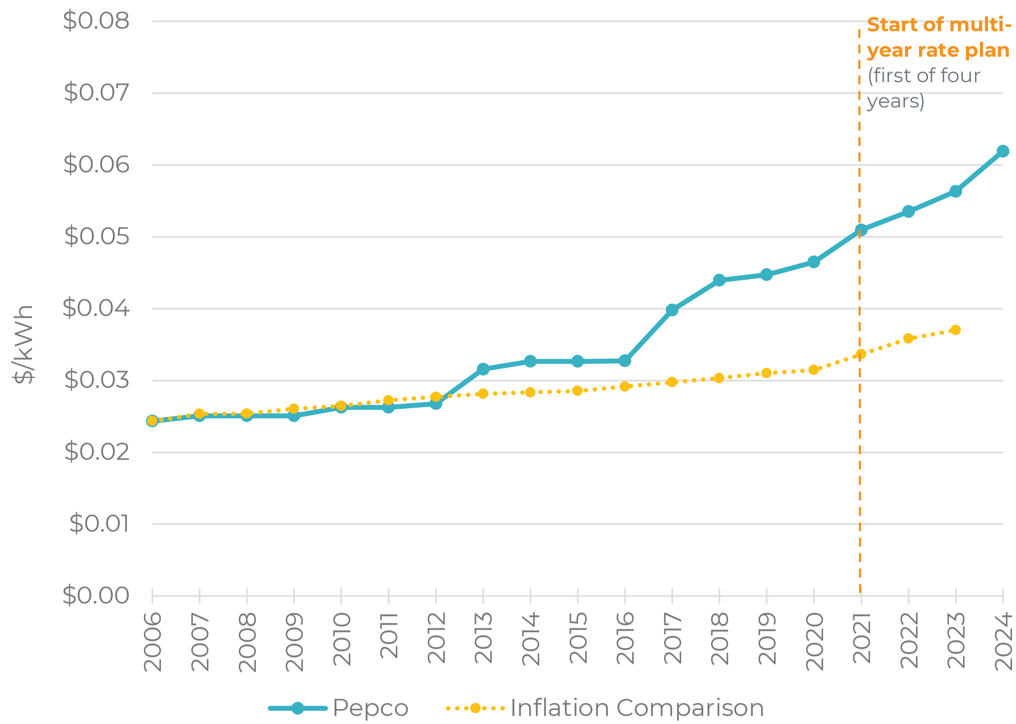
Customer charge: $8.44/month

Supply cost: $0.10704/kWh (February 2025)

EmPOWER surcharge: $0.01379/kWh

PEPCO

Distribution Rate



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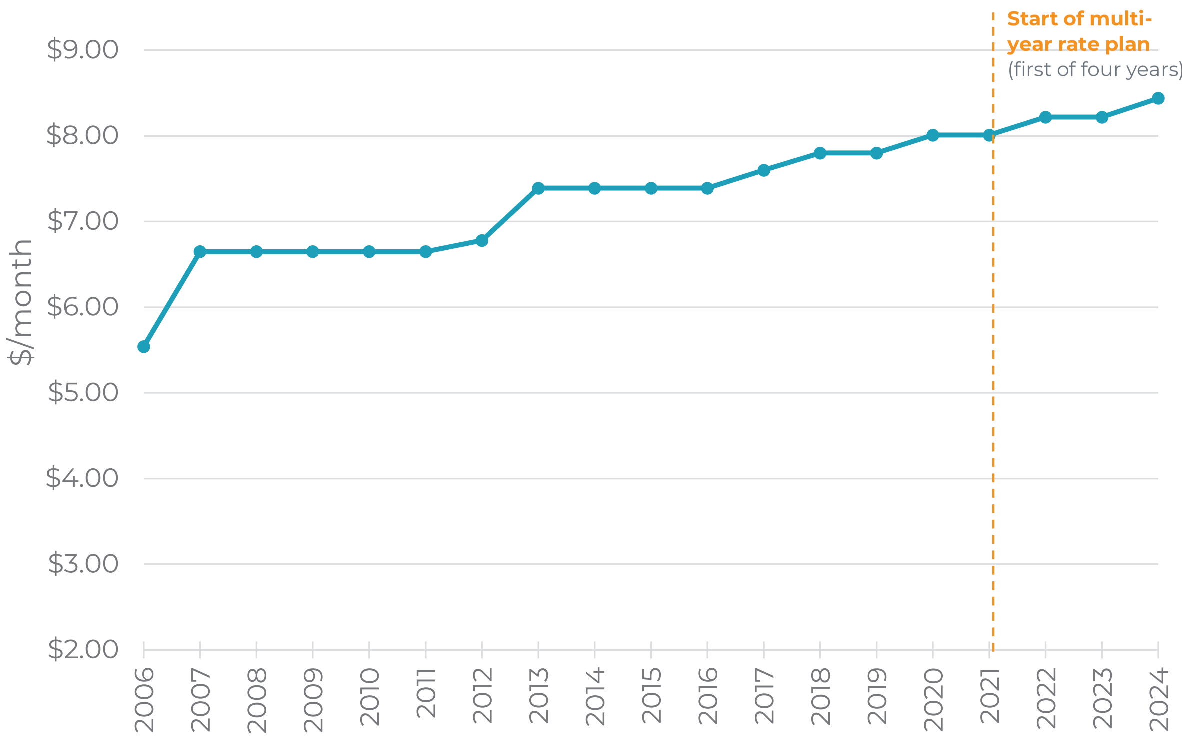
PEPCO
Monthly Customer Charge



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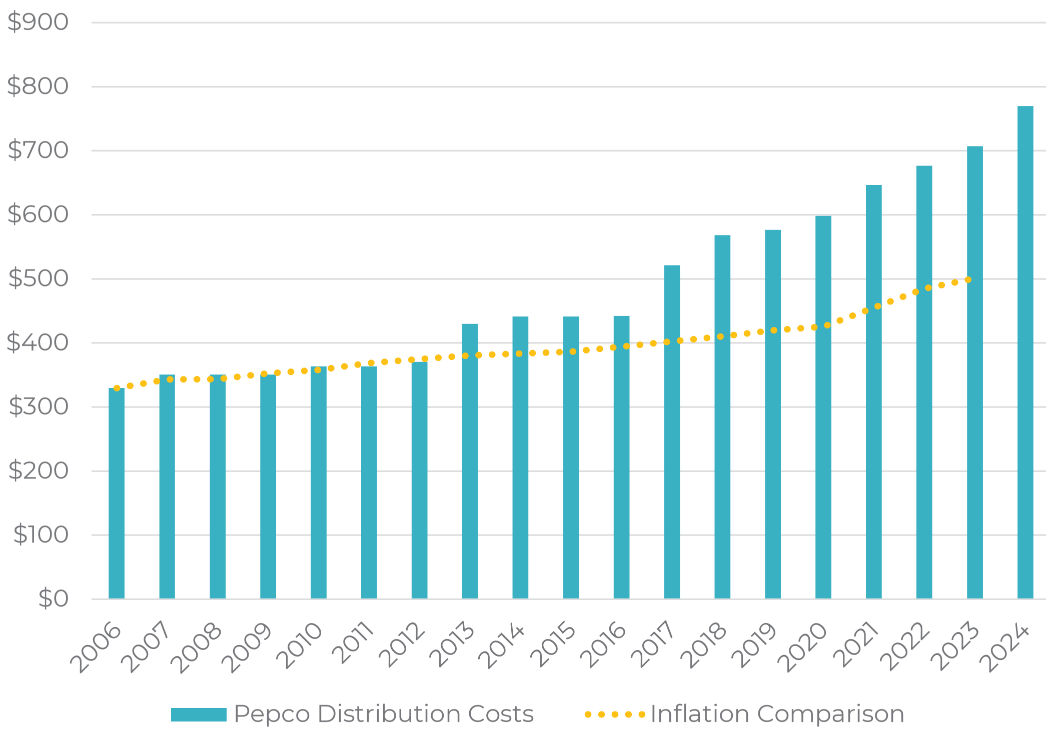
PEPCO

Total Annual Delivery Charges



Charges based on monthly consumption of 900 kWhs.

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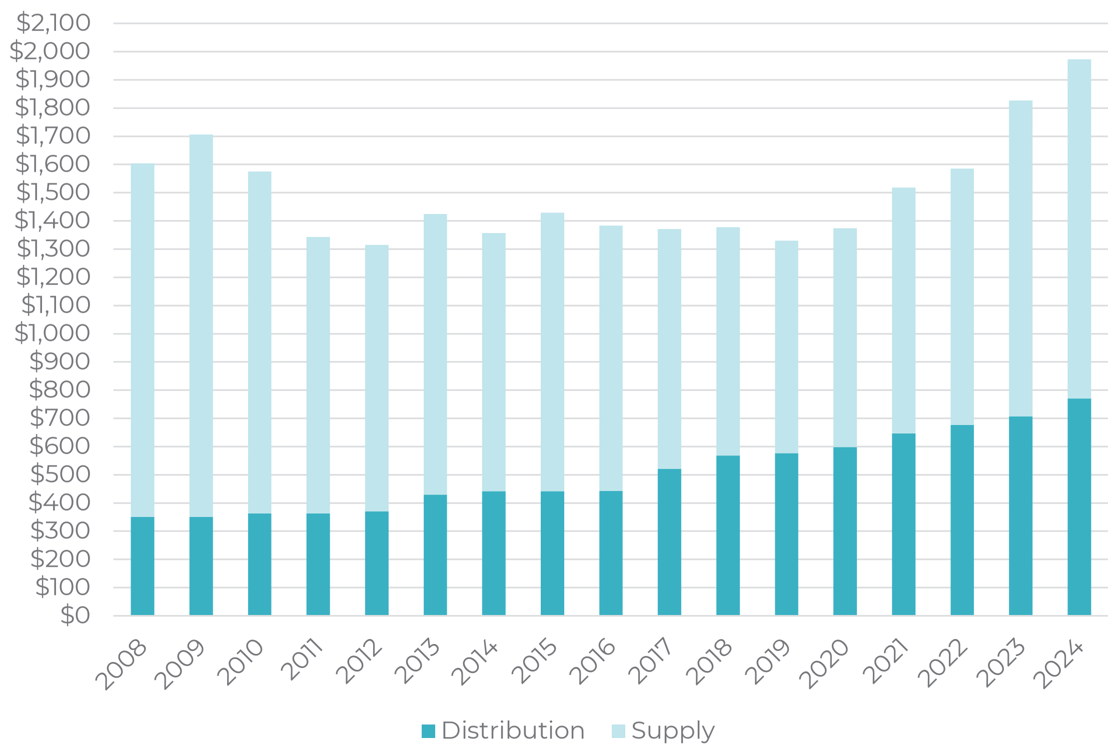
PEPCO

Total Annual Bill: Delivery Plus Supply Charges



Charges based on monthly consumption of 900 kWhs.

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Potomac Edison

Potomac Edison

Potomac Edison Company is a subsidiary of First Energy, and has affiliated utilities operating in Pennsylvania, Virginia and West Virginia. The utility provides electric service to 285,000 Maryland customers in Allegany, Washington and Frederick Counties, and portions of Carroll, Howard and Montgomery counties.

Potomac Edison's last rate case was in 2023. The Public Service Commission order in the case was issued on October 18, 2023. You can access the order and the case here.

Potomac Edison

Current rates

Electric bills include two primary categories of charges: *distribution charges* and *supply charges*. These categories of charges and additional charges are explained here. The distribution rate covers most of the average customer's distribution costs. For the average Potomac Edison customer in 2024, the volumetric rate makes up 77 percent of distribution costs.

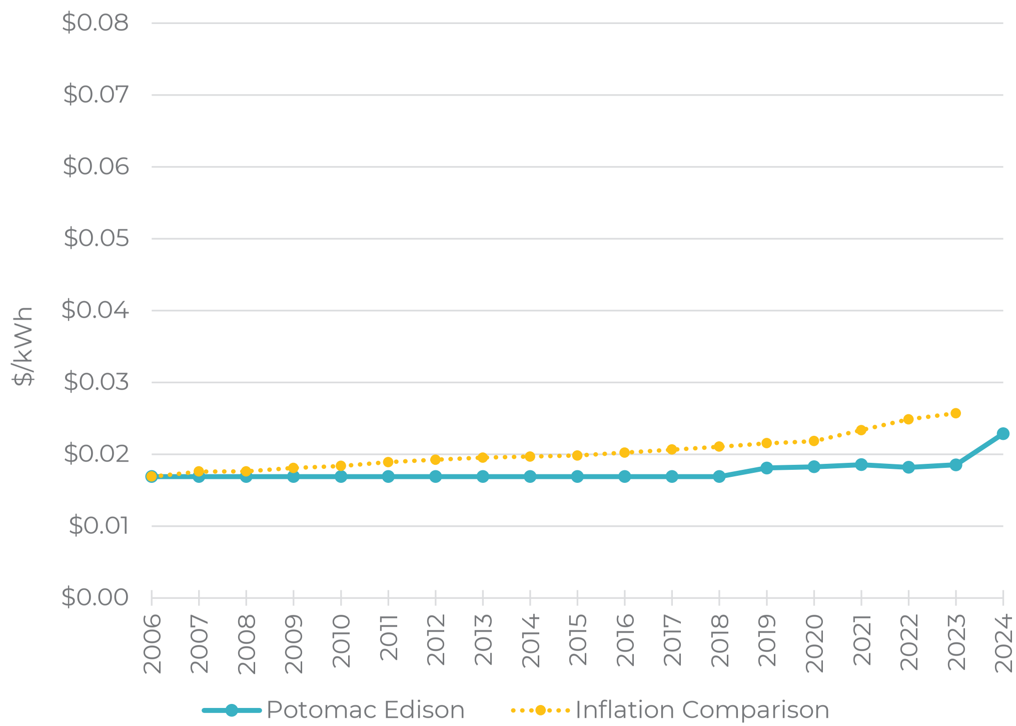
Volumetric distribution rate: $0.02287/kWh

Customer charge: $6.00/month

Supply cost: $0.09302/kWh (February 2025)

EmPOWER surcharge: $0.01009/kWh

POTOMAC EDISON
Distribution Rate



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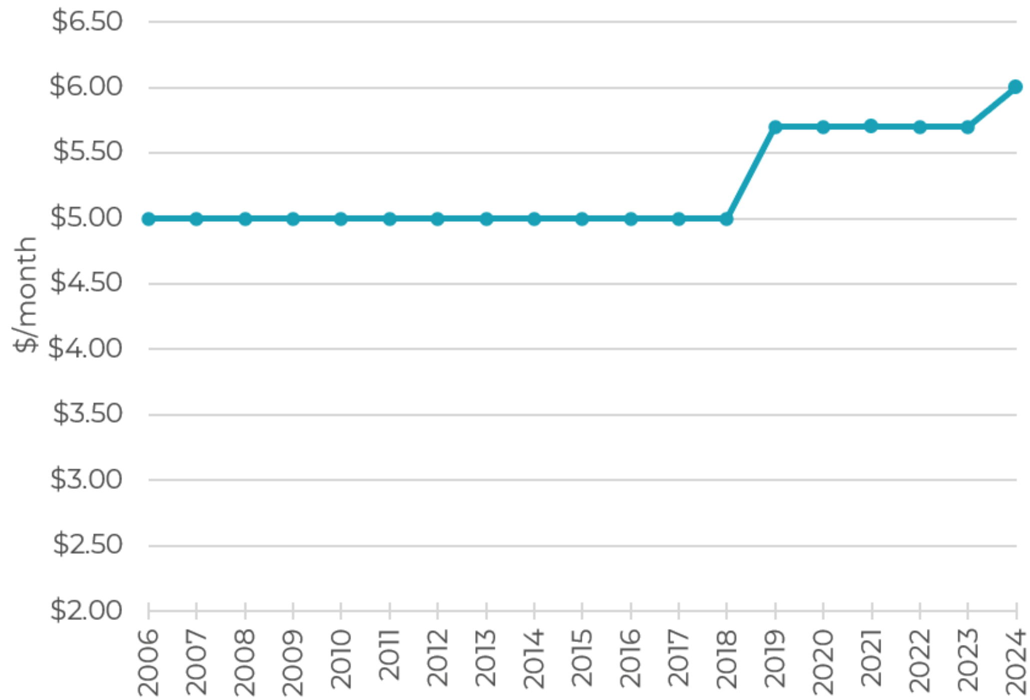
POTOMAC EDISON

Monthly Customer Charge



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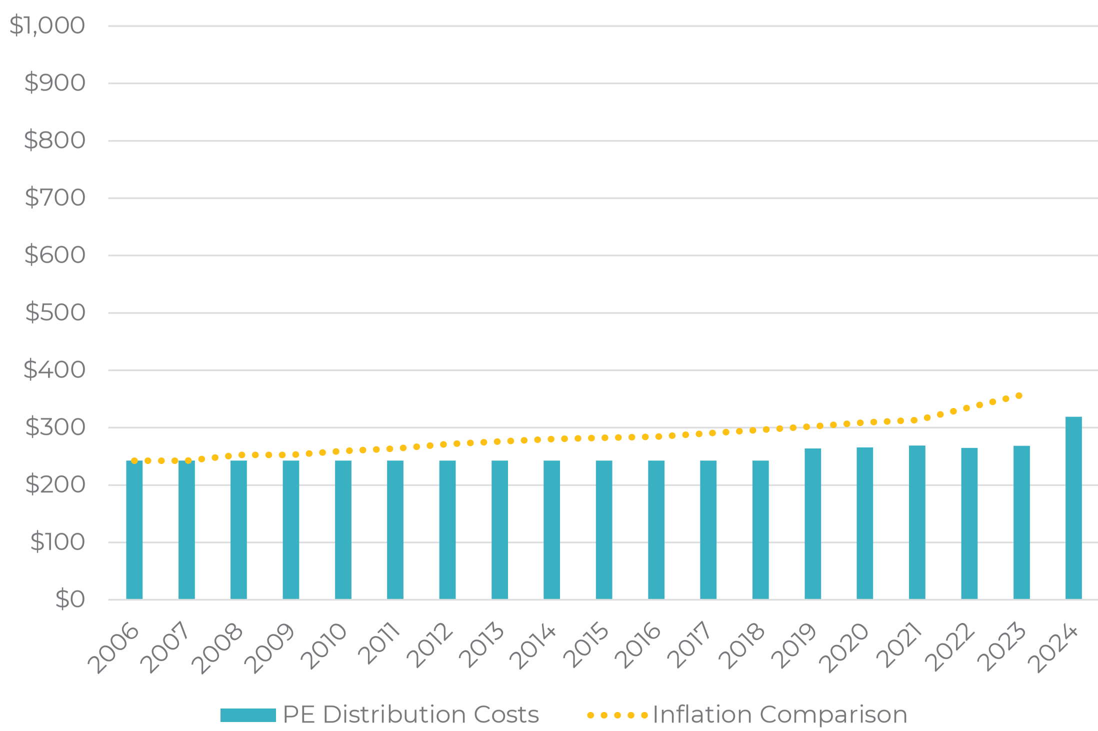
POTOMAC EDISON

Total Annual Delivery Charges



Charges based on monthly consumption of 900 kWhs.

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POTOMAC EDISON

Total Annual Bill: Delivery Plus Supply Charges

Charges based on monthly consumption of 900 kWhs.

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Southern Maryland Electric Cooperative

SMECO

Southern Maryland Electric Cooperative, Inc. (SMECO) provides electricity service to its 161,000 cooperative members in Southern Maryland, in Calvert, Charles, Prince George's, and St. Mary's counties.

SMECO's last rate case was in 2023. The Public Service Commission order in the case was issued on May 15, 2023. You can access the order and the case here.

SMECO

Current rates

Electric bills include two primary categories of charges: *distribution charges* and *supply charges*. These categories of charges and additional charges are explained here. The distribution rate covers most of the average customer's distribution costs. For the average SMECO customer in 2024, the volumetric rate makes up 82 percent of distribution costs.

Volumetric distribution rate: $0.04704/kWh

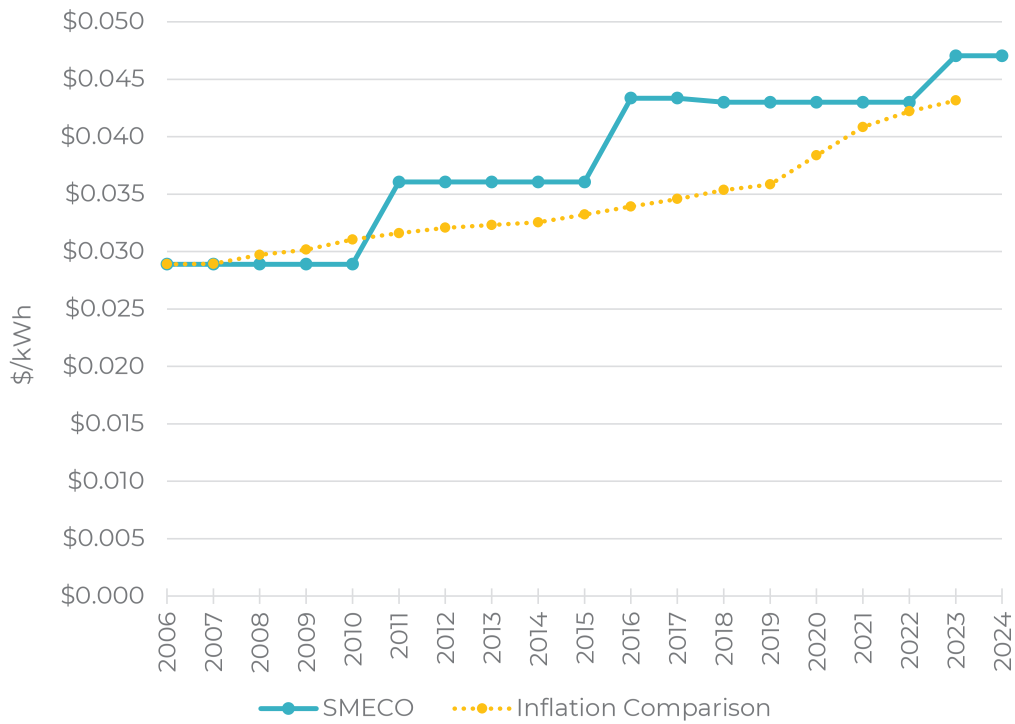
Customer charge: $9.50/month

Supply cost: $ 0.09210/kWh (February 2025)

EmPOWER surcharge: $0.01123/kWh

SMECO

Distribution Rate



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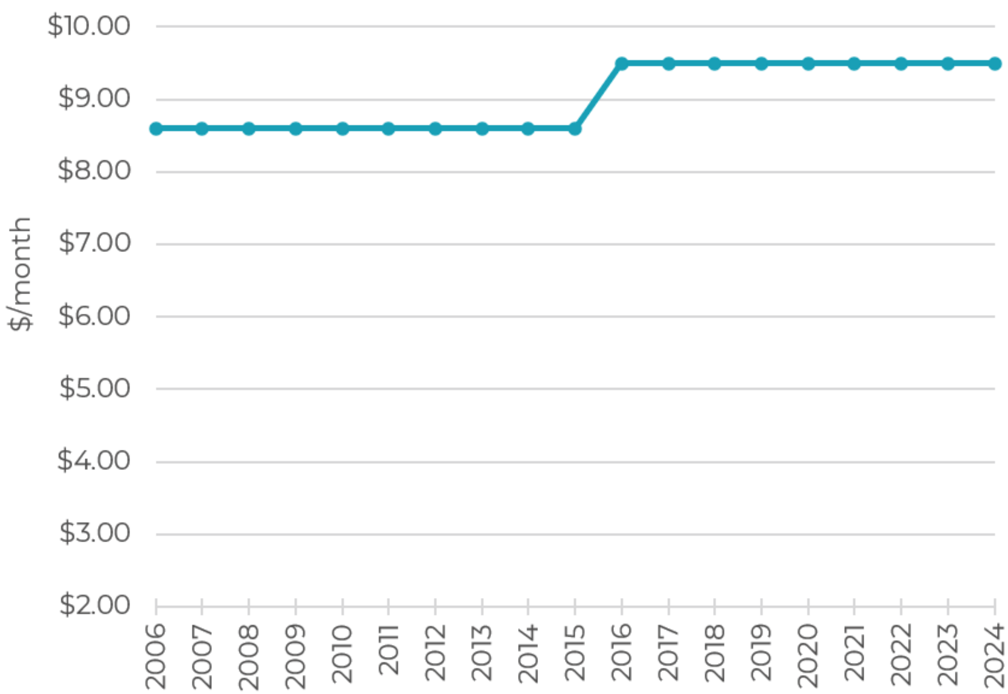
SMECO

Monthly Customer Charge



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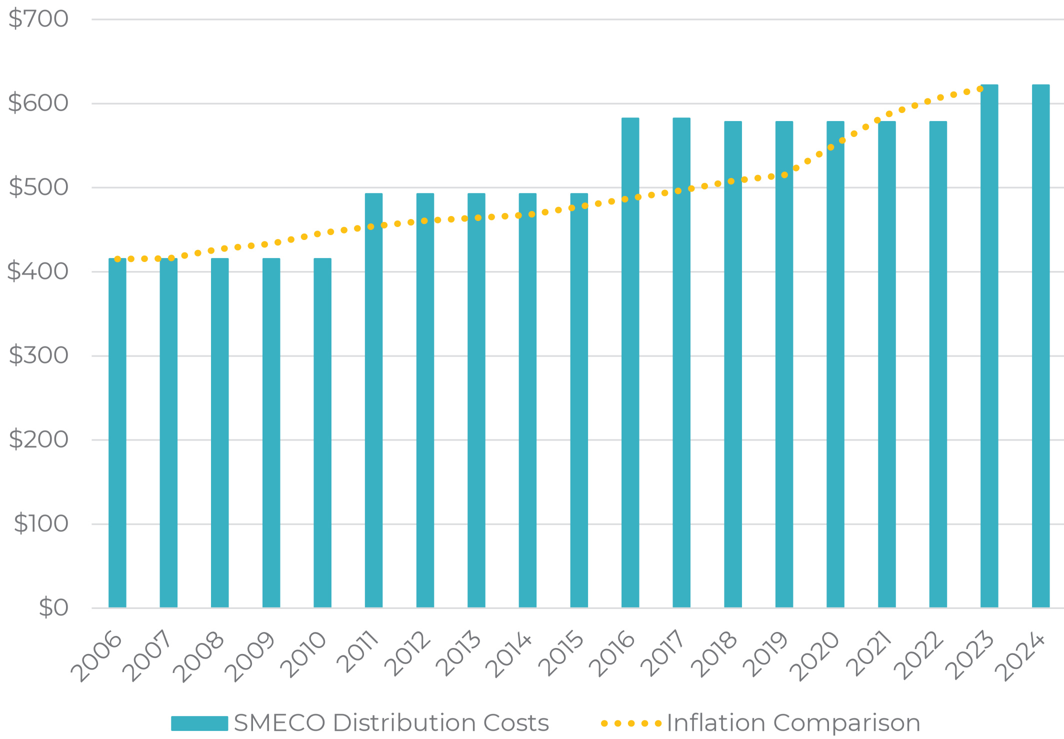
SMECO

Total Annual Delivery Charges



Charges based on monthly consumption of 900 kWhs.

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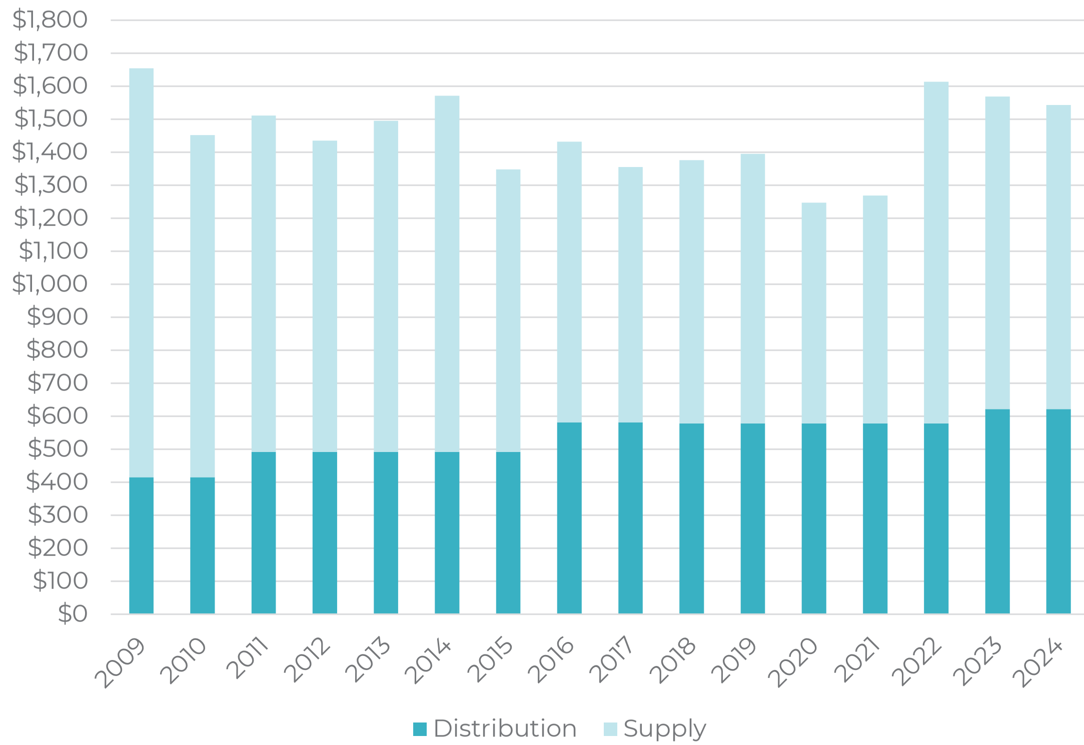
SMECO

Total Annual Bill: Delivery Plus Supply Charges



Charges based on monthly consumption of 900 kWhs.

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Washington Gas Light

Washington Gas

Washington Gas Light is an affiliate of Canadian-based AltaGas. The utility provides service to about 513,000 customers in Montgomery County and Prince George's County, as well as Calvert, Charles, and St. Mary's counties. In addition to Maryland, Washington Gas is a multi-jurisdictional utility that is regulated in two other regions, the District of Columbia and Virginia.

WGL's last rate case was in 2023. The final PSC ruling was issued on December 14, 2023. You can access the case here.

Washington Gas

Current rates

Gas bills include two primary categories of charges: *distribution charges* and *supply charges*. These categories of charges and additional charges are explained here. The distribution rate covers most of the average customer's distribution costs. For the average Washington Gas customer in 2024, the volumetric rate makes up 75 percent of distribution costs.

Volumetric distribution rate: $0.4621/therm

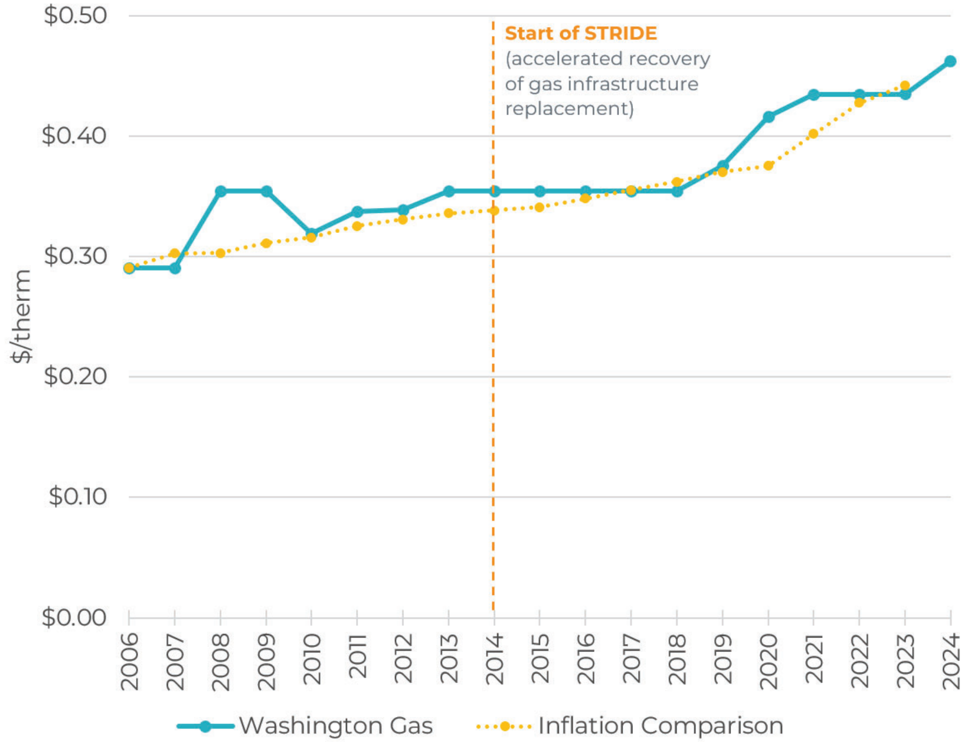
Customer charge: $11.85/month

Gas supply cost: $0.5798/therm (June 2024)

EmPOWER surcharge: $0.0431/therm

WASHINGTON GAS

Distribution Rate



The STRIDE surcharge is not included in this chart. In rate cases, prudently incurred STRIDE costs included in the surcharge are incorporated into utility base rates and reflected in the volumetric and customer charges. Click here for more information about STRIDE.

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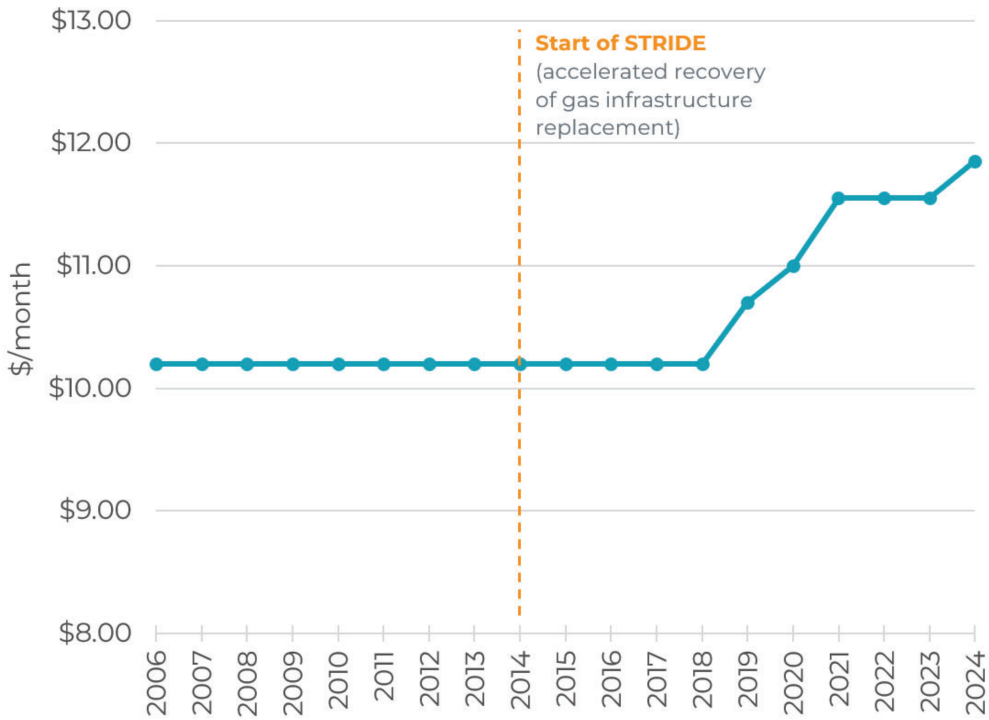
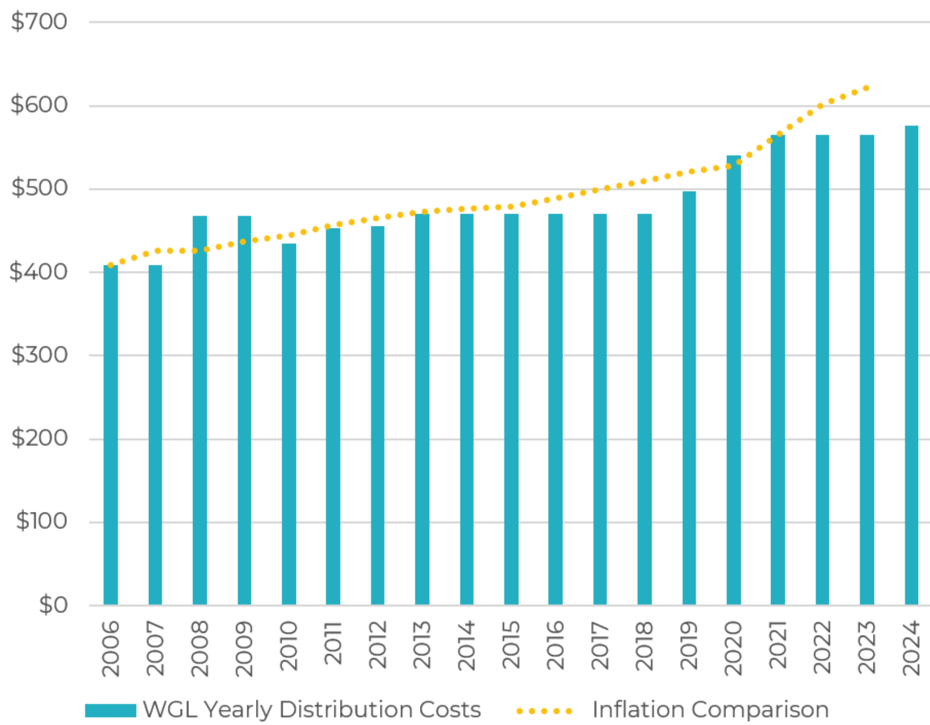
WASHINGTON GAS
Monthly Customer Charge



The STRIDE surcharge is not included in this chart. In rate cases, prudently incurred STRIDE costs included in the surcharge are incorporated into utility base rates and reflected in the volumetric and customer charges. Click here for more information about STRIDE.

WASHINGTON GAS

Total Annual Delivery Charges



Charges based on annual consumption of 940 therms.

OPC
Office of People's Counsel
State of Maryland

WASHINGTON GAS

Total Annual Bill: Delivery Plus Supply Charges

Charges based on annual consumption of 940 therms.

OPC
Office of People's Counsel
State of Maryland

Baltimore Gas and Electric

BGE is a company that provides both electricity and gas to Maryland. It is owned by a larger Illinois-based company called Exelon. BGE serves about 1.3 million electric customers and 700,000 gas customers. Those customers are located in Baltimore City, Baltimore County, and Anne Arundel County, most of Howard, Carroll and Harford Counties, and parts of Prince George's, Montgomery and Calvert Counties.

In July 2026, BGE filed its most recent electric rate case, proposing to collect an additional $156.1 million from customers, increasing distribution rates for residential electric customers by roughly 17 percent from 4.9 cents per kilowatt-hour (kWh) to 5.8 cents per kWh. This increase includes the "reconciliation" charge that was authorized by the PSC in 2025 and lasts through December 2027.

BGE is not currently requesting to increase its distribution rate for gas.

If BGE's increase is approved, its electric distribution rates will have increased by 58 percent since 2020 and 129 percent since Illinois-based Exelon Corp. acquired BGE in 2012—significantly outpacing inflation.

To better explain BGE's recent rate proposal, OPC prepared a "Consumer's Guide to BGE's Proposed Electric Rate Increase." The Consumer Guide identifies how rates have changed over time, the categories of costs at issue in the rate case, the average residential customer bill impact, how utilities generate profits, and how customers can get involved. **To read our Consumer Guide, click here. (/Portals/0/Files/Publications/BGE%20Consumer%27s%20Guide%20-%202026%20-%20FINAL%20VERSION.pdf?ver=OQulELqGzpKL7xWi5A9GKg%3d%3d)**

BGE's last completed rate case was in 2023 and was a multi-year rate case. The Public Service Commission order in the case was issued on Dec. 14, 2023. You can access the PSC order and the multi-year rate case here **(https://webpscxb.psc.state.md.us/DMS/case/9692)**.

Read more about BGE's most recent multi-year rate plan, along with information on its last multi-year rate plan. **(/Multi-Year-Rate-Cases?utm_)**

Why is my BGE bill so high?

If you've had sticker shock from your recent BGE bill, you're not alone. Most BGE customers are seeing substantial increases in their monthly bills. **Click here to read an explainer on why bills are going up. (/Why-is-my-2026-summer-BGE-bill-so-high)**

Current rates

Electric and gas bills include two primary categories of charges: distribution charges and supply charges. These categories of charges and additional charges are explained here **(/Consumer-Learning/Utility-Rates-and-Basics)**. The distribution rate covers most of the average customer's distribution costs. In 2026, the volumetric rate makes up 81 percent of distribution costs for the average BGE gas customer and 82 percent of distribution costs for the average BGE electric customer.

Note: The rates referenced below are base rates which may vary from what you see on your bill because of additional adjustments, such as adjustments made for weather and changes in usage.

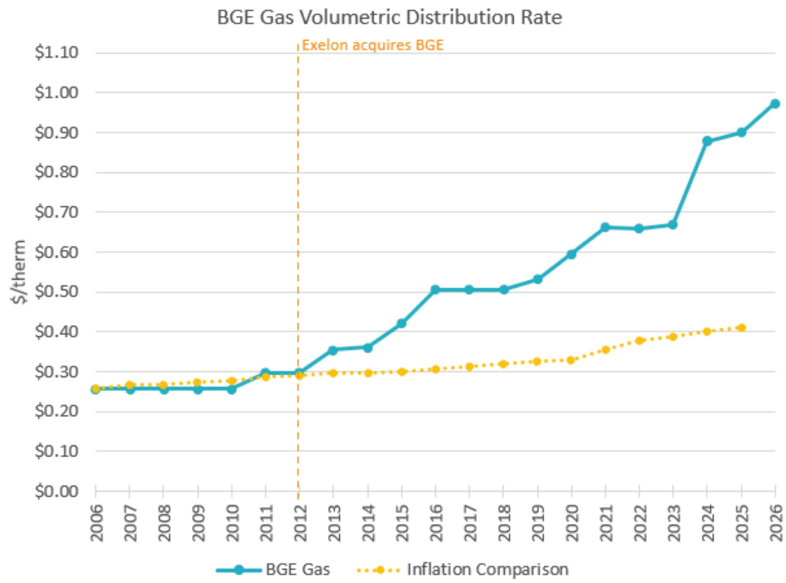
Gas Service

- Volumetric distribution rate: $0.9733/therm (September 2026)
- Customer charge: $16.15/month (September 2026)
- Supply cost: $0.3101/therm (September 2026)
- EmPOWER surcharge (gas): $0.0712/therm (September 2026)

Electric Service

- Volumetric distribution rate: $0.04945/kWh (September 2026)
- Customer charge: $10.00/month (September 2026)
- EmPOWER surcharge (electric): $0.01310/kWh (September 2026)
- Supply cost: $0.12519/kWh (September 2026)
- Transmission cost: $0.02322/kWh (Septmeber 2026)
- Total supply cost (supply + transmission): $0.14841/kWh (Septemeber 2026)

BGE
Gas Delivery Costs: Distribution Rate

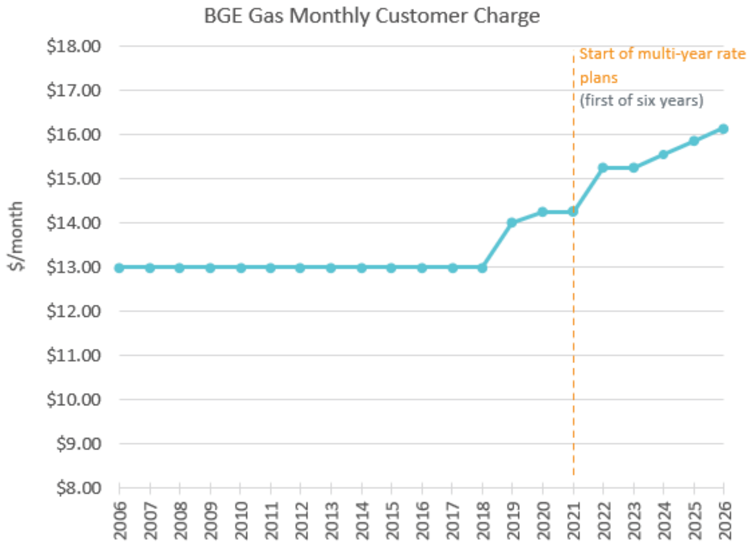


The STRIDE surcharge is not included in any of the charts. In rate cases, prudently incurred STRIDE costs included in the surcharge are incorporated into utility base rates and reflected in the volumetric and customer charges.

*BGE had a STRIDE surcharge until recently, but it is now doing its STRIDE--eligible work through its multi-year rate plan in which it continues to receive the same accelerated cost recovery as it received under STRIDE. **Click here for more information about STRIDE (/Consumer-Learning/Natural-Gas/STRIDE)**.*

BGE
Gas Monthly Customer Charge

Attachment RN-3
Page 3 of 6



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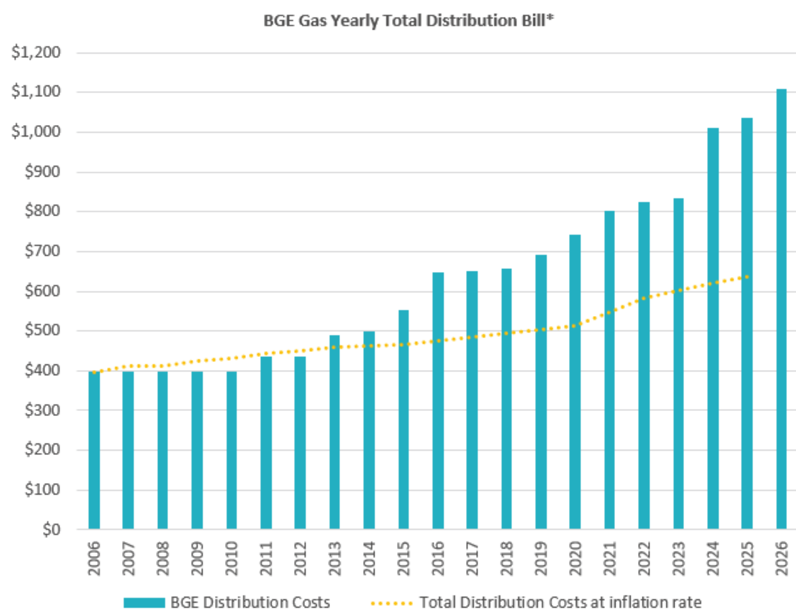
BGE

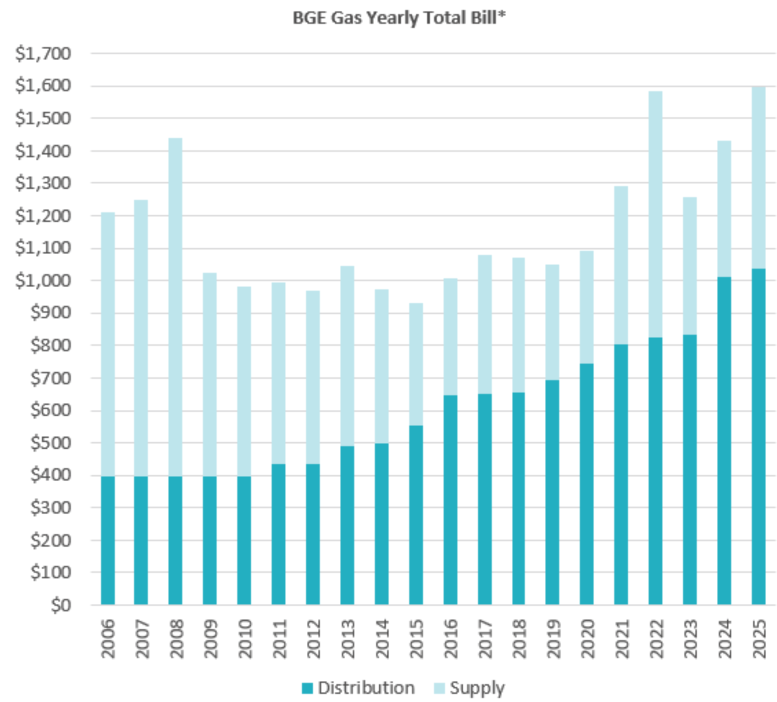
Gas Total Annual Delivery Charges



**Based on 940 therms/year usage*

BGE

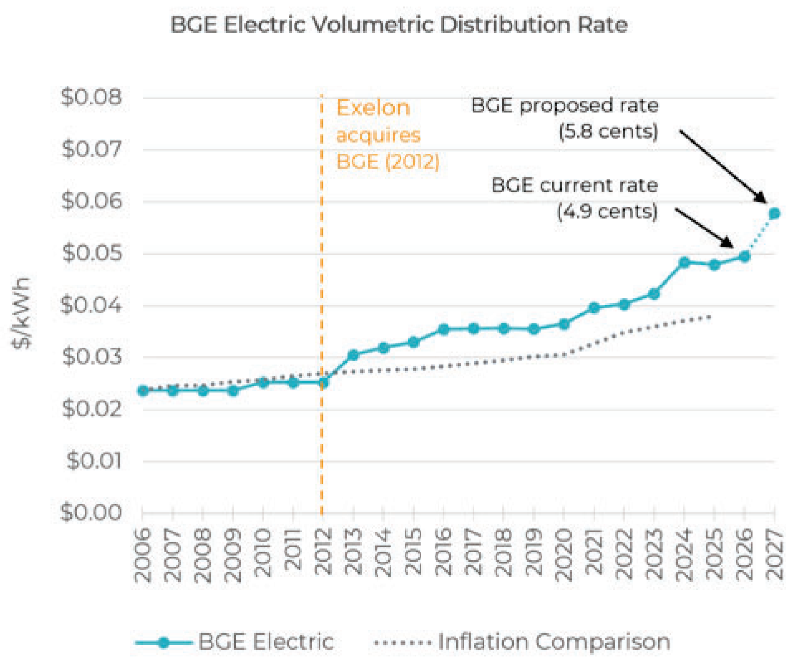
Gas Total Annual Bill: Delivery Plus Supply Charges



Based on 940 therms/year usage

BGE

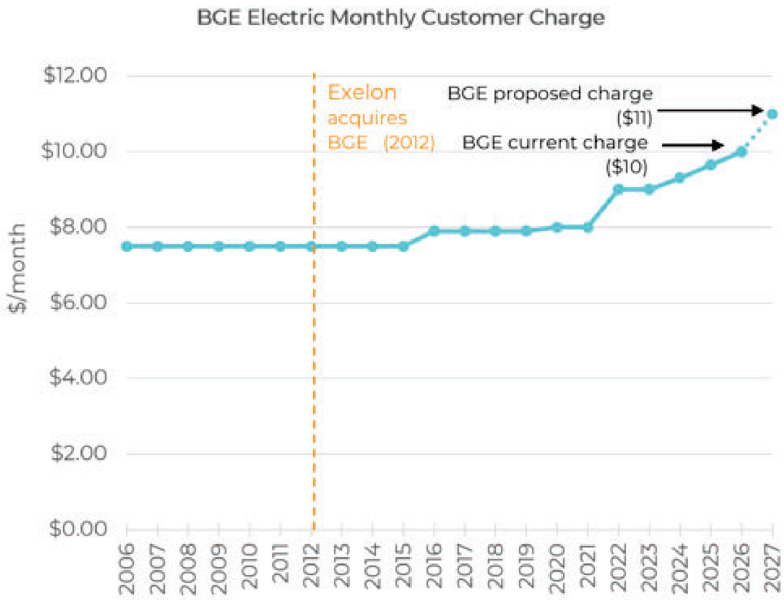
Electric Distribution Rate



BGE

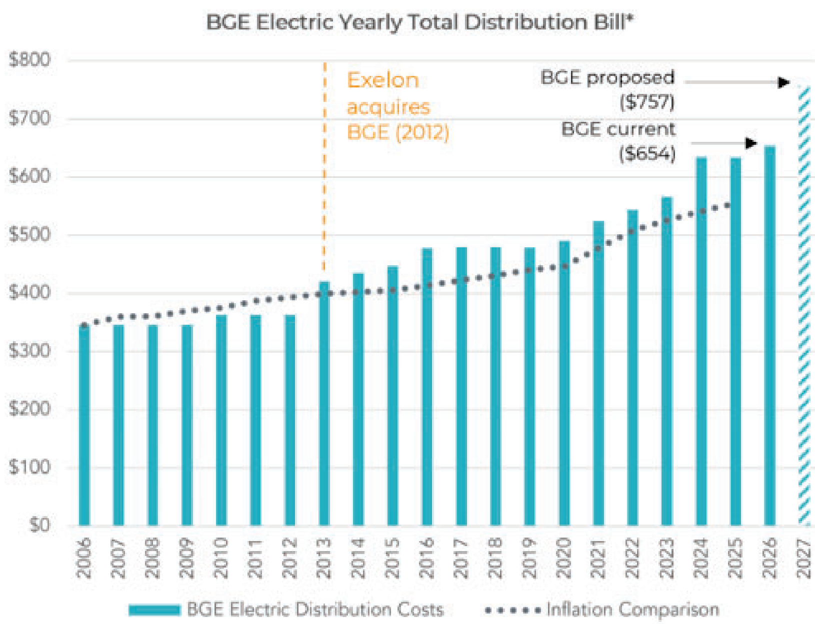
Electric Monthly Customer Charge

Attachment RN-3
Page 5 of 6



BGE

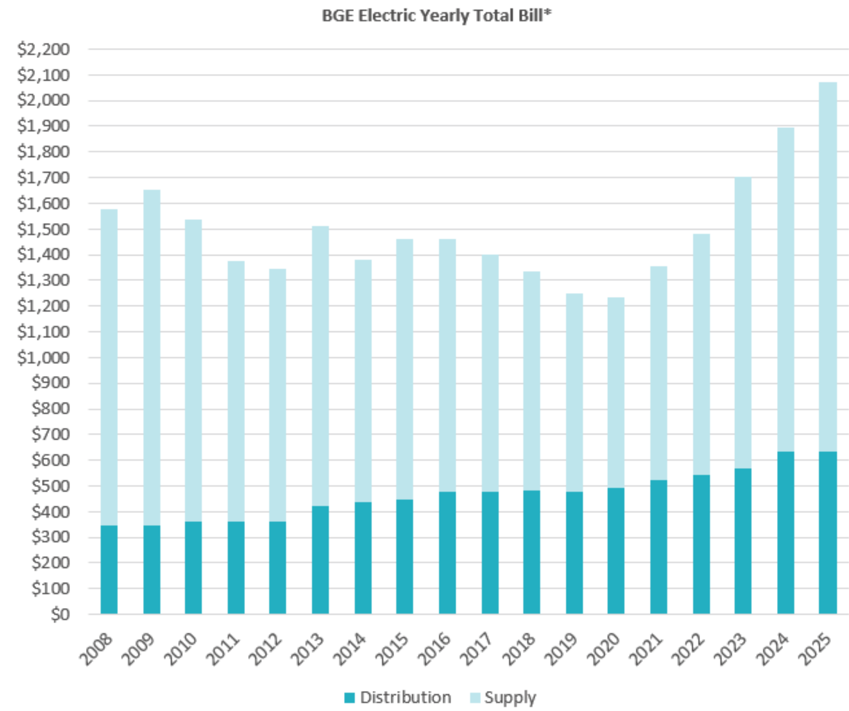
Electric Total Annual Delivery Charges



While BGE assumes average monthly usage of 851 kWh, OPC assumes average monthly usage of 900 kWh/month, resulting in slightly higher bill impacts than under BGE's assumption.

BGE

Electric Total Annual Bill: Delivery Plus Supply Charges



**Based on 900 kWh/month usage*

Watch a previously recorded webinar on how to read your BGE bill. (https://www.youtube.com/watch?v=2lHRMtJ9xYo)