BEFORE THE
MARYLAND PUBLIC SERVICE COMMISSION

IN THE MATTER OF THE	*	
APPLICATION OF BALTIMORE		
GAS AND ELECTRIC COMPANY	*	CASE NO. 9692
FOR AN ELECTRIC AND GAS		
MULTI-YEAR PLAN	*	

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DIRECT TESTIMONY

OF

Eric Borden

ON BEHALF OF THE OFFICE OF PEOPLE'S COUNSEL

June 20, 2023

TABLE OF CONTENTS

DIRECT TESTIMONY OF ERIC BORDEN

INTRODUCTION

Q. Please state your name and business address.

A. My name is Eric Borden. I am a Principal Associate at Synapse Energy Economics, Inc. (Synapse) located at 485 Massachusetts Avenue, Suite 3, Cambridge, MA 02139.

Q. Please describe Synapse Energy Economics.

A. Synapse is a research and consulting firm specializing in electricity and gas industry regulation, planning, and analysis. Our work covers a range of issues, including economic and technical assessments of demand-side and supply-side energy resources; energy efficiency policies and programs; regulatory issues and cost recovery; integrated resource planning; electricity market modeling and assessment; renewable resource technologies and policies; and climate change strategies. Synapse works for a wide range of clients, including attorneys general, offices of consumer advocates, public utility commissions, environmental advocates, the U.S. Environmental Protection Agency, the U.S. Department of Energy, the U.S. Department of Justice, the Federal Trade Commission, and the National Association of Regulatory Utility Commissioners. Synapse has over 40 professional staff with extensive experience in the electricity industry.

Q. Please describe your educational background and qualifications.

A. I hold a Master's degree in Public Affairs with a concentration in Energy and Environmental Policy from the University of Texas at Austin LBJ School. My undergraduate degree is in finance and entrepreneurship from Washington University in St. Louis. My resume is attached in Appendix A.

Q. Please describe your professional experience.

A. At Synapse, I conduct economic, environmental, and policy analysis of energy system technologies, planning and regulations associated with both supply- and demand-side resources. I have worked on numerous utility cost recovery proceedings, including General Rate Cases, to review forecasted and incurred costs to assess the reasonableness of utility requests. My previous testimony has addressed ratemaking alternatives including disallowances when I have found costs were not reasonably incurred.

Q. Have you previously testified in regulatory proceedings that concern cost recovery and ratemaking?

A. I have testified in numerous proceedings related to cost recovery and ratemaking issues. These were related to utility subsidies for electric vehicle infrastructure and charging stations, reasonableness reviews of wildfire expenditures, coal ash remediation costs, general rate case and multi-year rate plans, and others.

Q. Have you previously testified in proceedings before state utility commissions in other jurisdictions?

A. I have testified on numerous occasions at the California Public Utilities Commission (CPUC) and submitted testimony and testified in multiple other states and Canada, including in Illinois, Maine, Minnesota, Nova Scotia (Canada), and South Carolina. I have also contributed to projects and testimony on regulated utility issues in New Hampshire, New Mexico, and New Jersey.

Q. On whose behalf are you appearing?

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

Q. What is the purpose of your testimony in this proceeding?

A. The purpose of my testimony is to respond to Baltimore Gas and Electric Company's ("BGE" or the "Company") building electrification and non-road electrification cost recovery proposals presented by witness Mark D. Case on behalf of the Company.

Q. What materials did you rely on to develop your testimony?

A. The sources for my testimony are BGE's Application, in particular filings by Witness Case, responses to discovery requests, and my personal knowledge and experience.

Q. Was this testimony prepared by you or under your direction?

A. Yes. My testimony was prepared by me or under my direct supervision and control.

I. Summary and Recommendations

Q. Please summarize your primary conclusions concerning BGE's proposed cost recovery mechanism.

A. I conclude that, if any cost recovery is allowed for electrification programs in this multi-year rate plan (MYRP), the Company's proposal for a regulatory asset should be denied: this cost recovery mechanism is contrary to standard ratemaking, costlier for customers in the long-run, and unnecessary. Instead, expenditures should be expensed in the year incurred.

II. BGE's Electrification Program Should Not be Allowed Regulatory Asset Treatment.

A. Capitalization of Electrification Expenditures is Contrary to Standard Ratemaking Principles.

Q. Please describe BGE's cost recovery proposal for electrification expenditures and the Company's underlying rationale.

A. BGE proposes to include all of its spending on electrification programs – building**,** non-road, and workforce – in a regulatory asset. BGE states this is due to the "long-term benefits and value provided by the assets such as electric heat pumps and commercial equipment involved, and concerns with affordability for customers."[1] The Company claims that inclusion of these costs in a regulatory asset is "proper from a cost causation standpoint," and "also the right answer from a rate gradualism and customer affordability perspective."[2] The $272 million in proposed direct costs for electrification programs would be included in rate base for 12.5 years, the average measure useful life calculated by the Company.[3]

Q. Will BGE own the assets installed under its proposed electrification programs?

[1] Direct Testimony of John Frain, pp. 16-17: 19-1.
[2] OPCDR20-1B.
[3] Direct Testimony of John Frain, p. 17.

A. No. BGE will not own or maintain the assets installed. Yet under regulatory asset treatment costs will be treated as if they are capital expenditures.

Q. Do you agree with the Company's claim that its regulatory asset proposal is "proper from a cost causation standpoint?"

A. I do not. The primary expenditures contemplated for electrification programs are rebates provided to customers for the installation of technology. This provides an immediate benefit to the individual customer. Further, under standard regulatory principles, the costs are utility expenses, not capital investments. Under the Company's logic, all operation and maintenance (O&M) expenditures should be amortized and earn a return based on the life of utility equipment that is repaired. The Company's statements in this regard are factually inaccurate and contrary to well-established ratemaking principles.

Q. How are non-capital expenditures normally recovered?

A. These types of costs are traditionally expensed at the time they are incurred, precisely because they are not capital investments on the part of the utility. The life of the asset that an O&M-type expenditure supports has no bearing on cost recovery.

Q. Do you oppose regulatory asset treatment of all non-capital expenditures?

A. I do not, and the issue is worth considering on a case-by-case basis. For example, I agree with the Commission's policy determination that for expenses that are outside the control of the utility or extraordinary (e.g. due to COVID), and nonrecurring, regulatory asset treatment can be appropriate.[4] I would consider these types of cost recovery issues on a case by case basis. I have done so here, and find that regulatory asset treatment of electrification expenditures is not warranted at this time.

B. Regulatory asset treatment is Not "More Affordable" for Customers

Q. Is it true that amortizing costs as part of a regulatory asset is more "affordable" for customers?

A. Not over the longer term. It is true that with regulatory asset treatment, the revenue requirement for the initial years of 2024-2026 would be lower than the revenue requirement associated with treating these costs as an expense. However, in the longer term, regulatory asset treatment would result in total ratepayer costs of $400 million over the time period, compared with $272 million in direct incentives[5]—an additional 47 percent cost burden that would be shouldered by ratepayers over the life of the asset due to the additional costs necessary to include costs in rate-base. In my view, customer affordability should consider both short- and long-term rate impacts, so I find that BGE's statements on customer affordability fundamentally lack context, and that in the long term they are inaccurate.

Q. How else will customer affordability be impacted over the longer-term?

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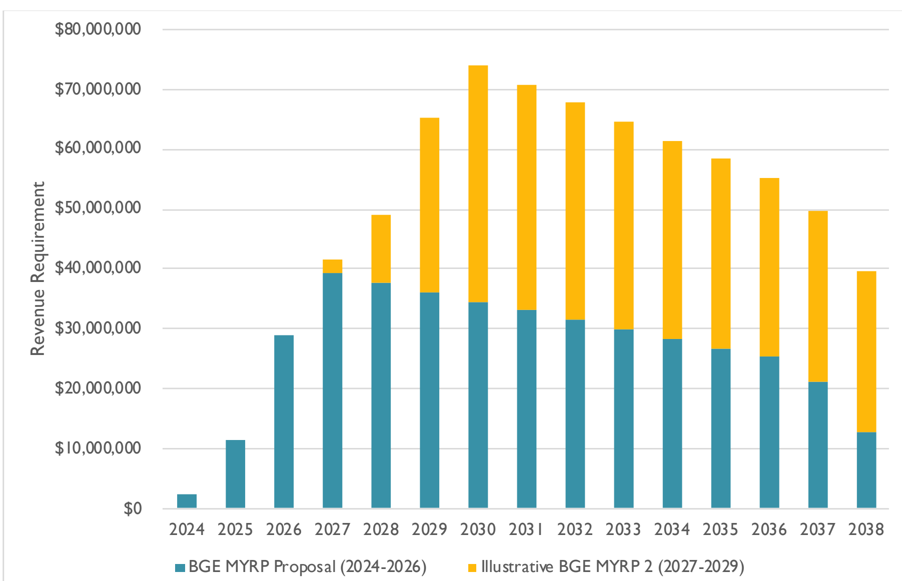
[4] Order No. 89542, April 9, 2020, *Order Authorizing Establishment of a Regulatory Asset for COVID-19 Related Incremental Costs,* pp. 2-3. In this case, the creation of the regulatory asset was also ordered "in an effort to minimize adverse financial impacts to Maryland Utilities," which is not an issue as it relates to electrification expenditures. In this Order, the Commission did not approve a specific amortization period or level of return (p. 3).
[5] Nominal dollars. OPCDR09-10-Attachment 1-REVISED.

A. Electrifying end-use appliances in BGE's service territory will likely require longer-term programs and investments beyond the three-year MYRP. Additional costs of regulatory asset treatment will be compounded if BGE proposes or the Commission requires ongoing incentives beyond this rate case. This is shown in the following figure, which illustrates the compounding revenue requirements if BGE were to utilize regulatory asset treatment for both the current proposal and a hypothetical one of the exact same size and revenue requirement in an MYRP running from 2027 to 2029. This would be further exacerbated with another program after 2029, and so on. Much like a credit card on which a customer is only able to pay a fraction of the principal and must accrue interest every month, any short-term benefit of capitalization becomes a long-term and growing financial burden to ratepayers.

Figure 1. Illustrative cumulative revenue requirements due to regulatory asset treatment of ongoing electrification expenditures



Q. What additional motivations does the utility have to include these costs in a regulatory asset?

A. The most obvious from the utility's perspective is that regulatory asset treatment allows BGE to earn a return for its shareholders on these expenditures, which expensing does not allow. Return to shareholders represents an additional $66 million from 2024-2038 compared with expensing costs, based on BGE's proposed and forecast return on equity estimates.[6]

C. The EmPOWER program, and recent developments in California, demonstrate that unnecessary capitalization of costs can result in worse affordability impacts for customers.

Q. How should the Commission's recent experience with EmPOWER program costs inform its thinking on electrification expenditures?

A. The cost recovery mechanisms originally allowed for EmPOWER program costs resulted in an untenable affordability situation for ratepayers as costs accumulated due to the long-term impacts of capitalizing expenditures, discussed above. As the Commission discussed in its order to address these balances:

> While this cost recovery method [capitalization] helped to minimize the impact of EmPOWER's upfront costs to ratepayers and allowed ratepayers to experience a relatively steady monthly surcharge, it has also resulted in the accumulation of uncollected program costs. This, when combined with program costs progressively increasing over time, has led to a current combined balance for the utilities of over $800 million in unamortized program costs and interest.[7]

The Commission ultimately found it was not in the public interest to continue to amortize these costs beyond 2029, as would have been required with

[6] Calculated from OPCDR09-10-Attachment 1- REVISED.
[7] Order No. 90456, 12/29/22, p. 3.

capitalization.[8] The Commission also found it best to move away from capitalization towards "the smooth and gradual transition to an expensing of costs-based system of cost recovery."[9] Exelon was ordered to phase in expensing these costs over a few years, based on a proposal from Southern Maryland Electric Cooperative (SMECO).[10] Exelon requested a rehearing of these issues, which was recently denied by the Commission on multiple counts.[11]

Q. How else does the Commission's treatment of EmPOWER costs inform electrification related cost recovery?

A. In its recent denial of Exelon's application for rehearing, the Commission confirmed the motivation I discuss above, stating "it appears the Exelon Utilities would prefer a cost recovery method that guarantees a return."[12] The Commission also noted the following:

- Exelon has "a duty to comply with State law regarding greenhouse gas reductions regardless of whether or not a return is earned."
- The Commission has "discretion as to whether financial incentives should be afforded to utilities."[13]

These statements of fact are important to recognize as utilities and the Commission embark on building electrification programs.

Q. Are you aware of any other jurisdictions where Commissions have addressed utility efforts to earn a return on infrastructure that is not traditional utility investment?

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[8] *Ibid.*
[9] Order No. 90456, 12/29/22, p. 20.
[10] *Ibid.*
[11] Order No. 90592, 4/18/23.
[12] Order No. 90592, 4/18/23, p. 10.
[13] Order No. 90592, 4/18/23, pp. 10-11.

A. While I have not done an exhaustive review, I am aware that California's Investor Owned Utilities (IOUs) were previously allowed in some instances to own (and thus capitalize) some customer-side infrastructure costs in the context of electric vehicle (EV) subsidies, including infrastructure work on the customer side of the meter, and charging stations. This approach was recently ended as the California Public Utilities Commission (CPUC) seeks to transition programs to a rebate structure where costs are expensed, primarily due to the same affordability concerns noted by the Maryland Commission. In its decision, the CPUC stated:

> We find it appropriate to eliminate all IOU ownership of BTM [behind the meter] infrastructure beginning with FC1 [Funding Cycle 1]. Such a shift in the ownership paradigm allows for technology and construction flexibility, **while reducing the cost burden that capitalized IOU expenditures impose on ratepayers.**
>
> […]
>
> capitalizing these costs will be significantly more expensive for ratepayers over time. This approach [towards rebates that are expensed] is consistent with recent decisions and with our directives in those decisions to limit the amount of utility ownership of BTM infrastructure and thus capitalization of those assets. One of the main objectives of the funding cycle proposal and the FC1 structure is to reduce total costs to ratepayers. **Allowing the capitalization of BTM infrastructure costs runs counter to this objective because it unnecessarily adds costs for ratepayers**.[14]

III. Conclusion

Q. What is your cost recovery recommendation for electrification expenditures?

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[14] Emphasis added. D.22-11-040, 11/21/22, pp. 103 and 105, https://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M499/K005/499005805.PDF.

A. Expenditures on electrification subsidies for customer equipment should be expensed in the year incurred, if any are approved in this base rate case. This avoids the cumulative affordability impacts down the road that arise when program costs are capitalized, as recently illustrated by the EmPOWER program, where the Commission has now corrected course. Customers should not pay more than what programs cost due to the use of accounting mechanisms that unnecessarily enrich shareholders. Instead, it will be important that annual budgets for electrification and other related programs are set to be consistent with need and affordable rate increases.

Eric Borden, Principal Associate

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eborden@synapse-energy.com

PROFESSIONAL EXPERIENCE

Synapse Energy Economics, Inc., Cambridge, MA*. Principal Associate,* May 2022 – Present

- Sponsors expert testimony and performs analyses related to utility electric vehicle incentives and policy, wildfire mitigation strategies and costs, risk modeling, rate design, cost allocation, and revenue requirement issues in General Rate Cases and Multi-year Rate Plans.
- Conducts research and analysis related to the cost-effectiveness of distributed energy resources and Integrated Resource Plans.
- Examines utility performance incentives and provides expertise on ratemaking issues.

The Utility Reform Network (TURN), San Francisco, CA*, Energy Policy Expert,* February 2015 - May 2022

- Prepared testimony, conducted analyses, drafted comments, and represented TURN in various proceedings at the California Public Utilities Commission (CPUC) related to general rate cases, wildfire-related safety applications, electric vehicle charging infrastructure, utility procurement, rate design, and demand response.

4 Thought Energy LLC, Chicago, IL. *Senior Energy Analyst*, June 2013 – January 2015

- Created financial models to forecast profits of potential site installations
- Researched state and regional public policy frameworks governing CHP
- Conducted analyses over electricity and natural gas price trends
- Developed presentations and marketing materials for investor meetings

International Renewable Energy Agency (IRENA) Bonn, Germany. *Consultant,* February 2014 – October 2014

- Hired to write a report on worldwide electricity sector battery storage, including primary applications for renewable energy integration, market developments, trends, and case studies
- Conduct research, review literature, interview key industry players, develop case study material
- Travel to Bonn, company sites, and research facilities
- Written report will be sent to policymakers in 167 IRENA member countries

Alexander von Humboldt Foundation (hosted by DIW Berlin), Berlin, Germany. *German Chancellor Fellow*, July 2012 – November 2013

- Research Project: “Energy Storage Technology and the Large-Scale Integration of Renewable Energy”
- Investigated the role of energy storage in Germany for renewable integration through literature review, interviews with German energy experts, and analysis comparing public policy support in Germany and the U.S. for storage technologies
- Invited to hold a presentation at the International Renewable Energy Storage Conference and Exhibition (IRES 2013)
- Discussions with German businesses and governmental ministries; special visit to European Union and NATO headquarters in Brussels
- Attended energy conferences and workshops in Berlin

The Kenrich Group, LLC, Chicago, IL. *Senior Consultant*, June 2008 – July 2009

- Consulted for multiple energy utilities in legal disputes with the Department of Energy (DOE)
- Performed detailed research and quantitative/qualitative analysis to analyze financial impact related to construction of coal-fired power plants, liquid natural gas facilities, and other types of construction
- Contributed to final reports and presentations submitted in arbitration, settlement, or court of law presenting KRG’s expert opinion

Charles River Associates, Chicago, IL. *Associate - Intellectual Property*, July 2006 – May 2008

- Developed complex financial models including discounted cash flow, lost profit, and regression analyses to support expert reports within the context of intellectual property and financial litigation in multiple industries
- Created valuation models and supporting materials to value business entities
- Contributed to final reports and presentations submitted in arbitration, settlement, or court of law presenting CRA’s expert opinion

EDUCATION

University of Texas, LBJ School of Public Affairs, Austin, Texas

Master of Public Affairs, specialization in Natural Resources and the Environment, 2012

Washington University, St. Louis, MO

B.S.B.A. Finance, Entrepreneurship, 2006

PUBLICATIONS

Battery Storage for Renewables: Market Status and Technology Outlook, International Renewable Energy Agency (IRENA), co-author with Ruud Kempener, 2015.

Germany's Energiewende, chapter 15 in Global Sustainable Communities Design Handbook, ed. Dr. Woodrow Clark, Elsevier Press, 2014.

Expert Views on the Role of Energy Storage for the German Energiewende, DIW Berlin and BMU "Stores" project, 2014.

Policy efforts for the development of storage technologies in the U.S. and Germany, DIW Discussion Paper, 2013.

Electric Vehicles and Public Charging Infrastructure: Impediments and Opportunities for Success in the United States, The University of Texas at Austin, 2012.

Clean Energy Technology and Public Policy, LBJ Journal of Public Affairs, editor and contributor, 2011.

TESTIMONY

Public Utilities Commission of Maine (Docket No. 2022-00152): Direct Testimony of Melissa Whited-and Eric Borden regarding Central Maine Power Company's request for rate design increase and changes. On behalf of the Maine Office of the Public Advocate. December 2, 2022.

A.21-06-021: Prepared Testimony Addressing Pacific Gas and Electric's Test Year 2023 General Rate Case – Wildfire Mitigation and New Customer Connections Cost Requests. June 13, 2022.

A.21-09-008: Prepared Testimony Addressing the Reasonableness of Pacific Gas and Electric 2020 Vegetation Management Balancing Account Overspend. May 25. 2022.

A.21-06-022: Prepared Testimony Addressing Pacific Gas and Electric's Framework for Substation Microgrid Solutions. March 30, 2022.

A.21-10-010: Prepared Testimony Addressing Pacific Gas and Electric's Electric Vehicle Charge 2 Proposal. March 2, 2022.

A.20-09-019: Prepared Testimony Addressing Pacific Gas and Electric's Wildfire Mitigation Memorandum Accounts. April 14, 2021.

A.19-08-013: Prepared Testimony Addressing Southern California Edison's Test Year 2021 Track 2 General Rate Case Memorandum Account Request – Wildfire Expenditures. September 4, 2020.

A.20-03-004: Joint Testimony with Eduyng Castano (SCE) Addressing Data Collection and Evaluation of the New Homes Battery Storage Pilot Program. September 1, 2020.

A.19-10-012: Prepared Testimony Addressing San Diego Gas and Electric's Power Your Drive 2 Electric Vehicle Charging Infrastructure Proposal. May 18, 2020.

A.19-08-013: Prepared Testimony Addressing Southern California Edison's General Rate Case Wildfire Management, Wildfire Risk, Vegetation Management, and New Service Connection Policy Issues and Cost Forecasts. May 5, 2020.

A.18-12-009: Prepared Testimony Addressing Pacific Gas and Electric's Enhanced Vegetation Management and System Hardening Wildfire Mitigation Expenditures. July 26, 2019.

A.18-09-002: Direct Testimony Addressing SCE's Grid Safety and Reliability Program Infrastructure Proposal. April 23, 2019.

A.18-06-015: Rebuttal Testimony Addressing SCE's Charge Ready 2 EV Infrastructure Proposal. December 21, 2018.

A.18-06-015: Direct Testimony Addressing SCE's Charge Ready 2 EV Infrastructure Proposal. November 20, 2018.

A.17-12-011: Direct Testimony Regarding Potential Effects of More "Cost Based" TOU Rates and Seasonal Differentiation of Tiered Rates. October 26, 2018.

A.18-02-016 et al.: Prepared Testimony Addressing Issues Pertaining to AB 2868 (Energy Storage). August 10, 2018.

A.17-12-002 et al.: Prepared Testimony Addressing the Proposal of SCE for Energy Storage Procurement. April 9, 2018.

A.17-01-020: Direct Testimony Addressing the Proposal of PG&E for a Fast Charging Infrastructure Program. July 25, 2017.

R.12-06-013: Direct Testimony Evaluating Hardship due to TOU Rates on Vulnerable Populations in Hot climate Zones. April 19, 2017.

A.15-09-001: Direct Testimony Addressing the Proposal of PG&E for Electric Distribution and New Business Expenditures. April 29, 2016.

A.15-02-009: Rebuttal Testimony Regarding PG&E's A.15-02-009 for EV Infrastructure and Education Program. December 21, 2015.

A.15-02-009: Direct Testimony Regarding PG&E's EV Infrastructure and Education Program. November 20, 2015.

A.14-11-003: Direct Testimony Addressing the Treatment of Solar Distributed Generation for Estimating Distribution System Capacity/Expansion Expenditures. May 15, 2015.

A.14-04-014/R.13-11-007: Testimony Regarding SDG&E's Application for Authority to Build Electric Vehicle Charging Infrastructure. April 13, 2015.

Resume updated January 2023

Case No. 9692
Baltimore Gas and Electric Co.
Response to OPC Data Request 9
Request Received: April 17, 2023
Response Date: May 01, 2023
Revised Response Date: May 05, 2023
Sponsor(s): John C. Frain

Item No.: OPCDR09-10

Please refer to page 63 of the Direct Testimony of Mark D. Case Direct Testimony that describes BGE's proposal to include customer electrification programs, recovered over an average of 12.5 years.

A. In Microsoft Excel, please provide the annual revenue requirement for each program separately, and all customer electrification programs, in total, pursuant to the regulatory asset proposal. Please include in the response all supporting workpapers, calculations, and assumptions in Excel with formulas intact.
B. In Microsoft Excel, please provide the annual revenue requirement for BGE's proposal, assuming these program funds are treated as an expense and not a regulatory asset. Please include in the response all supporting workpapers, calculations, and assumptions in Excel with formulas intact.

REVISED RESPONSE:

Please see OPCDR09-10-*Attachment 1-REVISED*[1] for the annual revenue requirement over the 12.5 year period for each program separately, and all customer electrification programs in total pursuant to BGE's regulatory asset proposal.

Please see OPCDR09-10-*Attachment 2* for the annual revenue requirement for BGE's proposal assuming the program funds are treated as an expense and not a regulatory asset.

[1] OPC has followed-up regarding BGE's original response and clarified that it wanted the annual revenue requirement provided for the entire 12.5 year period, not just the years at issue in this proceeding. BGE has revised OPCDR09-10-Attachment 1 accordingly.

Total Electrification Building Program Revenue Requirement Over the Life of the Program

	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038
Electrification Building Program Spend Deferred	$ 28,460,642	87,164,423	$ 146,178,447												
Amortization - 2024 Electrification Building Spend	$ (1,138,426)	$ (2,276,851)	$ (2,276,851)	$ (2,276,851)	$ (2,276,851)	$ (2,276,851)	$ (2,276,851)	$ (2,276,851)	$ (2,276,851)	$ (2,276,851)	$ (2,276,851)	$ (2,276,851)	$ (2,276,851)	$ -	$ -
Amortization - 2025 Electrification Building Spend		(3,486,577)	(6,973,154)	(6,973,154)	(6,973,154)	(6,973,154)	(6,973,154)	(6,973,154)	(6,973,154)	(6,973,154)	(6,973,154)	(6,973,154)	(6,973,154)	(6,973,154)	
Amortization - 2026 Electrification Building Spend			(5,847,138)	(11,694,276)	(11,694,276)	(11,694,276)	(11,694,276)	(11,694,276)	(11,694,276)	(11,694,276)	(11,694,276)	(11,694,276)	(11,694,276)	(11,694,276)	(11,694,276)
Reg Asset Balance as of 12/31	$27,322,216	$108,723,211	$239,804,515	$ 218,860,234	$ 197,915,953	$ 176,971,672	$ 156,027,391	$ 135,083,110	$ 114,138,829	$ 93,194,548	$ 72,250,267	$ 51,305,986	$ 30,361,705	$ 11,694,276	$ (0)
ADIT	(7,518,391)	(29,917,910)	(65,988,207)	(60,224,865)	(54,461,522)	(48,698,180)	(42,934,837)	(37,171,495)	(31,408,152)	(25,644,810)	(19,881,467)	(14,118,125)	(8,354,782)	(3,217,972)	0
Terminal Rate Base as of 12/31	$ 19,803,825	$ 78,805,301	$ 173,816,308	$ 158,635,369	$ 143,454,431	$ 128,273,492	$ 113,092,554	$ 97,911,615	$ 82,730,677	$ 67,549,738	$ 52,368,800	$ 37,187,862	$ 22,006,923	$ 8,476,303	$ (0)
Average Rate Base as of 12/31	$ 9,901,913	$ 49,304,563	$ 126,310,804	$ 166,225,838	$ 151,044,900	$ 135,863,961	$ 120,683,023	$ 105,502,085	$ 90,321,146	$ 75,140,208	$ 59,959,269	$ 44,778,331	$ 29,597,392	$ 15,241,613	$ 4,238,152
ROR per Case No. 9692 Filing, Grossed Up	9.69%	9.76%	9.87%	9.87%	9.87%	9.87%	9.87%	9.87%	9.87%	9.87%	9.87%	9.87%	9.87%	9.87%	9.87%
Return	$ 959,911	$ 4,812,509	$ 12,467,079	$ 16,406,756	$ 14,908,373	$ 13,409,991	$ 11,911,608	$ 10,413,225	$ 8,914,842	$ 7,416,459	$ 5,918,076	$ 4,419,693	$ 2,921,310	$ 1,504,372	$ 418,312
Amortization Expense	1,138,426	5,763,428	15,097,143	20,944,281	20,944,281	20,944,281	20,944,281	20,944,281	20,944,281	20,944,281	20,944,281	20,944,281	20,944,281	18,667,430	11,694,276
Tax Effect	(313,266)	(1,585,951)	(4,154,356)	(5,763,343)	(5,763,343)	(5,763,343)	(5,763,343)	(5,763,343)	(5,763,343)	(5,763,343)	(5,763,343)	(5,763,343)	(5,763,343)	(5,136,810)	(3,217,972)
Amortization Expense, Net of Tax	825,159	4,177,477	10,942,787	15,180,938	15,180,938	15,180,938	15,180,938	15,180,938	15,180,938	15,180,938	15,180,938	15,180,938	15,180,938	13,530,620	8,476,303
Electrification Program Revenue Requirement - Building Program	$ 2,128,972	$ 10,731,033	$ 27,970,491	$ 37,914,655	$ 36,416,272	$ 34,917,889	$ 33,419,506	$ 31,921,123	$ 30,422,740	$ 28,924,357	$ 27,425,974	$ 25,927,591	$ 24,429,208	$ 20,674,148	$ 12,427,285
														Total Revenue Requirement	$ 385,651,241

Total Electrification Non-Road Program Revenue Requirement Over the Life of the Program

	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038
Electrification Non-Road Program Spend Deferred	$ 1,740,006	2,242,768	$ 2,637,146												
Amortization - 2024 Electrification Non-Road Spend	$ (69,600)	$ (139,200)	$ (139,200)	$ (139,200)	$ (139,200)	$ (139,200)	$ (139,200)	$ (139,200)	$ (139,200)	$ (139,200)	$ (139,200)	$ (139,200)	$ (139,200)	$ -	$ -
Amortization - 2025 Electrification Non-Road Spend		(89,711)	(179,421)	(179,421)	(179,421)	(179,421)	(179,421)	(179,421)	(179,421)	(179,421)	(179,421)	(179,421)	(179,421)	(179,421)	
Amortization - 2026 Electrification Non-Road Spend			(105,486)	(210,972)	(210,972)	(210,972)	(210,972)	(210,972)	(210,972)	(210,972)	(210,972)	(210,972)	(210,972)	(210,972)	(210,972)
Reg Asset Balance as of 12/31	$1,670,406	$3,684,263	$5,897,301	$ 5,367,707	$ 4,838,114	$ 4,308,520	$ 3,778,926	$ 3,249,333	$ 2,719,739	$ 2,190,146	$ 1,660,552	$ 1,130,958	$ 601,365	$ 210,972	$ 0
ADIT	(459,654)	(1,013,817)	(1,622,790)	(1,477,059)	(1,331,328)	(1,185,597)	(1,039,866)	(894,135)	(748,404)	(602,673)	(456,942)	(311,211)	(165,481)	(58,054)	(0)
Terminal Rate Base as of 12/31	$ 1,210,752	$ 2,670,446	$ 4,274,511	$ 3,890,648	$ 3,506,786	$ 3,122,923	$ 2,739,060	$ 2,355,198	$ 1,971,335	$ 1,587,472	$ 1,203,610	$ 819,747	$ 435,884	$ 152,918	$ 0
Average Rate Base as of 12/31	$ 605,376	$ 1,940,599	$ 3,472,478	$ 4,082,580	$ 3,698,717	$ 3,314,854	$ 2,930,992	$ 2,547,129	$ 2,163,266	$ 1,779,404	$ 1,395,541	$ 1,011,678	$ 627,816	$ 294,401	$ 76,459
ROR per Case No. 9692 Filing, Grossed Up	9.69%	9.76%	9.87%	9.87%	9.87%	9.87%	9.87%	9.87%	9.87%	9.87%	9.87%	9.87%	9.87%	9.87%	9.87%
Return	$ 58,686	$ 189,418	$ 342,739	$ 402,957	$ 365,069	$ 327,181	$ 289,294	$ 251,406	$ 213,518	$ 175,630	$ 137,742	$ 99,854	$ 61,966	$ 29,058	$ 7,547
Amortization Expense	69,600	228,911	424,108	529,594	529,594	529,594	529,594	529,594	529,594	529,594	529,594	529,594	529,594	390,393	210,972
Tax Effect	(19,152)	(62,991)	(116,704)	(145,731)	(145,731)	(145,731)	(145,731)	(145,731)	(145,731)	(145,731)	(145,731)	(145,731)	(145,731)	(107,426)	(58,054)
Amortization Expense, Net of Tax	50,448	165,921	307,404	383,863	383,863	383,863	383,863	383,863	383,863	383,863	383,863	383,863	383,863	282,967	152,918
Electrification Program Revenue Requirement - Non-Road Program	$ 130,160	$ 424,489	$ 778,260	$ 946,802	$ 908,914	$ 871,027	$ 833,139	$ 795,251	$ 757,363	$ 719,475	$ 681,587	$ 643,699	$ 605,812	$ 429,957	$ 224,196
														Total Revenue Requirement	$ 9,750,129

Total Electrification Workforce Development Initiative Program Revenue Requirement Over the Life of the Program

	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038
Electrification Workforce Development Program Spend Deferred	$ 1,250,000	922,500	$ 922,500												
Amortization - 2024 Electrification Wordforce Development Spend	$ (50,000)	$ (100,000)	$ (100,000)	$ (100,000)	$ (100,000)	$ (100,000)	$ (100,000)	$ (100,000)	$ (100,000)	$ (100,000)	$ (100,000)	$ (100,000)	$ (100,000)	$ -	$ -
Amortization - 2025 Electrification Workforce Development Spend		(36,900)	(73,800)	(73,800)	(73,800)	(73,800)	(73,800)	(73,800)	(73,800)	(73,800)	(73,800)	(73,800)	(73,800)	(73,800)	
Amortization - 2026 Electrification Workforce Development Spend			(36,900)	(73,800)	(73,800)	(73,800)	(73,800)	(73,800)	(73,800)	(73,800)	(73,800)	(73,800)	(73,800)	(73,800)	(73,800)
Reg Asset Balance as of 12/31	$1,200,000	$1,985,600	$2,697,400	$ 2,449,800	$ 2,202,200	$ 1,954,600	$ 1,707,000	$ 1,459,400	$ 1,211,800	$ 964,200	$ 716,600	$ 469,000	$ 221,400	$ 73,800	$ -
ADIT	(330,210)	(546,387)	(742,257)	(674,124)	(605,990)	(537,857)	(469,724)	(401,590)	(333,457)	(265,324)	(197,190)	(129,057)	(60,924)	(20,308)	-
Terminal Rate Base as of 12/31	$ 869,790	$ 1,439,213	$ 1,955,143	$ 1,775,676	$ 1,596,210	$ 1,416,743	$ 1,237,276	$ 1,057,810	$ 878,343	$ 698,876	$ 519,410	$ 339,943	$ 160,476	$ 53,492	$ -
Average Rate Base as of 12/31	$ 434,895	$ 1,154,501	$ 1,697,178	$ 1,865,410	$ 1,685,943	$ 1,506,476	$ 1,327,010	$ 1,147,543	$ 968,076	$ 788,610	$ 609,143	$ 429,676	$ 250,210	$ 106,984	$ 26,746
ROR per Case No. 9692 Filing, Grossed Up	9.69%	9.76%	9.87%	9.87%	9.87%	9.87%	9.87%	9.87%	9.87%	9.87%	9.87%	9.87%	9.87%	9.87%	9.87%
Return	$ 42,160	$ 112,688	$ 167,514	$ 184,119	$ 166,405	$ 148,692	$ 130,978	$ 113,264	$ 95,551	$ 77,837	$ 60,123	$ 42,410	$ 24,696	$ 10,560	$ 2,640
Amortization Expense	50,000	136,900	210,700	247,600	247,600	247,600	247,600	247,600	247,600	247,600	247,600	247,600	247,600	147,600	73,800
Tax Effect	(13,759)	(37,671)	(57,979)	(68,133)	(68,133)	(68,133)	(68,133)	(68,133)	(68,133)	(68,133)	(68,133)	(68,133)	(68,133)	(40,616)	(20,308)
Amortization Expense, Net of Tax	36,241	99,229	152,721	179,467	179,467	179,467	179,467	179,467	179,467	179,467	179,467	179,467	179,467	106,984	53,492
Electrification Program Revenue Requirement - Workforce Development Initiative	$ 93,505	$ 253,272	$ 383,884	$ 438,382	$ 420,668	$ 402,955	$ 385,241	$ 367,527	$ 349,814	$ 332,100	$ 314,386	$ 296,673	$ 278,959	$ 162,131	$ 78,426

Total Revenue Requirement $ 4,557,924

Total Electrification Program Revenue Requirement Over the Life of the Program

	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038
Electrification Spend Deferred															
2024	$ 31,450,648	90,329,691	$ 149,738,093												
2025															
2026															
Amortization - 2024 Electrification Spend	$ (1,258,026)	$ (2,516,052)	$ (2,516,052)	$ (2,516,052)	$ (2,516,052)	$ (2,516,052)	$ (2,516,052)	$ (2,516,052)	$ (2,516,052)	$ (2,516,052)	$ (2,516,052)	$ (2,516,052)	$ (2,516,052)	$ -	$ -
Amortization - 2025 Electrification Spend		(3,613,188)	(7,226,375)	(7,226,375)	(7,226,375)	(7,226,375)	(7,226,375)	(7,226,375)	(7,226,375)	(7,226,375)	(7,226,375)	(7,226,375)	(7,226,375)	(7,226,375)	
Amortization - 2026 Electrification Spend			(5,989,524)	(11,979,047)	(11,979,047)	(11,979,047)	(11,979,047)	(11,979,047)	(11,979,047)	(11,979,047)	(11,979,047)	(11,979,047)	(11,979,047)	(11,979,047)	(11,979,047)
Reg Asset Balance as of 12/31	$30,192,622	$114,393,074	$248,399,216	$ 226,677,741	$ 204,956,267	$ 183,234,792	$ 161,513,318	$ 139,791,843	$ 118,070,368	$ 96,348,894	$ 74,627,419	$ 52,905,945	$ 31,184,470	$ 11,979,047	$ (0)
ADIT	(8,308,255)	(31,478,114)	(68,353,254)	(62,376,047)	(56,398,841)	(50,421,634)	(44,444,427)	(38,467,220)	(32,490,014)	(26,512,807)	(20,535,600)	(14,558,393)	(8,581,187)	(3,296,334)	0
Terminal Rate Base as of 12/31	$ 21,884,367	$ 82,914,960	$ 180,045,962	$ 164,301,694	$ 148,557,426	$ 132,813,158	$ 117,068,890	$ 101,324,623	$ 85,580,355	$ 69,836,087	$ 54,091,819	$ 38,347,551	$ 22,603,284	$ 8,682,713	$ (0)
Average Rate Base as of 12/31	$ 10,942,184	$ 52,399,663	$ 131,480,461	$ 172,173,828	$ 156,429,560	$ 140,685,292	$ 124,941,024	$ 109,196,756	$ 93,452,489	$ 77,708,221	$ 61,963,953	$ 46,219,685	$ 30,475,417	$ 15,642,998	$ 4,341,357
ROR per Case No. 9692 Filing, Grossed Up	9.69%	9.76%	9.87%	9.87%	9.87%	9.87%	9.87%	9.87%	9.87%	9.87%	9.87%	9.87%	9.87%	9.87%	9.87%
Return	$ 1,060,756	$ 5,114,615	$ 12,977,332	$ 16,993,832	$ 15,439,848	$ 13,885,864	$ 12,331,879	$ 10,777,895	$ 9,223,910	$ 7,669,926	$ 6,115,941	$ 4,561,957	$ 3,007,972	$ 1,543,989	$ 428,499
Amortization Expense	1,258,026	6,129,239	15,731,951	21,721,475	21,721,475	21,721,475	21,721,475	21,721,475	21,721,475	21,721,475	21,721,475	21,721,475	21,721,475	19,205,423	11,979,047
Tax Effect	(346,177)	(1,686,613)	(4,329,040)	(5,977,207)	(5,977,207)	(5,977,207)	(5,977,207)	(5,977,207)	(5,977,207)	(5,977,207)	(5,977,207)	(5,977,207)	(5,977,207)	(5,284,852)	(3,296,334)
Amortization Expense, Net of Tax	911,849	4,442,626	11,402,911	15,744,268	15,744,268	15,744,268	15,744,268	15,744,268	15,744,268	15,744,268	15,744,268	15,744,268	15,744,268	13,920,571	8,682,713
Electrification Program Revenue Requirement - Total	$ 2,352,636	$ 11,408,794	$ 29,132,635	$ 39,299,839	$ 37,745,854	$ 36,191,870	$ 34,637,885	$ 33,083,901	$ 31,529,917	$ 29,975,932	$ 28,421,948	$ 26,867,963	$ 25,313,979	$ 21,266,236	$ 12,729,906
														Total Revenue Requirement	$ 399,959,294
By Program:															
Building Program	$2,128,972	$10,731,033	$27,970,491	$37,914,655	$36,416,272	$34,917,889	$33,419,506	$31,921,123	$30,422,740	$28,924,357	$27,425,974	$25,927,591	$24,429,208	$20,674,148	$12,427,285
Non-Road Program	130,160	424,489	778,260	946,802	908,914	871,027	833,139	795,251	757,363	719,475	681,587	643,699	605,812	429,957	224,196
Worforce Development Initiative Program	93,505	253,272	383,884	438,382	420,668	402,955	385,241	367,527	349,814	332,100	314,386	296,673	278,959	162,131	78,426
Total	$2,352,636	$11,408,794	$29,132,635	$39,299,839	$37,745,854	$36,191,870	$34,637,885	$33,083,901	$31,529,917	$29,975,932	$28,421,948	$26,867,963	$25,313,979	$21,266,236	$12,729,906
														Total Revenue Requirement	$ 399,959,294

BALTIMORE GAS AND ELECTRIC
Rate of Return Summary - Case No. 9692

2024 per MYP2 Direct	%	Cost	Wgted	Net of Tax
Debt	48.0%	4.12%	2.0%	1.4%
Equity	52.0%	10.4%	5.4%	5.4%
Total			7.39%	6.8%
Conversion Factor				1.41677
Grossed Up ROR				9.69%

2025 per MYP2 Direct	%	Cost	Wgted	Net of Tax
Debt	48.0%	4.26%	2.0%	1.5%
Equity	52.0%	10.4%	5.4%	5.4%
Total			7.45%	6.9%
Conversion Factor				1.41677
Grossed Up ROR				9.76%

2026 per MYP2 Direct	%	Cost	Wgted	Net of Tax
Debt	48.0%	4.48%	2.2%	1.6%
Equity	52.0%	10.4%	5.4%	5.4%
Total			7.56%	7.0%
Conversion Factor				1.41677
Grossed Up ROR				9.87%

Case No. 9692
Baltimore Gas and Electric Co.
Response to OPC Data Request 20
Request Received: April 27, 2023
Response Date: May 11, 2023
Sponsor(s): Mark D. Case

Item No.: OPCDR20-01

Refer to the Direct Testimony of Mark D. Case at pages 49-50, BGE's Exhibit MDC-5, and BGE's response to StaffDR25-04.

A. Regarding BGE's plan to execute its proposed building and non-road electrification proposals "with a portfolio designed and developed based on industry best practices and our successes in driving deeper emissions reductions through programs such as those in our prior EmPOWER MD and EVSmart portfolios," will the entire portfolio that BGE develops be included in BGE's 2024-26 EmPOWER plan in Public Service Commission Case No. 9648?
B. If BGE's answer to question A. is yes, please explain why BGE has included the building and non-road electrification proposal in the MYP 2.
C. If BGE's answer to question A above is no, please provide any reason for not including the electrification portfolio in BGE's 2024-26 EmPOWER plan in Case No. 9648.

RESPONSE:

A. BGE anticipates including the portfolio in at least one of the three separate EmPOWER scenarios which the Commission directed BGE to file by August 1, 2023, in Order No.90546 in Case No. 9648.

B. The proposed Customer Electrification Plan programs are expected to cost multiples of the existing EmPOWER energy efficiency programs. In order to better match the costs of these programs with their benefits and ensure customers do not prepay for these longer-life measures, BGE is proposing that the costs be recovered in base rates by deferral in a regulatory asset that is recovered over the weighted average measure life of all measures within the portfolio, which is 12.5 years. This is not only the proper approach from a cost causation standpoint, but it is also the right answer from a rate gradualism and customer affordability perspective. Without a regulatory asset that is recovered over a period approximating the benefits period received by customers, customers who simply cannot afford these programs will be left behind and even customers who might afford these programs will likely simply choose to delay, placing Maryland's decarbonization goals in jeopardy at the very outset. Please also see the response to OPCDR20-06.

C. Please see the response to subpart (B), above.