BEFORE THE
MAYLAND PUBLIC SERVICE COMMISSION

PETITION OF THE OFFICE OF PEOPLE'S COUNSEL FOR NEAR-TERM PRIORITY ACTIONS AND COMPREHENSIVE, LONG-TERM PLANNING FOR MARYLAND'S GAS COMPANIES	* * *	CASE NO. 9707 (Phase II)

* * * * * * * * * * * * *

REBUTTAL TESTIMONY

OF

KENJI TAKAHASHI

ON BEHALF OF THE OFFICE OF PEOPLE'S COUNSEL

July 13, 2026

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I. Introduction

Q. Please state your name and business address.

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

Q. Have you previously testified in Case No. 9707?

A. Yes. I provided initial and reply testimony on May 4, 2026.

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 rebuttal testimony?

A. The purpose of my rebuttal testimony is to respond to two categories of issues. First, I respond to claims by Washington Gas Light Company witnesses Stephen B. Wemple and Mark Karl, Columbia Gas of Maryland witness Cyndee Fang, and Chesapeake Utilities witness Shane Breakie (the "utility electric sector planning witnesses") regarding the electric system impacts, costs, emissions effects, and risks of electrification. Second, I respond to Staff witness Evan Thomas's analysis of customer counts and weather-normalized throughput and explain why that analysis does not resolve broader gas demand forecasting and planning issues. In each area, I explain why the record supports a more realistic, forward-looking, transparent, and validated approach to evaluating electrification impacts, gas demand forecasts, and design day planning requirements.

Note, this testimony does not respond to utility and Staff arguments exhaustively; my silence on any particular argument should not be construed to mean I agree with that argument, nor should any other conclusion be drawn from that silence.

Q. Have you prepared exhibits to accompany your testimony?

A. Yes. I have prepared the following exhibits:

- Exhibit KT-R1: an Excerpt of *Assessment of Heat Pumps in Maine Homes* prepared by Ridgeline Energy Analytics and Demand Side Analytics for Efficiency Maine Trust (2026)
- Exhibit KT-R2: reproduced data from PJM Interconnection's digital 2026 Load Forecast Report Tables
- Exhibit KT-R3: the Public Service Commission's *Ten-Year Plan (2025–2034) of Electric Companies in Maryland* (2025)
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II. The utility electric sector planning witnesses' claims regarding the electric system impacts and risks of electrification are irrelevant and premised on unreasonable assumptions.

Q. Please provide an overview of this section of your testimony.

A. In this section, I address concerns raised by the utility electric sector planning witnesses—Mr. Breakie, Ms. Fang, Mr. Karl, and Mr. Wemple—regarding large-scale electrification and fuel switching. I did not respond to these arguments in my initial and reply testimony because, prior to the due date for that testimony, the Special Master had granted the Office of People's Counsel's motion to strike that testimony.[1] On June 30, 2026, the Public Service Commission reversed the Special Master's decision striking the testimony,[2] leaving this rebuttal testimony as the only opportunity to respond to it.

[1] Maillog No. 329666.
[2] Order No. 92489.

Q. What are the primary arguments that the utility electric sector planning witnesses presented against electrification of Maryland's gas customers?

A. The utility electric sector planning witnesses variously claim that full electrification and other forms of fuel switching away from natural gas could: (1) substantially increase winter electric peak demand and create major electric grid reliability and infrastructure challenges; (2) impose very large customer and electric system costs; (3) fail to produce meaningful emissions reductions—or potentially increase emissions under certain current PJM Interconnection, LLC grid conditions; and (4) be less practical and cost-effective than hybrid gas-electric pathways. In the following sections, I address each of these principal claims and evaluate the methodological soundness of the assumptions underlying them.

Q. What are your concerns about the testimony of the electric sector planning witnesses?

A. As an initial matter, this proceeding is not an appropriate venue to address broader joint electric and gas planning, given that there are many pressing issues specific to gas companies that need to be addressed.[3] More importantly, arguments focused on electric sector planning do not resolve the gas-specific planning issues before the Commission. The relevant

[3] *See* OPC Witness Napoleon Initial and Reply Testimony at 49:12-52:11; *see also* Order No. 92489 at 3 ("This is a gas planning proceeding . . . the Commission already has other proceedings studying electric planning issues.")

concern is that per-customer gas usage is declining, and total gas consumption has been stagnant or declining for some utilities, while gas system investment and revenue requirements continue to increase.[4] This combination can place upward pressure on customer rates because rising fixed gas-system costs must be recovered over flat or declining sales. Regardless of the causes of these trends, gas utilities should plan in a manner that reflects flat or declining usage and protects remaining gas customers from unreasonable investment patterns, stranded asset risk, and the resulting rate pressures.

Moreover, as the Commission's reversal order stated, the Special Master should give "appropriate weight [to utility electric sector planning witnesses' testimony] as it relates to the issues within scope" but "need not . . . address broader electric-sector planning questions or PJM market issues."[5] The portions of the utility electric sector planning witnesses' testimony to which I am responding address the "broader electric-sector planning questions or PJM market issues" that the Commission determined the Special Master need not address.

Nevertheless, since the testimony has been restored to the record, I have evaluated the utility electric sector planning witnesses' conclusions.

[4] OPC Witness Takahashi Initial and Reply Testimony at 25.
[5] Order No. 92489 at 4.

Their principal conclusions rely heavily on flawed or outdated assumptions regarding electric peak loads, heat pump performance, infrastructure costs, gas system retirement opportunities, and future grid emissions.

A. Grid Reliability Claims

Q. Please summarize the electric sector planning witnesses' claims about the impacts of electrification on the electric system.

WGL witness Wemple conducts a design-day analysis that converts all gas heating load served by WGL and other Maryland gas utilities into equivalent winter electric load using assumed heat pump performance under cold-weather conditions. Based on that analysis, Mr. Wemple argues that widespread electrification of gas heating would substantially increase winter electric peak demand, shift Maryland electric utilities from summer-peaking to winter-peaking systems, and require major new generation, transmission, and distribution infrastructure. His analysis estimates that electrification of all gas heating currently served by WGL in Maryland would approximately double Pepco's Maryland peak load from 4,137 MW to 8,469 MW.[6] He also estimates that statewide electrification of gas heating would add approximately 10,535 MW of net new peak load.[7]

[6] WGL Witness Wemple Direct Testimony at 12:2–9.
[7] *Id.* at 17:6–8.

WGL witness Mark Karl focuses his analysis on PJM.[8] Mr. Karl claims that PJM is already facing resource adequacy and reliability constraints and that large-scale electrification of gas heating loads would add substantial electric demand, increasing reliability and cost risks and calling into question the feasibility of moving away from natural gas.[9] Mr. Karl also makes claims regarding operational issues associated with shifting from summer-peaking to winter-peaking conditions due to electrification of heating loads.[10]

Similar to Mr. Karl, Columbia witness Fang evaluates Maryland electrification feasibility in the context of regional PJM generation and capacity adequacy.[11] Similar to Mr. Wemple, Ms. Fang claims that electrification of space and water heating in Maryland would increase winter peak demand and could shift the electric system from historical summer-peaking conditions to winter-peaking conditions.[12]

Chesapeake Utilities' witness Breakie claims that PJM is already strained, "especially" on the Eastern Shore, citing PJM's treatment of its

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[8] WGL Witness Karl Direct Testimony at 3:4-5 ("The purpose of my testimony is to discuss the current and anticipated resource adequacy and reliability status of the PJM electric power system.").
[9] *Id.* at 3:3–5:4, 26:4–20.
[10] *Id.* at 40:8-50:15.
[11] Columbia Witness Fang Direct Testimony at 11:20-22 ("Electrification feasibility in Maryland should be evaluated within the context of regional generation and capacity adequacy in the Pennsylvania-New Jersey Maryland Interconnection ('PJM') market.").
[12] Columbia Witness Fang Direct Testimony at 11:6-12:20.

DPL-South region as a constrained area and Mr. Wemple's analysis that electrifying gas space-heating loads would require substantial incremental electric capacity and materially stress the grid.[13]

Q. What are the primary limitations of Mr. Wemple's analysis of grid impacts from electrification?

A. Mr. Wemple's analysis relies on several erroneous, overly conservative, or otherwise problematic assumptions that materially overstate projected electric peak demand and infrastructure impacts from electrification.

First, Mr. Wemple's analysis is primarily a theoretical full-conversion stress test, in which gas heating demand is assumed to be converted comprehensively and nearly simultaneously to electric load under extreme winter design-day conditions.[14] This analysis is not a realistic assessment of likely grid impacts under plausible market-driven, policy-driven, or targeted adoption electrification pathways that would occur gradually over many years. As a result, this framework is considerably less informative for understanding likely real-world electric system impacts than an analysis incorporating phased electrification, targeted deployment, or managed transition strategies.

Second, Mr. Wemple's analysis relies on conservative assumptions regarding heat pump cold-weather performance that likely overstate

[13] Chesapeake Witness Breakie Direct Testimony at 12:18-13:15.
[14] WGL Witness Wemple Direct Testimony at 8:1–8.

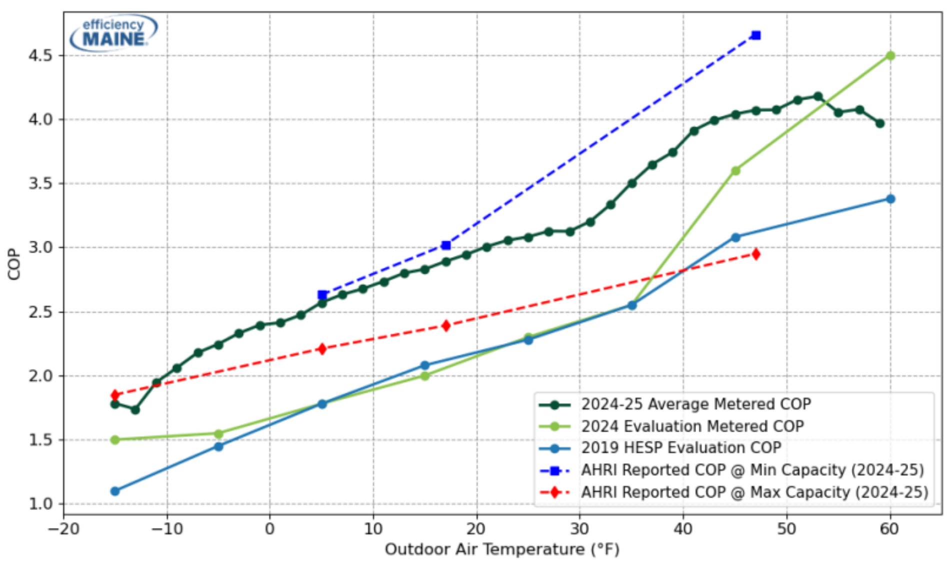
projected winter peak electric demand. More specifically, his analysis relies on ENERGY STAR minimum cold-climate heat pump coefficient of performance ("COP") assumptions at a 5°F design condition—a COP of approximately 1.75—as a basis for converting gas heating loads into electric peak demand.[15] This assumption is conservative because it emphasizes near-minimum performance levels rather than likely average field performance across modern cold-climate heat pumps.

For example, the 2026 Efficiency Maine Whole-Home Heat Pump Study,[16] which evaluated 78 installed cold-climate heat pumps in the state of Maine, found that average field-measured COPs at approximately 5°F were materially higher than 1.75—exceeding 2.5 on average across the sample—indicating that real-world cold-climate heat pump performance is substantially higher than the minimum assumptions used by Mr. Wemple.[17] As shown in **Figure 1**, the study compared average COP values by outdoor temperature across Efficiency Maine heat pump evaluations conducted in 2019, 2024, and 2024–2025, and found that field-measured COP values have improved over time, with the most recent results generally exceeding

[15] WGL Witness Wemple Direct Testimony at 8:8–12. COP, or coefficient of performance, is the ratio of useful heating or cooling output to electric energy input. For example, a COP of 1.75 means that a heat pump produces 1.75 units of heat for every 1 unit of electricity consumed.
[16] David Korn, et al., *Assessment of Heat Pumps in Maine Homes* (Efficiency Maine Trust, Jan. 2026), available at: https://www.efficiencymaine.com/docs/Efficiency_Maine_Whole_Home_Heat_Pump_Study_2026.pdf (excerpt attached as Exhibit KT-R1).
[17] *Id.* at 74, KT-5 at 4.

the earlier field-measured values across much of the observed temperature range. This indicates that real-world cold-climate heat pump performance is substantially higher than the minimum assumptions used by Mr. Wemple. To the extent actual installed performance is materially higher than assumed, projected electric peak loads and related infrastructure requirements are likewise materially overstated.

Figure 1. Field-Measured Heat Pump COP by Outdoor Temperature in Efficiency Maine Studies, 2019–2025



Note: The "AHRI reported COP" values are manufacturer-reported equipment ratings at minimum and maximum heating capacity, rather than field-measured results
Source: Korn, et al., Assessment of Heat Pumps in Maine Homes, Exhibit KT-R1 at 9.

Third, Mr. Wemple's analysis does not consider managed electrification strategies—including demand response, thermal storage, weatherization, targeted electrification, strategic hybrid deployment, improved building envelopes, or other peak-mitigating measures—that could substantially reduce projected winter peak impacts.[18] By framing electrification as an aggregate, unmanaged load conversion exercise, the analysis overstates electric system requirements relative to more optimized or managed electrification pathways.

Fourth, Mr. Wemple emphasizes electric infrastructure additions without evaluating broader integrated planning considerations, including geographically targeted electrification strategies that focus heat pump adoption in areas where gas pipeline segments could potentially be retired and where the electric system can accommodate new load; avoided gas infrastructure replacement; strategic gas system retirement; least-cost planning across the gas and electric systems; and potential avoided stranded gas asset risks.[19] Evaluating electric infrastructure expansion in isolation, without comparably assessing avoided or reduced gas system costs, can materially overstate the net long-term system costs and infrastructure implications of electrification.

Q. How do Mr. Wemple's projected electric-peak impacts compare with other Maryland-specific decarbonization and electrification studies?

A. They are extremely higher. Other Maryland-specific decarbonization and electrification studies with which I am familiar project substantially smaller

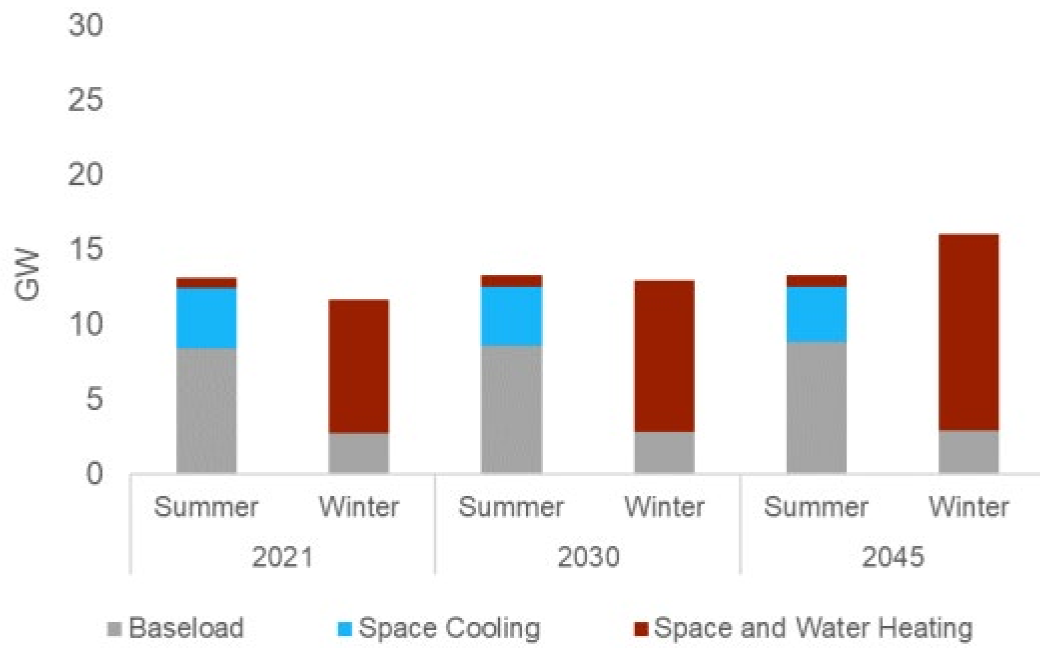
[18] *See* Exhibit WGL-SBW-2, showing the steps taken to estimate peak load impacts of electrification.
[19] Exhibit WGL-SBW-2.

electric peak impacts than those presented by Mr. Wemple, particularly when electrification is modeled as part of policy-driven, phased, and managed transition pathways that also incorporate energy efficiency improvements, building shell upgrades, and other peak-mitigating strategies, rather than as an immediate, near-full conversion scenario.

For example, the 2021 Energy and Environmental Economics ("E3") *Maryland Building Decarbonization Study*, prepared for the Maryland Commission on Climate Change Mitigation Working Group ("MCCC E3 Study"),[20] found that under its "MWG Policy Scenario"—which includes substantial building electrification alongside energy efficiency improvements, shell upgrades, and broader policy measures—Maryland becomes winter-peaking, but projected peak load growth is well below the levels implied by Mr. Wemple's full-conversion analysis. As shown in **Figure 2**, E3 projects approximately 3 GW of incremental peak load growth by 2045 relative to current system peak levels of approximately 13 GW—an increase of roughly 23 percent.[21]

[20] Energy and Environmental Economics, Inc., *Maryland Building Decarbonization Study* (Oct. 2021), available at: https://mde.maryland.gov/programs/Air/ClimateChange/MCCC/Documents/MWG_Buildings%20Ad%20Hoc%20Group/E3%20Maryland%20Building%20Decarbonization%20Study%20-%20Final%20Report.pdf (previously filed as Exhibit KT-3). Note that while this report was prepared by the same consulting firm as the "E3" study relied on by BGE, they are distinct as discussed further below.
[21] *Id.* at 50.

Figure 2. E3 Maryland MWG Policy Scenario: Projected Electric Peak Growth Remains Moderate Under Managed Electrification with Energy Efficiency and Building Shell Improvements (2045)



Source: Energy and Environmental Economics, Inc. (E3). 2021. *Maryland Building Decarbonization Study.* Prepared for the Maryland Commission on Climate Change, Slide 51.

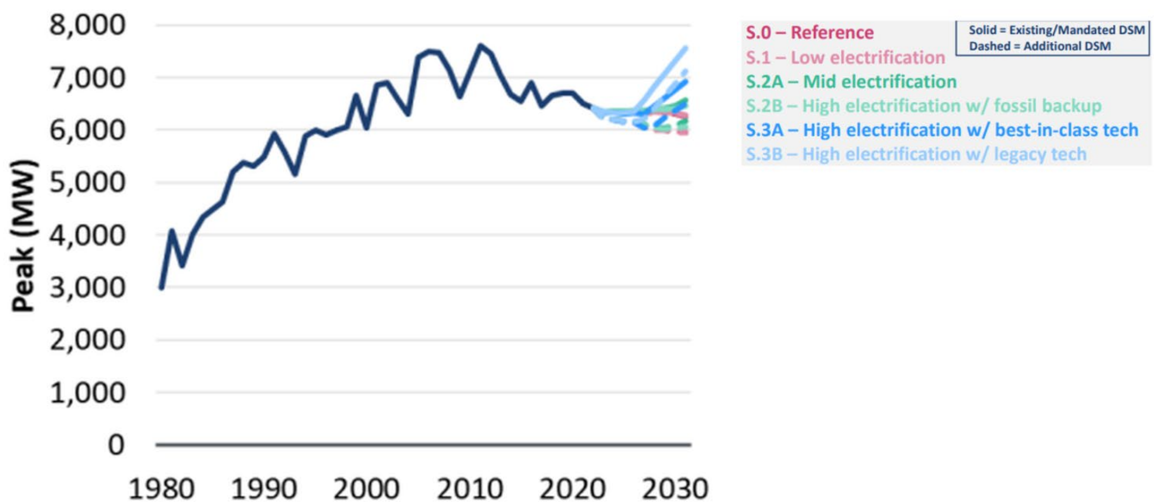
By contrast, Mr. Wemple estimates that statewide electrification of gas heating would increase Maryland's annual system peak by approximately 10.5 GW, or roughly 80 percent relative to Maryland's current summer peak, essentially overnight.[22] The MCCC E3 Study also assumes that improved building shells reduce residential heating demand by 29 percent and commercial heating demand by 34 percent relative to typical existing buildings.[23]

[22] Exhibit WGL-SBW-6. line No. 17.
[23] *Id.* at 74.

Similarly, the Maryland Public Service Commission's more recent electrification study from 2023 conducted by The Brattle Group through an extensive stakeholder process (the "Brattle Maryland Electrification Study") evaluated multiple Maryland electrification scenarios through 2031, including scenarios with different levels of building electrification, transportation electrification, demand-side management ("DSM"), fossil fuel backup, and technology performance.[24] As shown in **Figure 3**, Brattle's projected Baltimore Gas and Electric Company ("BGE") peak loads under its electrification scenarios remain close to recent historical peak levels through 2031, under Scenario S.3A, which includes both building and transportation electrification under high-electrification and best-in-class technology assumptions. Under Scenario S.3A, BGE's peak load increases from approximately 6,414 MW in 2022 to approximately 6,917 MW by 2031—roughly 8 percent growth over nine years—well below the peak increases implied by Mr. Wemple's full-conversion design-day analysis.[25] By comparison, as I discussed above, Mr. Wemple estimates that electrifying all gas heating would increase Maryland's statewide annual system peak by approximately 80 percent more or less immediately.

[24] The Brattle Group, *Maryland Electrification Study: Final Report* (Dec. 2023), available at: https://psc.maryland.gov/wp-content/uploads/Corrected-MDPSC-Electrification-Study-Report-2.pdf (previously filed as Exhibit KT-4).
[25] *Id*. at Technical Appendix 92, Exhibit KT-4 at 86.

Figure 3. Historical and Projected BGE Peak Load in the Brattle Maryland Electrification Study



Source: Brattle Maryland Electrification Study, Technical Appendix at 101, Exhibit KT-4 at 106.

Q. Does Mr. Wemple's discussion of PJM's 2027/2028 resource adequacy concerns demonstrate that near-term heating electrification in Maryland will create additional PJM generation capacity requirements?

A. No. Mr. Wemple correctly identifies PJM resource adequacy as a relevant concern for regional electric planning, but his discussion does not show that near-term heating electrification in Maryland is a material driver of PJM's 2027/2028 capacity shortfall. As shown in **Table 1**, the Maryland-relevant load areas remain summer-peaking on a combined basis through 2034 under the PJM and Commission forecasts reflected in the table. A gradual increase in winter heating load would therefore first reduce the existing gap between forecast summer and winter peaks, rather than immediately establish a new annual system peak.

More specifically, projected winter peak loads for Baltimore Gas and Electric Company ("BGE"), Potomac Electric Power Company ("PEPCO"), and Delmarva Power & Light Company ("DPL") remain below projected summer peak loads through 2034. Potomac Edison Company ("PE") is the exception, consistent with its higher electric-heating penetration. On a combined Maryland-relevant PJM load-area basis, however, projected winter peak load remains below projected summer peak load in every year from 2026 through 2034, with approximately 1,073 MW of winter headroom in 2027 and 961 MW in 2028.

Table 1. Projected Summer and Winter Peak Loads for Maryland-Relevant PJM Load Areas and Potomac Edison Maryland Service Territory, 2026–2034

Peak Load (MW)		2026	2027	2028	2029	2030	2031	2032	2033	2034
BGE	Summer	6,471	6,436	6,412	6,445	6,484	6,533	6,589	6,641	6,650
	Winter	5,855	5,853	5,856	5,884	5,931	6,008	6,082	6,151	6,174
PEPCO	Summer	6,003	5,992	5,980	5,989	6,143	6,247	6,485	6,728	6,936
	Winter	5,353	5,355	5,377	5,372	5,373	5,560	5,748	5,979	6,189
DPL	Summer	4,008	3,986	3,971	3,958	3,949	3,948	3,946	3,958	3,973
	Winter	3,775	3,787	3,801	3,781	3,778	3,771	3,792	3,807	3,796
PE	Summer	3,680	4,048	4,081	4,118	4,164	4,202	4,246	4,280	4,326
	Winter	4,223	4,394	4,449	4,517	4,574	4,627	4,688	4,741	4,810
Total IOUs	Summer	20,162	20,462	20,444	20,510	20,740	20,930	21,266	21,607	21,885
	Winter	19,206	19,389	19,483	19,554	19,656	19,966	20,310	20,678	20,969
	Winter headroom (Summer – Winter)	**956**	**1,073**	**961**	**956**	**1,084**	**964**	**956**	**929**	**916**

Note: BGE, DPL, and PEPCO values reflect PJM load-area forecasts from PJM's 2026 Load Forecast. Potomac Edison values are from the Maryland Public Service Commission's Ten-Year Plan (2025-2034) of Electric Companies in Maryland because PJM reports Potomac Edison within the broader APS/Allegheny Power zone. The table is intended as a Maryland-relevant PJM capacity-context comparison, not a strict Maryland-only retail forecast.

Sources: PJM Interconnection, LLC, *2026 Load Forecast Report Tables* (2026), available at: https://www.pjm.com/-/media/DotCom/planning/res-adeq/load-forecast/2026-load-report-tables.xlsx (excerpts from tab B1 and B2 produced as Exhibit KT-R2); Maryland Public Service Commission, *Ten-Year Plan (2025–2034) of Electric Companies in Maryland* (2025), available at: https://psc.maryland.gov/wp-content/uploads/2026/01/10-year-plan.docx-1.pdf (attached as Exhibit KT-R3).

The headroom between summer and winter peaking matters because incremental heat-pump load primarily affects winter peak demand. In the near term, the forecast indicates that heating electrification would first reduce existing winter headroom rather than shift the combined planning peak from summer to winter. In the medium term, the same general conclusion holds through 2034: projected winter peak load remains 916 MW to 1,084 MW below projected summer peak load on a combined Maryland-relevant PJM load-area basis.

As discussed above, Mr. Wemple's assessment is a theoretical full-conversion stress test that assumes conversion of all gas heating load to electric heat pumps essentially immediately, rather than a forecast of a realistic, gradual heat-pump adoption pathway. He has not shown that the winter-peak impacts of realistic, near-term heat-pump adoption would be sufficient to eliminate the projected headroom or cause winter demand to establish a new combined annual peak in the 2027/2028 planning period. Nor has he shown that this would occur any time before 2034 under the PJM and Commission forecasts reflected in **Table 1**.

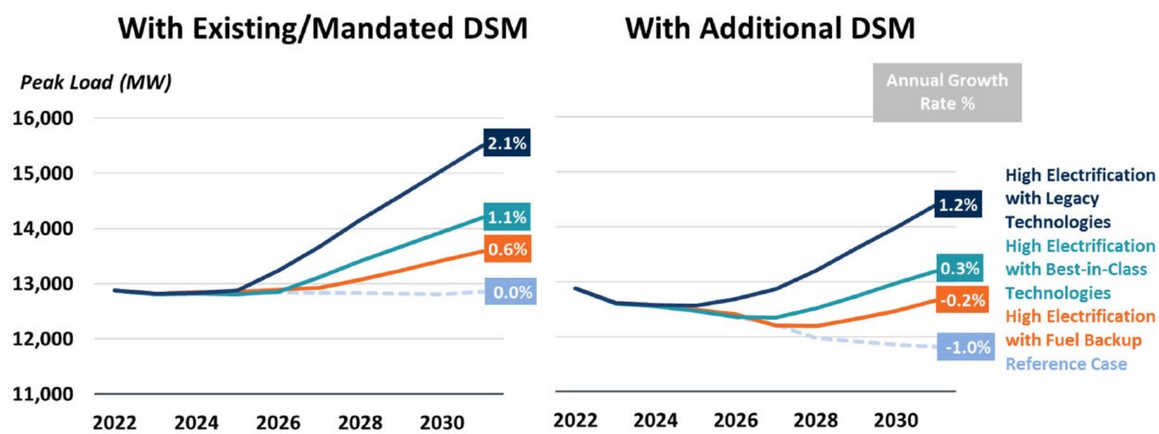
Q. How does the Maryland statewide electrification study prepared by Brattle inform this assessment?

A. Brattle's statewide electrification study provides additional context because it evaluates the combined peak-load impacts of building and transportation electrification under multiple technology and DSM scenarios. As shown in **Figure 44**, Brattle's statewide electrification study projects annual peak load growth of approximately 1.1 percent under the High Electrification with Best-in-Class Technologies scenario with existing/mandated DSM.[26] Based

[26] Brattle Maryland Electrification Study, Exhibit KT-4 at 24.

on that figure, this corresponds to an increase of roughly 1,000 MW relative to the 2022 base-year peak over the following decade.

Figure 4. Projected Maryland Peak Load Growth With and Without Additional DSM



Source: Brattle Maryland Electrification Study, Figure 7, "Projected Aggregate Maryland System Peak Load In Electrification Scenarios," Exhibit KT-4 at 24.

I focus on the Best-in-Class Technologies scenario because it is more relevant to a policy-driven electrification pathway in Maryland than Brattle's Legacy Technologies scenario.[27] Maryland's climate and efficiency programs support high-efficiency heat pumps, including cold-climate heat pumps, rather than widespread adoption of less-efficient legacy heat-pump systems with electric resistance backup. The Legacy Technologies scenario is therefore better understood as a sensitivity showing the consequences of

[27] Brattle defines the High Electrification with Best-in-Class Technologies scenario as assuming widespread adoption of more efficient technologies, including best-in-class heat pumps, while the Legacy Technologies scenario reflects less-efficient technology assumptions, including greater reliance on electric resistance backup. Brattle Maryland Electrification Study, Exhibit KT-4 at 9.

inefficient technology adoption, rather than the most relevant case for evaluating managed electrification under Maryland climate policy.

The projected increase under the High Electrification with Best-in-Class Technologies scenario is close to, and slightly above the lower end of, the 916 MW to 1,084 MW of projected winter headroom shown in **Table 1**, for 2026–2034. Importantly, however, Brattle's estimate reflects both building and transportation electrification statewide, not near-term heat pump adoption alone.

Brattle also shows that peak impacts can be substantially reduced through additional DSM. Under the High Electrification with Best-in-Class Technologies scenario with additional DSM, statewide peak load growth is only about 0.3 percent per year, corresponding to less than 300 MW of additional peak load relative to the 2022 base year. That level of increase is well within the projected winter headroom shown in **Table 1**. This demonstrates that electrification-related peak impacts depend heavily on technology efficiency, load management, and DSM assumptions, and that managed electrification can substantially reduce capacity impacts.

B. Cost Claims

Q. Summarize the utility electric sector planning witnesses' claims regarding the costs of electrification.

A. One utility witness, Mr. Wemple, testified substantially on this issue.[28] He argues that "replacing all the gas space heating in Maryland with electric air source heat pumps" would impose very large customer and electric system costs.[29] His testimony estimates approximately $74.5 billion in statewide electrification costs, including both customer heat pump installations and major electric generation, transmission, and distribution infrastructure investments needed to support increased electric heating loads.

Q. What are the primary limitations of Mr. Wemple's cost analysis?

A. Mr. Wemple's cost estimates materially overstate the net long-term costs of electrification because a substantial share of his projected costs is directly driven by the same considerably overstated winter peak growth and electric infrastructure expansion assumptions discussed above.[30] As noted above, Maryland-specific decarbonization pathway studies such as the 2021 E3 Maryland MWG Policy Scenario project more moderate peak growth under managed electrification, energy efficiency, and building shell improvements

[28] UGI Witness Jessica Rogers also makes general, unquantified claims that customers may not choose to switch to electricity based on the costs and inconvenience involved. *See* UGI Witness Jessica Rogers Direct Testimony at 18:21-19:7.
[29] WGL Witness Wemple Direct Testimony at 5:15–21 to 6:1–5.
[30] Exhibit WGL-SBW-2.

than the extreme full-conversion framework underlying Mr. Wemple's analysis.[31] Because his winter peak and related electric infrastructure assumptions are considerably overstated, the associated generation, transmission, and distribution cost projections are likewise substantially overstated. In addition, Mr. Wemple's analysis places primary emphasis on projected electric system and customer electrification costs, while providing inadequate consideration of avoided future gas infrastructure replacement costs, avoided gas commodity costs, reduced long-term gas system capital expenditures, and broader integrated gas-electric planning considerations.

C. Emissions Claims

Q. Summarize the utility electric sector planning witnesses' claims regarding emissions impacts from electrification.

A. The emissions claim in this area is primarily presented by Mr. Wemple and cited or echoed by other utility witnesses.[32] Mr. Wemple argues that under current PJM marginal emissions assumptions, widespread conversion of gas heating to electric heat pumps would provide limited greenhouse-gas reductions benefits and could increase emissions depending on the type and efficiency of heat pumps installed.[33] To support this claim, Mr. Wemple compares current emissions from natural gas space heating with the

[31] *See* MCCC E3 Study at 50, Exhibit KT-3 at 50.
[32] *See, e.g.*, Chesapeake Witness Breakie Direct Testimony at 13:8-15.
[33] WGL Witness Wemple Direct Testimony at 20:2-24:2.

emissions that would result if the same space-heating load were served by electric air-source heat pumps using electricity from the PJM wholesale market. His testimony concludes that replacing all Maryland gas space-heating load with electric air-source heat pumps at current federal efficiency standards could increase statewide GHG emissions by approximately 11 percent, or 886,000 short tons per year, relative to continuing to serve that space-heating load with natural gas.[34] He further concludes that even if all customers installed cold-climate heat pumps, statewide GHG emissions would decline by only approximately 2 percent, or 173,000 short tons per year.[35]

Q. Does the actual emissions impact of state policies and gas consumption trends have any bearing on your ultimate recommendations?

A. No. The primary purpose of this proceeding, and my testimony, is to investigate the planning and investment practices of gas utilities to ensure that they are reasonable in light of observed gas usage trends and continued gas system investments. These trends likely reflect in part market and technological changes, as well as policies aimed at reducing GHG emissions. The planning purpose does not depend on proving the precise emissions impacts of those policies. The relevant concern is that per-customer gas consumption has generally been declining over time, and total

[34] *Id.* at 20:3–22:4.
[35] *Id.* at 23:3–9.

gas consumption has been stagnant or declining for some utilities, while gas system investment and revenue requirements continue to increase. That combination will, all else equal, place upward pressure on customer rates because rising fixed gas system costs must be recovered over flat or declining sales. Accordingly, customers who remain on the gas system should be protected against unreasonable investment patterns that do not reflect those demand trends and that could increase rates or create stranded asset risks.

Q. What are the primary limitations of Mr. Wemple's emissions analysis?

A. Again, none of these claims inform the ultimate purpose of this proceeding that gas utilities should plan in a manner that reflects flat or declining usage and protects remaining gas customers from rate increases and stranded asset risk. Moreover, Mr. Wemple's emissions analysis is flawed because it materially overstates the long-term emissions impacts of electrification by placing disproportionate weight on current PJM marginal emissions assumptions[36] while understating likely future grid decarbonization, and because his conclusions are inconsistent with WGL's own prior Maryland-specific comparative analysis.[37]

[36] PJM's marginal emissions rate represents the emissions associated with the marginal generating units that would change output to serve the next increment of electricity demand at a given location and time. See WGL Witness Wemple Direct Testimony at 21:8-10.
[37] Washington Gas Light Company and GTI Energy, *Washington Gas Maryland Gas Heat Pump Pilot Final Report,* Appendix C: "Methodology & Results of Comparative Analysis of Gas Versus

First, by emphasizing current PJM marginal emissions rates, Mr. Wemple's analysis effectively treats *current* PJM grid conditions as a proxy for the *long-term* emissions impacts of electrification. PJM publishes historical and near-real-time marginal emissions data, but I am not aware of a PJM long-term emissions-rate forecast comparable to PJM's long-term load forecast. Moreover, PJM's own historical data show that average CO_2 emission rates across its footprint declined by 43 percent from 2005 to 2023, while NO_x and SO_2 emission rates declined by 90 percent and 96 percent, respectively.[38] This demonstrates at least that PJM emissions conditions are not static. Mr. Wemple's analysis therefore fails to reflect expected long-term declines.

By contrast, WGL's own Gas Heat Pump Pilot comparative analysis—a Maryland PSC-directed, Maryland-specific study comparing gas heat pumps, gas furnaces, and electric heat pumps across multiple current and future emissions scenarios—provides a more forward-looking framework by evaluating lifetime emissions under Maryland policy and future grid assumptions.[39] As shown in **Figure 5**, that study found that high-efficiency electric heat pumps produced substantially lower lifetime

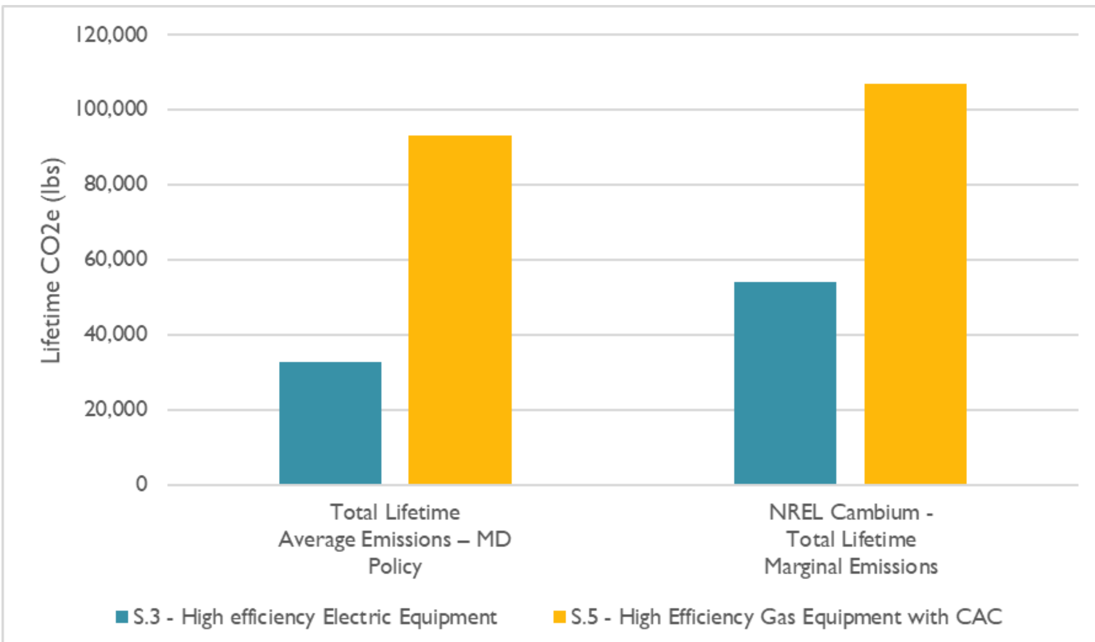
Electric Heat Pumps," Table 4, (filed September 12, 2024, Case No. 9705) (attached as Exhibit KT-R4) ("WGL Heat Pump Report").

[38] PJM. 2024. "Emission Rates in PJM Reach All-Time Low." PJM Inside Lines, March 28, 2024. Available at: https://insidelines.pjm.com/emission-rates-in-pjm-reach-all-time-low/ (attached at Exhibit KT-R5).

[39] WGL Heat Pump Report at Appendix C, Exhibit KT-R4 at 53-75.

emissions than high-efficiency gas furnace systems paired with central air conditioners ("CACs")—approximately 50 to 65 percent lower depending on scenario—demonstrating that when future grid evolution is properly considered, electrification produces substantially lower long-term emissions outcomes.[40]

Figure 5. Lifetime Greenhouse Gas Emissions Comparison: High-Efficiency Electric Heat Pumps vs. High-Efficiency Gas Heating (WGL Gas Heat Pump Pilot)



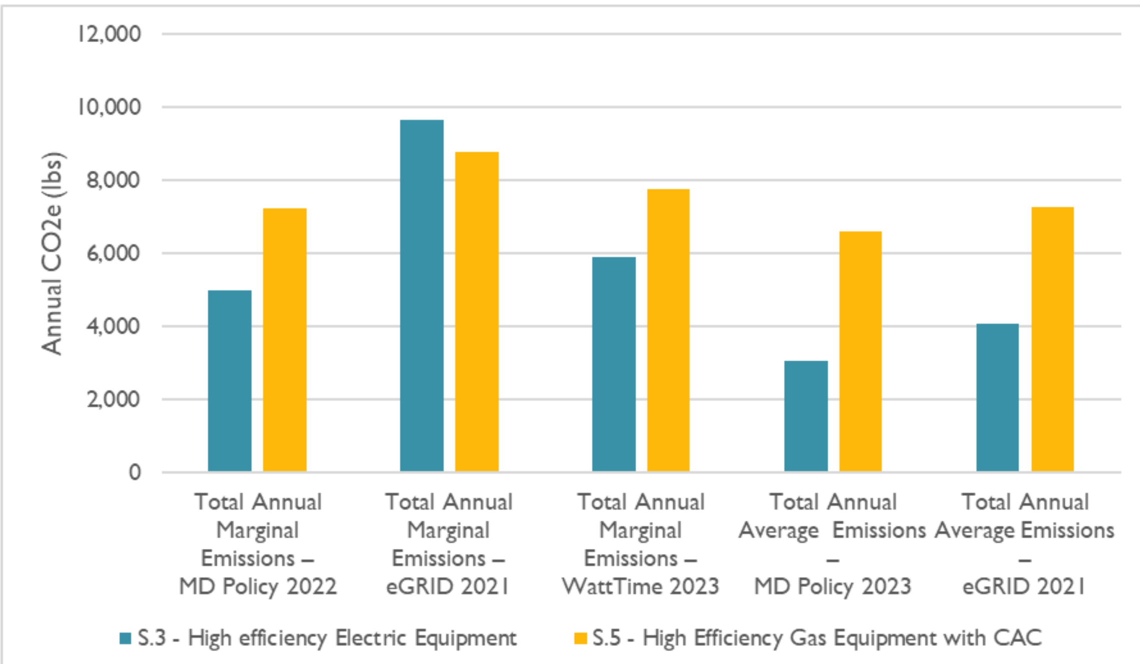
Note: CAC = central air conditioner. Source: WGL Heat Pump Report at Appendix C, Table 4, Exhibit KT-R4 at 68-75.

Second, WGL's own pilot study also found that electric heat pumps already outperform gas furnace systems across most modeled annual emissions scenarios. As shown in **Figure 6**, WGL's Maryland-specific comparative analysis found that electric heat pumps produced lower annual

[40] The gas furnace heating option includes central air conditioners ("CACs") so that it can be compared fairly with heat pumps, which provide both heating and cooling services.

emissions than high-efficiency gas furnace systems in four of five modeled scenarios, including under Maryland policy and average emissions cases. Thus, WGL's own prior analysis demonstrates that electric heat pumps already provide lower emissions than gas heating across most modeled current scenarios, even before accounting for further grid decarbonization.

Figure 6. Annual Greenhouse Gas Emissions Comparison Across Maryland-Specific Scenarios: High-Efficiency Electric Heat Pumps vs. High-Efficiency Gas Heating



Source: Washington Gas Light Company and GTI Energy. 2024. *Washington Gas Maryland Gas Heat Pump Pilot Final Report,* Appendix C: "Methodology & Results of Comparative Analysis of Gas Versus Electric Heat Pumps," Table 4. (Case No. 9705).

Third, other Maryland-specific evidence also confirms that Mr. Wemple's reliance on maintaining the current PJM marginal emissions rate is inappropriate for evaluating long-term electrification impacts. As Sierra Club witness Jim Grevatt explains, the EmPOWER Future Programming

Work Group worked with the Maryland Department of the Environment ("MDE") to apply declining electric-sector emissions projections when developing proposed EmPOWER greenhouse gas abatement goals.[41] The Work Group applied an average 15-year marginal emissions rate of approximately 559 pounds of CO_2e per MWh—less than half the current PJM marginal emissions rate assumed by Mr. Wemple's analysis.[42] Mr. Grevatt also notes that BGE's Integrated Decarbonization Study assumed continued grid decarbonization, with all scenarios projecting substantial declines in electric-sector emissions over time.[43]

D. Hybrid Gas-Electric System Claims

Q. Summarize the utility electric sector planning witnesses' claims regarding hybrid gas-electric systems.

A. Mr. Wemple is the primary utility witness who addresses this issue. Mr. Wemple presents continued use of the gas system, including hybrid gas-electric pathways, as a lower-cost alternative to full electrification that would avoid the winter electric reliability concerns he claims are associated with converting gas heating load to electric heat pumps.[44] He also cites the E3 Integrated Decarbonization Study for the proposition that a hybrid

[41] Sierra Club Witness Grevatt Direct Testimony at 14:8–15:5
[42] *Id.* at 14: 19–20; 15: 1.
[43] *Id.* at 15:1–5
[44] WGL Witness Wemple Direct Testimony at 5:7–10; 7:3–17; 30:18–31:8.

pathway would cost less than a pathway involving deep reductions in gas sales.[45] In addition, he characterizes continued gas energy efficiency investments and replacement-in-kind gas appliances as prudent near-term or "no-regrets" strategies.[46]

Q. What are the primary limitations of Mr. Wemple's discussion of hybrid gas-electric systems and continued gas efficiency investments?

A. Mr. Wemple's discussion has three primary limitations:

- His cost argument relies substantially on BGE's utility-commissioned E3 study ("BGE E3 Study"), which uses assumptions regarding gas-system retirement and heat-pump costs that favor pathways retaining the gas system.[47]
- He does not address the separate statewide E3 study ("MCCC E3 Study"), which was developed through an extensive stakeholder process and found that the MWG Policy Scenario—a pathway centered on residential electrification with flexibility for certain commercial buildings—was the lowest-cost scenario modeled.[48]

[45] Again, this study is distinct from the E3 study developed for the Commission.
[46] WGL Witness Wemple Direct Testimony at 30:1–13, 30:18–23.
[47] Direct Testimony of Kenji Takahashi on behalf of OPC, Maryland PSC Case No. 9692, at 45–52 (June 20, 2023) ("Takahashi 9692 Testimony") attached as Exhibit KT-R6.
[48] Maryland Commission on Climate Change, *Building Energy Transition Plan* (Nov. 2021), at 4, 6, 9–11 available at https://mde.maryland.gov/programs/air/ClimateChange/MCCC/Commission/Building%20Energy%20Transition%20Plan%20-%20MCCC%20approved.pdf ("MCCC Building Transition Plan," attached as Exhibit KT-R7); MCCC E3 Study at 43–44, 55, Exhibit KT-3.

- He does not adequately account for the long-term utility and customer costs of maintaining parallel gas and electric heating systems.[49]

For these reasons, the analyses cited by Mr. Wemple do not demonstrate that widespread hybrid heating is the most practical or least-cost long-term pathway. I explain each point below.

Q. What limitations did you identify in your prior testimony concerning the BGE E3 Study on which Mr. Wemple relies?

A. In my prior testimony in BGE's Multi-Year Plan ("MYP") base rate case, Maryland PSC Case No. 9692, I identified, among other issues, two assumptions in the BGE E3 Study that materially favored pathways retaining the gas system over pathways involving extensive electrification. The study assumed little or no retirement of gas-system assets even though its Limited Gas pathway, which focused on extensive building electrification, projected an approximately 88 percent reduction in gas customers by 2045.[50] I also found that the study used air-source heat-pump cost assumptions that were materially higher than other estimates available at the time, including estimates used or commissioned by BGE.[51] These assumptions in the BGE E3 Study reduced the modeled gas-system savings

[49] MCCC Building Energy Transition Plan at 9–10, 13–15, Exhibit KT-R7.
[50] Takahashi 9692 Testimony at 46–48, Exhibit KT-R6.
[51] *Id.* at 50:13–52:7, Exhibit KT-R6.

under the Limited Gas pathway and increased the modeled equipment costs of the pathway with the greatest electrification. Accordingly, the study's comparative cost results do not demonstrate that hybrid heating is generally the least-cost pathway for Maryland.

Q. What does the MCCC E3 Study indicate about the appropriate role and cost of hybrid heating?

A. The statewide MCCC E3 Study provides an important counterpoint. It was developed for the Maryland Commission on Climate Change through an extensive stakeholder process. After stakeholders raised concerns about the practicality, affordability, and equity of maintaining gas backup—including the cost of maintaining both utility systems as gas use declines—E3 modeled the additional MWG Policy Scenario.[52]

The MWG Policy Scenario combines all-electric new construction and near-complete residential electrification with dual-fuel heat pump retrofits for existing commercial buildings.[53] The MCCC-approved Plan identifies the MWG Policy Scenario as the lowest-cost scenario modeled and states that it avoids requiring homeowners to maintain backup heating systems or rely on expensive low-carbon fuels.[54] Although the statewide E3 Study's detailed cost ranges for the MWG Policy Scenario overlap with

[52] MCCC Building Transition Plan at 4, 9–10, Exhibit KT-R7.
[53] MCCC E3 Study, Exhibit KT-3 at 43-44.
[54] MCCC Building Transition Plan at 10, Exhibit KT-R7.

those of the Fuel Backup Scenario, which retains backup fuel use in a larger share of buildings, the results show that an electrification-centered pathway need not be substantially more expensive than widespread hybrid heating.[55] Summarizing the statewide E3 study, the MCCC-approved Plan indicates that hybrid systems may have a role in certain difficult-to-electrify buildings, including some commercial building retrofits.[56]

Q. What long-term costs can result from widespread reliance on hybrid heating?

A. A valid cost analysis of hybrid heating must consider the lifecycle costs of both systems—including equipment, operations and maintenance, and utility bills—rather than focusing only on near-term equipment costs.[57]

Hybrid heating can create long-term costs by requiring both utilities and customers to maintain parallel systems. At the utility level, gas companies would continue maintaining and investing in gas infrastructure for backup use. As gas use and customer counts decline, gas-system costs must be recovered from fewer customers, placing upward pressure on gas rates and increasing the risk that some gas-system investments become underutilized.[58]

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[55] MCCC E3 Study, at 55, 72, Exhibit KT-3.
[56] MCCC Building Transition Plan at 15, Exhibit KT-R7.
[57] MCCC Building Transition Plan at 15, Exhibit KT-R7.
[58] *Id.* at 9, 14; *see also* Exhibit DHInfrastructure. February 2025. Maryland Gas Utility Spending: Projections and Analysis of Future Capital Investments. Prepared for the Office of the People's Counsel, available at: https://opc.maryland.gov/Portals/0/Files/Publications/Gas%20Utility%20Spending%20Report%20

At the customer level, households retaining gas backup must maintain both a heat pump and a gas furnace or boiler and may eventually need to replace the backup system when it fails. They also remain gas customers and continue paying fixed gas customer charges even if they use little gas annually.[59]

Q. Should continued investments in efficient gas use and replacement-in-kind gas appliances be considered "no-regrets" strategies?

A. Not categorically. Building-shell efficiency and other measures that reduce energy consumption regardless of the heating fuel often represent prudent no-regrets investments. Replacing an aging gas appliance with another long-lived gas appliance, however, may delay future building electrification, extend the customer's reliance on the gas system, and contribute to continued investment in infrastructure that may become increasingly underutilized. Replacement-in-kind gas investments should therefore be evaluated over their expected lives, considering future electrification opportunities and projected gas rates.

Februa ry%202025.pdf?ver=RP_bNtF-Hn7szyL7eLY-Lw%3d%3d, previously attached as Exhibit AN-2 to the Initial and Reply Testimony of OPC Witness Alice Napoleon.

[59] Takahashi 9692 Testimony at 44:6–13, attached as Exhibit KT-R6.

Q. What conclusion should the Commission draw regarding hybrid gas-electric systems?

A. Mr. Wemple's testimony does not demonstrate that pipeline-gas hybrid heating should be treated as the preferred or categorically least-cost long-term pathway, particularly for residential customers.

For commercial buildings, hybrid applications should instead be evaluated case by case, considering building type, heat-pump performance, electric peak impacts, customer equipment and maintenance costs, avoided gas-system investments, future gas-rate impacts, stranded-asset risks, and whether an alternative backup source could facilitate gas-pipeline retirement.

For instance, heat pumps paired with propane backup may also be appropriate in limited circumstances for harder-to-decarbonize commercial buildings. Because propane backup would not require continued connection to the gas distribution system, it could provide supplemental heating while potentially allowing aging gas pipelines to be retired where feasible. Any such option would need to be evaluated based on lifecycle costs, emissions, reliability, on-site fuel-storage requirements, and local conditions.

III. Staff witness Thomas's gas demand forecasting testimony has limited usefulness and ignores the key ratepayer-protection concerns at issue here.

Q. Please provide an overview of this section of your testimony.

A. In this section, I respond to Staff witness Evan Thomas's central rate-design conclusion on Issue 5: that recent customer-count and weather-normalized throughput data do not show material changes warranting "immediate changes to existing gas rate design."[60] That conclusion has limited usefulness in this proceeding. This case is not limited to whether immediate rate design changes are warranted; it concerns broader questions of gas system planning, demand forecasting, future cost recovery, customer rate impacts, stranded asset risk, and ratepayer protection.

Specifically, I explain that Mr. Thomas's analysis:

- does not present a true historical trend analysis that identifies whether gas usage is declining, flat, or increasing over time;
- relies on weather-normalized throughput without evaluating whether actual gas sales and system utilization may have been affected by warming trends;
- does not evaluate whether average use per customer is declining, which can create rate pressure even where customer counts remain

[60] Staff Witness Evan Thomas Direct Testimony at 3:16–18.

stable or increase and utilities continue to invest in long-lived infrastructure; and

- concludes that current climate policies and possible future policy or legislative changes do not provide a sufficient basis for *immediate* rate-design changes, without addressing how those factors should be reflected in *forward-looking* demand forecasts.

These issues with Mr. Thomas's analysis matter because annual gas consumption and usage per customer affect utility sales revenues, the recovery of fixed system costs, and the rates and bills paid by customers. If gas sales decline while utility costs and capital investment continue to increase, those costs must be recovered through higher rates.

Q. Why is accurate gas demand forecasting important in this proceeding?

A. Gas demand forecasting is central to gas planning. Annual sales forecasts and design-day forecasts inform utility revenue projections, rate design, gas supply planning, capacity procurement, distribution infrastructure planning, and evaluations of non-pipeline alternatives. If a utility overestimates future sales or peak demand, it may over-build distribution infrastructure, over-contract for gas supply or capacity, or otherwise make long-lived investments that are not needed under future demand conditions. If actual sales then turn out to be lower than forecasted, the utility must recover fixed costs over a smaller sales base, placing upward pressure on rates, all else equal. Annual sales forecasts and design-day demand forecasts serve related but distinct purposes. Annual sales forecasts inform utility revenue projections, rate setting, evaluations of system utilization, and assessments of how fixed system costs will be recovered from customers. Design-day forecasts more directly inform gas supply, capacity procurement, and distribution infrastructure needs.[61]

Separately, if a utility overestimates future peak demand, it may over-contract for gas supply or capacity or make infrastructure investments that are not needed under future conditions. This problem of over estimation is especially important because long-lived gas infrastructure investments can affect customer rates for many years. It is also important because, as discussed in detail in my initial and reply testimony, Maryland's building market and state and local climate policies are increasingly moving toward building decarbonization, which is expected to reduce gas use in buildings.[62]

Q. Please summarize Mr. Thomas's central rate-design conclusion.

A. Mr. Thomas concludes that immediate changes to gas rate design are not necessary because the recent customer-count and weather-normalized throughput data he reviewed do not show material changes in demand. He also recommends that rate design be based on "observed system conditions,

[61] *See* Initial and Reply Testimony of OPC Witness Kenji Takahashi at 12:12–13:14; 14:13–16.
[62] OPC Witness Takahashi Initial and Reply Testimony at 26–34, 40–42.

established rate design principles, and not speculative assumptions regarding future demand, climate policies, or legislative changes."[63]

Q. Can the Commission draw any helpful conclusions from Mr. Thomas's rate-design presentation?

A. No. Mr. Thomas's conclusion—that recent customer-count and weather-normalized throughput data do not show material changes warranting immediate rate design changes—addresses only a narrow question and should not be used to discount the need for improved gas demand forecasting and long-term gas planning.[64] Even if the Commission were to conclude that immediate rate design changes are not warranted based on the limited data Staff reviewed, that conclusion would not resolve whether the gas companies' demand forecasts adequately account for key factors affecting future gas demand, including declining usage per customer, recent actual consumption trends, projected customer counts, emerging market changes, and current and forthcoming policies. Nor would it resolve whether anticipated demand trends should affect the amount or timing of future gas system investments, or the risk that customers may bear the costs of underused infrastructure. Those are different questions, and they are directly relevant to prudent gas system planning.

[63] Staff Witness Thomas Direct Testimony at 3:13–4:3.
[64] I do not address in this section whether a particular rate design change must be adopted immediately.

Q. Are there other weaknesses in Mr. Thomas's trend analysis?

A. Mr. Thomas's trend analysis is too limited to identify the direction or persistence of any trend.. Mr. Thomas compares recent weather-normalized throughput to a historical range, but that approach does not properly evaluate whether gas usage is declining, flat, or increasing over time.[65] A comparison to a historical range may show that recent values fall within prior experience, but it does not identify the direction or persistence of a trend. It also does not show whether recent usage is moving toward the low end of the historical range, whether usage per customer is declining, or whether future policy and market drivers are likely to move demand below historical levels.

Whether demand is moving below historical levels matters because declining sales can reduce the revenue base over which gas system costs are recovered, placing upward pressure on rates for residential and other remaining gas customers. As shown in **Table 2**, Mr. Thomas summarizes the 2014 through 2022 data as a range and then compares 2023 and 2024 values, without showing the annual values, the beginning and ending points, or whether the overall trend is downward, flat, or increasing.[66]

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[65] Staff Witness Thomas Direct Testimony at 12-14
[66] *Id.* at 12-13.

Table 2. Witness Thomas's Comparison of Weather-Normalized Annual Throughput: 2014–2022 Range vs. 2023–2024 Values

Utility	*2014 to 2022 Range*[21]	*2023*[22]	*2024*
BGE	90.4—98.2	97.1	93.7
Columbia	5.8—6.4[23]	6.1	6.2
WGL	69.6—73.4	73.6	74.0

Source: Direct Testimony of Staff Witness Evan Thomas at 13. Table 2.

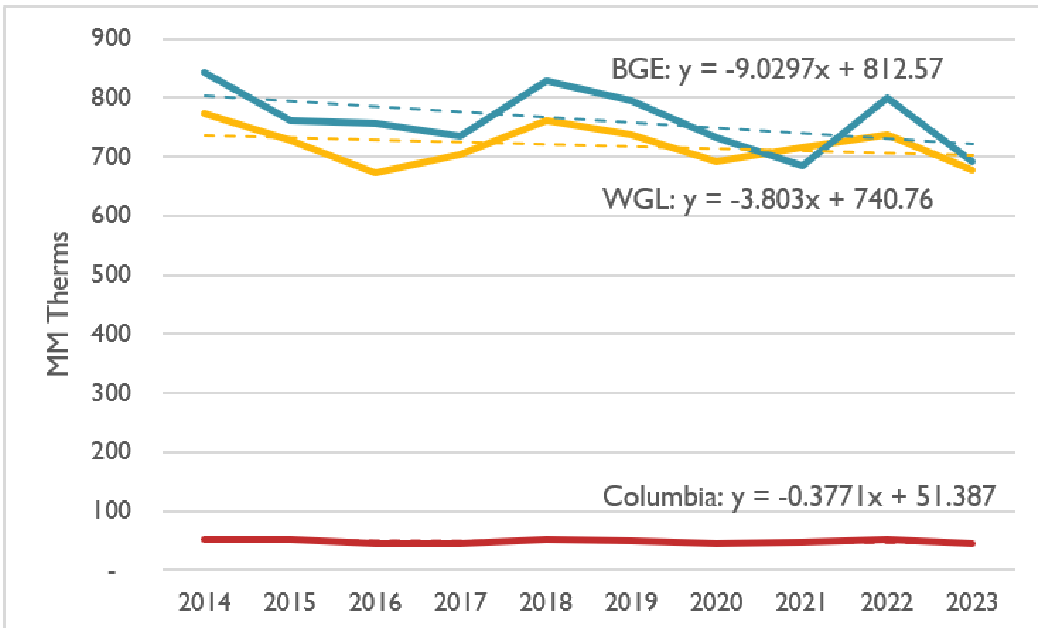
Q. What does a proper historical trend analysis show about recent gas consumption?

A. **Figure 7** shows recent residential and commercial gas consumption trends for BGE, WGL, and Columbia Gas of Maryland from 2014 through 2023. This period is useful because it corresponds generally to the recent historical period referenced by Staff witness Thomas, while also showing the actual beginning and end points and the trend over time. The data indicate that residential and commercial gas consumption declined across all three gas utilities over this period. BGE and WGL show modest declining trends, while Columbia is approximately flat to slightly declining. Because **Figure 7** shows total residential and commercial consumption, rather than per-customer usage, it should be read together with the declining residential use-per-customer trend discussed in my initial and reply testimony.[67] Because residential and commercial gas use is the portion of gas demand most directly affected by building decarbonization policies, heating equipment

[67] OPC Witness Takahashi Initial and Reply Testimony at 7:18–24.

choices, and electrification trends, these data provide important context for evaluating whether current forecasting methods adequately reflect emerging demand risks.

Figure 7. Residential and Commercial Gas Consumption by Utility, 2014-2023



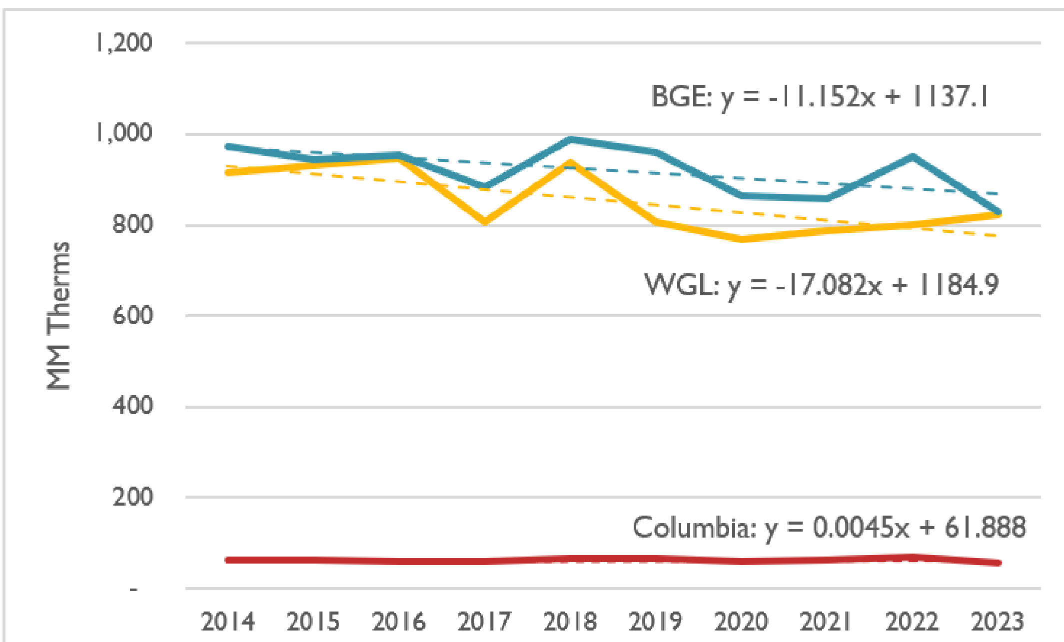
Source: EIA-176 database. Available at: https://www.eia.gov/naturalgas/ngqs/#?year1=2021&year2=2024&company=Name.

Q. Why is the residential and commercial sector trend particularly relevant?

A. The residential and commercial sectors are the building-sector uses most directly affected by building decarbonization policies and market changes discussed in this proceeding, including electric heating adoption, heat pump adoption, EmPOWER heat pump and fuel-switching activity, Building Energy Performance Standards, the Clean Heat Standard, the Zero-Emission Heating Equipment Standard, and local building electrification requirements. The trends in **Figure 7** are therefore especially relevant to the

Commission's assessment of whether the gas companies' forecasts adequately address future building-sector demand. At the same time, the decline in residential and commercial consumption is milder than the broader total consumption trend for BGE and WGL, as shown in **Figure 8**, which is important context. **Figure 8** therefore provides broader system-level context: total gas consumption excluding power generation has declined for BGE and WGL and remained approximately flat for Columbia. Because those broader trends include other customer classes, they should not be attributed solely to residential and commercial customers.

Figure 8. Total Gas Consumption by Utility, Excluding Power Generation, 2014-2023



Source: EIA-176 database. Available at: https://www.eia.gov/naturalgas/ngqs/#?year1=2021&year2=2024&company=Name.

Q. What does the broader total gas consumption trend in Figure 8 indicate?

A. **Figure 8** presents total gas consumption for all sectors except power generation over the 2014 through 2023 period discussed by Mr. Thomas. This broader measure shows more pronounced declining trends for BGE and WGL, and an approximately flat trend for Columbia. Although this broader measure includes sectors not directly addressed by building decarbonization policy, it is relevant to gas system planning because total throughput affects system utilization, cost recovery, and customer rate pressure. Taken together, **Figure 7** and **Figure 8** show that recent gas use trends do not support an assumption of continued growth and reinforce the need for forward-looking demand forecasting that accounts for emerging trends.

Q. How should the Commission interpret the difference between the residential gas consumption data in Figure 7 and the total gas consumption data in Figure 8?

A. The difference between the two figures is important. **Figure 7** focuses on residential and commercial consumption, which is the most directly relevant measure for evaluating building decarbonization and heating electrification. **Figure 8** provides broader system context by showing total gas consumption excluding power generation. The all-sector trends are more negative than the residential and commercial trends, which suggests that broader system utilization may be declining more than the building-sector-only data suggest. However, because some non-building-sector changes may be driven by industrial or other sector-specific factors, the Commission should not rely on **Figure 8** alone to evaluate building decarbonization impacts. Instead, the figures should be read together: the building-sector chart shows no material growth and modest declines for BGE and WGL, while the broader chart points to greater system-level concern regarding throughput, system utilization, and potential cost-recovery pressure if those trends continue.

Q. Why is actual, non-weather-normalized consumption relevant to gas planning?

A. Weather-normalized throughput is useful for isolating consumption trends distinct from year-to-year weather variation, and I do not recommend ignoring it. However, actual non-weather-normalized consumption is also relevant because it reflects real-world gas sales, actual system utilization, billed throughput, and the combined effects of changing weather conditions, customer behavior, efficiency, electrification, and other market changes. Warming trends are not merely statistical noise from a planning perspective. They can reduce actual sales and system utilization over time, which affects cost recovery and rate pressure. A meaningful planning assessment should therefore examine both weather-normalized and actual consumption trends, rather than relying on weather-normalized data alone.

Q. Is there anything missing from Mr. Thomas's analysis?

A. Yes. Mr. Thomas evaluates total customer counts and weather-normalized annual throughput, but he does not evaluate average gas use per customer.

As discussed in my initial and reply testimony, residential gas consumption per customer has steadily declined over time.[68] Average use per customer is an important metric because fixed gas system costs must be recovered from customers through rates, and declining usage can place upward pressure on those rates. A utility can therefore face increasing rate pressure and stranded cost risk before customer counts decline, even where customer counts remain stable or grow modestly, if each customer uses less gas on average while the utility continues to invest in long-lived infrastructure.

Q. How should customer counts, total consumption, and average use per customer be evaluated?

A. They should be evaluated together. Customer counts identify the number of accounts over which fixed customer-related costs may be allocated. Total consumption identifies the sales base over which volumetric costs and some fixed costs may be recovered. Average use per customer links those two metrics and shows whether each customer is using more or less gas over time. Looking only at customer counts and total weather-normalized throughput can obscure a declining-use-per-customer trend. This is true even where customer counts are increasing: customer growth may mask declining average usage and may not offset the rate pressure created by declining actual throughput combined with continued capital investment. In the

[68] OPC Witness Takahashi Initial and Reply Testimony at 7:18–24.

context of long-term gas planning, declining use per customer is an important indicator of rate pressure and underutilization risk, particularly where overall consumption has declined or remained flat over many years and continued capital additions must be recovered over a flat or declining sales base.

Q. How does Mr. Thomas treat climate policies and legislative changes?

A. Mr. Thomas recommends that rate design not be based on "speculative" assumptions regarding future demand, climate policies, or legislative changes.[69]

Q. Should current and forthcoming policy impacts be ignored in forward-looking gas demand forecasts?

No. While Mr. Thomas's concerns about speculation may be relevant to whether policy impacts support immediate rate-design changes, it should not be used to exclude policy impacts from forward-looking gas demand forecasting. Indeed, in response to OPC discovery, Mr. Thomas clarified that his testimony should not be read to suggest that future gas demand, climate policies, or legislative changes are irrelevant to planning.[70] As discussed in my initial and reply testimony, current and forthcoming state and local policy changes, including Building Performance Standards, the Clean Heat Standard, and the Zero-Emission Heating Equipment

[69] Staff Witness Thomas Direct Testimony at 3:13–4:3.
[70] Staff Response to OPC Data Request 1-10(a) (attached as Exhibit KT-R8).

Standard, should not be ignored simply because their full impacts are not yet reflected in historical gas usage data.[71] Waiting for those impacts to be fully embedded in historical data creates a planning lag. Because gas infrastructure and capacity commitments are long-lived, that lag increases the risk that planning decisions will be based on demand levels that are higher than future conditions warrant.[72]

Q. What market and policy drivers should be considered in the gas companies' forecasts?

A. As discussed in my initial and reply testimony, the gas companies should consider, at a minimum, electric heating adoption, declining gas heating share, heat pump adoption, EmPOWER heat pump and fuel-switching activity, Building Energy Performance Standards, the Clean Heat Standard, the Zero-Emission Heating Equipment Standard, and local building electrification requirements. These market and policy factors are directly relevant to gas customer counts, usage per customer, annual sales, design day demand, and the need for future infrastructure and supply resources.[73]

Q. How do these market and policy drivers affect the risks associated with traditional forecasting methods?

A. As I explained in my initial and reply testimony, traditional regression-based forecasting methods rely heavily on historical relationships between gas

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[71] OPC Witness Takahashi Initial and Reply Testimony at 40:13–42:4.
[72] *Id.* at 38-42.
[73] *Id.* at 26-34.

demand and drivers such as weather, economic activity, and customer counts. Those methods can be reasonable under stable conditions, but they are not well suited to capturing structural changes that are only partially reflected in historical data.[74] If electrification, fuel switching, building performance requirements, and customer fuel-choice changes accelerate beyond their historical levels, forecasts that primarily extrapolate historical relationships are likely to overestimate future annual sales and design day demand. That can lead to overbuilding, underutilized assets, stranded costs, and higher rates for remaining gas customers.[75]

Q. Have other parties raised similar concerns about consumption trends and load forecasting?

A. Yes. The Maryland Department of the Environment has recognized that natural gas consumption in the building sector has been relatively flat for nearly 20 years.[76] In addition, MEA, and CCAN generally raise concerns that are directionally consistent with my position: gas planning should not rely solely on backward-looking forecasts and should account for market and policy changes that may influence future gas demand.[77] While the details of each party's recommendations differ, the common theme is that historical trends alone are not sufficient for long-term gas planning in the

[74] *Id.* at 35:17–37:4.
[75] *Id.* at 41: 9–42:19.
[76] MDE Witness Chris Hoagland Direct Testimony at 16.
[77] MEA Witness Joyce Lombardi Direct Testimony at 7, CCAN Witness Bradley Cebulko Direct Testimony at 6.

context of Maryland's climate policies and changing building energy markets.

Q. How should the Commission view Mr. Thomas's conclusion that recent customer-count and weather-normalized throughput data do not warrant immediate changes to gas rate design?

A. The Commission should recognize that Mr. Thomas's analysis is of limited usefulness for the broader planning issues being considered in this proceeding. His analysis may be relevant to the narrow question of whether immediate rate design changes are warranted based on the data Mr. Thomas reviewed, but this proceeding is not limited to immediate rate design changes. Mr. Thomas's analysis does not demonstrate that the gas companies' current forecasting methods adequately account for consumption per customer, projected customer counts, planned and projected gas system investments, actual and projected annual throughput, market-driven electrification, or policy-driven reductions in gas demand. Those issues require a broader and more forward-looking assessment.

Q. What forecasting requirements should the Commission adopt?

A. Consistent with the recommendations in my initial and reply testimony, the Commission should require the gas companies to incorporate forward-looking market analyses, heating equipment and fuel-choice data, and scenario-based demand forecasts.[78] Those forecasts should evaluate customer counts, usage per customer, annual consumption, actual and projected non-weather-normalized throughput, design day demand, planned and projected gas system investments, gas supply and capacity requirements, and non-pipeline alternative opportunities under a range of plausible futures. At a minimum, the scenarios should include a business-as-usual case reflecting current planning assumptions and observed trends, a policy-aligned case reflecting current and forthcoming Maryland policies, and sensitivities around the policy-aligned case that evaluate how gas demand may vary with different levels and timing of electrification, fuel switching, energy efficiency adoption, and customer behavior.

Q. How should these improved forecasts be used to protect customers and inform planning?

A. The Commission should require the gas utilities to incorporate the forecasts directly and transparently into revenue and rate projections, infrastructure planning, capital investment decisions, gas supply planning, and long-term gas system planning. Forward-looking and scenario-based forecasts should not be prepared simply as informational analyses; they should be used to

[78] This recommendation relates most directly to Issue 3 identified in Order No. 91791: "What policies, guidelines, or regulations, if any, should be adopted to ensure that future natural gas company planning practices adequately address the State's climate goals?" It also relates to Issue 1, which requires a description of current natural gas capacity, supply, and capital investment planning practices, including how current gas company planning practices address State climate goals, and Issue 12, which asks how future technological innovations, demand response programs, more efficient appliances, and other mechanisms should be addressed in gas company planning.

inform actual planning, rate, and investment decisions. Their purpose is to assess how lower annual sales and declining usage per customer could affect revenue recovery; whether proposed infrastructure and supply investments remain needed under plausible lower-demand futures; whether non-pipeline alternatives can defer or avoid investments; how stranded asset exposure changes across scenarios, and how customer rates and bills may be affected if sales decline while capital costs continue to rise.

Q. Please summarize your recommendations on this issue.

A. Consistent with my initial and reply testimony and the rebuttal points discussed above, I recommend that the Commission: (1) recognize that Mr. Thomas's narrow analysis of customer counts and weather-normalized throughput is of limited usefulness for the broader planning issues in this proceeding; (2) require the gas companies to evaluate actual and projected customer counts, actual and projected annual gas consumption, actual and projected average use per customer, planned and projected gas system investments, and actual and projected annual throughput together; (3) require forward-looking market analyses using heating equipment, electrification, and fuel-choice data; (4) require scenario-based demand forecasts that account for current and forthcoming policy changes; and (5) require gas utilities to integrate those analyses into infrastructure planning, capital investment decisions, and long-term gas system planning to assess infrastructure needs, overinvestment risk, stranded asset exposure, and customer rate and bill impacts.

Q. Does this conclude your rebuttal testimony?

A. Yes.

Assessment of Heat Pumps in Maine Homes (2026)

Final Report | January 2026

Assessment of Heat Pumps in Maine Homes (2026)

Final Report

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Notice

This report was prepared by Ridgeline Energy Analytics and Demand Side Analytics in the course of performing work contracted for and sponsored by the Efficiency Maine Trust (hereafter "Efficiency Maine"). Reference to any specific product, service, process, or method does not constitute an implied or expressed recommendation or endorsement of it.

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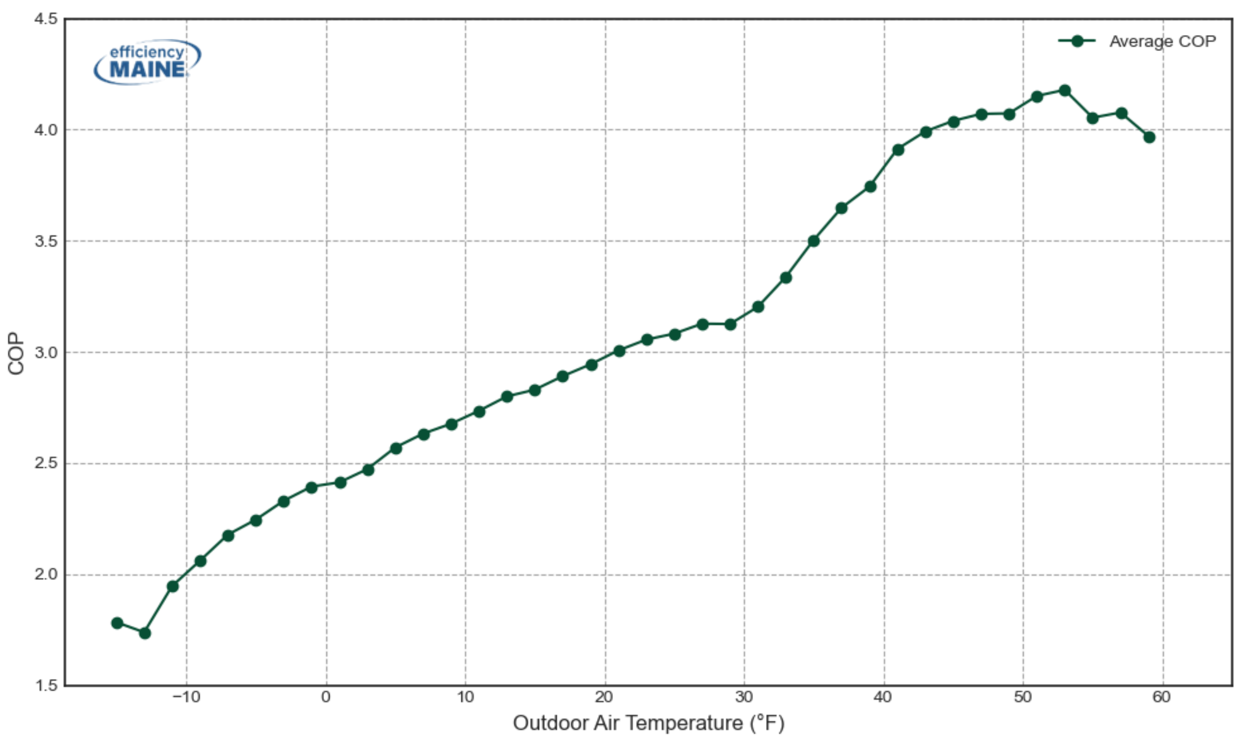
7 METERED HEAT PUMP OPERATING EFFICIENCY

7.1.1 Coefficient of Performance (COP)

The Coefficient of Performance (COP) is the simplest measurement of a heat pump's performance and is equal to the ratio of the energy of heat delivered to the energy of electricity required to achieve this heat transfer (measured in the same units). COP values for heat pumps designed to perform in cold climates typically range from 2 at colder temperatures to 5 at 47°F due to partial loading at low heating loads. This indicates that heat pumps can deliver 2 to 5 units of heat for every unit of energy consumed.

Figure 53 shows the average measured COP across all 166 metered heat pump indoor units. These values were calculated by dividing the total heating energy output across all units by the total electric energy used by all units within each 2-degree temperature bin. The heating COP decreases with decreasing evaporating (outdoor) temperatures primarily due to the increased difference between outside and desired indoor temperatures. Metered COP averaged 2 at-10°F. This means that even for these very cold temperatures, heat pumps are still twice as efficient as electric resistance. The average combined field-metered heating COP across all outdoor temperatures was 3.15, which includes energy used for defrosting.

Figure 53. Average Measured COP vs. Outdoor Air Temperature



7.1.2 Manufacturer-Reported Heat Pump Efficiency Ratings

Heat pumps are rated several ways. Manufacturers publish:

- Coefficient of Performance (COP): This is reported at minimum, maximum, and rated capacities for outdoor air temperatures of 47°F, 17°F, and 5°F. Temperatures at which COPs are reported below 5°F vary between -5°F to -22°F and differ among manufacturers. COPs are unitless.
- Heating Seasonal Performance Factor (HSPF and HSPF2): This is a single seasonal factor that captures a heat pump's overall heating performance over a prescribed set of operating conditions (indoor temperatures, outdoor temperatures, and compressor settings) that represent a full heating season in Region IV (mid-Atlantic). The units for an HSPF or HSPF2 rating are Btu/Wh, and the HSPF and HSPF2 factors can be derived from ~3.412 (Btu to Wh conversion rate) times an equivalent COP. HSPF2 is the more recently updated rating, and it better represents actual heating conditions. For example, the external static pressure is raised from 0.1 to 0.5 inches of water column for ducted systems, which is a more field-representative value. To better simulate performance in colder climates, the average outdoor temperature used in the HSPF2 testing procedures is lower than the one used for the original HSPF calculation.
- Seasonal Energy Efficiency Ratio (SEER2): This is the ratio of the total cooling energy output over a prescribed set of operating conditions (indoor temperatures, outdoor temperatures, and compressor settings) that represent a full cooling season in Region IV (mid-Atlantic) to the total electric energy input over the same period. SEER2 is the more stringent update to SEER.
- Energy Efficiency Ratio (EER2): This is the ratio of cooling energy to electric energy consumed at 95°F. EER2 is the more stringent update to EER.

Manufacturer-reported values for these ratings were obtained for all 160 heat pumps in this study from Northeast Energy Efficiency Partnerships' (NEEP) *Cold Climate Air Source Heat Pump List*.[28] These ratings reflect those discussed earlier in AHRI's *Directory of Certified Product Performance.*[29] Refer to the *AHRI Standard 210/240: Performance Rating of Unitary Air-conditioning and Air-source Heat Pump Equipment* for more information on these tests and ratings.[30]

[28] Northeast Energy Efficiency Partnerships. ccASHP Specification & Product List.

[29] Air-Conditioning, Heating, and Refrigeration Institute. Directory of Certified Product Performance.

[30] Air-Conditioning, Heating, and Refrigeration Institute. AHRI Standard 210/240-2024 (I-P): "Performance Rating of Unitary Air-conditioning and Air-source Heat Pump Equipment."

Table 14 shows the average ratings of all heat pumps in the metering study. It is important to note that not every heat pump in the metered sample is rated across all these ratings. Some of the older models, which were most likely not rebated by the WHHP program but were already installed in homes prior to participating in the WHHP program, are not rated for the updated, more stringent HSPF2, SEER2, and EER2 standards. For one heat pump found in the sample, only the rated COP, nominal capacity, maximum capacity at 5°F, and HSPF are known.

Table 14. Manufacturer-Reported Ratings for Metered Heat Pumps

	Outdoor Air Temperatures (OA)		
Ratings (n = 160)	47°F	17°F	5°F
Min Capacity (Btu/h) (BTU_{min}^{OA})	3,694 (n = 159)	3,594 (n = 158)	2,945 (n = 158)
Max Capacity (Btu/h) (BTU_{max}^{OA})	22,130 (n = 159)	18,287 (n = 159)	16,604 (n = 160)
COP at Min Capacity (COP_{min}^{OA})	4.66 (n = 158)	3.02 (n = 158)	2.63 (n = 158)
COP at Max Capacity (COP_{max}^{OA})	2.95 (n = 158)	2.40 (n = 158)	2.21 (n = 158)
HSPF (Btu/Wh)	12.9 (n = 157)		
HSPF2 (Btu/Wh)	11.4 (n = 146)		
SEER2 (Btu/Wh)	25.9 (n = 146)		
EER2 (Btu/Wh)	14.9 (n = 146)		

Manufacturers also publish engineering tables that show maximum heating capacity and electricity input versus outdoor temperature.[31] Table 15 shows an example of one of these tables for a 12,000 Btu_{Rated}[47], 12 HSPF unit.

Table 15. Example Heat Pump Engineering Data

INDOOR	OUTDOOR TEMPERATURE (°FWB)															
EDB	–13		–4		5		14		23		32		43		60	
°F	TC	PI	TC	PI	TC	PI	TC	PI	TC	PI	TC	PI	TC	PI	TC	PI
59.0	9.73	1.65	12.55	1.68	15.27	1.72	16.23	1.68	17.21	1.63	18.22	1.58	19.45	1.53	23.48	1.65
70.0	8.72	1.70	11.58	1.73	14.33	1.77	15.39	1.72	16.46	1.67	17.52	1.62	18.80	1.56	22.83	1.68
71.6	7.88	1.58	10.93	1.68	13.95	1.79	15.06	1.74	16.16	1.69	17.24	1.64	18.54	1.58	21.97	1.63
75.2	6.55	1.29	9.60	1.46	12.65	1.61	14.73	1.76	15.85	1.70	16.96	1.65	18.28	1.59	20.64	1.51
77.0	5.88	1.15	8.93	1.35	11.98	1.52	14.56	1.77	15.70	1.71	16.82	1.66	18.15	1.60	19.97	1.46
80.6	4.55	0.88	7.60	1.14	10.65	1.33	13.32	1.60	15.40	1.73	16.54	1.68	17.89	1.61	18.64	1.34

In the table at the highlighted heat output of 18,800 Btu/h at 43°F, the COP can be calculated by the following equation:

$$COP = \frac{TC}{PI\ x\ 3.412} = \frac{18{,}800}{1{,}560\ x\ 3.412} = 3.53$$

Where:

[31] The table shows maximum heating capacity, and the actual operation will follow this table when full capacity is used at colder temperatures. At temperatures above freezing for example, the capacity is not fully used, and one would expect higher efficiencies. Some manufacturers publish a second table showing rated inputs at partial load capacities.

TC = Total Capacity in kBtu/h
PI = Power in kW

Only a fraction of the 18,800 Btu/h that the heat pump could provide at 43°F would be needed. If the heat pump were sized to just meet needs at -4°F, then the heat pump would only need to provide (70 - 43) / (70 - (-4)) * 11,580 = 4,225 Btu/h, or about 22% of the heat capacity at 43°F.

7.1.3 Field-Metered COP versus Manufacturer-Reported COP

In Figure 54, the field-metered COPs are compared against the average manufacturer-reported ratings for 47°F, 17°F, and 5°F. The average, field-metered COPs run between the reported manufacturer ratings. The average reported COP at the maximum capacity at the lowest catalogued temperature in the AHRI directory is 1.85 across the sample. The lowest catalogued temperature differs between models and manufacturers and ranges from -4°F to -22°F. The average lowest catalogued temperature was -15°F in the metered sample.

Figure 54. Average Field-Metered COP and Manufacturer-Reported COP vs. Outdoor Air Temperature

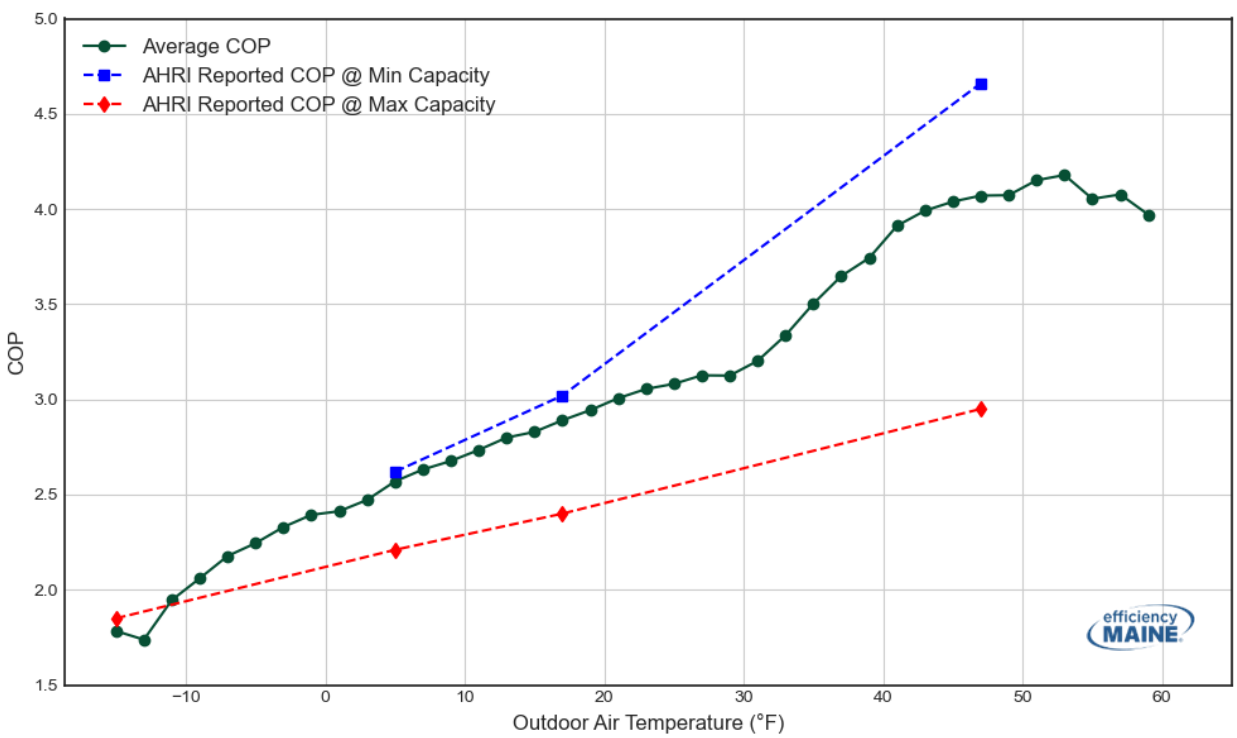
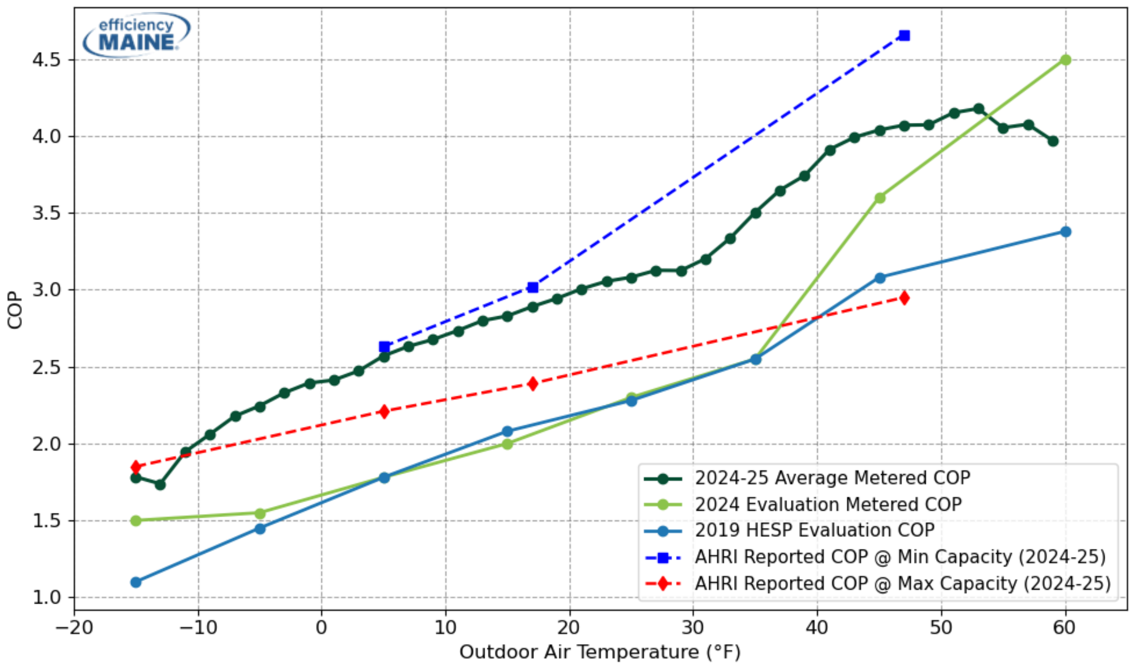


Figure 55 shows both the field-metered COP and the AHRI-reported COPs and two previous studies conducted in Maine. The average metered COP runs between the average minimum and maximum AHRI reported COPs. These metered COPs are higher than previous studies that covered heat pumps manufactured from 2015 to 2021. We believe there are several reasons:

- New heat pumps have increased their ability to provide partial load heating and have increased their ratings at both warm and cold temperatures.
- Heat pumps in this study are used more continuously than past studies.
- This study used web connected meters that provided continuous data with nearly no gaps, reducing the need for data extrapolation.

Figure 55. Average Field-Metered COP and Manufacturer-Reported COP vs. Outdoor Air Temperature, with Metered COP from 2024 HP Evaluation[32] and 2019 HESP Evaluation[33]



7.1.4 Manufacturer-Reported HSPF2 versus Manufacturer-Reported COP

HSPF ratings are calculated using complex formulas and laboratory data. They do not necessarily match actual seasonal efficiency since field conditions are less controlled than a laboratory setting, and the heating needs and temperatures do not always match the assumptions built into the HSPF calculations. Since HSPF is calculated using very specific, limited conditions, the relationship between COP versus temperature and HSPF ratings is not always proportional. Figure 56 shows no clear relationship between manufacturer-reported HSPF2 and COP_{rated}[17]. Figure 57 shows a clearer relationship between manufacturer-reported HSPF2 and COP_{rated}[47]. Of the 41 unique heat pump models metered in this study, 31 of the models had reported HSPF2 factors. The models that did not report HSPF2 were the older heat

[32] Efficiency Maine Residential Heat Pump Impact Evaluation. 2024.

[33] Efficiency Maine Trust Home Energy Savings Program Impact Evaluation. 2019.

pumps in the fleet that were most likely installed before the WHHP rebate program. Most of the heat pumps that lacked reported HSPF2 factors were the only ones of their models within the sample.

Figure 56. Manufacturer-Reported HSPF2 versus Manufacturer-Reported COP_{rated} 17 (n = 31)

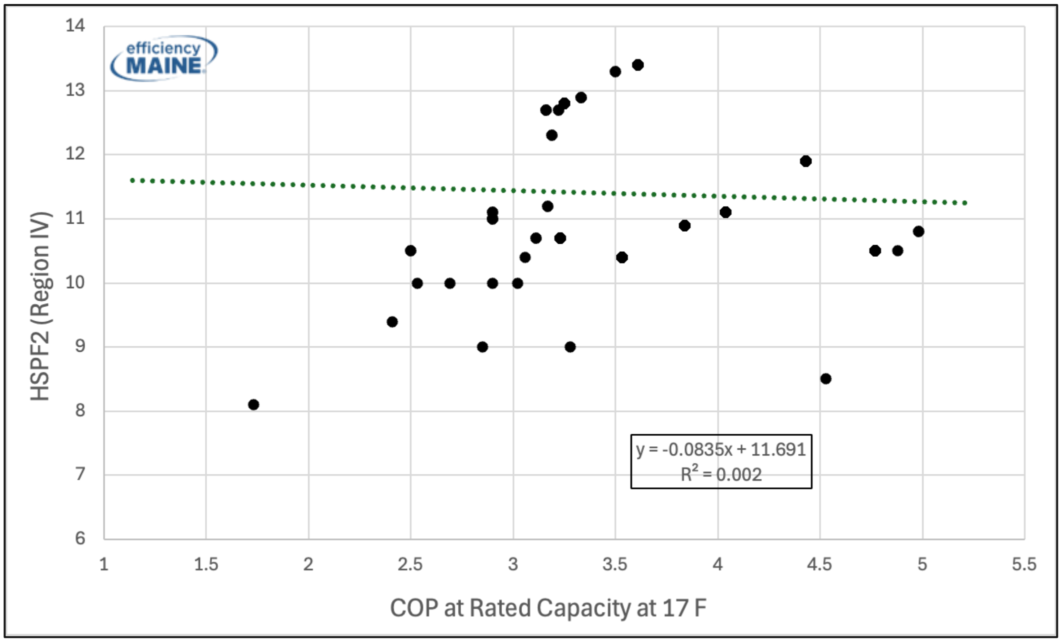
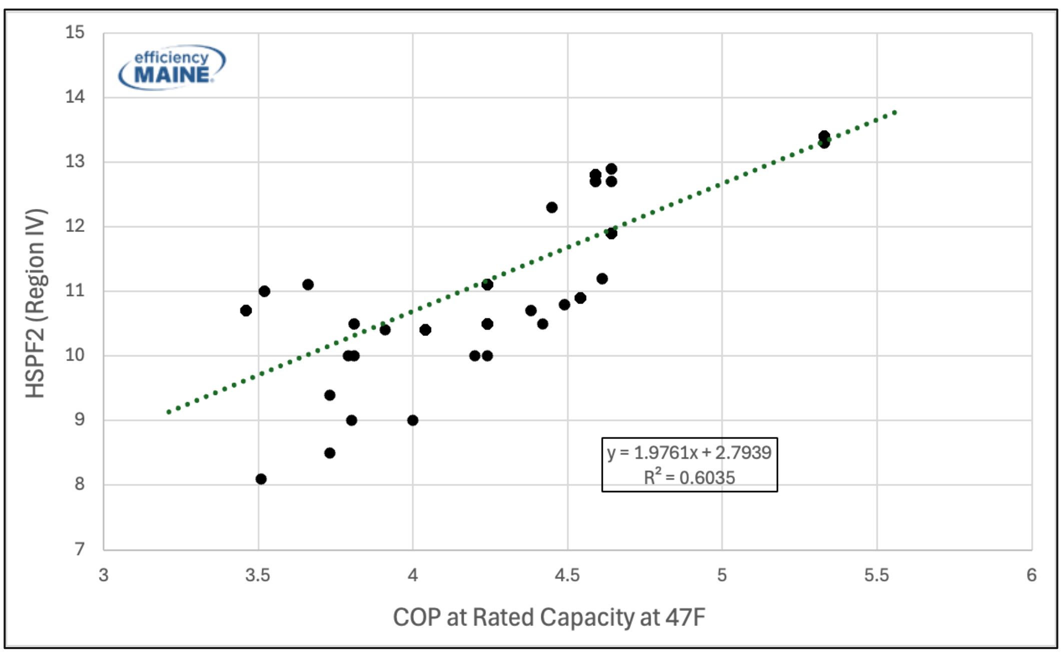


Figure 57. Manufacturer-Reported HSPF2 versus Manufacturer-Reported COP_{rated} 47 (n = 31)



7.1.5 Field-Metered COP versus Manufacturer-Reported HSPF2 and COP_{min} 47

We expected that there might be some relationship between field-metered COPs for heat pumps and their ratings. To test this expectation, we graphed field-metered COP versus HSPF2 and COP_{min} 47 in

Figure 58 and Figure 59. While there are slight upward trends in field-metered COP versus HSPF2 and COP_{min} [47], they are not strong trends. We believe that variability in how heat pumps are operated is a stronger factor impacting field-metered COP than the ratings of the heat pump.

Figure 58. Field-Metered COP versus Manufacturer-Reported HSPF2 (n = 146)

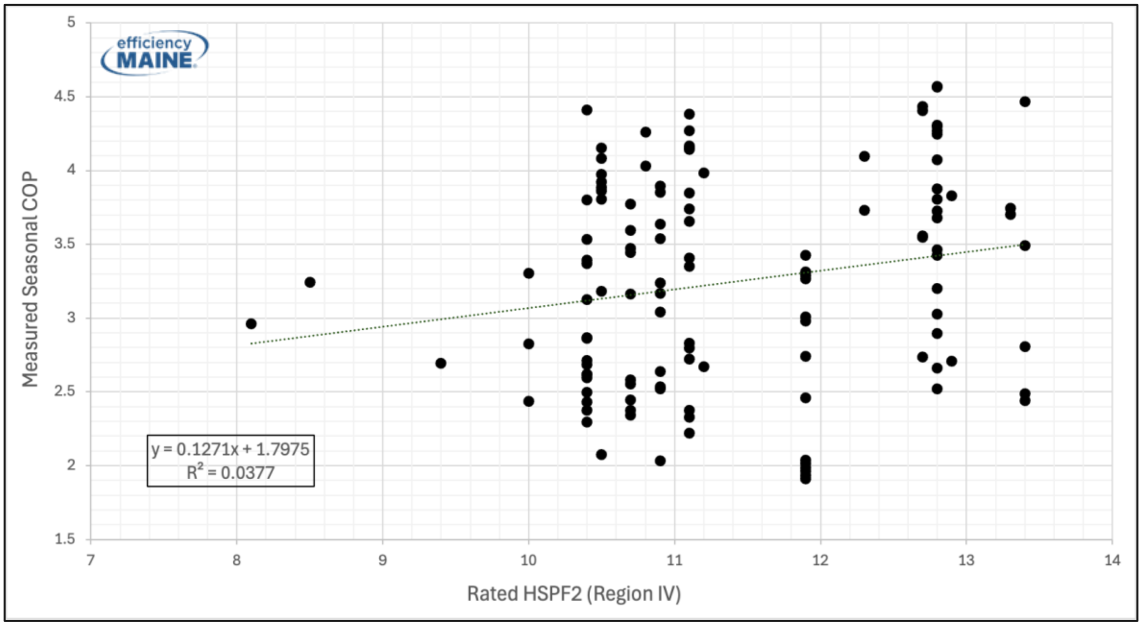


Figure 59. Field-Metered COP versus Manufacturer-Reported COP_{Min} [47] (n = 158)

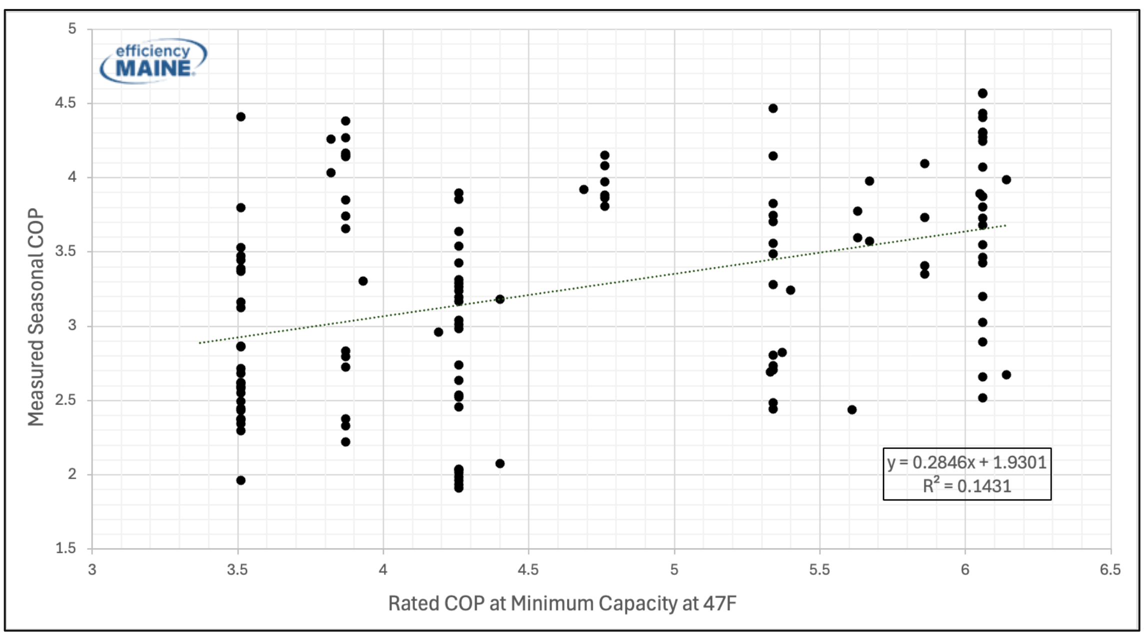


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Table B-1

Summer Peak Load (MW) and Growth Rates for Each PJM Zone and Geographic Region (2026 - 2046)

	Metered 2025	Unrestricted 2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045	2046	Annual Growth Rate (10 yr)	Annual Growth Rate (20 yr)
AE	2,710	2,716	2,563	2,551	2,536	2,524	2,517	2,514	2,518	2,527	2,538	2,555	2,583	2,616	2,653	2,695	2,738	2,781	2,819	2,855	2,887	2,923	2,956	0.1%	0.7%
	.	.	.	-0.5%	-0.6%	-0.5%	-0.3%	-0.1%	0.2%	0.4%	0.4%	0.7%	1.1%	1.3%	1.4%	1.6%	1.6%	1.6%	1.4%	1.3%	1.1%	1.2%	1.1%	.	.
BGE	6,585	6,612	6,471	6,436	6,412	6,445	6,484	6,533	6,589	6,641	6,650	6,669	6,709	6,755	6,803	6,869	6,941	7,010	7,082	7,151	7,215	7,271	7,325	0.4%	0.6%
	.	.	.	-0.5%	-0.4%	0.5%	0.6%	0.8%	0.9%	0.8%	0.1%	0.3%	0.6%	0.7%	0.7%	1.0%	1.0%	1.0%	1.0%	1.0%	0.9%	0.8%	0.7%	.	.
DPL	4,199	4,236	4,008	3,986	3,971	3,958	3,949	3,948	3,946	3,958	3,973	3,986	4,006	4,031	4,055	4,090	4,128	4,165	4,204	4,241	4,272	4,311	4,346	0.0%	0.4%
	.	.	.	-0.5%	-0.4%	-0.3%	-0.2%	-0.0%	-0.1%	0.3%	0.4%	0.3%	0.5%	0.6%	0.6%	0.9%	0.9%	0.9%	0.9%	0.9%	0.7%	0.9%	0.8%	.	.
JCPL	6,274	6,286	6,044	6,034	5,997	5,997	6,060	6,080	6,164	6,323	6,467	6,573	6,689	6,839	6,976	7,129	7,265	7,391	7,528	7,666	7,783	7,899	8,021	1.0%	1.4%
	.	.	.	-0.2%	-0.6%	0.0%	1.1%	0.3%	1.4%	2.6%	2.3%	1.6%	1.8%	2.2%	2.0%	2.2%	1.9%	1.7%	1.9%	1.8%	1.5%	1.5%	1.5%	.	.
METED	3,000	3,037	3,013	3,019	3,022	3,048	3,130	3,159	3,234	3,344	3,437	3,487	3,548	3,609	3,666	3,729	3,794	3,855	3,917	3,978	4,038	4,100	4,169	1.6%	1.6%
	.	.	.	0.2%	0.1%	0.9%	2.7%	0.9%	2.4%	3.4%	2.8%	1.5%	1.7%	1.7%	1.6%	1.7%	1.7%	1.6%	1.6%	1.6%	1.5%	1.5%	1.7%	.	.
PECO	8,380	8,476	8,539	8,571	8,718	8,908	9,190	9,499	9,794	9,967	10,102	10,160	10,222	10,299	10,376	10,469	10,531	10,626	10,721	10,831	10,938	11,035	11,104	1.8%	1.3%
	.	.	.	0.4%	1.7%	2.2%	3.2%	3.4%	3.1%	1.8%	1.4%	0.6%	0.6%	0.8%	0.7%	0.9%	0.6%	0.9%	0.9%	1.0%	1.0%	0.9%	0.6%	.	.
PENLC	2,885	2,917	2,820	2,805	2,781	2,773	2,778	2,780	2,778	2,778	2,789	2,803	2,841	2,867	2,889	2,914	2,942	2,974	3,011	3,040	3,059	3,092	3,121	0.1%	0.5%
	.	.	.	-0.5%	-0.9%	-0.3%	0.2%	0.1%	-0.1%	0.0%	0.4%	0.5%	1.4%	0.9%	0.8%	0.9%	1.0%	1.1%	1.2%	1.0%	0.6%	1.1%	0.9%	.	.
PEPCO	6,016	6,026	6,003	5,992	5,980	5,989	6,143	6,247	6,485	6,728	6,936	7,137	7,334	7,409	7,476	7,561	7,640	7,740	7,829	7,917	8,001	8,087	8,170	2.0%	1.6%
	.	.	.	-0.2%	-0.2%	0.2%	2.6%	1.7%	3.8%	3.7%	3.1%	2.9%	2.8%	1.0%	0.9%	1.1%	1.0%	1.3%	1.1%	1.1%	1.1%	1.1%	1.0%	.	.
PL	7,366	7,508	7,359	7,568	8,434	9,041	12,155	13,085	13,427	13,500	13,518	13,556	13,641	13,715	13,783	13,866	13,933	14,021	14,117	14,198	14,269	14,334	14,411	6.4%	3.4%
	.	.	.	2.8%	11.4%	7.2%	34.4%	7.7%	2.6%	0.5%	0.1%	0.3%	0.6%	0.5%	0.5%	0.6%	0.5%	0.6%	0.7%	0.6%	0.5%	0.5%	0.5%	.	.
PS	10,230	10,259	10,046	10,098	10,284	10,560	11,029	11,547	11,990	12,325	12,441	12,556	12,727	12,929	13,124	13,328	13,552	13,738	13,922	14,105	14,269	14,458	14,606	2.4%	1.9%
	.	.	.	0.5%	1.8%	2.7%	4.4%	4.7%	3.8%	2.8%	0.9%	0.9%	1.4%	1.6%	1.5%	1.6%	1.7%	1.4%	1.3%	1.3%	1.2%	1.3%	1.0%	.	.
RECO	423	423	406	402	397	394	391	389	389	391	392	395	399	405	411	418	425	430	436	442	448	454	459	-0.2%	0.6%
	.	.	.	-1.0%	-1.2%	-0.8%	-0.8%	-0.5%	0.0%	0.5%	0.3%	0.8%	1.0%	1.5%	1.5%	1.7%	1.7%	1.2%	1.4%	1.4%	1.4%	1.3%	1.1%	.	.
UGI	218	218	202	201	199	199	198	197	197	197	197	198	199	201	202	204	206	207	210	212	214	215	218	-0.1%	0.4%
	.	.	.	-0.5%	-1.0%	0.0%	-0.5%	-0.5%	0.0%	0.0%	0.0%	0.5%	0.5%	1.0%	0.5%	1.0%	1.0%	0.5%	1.4%	1.0%	0.9%	0.5%	1.4%	.	.
AEP	23,338	23,564	24,635	26,176	27,530	29,145	30,869	32,333	33,795	35,576	37,406	39,221	41,105	43,379	44,476	44,709	44,952	45,170	45,428	45,657	45,862	46,104	46,354	5.3%	3.2%
	.	.	.	6.3%	5.2%	5.9%	5.9%	4.7%	4.5%	5.3%	5.1%	4.9%	4.8%	5.5%	2.5%	0.5%	0.5%	0.5%	0.6%	0.5%	0.4%	0.5%	0.5%	.	.
APS	8,996	9,081	8,814	8,926	8,947	9,253	9,904	10,281	10,694	11,000	11,491	11,584	11,697	11,791	11,891	11,996	12,101	12,361	12,467	12,561	12,656	12,751	12,848	2.9%	1.9%
	.	.	.	1.3%	0.2%	3.4%	7.0%	3.8%	4.0%	2.9%	4.5%	0.8%	1.0%	0.8%	0.8%	0.9%	0.9%	2.1%	0.9%	0.8%	0.8%	0.8%	0.8%	.	.
ATSI	12,658	12,890	12,770	12,769	12,851	12,986	13,677	13,869	14,121	14,465	14,745	14,987	15,152	15,278	15,386	15,516	15,650	15,762	15,889	16,017	16,148	16,273	16,413	1.7%	1.3%
	.	.	.	-0.0%	0.6%	1.1%	5.3%	1.4%	1.8%	2.4%	1.9%	1.6%	1.1%	0.8%	0.7%	0.8%	0.9%	0.7%	0.8%	0.8%	0.8%	0.8%	0.9%	.	.
COMED	20,714	20,714	20,847	21,077	21,707	23,035	24,644	26,264	27,918	29,373	30,079	30,359	30,468	30,566	30,619	30,689	30,742	30,770	30,828	30,927	31,015	31,113	31,227	3.9%	2.0%
	.	.	.	1.1%	3.0%	6.1%	7.0%	6.6%	6.3%	5.2%	2.4%	0.9%	0.4%	0.3%	0.2%	0.2%	0.2%	0.1%	0.2%	0.3%	0.3%	0.3%	0.4%	.	.
DAYTON	3,397	3,397	3,357	3,478	3,594	3,721	4,259	4,694	5,123	5,451	5,558	5,568	5,588	5,614	5,635	5,658	5,683	5,706	5,734	5,767	5,796	5,826	5,863	5.2%	2.8%
	.	.	.	3.6%	3.3%	3.5%	14.5%	10.2%	9.1%	6.4%	2.0%	0.2%	0.4%	0.5%	0.4%	0.4%	0.4%	0.4%	0.5%	0.6%	0.5%	0.5%	0.6%	.	.
DEOK	5,190	5,256	5,323	5,330	5,332	5,346	5,371	5,398	5,435	5,476	5,529	5,583	5,656	5,729	5,791	5,854	5,921	5,984	6,060	6,134	6,198	6,266	6,337	0.6%	0.9%
	.	.	.	0.1%	0.0%	0.3%	0.5%	0.5%	0.7%	0.8%	1.0%	1.0%	1.3%	1.3%	1.1%	1.1%	1.1%	1.1%	1.3%	1.2%	1.0%	1.1%	1.1%	.	.
DLCO	2,695	2,738	2,674	2,663	2,655	2,656	2,705	2,737	2,753	2,765	2,780	2,800	2,828	2,855	2,885	2,917	2,956	2,992	3,028	3,065	3,102	3,145	3,184	0.6%	0.9%
	.	.	.	-0.4%	-0.3%	0.0%	1.8%	1.2%	0.6%	0.4%	0.5%	0.7%	1.0%	1.0%	1.1%	1.1%	1.3%	1.2%	1.2%	1.2%	1.2%	1.4%	1.2%	.	.
EKPC	2,162	2,348	2,124	2,127	2,127	2,132	2,135	2,142	2,147	2,157	2,170	2,185	2,202	2,220	2,238	2,261	2,286	2,307	2,334	2,360	2,383	2,408	2,434	0.4%	0.7%
	.	.	.	0.1%	0.0%	0.2%	0.1%	0.3%	0.2%	0.5%	0.6%	0.7%	0.8%	0.8%	0.8%	1.0%	1.1%	0.9%	1.2%	1.1%	1.0%	1.0%	1.1%	.	.
OVEC	78	78	80	80	80	80	80	80	80	80	80	80	80	80	80	80	80	80	80	80	80	80	80	0.0%	0.0%
	.	.	.	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	.	.
DOM	23,826	24,271	25,193	27,008	28,696	29,966	31,939	33,904	35,852	37,527	39,061	40,855	42,803	45,371	47,655	49,429	50,730	51,754	52,757	53,683	54,563	55,383	56,242	5.4%	4.1%
	.	.	.	7.2%	6.3%	4.4%	6.6%	6.2%	5.7%	4.7%	4.1%	4.6%	4.8%	6.0%	5.0%	3.7%	2.6%	2.0%	1.9%	1.8%	1.6%	1.5%	1.6%	.	.
DIVERSITY - TOTAL(-)	.	.	6,918	6,846	6,683	6,626	6,599	6,663	6,514	6,465	6,457	6,425	6,371	6,458	6,417	6,468	6,379	6,408	6,548	6,658	6,698	6,768	6,811	.	.
PJM RTO	159,660	160,709	156,373	160,451	165,567	171,530	183,008	191,017	198,915	206,084	211,882	216,872	222,106	228,100	232,653	235,913	238,817	241,416	243,853	246,229	248,498	250,760	253,077	3.6%	2.4%
	.	.	.	2.6%	3.2%	3.6%	6.7%	4.4%	4.1%	3.6%	2.8%	2.4%	2.4%	2.7%	2.0%	1.4%	1.2%	1.1%	1.0%	1.0%	0.9%	0.9%	0.9%	.	.
DIVERSITY - MID-ATLANTIC(-)	.	.	1,478	1,525	1,628	1,687	1,582	1,572	1,560	1,594	1,523	1,464	1,448	1,429	1,437	1,483	1,479	1,426	1,485	1,504	1,594	1,641	1,624	.	.
PJM MID-ATLANTIC	57,965	58,434	55,996	56,138	57,103	58,149	62,442	64,406	65,951	67,085	67,917	68,611	69,450	70,246	70,977	71,789	72,616	73,512	74,311	75,132	75,799	76,538	77,282	2.2%	1.6%
	.	.	.	0.3%	1.7%	1.8%	7.4%	3.1%	2.4%	1.7%	1.2%	1.0%	1.2%	1.1%	1.0%	1.1%	1.2%	1.2%	1.1%	1.1%	0.9%	1.0%	1.0%	.	.
DIVERSITY - WESTERN(-)	.	.	1,733	1,732	1,778	1,887	1,852	1,908	1,885	1,902	1,806	1,730	1,737	1,810	1,758	1,848	1,874	1,879	1,966	2,000	1,982	1,969	2,028	.	.
PJM WESTERN	78,912	78,940	78,891	80,894	83,045	86,467	91,792	95,890	100,181	104,441	108,032	110,637	113,039	115,702	117,243	117,832	118,497	119,253	119,882	120,568	121,258	121,997	122,712	3.7%	2.2%
	.	.	.	2.5%	2.7%	4.1%	6.2%	4.5%	4.5%	4.3%	3.4%	2.4%	2.2%	2.4%	1.3%	0.5%	0.6%	0.6%	0.5%	0.6%	0.6%	0.6%	0.6%	.	.
FE-EAST	12,080	12,215	11,632	11,614	11,575	11,574	11,732	11,783	11,946	12,213	12,466	12,630	12,853	13,094	13,317	13,554	13,790	14,022	14,242	14,467	14,663	14,866	15,060	1.0%	1.3%
	.	.	.	-0.2%	-0.3%	-0.0%	1.4%	0.4%	1.4%	2.2%	2.1%	1.3%	1.8%	1.9%	1.7%	1.8%	1.7%	1.7%	1.6%	1.6%	1.4%	1.4%	1.3%	.	.
PLGRP	7,583	7,726	7,561	7,767	8,633	9,235	12,350	13,282	13,619	13,696	13,715	13,754	13,838	13,911	13,982	14,070	14,139	14,228	14,323	14,410	14,480	14,546	14,624	6.2%	3.4%
	.	.	.	2.7%	11.1%	7.0%	33.7%	7.5%	2.5%	0.6%	0.1%	0.3%	0.6%	0.5%	0.5%	0.6%	0.5%	0.6%	0.7%	0.6%	0.5%	0.5%	0.5%	.	.

Notes:
All forecast values are non-coincident as estimated by PJM staff.

All forecast values represent unrestricted peaks, after reductions for distributed solar generation, reductions for distributed battery storage, additions for plug-in electric vehicles, and prior to reductions for load management.

All average growth rates are calculated from the first year of the forecast (2026). Summer season indicates peak from June, July, August.

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Table B-2

Winter Peak Load (MW) and Growth Rates for Each PJM Zone and Geographic Region (2025/26 - 2045/46)

	Metered 24/25	Unrestricted 24/25	25/26	26/27	27/28	28/29	29/30	30/31	31/32	32/33	33/34	34/35	35/36	36/37	37/38	38/39	39/40	40/41	41/42	42/43	43/44	44/45	45/46	Annual Growth Rate (10 yr)	Annual Growth Rate (20 yr)
AE	1,609	1,609	1,587	1,592	1,605	1,601	1,605	1,612	1,626	1,636	1,650	1,666	1,691	1,713	1,741	1,779	1,819	1,848	1,880	1,906	1,936	1,960	1,988	0.6%	1.1%
	.	.	.	0.3%	0.8%	-0.2%	0.2%	0.4%	0.9%	0.6%	0.9%	1.0%	1.5%	1.3%	1.6%	2.2%	2.2%	1.6%	1.7%	1.4%	1.6%	1.2%	1.4%	.	.
BGE	6,464	6,464	5,855	5,853	5,856	5,884	5,931	6,008	6,082	6,151	6,174	6,202	6,228	6,273	6,335	6,392	6,449	6,534	6,604	6,677	6,766	6,845	6,941	0.6%	0.9%
	.	.	.	-0.0%	0.1%	0.5%	0.8%	1.3%	1.2%	1.1%	0.4%	0.5%	0.4%	0.7%	1.0%	0.9%	0.9%	1.3%	1.1%	1.1%	1.3%	1.2%	1.4%	.	.
DPL	4,169	4,169	3,775	3,787	3,801	3,781	3,778	3,771	3,792	3,807	3,796	3,807	3,817	3,828	3,849	3,867	3,891	3,895	3,920	3,953	3,995	4,017	4,034	0.1%	0.3%
	.	.	.	0.3%	0.4%	-0.5%	-0.1%	-0.2%	0.6%	0.4%	-0.3%	0.3%	0.3%	0.3%	0.5%	0.5%	0.6%	0.1%	0.6%	0.8%	1.1%	0.6%	0.4%	.	.
JCPL	3,639	3,639	3,809	3,843	3,891	3,918	3,973	4,089	4,165	4,305	4,454	4,577	4,681	4,803	4,933	5,066	5,202	5,299	5,420	5,522	5,635	5,738	5,858	2.1%	2.2%
	.	.	.	0.9%	1.2%	0.7%	1.4%	2.9%	1.9%	3.4%	3.5%	2.8%	2.3%	2.6%	2.7%	2.7%	2.7%	1.9%	2.3%	1.9%	2.0%	1.8%	2.1%	.	.
METED	2,825	2,825	2,746	2,759	2,805	2,804	2,876	2,929	2,997	3,108	3,197	3,247	3,303	3,344	3,397	3,459	3,525	3,570	3,627	3,691	3,782	3,844	3,929	1.9%	1.8%
	.	.	.	0.5%	1.7%	-0.0%	2.6%	1.8%	2.3%	3.7%	2.9%	1.6%	1.7%	1.2%	1.6%	1.8%	1.9%	1.3%	1.6%	1.8%	2.5%	1.6%	2.2%	.	.
PECO	6,835	6,835	6,619	6,671	6,851	7,044	7,288	7,647	8,024	8,234	8,352	8,454	8,540	8,548	8,599	8,654	8,751	8,730	8,786	8,852	8,991	9,028	9,131	2.6%	1.6%
	.	.	.	0.8%	2.7%	2.8%	3.5%	4.9%	4.9%	2.6%	1.4%	1.2%	1.0%	0.1%	0.6%	0.6%	1.1%	-0.2%	0.6%	0.8%	1.6%	0.4%	1.1%	.	.
PENLC	2,909	2,909	2,805	2,797	2,811	2,795	2,794	2,800	2,820	2,815	2,825	2,839	2,869	2,875	2,896	2,923	2,965	2,977	3,003	3,032	3,066	3,090	3,129	0.2%	0.5%
	.	.	.	-0.3%	0.5%	-0.6%	-0.0%	0.2%	0.7%	-0.2%	0.4%	0.5%	1.1%	0.2%	0.7%	0.9%	1.4%	0.4%	0.9%	1.0%	1.1%	0.8%	1.3%	.	.
PEPCO	5,780	5,780	5,353	5,355	5,377	5,372	5,373	5,560	5,748	5,979	6,189	6,374	6,578	6,677	6,742	6,807	6,874	6,969	7,041	7,111	7,192	7,271	7,355	2.1%	1.6%
	.	.	.	0.0%	0.4%	-0.1%	0.0%	3.5%	3.4%	4.0%	3.5%	3.0%	3.2%	1.5%	1.0%	1.0%	1.0%	1.4%	1.0%	1.0%	1.1%	1.1%	1.2%	.	.
PL	7,840	7,840	7,408	7,674	8,173	8,955	9,682	12,936	13,590	13,786	13,797	13,828	13,867	13,919	13,961	14,030	14,069	14,117	14,171	14,217	14,282	14,326	14,385	6.5%	3.4%
	.	.	.	3.6%	6.5%	9.6%	8.1%	33.6%	5.1%	1.4%	0.1%	0.2%	0.3%	0.4%	0.3%	0.5%	0.3%	0.3%	0.4%	0.3%	0.5%	0.3%	0.4%	.	.
PS	6,761	6,761	6,767	6,940	7,155	7,432	7,812	8,470	9,009	9,442	9,664	9,779	9,919	10,077	10,250	10,422	10,584	10,735	10,883	11,006	11,149	11,244	11,386	3.9%	2.6%
	.	.	.	2.6%	3.1%	3.9%	5.1%	8.4%	6.4%	4.8%	2.4%	1.2%	1.4%	1.6%	1.7%	1.7%	1.6%	1.4%	1.4%	1.1%	1.3%	0.9%	1.3%	.	.
RECO	206	206	221	222	224	226	227	229	231	233	236	239	243	247	252	257	261	266	271	275	279	283	286	1.0%	1.3%
	.	.	.	0.5%	0.9%	0.9%	0.4%	0.9%	0.9%	0.9%	1.3%	1.3%	1.7%	1.6%	2.0%	2.0%	1.6%	1.9%	1.9%	1.5%	1.5%	1.4%	1.1%	.	.
UGI	218	218	204	204	204	203	202	202	202	202	202	202	203	204	204	206	207	208	210	211	213	214	215	0.0%	0.3%
	.	.	.	0.0%	0.0%	-0.5%	-0.5%	0.0%	0.0%	0.0%	0.0%	0.0%	0.5%	0.5%	0.0%	1.0%	0.5%	0.5%	1.0%	0.5%	0.9%	0.5%	0.5%	.	.
AEP	23,717	23,732	23,423	25,584	27,104	28,486	30,136	31,587	33,256	34,829	36,613	38,393	40,231	42,324	44,038	44,493	44,751	44,958	45,182	45,410	45,680	45,911	46,174	5.6%	3.5%
	.	.	.	9.2%	5.9%	5.1%	5.8%	4.8%	5.3%	4.7%	5.1%	4.9%	4.8%	5.2%	4.0%	1.0%	0.6%	0.5%	0.5%	0.5%	0.6%	0.5%	0.6%	.	.
APS	9,792	9,792	9,114	9,392	9,464	9,643	9,946	10,647	10,998	11,482	11,739	12,172	12,263	12,341	12,431	12,526	12,635	12,720	12,956	13,040	13,154	13,214	13,302	3.0%	1.9%
	.	.	.	3.1%	0.8%	1.9%	3.1%	7.0%	3.3%	4.4%	2.2%	3.7%	0.7%	0.6%	0.7%	0.8%	0.9%	0.7%	1.9%	0.6%	0.9%	0.5%	0.7%	.	.
ATSI	10,650	10,650	10,511	10,601	10,708	10,912	11,083	11,820	12,065	12,422	12,749	12,982	13,166	13,288	13,406	13,520	13,640	13,719	13,823	13,950	14,124	14,275	14,459	2.3%	1.6%
	.	.	.	0.9%	1.0%	1.9%	1.6%	6.6%	2.1%	3.0%	2.6%	1.8%	1.4%	0.9%	0.9%	0.9%	0.9%	0.6%	0.8%	0.9%	1.2%	1.1%	1.3%	.	.
COMED	15,183	15,183	15,011	15,319	15,933	17,073	18,682	20,448	22,240	23,933	25,080	25,639	25,879	26,002	26,124	26,254	26,382	26,442	26,539	26,614	26,764	26,871	27,032	5.6%	3.0%
	.	.	.	2.1%	4.0%	7.2%	9.4%	9.5%	8.8%	7.6%	4.8%	2.2%	0.9%	0.5%	0.5%	0.5%	0.5%	0.2%	0.4%	0.3%	0.6%	0.4%	0.6%	.	.
DAYTON	3,170	3,170	2,982	3,040	3,190	3,318	3,396	4,117	4,552	4,967	5,207	5,209	5,225	5,233	5,253	5,274	5,306	5,317	5,341	5,370	5,415	5,439	5,478	5.8%	3.1%
	.	.	.	1.9%	4.9%	4.0%	2.4%	21.2%	10.6%	9.1%	4.8%	0.0%	0.3%	0.2%	0.4%	0.4%	0.6%	0.2%	0.5%	0.5%	0.8%	0.4%	0.7%	.	.
DEOK	4,880	4,880	4,542	4,549	4,580	4,595	4,609	4,631	4,660	4,703	4,733	4,767	4,816	4,858	4,913	4,974	5,044	5,107	5,168	5,237	5,324	5,386	5,462	0.6%	0.9%
	.	.	.	0.2%	0.7%	0.3%	0.3%	0.5%	0.6%	0.9%	0.6%	0.7%	1.0%	0.9%	1.1%	1.2%	1.4%	1.2%	1.2%	1.3%	1.7%	1.2%	1.4%	.	.
DLCO	2,043	2,065	1,982	1,987	1,995	2,002	2,005	2,076	2,119	2,131	2,145	2,161	2,185	2,206	2,231	2,260	2,293	2,316	2,347	2,390	2,442	2,489	2,546	1.0%	1.3%
	.	.	.	0.3%	0.4%	0.4%	0.1%	3.5%	2.1%	0.6%	0.7%	0.7%	1.1%	1.0%	1.1%	1.3%	1.5%	1.0%	1.3%	1.8%	2.2%	1.9%	2.3%	.	.
EKPC	3,352	3,352	2,802	2,805	2,818	2,814	2,812	2,814	2,822	2,819	2,828	2,837	2,852	2,857	2,870	2,889	2,915	2,936	2,959	2,981	3,019	3,033	3,063	0.2%	0.4%
	.	.	.	0.1%	0.5%	-0.1%	-0.1%	0.1%	0.3%	-0.1%	0.3%	0.3%	0.5%	0.2%	0.5%	0.7%	0.9%	0.7%	0.8%	0.7%	1.3%	0.5%	1.0%	.	.
OVEC	102	102	95	95	95	95	95	95	95	95	95	95	95	95	95	95	95	95	95	95	95	95	95	0.0%	0.0%
	.	.	.	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	.	.
DOM	24,679	24,680	24,779	26,388	28,128	29,367	30,890	32,673	34,491	36,127	37,504	39,080	40,845	42,872	45,119	46,882	48,262	49,342	50,354	51,256	52,139	52,898	53,706	5.1%	3.9%
	.	.	.	6.5%	6.6%	4.4%	5.2%	5.8%	5.6%	4.7%	3.8%	4.2%	4.5%	5.0%	5.2%	3.9%	2.9%	2.2%	2.1%	1.8%	1.7%	1.5%	1.5%	.	.
DIVERSITY - TOTAL(-)	.	.	4,720	4,921	4,961	4,886	5,069	4,959	4,685	5,061	5,047	4,927	4,846	4,787	4,940	4,798	4,714	4,385	4,041	3,818	3,729	3,318	3,261	.	.
PJM RTO	143,319	143,336	137,670	142,536	147,807	153,434	160,126	172,202	180,899	188,145	194,182	199,622	204,650	209,797	214,699	218,231	221,206	223,715	226,539	228,978	231,713	234,153	236,693	4.0%	2.7%
	.	.	.	3.5%	3.7%	3.8%	4.4%	7.5%	5.1%	4.0%	3.2%	2.8%	2.5%	2.5%	2.3%	1.6%	1.4%	1.1%	1.3%	1.1%	1.2%	1.1%	1.1%	.	.
DIVERSITY - MID-ATLANTIC(-)	.	.	819	864	597	726	860	773	768	655	722	760	730	811	798	697	735	927	992	995	964	1,053	1,081	.	.
PJM MID-ATLANTIC	48,037	48,037	46,330	46,833	48,156	49,289	50,681	55,480	57,518	59,043	59,814	60,454	61,209	61,697	62,361	63,165	63,862	64,221	64,824	65,458	66,322	66,807	67,556	2.8%	1.9%
	.	.	.	1.1%	2.8%	2.4%	2.8%	9.5%	3.7%	2.7%	1.3%	1.1%	1.2%	0.8%	1.1%	1.3%	1.1%	0.6%	0.9%	1.0%	1.3%	0.7%	1.1%	.	.
DIVERSITY - WESTERN(-)	.	.	1,873	1,828	1,899	1,872	1,798	1,755	1,851	1,779	1,813	1,738	1,725	1,612	1,610	1,597	1,635	1,246	1,097	920	926	737	610	.	.
PJM WESTERN	71,709	71,724	68,589	71,544	73,988	77,066	80,966	86,480	90,956	95,602	99,376	102,517	104,987	107,592	109,751	110,688	111,426	112,364	113,313	114,167	115,091	115,976	117,001	4.3%	2.7%
	.	.	.	4.3%	3.4%	4.2%	5.1%	6.8%	5.2%	5.1%	3.9%	3.2%	2.4%	2.5%	2.0%	0.9%	0.7%	0.8%	0.8%	0.8%	0.8%	0.8%	0.9%	.	.
FE-EAST	9,220	9,220	9,280	9,327	9,439	9,440	9,556	9,725	9,923	10,181	10,406	10,589	10,774	10,949	11,149	11,366	11,586	11,746	11,935	12,101	12,309	12,484	12,726	1.5%	1.6%
	.	.	.	0.5%	1.2%	0.0%	1.2%	1.8%	2.0%	2.6%	2.2%	1.8%	1.7%	1.6%	1.8%	1.9%	1.9%	1.4%	1.6%	1.4%	1.7%	1.4%	1.9%	.	.
PLGRP	8,057	8,057	7,605	7,871	8,377	9,145	9,874	13,130	13,786	13,984	13,996	14,023	14,059	14,110	14,160	14,226	14,265	14,314	14,375	14,415	14,487	14,537	14,598	6.3%	3.3%
	.	.	.	3.5%	6.4%	9.2%	8.0%	33.0%	5.0%	1.4%	0.1%	0.2%	0.3%	0.4%	0.4%	0.5%	0.3%	0.3%	0.4%	0.3%	0.5%	0.3%	0.4%	.	.

Notes:

All forecast values are non-coincident as estimated by PJM staff.

All forecast values represent unrestricted peaks, after reductions for distributed solar generation, reductions for distributed battery storage, additions for plug-in electric vehicles, and prior to reductions for load management.

All average growth rates are calculated from the first year of the forecast (2025/26).

Winter season indicates peak from December, January, February.

PUBLIC SERVICE COMMISSION OF MARYLAND

TEN-YEAR PLAN (2025 – 2034) OF ELECTRIC COMPANIES IN MARYLAND

Prepared for the
Maryland Department of Natural Resources
In compliance with §7-201
Of the Public Utilities Article, *Annotated Code of Maryland*

December 2025

State of Maryland
Public Service Commission

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This report was drafted by the Commission's Energy Analysis and Planning Division.

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I. Introduction

This report constitutes the Maryland Public Service Commission's ("The Commission") *Ten-Year Plan (2025-2034) of Electric Companies in Maryland*. The Ten-Year Plan is submitted annually by the Commission to the Secretary of the Department of Natural Resources in compliance with §7-201 of the Public Utilities Article, *Annotated Code of Maryland*. It is a compilation of information pertaining to the long-range plans of Maryland's electric companies. The report also includes discussion of selected developments that may affect these long-range plans. The analysis contained in the Ten-Year Plan uses forecasts provided by Maryland utilities, PJM Interconnection, LLC ("PJM"), and other state and federal agencies.

The 2025–2034 Ten-Year Plan provides a forward-looking analysis of the composition of Maryland's electricity and generation profile and covers topics relevant to Maryland, including load growth forecasts, and the status of the State's generation resources and electric transmission system.

Changes to Maryland's supply and demand profile may necessitate additional infrastructure investment in the State's distribution network to ensure the safe, reliable, and economic supply of electricity to end users. The Commission exercises its statutory and regulatory power to ensure adequate, economical, and efficient delivery of utility services in the State. A record of these proceedings is published in the Commission's annual report.

II. Background

Maryland is geographically divided into 13 electric utility service territories.[1] The four largest, by number of Maryland customers, are served by investor-owned utilities ("IOUs"); four represent electric cooperatives (two of which serve mainly rural areas of Maryland); and five are served by electric municipal operations.[2] PJM sub-regions, known as zones, generally correspond with the IOU service territories. PJM zones for three of the four IOUs traverse state boundaries and extend into other jurisdictions.[3] Figure 1 provides a geographic picture of the Maryland utilities' service territories. Figure 2 depicts Maryland's PJM zones.

---

[1] The Maryland utilities: Baltimore Gas and Electric Company ("BGE"), Delmarva Power & Light Company ("DPL"), The Potomac Edison Company ("PE"), Potomac Electric Power Company ("Pepco"), Berlin Municipal Electric Plant ("Berlin"), Easton Utilities Commission ("Easton"), City of Hagerstown Light Department ("Hagerstown"), Thurmont Municipal Light Company ("Thurmont"), Williamsport Municipal Electric Light System ("Williamsport"), A&N Electric Cooperative ("A&N"), Choptank Electric Cooperative, Inc. ("Choptank"), Somerset Rural Electric Cooperative ("Somerset"), and Southern Maryland Electric Cooperative, Inc. ("SMECO").

[2] The Commission regulates all Maryland public service companies, as defined by §1-101(z) of the Public Utilities Article, *Annotated Code of Maryland*.

[3] Pepco, DPL, and PE are the three IOUs that extend into other jurisdictions. Pepco, DPL, and PE data are a subset of the PJM zonal data since PJM's zonal forecasts are not limited to Maryland. The BGE zone, alone, resides solely within the State of Maryland.

Figure 1: Maryland Utilities and their Service Territories in Maryland[4]

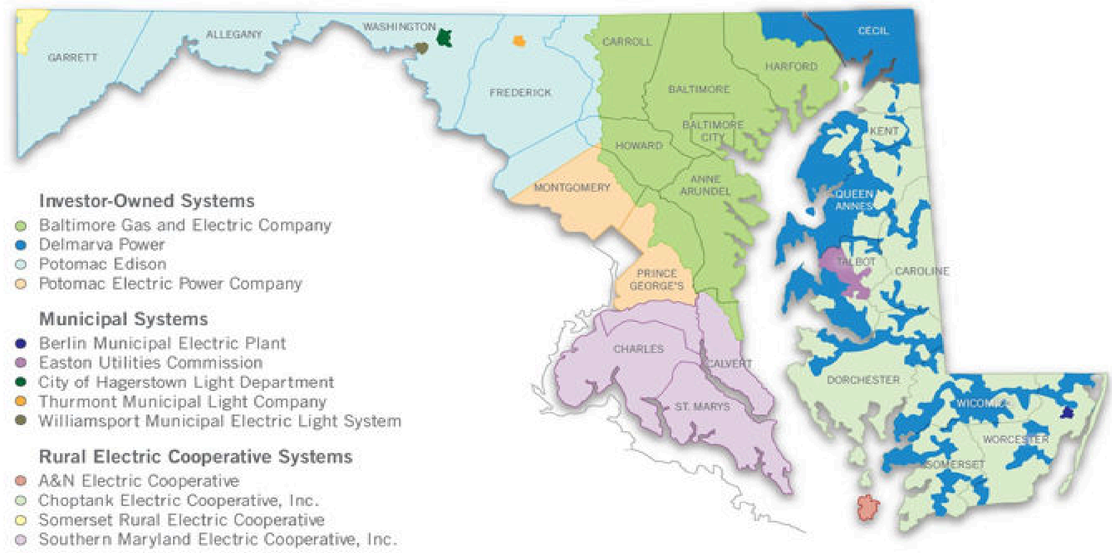
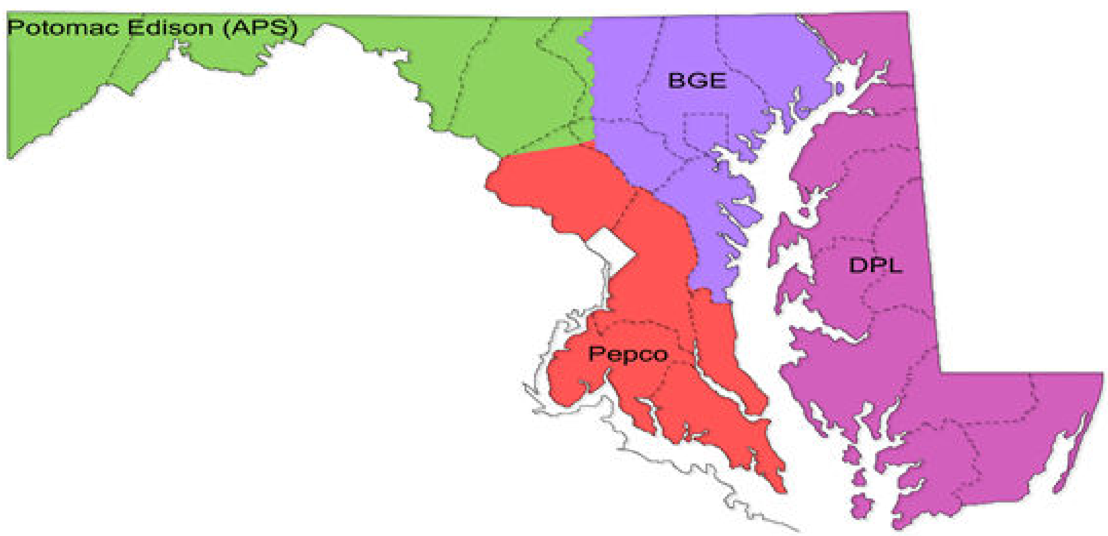


Figure 2: PJM Maryland Zones[5]



III. Maryland Load Growth Forecasts

Demand forecasts submitted by the Maryland utilities for the 2025-2034 planning period indicate projected annual growth in the number of customers, energy sales, and demand throughout the State at higher rates than in previous planning horizons, as shown in Table 1.

[4] *Cumulative Environmental Impact Report 18*, Maryland Department of Natural Resources, Figure 2-16, http://www.pprp.info/ceir18/HTML/Report-18-Chapter-2-4.html (last updated September 2018).
[5] *PJM Load Forecast Report,* PJM, (Jan. 2021), https://www.pjm.com/-/media/library/reports-notices/load-forecast/2021-load-report.ashx.

Table 1: Comparison of Compound Annual Growth Rate Projections – 2022, 2023, 2024 and 2025[6]

Forecasts	Ten Year Plan 2022-2031	Ten Year Plan 2023-2032	Ten Year Plan 2024-2033	Ten Year Plan 2025-2034
Customer Growth	0.7%	0.6%	0.6%	0.6%
Energy Sales	0.4%	0.3%	1.4%	2.3%
Summer Peak Demand	0.9%	0.7%	1.3%	1.6%
Winter Peak Demand	0.8%	0.4%	1.5%	2.0%

This trend of higher rates projected in the recent planning period than in previous planning horizons also appears in the results of forecasting conducted by PJM at the regional level in 2025 as compared to 2024, as discussed further below.[7]

PJM's process for modeling the load forecast involves creating a series of models where daily load is regressed on calendar, weather, economic, and end-use variables. The economic, weather, and end-use variables are compiled into indices which are then treated as independent variables in the final regression.[8]

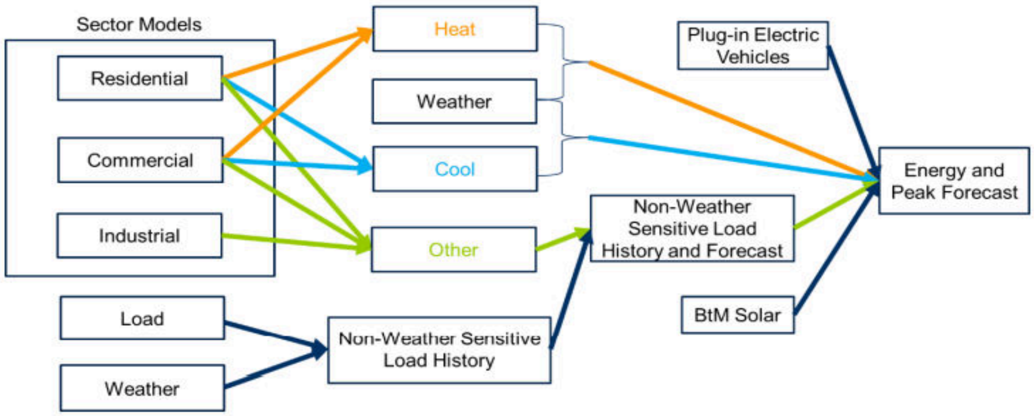
---

[6] *See* Appendix Tables 1(a)(i), 2(a)(i), 3(a)(i), 3(a)(iii). For values from previous Ten-Year Plans, refer to those respective reports of past years, available online.

[7] PJM's forecasting is derived in part from an independent economic forecast prepared by Moody's Analytics. This economic analysis includes projections related to the expected annual growth of the gross domestic product and can provide insight into possible trends for regional population growth and household disposable income which in turn can impact energy sector planning. PJM's forecast is also informed by load adjustments submitted by utilities throughout the region to account for variables such as projected discrete large load additions like data centers. Their modeling also accounts for weather variation, trends like electric vehicle adoption, behind-the-meter battery storage, and other factors. *See 2025 Long-Term Load Forecast Supplement,* PJM (Jan. 2025).

[8] *PJM Long-Term Load Forecast Supplement,* PJM, (Jan. 2025) https://www.pjm.com/-/media/DotCom/planning/res-adeq/load-forecast/2025-long-term-load-forecast-supplement.pdf.

Figure 3: Example of PJM Load Forecast Modeling



In the 2025 PJM load forecast, net energy load growth is projected to average 4.8% per year over the next 10-year period.[9] Meanwhile in 2024, this projection was 2.3% per year over the 10-year period following that forecast.[10] PJM indicates that, within the region, "the demand for electricity is growing at the fastest pace in years, primarily from the proliferation of data centers, electrification of buildings and vehicles, and manufacturing."[11]

A. Customer Growth Forecasts[12]

At the close of 2024, approximately 90 percent of utility customers in Maryland were categorized as residential ratepayers; however, residential sales represented only 45 percent of the year's total retail energy sales, as illustrated in Figure 4 below.[13] In contrast, commercial and industrial ("C&I") customers represented 10 percent of Maryland utility customers but accounted for over half of the total retail energy sales for the State.

[9] *PJM Load Forecast Report,* PJM, (Jan. 2025) at 6, https://www.pjm.com/-/media/DotCom/library/reports-notices/load-forecast/2025-load-report.ashx.
[10] *PJM Load Forecast* Report, PJM, (Jan. 2024) at 2, https://www.pjm.com/-/media/DotCom/library/reports-notices/load-forecast/2024-load-report.pdf.
[11] "2025 Long-Term Load Forecast Report Predicts Significant Increase in Electricity Demand," PJM Inside Lines, (Jan. 2025), https://insidelines.pjm.com/2025-long-term-load-forecast-report-predicts-significant-increase-in-electricity-demand/.
[12] *See* Appendix Tables 1(a)(i-vi) for a detailed breakdown of utility-by-utility customer growth forecasts.
[13] *See* Appendix Tables 1(b)(i) and 1(b)(ii).

Figure 4: Total Customers and Energy Sales (in GWh) by Customer Class for 2024

As reflected in Table 2 below, the statewide forecasted compound annual growth rate during the planning period is 0.58 percent for all customer classes which translates into a 5.32 percent increase in the total number of Maryland customers by the end of this 10-year planning period.

Table 2: Maryland Customer Forecast (All Customer Classes)[14]

Year	Berlin	BGE	DPL	Easton	Hagers-town	PE	Pepco	SMECO	Thur-mont	William-sport	Total
2025	2,754	1,351,672	222,003	11,103	17,780	293,356	612,618	180,737	2,903	1,023	**2,695,949**
2026	2,743	1,359,699	223,180	11,154	17,821	295,602	619,357	183,072	2,903	1,023	**2,716,553**
2027	2,757	1,367,521	224,160	11,204	17,862	297,903	624,750	185,361	2,903	1,023	**2,735,444**
2028	2,770	1,374,304	224,998	11,255	17,903	300,506	629,487	187,634	2,903	1,023	**2,752,782**
2029	2,784	1,380,857	225,787	11,307	17,944	303,352	633,975	189,834	2,903	1,023	**2,769,765**
2030	2,812	1,387,185	226,578	11,358	17,985	306,356	638,498	191,974	2,903	1,023	**2,786,672**
2031	2,840	1,383,328	227,372	11,410	18,026	309,349	643,055	194,050	2,903	1,023	**2,793,356**
2032	2,869	1,388,583	228,170	11,462	18,067	312,247	647,646	196,075	2,903	1,023	**2,809,043**
2033	2,897	1,393,759	228,970	11,514	18,109	315,063	652,272	198,035	2,903	1,023	**2,824,544**
2034	2,926	1,398,496	229,773	11,566	18,150	317,689	656,932	199,972	2,903	1,023	**2,839,430**
Change (2025-2034)	**172**	**46,823**	**7,770**	**463**	**370**	**24,333**	**44,314**	**19,235**	**0**	**0**	**143,481**
Percent Change (2025-2034)	**6.26%**	**3.46%**	**3.50%**	**4.17%**	**2.08%**	**8.29%**	**7.23%**	**10.64%**	**0.00%**	**0.00%**	**5.32%**
Compound Annual Growth Rate	**0.68%**	**0.38%**	**0.38%**	**0.45%**	**0.23%**	**0.89%**	**0.78%**	**1.13%**	**0.00%**	**0.00%**	**0.58%**

[14] *See* Appendix Table 1(a)(i). Note that Choptank, A&N and Somerset did not provide the requested applicable information in response to the Commission's 2025 data request for the Ten-Year Plan.

The customer forecasts provided by the utilities are comparable to the forecasts they provided for the 2024-2033 Ten-Year Plan. Overall, the increase in the number of customers across Maryland is primarily driven by growth in the residential class. Growth in the residential sector is projected to account for an additional 134,284 customers by 2034, or 94 percent of total new customers projected. The largest percentage increase in the number of customers is projected to occur in SMECO's service territory with an increase of 10.5 percent or 17,229 new residential customers. The largest absolute increase in the number of customers is projected to come from BGE's residential customer base with the addition of 44,143 residential customers forecasted during this planning period.[15] BGE's projected increase in its residential customer base accounts for 33 percent of the total number of new residential customers across all service territories during the 10-year planning period.[16] The increase in residential customers for BGE translates into a compound annual growth rate of 0.39 percent.[17]

Maryland utilities are projecting a slight reduction in the amount of growth of the collective Maryland customer base during this planning period relative to the last planning period. Table 3 below shows that the aggregated utilities' customer forecasts are 0.17 percent lower than the projections provided during the previous planning period. The most significant percentage change observable in the aggregated statewide data between the previous and current Ten-Year Plan forecasts is within the "Commercial" customer class[18] in large part due to a decreased projection by BGE.

Table 3: Projected Percentage Increase in the Number of Customers by Class, 2025 – 2034[19]

	All Utilities		
Class	**2024 to 2033**	**2025 to 2034**	**Difference**
Residential	5.69%	5.54%	-0.15%
Commercial	3.48%	3.10%	-0.39%
Industrial	9.47%	9.18%	-0.29%
Other	-0.93%	-0.89%	0.04%
Resale	0.00%	0.00%	0.00%
Total Customers	**5.50%**	**5.32%**	**-0.17%**

15 *See* Appendix Table 1(a)(ii).
16 *Id*.
17 *Id*.
18 The "Other" rate class refers to customers that do not fall into one of the listed classes; street lighting is an example of a rate class included under "Other." The Resale class refers to Sales for Resale which is energy supplied to other electric utilities, cooperatives, municipalities, and federal and state electric agencies for resale to end use consumers. PE is the only utility with any resale customers; these wholesale customers are Monongahela Power Company, West Penn Power Company, and Old Dominion Electric Cooperative.
19 *See* Appendix Tables 1(a)(i)-(vi) for more information.

B. Energy Sales Forecast

The Maryland utilities provide forecasts for energy sales and peak load in terms of "Gross of Demand Side Management ("DSM")" and "Net of DSM."[20] (DSM programs are discussed in greater detail in Section III.D of this report). In order to provide a more complete look at Maryland energy sales and peak demand forecasts, Sections III.B and III.C discuss the forecasts in "Gross of DSM" terms which reflect the forecasts *before* the impact of DSM programs. Table 4 shows the energy sales forecast within Maryland (Gross of DSM) for the 10-year planning period, as provided by the utilities.

Table 4: Maryland Energy Sales Forecast (GWh) (Gross of DSM)[21]

	Berlin	BGE	DPL	Easton	Hagers town	PE	Pepc o	SMEC O	Total
Change (2025-2034)	4	3,686	-7	28	7	9,644	49	398	13,809
Percent Change (2025-2034)	7.22%	12.50%	-0.16%	11.58%	2.27%	108.04%	0.36 %	11.35%	22.80 %
Compound Annual Growth Rate	0.78%	1.32%	-0.02%	1.22%	0.25%	8.48%	0.04 %	1.20%	2.31%

The aggregated forecasts show a compound annual increase of 2.31 percent across all the Maryland service territories for 2025-2034, an increase from the 1.38 percent annual growth rate reported in the 2024-2033 Ten-Year Plan. This result is primarily due to PE's and BGE's increased projections of energy sales growth rate in this year's reporting relative to last year's. The overall growth projected by PE for this 10-year planning period is the highest of any Maryland utility in absolute terms with the company projecting a 9,644 GWh increase in yearly energy sales by 2034. PE attributes the sizable increase in forecasted Maryland energy sales to anticipated data center growth within PE's service territory. PE expects that data centers in its service territory will come online in 2025 and ramp up usage in 2027. BGE attributes its increase in forecasted Maryland Energy Sales to impacts of data centers, electric vehicles, and customer growth.

Other utilities projecting a percent change in annual energy sales above 10% by 2034 include SMECO and the municipality of Easton. SMECO largely attributes the sales growth to an increase in residential customers within the service territory. Easton attributes the increase to residential load growth with some commercial growth factored in multiple years out. The only utility forecasting a reduction in yearly gross energy sales is DPL which attributes its decrease in forecasted Maryland energy sales to impacts of energy efficiency and behind-the-meter solar partially offset by customer and electric vehicle growth.

[20] *See* Appendix Table 2(a)(ii) for the Maryland Energy Sales forecast, Net of DSM programs; Appendix Table 3(a)(ii) for the Maryland Summer Peak Demand Forecast, Net of DSM programs; and Appendix Table 3(a)(iv) for the Maryland Winter Peak Demand Forecast, Net of DSM programs.

[21] *See* Appendix Table 2(a)(i) for utility-by-utility energy sales forecasts for service territory within Maryland available by Gross and Net of DSM. *See* Appendix Table 2(b) for the same information on a utility system-wide basis.

C. Peak Load Forecasts

PJM's 2025 Load Forecast Report includes long-term projections of peak loads for the entire wholesale market region and each PJM zone.[22,23] Because most of the PJM zones containing Maryland also extend outside of the state, the utilities submit peak demand forecasts restricted to their Maryland service territories as part of the Ten-Year Plan.[24] According to PJM's 2025 Load Forecast Report, the PJM Regional Transmission Organization ("RTO") will continue to be summer peaking during the next 20 years.[25] In 2025, three of the four PJM zones of which Maryland is a part were projected in PJM's Report (which was released in January 2025) to experience their peak demands during the month of July,[26] the same month as the broader PJM mid-Atlantic region.[27] The fourth PJM zone containing Maryland, APS, was projected to experience its peak demand in 2025 in January.

Unlike PJM's forecasts for the whole RTO, Berlin, DPL, Hagerstown, PE, SMECO, Thurmont, and Williamsport are forecasting their peak demands to occur in the winter in some or all of the forecasted years from 2025-2034.[28] These utilities have generally peaked in the winter over the past few planning periods for reasons including higher concentrations of electric heating, geographical features, and colder temperatures.

Figure 5 compares the average of the Maryland utilities' forecasted summer peak demands for their Maryland service territories with summer forecasts for the PJM mid-Atlantic region and for the PJM RTO as a whole. In the long-term, the Maryland utilities are showing a weaker peak demand growth rate than the PJM RTO and the PJM mid-Atlantic region. The Maryland utilities are projected to show faster peak demand growth than the PJM mid-Atlantic region in the short-term until about 2027. Also reflected in Figure 5, is a slowdown in the summer peak demand growth rates for the Maryland utilities from 2026–2028, after which the growth rates stabilize through 2034. The wider PJM region is projected by PJM to have a larger annual growth rate in peak demand over the next 10 years than either Maryland or the mid-Atlantic region.

[22] *PJM Load Forecast Report Excel Tables,* PJM, (Jan. 2025), Table B-1, https://www.pjm.com/-/media/DotCom/planning/res-adeq/load-forecast/2025-load-report-tables.xlsx.

[23] The four PJM zones spanning the Maryland service territory include APS, BGE, DPL, and PEPCO. *See supra* Figure 2 for a map of the Maryland zones. "APS" represents the Allegheny Power Zone of which PE is a sub-zone.

[24] *See* Appendix Tables 3(a)(i)-(iv) for more information on in-state peak demand forecasts for Maryland utilities, available for summer and winter, and by gross and net of DSM programs. *See* Appendix Tables 3(b)(i)-(iv) for the same information presented as system wide data for utilities operating in Maryland.

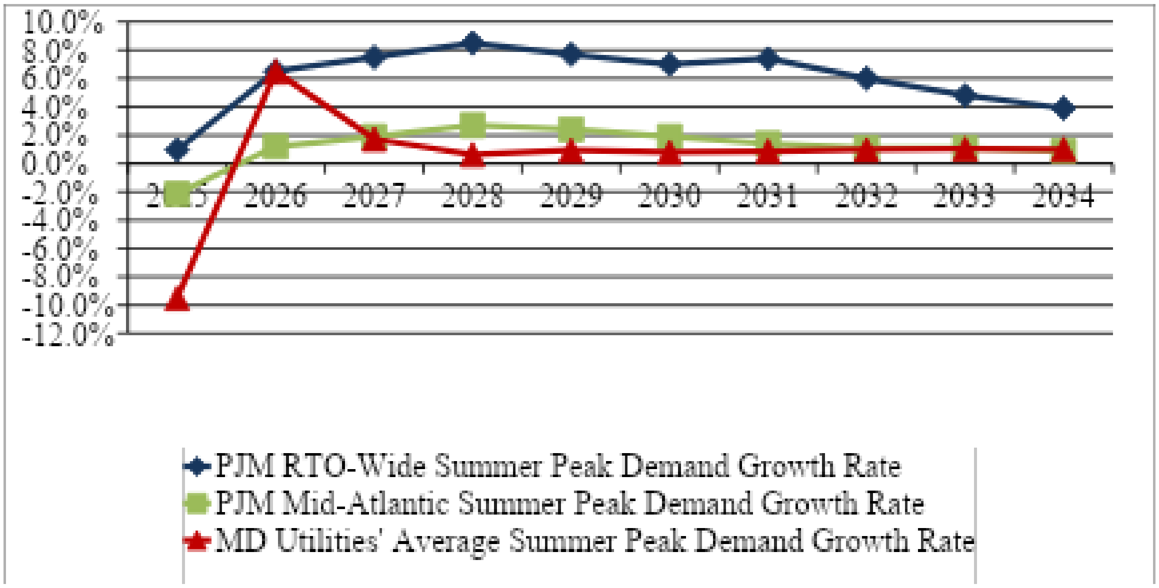
[25] *PJM Load Forecast Report,* PJM, (Jan. 2025) at 6, https://www.pjm.com/-/media/DotCom/library/reports-notices/load-forecast/2025-load-report.ashx.

[26] *PJM Load Forecast Report Excel Tables,* PJM, (Jan. 2025), Table B-5, https://www.pjm.com/-/media/DotCom/planning/res-adeq/load-forecast/2025-load-report-tables.xlsx.

[27] *Id.* Three of the Maryland PJM zones (BGE, DPL, and Pepco) are part of the PJM Mid-Atlantic Region. The fourth Maryland PJM zone (APS) is part of the PJM Western Region data set.

[28] *See* Appendix Tables 3(a)(i) and 3(a)(iii).

Figure 5: Average of Utilities' Projected Summer Peak Demand Growth Rates (Gross of DSM) Compared to Projected Summer Peak Demand Growth Rates for PJM Mid-Atlantic and PJM RTO[29,30]



The Maryland utilities also provided peak demand forecasts for the winter season in response to the Ten-Year Plan data request. Figure 6 below depicts an average of the Maryland utilities' forecasted winter peak demands contrasted with winter peak demand forecasts for the PJM mid-Atlantic region and for the PJM RTO.

[29] *PJM Load Forecast Report Excel Tables*, PJM, (Jan. 2025), Table B-1, https://www.pjm.com/-/media/DotCom/planning/res-adeq/load-forecast/2025-load-report-tables.xlsx.
[30] *See* Appendix Table 3(a)(i).

Figure 6: Average of Utilities' Projected Winter Peak Demand Growth Rates (Gross of DSM) Compared to Projected Winter Peak Demand Growth Rates for PJM Mid-Atlantic and PJM RTO[31,32]

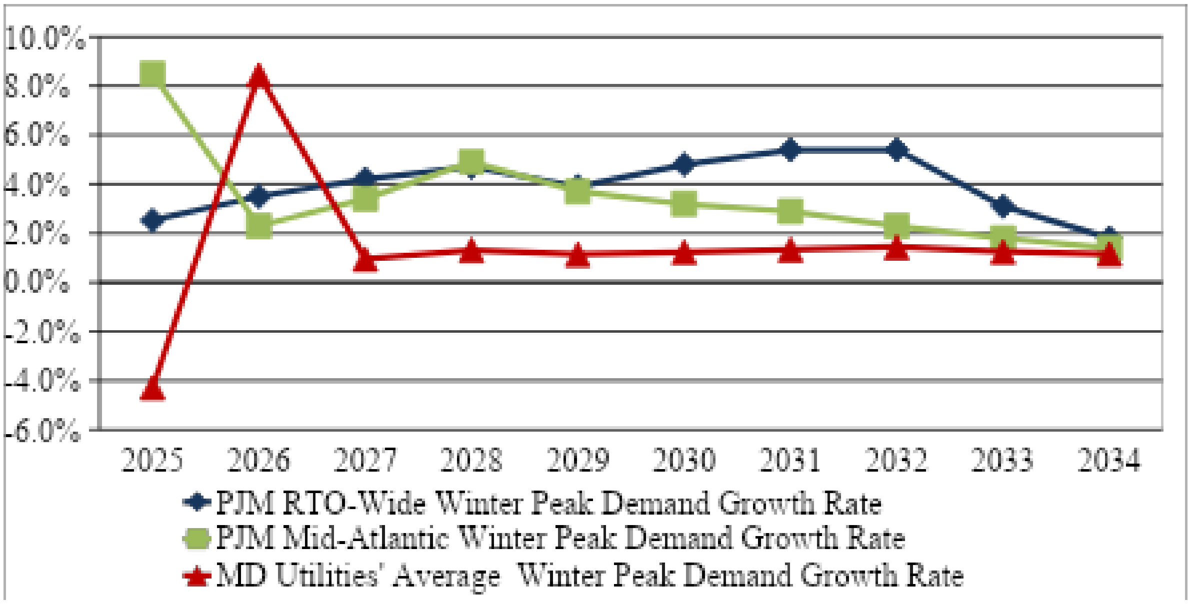
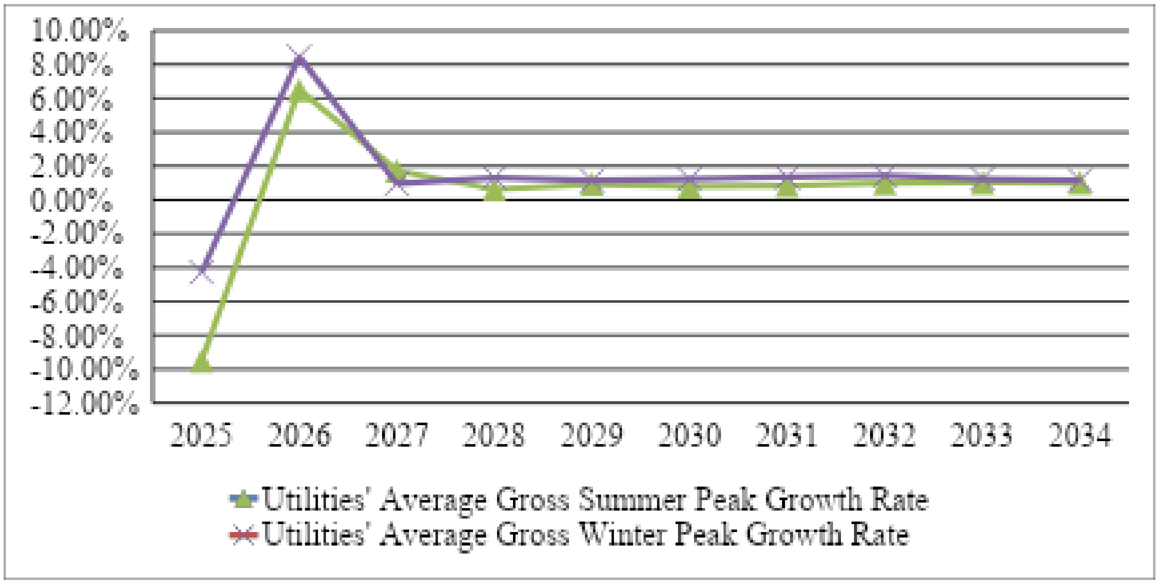


Figure 7 shows that the utilities' average gross winter peak growth rate plummets from 2026 to 2027 and then stabilizes through 2034. The utilities' average gross summer peak growth rate follows the same general pattern as the winter growth rate albeit slightly more gradually.

[31] *See* Appendix Table 3(a)(iii).
[32] *PJM Load Forecast Report Excel Tables, PJM,* (Jan. 2025), Table B-2, https://www.pjm.com/-/media/DotCom/planning/res-adeq/load-forecast/2025-load-report-tables.xlsx.

Figure 7: Utilities' Projected Summer Peak Demand Growth Rates (Gross of DSM) Compared to Utilities' Projected Winter Peak Demand Growth Rates (Gross of DSM)



As shown in Table 5 and Table 6 below, the 10-year forecasted Maryland annual growth rates of summer and winter peak demand (gross of DSM) are 1.59 percent and 2.01 percent, respectively.[33] In 2034, at the end of this planning timeframe, these growth rates translate into an expected summer peak demand load (gross of DSM) for the Maryland service territory of 16,686 MW and an expected winter peak demand load (gross of DSM) for Maryland of 14,977 MW.[34]

Table 5: Maryland Summer Peak Demand Forecast (MW) (Gross of DSM)[35,36]

	Berlin	BGE	DPL	Easton	Hagers-town	PE	Pepco	SMECO	Total
Change (2025-2034)	1	258	11	7	1	1,720	108	104	2,211
Percent Change (2025-2034)	7.75%	3.67%	1.06%	11.58%	2.27%	101.86%	2.99%	11.15%	15.27%
Compound Annual Growth Rate	0.83%	0.40%	0.12%	1.23%	0.25%	8.12%	0.33%	1.18%	1.59%

[33] *See* Appendix Tables 3(a)(i) and 3(a)(iii).
[34] *Id*.
[35] *See* Appendix Table 3(a)(i).
[36] Thurmont and Williamsport were not included in this table because the companies do not have any changes in their peak demand forecasts over the 10-year period.

Table 6: Maryland Winter Peak Demand Forecast (MW) (Gross of DSM)[37,38]

	Berlin	BGE	DPL	Easton	Hagers-town	PE	Pepco	SMECO	Total
Change (2025-2034)	1	453	54	7	7	1,773	138	21	2,453
Percent Change (2025-2034)	7.75%	7.59%	5.39%	11.87%	9.37%	102.32%	5.25%	2.02%	19.58%
Compound Annual Growth Rate	0.83%	0.82%	0.58%	1.25%	1.00%	8.14%	0.57%	0.22%	2.01%

D. Impact of Demand Side Management

DSM refers to programs which are typically designed to reduce demand on the grid, either overall or at moments of peak system stress. DSM programs result in lower net growth of both energy sales and peak demand. To evaluate the impact of DSM programs, this section reflects the Maryland utilities' energy sales forecasts *after* the benefits of DSM programs are included ("net of DSM"). For purposes of this section, only the five utilities participating in EmPOWER Maryland[39] are evaluated: BGE, DPL, PE, Pepco, and SMECO ("the participating utilities").[40]

The tables below compare the growth in DSM savings across the participating utilities from 2025 to 2028. The forecasted savings post-2026 vary in forecasting method and amount across the participating utilities given that Commission-approved plans for utility-implemented energy efficiency and conservation ("EE&C") programs pertain only to the 2024-2026 program cycle.[41] Table 7 shows the growth in demand savings from DSM programs due to EE&C portfolios while Table 8 shows the growth in total demand savings attributable to DSM programs as a whole. The variation in the magnitude of impact of the EE&C and DSM programs by utility are due to the different sizes of the programs offered and the way in which the data was forecasted by the participating utilities. DPL, Pepco, and SMECO are forecasting substantially lower demand savings over 2025-2028 relative to the savings projected for 2024-2027 in last year's Ten-Year Plan. DPL and Pepco indicate that the transition from energy savings measured in

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[37] *See* Appendix Table 3(a)(iii).
[38] Thurmont and Williamsport were not included in this table because the companies do not have any changes in their peak demand forecasts over the 10-year period.
[39] The EmPOWER Maryland Energy Efficiency Act of 2008 created the EmPOWER Maryland program to incentivize EE&C efforts. As part of their EmPOWER Maryland portfolios, Maryland's five largest electric utilities offer programs to help Maryland's households and businesses save energy and money through a variety of incentives such as free or discounted energy audits, weatherization, and efficient appliances.
[40] *See* The EmPOWER Maryland Report to the General Assembly for more information on the energy efficiency and demand response programs associated with EmPOWER Maryland, *available at:* https://www.psc.state.md.us/wp-content/uploads/2025-EmPOWER-Maryland-Energy-Efficiency-Act-Standard-Report-Final.pdf.
[41] Because the Commission has not approved plans beyond the 2024-2026 program cycle at this time, BGE did not include any EE&C savings projections after 2026. The other participating utilities assume a level of savings post-2026.

megawatt-hours to greenhouse gas reductions following the passage of House Bill 864 has been a key driver to forecast changes over time. The Commission notes that demand savings projections later in the 2025-2034 planning horizon may be affected by future iterations of EmPOWER Maryland program cycle proposals.

Table 7: Average Annual Increase in Demand Savings due to DSM Programs from 2025 to 2028 for EE&C Programs[42]

Description	BGE	DPL	PE	Pepco	SMECO
Average Annual MW Savings Change due to DSM Programs	-6.0%	0.2%	12.2%	0.1%	0.0%

Table 8: Average Annual Increase in Demand Savings due to DSM Programs from 2025 to 2028 for All DSM Programs[43]

Description	BGE	DPL	PE	Pepco	SMECO
Average Annual MW Savings Change due to DSM Programs	-7.3%	0.2%	11.6%	0.0%	0.0%

BGE does not forecast increases in average demand savings attributable to DSM programs beyond 2026, with the exception of the Residential Demand Response program. Using the 2024-2026 data for which there are projections, BGE's forecasted average increase in demand savings is 4.98% for EE&C programs and 4.63% for all DSM programs.

IV. Transmission, Supply, and Generation

To ensure a safe, reliable, and economic supply of electricity in Maryland, an appropriate balance of generation, DSM, imports, and transmission must be achieved. While importation and DSM offer ancillary benefits to managing the power supply, establishing and maintaining local generation helps to mitigate the risk to Maryland's long-term reliability.

In this Ten-Year Plan, the congestion costs and the role of transmission infrastructure in planning processes are discussed in Section IV.A. Section IV.B focuses on the state-specific impact of Maryland's status as a net importer of electricity. Information related to the capacity, composition, and age of Maryland's current generation profile is discussed in Section IV.C.

Maryland depends on PJM to operate the regional transmission system and to schedule the flows of power around the State (including importing power from other areas into Maryland). All load serving entities in PJM are required to ensure that they have sufficient capacity contracts to provide reliable electric service during periods of

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[42] Responses to the Commission's Ten-Year Plan data requests.
[43] *Id.*

peak demand. As of 2024, Maryland's net summer generating capacity was 11,718 MW.[44] Maryland's peak demand forecast for 2025, net of utility DSM and energy conservation measures, is approximately 13,166 MW.[45] Maryland had the capability to meet 98.4 percent of its summer peak demand with in-state generation in 2024.[46] Notwithstanding the ability to meet 98.4 percent of peak capacity with in-state generation, Maryland imports a significant portion of its electricity needs as discussed in more detail in Part B of this section.

A. Regional Transmission[47]

In its 2024 Regional Transmission Expansion Plan ("RTEP"), PJM authorized about $5.9 billion in system transmission improvement projects. [48] The development of the RTEP considers the forecasted impacts of system trends which are often driven by federal and state policy decisions. The planning process applies the North American Electric Reliability Corporation ("NERC") Planning Standard through the application of a wide range of reliability analyses (including load and generation deliverability tests) over a 15-year planning horizon.

1. Regional Transmission Congestion

This section of the Ten-Year Report discusses congestion in the PJM region. Congestion reflects the underlying characteristics of the power system, including the nature and capability of transmission facilities as well as the cost and geographical distribution of facilities. Congestion occurs when available, least-cost energy cannot be delivered to all loads because of inadequate transmission facilities, thereby causing the price of energy in the constrained area to be higher than in an unconstrained area. PJM's Locational Marginal Pricing ("LMP") system is designed to reflect the value of energy at a specific location and time of delivery, thus measuring the impact of congestion throughout the PJM system. Total congestion costs for the PJM RTO increased by 64.2 percent ($685.8 million) between 2023 and 2024.[49]

2. Regional Transmission Upgrades

The Commission recognizes the need to maintain and improve the transmission system within Maryland in order to ensure safe, reliable, and economic electric service to

[44] *Maryland Electricity Profile 2024*, The U.S. Energy Information Administration ("EIA"), (November 10, 2025), https://www.eia.gov/electricity/state/maryland. The EIA's most recent data available is from 2024. The next anticipated release date is listed as November 2026.
[45] *See* Appendix Table 3(a)(ii).
[46] The peak demand net of DSM programs for the summer of 2024 was 11,908 MWs according to the 2024-2033 Ten-Year Plan. 11,718/11,908 = 98.4%.
[47] *See* Appendix Table 4 for a full list of transmission enhancements proposed by Maryland utilities.
[48] *2024 Regional Transmission Expansion Plan.* PJM, (April 17, 2025) at 1, https://www.pjm.com/-/media/library/reports-notices/2024-rtep/2024-rtep-report.ashx.
[49] Monitoring Analytics, *State of the Market Report for PJM - 2023*, PJM, (March 13, 2025) at 607, https://www.monitoringanalytics.com/reports/PJM_State_of_the_Market/2024/2024-som-pjm-sec11.pdf.

the state's ratepayers. As with increases in local generating capacity and the reduction of system load, transmission expansions and improvements can reduce congestion and LMP differences among zones. Such improvements may also support reliability requirements and mitigate economic concerns. PJM's 2024 RTEP identified 28 transmission projects in Maryland for approximately $396 million,[50] compared to 50 identified transmission projects in Maryland for approximately $2.0 billion in PJM's 2023 RTEP.[51]

Appendix 4 lists all transmission enhancements identified by the Maryland utilities in response to data requests for the Ten-Year Plan. Together, the 24 identified transmission enhancements in Appendix Table 4 account for 127 miles of upgrades.

B. Electricity Imports

Maryland continues to be a net importer of electricity, similar to many other states in PJM.[52] In 2024, 43 percent of the electricity consumed in the State was imported from other states.[53] Nine of the 13 PJM states plus the District of Columbia are net importers of electricity. In a nationwide comparison, Maryland is the fifth largest electricity importer based on percentage of electricity sales.[54] Only the District of Columbia, Massachusetts, Delaware, and Vermont exceed Maryland in the percentage of electricity sales that are imported. As of 2024, the states within the PJM region that exported more electricity in aggregate than was sold within each state are: Illinois, Pennsylvania, Michigan, and West Virginia.[55]

In-state generation has declined in recent years in Maryland. In 2009, Maryland resources generated over 43 million MWh in electricity. In 2024, in-state resources generated 35.4 million MWh.[56] The EmPOWER Maryland program, together with other energy efficiency efforts across the State, contributes to a decrease in the peak demand which reduces the need to increase capacity and generation capabilities both in Maryland

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[50] The total reported number of projects reflects baseline, network, and supplemental projects within Maryland. The PJM RTEP report combines the District of Columbia and Maryland projects together – there were 31 total projects identified in the District of Columbia and Maryland combined, and 28 of these are within Maryland. *See 2024 Regional Transmission Expansion Plan.* PJM, (April 17, 2025) at 164-168. https://www.pjm.com/-/media/library/reports-notices/2024-rtep/2024-rtep-report.ashx.

[51] 2023 Maryland and District of Columbia State Infrastructure Report, PJM, at 15-17, (June 2024), https://www.pjm.com/-/media/library/reports-notices/state-specific-reports/2023/maryland-and-dc.ashx.

[52] PJM operates, but does not own, the transmission systems in: (1) Maryland; (2) all or part of 12 other states; and (3) the District of Columbia. With FERC approval, PJM undertakes the task of coordinating the movement of wholesale electricity and provides access to the transmission grid for utility and non-utility users alike. Within the PJM region, power plants are dispatched to meet load requirements without regard to operating company boundaries. Generally, adjacent utility service territories import or export wholesale electricity as needed to reduce the total amount of capacity required by balancing retail load and generation capacity.

[53] Table 10 in download of "Full data tables" at *Maryland Electricity Profile 2024*, EIA, (November 10, 2025), https://www.eia.gov/electricity/state/maryland.

[54] *US Electricity Profile 2024,* EIA (November 10, 2025), https://www.eia.gov/electricity/state/.

[55] *Id.*

[56] Table 5 in download of "Full data tables" at *Maryland Electricity Profile 2024*, EIA, (November 10, 2025), https://www.eia.gov/electricity/state/maryland.

and throughout the PJM region. According to EIA, Maryland is ranked 43rd in the country for per capita energy consumption.[57]

C. Maryland Capacity and Generation Profiles

The capacity and generation profiles of in-state resources must be comprehensively analyzed for both short-term and long-term reliability planning purposes. The following sections detail such profiles in Maryland.

1. Capacity and Generation Profiles

Table 9 and Table 10 below depict the electric generating capacity in Maryland, as well as the age of plants by fuel type.[58]

Table 9: Maryland Summer Peak Capacity Profile, 2024

Primary Fuel Type	Capacity	
	Summer (MW)	Percent of Total
Coal	1,273.0	10.9%
Oil	1,546.3	13.2%
Natural Gas	5,629.1	48.1%
Nuclear	1,745.2	14.9%
Hydroelectric	514.9	4.4%
Other and Renewables	992.6	8.5%
Total	**11,701.1**	**100.0%**

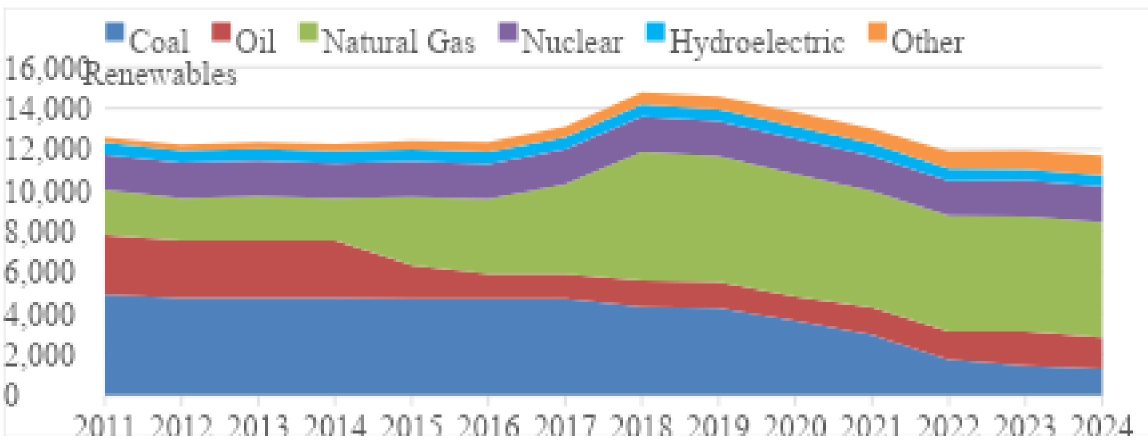
[57] *Maryland State Energy Profile*, U.S. Energy Information Administration (September 18, 2025). https://www.eia.gov/state/print.php?sid=MD.
[58] *See* Appendix Table 5 for a list of Maryland generation capacity in 2024.

Table 10: Age of Maryland Generation by Fuel Type, 2024

Primary Fuel Type	Age of Plants, By Percent			
	1-10 Years	11-20 Years	21-30 Years	31+ Years
Coal	0%	0%	0%	100%
Oil	2%	4%	15%	79%
Natural Gas	30%	15%	32%	23%
Nuclear	0%	0%	0%	100%
Hydroelectric	0%	0%	0%	100%
Other and Renewables	61%	32%	4%	3%

Maryland's summer peak capacity profile decreased by 213.5 MW in 2024 compared to 2023, as illustrated in Figure 8. The decreased capacity in 2024 can be almost entirely attributed to decreases in coal.

Figure 8: Maryland Summer Capacity Profile (MW), 2011 – 2024[59]



Maryland's generating profile differs from its capacity profile. For example, nuclear power provided 41.6 percent of the electricity generated in Maryland in 2024 though this resource represented just under 15 percent of in-state capacity. Conversely, oil facilities, which operate as mid-merit or peaking units that come on-line when needed, generate 0.6 percent of the electric energy produced in Maryland while representing 13.2 percent of in-state capacity. Table 11 summarizes Maryland's 2024 in-state generation profile according to fuel source.

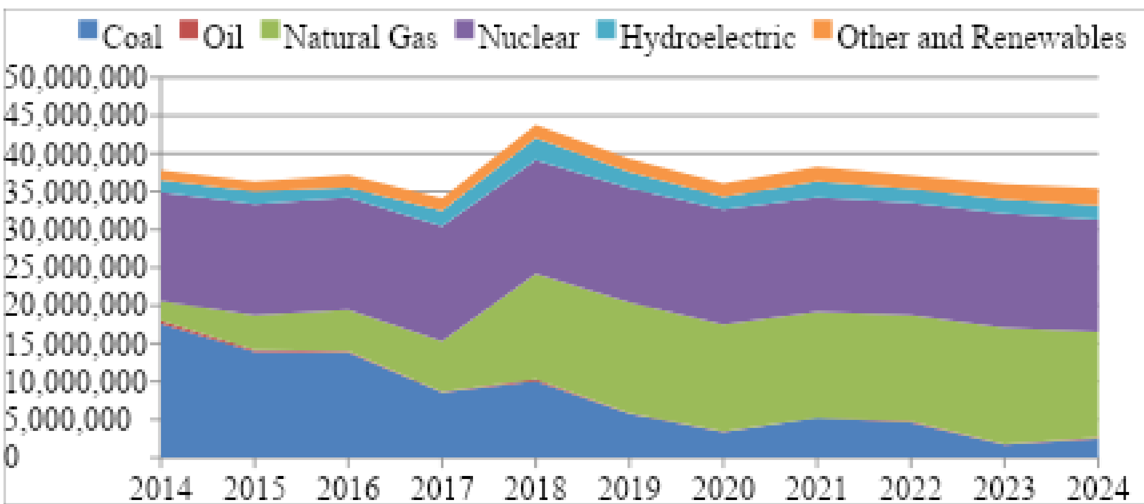
[59] U.S. Energy Information Administration, Form EIA-923, "Power Plant Operations Report."

Table 11: Maryland Generation Profile, 2024[60]

Primary Fuel Source	Generation	
	Annual (MWh)	**Percent of Total**
Coal	2,465,722	7.0%
Oil	211,556	0.6%
Gas	13,910,094	39.3%
Nuclear	14,724,068	41.6%
Hydroelectric	1,848,233	5.2%
Other & Renewables	2,265,144	6.4%
Total	**36,000,648**	**100.0%**

The percentage of in-state generation derived from various fuel sources continues to evolve as illustrated in Figure 9 below. The percentage of generation from coal has dropped from 47 percent in 2014 to 7 percent in 2024. The decrease in in-state generation can be largely attributed to this drop in coal generation over time.

Figure 9: Maryland Generation Profile, 2014 – 2024[61]



PJM lists two plants as retired in 2024 in Maryland: a coal-powered plant in the APS zone accounting for 180 MW in capacity and a battery-powered plant, also in the APS zone accounting for an additional 5 MW. The two retirements total 185 MW of capacity.[62] There are four pending deactivation requests in Maryland, all in the BGE service territory. The Maryland generators pending deactivation combine for an aggregate capacity of 1,983.6 MW; these pending requests are impacted by the Federal Energy Regulatory Commission ("FERC"). FERC orders delaying their retirement, as discussed

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[60] Table 5 in download of "Full data tables" at *Maryland Electricity Profile 2024*, EIA, (November 10, 2025), https://www.eia.gov/electricity/state/maryland.
[61] *Id.*
[62] Generation Deactivations, PJM, https://www.pjm.com/planning/service-requests/gen-deactivations.aspx. Accessed December 2025.

in greater detail below. PJM registers 8.48 GW of capacity resources requesting deactivation within the RTO as of December 2025.[63]

On May 1, 2025, FERC issued an order approving contested settlements for the Brandon Shores and H.A. Wagner plants to provide reliability-must-run ("RMR") service under black box settlement rates effective June 1, 2025 through May 31, 2029.[64] The settlements reduce annual fixed-cost charges by about 17% from the initial filings, cap certain regulatory and project investment costs, and require crediting of capacity market revenues to customers. Both plants were originally scheduled for deactivation on June 1, 2025, but will now remain operational under these agreements to address PJM system reliability concerns.

2. Proposed Generation Additions[65]

The construction of new generation is one way to address the in-state capacity and electricity import issues discussed in previous sections. As of June 2025, there were 4,484.7 MWs of proposed new generation in Maryland active in the PJM queue with 31 percent consisting of solar projects.[66]

The Commission recognizes the importance renewable generation plays in meeting Maryland's energy needs while also addressing environmental concerns. Based on the PJM queue as of June 2025, Maryland's renewable generation capacity is planned to increase by an estimated 1,474 MW over the next several years as shown in Table 12 below. This does not, however, account for smaller renewable generators, notably residential solar; these smaller renewable generators are not required to obtain PJM interconnection status but simply require interconnection with the local utility.

[63] *Id.*
[64] 191 FERC 61,098 (2025).
[65] *See* Appendix Table 6 for a complete list of new renewable generation proposed in Maryland.
[66] Serial Service Request Status, PJM (June 2025), https://www.pjm.com/planning/service-requests/serial-service-request-status.

Table 12: Proposed New Renewable Generation in Maryland

Utility	Fuel Type	In-Service Date Range	Total Capacity (MW)
PE (APS)	Solar	2023-2026	205.7
	Hydro	2023	14.0
	Wind	2021-2024	59.7
BGE	Solar	2023	33.0
DPL	Solar	2021-2028	404.9
Pepco	Solar	2023-2025	741.7
SMECO	Solar	2026	15.0
		Total (MW):	**1,473.9**

The amount of solar resources in Maryland is anticipated to continue to increase due to a suite of State policy initiatives: the requirement that the Renewable Portfolio Standard ("RPS") solar carve-out be interconnected to the distribution network serving Maryland; net metering incentives; tax incentives; the community solar pilot program (now a permanent program); Solar Renewable Energy Credit ("SREC") incentives; and grants administered by the Maryland Energy Administration.

On May 11, 2017, the Commission approved US Wind's 248 MW Maryland Offshore Wind Project ("MarWin") and Ørsted's 120 MW Skipjack Wind 1 Farm through the Round 1 Offshore Wind Renewable Energy Credit ("OREC") Program in compliance with the Maryland Offshore Wind Energy Act of 2013.[67] On December 17, 2021, the Commission approved US Wind's 808.5 MW Momentum Wind and Ørsted's 846 MW Skipjack Wind 2 Farm through the Round 2 OREC Program in compliance with the Clean Energy Jobs Act of 2019 ("CEJA").[68] Maryland's approved OREC projects totaled 2,022.5 MW; however, on January 25, 2024, Ørsted withdrew its Skipjack 1 and 2 Projects, reducing the total to 1,056.5 MW.[69]

On January 24, 2025, the Commission approved US Wind's application for a Revised Round 2 OREC Project in compliance with An Act Concerning Electricity - Offshore Wind Projects - Alterations Act enacted in 2024. US Wind's total project consists of 1,710 MW to be constructed in four phases by 2030. The Maryland Offshore Wind Project will generate 1.68 million MWh annually after its Phase 1 completion at the end of 2028. The generation will increase to almost 7 million MWh annually beginning in December 2030 after completion of the remaining three project phases.[70]

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[67] Case No. 9431, *In The Matter Of The Applications Of US Wind, Inc. And Skipjack Offshore Energy, LLC For A Proposed Offshore Wind Project(s) Pursuant To The Maryland Offshore Wind Energy Act Of 2013*. Order No. 88122, at 121 (May 11, 2017).
[68] Case No. 9666, *Skipjack Offshore Energy, LLC and US Wind, Inc.'s Offshore Wind Applications under the Clean Energy Jobs Act of 2019*. Order No. 90011, at 149 (December 17, 2021).
[69] Case No. 9666, *Skipjack Offshore Energy, LLC and US Wind, Inc.'s Offshore Wind Applications under the Clean Energy Jobs Act of 2019*. Skipjack Letter Withdrawing from OREC Orders (January 25, 2024).
[70] Case No. 9666, Order No. 91496, at 220 (January 24, 2025).

US Wind has completed the federal, State, and county permitting processes for the Maryland Offshore Wind and Momentum Wind Projects. US Wind has completed all of the required federal permitting authorizations from several federal agencies in compliance with the National Environmental Policy Act ("NEPA").[71] The most significant was the Bureau of Ocean Energy Management ("BOEM") approval of its Construction and Operations Plan on December 3, 2024.[72] Stakeholders have filed appeals against a number of these permit approvals.

US Wind has also completed all the required State permitting authorizations with Maryland and Delaware. The Environmental Protection Agency ("EPA") delegated authority of its Outer Continental Shelf ("OCS") Air Permit to the Maryland Department of Environment ("MDE"). MDE issued its approval of US Wind's OCS Air Permit on June 5, 2025.[73] On November 20, 2024, the Maryland Board of Public Works approved US Wind's tidal wetlands license authorizing US Wind to build a pier that would support its Operations and Maintenance facility on the Sinepuxent Bay in Maryland.[74] The Delaware Department of Natural Resources and Environmental Control ("DNREC") issued a number of environmental permits for the project's transmission cable landfall site at the 3R's Beach State Park and cable route to the point of interconnection at Indian River Power Plant on January 8, 2025 and January 10, 2025.[75] Stakeholders have filed appeals against a number of these permit approvals.

Meanwhile, the Sussex County Council denied US Wind's application for a conditional use permit to construct the onshore substation at Indian River Power Plant on December 17, 2024.[76] US Wind appealed the County's decision with the Delaware Superior Court on December 26, 2024.[77] In response, Delaware enacted Senate Bill 159 on June 30, 2025, which retro-actively overturned the Sussex County Council's decision on US Wind's conditional use permit for its onshore substation at the Indian River Power Plant.[78]

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[71] Maryland Offshore Wind Project, Permitting Dashboard | Federal Infrastructure Projects, https://www.permits.performance.gov/permitting-project/fast-41-covered-projects/maryland-offshore-wind-project (August 11, 2025).
[72] Maryland Offshore Wind, Bureau of Ocean Energy Management, https://www.boem.gov/renewable-energy/state-activities/maryland-offshore-wind (August 11, 2025).
[73] Maryland Offshore Wind Project, Maryland Department of Environment, https://mde.maryland.gov/programs/permits/AirManagementPermits/Pages/U.-S.-Wind-Maryland-Offshore-Wind-Project-.aspx (August 11, 2025).
[74] Memorandum of Understanding between the Maryland Department of Natural Resources and US Wind, Inc., Maryland Department of Natural Resources, https://dnr.maryland.gov/ccs/Documents/MDNR_US_Wind_MOU_executed.pdf (May 13, 2025).
[75] US Wind Project, Delaware Department of Natural Resources and Environmental Control, https://dnrec.delaware.gov/us-wind/ (August 11, 2025).
[76] Sussex County Council, https://connect.sussexcountyde.gov/PublicDocket/#/details/CU%202515 (December 17, 2024).
[77] Docket Report Results, Delaware Superior Court, https://courtconnect.courts.delaware.gov/cc/cconnect/ck_public_qry_doct.cp_dktrpt_frames?backto=P&case_id=S24A-12-002&begin_date=&end_date= (December 26, 2024).
[78] Senate Bill 159, Delaware General Assembly, https://legis.delaware.gov/BillDetail?LegislationId=142363 (August 11, 2025).

3. Nuclear Generation

The Commission also recognizes the important role nuclear generation plays in meeting Maryland's energy needs. Nuclear energy provides reliability to the grid while assisting Maryland in reaching its Regional Greenhouse Gas Initiative ("RGGI") commitments and its goals under the Greenhouse Gas Emissions Reduction Act. CEJA required DNR to conduct an additional study on the relevancy and outlook for nuclear capacity on Maryland's generating portfolio both currently and in the future. In 2025, the Next Generation Energy Act ("NGEA") was enacted which created a competitive solicitation for nuclear zero emission credits ("ZEC") to promote development of nuclear generation at new or existing facilities in Maryland. NGEA requires the Commission to adopt regulations to implement the ZEC competitive solicitation by July 1, 2027. On June 25, 2025, the Commission convened Public Conference ("PC") 71 and established the Nuclear Procurement Work Group to develop draft regulations. In addition, NGEA requires the Commission to provide the General Assembly with a report identifying necessary legislative changes to implement the ZEC competitive solicitation by January 15, 2026.

4. Storage

The Energy Storage–Targets and Maryland Energy Storage Program–Establishment Act was passed in 2023 and requires the Commission to establish targets for the cost-effective deployment of new energy storage devices in the State with a goal of achieving 3,000 MW cumulative energy storage capacity by the end of delivery year 2033 (May 2034). The first milestone for the 3,000 MW capacity goal is 750 MW by delivery year 2027 (May 2028). In further support of these goals, NGEA was passed in 2025 providing additional granularity for goal allocations of certain types of energy storage. These goals include at least 150 MW of distribution-connected front-of-the-meter ("FTM") energy storage achieved through utility submitted plans and two different Commission procurements for a maximum in each procurement of 800 MW of transmission-connected FTM energy storage. The NGEA also specified a goal for 30 percent of the distribution-connected FTM energy storage devices to be owned by a third party.

The Commission has issued multiple orders in 2025 in recognition of the stated energy storage goals. In Order No. 91705, issued June 24, 2025, the Commission determined that the 150 MW minimum distribution-connected FTM energy storage deployment goal created by the NGEA will be allocated to utility territories according to 2024 energy sales and accordingly directed the utilities to propose plans by November 1, 2025 to achieve at least one-third of their target. Additionally, on October 15, 2025, the Commission opened PC 75 to begin the process for procuring transmission-connected FTM energy storage.

There are several storage projects in the PJM queue that are projected to begin operating in the near future as illustrated in Table 13 below.

Table 13: Proposed New Storage Generation in Maryland PJM Queue Effective Date: June 2025

Transmission Owner	Project Name	County Location	PJM Queue Status	PJM Queue #	Project Capacity (MW)	Commercial Operation Milestone
DPL	Airey-Vienna 69 kV II	Dorchester	Active	AG1-450 - moved to TC1	25.0	12/31/2022
DPL	Church 138 kV	Queen Anne's	Active	AG2-281 - moved to TC2	50.0	5/1/2024
DPL	Carville 138 kV IV	Queen Anne's	Active	AG2-380 - moved to TC2	20.0	9/15/2023
BGE	Northeast - Riverside 230 kV	Baltimore County	Active	AH1-261 - moved to TC2	135.0	6/30/2025
DPL	Church-Oil City 138kV	Queen Anne's	Active	AH1-536 - moved to TC2	8.5	3/1/2025
PEPCO	Chalk Point 230 kV	Prince George's	Active	AH1-552 - moved to TC2	670.2	6/1/2025
BGE	Conastone 500 kV	Harford	Active	AH1-725 - moved to TC2	500.0	6/11/2029
DPL	Crisfield 69kV	Somerset	Active	AH2-049	20.0	6/2/2025
BGE	Northeast-CP Crane 115kV	Baltimore County	Active	AH2-162	200.0	3/1/2026
APS	Catoctin-Carroll 138 kV	Frederick	Active	AH2-262	10.2	3/1/2026
PEPCO	Oak Grove - Hawkins Gate 230kV	Charles	Active	AH2-265	200.0	3/1/2026
PEPCO	Talbert 230kV	Prince George's	Active	AH2-332	115.0	12/31/2025
DPL	Talbot 69 kV	Worcester	Active	AH2-337	80.0	2/27/2026
SMECO	Sollers 230kV	Calvert	Active	AH2-423	180.0	12/31/2025
BGE	Northeast-CP Crane 115kV	Baltimore County	Active	AI1-130	75	9/7/2026
BGE	TBD 115 kV	Baltimore County	Active	AI1-131	75	9/7/2026
BGE	Northeast - Windy Edge 115 kV	Baltimore County	Active	AI1-189	110	12/31/2027
DPL	Rock Springs 500 kV	Cecil	Active	AI2-054	0	6/1/2028
DPL	Colora 230 kV	Cecil	Active	AI2-307	60.48	9/10/2026
APS	Ringgold 138 kV II	Washington	Active	AI2-311	30	1/11/2025
PEPCO	Morgantown 230 kV	Charles	Active	AI2-457	1122	10/1/2027
DPL	Bishopville – Worcester 138 kV	Worcester	Active	AJ1-018	39	12/29/2028
				Total	**3,725.4**	

D. PJM's Reliability Pricing Model

As a means of ensuring reliability of the electric system in the RTO, PJM annually conducts a long-term planning process that compares the potential available generation capacity located within the RTO and the import capability of the RTO against the estimated demand of customers within the RTO. Consequently, the model projects the amount of generation and transmission required to maintain the reliability of the electric grid within PJM. The amount of capacity procured in PJM's Reliability Pricing Model

("RPM") is roughly based upon a forecast of the peak load projected by PJM for a particular year, plus a reserve margin. The RPM works in conjunction with PJM's RTEP to ensure reliability in the PJM region for future years. Locational constraints are also identified for a delivery year in the PJM Regional Transmission Expansion Planning Process ("RTEPP") prior to each Base Residual Auction ("BRA"). Locational constraints are capacity import capability limitations that are caused by transmission facility limitations or voltage limitations. Resources in the unconstrained Locational Deliverability Areas ("LDA") (and capacity imported into constrained LDAs) are paid the Unconstrained (lower) Resource Clearing Price.

Using this information, PJM evaluates offers from resources three years in advance to be available for a one-year delivery period running from June through May (up to three years for new generation) through the BRA.[79] Once PJM completes its RTEPP and conducts the BRA, PJM is in a position to evaluate the reliability of its system. PJM must operate the transmission system to meet reliability criteria established by FERC and administered by NERC.

The Mid-Atlantic Advisory Council ("MAAC") LDA[80] has experienced significant volatility in Net Zonal Load[81] capacity prices as a result of the past 10 BRAs. The historical pattern suggests that future BRA results could vary significantly from year to year and must be closely monitored by PJM.

BGE's BRA result for the 2025/2026 Delivery Year and Pepco's BRA result for the 2026/2027 Delivery Year are both outliers with respect to each utility's set of delivery year results from 2016–2027, according to Tukey's Fences method for outlier detection.[82] As with the 2025/2026 Delivery Year, capacity prices remain high across the zones which encompass Maryland. PJM mainly attributed the continually high auction prices to increased electricity demand resultant of data center expansion, electrification, and economic growth across the Mid-Atlantic.[83]

[79] PJM Manual 18: PJM Capacity Market, Section 1: Overview of the PJM Capacity Market Reliability Pricing Model, PJM Markets & Operations (last revised June 27, 2024), https://www.pjm.com/directory/manuals/m18/index.html#Sections/Section%201%20Overview%20of%20the%20PJM%20Capacity%20Market.html.
[80] MAAC includes the South-West MAAC ("SWMAAC") which is the zone serving central Maryland.
[81] The Zonal Net Load capacity price reflects the BRA resource clearing price and credits from any transmission capacity transfer rights.
[82] John Tukey's Fences method prescribes that an outlier is any point in a dataset that is less than a lower fence of 1.5-fold the interquartile range subtracted from the 25th percentile, or greater than an upper fence of 1.5-fold the interquartile range added to the 75th percentile.
[83] *PJM Auction Procures 134,311 MW of Generation Resources; Supply Responds to Price Signal*, PJM (July 22, 2025), https://insidelines.pjm.com/pjm-auction-procures-134311-mw-of-generation-resources-supply-responds-to-price-signal/#:~:text=At%20the%20same%20time%2C%20electricity,Supply%2FDemand%20Remains%20Tight.

Table 14: PJM BRA Capacity Prices by Zone[84]

Delivery Year	APS($/MW-day)	BGE($/MW-day)	DPL($/MW-day)	PEPCO ($/MW-day)	RTO Price ($/MW-day)
2016/2017	$59.37	$119.13	$119.13	$119.13	$59.37
2017/2018	$120.00	$120.00	$120.00	$120.00	$120.00
2018/2019	$164.77	$164.77	$225.42	$164.77	$164.77
2019/2020	$100.00	$100.30	$119.77	$100.00	$100.00
2020/2021	$76.53	$86.04	$187.87	$86.04	$76.53
2021/2022	$140.00	$200.30	$165.73	$140.00	$140.00
2022/2023	$50.00	$126.50	$97.86	$95.79	$50.00
2023/2024	$34.13	$69.95	$69.95	$49.49	$34.13
2024/2025	$28.92	$73.00	$90.64	$49.49	$28.92
2025/2026	$269.92	$466.35	$269.92	$269.92	$269.92
2026/2027	$329.17	$329.17	$329.17	$329.17	$329.17

V. Conclusion

Electricity sector planning will continue to be affected by several different issues over the next 10 years, including projections regarding Maryland utility customers, energy sales, and in-State capacity and generation profiles. Other factors that will play a significant role in the planning process will be Maryland's data center development and electrification.[85] The Maryland utilities' load forecasts indicate a significant amount of projected annual growth in energy sales and peak demand throughout the State during the 2025-2034 planning horizon.

Internally, the Commission created a work group on distribution system planning under its grid modernization proceeding, PC 44 and Case 9665. The PC 44 Distribution System Planning Work Group ("DSP WG") is reviewing the current planning processes in Maryland, related State policies, and existing utility programs that interface with distribution system planning. In Order No. 91256, the Commission ordered the DSP WG to develop and provide to the electric utilities a common framework for utility reporting on information regarding the current status of projects designed to promote State policy goals identified in PUA §7-802, including information on planning processes and implementation that promote these goals. In addition, Order No. 91256 directed the utilities to file status reports no later than November 15th of each year.

[84] *PJM RPM Auction User Information: Delivery Year*, PJM Markets & Operations (Delivery Years 2016-2027), https://www.pjm.com/markets-and-operations/rpm.aspx.
[85] FirstEnergy, Dominion Energy, American Electric Power Reach Joint Planning Agreement to Propose Regional Transmission Projects Across PJM Footprint, FirstEnergy (October 7, 2024), https://investors.firstenergycorp.com/investor-materials/news-releases/news-details/2024/FirstEnergy-Dominion-Energy-American-Electric-Power-reach-joint-planning-agreement-to-propose-regional-transmission-projects-across-PJM-footprint/default.aspx.

Order No. 91490, issued on January 21, 2025, reviewed the progress and recommendations of the DSP WG concerning the transformation of Maryland's Electric Distribution Systems and directed the Work Group to file proposed regulations consistent with the Commission's guidance on various consensus and non-consensus items, including requiring feeder-level information where system constraints exist and modernizing forecasting methodologies, on or before May 1, 2025.

Order No. 91751, issued July 28, 2025, directed Phase III of the DSP WG to consider outstanding non-consensus issues discussed during the Rule Making 89 proceeding, such as discovery procedures, uniform planning disclosures, metrics, and the definition of "System Constraints" while also appointing Samrawit Dererie as the new Work Group Leader and requiring the group to propose a staggered submission schedule for Annual Plan Updates and Preliminary Electric System Plans by November 1, 2025.

Relevant to planning of the distribution system in Maryland is the implementation of the 2024 Distribution Renewable Integrated and Vehicle Electrification ("DRIVE") Act, codified at PUA §7-1001 *et seq*. Pursuant to implementation of this Act, on July 11, 2024, the Commission issued Order No. 91218 which directed the State's investor-owned utilities to file (1) "opt-in" time-of-use ("TOU") tariff offerings; and (2) proposals for a pilot program or temporary tariff for electric distribution system support services ("EDSSS") as provided through virtual power plant ("VPP") and/or vehicle-to-grid programs. The utilities each submitted pursuant EDSSS pilot program proposals and TOU rate offerings. In Order No. 91917, issued October 21, 2025, the Commission accepted the utilities' TOU offerings with modifications, and gave the utilities an opportunity to cure defects in their EDSSS pilot proposals and resubmit their pilot proposals. This proceeding is ongoing.

On October 10, 2024, the Commission docketed PC 66 on resource adequacy. The Commission asked parties to file comments providing advice, suggestions, and innovative approaches regarding how to bring the capacity market back into equilibrium. After receiving public comments from parties in early November, the Commission set the matter for a Technical Conference, which convened on December 3, 2024.

Following the December 3, 2024 hearing, the Commission sought clarification on its existing authority from Staff and OPC. In particular, the Commission expressed a desire to address pricing and cost recovery for ratepayer-paid generation for Maryland ratepayers while being careful not to violate provisions of the Federal Power Act and Commerce Clause and interfering with the PJM wholesale market. Accordingly, the Commission requested further comments from parties on December 30, 2024 asking for such comments to be filed in the PC 66 docket by January 17, 2025. Further comments were filed by OPC, the Exelon utilities, International Brotherhood of Electrical Workers Local 410, and Staff.

In response to these and other developments, the 2025-2034 Ten-Year Plan will enable continued review and assessment of the impacts that the above-mentioned issues will have on Maryland's long-term electricity resource planning.

Appendices to the Public Service Commission of Maryland's Ten-Year Plan (2025-2034) of Electric Companies in Maryland

*Data in Appendices 1-4 was derived from the Utilities' responses to Staff's Data Requests

Appendix 1(a): Maryland Customer Forecasts

Appendix Table 1(a)(i): All Customer Classes (number of customers)

Year	Berlin	BGE	DPL	Easton	Hagerstown	PE	Pepco	SMECO	Thurmont	Williamsport	Total
2025	2,754	1,351,672	222,003	11,103	17,780	293,356	612,618	180,737	2,903	1,023	**2,695,949**
2026	2,743	1,359,699	223,180	11,154	17,821	295,602	619,357	183,072	2,903	1,023	**2,716,553**
2027	2,757	1,367,521	224,160	11,204	17,862	297,903	624,750	185,361	2,903	1,023	**2,735,444**
2028	2,770	1,374,304	224,998	11,255	17,903	300,506	629,487	187,634	2,903	1,023	**2,752,782**
2029	2,784	1,380,857	225,787	11,307	17,944	303,352	633,975	189,834	2,903	1,023	**2,769,765**
2030	2,812	1,387,185	226,578	11,358	17,985	306,356	638,498	191,974	2,903	1,023	**2,786,672**
2031	2,840	1,383,328	227,372	11,410	18,026	309,349	643,055	194,050	2,903	1,023	**2,793,356**
2032	2,869	1,388,583	228,170	11,462	18,067	312,247	647,646	196,075	2,903	1,023	**2,809,043**
2033	2,897	1,393,759	228,970	11,514	18,109	315,063	652,272	198,035	2,903	1,023	**2,824,544**
2034	2,926	1,398,496	229,773	11,566	18,150	317,689	656,932	199,972	2,903	1,023	**2,839,430**
Change (2025-2034)	**172**	**46,823**	**7,770**	**463**	**370**	**24,333**	**44,314**	**19,235**	**0**	**0**	**143,481**
Percent Change (2025-2034)	**6.26%**	**3.46%**	**3.50%**	**4.17%**	**2.08%**	**8.29%**	**7.23%**	**10.64%**	**0.00%**	**0.00%**	**5.32%**
Compound Annual Growth Rate	**0.68%**	**0.38%**	**0.38%**	**0.45%**	**0.23%**	**0.89%**	**0.78%**	**1.13%**	**0.00%**	**0.00%**	**0.58%**

Note: A&N, Choptank, and Somerset did not report applicable information for this table.

Appendix Table 1(a)(ii): Residential (number of customers)

Year	Berlin	BGE	DPL	Easton	Hagerstown	PE	Pepco	SMECO	Thurmont	Williamsport	Total
2025	2,267	1,222,774	187,671	8,686	14,900	258,393	561,420	164,121	2,520	861	**2,423,613**
2026	2,267	1,230,504	188,676	8,730	14,937	260,380	568,098	166,229	2,520	861	**2,443,202**
2027	2,278	1,238,028	189,512	8,775	14,975	262,429	573,435	168,271	2,520	861	**2,461,084**
2028	2,290	1,244,514	190,224	8,819	15,012	264,756	578,107	170,294	2,520	861	**2,477,396**
2029	2,301	1,250,769	190,893	8,864	15,050	267,302	582,527	172,249	2,520	861	**2,493,335**
2030	2,324	1,256,800	191,563	8,909	15,087	269,987	586,981	174,154	2,520	861	**2,509,187**
2031	2,347	1,252,645	192,237	8,955	15,125	272,659	591,469	176,008	2,520	861	**2,514,825**
2032	2,371	1,257,601	192,912	9,000	15,163	275,242	595,991	177,824	2,520	861	**2,529,485**
2033	2,395	1,262,479	193,590	9,046	15,201	277,749	600,548	179,596	2,520	861	**2,543,985**
2034	2,419	1,266,917	194,271	9,092	15,239	280,088	605,140	181,351	2,520	861	**2,557,897**
Change (2025-2034)	**152**	**44,143**	**6,600**	**406**	**339**	**21,695**	**43,720**	**17,229**	**0**	**0**	**134,284**
Percent Change (2025-2034)	**6.69%**	**3.61%**	**3.52%**	**4.67%**	**2.27%**	**8.40%**	**7.79%**	**10.50%**	**0.00%**	**0.00%**	**5.54%**
Compound Annual Growth Rate	**0.72%**	**0.39%**	**0.38%**	**0.51%**	**0.25%**	**0.90%**	**0.84%**	**1.12%**	**0.00%**	**0.00%**	**0.60%**

Note: A&N, Choptank, and Somerset did not report applicable information for this table.

Appendix 1(a) (Continued): Maryland Customer Forecasts

Appendix Table 1(a)(iii): Commercial (number of customers)

Year	Berlin	BGE	DPL	Easton	Hagerstown	PE	Pepco	SMECO	Thurmont	Williamsport	Total
2025	312	115,387	29,922	2,417	2,800	32,127	49,974	16,071	339	146	**249,496**
2026	312	115,514	30,089	2,424	2,804	32,397	50,040	16,299	339	146	**250,363**
2027	314	115,640	30,229	2,430	2,807	32,660	50,101	16,546	339	146	**251,211**
2028	315	115,767	30,350	2,436	2,811	32,944	50,171	16,796	339	146	**252,075**
2029	317	115,894	30,466	2,442	2,814	33,252	50,244	17,042	339	146	**252,955**
2030	320	116,020	30,582	2,449	2,818	33,578	50,318	17,276	339	146	**253,846**
2031	323	116,147	30,699	2,455	2,821	33,907	50,391	17,498	339	146	**254,726**
2032	326	116,273	30,816	2,461	2,825	34,228	50,465	17,707	339	146	**255,586**
2033	330	116,400	30,934	2,468	2,828	34,540	50,539	17,895	339	146	**256,419**
2034	333	116,527	31,052	2,474	2,832	34,833	50,613	18,077	339	146	**257,225**
Change (2025-2034)	**21**	**1,140**	**1,130**	**57**	**32**	**2,706**	**639**	**2,006**	**0**	**0**	**7,729**
Percent Change (2025-2034)	**6.69%**	**0.99%**	**3.78%**	**2.36%**	**1.13%**	**8.42%**	**1.28%**	**12.48%**	**0.00%**	**0.00%**	**3.10%**
Compound Annual Growth Rate	**0.72%**	**0.11%**	**0.41%**	**0.26%**	**0.12%**	**0.90%**	**0.14%**	**1.32%**	**0.00%**	**0.00%**	**0.34%**

Note: A&N, Choptank, and Somerset did not report applicable information for this table.

Appendix Table 1(a)(iv): Industrial (number of customers)

Year	Berlin	BGE	DPL	Easton	Hagerstown	PE	Pepco	SMECO	Thurmont	Williamsport	Total
2025	148	13,253	544	N/A	80	2,541	N/A	7	9	8	**16,590**
2026	136	13,426	549	N/A	80	2,530	N/A	7	9	8	**16,745**
2027	137	13,598	554	N/A	80	2,520	N/A	7	9	8	**16,912**
2028	137	13,771	558	N/A	80	2,511	N/A	7	9	8	**17,081**
2029	138	13,944	563	N/A	80	2,502	N/A	7	9	8	**17,251**
2030	139	14,116	567	N/A	80	2,495	N/A	7	9	8	**17,422**
2031	141	14,289	571	N/A	80	2,489	N/A	7	9	8	**17,594**
2032	142	14,462	575	N/A	80	2,483	N/A	7	9	8	**17,766**
2033	144	14,634	580	N/A	80	2,478	N/A	7	9	8	**17,940**
2034	145	14,807	584	N/A	80	2,474	N/A	7	9	8	**18,114**
Change (2025-2034)	**(3)**	**1,554**	**40**	**0**	**0**	**(68)**	**0**	**0**	**0**	**0**	**1,523**
Percent Change (2025-2034)	**-1.85%**	**11.73%**	**7.33%**	**N/A**	**0.00%**	**-2.66%**	**N/A**	**0.00%**	**0.00%**	**0.00%**	**9.18%**
Compound Annual Growth Rate	**-0.21%**	**1.24%**	**0.79%**	**N/A**	**0.00%**	**-0.30%**	**N/A**	**0.00%**	**0.00%**	**0.00%**	**0.98%**

Note: A&N, Choptank, and Somerset did not report applicable information for this table.

Appendix 1(a) (Continued): Maryland Customer Forecasts

Appendix 1(a) (Continued): Maryland Customer Forecasts

Appendix Table 1(a)(v): Other (number of customers)

Year	Berlin	BGE	DPL	Easton	Hagerstown	PE	Pepco	SMECO	Thurmont	Williamsport	Total
2025	27	258	3,866	N/A	N/A	292	1,224	537	35	8	**6,247**
2026	28	256	3,866	N/A	N/A	292	1,219	537	35	8	**6,241**
2027	28	254	3,866	N/A	N/A	292	1,214	537	35	8	**6,234**
2028	28	252	3,866	N/A	N/A	292	1,209	537	35	8	**6,227**
2029	28	251	3,866	N/A	N/A	292	1,204	537	35	8	**6,221**
2030	29	249	3,866	N/A	N/A	292	1,199	537	35	8	**6,215**
2031	29	248	3,866	N/A	N/A	292	1,194	537	35	8	**6,209**
2032	29	247	3,866	N/A	N/A	292	1,189	537	35	8	**6,203**
2033	29	246	3,866	N/A	N/A	292	1,184	537	35	8	**6,197**
2034	30	244	3,866	N/A	N/A	292	1,179	537	35	8	**6,191**
Change (2025-2034)	**3**	**(14)**	**0**	**0**	**0**	**0**	**(45)**	**0**	**0**	**0**	**(56)**
Percent Change (2025-2034)	**9.98%**	**5.30%**	**0.00%**	**N/A**	**N/A**	**0.00%**	**3.64%**	**0.00%**	**0.00%**	**0.00%**	**0.89%**
Compound Annual Growth Rate	**1.06%**	**0.60%**	**0.00%**	**N/A**	**N/A**	**0.00%**	**0.41%**	**0.00%**	**0.00%**	**0.00%**	**0.10%**

Note: A&N, Choptank, and Somerset did not report applicable information for this table.
Note: The "Other" rate class refers to customers that do not fall into one of the listed classes, for example street lighting.

Appendix Table 1(a)(vi): Resale (number of customers)

Year	Berlin	BGE	DPL	Easton	Hagerstown	PE	Pepco	SMECO	Thurmont	Williamsport	Total
2025	N/A	0	0	N/A	N/A	3	N/A	N/A	N/A	N/A	**3**
2026	N/A	0	0	N/A	N/A	3	N/A	N/A	N/A	N/A	**3**
2027	N/A	0	0	N/A	N/A	3	N/A	N/A	N/A	N/A	**3**
2028	N/A	0	0	N/A	N/A	3	N/A	N/A	N/A	N/A	**3**
2029	N/A	0	0	N/A	N/A	3	N/A	N/A	N/A	N/A	**3**
2030	N/A	0	0	N/A	N/A	3	N/A	N/A	N/A	N/A	**3**
2031	N/A	0	0	N/A	N/A	3	N/A	N/A	N/A	N/A	**3**
2032	N/A	0	0	N/A	N/A	3	N/A	N/A	N/A	N/A	**3**
2033	N/A	0	0	N/A	N/A	3	N/A	N/A	N/A	N/A	**3**
2034	N/A	0	0	N/A	N/A	3	N/A	N/A	N/A	N/A	**3**
Change (2025-2034)	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**N/A**	**N/A**	**N/A**	**0**
Percent Change (2025-2034)	**N/A**	**N/A**	**N/A**	**N/A**	**N/A**	**0.00%**	**N/A**	**N/A**	**N/A**	**N/A**	**0.00%**
Compound Annual Growth Rate	**N/A**	**N/A**	**N/A**	**N/A**	**N/A**	**0.00%**	**N/A**	**N/A**	**N/A**	**N/A**	**0.00%**

Note: A&N, Choptank, and Somerset did not report applicable information for this table.
Note: The "Resale" class refers to "Sales for Resale," which is energy supplied to other electric utilities, cooperatives, municipalities, and federal and state electric agencies for resale to end-use consumers. PE is the only utility with any resale customers.

Appendix 1(b): 2024 Customer Numbers and Energy Sales

Appendix Table 1(b)(i): Customer Class Breakdown as of December 31, 2024 (number of customers)

	System Wide						Maryland					
Utility	Residential	Com-mercial	In-dustrial	Other	Sales for Resale	Total	Resi-dential	Com-mercial	In-dustrial	Other	Sales for Resale	Total
Berlin	2,266	320	139	27	-	**2,752**	2,266	320	139	27	-	**2,752**
BGE	1,214,100	115,309	13,087	260	-	**1,342,757**	1,214,100	115,309	13,087	260	-	**1,342,757**
DPL	488,409	65,541	242	597	-	**554,789**	186,368	28,348	135	260	-	**215,111**
Easton	8,590	2,400	-	-	-	**10,990**	8,590	2,400	-	-	-	**10,990**
Hagers-town	15,099	2,592	52	-	-	**17,742**	15,099	2,592	52	-	-	**17,742**
PE	391,842	50,833	4,328	591	5	**447,598**	256,487	31,394	2,536	294	3	**290,714**
PEPCO	872,387	78,116	N/A	207	N/A	**950,710**	553,607	50,624	N/A	177	N/A	**604,408**
SMECO	160,882	15,738	7	528	N/A	**177,154**	160,882	15,738	7	528	N/A	**177,154**
Thurmont	2,522	343	9	35	N/A	**2,909**	2,522	343	9	35	N/A	**2,909**
William-sport	861	147	8	8	N/A	**1,024**	861	147	8	8	N/A	**1,024**
Total	**3,156,957**	**331,338**	**17,872**	**2,254**	**5**	**3,508,426**	**2,400,781**	**247,215**	**15,973**	**1,590**	**3**	**2,665,562**

Note: A&N, Choptank, and Somerset did not report applicable information for this table.
Note: "System wide" includes the entire distribution system of a utility, which may extend beyond the Maryland service territory into Washington, D.C.; Delaware; and parts of West Virginia. The affected utilities include DPL, PE, and Pepco.

Appendix Table 1(b)(ii): Utilities' 2024 Energy Sales by Customer Class (GWh)

	System Wide						Maryland					
Utility	Resi-dential	Com-mercial	In-dustrial	Other	Sales for Resale	Total	Resi-dential	Com-mercial	In-dustrial	Other	Sales for Resale	Total
Berlin	27	3	15	0	-	**46**	27	3	15	0	-	**46**
BGE	12,740	2,755	13,077	203	-	**28,776**	12,740	2,755	13,077	203	-	**28,776**
DPL	5,281	5,127	1,344	43	-	**11,795**	2,112	1,682	332	11	-	**4,137**
Easton	107	132	-	-	-	**239**	107	132	-	-	-	**239**
Hagers-town	165	86	68	-	-	**319**	165	86	68	-	-	**319**
PE	5,230	2,877	2,306	21	42	**10,476**	3,298	2,058	1,315	15	10	**6,697**
PEPCO	7,928	14,896	-	78	-	**22,902**	5,478	7,571	-	57	-	**13,106**
SMECO	2,197	1,194	35	7	-	**3,434**	2,197	1,194	35	7	-	**3,434**
Thurmont	36	15	20	1	-	**72**	36	15	20	1	-	**72**
William-sport	9	3	6	0	-	**19**	9	3	6	0	-	**19**
Total	**33,722**	**27,089**	**16,872**	**353**	**42**	**78,079**	**26,171**	**15,500**	**14,869**	**294**	**10**	**56,845**

Note: A&N, Choptank, and Somerset did not report applicable information for this table.
Note: "System wide" includes the entire distribution system of a utility, which may extend beyond the Maryland service territory into Washington, D.C.; Delaware; and parts of West Virginia. The affected utilities include DPL, PE, and Pepco.

Appendix 2(a): Energy Sales Forecast by Utility (Maryland Service Territory Only)

Appendix Table 2(a)(i): Maryland Energy Sales Forecast, Gross of DSM (GWh)

Year	Berlin	BGE	DPL	Easton	Hagerstown	PE	Pepco	SMECO	Thurmont	Williamsport	Total
2025	50	29,480	4,275	241	315	8,926	13,674	3,503	74	20	**60,558**
2026	50	29,664	4,261	242	316	12,818	13,618	3,537	74	20	**64,599**
2027	50	29,283	4,250	243	317	16,308	13,572	3,608	74	20	**67,724**
2028	50	29,659	4,242	244	317	16,573	13,567	3,653	74	20	**68,400**
2029	51	29,992	4,246	262	318	16,860	13,593	3,697	74	20	**69,113**
2030	51	30,644	4,251	263	319	17,251	13,619	3,754	74	20	**70,246**
2031	52	31,286	4,255	265	320	17,566	13,645	3,797	74	20	**71,280**
2032	52	32,013	4,260	266	321	17,903	13,671	3,841	74	20	**72,421**
2033	53	32,588	4,264	267	321	18,215	13,697	3,872	74	20	**73,372**
2034	53	33,166	4,268	268	322	18,571	13,723	3,900	74	20	**74,366**
Change (2025-2034)	**4**	**3,686**	**(7)**	**28**	**7**	**9,644**	**49**	**398**	**-**	**-**	**13,809**
Percent Change (2025-2034)	**7.22%**	**12.50%**	**0.16%**	**11.58%**	**2.27%**	**108.04%**	**0.36%**	**11.35%**	**0.00%**	**0.00%**	**22.80%**
Compound Annual Growth Rate	**0.78%**	**1.32%**	**0.02%**	**1.22%**	**0.25%**	**8.48%**	**0.04%**	**1.20%**	**0.00%**	**0.00%**	**2.31%**

<u>Note:</u> A&N, Choptank, and Somerset did not report applicable information for this table.

Appendix Table 2(a)(ii): Maryland Energy Sales Forecast, Net of DSM (GWh)

Year	Berlin	BGE	DPL	Easton	Hagerstown	PE	Pepco	SMECO	Thurmont	Williamsport	Total
2025	50	28,866	4,183	241	315	7,450	13,337	3,445	74	20	**57,979**
2026	50	29,021	4,169	242	316	11,220	13,280	3,478	74	20	**61,870**
2027	50	29,283	4,157	243	317	14,573	13,234	3,550	74	20	**65,500**
2028	50	29,659	4,150	244	317	14,703	13,229	3,595	74	20	**66,042**
2029	51	29,992	4,154	262	318	14,857	13,255	3,639	74	20	**66,621**
2030	51	30,644	4,158	263	319	15,113	13,281	3,696	74	20	**67,619**
2031	52	31,286	4,163	265	320	15,293	13,307	3,739	74	20	**68,518**
2032	52	32,013	4,167	266	321	15,496	13,333	3,783	74	20	**69,525**
2033	53	32,588	4,171	267	321	15,674	13,359	3,814	74	20	**70,342**
2034	53	33,166	4,176	268	322	15,895	13,385	3,842	74	20	**71,202**
Change (2025-2034)	**4**	**4,300**	**(7)**	**28**	**7**	**8,445**	**49**	**398**	**-**	**-**	**13,223**
Percent Change (2025-2034)	**7.22%**	**14.90%**	**0.17%**	**11.58%**	**2.27%**	**113.36%**	**0.36%**	**11.54%**	**0.00%**	**0.00%**	**22.81%**
Compound Annual Growth Rate	**0.78%**	**1.55%**	**0.02%**	**1.22%**	**0.25%**	**8.78%**	**0.04%**	**1.22%**	**0.00%**	**0.00%**	**2.31%**

<u>Note:</u> A&N, Choptank, and Somerset did not report applicable information for this table.

Appendix 2(b): Energy Sales Forecast by Utility (System Wide)

Appendix Table 2(b)(i): System Wide Energy Sales Forecast, Gross of DSM (GWh)

Year	Berlin	BGE	DPL	Easton	Hagerstown	PE	Pepco	SMECO	Thurmont	Williamsport	Total
2025	50	29,480	12,035	241	315	16,773	23,783	3,503	74	20	**86,273**
2026	50	29,664	12,011	242	316	20,903	23,655	3,537	74	20	**90,471**
2027	50	29,283	12,008	243	317	24,480	23,472	3,608	74	20	**93,554**
2028	50	29,659	12,035	244	317	24,844	23,299	3,653	74	20	**94,196**
2029	51	29,992	12,106	262	318	25,211	23,149	3,697	74	20	**94,880**
2030	51	30,644	12,178	263	319	25,693	23,003	3,754	74	20	**95,999**
2031	52	31,286	12,251	265	320	26,090	22,860	3,797	74	20	**97,014**
2032	52	32,013	12,324	266	321	26,516	22,720	3,841	74	20	**98,146**
2033	53	32,588	12,398	267	321	26,901	22,583	3,872	74	20	**99,077**
2034	53	33,166	12,472	268	322	27,339	22,449	3,900	74	20	**100,064**
Change (2025-2034)	**4**	**3,686**	**437**	**28**	**7**	**10,566**	**(1,334)**	**398**	**-**	**-**	**13,791**
Percent Change (2025-2034)	**7.22%**	**12.50%**	**3.63%**	**11.58%**	**2.27%**	**62.99%**	**5.61%**	**11.35%**	**0.00%**	**0.00%**	**15.99%**
Compound Annual Growth Rate	**0.78%**	**1.32%**	**0.40%**	**1.22%**	**0.25%**	**5.58%**	**0.64%**	**1.20%**	**0.00%**	**0.00%**	**1.66%**

<u>Note:</u> A&N, Choptank, and Somerset did not report applicable information for this table.
<u>Note:</u> "System wide" includes the entire distribution system of a utility, which may extend beyond the Maryland service territory into Washington, D.C., Delaware, and parts of West Virginia. The affected utilities include DPL, PE, and Pepco.

Appendix Table 2(b)(ii): System Wide Energy Sales Forecast, Net of DSM (GWh)

Year	Berlin	BGE	DPL	Easton	Hagerstown	PE	Pepco	SMECO	Thurmont	Williamsport	Total
2025	50	28,866	11,943	241	315	15,236	23,445	3,445	74	20	**83,634**
2026	50	29,021	11,919	242	316	19,244	23,317	3,478	74	20	**87,681**
2027	50	29,283	11,915	243	317	22,684	23,134	3,550	74	20	**91,270**
2028	50	29,659	11,942	244	317	22,914	22,960	3,595	74	20	**91,777**
2029	51	29,992	12,014	262	318	23,146	22,811	3,639	74	20	**92,326**
2030	51	30,644	12,086	263	319	23,494	22,665	3,696	74	20	**93,311**
2031	52	31,286	12,158	265	320	23,756	22,522	3,739	74	20	**94,192**
2032	52	32,013	12,231	266	321	24,048	22,382	3,783	74	20	**95,190**
2033	53	32,588	12,305	267	321	24,298	22,245	3,814	74	20	**95,986**
2034	53	33,166	12,379	268	322	24,603	22,111	3,842	74	20	**96,839**
Change (2025-2034)	**4**	**4,300**	**437**	**28**	**7**	**9,367**	**(1,335)**	**398**	**-**	**-**	**13,205**
Percent Change (2025-2034)	**7.22%**	**14.90%**	**3.66%**	**11.58%**	**2.27%**	**61.48%**	**5.69%**	**11.54%**	**0.00%**	**0.00%**	**15.79%**

Appendix 1(a) (Continued): Maryland Customer Forecasts

Compound Annual Growth Rate	**0.78 %**	**1.55%**	**0.40 %**	**1.22%**	**0.25%**	**5.47%**	**0.65%**	**1.22%**	**0.00%**	**0.00%**	**1.64%**

Note: A&N, Choptank, and Somerset did not report applicable information for this table.
Note: "System wide" includes the entire distribution system of a utility, which may extend beyond the Maryland service territory into Washington, D.C.; Delaware; and parts of West Virginia. The affected utilities include DPL, PE, and Pepco.

Appendix 3(a): Peak Demand Forecasts (Maryland Service Territory Only)

Appendix Table 3(a)(i): Maryland Summer, Gross of DSM Programs (MW)

Year	Berlin	BGE	DPL	Easton	Hagerstown	PE	Pepco	SMECO	Thurmont	Williamsport	Total
2025	11	7,040	1,034	59	62	1,689	3,630	933	15	4	**14,476**
2026	11	7,066	1,033	59	62	2,577	3,644	946	15	4	**15,416**
2027	12	6,947	1,032	59	62	2,940	3,653	960	15	4	**15,683**
2028	12	6,966	1,032	60	62	2,998	3,662	972	15	4	**15,781**
2029	12	7,021	1,033	64	63	3,061	3,673	984	15	4	**15,928**
2030	12	7,053	1,033	64	63	3,134	3,682	996	15	4	**16,054**
2031	12	7,099	1,035	65	63	3,200	3,695	1,007	15	4	**16,192**
2032	12	7,158	1,037	65	63	3,271	3,709	1,018	15	4	**16,351**
2033	12	7,234	1,041	65	63	3,335	3,723	1,028	15	4	**16,519**
2034	12	7,298	1,045	66	63	3,409	3,738	1,037	15	4	**16,686**
Change (2025-2034)	**1**	**258**	**11**	**7**	**1**	**1,720**	**108**	**104**	**-**	**-**	**2,211**
Percent Change (2025-2034)	**7.75%**	**3.67%**	**1.06%**	**11.58%**	**2.27%**	**101.86%**	**2.99%**	**11.15%**	**0.00%**	**0.00%**	**15.27%**
Compound Annual Growth Rate	**0.83%**	**0.40%**	**0.12%**	**1.23%**	**0.25%**	**8.12%**	**0.33%**	**1.18%**	**0.00%**	**0.00%**	**1.59%**

Note: A&N, Choptank, and Somerset did not report applicable information for this table.

Appendix Table 3(a)(ii): Maryland Summer, Net of DSM Programs (MW)

Year	Berlin	BGE	DPL	Easton	Hagerstown	PE	Pepco	SMECO	Thurmont	Williamsport	Total
2025	6	6,544	956	59	62	1,441	3,209	871	15	4	**13,166**
2026	6	6,547	955	59	62	2,300	3,222	884	15	4	**14,053**
2027	6	6,565	953	59	62	2,628	3,232	898	15	4	**14,423**
2028	6	6,584	953	60	62	2,653	3,241	910	15	4	**14,487**
2029	6	6,639	954	64	63	2,683	3,251	922	15	4	**14,601**
2030	6	6,671	955	64	63	2,723	3,260	934	15	4	**14,694**
2031	6	6,717	956	65	63	2,755	3,273	945	15	4	**14,799**
2032	6	6,776	959	65	63	2,793	3,287	956	15	4	**14,924**
2033	7	6,852	963	65	63	2,824	3,301	966	15	4	**15,059**
2034	7	6,916	967	66	63	2,865	3,316	975	15	4	**15,193**
Change (2025-2034)	**1**	**372**	**11**	**7**	**1**	**1,424**	**108**	**104**	**-**	**-**	**2,027**
Percent Change (2025-2034)	**15.38%**	**5.68%**	**1.10%**	**11.58%**	**2.27%**	**98.82%**	**3.36%**	**11.94%**	**0.00%**	**0.00%**	**15.40%**
Compound Annual Growth Rate	**1.60%**	**0.62%**	**0.12%**	**1.23%**	**0.25%**	**7.94%**	**0.37%**	**1.26%**	**0.00%**	**0.00%**	**1.60%**

Note: A&N, Choptank, and Somerset did not report applicable information for this table.

Appendix 3(a) (Continued): Peak Demand Forecasts (Maryland Service Territory Only)

Appendix Table 3(a)(iii): Maryland Winter, Gross of DSM Programs (MW)

Year	Berlin	BGE	DPL	Easton	Hagerstown	PE	Pepco	SMECO	Thurmont	Williamsport	Total
2025	16	5,962	1,000	56	70	1,733	2,624	1,036	22	5	**12,524**
2026	16	5,993	1,008	56	71	2,794	2,642	976	22	5	**13,583**
2027	16	5,960	1,016	56	71	2,949	2,657	960	22	5	**13,713**
2028	16	6,016	1,025	56	72	3,021	2,683	976	22	5	**13,893**
2029	16	6,060	1,027	61	73	3,109	2,685	993	22	5	**14,052**
2030	16	6,124	1,032	61	74	3,185	2,698	1,008	22	5	**14,225**
2031	17	6,199	1,037	61	74	3,258	2,719	1,022	22	5	**14,415**
2032	17	6,283	1,045	62	75	3,341	2,737	1,035	22	5	**14,622**
2033	17	6,360	1,050	62	76	3,417	2,750	1,046	22	5	**14,805**
2034	17	6,415	1,054	62	77	3,506	2,761	1,057	22	5	**14,977**
Change (2025-2034)	**1**	**453**	**54**	**7**	**7**	**1,773**	**138**	**21**	**-**	**-**	**2,453**
Percent Change (2025-2034)	**7.75%**	**7.59%**	**5.39%**	**11.87%**	**9.37%**	**102.32%**	**5.25%**	**2.02%**	**0.00%**	**0.00%**	**19.58%**
Compound Annual Growth Rate	**0.83%**	**0.82%**	**0.58%**	**1.25%**	**1.00%**	**8.14%**	**0.57%**	**0.22%**	**0.00%**	**0.00%**	**2.01%**

Note: A&N, Choptank, and Somerset did not report applicable information for this table.

Appendix Table 3(a)(iv): Maryland Winter, Net of DSM Programs (MW)

Year	Berlin	BGE	DPL	Easton	Hagerstown	PE	Pepco	SMECO	Thurmont	Williamsport	Total
2025	16	5,897	1,000	56	70	1,495	2,624	1,036	22	5	**12,221**
2026	16	5,928	1,008	56	71	2,527	2,642	976	22	5	**13,252**
2027	16	5,960	1,016	56	71	2,650	2,657	960	22	5	**13,414**
2028	16	6,016	1,025	56	72	2,691	2,683	976	22	5	**13,563**
2029	16	6,060	1,027	61	73	2,747	2,685	993	22	5	**13,690**
2030	16	6,124	1,032	61	74	2,791	2,698	1,008	22	5	**13,832**
2031	17	6,199	1,037	61	74	2,833	2,719	1,022	22	5	**13,990**
2032	17	6,283	1,045	62	75	2,883	2,737	1,035	22	5	**14,165**
2033	17	6,360	1,050	62	76	2,928	2,750	1,046	22	5	**14,316**
2034	17	6,415	1,054	62	77	2,985	2,761	1,057	22	5	**14,456**
Change (2025-2034)	**1**	**518**	**54**	**7**	**7**	**1,490**	**138**	**21**	**-**	**-**	**2,235**
Percent Change (2025-2034)	**7.75%**	**8.78%**	**5.39%**	**11.87%**	**9.37%**	**99.68%**	**5.25%**	**2.02%**	**0.00%**	**0.00%**	**18.29%**
Compound Annual Growth Rate	**0.83%**	**0.94%**	**0.58%**	**1.25%**	**1.00%**	**7.99%**	**0.57%**	**0.22%**	**0.00%**	**0.00%**	**1.88%**

Note: A&N, Choptank, and Somerset did not report applicable information for this table.

Appendix 3(b): Peak Demand Forecasts (System Wide)

Appendix Table 3(b)(i): System Wide Summer, Gross of DSM (MW)

Year	Berlin	BGE	DPL	Easton	Hagerstown	PE	Pepco	SMECO	Thurmont	Williamsport	Total
2025	11	7,040	4,083	59	62	3,098	6,490	933	15	4	**21,793**
2026	11	7,066	4,075	59	62	3,966	6,517	946	15	4	**22,721**
2027	12	6,947	4,070	59	62	4,368	6,535	960	15	4	**23,030**
2028	12	6,966	4,070	60	62	4,434	6,552	972	15	4	**23,145**
2029	12	7,021	4,074	64	63	4,504	6,572	984	15	4	**23,311**
2030	12	7,053	4,075	64	63	4,583	6,589	996	15	4	**23,453**
2031	12	7,099	4,083	65	63	4,654	6,613	1,007	15	4	**23,613**
2032	12	7,158	4,092	65	63	4,732	6,640	1,018	15	4	**23,798**
2033	12	7,234	4,109	65	63	4,800	6,666	1,028	15	4	**23,995**
2034	12	7,298	4,127	66	63	4,879	6,695	1,037	15	4	**24,195**
Change (2025-2034)	**1**	**258**	**44**	**7**	**1**	**1,781**	**205**	**104**	**-**	**-**	**2,401**
Percent Change (2025-2034)	**7.75%**	**3.67%**	**1.09%**	**11.58%**	**2.27%**	**57.50%**	**3.15%**	**11.15%**	**0.00%**	**0.00%**	**11.02%**
Compound Annual Growth Rate	**0.83%**	**0.40%**	**0.12%**	**1.23%**	**0.25%**	**5.18%**	**0.35%**	**1.18%**	**0.00%**	**0.00%**	**1.17%**

<u>Note:</u> A&N, Choptank, and Somerset did not report applicable information for this table.
<u>Note:</u> "System wide" includes the entire distribution system of a utility, which may extend beyond the Maryland service territory into Washington, D.C.; Delaware; and parts of West Virginia. The affected utilities include DPL, PE, and Pepco.

Appendix Table 3(b)(ii): System Wide Summer, Net of DSM (MW)

Year	Berlin	BGE	DPL	Easton	Hagerstown	PE	Pepco	SMECO	Thurmont	Williamsport	Total
2025	6	6,544	4,005	59	62	2,842	6,069	871	15	4	**20,476**
2026	6	6,547	3,997	59	62	3,680	6,095	884	15	4	**21,349**
2027	6	6,565	3,992	59	62	4,048	6,113	898	15	4	**21,762**
2028	6	6,584	3,992	60	62	4,081	6,130	910	15	4	**21,844**
2029	6	6,639	3,996	64	63	4,118	6,150	922	15	4	**21,976**
2030	6	6,671	3,997	64	63	4,164	6,167	934	15	4	**22,085**
2031	6	6,717	4,005	65	63	4,202	6,191	945	15	4	**22,212**
2032	6	6,776	4,014	65	63	4,246	6,218	956	15	4	**22,363**
2033	7	6,852	4,031	65	63	4,280	6,244	966	15	4	**22,527**
2034	7	6,916	4,049	66	63	4,326	6,273	975	15	4	**22,693**
Change (2025-2034)	**1**	**372**	**44**	**7**	**1**	**1,485**	**204**	**104**	**-**	**-**	**2,218**
Percent Change (2025-2034)	**15.38%**	**5.68%**	**1.10%**	**11.58%**	**2.27%**	**52.25%**	**3.36%**	**11.94%**	**0.00%**	**0.00%**	**10.83%**
Compound Annual Growth Rate	**1.60%**	**0.62%**	**0.12%**	**1.23%**	**0.25%**	**4.78%**	**0.37%**	**1.26%**	**0.00%**	**0.00%**	**1.15%**

<u>Note:</u> A&N, Choptank, and Somerset did not report applicable information for this table.
<u>Note:</u> "System wide" includes the entire distribution system of a utility, which may extend beyond the Maryland service territory into Washington, D.C.; Delaware; and parts of West Virginia. The affected utilities include DPL, PE, and Pepco.

Appendix 3(b) (Continued): Peak Demand Forecasts (System Wide)

Appendix Table 3(b)(iii): System Wide Winter, Gross of DSM (MW)

Year	Berlin	BGE	DPL	Easton	Hagerstown	PE	Pepco	SMECO	Thurmont	Williamsport	Total
2025	16	5,962	3,731	56	70	3,449	5,389	1,036	22	5	**19,736**
2026	16	5,993	3,760	56	71	4,498	5,427	976	22	5	**20,824**
2027	16	5,960	3,789	56	71	4,700	5,458	960	22	5	**21,038**
2028	16	6,016	3,823	56	72	4,787	5,511	976	22	5	**21,285**
2029	16	6,060	3,831	61	73	4,888	5,516	993	22	5	**21,465**
2030	16	6,124	3,848	61	74	4,976	5,542	1,008	22	5	**21,676**
2031	17	6,199	3,869	61	74	5,060	5,585	1,022	22	5	**21,915**
2032	17	6,283	3,899	62	75	5,153	5,623	1,035	22	5	**22,174**
2033	17	6,360	3,916	62	76	5,238	5,648	1,046	22	5	**22,390**
2034	17	6,415	3,932	62	77	5,338	5,672	1,057	22	5	**22,598**
Change (2025-2034)	**1**	**453**	**201**	**7**	**7**	**1,890**	**283**	**21**	**-**	**-**	**2,862**
Percent Change (2025-2034)	**7.75%**	**7.59%**	**5.39%**	**11.87%**	**9.37%**	**54.79%**	**5.25%**	**2.02%**	**0.00%**	**0.00%**	**14.50%**
Compound Annual Growth Rate	**0.83%**	**0.82%**	**0.58%**	**1.25%**	**1.00%**	**4.97%**	**0.57%**	**0.22%**	**0.00%**	**0.00%**	**1.52%**

Note: A&N, Choptank, and Somerset did not report applicable information for this table.
Note: "System wide" includes the entire distribution system of a utility, which may extend beyond the Maryland service territory into Washington, D.C.; Delaware; and parts of West Virginia. The affected utilities include DPL, PE, and Pepco.

Appendix Table 3(b)(iv): System Wide Winter, Net of DSM (MW)

Year	Berlin	BGE	DPL	Easton	Hagerstown	PE	Pepco	SMECO	Thurmont	Williamsport	Total
2025	16	5,897	3,731	56	70	3,203	5,389	1,036	22	5	**19,425**
2026	16	5,928	3,760	56	71	4,223	5,427	976	22	5	**20,484**
2027	16	5,960	3,789	56	71	4,394	5,458	960	22	5	**20,732**
2028	16	6,016	3,823	56	72	4,449	5,511	976	22	5	**20,947**
2029	16	6,060	3,831	61	73	4,517	5,516	993	22	5	**21,095**
2030	16	6,124	3,848	61	74	4,574	5,542	1,008	22	5	**21,274**
2031	17	6,199	3,869	61	74	4,627	5,585	1,022	22	5	**21,481**
2032	17	6,283	3,899	62	75	4,688	5,623	1,035	22	5	**21,709**
2033	17	6,360	3,916	62	76	4,741	5,648	1,046	22	5	**21,893**
2034	17	6,415	3,932	62	77	4,810	5,672	1,057	22	5	**22,069**
Change (2025-2034)	**1**	**518**	**201**	**7**	**7**	**1,607**	**283**	**21**	**-**	**-**	**2,644**
Percent Change (2025-2034)	**7.75%**	**8.78%**	**5.39%**	**11.87%**	**9.37%**	**50.16%**	**5.25%**	**2.02%**	**0.00%**	**0.00%**	**13.61%**
Compound Annual Growth Rate	**0.83%**	**0.94%**	**0.58%**	**1.25%**	**1.00%**	**4.62%**	**0.57%**	**0.22%**	**0.00%**	**0.00%**	**1.43%**

Note: A&N, Choptank, and Somerset did not report applicable information for this table.
Note: "System wide" includes the entire distribution system of a utility, which may extend beyond the Maryland service territory into Washington, D.C.; Delaware; and parts of West Virginia. The affected utilities include DPL, PE, and Pepco.

Appendix 4: Transmission Enhancements, by Service Territory

								Start location		End Location	
Transmission Owner	**Voltage (kV)**	**Length (miles)**	**No. of Circuits**	**Start Date**	**Comp. Date**	**In-Service Date**	**Purpose**	**County**	**Terminal**	**County**	**Terminal**
BGE	115	20.7	2	Jul-05	Jun-25	Jun-25	Aging Infrastructure	Harford	Five Forks	Baltimore	Windy Edge
DPL	138	13.73	1	Jul-05	Dec-24	Dec-24	Capacity Expansion	Dorchester, MD	Vienna	Sussex, DE	Nelson
DPL	69	19.2	1	Jul-05	Dec-24	Dec-24	Aging Infrastructure	Dorchester, MD	Vienna	Dorchester, MD	West Cambridge
PE	138	3.2	1	Jul-05	Jul-05	Jul-05	Baseline Transmission Reliability	Allegany	Messick Road	Mineral	Ridgeley (WV)
PE	138	17.7	1	Jul-05	Jul-05	Jul-05	Baseline Transmission Reliability	Allegany	Messick Road	Morgan	Morgan (WV)
PE	138	0.1	2	Jul-05	Jul-05	Jul-05	Accommodate for Generator Interconnection	Allegany	Dans Mountain (new)	Allegany	Carlos Junction-Ridgeley (WV)
PE	230	0	1	Jul-05	Suspended	Suspended	Baseline Transmission Reliability	Washington	Ringgold	Washington	Ringgold
PE	230	0	1	Jul-05	Suspended	Suspended	Baseline Transmission Reliability	Frederick	Catoctin	Frederick	Catoctin
PE	230	9.7	1	Jul-05	Suspended	Suspended	Baseline Transmission Reliability	Washington	Ringgold	Frederick	Catoctin
PE	500	0.1	1	Jul-05	Jul-05	Jul-05	Baseline Transmission Reliability	Frederick	Doubs	York (PA)	Otter Creek PPL (PA)
PE	230	11.1	2	Jul-05	Jul-05	Jul-05	Baseline Transmission Reliability	Adams (PA)	Hunterstown	Carroll	Carroll
PE	138	2.6	1	Jul-05	Jul-05	Jul-05	Baseline Transmission Reliability	Frederick	Doubs	Jefferson	Millville (WV)
PE	138	0.1	1	Jul-05	Jul-05	Jul-05	Accommodate for Generator Interconnection	Preston	Albright (WV)	Mineral	Cross School

Appendix 4: Transmission Enhancements, by Service Territory

PE	230	0.1	1	Jul-05	Jul-05	Jul-05	Baseline Transmission Reliability	Frederick	Doubs	Frederick	Lime Kiln 231
PE	230	0.1	1	Jul-05	Jul-05	Jul-05	Baseline Transmission Reliability	Frederick	Doubs	Frederick	Lime Kiln 231
PE	230	3.4	1	Jul-05	Jul-05	Jul-05	Baseline Transmission Reliability	Frederick	Doubs	Frederick	Lime Kiln 207
PE	230	0.1	1	Jul-05	Jul-05	Jul-05	Baseline Transmission Reliability	Frederick	Doubs	Frederick	Lime Kiln 207
PE	230	5	1	Jul-05	Jul-05	Jul-05	Baseline Transmission Reliability	Montgomery	Damascus	Montgomery	Montgomery
PE	138	0.3	1	Jul-05	Jul-05	Jul-05	Baseline Transmission Reliability	Allegany	Black Oak	Hampshire (WV)	Junction (WV)
PE	500, 138	3.8	2	Jul-05	Jul-05	Jul-05	Baseline Transmission Reliability	Frederick	Doubs	Jefferson (WV)	Millville (WV)
PE	765	3	1	Jul-05	Jul-05	Jul-05	Baseline Transmission Reliability	Hardy (WV)	Welton Spring (WV)	Frederick	Rocky Point
PE	500	0.5	1	Jul-05	Jul-05	Jul-05	Accommodate for Generator Interconnection	Allegany	Black Oak	Green (PA)	Hatfield (PA)
PE	500	2.4	1	Jul-05	Jul-05	Jul-05	Baseline Transmission Reliability	Allegany	Black Oak	Frederick	Woodside (VA)
Pepco	230	10.1	2	Jul-05	Sep-26	May-26	Aging infrastructure	Prince George's	Talbert	Prince George's	Oak Grove

Appendix 5: List of Maryland Generators, as of December 31, 2024

Owner / Operator	Plant Name	County	Capacity Statistics (MW)		
			Nameplate	Summer	% Summer
Brandon Shores LLC	Brandon Shores	Anne Arundel	685.1	635.0	93%
Brandon Shores LLC	Brandon Shores	Anne Arundel	685.1	638.0	93%
H.A. Wagner LLC	Herbert A. Wagner	Anne Arundel	132.8	126.0	95%
H.A. Wagner LLC	Herbert A. Wagner	Anne Arundel	359.0	305.0	85%
H.A. Wagner LLC	Herbert A. Wagner	Anne Arundel	414.7	397.0	96%
H.A. Wagner LLC	Herbert A. Wagner	Anne Arundel	16.0	12.9	81%
Constellation Power Source Generation, LLC	Perryman	Harford	53.1	52.0	98%
Constellation Power Source Generation, LLC	Perryman	Harford	53.1	51.0	96%
Constellation Power Source Generation, LLC	Perryman	Harford	53.1	52.0	98%
Constellation Power Source Generation, LLC	Perryman	Harford	192.0	139.0	72%
Constellation Power Source Generation, LLC	Perryman	Harford	141.0	109.8	78%
Constellation Power Source Generation, LLC	Philadelphia	Baltimore City	20.7	15.3	74%
Constellation Power Source Generation, LLC	Philadelphia	Baltimore City	20.7	14.8	71%
Constellation Power Source Generation, LLC	Philadelphia	Baltimore City	20.7	14.8	71%
Constellation Power Source Generation, LLC	Philadelphia	Baltimore City	20.7	14.8	71%
Calpine Mid-Atlantic Generation LLC	Crisfield	Somerset	2.9	2.6	90%
Calpine Mid-Atlantic Generation LLC	Crisfield	Somerset	2.9	2.6	90%
Calpine Mid-Atlantic Generation LLC	Crisfield	Somerset	2.9	2.6	90%
Calpine Mid-Atlantic Generation LLC	Crisfield	Somerset	2.9	2.6	90%
NRG Vienna Operations, Inc.	Vienna Operations	Dorchester	18.6	14.3	77%
NRG Vienna Operations, Inc.	Vienna Operations	Dorchester	162.0	153.0	94%
BP Piney & Deep Creek LLC	Deep Creek	Garrett	10.0	9.0	90%
BP Piney & Deep Creek LLC	Deep Creek	Garrett	10.0	9.0	90%
Chalk Point Power, LLC	Chalk Point Power	Prince George's	659.0	595.0	90%
Chalk Point Power, LLC	Chalk Point Power	Prince George's	659.0	585.3	89%
Chalk Point Power, LLC	Chalk Point Power	Prince George's	16.0	18.0	113%
Chalk Point Power, LLC	Chalk Point Power	Prince George's	35.0	26.0	74%
Chalk Point Power, LLC	Chalk Point Power	Prince George's	103.0	86.0	83%
Chalk Point Power, LLC	Chalk Point Power	Prince George's	103.0	86.0	83%
Chalk Point Power, LLC	Chalk Point Power	Prince George's	125.0	109.0	87%
Chalk Point Power, LLC	Chalk Point Power	Prince George's	125.0	109.0	87%
Dickerson Power, LLC	Dickerson Power	Montgomery	163.0	147.0	90%
Dickerson Power, LLC	Dickerson Power	Montgomery	163.0	152.0	93%
Lanyard Power Holdings, LLC	Morgantown Generating Plant	Charles	65.0	54.0	83%
Lanyard Power Holdings, LLC	Morgantown Generating Plant	Charles	65.0	54.0	83%
Constellation Power, Inc.	Conowingo	Harford	45.0	41.0	91%
Constellation Power, Inc.	Conowingo	Harford	55.6	56.1	101%
Constellation Power, Inc.	Conowingo	Harford	55.6	52.0	94%

Appendix 5: List of Maryland Generators, as of December 31, 2024

Constellation Power, Inc.	Conowingo	Harford	36.0	32.7	91%
Constellation Power, Inc.	Conowingo	Harford	48.0	41.9	87%
Constellation Power, Inc.	Conowingo	Harford	47.7	41.9	88%
Constellation Power, Inc.	Conowingo	Harford	36.0	32.7	91%
Constellation Power, Inc.	Conowingo	Harford	47.7	42.3	89%
Constellation Power, Inc.	Conowingo	Harford	48.0	42.3	88%
Constellation Power, Inc.	Conowingo	Harford	55.6	56.7	102%
Constellation Power, Inc.	Conowingo	Harford	55.6	57.3	103%
Easton Utilities Comm	Easton	Talbot	3.5	3.5	100%
Easton Utilities Comm	Easton	Talbot	1.5	1.5	100%
Easton Utilities Comm	Easton	Talbot	1.5	1.5	100%
Easton Utilities Comm	Easton	Talbot	3.8	3.6	95%
Easton Utilities Comm	Easton	Talbot	4.1	4.1	100%
Easton Utilities Comm	Easton	Talbot	5.6	5.6	100%
Easton Utilities Comm	Easton	Talbot	5.6	5.6	100%
Easton Utilities Comm	Easton	Talbot	2.5	2.0	80%
Easton Utilities Comm	Easton	Talbot	3.0	2.5	83%
Easton Utilities Comm	Easton 2	Talbot	1.5	1.5	100%
Easton Utilities Comm	Easton 2	Talbot	1.5	1.5	100%
Easton Utilities Comm	Easton 2	Talbot	5.4	4.5	83%
Easton Utilities Comm	Easton 2	Talbot	5.4	4.5	83%
Easton Utilities Comm	Easton 2	Talbot	6.2	6.2	100%
Easton Utilities Comm	Easton 2	Talbot	6.2	6.2	100%
Easton Utilities Comm	Easton 2	Talbot	6.3	6.3	100%
Easton Utilities Comm	Easton 2	Talbot	6.3	6.3	100%
Constellation Nuclear	Calvert Cliffs Nuclear Power Plant	Calvert	918.0	884.2	96%
Constellation Nuclear	Calvert Cliffs Nuclear Power Plant	Calvert	932.4	861.0	92%
A & N Electric Coop	Smith Island	Somerset	0.5	0.4	80%
A & N Electric Coop	Smith Island	Somerset	1.0	1.0	100%
Town of Berlin - (MD)	Berlin	Worcester	1.1	1.1	100%
Town of Berlin - (MD)	Berlin	Worcester	2.5	2.5	100%
Town of Berlin - (MD)	Berlin	Worcester	2.0	2.0	100%
Essential Power Operating Services LLC	Essential Power Rock Springs LLC	Cecil	198.9	167.3	84%
Essential Power Operating Services LLC	Essential Power Rock Springs LLC	Cecil	198.9	164.1	83%
Essential Power Operating Services LLC	Essential Power Rock Springs LLC	Cecil	198.9	169.0	85%
Essential Power Operating Services LLC	Essential Power Rock Springs LLC	Cecil	198.9	166.3	84%
Wheelabrator Environmental Systems	Wheelabrator Baltimore Refuse	Baltimore City	60.2	57.0	95%
Wheelabrator Environmental Systems	Wheelabrator Baltimore Refuse	Baltimore City	4.3	4.3	100%
Maryland Environmental Service	Eastern Correctional Institute	Somerset	1.9	1.3	68%
Maryland Environmental Service	Eastern Correctional Institute	Somerset	1.9	1.3	68%
Maryland Environmental Service	Eastern Correctional Institute	Somerset	1.0	1.0	100%
Maryland Environmental Service	Eastern Correctional Institute	Somerset	1.0	1.0	100%
Prince George's County	Brown Station Road Plant I	Prince George’s	0.9	0.8	89%

Appendix 5: List of Maryland Generators, as of December 31, 2024

Prince George's County	Brown Station Road Plant I	Prince George's	0.9	0.8	89%
Prince George's County	Brown Station Road Plant I	Prince George's	0.9	0.8	89%
Covanta Montgomery, Inc.	Montgomery County Resource Recovery	Montgomery	67.8	54.0	80%
American Sugar Refining, Inc.	Domino Sugar Baltimore	Baltimore City	5.0	5.0	100%
American Sugar Refining, Inc.	Domino Sugar Baltimore	Baltimore City	2.5	2.5	100%
American Sugar Refining, Inc.	Domino Sugar Baltimore	Baltimore City	10.0	10.0	100%
KMC Thermo, LLC	Brandywine Power Facility	Prince George's	98.7		
KMC Thermo, LLC	Brandywine Power Facility	Prince George's	98.7		
KMC Thermo, LLC	Brandywine Power Facility	Prince George's	91.4	230.0	252%
Prince George's County	Brown Station Road Plant II	Prince George's	1.0	0.8	80%
Prince George's County	Brown Station Road Plant II	Prince George's	1.0	0.8	80%
Prince George's County	Brown Station Road Plant II	Prince George's	1.0	0.8	80%
Prince George's County	Brown Station Road Plant II	Prince George's	1.0	0.8	80%
Trigen-Cinergy Solutions College Park	UMCP CHP Plant	Prince George's	11.0	9.4	85%
Trigen-Cinergy Solutions College Park	UMCP CHP Plant	Prince George's	11.0	9.4	85%
Trigen-Cinergy Solutions College Park	UMCP CHP Plant	Prince George's	5.4	2.0	37%
Trigen Inner Harbor East, LLC	Inner Harbor East Heating	Baltimore City	2.1	2.1	100%
NextEra Renewable Fuels, LLC	Eastern Landfill Gas LLC	Baltimore	1.0	1.3	130%
NextEra Renewable Fuels, LLC	Eastern Landfill Gas LLC	Baltimore	1.0	1.3	130%
NextEra Renewable Fuels, LLC	Eastern Landfill Gas LLC	Baltimore	1.0	1.3	130%
NextEra Renewable Fuels, LLC	Eastern Landfill Gas LLC	Baltimore	1.0	1.3	130%
National Institutes of Health	NIH Cogeneration Facility	Montgomery	28.0	27.6	99%
Industrial Power Generating Company LLC	Wicomico	Wicomico	0.3	0.3	100%
Industrial Power Generating Company LLC	Wicomico	Wicomico	0.3	0.3	100%
Industrial Power Generating Company LLC	Wicomico	Wicomico	0.3	0.3	100%
Industrial Power Generating Company LLC	Wicomico	Wicomico	0.3	0.3	100%
Industrial Power Generating Company LLC	Wicomico	Wicomico	0.3	0.3	100%
Industrial Power Generating Company LLC	Wicomico	Wicomico	0.3	0.3	100%
Industrial Power Generating Company LLC	Wicomico	Wicomico	0.3	0.3	100%
Industrial Power Generating Company LLC	Wicomico	Wicomico	0.3	0.3	100%
Industrial Power Generating Company LLC	Wicomico	Wicomico	0.3	0.3	100%
Industrial Power Generating Company LLC	Wicomico	Wicomico	0.3	0.3	100%
Industrial Power Generating Company LLC	Wicomico	Wicomico	0.3	0.3	100%
Industrial Power Generating Company LLC	Wicomico	Wicomico	0.3	0.3	100%
Industrial Power Generating Company LLC	Wicomico	Wicomico	0.3	0.3	100%
Industrial Power Generating Company LLC	Wicomico	Wicomico	0.3	0.3	100%
Industrial Power Generating Company LLC	Wicomico	Wicomico	0.3	0.3	100%
Industrial Power Generating Company LLC	Wicomico	Wicomico	0.3	0.3	100%
Industrial Power Generating Company LLC	Wicomico	Wicomico	0.3	0.3	100%
Industrial Power Generating Company LLC	Wicomico	Wicomico	0.3	0.3	100%
CPV Maryland LLC	CPV St Charles Energy Center	Charles	223.6	213.4	95%
CPV Maryland LLC	CPV St Charles Energy Center	Charles	223.6	213.9	96%
CPV Maryland LLC	CPV St Charles Energy Center	Charles	328.1	305.0	93%

Appendix 5: List of Maryland Generators, as of December 31, 2024

Roth Rock Wind Farm LLC	Roth Rock Wind Farm LLC	Garrett	40.0	40.0	100%
Roth Rock Wind Farm LLC	Roth Rock North Wind Farm, LLC	Garrett	10.0	10.0	100%
Criterion Power Partners LLC	Criterion	Garrett	70.0	70.0	100%
Luminace Solar Maryland, LLC	McCormick & Co. Inc. at Belcamp	Harford	1.4	1.4	100%
NW Stadium Solar Plant	FedEx Field Solar Facility	Prince George's	2.0	2.0	100%
Constellation Solar Horizons LLC	Mount Saint Mary's	Frederick	13.7	13.7	100%
Terraform Arcadia	Perdue Salisbury Photovoltaic	Wicomico	1.0	1.0	100%
IKEA Property, Inc.	IKEA Perryville 460	Cecil	2.1	2.0	95%
IKEA Property, Inc.	IKEA College Park 411	Prince George's	1.0	1.0	100%
IKEA Property, Inc.	IKEA College Park 411	Prince George's	1.0	1.0	100%
GSA Metropolitan Service Center	Central Utility Plant at White Oak	Montgomery	5.7	5.6	98%
GSA Metropolitan Service Center	Central Utility Plant at White Oak	Montgomery	2.3	2.3	100%
GSA Metropolitan Service Center	Central Utility Plant at White Oak	Montgomery	2.3	2.3	100%
GSA Metropolitan Service Center	Central Utility Plant at White Oak	Montgomery	5.0	5.0	100%
GSA Metropolitan Service Center	Central Utility Plant at White Oak	Montgomery	2.3	2.3	100%
GSA Metropolitan Service Center	Central Utility Plant at White Oak	Montgomery	4.3	4.3	100%
GSA Metropolitan Service Center	Central Utility Plant at White Oak	Montgomery	4.3	4.3	100%
GSA Metropolitan Service Center	Central Utility Plant at White Oak	Montgomery	4.3	4.3	100%
GSA Metropolitan Service Center	Central Utility Plant at White Oak	Montgomery	4.3	4.3	100%
GSA Metropolitan Service Center	Central Utility Plant at White Oak	Montgomery	7.5	7.5	100%
GSA Metropolitan Service Center	Central Utility Plant at White Oak	Montgomery	7.5	7.5	100%
GSA Metropolitan Service Center	Central Utility Plant at White Oak	Montgomery	4.5	4.5	100%
Terraform Arcadia	Kent County-Kennedyville	Kent	1.0	1.0	100%
Terraform Arcadia	Rock Hall	Kent	1.0	1.0	100%
Terraform Arcadia	Kent County - Worton Complex	Kent	1.0	1.0	100%
LES Operations Services LLC	Millersville LFG	Anne Arundel	1.6	1.5	94%
LES Operations Services LLC	Millersville LFG	Anne Arundel	1.6	1.5	94%
Howard County - Maryland	Alpha Ridge LFG	Howard	1.0	1.0	100%
Luminace Solar Maryland II, LLC	UMMS at Pocomoke	Somerset	2.8	2.8	100%
Arevon Energy, Inc.	Maryland Solar	Washington	27.0	20.9	77%
SMECO Solar LLC	Herbert Farm Solar	Charles	5.5	5.5	100%
Tesla, Inc.	Queen Anne's County	Queen Anne's	2.0	2.0	100%
Fourmile Wind Energy, LLC	Fourmile Ridge	Garrett	40.0	40.0	100%
Mayor and City Council of Baltimore City	Back River Waste Water Treatment	Baltimore City	1.1	0.9	82%
Mayor and City Council of Baltimore City	Back River Waste Water Treatment	Baltimore City	1.1	0.9	82%
Mayor and City Council of Baltimore City	Back River Waste Water Treatment	Baltimore City	0.8	0.8	100%
Fair Wind Power Partners, LLC	Fair Wind	Garrett	30.0	30.0	100%
Old Dominion Electric Coop	Wildcat Point Generation Facility	Cecil	310.3	252.3	81%
Old Dominion Electric Coop	Wildcat Point Generation Facility	Cecil	310.3	241.1	78%
Old Dominion Electric Coop	Wildcat Point Generation Facility	Cecil	493.0	497.9	101%
SunE SEM 1, LLC	Chimes West Friendship (Nixon Farms)	Howard	1.2	1.2	100%
NVT LICENSES, LLC	UMES (MD) - Princess Anne	Somerset	2.0	2.1	105%
Rockfish Solar LLC	Rockfish Solar LLC	Charles	10.3	10.3	100%

Appendix 5: List of Maryland Generators, as of December 31, 2024

Luminace Solar Maryland, LLC	General Motors Corp at White Marsh MD	Baltimore	1.0	1.0	100%
Luminace Solar Maryland II, LLC	CNE at Cambridge MD	Dorchester	3.2	3.2	100%
Great Bay Solar I LLC	Great Bay Solar 1	Somerset	75.0	75.0	100%
Consolidated Edison Solutions, Inc.	CES VMT Solar	Washington	1.1	1.1	100%
Luminace Solar Holding, LLC	CCBC-Catonsville	Howard	1.6	1.6	100%
SunE DB27, LLC	Elkton Solar	Cecil	1.6	1.6	100%
Tesla, Inc.	Town of Chestertown- Chestertown WWTP	Kent	1.0	1.0	100%
PSEG Keys Energy Center, LLC	Keys Energy Center	Prince George's	359.6	763.0	212%
PSEG Keys Energy Center, LLC	Keys Energy Center	Prince George's	235.5		
PSEG Keys Energy Center, LLC	Keys Energy Center	Prince George's	235.5		
SunE DB42, LLC	Cecil County CCVT HS	Cecil	2.0	2.0	100%
Terraform Arcadia	Presbyterian Senior Living Service	Baltimore	1.0	1.0	100%
Tesla, Inc.	The Clorox Company	Harford	1.6	1.6	100%
Tesla, Inc.	Chesapeake College	Queen Anne's	1.5	1.5	100%
Altus Power America Management, LLC	MEBA	Talbot	1.5	1.5	100%
Tesla Inc.	Wye Mills VNEM CSG	Queen Anne's	10.0	10.0	100%
Luminace Solar MC, LLC	Archdiocese of Baltimore J	Harford	2.0	2.0	100%
Luminace Solar MC, LLC	Archdiocese of Baltimore L	Harford	2.0	2.0	100%
Luminace Solar MC, LLC	Baltimore City B	Harford	2.0	2.0	100%
Luminace Solar MC, LLC	Baltimore City D	Harford	2.0	2.0	100%
Luminace Solar MC, LLC	Baltimore City F	Harford	2.0	2.0	100%
Luminace Solar MC, LLC	Baltimore City G	Harford	2.0	2.0	100%
Luminace Solar MC, LLC	City of Havre De Grace C	Harford	2.0	2.0	100%
Luminace Solar MC, LLC	Sod Run WTP A	Harford	2.0	2.0	100%
Annapolis Solar Park, LLC	Annapolis Solar Park, LLC	Anne Arundel	12.0	12.0	100%
Luminace Solar MC, LLC	Havre de Grace II - E at Perryman	Harford	1.4	1.4	100%
MN8 Energy LLC	Longview Solar	Wicomico	13.6	13.6	100%
MN8 Energy LLC	Church Hill	Queen Anne's	6.0	6.0	100%
Tesla Inc.	Montgomery County Correctional Facility	Montgomery	1.4	1.4	100%
Tesla Inc.	Garrett County - DPU Treatment Plant	Garrett	1.2	1.2	100%
UGI Energy Services, LLC	Emmitsburg Solar Arrays	Frederick	1.7	1.7	100%
Terraform Arcadia	Pfeffers	Baltimore	1.0	1.0	100%
US Dept of Army, Garrison, APG	APG Combined Heat and Power Plant	Harford	7.9	6.2	78%
CleanCapital Holdings	IGS Solar I - BWI5	Baltimore	1.1	1.1	100%
Madison Energy Holdings LLC	IGS Solar I - BWI2	Baltimore	1.4	1.4	100%
Cypress Creek Renewables	Baker Point	Frederick	9.0	9.0	100%
Montevue Lane Solar, LLC	Fort Detrick Solar PV	Frederick	6.0	6.0	100%
Montevue Lane Solar, LLC	Fort Detrick Solar PV	Frederick	15.7	15.7	100%
Montgomery County Solar	Montgomery County Solar	Montgomery	1.9	1.9	100%
GWCC PV Solar Farm	GWCC PV Solar Farm	Prince George's	1.6	1.6	100%
Luminace Solar MC, LLC	Gateway Solar	Worcester	5.0	5.0	100%
Luminace Solar MC, LLC	Gateway Solar	Worcester	2.6	2.6	100%
NRG Chalk Point CT	NRG Chalk Point CT	Prince George's	94.0	80.2	85%

Appendix 5: List of Maryland Generators, as of December 31, 2024

Terraform Arcadia	Bowie State Solar	Prince George's	1.3	1.3	100%
Madison Energy Holdings LLC	First Baptist Church of Glenarden	Prince George's	1.5	1.6	107%
Tesla Inc.	Bd of Educ of Queen Anne's Cnty, Cnty HS	Queen Anne's	1.7	1.7	100%
Luminace Solar MC, LLC	NIST Solar	Montgomery	4.0	4.0	100%
Northstar Macy's Maryland 2015, LLC	Macy's MD Joppa Solar Project	Harford	1.8	1.8	100%
Altus Power America Management, LLC	Synergen Panorama, LLC CSG	Prince George's	5.0	5.0	100%
Greenbacker Renewable Energy Corporation	Sol Phoenix	Prince George's	2.5	2.5	100%
Greenbacker Renewable Energy Corporation	Blue Star	Kent	7.5	7.5	100%
Standard Solar	UMCES Ground Mount	Dorchester	2.0	2.0	100%
Standard Solar	Anne Arundel County Public Schools	Anne Arundel	1.0	1.0	100%
Onyx Asset Services Group	APG Old Bayside	Harford	1.7	1.7	100%
Onyx Asset Services Group	APG New Chesapeake	Harford	2.3	2.3	100%
Chester Woods Point Solar, LLC	Chester Woods Point Solar, LLC CSG	Queen Anne's	2.0	2.0	100%
Westbound Solar LLC	Amazon Maryland DCA1	Baltimore	1.3	1.3	100%
Standard Solar	MNCPPC Germantown Solar	Montgomery	1.0	1.0	100%
Greenbacker Renewable Energy Corporation	Solar Hagerstown	Washington	10.0	7.5	75%
Nautilus Solar Solutions	BTC2 Solar (CSG)	Baltimore	2.0	2.0	100%
Nautilus Solar Solutions	Upper Marlboro 1 CSG	Prince George's	2.0	2.0	100%
Nautilus Solar Solutions	White CSG	Baltimore	2.0	2.0	100%
Nautilus Solar Solutions	Gibbons CSG	Worcester	2.0	2.0	100%
Old Court Rd Solar, LLC	Old Court Rd Solar	Howard	2.0	2.0	100%
Francis Scott Key Mall	Francis Scott Key Mall	Frederick	1.6	1.6	100%
White Marsh Mall	White Marsh Mall	Baltimore	1.1	1.1	100%
Bluefin Origination 1, LLC	Bluefin Origination 1	Prince George's	2.0	2.0	100%
Tesla Inc.	Frederick County - Landfill	Frederick	2.0	2.0	100%
Tesla Inc.	Wor-Wic Community College - Offsite	Wicomico	2.0	2.0	100%
MN8 Energy LLC	Spruce - WCMD - Rubble II	Washington	2.0	2.0	100%
MN8 Energy LLC	Spruce - WCMD - Rubble I	Washington	2.0	2.0	100%
MN8 Energy LLC	Spruce - WCMD - Creek	Washington	2.0	2.0	100%
MN8 Energy LLC	Spruce - WCMD - Resh I	Washington	2.0	2.0	100%
Sheriff Rd Solar LLC	Sheriff Road	Prince George's	1.1	1.1	100%
Madison Energy Holdings LLC	Pinesburg Solar LLC	Washington	4.3	4.3	100%
Madison Energy Holdings LLC	Timonium Fairgrounds	Baltimore	1.9	1.9	100%
MN8 Energy LLC	Bluegrass Solar	Queen Anne's	79.6	79.6	100%
Forefront Power, LLC	MD - CS - Potomac Edison Co - GA29 TPE	Garrett	2.0	2.0	100%
Bioenergy DevCo	Maryland Bioenergy Center (Jessup)	Howard	1.1	1.1	100%
6685 Santa Barbara Ct	6685 Santa Barbara Ct	Howard	1.0	1.0	100%
Hartz Solar, LLC	7448 Candlewood Road	Anne Arundel	1.5	1.5	100%
Nautilus Solar Solutions	Kirby Road Solar, LLC	Prince George's	1.3	1.3	100%
Standard Solar	MNCPPC Randall Farm	Prince George's	1.4	1.4	100%
Nautilus Solar Solutions	Burns Solar One LLC	Baltimore	2.0	2.0	100%
Nautilus Solar Solutions	Hostetter Solar One, LLC	Washington	2.0	2.0	100%
Nautilus Solar Solutions	P52ES 1755 Henryton Rd Phase 1 LLC CSG	Howard	1.9	1.9	100%

Appendix 5: List of Maryland Generators, as of December 31, 2024

Nautilus Solar Solutions	P52ES 1755 Henryton Rd Phase 2 LLC	Howard	1.9	1.9	100%
Nautilus Solar Solutions	White Marsh Solar	Baltimore	1.5	1.5	100%
Nautilus Solar Solutions	Mason Solar One LLC	Cecil	1.0	1.0	100%
Nautilus Solar Solutions	Pittman Solar One LLC	Washington	2.0	2.0	100%
Nautilus Solar Solutions	Bulldog Solar One, LLC	Prince George's	2.0	2.0	100%
Distributed Solar Development, LLC	MD - PR97 (CSG)	Prince George's	2.0	2.0	100%
Invenergy Services LLC	Todd Solar	Dorchester	20.0	20.0	100%
Standard Solar	OER Checkerspot	Anne Arundel	1.5	1.5	100%
Tesla, Inc.	City of Bowie	Prince George's	2.0	2.0	100%
Hampstead Solar, LLC	Bomber CSG	Carroll	6.0	6.0	100%
ICFTS MD Solar, LLC	Hollins Ferry CSG	Baltimore City	1.5	1.5	100%
Distributed Solar Development, LLC	MD - CS - Potomac Edison Co - GA25 TPE (	Garrett	2.0	2.0	100%
Distributed Solar Development, LLC	MD - CS - BGE - PR24 TPE	Prince George's	2.0	2.0	100%
Standard Solar	OER Monarch CSG	Prince George's	2.0	2.0	100%
Standard Solar	OER Patuxent CSG	Anne Arundel	2.0	2.0	100%
Standard Solar	Shepherds Mill CSG	Carroll	2.0	2.0	100%
TPE MD MO32 LLC	MO32 (CSG)	Montgomery	2.0	2.0	100%
TPE MD MO33 LLC	MO33 CSG	Montgomery	2.0	2.0	100%
Snowden River Parkway, LLC	Snowden River CSG	Howard	1.9	1.9	100%
Altus Power America Management, LLC	Rockdale	Washington	2.0	2.0	100%
AlphaStruxure Service Co LP	Brookville Smart Bus Depot Microgrid	Montgomery	1.5	1.5	100%
AlphaStruxure Service Co LP	Brookville Smart Bus Depot Microgrid	Montgomery	0.6	0.6	100%
AlphaStruxure Service Co LP	Brookville Smart Bus Depot Microgrid	Montgomery	0.6	0.6	100%
AlphaStruxure Service Co LP	Brookville Smart Bus Depot Microgrid	Montgomery	0.6	0.6	100%
AlphaStruxure Service Co LP	Brookville Smart Bus Depot Microgrid	Montgomery	1.7	1.7	100%
MN8 Energy LLC	WMATA - Cheverly Metro (CSG)	Prince George's	1.9	1.9	100%
MN8 Energy LLC	WMATA - Naylor Rd. Metro	Prince George's	1.7	1.7	100%
MN8 Energy LLC	WMATA - S. Ave. Carport (East) (CSG)	Prince George's	1.7	1.7	100%
CleanCapital Holdings	KDC Solar TC Little Patuxent WWTP LLC	Howard	2.0	2.0	100%
CleanCapital Holdings	KDC Solar TC George Howard LLC	Howard	2.0	2.0	100%
CleanCapital Holdings	KDC Solar TC Blandair Park LLC	Howard	2.0	2.0	100%
Greenbacker Renewable Energy Corporation	Friendship I	Howard	2.0	2.0	100%
Greenbacker Renewable Energy Corporation	Friendship II	Howard	2.0	2.0	100%
MN8 Energy LLC	Ripley	Charles	27.5	27.5	100%
Convergent Energy and Power LP	Federalsburg Energy Storage 1 LLC	Caroline	1.2	1.2	100%
Convergent Energy and Power LP	Federalsburg Energy Storage 1 LLC	Caroline	0.8	0.8	100%
Solar DG MD Holabird Broening ACC, LLC	CPG - Duke 5300A Holabird	Baltimore City	1.5	1.5	100%
Solar DG MD Holabird Broening ACC, LLC	CPG - Duke 5300B Holabird	Baltimore City	1.5	1.5	100%
Solar DG MD Holabird AJCFB, LLC	CPG - Duke 5900 Holabird	Baltimore City	1.5	1.5	100%
Solar DG MD Holabird AJCFB, LLC	CPG - Duke 6000 Holabird	Baltimore City	1.5	1.5	100%
KDC Solar CV Ascend One LLC	KDC Solar CV Ascend One LLC	Howard	2	2	100%
KDC Solar CV Cedar Lane Park LLC	KDC Solar CV Cedar Lane Park LLC	Howard	2	2	100%
KDC Solar CV Central MD Regional Transit LLC	KDC Solar CV Central MD Regional Transit	Howard	2	2	100%

Appendix 5: List of Maryland Generators, as of December 31, 2024

KDC Solar CV Animal Control LLC	KDC Solar CV Animal Control LLC	Howard	2	2	100%
KDC Solar CV O'Donnell Property LLC	KDC Solar CV O'Donnell Property LLC	Howard	2	2	100%
Distributed Solar Development, LLC	THD Baltimore DC - 5830 Project Tiger	Baltimore	1.6	1.6	100%
Standard Solar	Holly Spring Meadows	Prince George’s	1.2	1.2	100%
AES Clean Energy	Cannonball Solar (CSG)	Frederick	2	2	100%
AES Clean Energy	Big Spring Solar (CSG)	Washington	2	2.1	105%
Citizens Enterprises Corporation	Union Bridge Solar	Carroll	8.2	8.2	100%
Greenbacker Renewable Energy Corporation	Oaks Landfill - ANEM	Montgomery	2	2	100%
Jade Meadow LLC	Jade Meadow LLC	Allegany	19.8	19.8	100%
Distributed Solar Development, LLC	THD Baltimore DCs - 5829 Project Lion	Baltimore	3.8	3.8	100%
FFP MD Freeland Project1, LLC	FFP - MD Foxhall	Baltimore	2	2	100%
Nautilus Solar Solutions	Ten Oaks	Howard	2	2	100%
Nautilus Solar Solutions	Lion One	Baltimore	2	2	100%
Nautilus Solar Solutions	Meeting House	Cecil	2	2	100%
Nautilus Solar Solutions	Mustang One	Dorchester	1.5	1.5	100%
Nautilus Solar Solutions	Bear One	Washington	2.0	2.0	100%
Nautilus Solar Solutions	Beech Road (CSG)	Prince George’s	3.0	3.0	100%
Nautilus Solar Solutions	Parker Place	Wicomico	2.0	2.0	100%
Madison Energy Investments LLC	Boyd Soccerplex	Montgomery	1.0	1.0	100%
Standard Solar	Hall Property	Prince George’s	2.0	2.0	100%
Spectrum Solar LLC	Spectrum Solar Hybrid	Prince George’s	3.0	3.0	100%
Spectrum Solar LLC	Spectrum Solar Hybrid	Prince George’s	2.6	2.6	100%
Greenbacker Renewable Energy Corporation	Oaks Landfill CS 1	Montgomery	2.0	2.0	100%
PFMD LL Jessup LLC	MD JESSUP 7950 OCEANO AVE	Howard	1.5	1.5	100%
Greenbacker Renewable Energy Corporation	Oaks Landfill CS 2	Montgomery	2.0	2.0	100%
SoCore Energy LLC	FedEx Hagerstown	Washington	1.8	1.8	100%
Madison Energy Investments LLC	Fairview Farms	Harford	30.0	30.0	100%
Baltimore Gas & Electric Co	Fairhaven	Anne Arundel	2.5	0.7	28%
MD CDG 001 LLC	MD CDG 001	Garrett	2.0	2.0	100%
MD CDG 002 LLC	MD CDG 002	Garrett	2.0	2.0	100%
			12,832.0	**11,652.9**	**91%**

Appendix 6: Proposed New Renewable Generation in Maryland PJM Queue Effective Date: June 2025

Transmission Owner	Project Name	County Location	PJM Queue Status	PJM Queue #	Fuel Type	Project Capacity (MW)	In-Service/Projected In-Service Date
APS	Frostburg 138 kV	Allegany	Active	AE2-289	Wind	11.76	12/31/2021
APS	Hagerstown-Conservit 34.5 kV	Washington	Active	AG2-279 - moved to TC2	Solar	12.9	9/30/2024
APS	Westvaco - Mt Zion 138 kV	Garrett	Active	AG2-505 - moved to TC2	Hydro	14	12/31/2023
APS	Carlos Junction-Garrett 138 kV	Allegany	Active	AG2-615 - moved to TC2	Solar	62.6	12/31/2023
APS	Mount Storm-Pruntytown 500kV	Garrett	Active	AH1-283 - moved to TC2	Solar	120	10/31/2024
APS	Catoctin-Carroll 138 kV	Frederick	Active	AH2-262	Solar; Storage	10.2	3/1/2026
APS	Carlos Jct. – Ridgeley 138 kV	Allegany	Active	AI2-353	Wind	16	4/1/2024
APS	Frostburg 138 kV	Allegany	Active	AI2-490	Wind	31.9	12/15/2023
BGE	Waugh Chapel 115 kV	Anne Arundel	Active	AG2-617 - moved to TC2	Solar	33	12/31/2023
DPL	Airey-Vienna 69 kV	Dorchester	Active	AF2-358 - moved to TC1	Solar	60	12/15/2023
DPL	Airey - Golden Hill 69 kV	Dorchester	Active	AG2-181 - moved to TC2	Solar	2.8	6/1/2024
DPL	Edgewood 12.47 kV	Wicomico	Active	AH1-057 - moved to TC2	Solar	3	1/31/2023
DPL	Mt Olive - Kenny 69kV	Worcester	Active	AH1-380 - moved to TC2	Solar	12	12/20/2024
DPL	Church-Oil City 138kV	Queen Anne's	Active	AH1-536 - moved to TC2	Solar; Storage	8.5	3/1/2025
DPL	New Hope 12.47 kV	Allegany	Active	AH2-052	Solar	0	12/2/2022
DPL	Mardela Springs 12.47 kV	Wicomico	Active	AH2-053	Solar	0	12/2/2022
DPL	Edgewood 12.47 kV I	Wicomico	Active	AH2-054	Solar	0	12/2/2022
DPL	TBD 69kV	Unknown	Active	AH2-055	Solar	0	2/15/2022
DPL	TBD 69kV	Prince George's	Active	AH2-065	Solar	0	12/1/2022
DPL	Edgewood 12.47 kV II	Wicomico	Active	AH2-070	Solar	0	1/27/2023
DPL	Edgewood 12.47 kV III	Wicomico	Active	AH2-071	Solar	0	1/27/2023
DPL	West Cambridge - Airey 69 kV	Dorchester	Active	AH2-096	Solar	8.19	5/1/2023
DPL	Mt. Hermon 69 kV	Wicomico	Active	AH2-198	Solar	53.8	6/30/2026
DPL	Talbot 69 kV	Worcester	Active	AH2-337	Solar; Storage	80	2/27/2026
DPL	Church - Oil City 138 kV III	Caroline	Active	AH2-370	Solar	17.816	11/15/2023
DPL	Sign Post - Stockton 69 kV	Worcester	Active	AH2-379	Solar	16.98	3/1/2026
DPL	Todd 69 kV	Dorchester	Active	AI2-176	Solar	14.5	12/31/2021
DPL	Todd 25 kV	Dorchester	Active	AI2-177	Solar	5.8	7/31/2021
DPL	Rockawalkin 69 kV	Wicomico	Active	AI2-207	Solar	5.35	3/30/2023
DPL	Price 25 kV	Queen Anne's	Active	AI2-211	Solar	2.6	3/3/2023
DPL	King's Creek 138 kV	Somerset	Active	AI2-235	Solar	62.652	3/2/2023

DPL	Hillsboro - Wye Mills 138 kV	Queen Anne's	Active	AI2-350	Solar	11.9	5/1/2025
DPL	Bishopville – Worcester 138 kV	Worcester	Active	AJ1-018	Solar; Storage	39	12/29/2028
PEPCO	Morgantown 230 kV	Charles	Active	AG2-618 - moved to TC2	Solar	71.5	12/31/2023
PEPCO	Chalk Point 230 kV	Prince George's	Active	AH1-552 - moved to TC2	Solar; Storage	670.2	6/1/2025
SMECO	Hughesville-Cedarvill e 69kV	Charles	Active	AH2-266	Solar	15	3/1/2026
					Total	**1473.9**	

Washington Gas
A WGL Company

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September 12, 2024

Via Electronic Filing

Andrew S. Johnston, Esq.
Executive Secretary
Public Service Commission of Maryland
6 St. Paul Street, 16th Floor
Baltimore, Maryland 21202

RE: Case No. 9705 – Final Report: Gas Heat Pump Pilot

Dear Mr. Johnston:

Enclosed for filing please find Washington Gas Light Company's final report regarding its Gas Heat Pump Pilot.

Please let us know if you have any questions.

Sincerely,

Spencer Nichols
Assistant General Counsel

Cc: Service List

FINAL REPORT:
GAS HEAT PUMP PILOT

SEPTEMBER 12, 2024

SUBMITTED BY:
WASHINGTON GAS

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EXECUTIVE SUMMARY

On August 23, 2021, Washington Gas Light Company (WGL or Company), filed an updated proposal before the Maryland Public Service Commission (PSC or Commission) to request approval to implement the Gas Heat Pump (GHP) pilot[1]. The pilot's objective was to identify, test, and evaluate the energy-saving potential of GHPs in Maryland. GHPs can include various applications, including residential and/or commercial heating, cooling, and hot water. The pilot was to include five components: market assessment, customer identification, contractor engagement, field tests at customer sites in Maryland, and monitoring as discussed in more detail in the filed proposal. On October 27, 2021, the Commission approved WGL's updated DR pilot proposal via administrative hearing and Letter Order[2].

Upon receiving approval from the Commission, WGL began working with its implementation vendor, GTI Energy (GTI), to conduct the market assessment. WGL filed its market assessment on January 5, 2023[3]. The next phase of the pilot involved customer and contractor recruitment to vet potential host sites for the field tests and identify qualified local contractors to receive training and complete the installations. In conjunction with outreach, WGL coordinated with its third-party evaluator, Guidehouse, to produce an EM&V plan that would evaluate pilot performance in line with EmPOWER Maryland guidance. The plan was reviewed and approved by the state's independent evaluator on December 15, 2022.

During the installation phase of the pilot, the Commission temporarily paused progress for some sites. After filed comments, hearings, and data requests, the Commission approved the continuation of the pilot along with an extended timeline for completion and added scope. These interventions resulted in installation delays that ultimately decreased the number of participating sites, but also enabled additional site monitoring time and regulatory requests for a comparative analysis of different heat pump technologies (gas versus electric).

Ultimately WGL installed, commissioned, and monitored GHPs in three sites in Maryland: two residential homes and one commercial building. Installation and operation presented limited challenges that were resolved through collaboration between the implementer, product manufacturer, and installation contractor.

At the conclusion of the monitoring period, GTI compiled and analyzed data from the monitoring equipment and utility billing data to produce energy savings calculations. According to analysis from GTI, all three pilot sites produced energy savings compared to baseline. Guidehouse's evaluation confirmed savings occurred, but at a lower level than those calculated by GTI.

To fulfill regulatory requirements, WGL engaged with the Evaluation Advisory Group (EAG) to document assumptions for the analysis of gas versus electric heat pumps. The EAG approved a methodology for conducting energy modeling based on multiple combinations of model homes;

[1] ML 236756
[2] ML 237601
[3] ML 300743

system configurations for space heating, water heating, and cooling; and fuel-specific and time-specific emissions assumptions. The analysis produced marginal, annual, and lifetime emissions outputs for each combination of variables.

Overall, the pilot confirmed the energy-saving potential of GHPs and produced useful findings about the technology. Given the state of the development of GHP technology, WGL will not seek the incorporation of GHPs into its portfolio at this time but may elect to do so in the future if regulatory and market conditions allow.

INTRODUCTION

In its filed 2021-2023 EmPOWER Program Plan, Washington Gas proposed a Natural Gas Advanced Technology and Equipment pilot intended to "to test and pilot advanced gas technologies and equipment in an array of settings throughout Maryland," including gas heat pumps.[4] In Order No. 89679 issued on December 18, 2020, the PSC denied the proposed pilot without prejudice and requested that Company provide more information about the pilot before proceeding with implementation.[5] On August 23, 2021, WGL filed an updated proposal for a more specific Gas Heat Pump (GHP) pilot[6], which the PSC approved[7] on October 28, 2021.

GOALS AND METRICS

Once approved, WGL procured an implementation vendor (GTI Energy) and began to implement the pilot with the following approved goals:

1. Identify best technology, market sector, and application for the pilot.
2. Train a minimum of two contractors/ service providers in WGL's existing network to provide all services necessary to sell, install and maintain GHPs for future customers.
3. Install a minimum of five GHP systems in Maryland service territory.
4. Demonstrate GHP energy savings and GHG emission reductions through a third-party evaluation (described further in Section 4.6).

In addition to the stated goals, WGL sought to produce data to report out on the following metrics related to the pilot:

1. Therms saved during heating season (and cooling season or full year depending on product application)
2. GHG emission reductions and other applicable system benefits
3. Total number of participating customers

[4] ML 231684
[5] ML 233021
[6] ML 236756
[7] ML 237601

4. Total number of participating contractors/ service providers
5. Customer satisfaction
6. Installer satisfaction

ADDED SCOPE

As discussed later in this report, additional outputs beyond originally filed goals and metrics were requested by the State's Office of People's Council (OPC)[8], and the PSC ordered WGL to produce an analysis that meets the following requirements[9]:

- Utilize Maryland-specific assumptions;
- Be over the lifespan of the asset;
- Include a comparative analysis between GHPs and EHPs;
- Assume changing greenhouse gas (GHG) emissions from the electric grid over time and assess both current Maryland state policy and zero emissions grid by 2045 for electric emissions, providing both marginal and average emissions results;
- Additional vetting of WGL's assumptions through the Evaluation Advisory Group (EAG).

While regulatory intervention increased the scope of the pilot's analysis activities, it did not alter the original goals and objectives. The following sections in this report provide more detailed information on activities that occurred during the pilot, results, and conclusions for future consideration.

PILOT ACTIVITIES

MARKET ASSESSMENT

In the initial phase of the pilot, GTI Energy consolidated research and field studies conducted in other parts of North America to inform recommendations for the pilot. GTI Energy compiled available data to assess the market for space and water heating equipment based on the building stock in Maryland. The market assessment[10] ultimately recommended that the pilot primarily focus on residential combination space and water heating ("combi") units and/or space heating units. If practical, GTI Energy also recommended including commercial water heating or hybrid space heating installations in the scope of the pilot.

[8] ML 301461
[9] ML 303445
[10] ML 300743

REGULATORY INTERVENTIONS

After WGL filed its market assessment, OPC filed comments challenging various elements of the report and called for the PSC to prematurely end the pilot.[11] WGL filed responses to OPC's comments[12] and the PSC heard testimony and asked questions on this issue during the Semiannual EmPOWER Hearing on May 2, 2023. After the hearing, the PSC denied OPC's request to end the GHP pilot and set additional requirements for WGL pilot summarized below[13]:

- Pause GHP installations in process unless the Company could document expenditures.
- File an updated timeline for the pilot.
- Confirm that the Company could complete the pilot within the approved budget.
- Produce comparative analysis of electric heat pumps (EHP) versus GHPs informed by input from the Evaluation Advisory Group (EAG).

WGL filed its updated timeline, provided costs to date on two installations in process[14], and confirmed the pilot could proceed with the extra requirements within the originally approved budget[15]. In October 2023, the PSC approved the extension of the pilot with an end date of September 30, 2024, and allowed the in-progress installations to commence[16].

CONTRACTOR RECRUITMENT

WGL and GTI Energy solicited contractors for participation in the GHP demonstration project through direct outreach to contractors in the WGL's EmPOWER contractor network. During outreach, both parties informed contractors of the requirements of pilot participation extending beyond a standard installation, including the need to install the GHP system in tandem with the traditional heating system for the duration of the pilot testing period, an obligation to support the system throughout the testing period, and the extra requirements for decommissioning and installing replacement equipment at the conclusion of the test period.

Initial outreach to WGL's network was promising, with twelve organizations indicating interest. However, gaining full buy-in from contractors proved difficult. Contractors cited various reasons in declining to participate. Contributing factors included broader macroeconomic trends such as a skilled labor shortage allowing contractors greater choice/flexibility in selecting jobs, and pilot-specific hurdles such as the need for a contract consisting of numerous milestones and additional paperwork. GTI Energy ultimately selected two installers to participate in the pilot.

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[11] ML 301461
[12] ML 302429
[13] ML 303445
[14] Two installations had already been complete at that time. WGL provided spending information on two additional installations in process. Due to regulatory delays, one of the two sites in progress pulled out the pilot.
[15] ML 304305
[16] ML 305420

PARTICIPANT RECRUITMENT

WGL recruited participants in parallel with contractor outreach. Based on the market assessment, regular engagement with GHP manufacturers, and direct experience testing GHP units, GTI Energy identified preferred criteria for test sites for the pilot. The following table lists key considerations for test sites that informed the recruitment and vetting process for test sites.

Table 1. Test Site Preferred Conditions

All sites	Residential	Commercial
Existing gas loads for space and/or water heating	Two or more occupants	Consistent, predictable water consumption
Space to accommodate both the current installed equipment and pilot system mechanical equipment	Single-family home	
Simple installation and removal of equipment based on existing layout	Owner occupied	
Host site willing to cooperate fully with all aspects of a pilot		

Washington Gas conducted outreach to potential host sites and GTI Energy sent an online survey to interested contacts. The project team screened responses from ten potential sites to confirm eligibility as Maryland Washington Gas customers with existing gas space and/or water heating equipment and space available for the installation. In addition, GTI Energy used several analysis methods to screen the sites, including a review of natural gas bills to determine each home's space heating loads, peak heating loads, ductwork static pressure, and air handler characteristics. These data informed whether the GHP was likely to adequately meet the space and/or water heating needs of each home. WGL, GTI Energy, and the participating contractors reviewed the above information to select the final sites, and determined the appropriate GHP application to be tested for each site. The project team ultimately selected three sites[17] with relevant details listed in the table below:

Table 2. Characteristics of Selected Sites

Site Name	GHP Application	Property Details	Occupants	Existing HVAC	Existing DHW Equipment
Site 1	Residential Space Heat	Two-story, 2015 build, 3,310 sq ft	2 adults, 3 children	Gas furnace	N/A
Site 2	Residential Combi	Split Level, 1963 build, 1,080 sq ft	2 adults,	Gas furnace	Gas storage water heater

[17] WGL selected a third residential site and began design and procurement for installation, but that site ultimately dropped out of the pilot due to a months-long delay for the installation from regulatory interventions.

			2 children[18]		
Site 3	Commercial Hot Water	Workout facility, 2,400 sq ft	N/A	N/A	2 gas storage water heaters

Site selections were made to allow for as many combinations of GHP applications and building types as possible, while staying within budget.

EVALUATION PLAN

WGL's third-party evaluator, Guidehouse, developed and executed an evaluation plan to quantify and assess the net energy usage and GHG impacts of the pilot. The evaluation included all sites participating in the pilot. Additional details on the evaluation plan are included in this report in Appendix A: Evaluation Plan.

EQUIPMENT INSTALLATION

Each site posed specific installation requirements and considerations that GTI Energy, the installation contractor, and the manufacturer collaborated to address. GTI Energy and its subcontractors installed GHP units and monitoring equipment to measure key performance characteristics. The installation team also commissioned the equipment at each site.

The GHP installation required modifications to existing hydronic lines and ductwork to integrate the new equipment in a way that retained the existing system's use for redundancy and system switchover capability. Installation complexity varied among the three sites and was based on system factors such as pipe length, number of available pumps, and mechanical configurations of the equipment. Similar to standard HVAC equipment, power requirements for GHP units is 120 volts, alternating current (AC), which satisfy relevant codes and standards for both the inside and outside components of the system. Site 1 necessitated the construction of a new supply duct branch that the hydronic air handler was installed in. Site 2 required modifications to the home's hydronic infrastructure to pipe in the indirect storage tank (IST) as well as the same redundant supply duct construction to accommodate the hydronic air handler. Site 3 required removal of one of the existing water heaters and the installation of a plate heat exchanger (PHX) and "pre-heat" tank in its place. The two systems providing space heating required the installation of an additional booster pump, plumbed in series with the pump internal to the air handling unit while the commercial water heating system required the use of two external pumps for GHP heating loop circulation and service hot water loop circulation.

Each site posed specific installation requirements and considerations. Site 1 was the simplest system to install for several reasons. It was space heating only, meaning there was limited mechanical equipment and, aside from the GHP hydronic loop, there was no additional piping

[18] Children are fully grown and stay at the home for extended visits sporadically throughout the year.

necessary. Site 2 faced space constraints that limited installation possibilities, the most significant being that the outdoor unit had to be installed in the front of the home due to inadequate spacing and significant grade around the sides of the home. Site 3 also had space constraints within the mechanical room but was a water heating only site, and therefore did not have any ductwork requirements. Across all sites, contractors noted challenges with material handling due to the significant weight of the outdoor GHP unit (>400 lbs.).

In addition to basic installation activities required for the GHP system to function, the pilot required additional equipment to monitor the performance of the unit directly rather than relying on utility-metered usage data. Installed monitoring equipment included additional fittings, enclosures, wiring, and sensors. Each system was also commissioned by the on-site contractor and GTI Energy, with assistance from the GHP manufacturer.

As previously mentioned, some installations had to be paused and/or rescheduled during the installation process due to regulatory intervention in Q2-Q3 2023. Once regulatory approval was issued, installation and commissioning were completed for each site in time to monitor performance during the 2023-2024 heating season.

PILOT RESULTS

ENERGY SAVINGS

GTI Energy's approach to calculating energy savings included an analysis of customer utility bills to establish a "billing baseline." In this approach, GTI Energy calculated the summer gas use per day as a proxy to determine non-space-heating loads, such as hot water usage, cooking, and laundry. For each month of billing, the calculated space heating gas use was normalized per day and per Heating Degree Day 65 (HDD65)[19]. This established the "envelope" or heating demand of the building. For each day of the heating season, the linear regressions for the baseline utility bills and field tested GHPs were used to calculate daily gas use against this "billing baseline". The difference of these two aggregations over the period of operation equated to the gas savings of the GHP compared to the baseline furnaces previously operating in each residential site.

In addition to developing a billing baseline, GTI Energy installed logging systems during preliminary site visits to monitor usage of baseline equipment at each test site. Utilizing the nameplate heating capacities of the baseline equipment the project team utilized daily runtime data to more accurately estimate daily gas consumption. This gas data was compared to the observed weather conditions as HDD65 to determine linear regressions of gas use for the furnaces; water heater operation was used to calculate daily average values for the DHW heating gas consumed.

[19] Used for weather normalization against a base temperature of 65 degrees Fahrenheit.

Throughout the pilot, GTI monitored actual gas usage from installed equipment and leveraged that data to calculate energy savings. The following table summarizes the energy savings results from the field test and from the evaluation for each site included in the pilot.

Table 3. Energy and GHG Savings from Pilot Sites

Site	Application	Annual therm savings (pilot analysis)	Evaluated annual therm savings[20]	Evaluated lifetime GHG emission Reductions (MT CO_2e)[21]
Site 1	Residential Space Heat	85– 123	154.2	19.2
Site 2	Residential Combi	318 – 391	108.9	13.6
Site 3	Commercial Hot Water	309	45.9	5.7

The difference between reported savings and evaluated savings reflects two different methodologies used by the implementer versus evaluator. The full evaluation report, which includes a detailed description of baselines used in evaluation, is provided in Appendix B. The difference in savings for this pilot underscores the importance of developing a consistent methodology and baselines for calculating savings. For any potential future GHP program in EmPOWER, a TRM measure should be vetted and accepted to ensure consistent and accurate reporting of savings. All pilot sites produced savings, verifying the potential for GHPs to reduce therm usage.

CUSTOMER AND INSTALLER SATISFACTION

GTI Energy surveyed pilot participants to inform WGL's understanding of customer satisfaction with the pilot and general impressions of GHPs following their direct experience with the equipment at their property. Observations from participating customers included:

- Site 1 perceived their home as being colder than with their previous furnace despite thermostat settings remaining consistent before and during the pilot period.
- Site 2 noted high temperature stability during the period of operation.
- Both residential sites noted that the outdoor unit was large.

[20] Evaluated First Year Savings in Appendix B.
[21] Evaluated Lifetime Savings in Appendix B.

- Site 3 observed high reliability of the water heating system during the project but acknowledged that their facility was not a fit for the capacity of the unit, leading to lower efficiencies than anticipated.

GTI Energy also received feedback from participating contractors after installations were completed. Feedback from contractors was generally positive. They estimated that installation costs would likely be 10%-15% lower for future installations. Contractors shared that the most significant challenge with the project was transporting the GHP unit due to its weight.

GOAL ASSESSMENT

At the conclusion of pilot implementation in Q3 2024, the pilot achieved the below outcomes against its approved goals:

Table 4. Pilot Goals and Outcomes

Goal	Outcome

Identify best technology, market sector, and application for the pilot.	• Market assessment recommended:
	  ○ Residential combi units and/or space heating units.
	  ○ Commercial: water heating or hybrid space heating installations

Train a minimum of two contractors/ service providers in WGL's existing network to provide all services necessary to sell, install and maintain GHPs for future customers.	• Two contractors participated in GHP installations. • Provided technical training on GHPs. Further training would be beneficial based on lessons learned from pilot to sell, install, and maintain systems.
Install a minimum of five GHP systems in Maryland service territory.	• Gained interest from 10 customers during outreach, identified four sites to complete installations, but lost one site due to regulatory delays. • Installed three GHP systems in Maryland Service territory: two residential and one commercial.
Demonstrate GHP energy savings and GHG emission reductions through a third-party evaluation.	• Completed third-party evaluation (see Appendix C)

ELECTRIC HEAT PUMP COMPARATIVE ANALYSIS

During multiple meetings with the EAG, WGL and GTI Energy presented a proposed methodology to complete the comparative analysis required by the PSC in Order No. 90663[22].

[22] ML 303445

The EmPOWER Statewide Evaluator, Loper Energy, and consultants from OPC provided input and the group developed a consensus methodology document with sources cited per PSC guidance. This methodology document, which includes full modeling results from all model homes, equipment scenarios, emissions data sources, time periods, and fuel sources, is provided in Appendix C. A sampling of the comparative analysis results (from Model Home 1) is listed in the table below to illustrate a few of the many outputs from the analysis:

Table 5. Comparative Analysis Results

Emissions Source (year produced)	Total Annual CO2e Emissions (lbs)	GHP Combi Unit with Central Air Conditioner (Scenario 1)	High Efficiency EHP with Electric Heat Pump Water Heater (Scenario 3)	Federal Minimum Standard Gas Furnace, Gas Water Heater, and Central Air Conditioner (Scenario 4)
Maryland Department of Environment[23] (2023)	Average	5,609	3,074	8,185
	Marginal	6,560	4,992	9,032
EPA eGRID (2021)	Average	6,391	4,099	9,037
	Marginal	8,792	9,676	11,173

The table above is reflective of trends seen across results for each model home scenario. Generally, based on the data sources identified by the EAG, GHP Combi units paired with Central Air Conditioners (Scenario 1) achieve meaningful reductions in annual average and marginal emissions compared to the federal minimum standard equivalent gas furnace, gas water heater, and central air conditioner configuration (Scenario 4). The high efficiency EHP and electric heat pump water heater configuration (Scenario 3) achieves the highest average annual emissions reduction of the three selected scenarios but produces higher marginal emissions than the GHP scenario when using the eGRID emissions source. Full results from all model homes, equipment scenarios, emissions data sources, time periods, and fuel sources are provided in Appendix C.

[23] Washington Gas does not endorse this emissions source and is only providing the analysis in response to the regulatory requirement and the methodology approved by the EAG.

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CONCLUSION

LESSONS LEARNED

This pilot provided numerous lessons learned and generated useful information for future consideration in EmPOWER. Most notably, in-depth field testing of the installed units confirmed that GHP technology is highly efficient and produced energy savings when compared to the baseline conditions of the sites. The energy savings produced were verified through third-party evaluation. Below are key lessons learned from the pilot and corresponding recommendations that could inform future review and implementation of GHPs and pilots:

- Field tested GHP units presented some installation and permitting challenges that are not typical for traditional space and water heating equipment. These challenges caused delays in the installation process.
  - **Recommendation:** Provide feedback to GHP manufacturers regarding difficulty with transportation given equipment weight.
  - **Recommendation:** Provide more robust contractor training with specific installation recommendations to address barriers identified during the pilot.
  - **Recommendation:** Engage with permitting bodies to develop best practices for submitting permits for GHP installations.
- The pilot's delayed approval coupled with regulatory delays and installation and recruitment challenges, resulted in suboptimal implementation period to complete all pilot activities.
  - **Recommendation:** Future gas equipment pilots should have at least two, and ideally, three full years of uninterrupted implementation to allow for additional time required to develop a robust implementation and evaluation plan, recruit participants and contractors, problem-solve potential installation pitfalls, and address closeout in time to inform program design for the next EmPOWER cycle.
- Savings potential from commercial water heating applications is highly dependent on occupancy.
  - **Recommendation:** Commercial water heating applications should be limited to facilities with a consistently high occupancy and hot water demand. This was identified as a preferred characteristic for the field test but should be treated as a requirement in future pilots related to water heating equipment.
- Certain commercial facilities require advanced notice and approval for on-site work, which delayed installation of the commercial unit due to multiple visits required for installation and maintenance.

- **Recommendation:** For future pilots where technologies require on-site installations, select facilities with open access and/or develop a streamlined approach in advance for gaining access to reduce delays.

FINAL RESOLUTION

The Company concluded all GHP pilot activities in Q3 2024 within the approved pilot budget. The pilot produced useful information about GHP applications in the field and produced verified energy savings offered by GHPs in two of three field test sites. The Company sees potential in the technology and anticipates the possibility of future energy and GHG emissions savings that could be produced through the installation of GHPs in its Maryland service territory. Washington Gas does not intend to pursue the inclusion of gas heat pumps in its portfolio in the 2024-2026 EmPOWER cycle. Should the Company consider their inclusion in a future program cycle, WGL would anticipate working through the EAG to develop a TRM measure for GHPs that could inform savings forecasts and program planning.

APPENDIX A – GHP PILOT EVALUATION PLAN

Appendix begins on next page.

Guidehouse

Memorandum

To: Erika Moore, Teagan Gorman, John Richards, Joshua McClelland (Washington Gas)

From: Mark van Eeghen, Kuldeep More (Guidehouse)

Date: December 15, 2023

Re: Evaluation Plan for Washington Gas Maryland Gas Heat Pump Pilot (update)

Objectives and Background

Washington Gas received approval from the PSC to conduct a Gas Heat Pump (GHP) pilot program (filed initially under the name "Natural Gas Advanced Technology and Equipment") for the 2021 – 2023 EmPOWER Maryland program cycle. The pilot will be implemented by the Gas Technology Institute (GTI).

Washington Gas indicated the following goals for the pilot in their filing:

1. Identify the best technology, market sector, and application for the pilot.
2. Train a minimum of 2 contractors / service providers in WGL's existing network to provide all services necessary to sell, install and maintain GHPs for future customers.
3. Install two (2) residential GHP systems and one (1) commercial GHP system in the Maryland service territory

GTI developed a market assessment that focused on goal 1, while goal 2 will be addressed via a separate activity. This evaluation plan, as part of goal 3, describes how Guidehouse is planning to evaluate first-year energy savings, lifetime energy savings, and lifetime gross greenhouse gas (GHG) emission reductions from each GHP project that is installed.

Implementation Approach

GTI indicated they are expecting to implement two residential GHP projects for both space heating and water heating end-uses, and one commercial GHP project for water heating end use. At each site, the GHP will fully replace in-situ furnace and/or water heater use. GTI indicated that GHP will replace gas equipment only, i.e., no fuel switching will occur. GTI anticipates that GHPs from Robur and Anesi will be implemented. The in-situ equipment will remain installed as a backup in the event of unexpected issues with the Anesi GHP. The in-situ equipment will be replaced with the commercially available Robur GHP system. The section below describes Guidehouse's approach to evaluate these projects.

Summary of Evaluation Approach

This section summarizes the evaluation approach, and next section provides further detail on each step of the approach.

Step 1: Review on-site data from GTI and historical utility consumption to determine baseline energy usage.

Step 2: Develop regression model for building load profiles that accounts for outdoor conditions.

Step 3: Conduct customer interviews

Step 4: Perform a bin analysis to calculate energy consumption for both the in-situ baseline, the code baseline, and the GHP system for each site.

Step 5: Calculate first-year gross savings, lifetime gross savings, and lifetime gross GHG emission reductions.

Detailed Evaluation Approach

Step 1: Review of Utility Bills and On-site Data

The purpose of this step is to estimate the annual hours for when baseline natural gas consumption is heavily dependent on space heating needs for the site using heating degree days and historical billing data. Guidehouse will review the previous 24 months of gas bills (November 2020 – October 2022) to determine the space heating and domestic hot water (DHW) usage. Guidehouse will confirm via customer interviews, if any other weatherization or energy efficiency activities were completed that may impact gas usage during the billing period requested. In addition, we will also be confirming historic occupancy patterns for the selected sites and that no other measures impacting gas usage will be implemented during this pilot.

For space heating usage, Guidehouse will determine a balance point for each site by performing a regression with respect to different HDD base temperatures. The balance point gives an indication for when the site's HVAC system switches from heating mode to cooling mode. The HDD will be plotted against the utility billed usage (therms), the HDD base temperature with the best co-efficient of determination (R^2- value) will be selected.

For hot water usage, Guidehouse will use only natural gas consumption during the cooling season to estimate natural gas consumption for DHW.

GTI has indicated that limited data for the in-situ equipment will be available before the initial set up of the GHP equipment and when the GHP is taken offline for maintenance. This data will be able to provide as estimate of DHW and space heating gas consumption however, it will be collected for a shorter period as compared to the GHP. As a result a combination of reviewing utility bills and the limited on-site data will be used to calibrate the load profiles for in-situ equipment and the baseline consumption calculated in Step 4: Bin Analysis

Other Baseline Considerations

Guidehouse learned from conversations with the implementer that each GHP will replace in-situ gas-fired equipment that has remaining useful life and for the purposes of this pilot. For the purposes of this pilot, Guidehouse will use baseline assumptions from the NEEP TRM v11, where available to calculate the lifetime savings for this pilot. Table 1 summarizes the key baseline assumptions for this pilot.

Table 1: Baseline Assumptions

	RUL Baseline	Post-RUL baseline	RUL Period	Effective Useful Life*
Residential Furnaces	Calculated in-situ baseline (see below)	AFUE = 80%	Actual – estimated through customer interviews	21 years
Residential Water Heaters	Calculated in-situ baseline (see below)	Calculated based on type (storage/tankless) draw pattern and tank size from MA TRM v11	Actual – estimated through customer interviews	13 years
Commercial Water Heaters	Calculated in-situ baseline (see below)	TE = 80%***	Actual – estimated through customer interviews	10 - 13 years**

**All effective useful lives are sourced from the NEEP TRM v11.*

To estimate energy consumption for the RUL period, GTI will perform a combustion analyzer test to obtain the current operating efficiency of the in-situ equipment. In the case a combustion analyzer test cannot be performed, Guidehouse will adjust the nameplate efficiency of the in-situ equipment using a degradation factor to account for mechanical wear and tear during the time spent in operation. The adjusted efficiency will be calculated as per the equation below,

$$\eta_{Adj} = \eta_{Base} * (1 - M)^{age}$$

Where,

η_{Adj} = Adjusted efficiency of the furnace or gas water heater

η_{Base} = Nameplate efficiency of the furnace or gas water heater

M = Maintenance Factor for furnace= 0.015[1]

= Maintenance Factor for water heater= 0.010[2]

Age = Age of in-situ equipment

For the post-RUL period, Guidehouse will determine the baseline consumption for space heating and DHW using a combination of calculated hourly loads, described in Step 2 and the post-RUL efficiency from Table 1.

Step 2: Develop Regression Model

The purpose of this step is to establish a relationship between the hourly loads that will be calculated using the on-site data and outside air temperature. This relationship can then be used to weather normalize energy savings via a bin analysis that uses TMY data.

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[1] *M Factor for Gas furnace, natural-draft combustion, standing pilot light, in conditioned space from* ***Hendron R. Building America Performance Analysis Procedures for In-situ Homes. National Renewable Energy Laboratory 2006****.*

[2] *M Factor for Gas water heater, 40-gallon tank, pilot light, natural-draft combustion, 1-in. insulation, no heat traps, standard flue baffling from* ***Hendron R. Building America Performance Analysis Procedures for b Homes. National Renewable Energy Laboratory 2006****.*

Guidehouse will request utility billing data for the three sites for the last 24 months prior to the GHP installation and to calibrate the efficiency of the in-situ water heating and space heating equipment. The billing data will be calendarized, aggregated monthly, and analyzed to determine baseline usage.

In preparation for the bin analysis, Gu]idehouse will calculate the space heating load profiles with respect to outdoor conditions and the hot water consumption statistics including daily draw volumes, draw rates, draw durations, and draws per day. An overview of equation used is provided below, all variables relating to flow and temperature measurements will be trended for all sites.

GHP Hydronic Loop Loads

The total load (DHW and Space Heating) on the GHP for every 15 min interval will be calculated using the following equation,

$$Q_{Hydronic} = \dot{V}_{Flow} C_P \rho \left(T_{Supply} - T_{Return}\right)$$

Where,

$Q_{Hydronic}$ = BTUh delivered by the GHP loop

V_{flow} = Flow rate in GPM for the GHP loop

$C_p\rho$ = Specific Heat of Water adjusted for propylene-glycol concentration.

T_{Supply} = Temperature of supply water for the GHP loop

T_{Return} = Temperature of return water for the GHP loop

The total load will be correlated with the outside air temperature for the monitoring period by developing a linear regression model. Guidehouse will also consider the operational schedule, indoor temperature and setpoint selection that will inform how the load varies during times of occupancy/unoccupancy.

DHW Load and Draw Pattern

Guidehouse will verify the draw patterns/rates for the DHW loop by performing a time series analysis and considering the flow rates and supply and return temperatures for the storage tank and GHP hydronic loop. Energy input into the storage tank from the GHP loop is given below,

$$Q_{DHW} = V_{DHW} C_P (T_{DHW} - T_{CW})$$

Where,

Q_{DHW} = BTUh delivered by the DHW supply

V_{DHW} = Flow rate in GPM for the DHW supply

C_p = Specific Heat of Water.

T_{DHW} = Temperature of DHW supply

T_{CW} = Temperature of incoming water from city mains

GTI will install 2 type T thermocouples and provide Guidehouse with supply and return temperatures for the indirect tank, which is part of the GHP hydronic loop. Guidehouse will calculate the stand-by loss by taking the difference in Btu/h delivered to the indirect tank vs. Btuh supplied to the DHW loop. The energy input for the indirect tank is given below:

$$Q_{ID} = V_{DHW} C_P \rho \left(T_{SupplyID} - T_{ReturnID}\right)$$

Where,

Q_{ID} = BTUh delivered by the Indirect Tank

V_{DHW} = Flow rate in GPM for the DHW loop

$C_p\rho$ = Specific Heat of Water adjusted for propylene-glycol concentration.

$T_{SupplyID}$ = Temperature of supply water for the Indirect Tank

$T_{ReturnID}$ = Temperature of the return water from the Indirect Tank

Stand-by loss ($Q_{standby\ loss}$) will be calculated from the equation:

$$Q_{standby\ loss} = Q_{ID} - Q_{DHW}$$

GHP Space Heating Loop

Guidehouse will calculate space heating loads using the difference between the total GHP hydronic loop load and DHW load, the equation is given below

$$Q_{SH} = Q_{Hydronic} - Q_{ID}$$

Where,

Q_{SH} = BTUh delivered by the GHP loop for space heating

$Q_{Hydronic}$ = BTUh delivered by the GHP loop

Q_{ID} = BTUh delivered by the Indirect Tank

Step 3: Customer Interviews

Guidehouse will conduct phone interviews for all sites for a virtual verification of:

- GHP equipment is installed and operating
- Baseline equipment specifications and operating conditions
- Key project-specific parameters (i.e., temperatures, setpoints, operating hours)

Guidehouse will incorporate the interview feedback from the customer regarding GHP performance, hours of operation, selection of setpoints and satisfaction relating to the operation of the equipment and occupant comfort.

Step 4: Bin Analysis

Using site data from GTI, the load for the hydronic space heating and DHW loops will be developed, as described in

Step 2: Develop Regression Model. Guidehouse will calculate space heating therm savings for each site using the following steps:

1. First, Guidehouse will weather normalize the hourly space heating and DHW loads for the pilot sites by using TMY3 data for the local weather station and the coefficients from the linear regression equation that will be created in Step 2: Develop Regression Model.
2. As the GHP system can operate in multiple modes concurrently, the hourly load calculation can lead to not realizing a correlation between outdoor conditions and indoor loads. Guidehouse may then choose to average daily consumption and compare that to daily HDD to reduce the impacts of data “noise” from the operation of the GHP.
3. For the GHP system, Guidehouse will separate the trended hourly natural gas usage data ($V_{NG,GHP}$, see Data Needs section for further detail) into space heating and DHW therm consumption. This will be done by multiplying the natural gas usage by ratio of the calculated space heating to DHW load for all data intervals. Guidehouse will also perform a time-series analysis on the hourly DHW load to isolate areas where the DHW is operational and there is a call for hot water. The consumption from these isolated hours will then be subtracted from total consumption as a secondary check for calculated natural gas consumption.
4. Guidehouse will then use the calculated natural gas consumption for the GHP system to develop a performance curve and establish the relationship between natural gas consumption and space heating loads.
5. The energy consumption for the GHP and the baseline system will be calculated by applying the efficiency curves for each system to the hourly load vs. outside air temperature regression across the temperature bins for the local weather station. For the GHP system, the performance curve developed in Step 2: Develop Regression Model of the bin analysis section will be used, whereas for the baseline systems, Guidehouse will use a DOE-2 standard noncondensing furnace part load curve [3] . This curve will be adjusted to reflect the in-situ efficiency for the RUL equipment as described in Step 1: Review of Utility Bills and On-site Data.
6. Guidehouse will compare the energy consumption for the GHP, in-situ and post RUL equipment for the outdoor air temperatures where the sites would call for space heating and determine the weather normalized therms savings for each site.

For DHW, the RUL period’s annual consumption will be estimated using a combination of utility bills and data collected for the in-situ gas fired water heater. For the post RUL period, Guidehouse will determine the therm consumption by using the hourly DHW load from the on-site data and dividing it by the post RUL efficiency from Table 1.

Step 5: Results Reporting

With the findings from the bin analysis, Guidehouse will calculate first-year and lifetime verified gross savings. From verified lifetime gross energy savings, Guidehouse will calculate lifetime GHG emission reductions using Avoided Emissions Calculator per MDE Policy taking into consideration the changing emissions from the electric grid over time.

Data Needs

Guidehouse will request the following data from GTI:

1. In-situ equipment specifications that include:
    a. The age of the in-situ equipment

---

[3] *Henderson, Hugh, Huang, Y J, and Parker, D. Residential equipment part load curves for use in DOE-2. United States: N. p., 1999 Henderson, Hugh, Huang, Y J, & Parker, D. Residential equipment part load curves for use in DOE-2. United States. https://doi.org/10.2172/6519.*

b. The design load of each home

c. Mechanical drawings for all sites

2. List of all other sources of natural gas consumption such as stoves, fireplace, ovens etc., for all sites.

3. A continuous set of data measurements which will be used to calculate the space heating and DHW loop load for the site (see Table 3). These measurements are to be collected for the GHP equipment.

Table 2: List of Continuous Measurement Data Points to be supplied by GTI

Measurement Category	Measured Quantity	Measurement Point(s) and Variable(s)	Units
Natural Gas Flow	Natural Gas Flow	GHP $V_{NG,GHP}$	ft^3
Power Consumption	Power Consumption	Hydronic AHU Q_{Elec_AHU}, Conventional AHU Q_{Elec_AHU}, GHP Q_{Elec_GHP}, Circulation pumps (individually and in aggregate) $Q_{Elec\_ pumps}$	Wh
DHW	Water Flow	DHW [VDHW]	gal.
Domestic Hot Water	Temperature	Hot Water Outlet T_{DHW}, Cold Water Inlet T_{CW}	°F
Ambient/ Indoor Air	Temperature	Indoor Mechanical Room T_{Air_Mech}, Outdoor GHP T_{Air_GHP}	°F
Hydronic Loops	Temperature	AHU Loop Supply T_{Supply_AHU}, AHU Loop Return T_{Return_AHU}, DHW Tank Supply $T_{Supply\_Ind\_Tank}$, DHW Tank Return $T_{Return\_Ind\_Tank}$, GHP Supply T_{Supply_GHP}, GHP Return T_{Return_GHP}	°F
Hydronic Loops	Flow Rate	GHP Hydronic Loop $\dot{V}_{GHP}$, AHU Loop $\dot{V}_{AHU}$, Indirect Tank Loop $\dot{V}_{Indirect\ Tank}$	GPM
GHP external	Temperature	GHP Flue Gas Outlet $T_{FG\ GHP}$	°F
Outside Air Temp	Temperature	Outside Air Dry Bulb Temperature	°F

4. A continuous set of measurements that will be used to determine the baseline DHW and space heating loads and energy usage. These measurements are to be collected for the in-situ equipment. A detailed description of the methodology used to determine the baseline energy consumption of the field sites is provided in Appendix C.

Table 3: List of Measurement Points to be collected by GTI for In-Situ Equipment

Measurement point	Sensor	Logging Device
Storage Water Heater Flue Gas	K-type Thermocouple Probe	HOBO UX100-014M
Furnace Gas Valve	Setra Current Switch	HOBO UX90-001M
Thermostat Ambient Temp	HOBO Temp/RH sensor	HOBO UX100-003
2nd Furnace Air (2) and A/C lines (2)	T-type beaded Thermocouple	HOBO UX120-014M

5. On-site pictures to verify in-situ equipment size, efficiency, and configuration.

Evaluation Schedule and Key Milestones

Table 5 shows the schedule for key deliverables and data transfer activities for the evaluation.

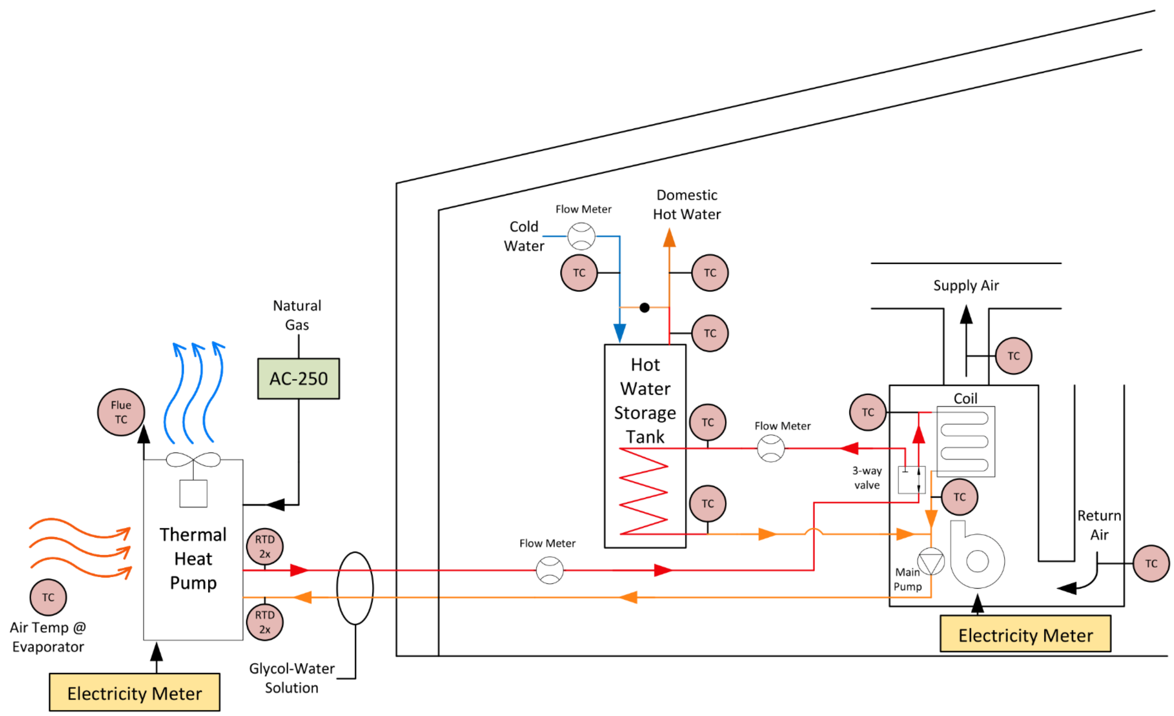
Table 4. GHP Evaluation Schedule – Key Deadlines

Key Milestone	Responsible Party	Date Delivered
Update Evaluation Plan	Guidehouse	Sept 19, 2023
Share updated evaluation plan with Loper Energy	Guidehouse	Dec 15, 2023
Preliminary Evaluation Data Received (incl. GHP, in-situ and site utility bills)	GTI/Washington Gas	Jan 26, 2024
Final Evaluation Data Received for three pilot sites	GTI/Washington Gas	April 19, 2024
Draft Evaluation Report to Washington Gas	Guidehouse	July 1, 2024
Comments on draft (10 Days)	Washington Gas	July 12, 2024
Final Report Draft to Washington Gas	Guidehouse	July 19, 2024

Appendix A: Schematic on GHP Set up

A representative diagram of the GHP system is given below:

Figure 1: Representative Diagram of Instrumentation during GHP System Monitoring



Appendix B: Methodology to estimate baseline DHW and Space Heating Loads

A thermocouple positioned above the exhaust vent of the tanked water heater set to record a temperature reading on 10s intervals. This will provide us with a signal for the flue gas temperature and when compared to an ambient temperature, will provide us with gas valve on time duration. Taking the derivative of the temperature signal will indicate the time start time and end time of a cycle. Pairing this information with nameplate firing rate, we can determine an estimated gas consumption for domestic hot water. This metric would be accumulated as energy (BTU) per day.

$$valve\ on\ start = \frac{dT_{flue}}{dt} > 10°F$$

$$valve\ on\ end = \frac{dT_{flue}}{dt} < -5°F$$

$$valve\ on\ (s) = \left\{where\ \left(T_{flue} > (T_{amb} + 40°F)\ OR\ \frac{dT_{flue}}{dt} > 10°F\right)\ AND\ NOT\left(\frac{dT_{flue}}{dt} < -5°F\right)\right\} \times t_{step}$$

Where t_{step} is 10 second intervals, T_{amb} is the average "gas valve off" temperature or tank water temperature (*i.e.*, 120°F), T_{flue} is the probe in the flue gas stream, and $40°F$ is an arbitrary dead-band that eliminates false positives. When the flue temperature rises faster than $10°F$ in 10 seconds, the gas valve is determined to be open. When the flue temperature drops faster than $5°F$ in 10 seconds the gas valve is determined to be closed. The time between these events is our gas valve runtime. This gas consumed will be calculated per day.

Note: the rates defined for the "valve on start" and "valve on end" events are field dependent and will be validated for each site.

$$Gas\ Consumption\ (BTU) = Valve\ on\ time\ (s) \times \frac{1\ (hr)}{3600\ (s)} \times nameplate\ firing\ rate\ \left(\frac{btu}{hr}\right)$$

A current switch was placed on the wires commanding the furnace gas valve. This will provide us with gas valve on time duration. Pair this information with nameplate firing rate, we can determine and estimated gas consumption for space heat. This data will be correlated with outdoor air temperature aggregated from local historical weather data. This metric will be calculated per day.

$$Gas\ Consumption\ (BTU) = Valve\ on\ time\ (s) \times \frac{1\ (hr)}{3600\ (s)} \times nameplate\ firing\ rate\ \left(\frac{btu}{hr}\right)$$

A site has a second air handler in the attic. This was fitted with two thermocouples to measure air temperature, and two thermocouples on the supply and return tubing for the attached heat pump. This will allow us to determine activity and, at best, derive an estimated heat delivered to the space.

$$duration\ of\ heat\ call\ (s) = \left(where\ \left(T_{supply} - T_{return}\right) > 10°F\right) \times t_{step}$$

$$Gas\ Consumption\ (BTU) = heat\ call\ duration\ (s) \times \frac{1\ (hr)}{3600\ (s)} \times nameplate\ firing\ rate\ \left(\frac{btu}{hr}\right)$$

Where T_{supply} and T_{return} are the temperature probes in the furnace's air stream and t_{step} is the 10 second data recording interval.

APPENDIX B – EVALUATION REPORT

Appendix begins on next page. This evaluation report has been submitted to the statewide evaluator for review.

Guidehouse
Outwit Complexity

Washington Gas Maryland: Gas Heat Pump Pilot Evaluation Report

Prepared for:

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July 9, 2024

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Summary of Results

Washington Gas received approval from the Public Service Commission (PSC) to conduct a Gas Heat Pump (GHP) pilot program as part of the 2021-2023 EmPOWER Maryland program cycle. The pilot was implemented by the Gas Technology Institute (GTI), which installed GHP systems at two residential sites and one commercial site. The GHPs served the space heating needs for both residential units, while also serving the water heater needs for Site 5. For the single commercial site that participated in the pilot, the GHP served the water heating needs only. Table 1 shows the end uses served by the installed GHP at these sites.

Table 1. GHPs Installed under the Pilot

Customer Segment	Site Number	Space Heating	Water Heating
Residential	5	Yes	Yes
Residential	10	Yes	No
Commercial	X	No	Yes

Source: GTI

Washington Gas requested Guidehouse to evaluate the impacts of the pilot. The goal of the evaluation was to address the following research questions:

1. What are the first year verified gross therms savings?
1. What are the lifetime verified gross therms savings?
2. What are the lifetime gross greenhouse gas (GHG) emissions reductions?

To address these questions, Guidehouse developed an evaluation plan, which includes the data needs, assumptions, and methods to quantify the savings and emissions reductions (see Appendix B for the full evaluation plan and data request). The evaluation approach can be summarized in the following five high level steps:

- **Step 1.** Review onsite data from GTI and 12+ months of historical utility consumption to determine baseline energy usage.[1]
- **Step 2.** Develop regression model for building load profiles that accounts for outdoor conditions.

[1] The purpose of this step is to estimate the annual hours for when baseline natural gas consumption is heavily dependent on space heating needs for the site using heating degree days and historical billing data. Guidehouse determined a balance point for each site by performing a regression with respect to different HDD base temperatures. The balance point gives an indication for when the site's HVAC system switches from heating mode to cooling mode. The HDD will be plotted against the utility billed usage (therms), the HDD base temperature with the best co-efficient of determination (R2- value) will be selected.

- **Step 3.** Confirm the installations and site-specific details through customer survey data provided by GTI.[2]
- **Step 4.** Perform a bin analysis to calculate energy consumption for the in-situ baseline, the code baseline, and the GHP system for each site.
- **Step 5.** Calculate first-year gross savings, lifetime gross savings, and lifetime gross GHG emission reductions.

Guidehouse reviewed the data and evaluated the impacts of each project. Overall, the residential sites in the pilot show gas savings of 16%-18% relative to average annual gas consumption, and the commercial site shows about 12% savings over the baseline. The key results of this impact evaluation are summarized in Table 2 and Table 3, and additional detail for each site is included in Appendix A.

Table 2. Evaluated First Year Savings

Site Number	End Uses	Annual Savings (therms)			Annual Baseline Consumption (therms)*	Savings as Percentage of Baseline Consumption
		Space Heating	Water Heating	Total		
5	Residential Space Heating and Water Heating	104.3	49.8	154.2	883.0	17.5%
10	Residential Space Heating	108.9	NA	108.9	651.1	16.7%
X	Commercial Water Heating	NA	45.9	45.9**	396.9***	11.6%

* Sum of monthly average consumption for a calendar year from the billing data before pilot implementation.
**Savings for commercial sites include savings from reduced operation of water heater 2 due to the installation of the GHP at the site.
***For the commercial site, baseline consumption includes counterfactual baseline consumption for GHP using code baseline & baseline consumption for water heater 2.
Source: Guidehouse analysis

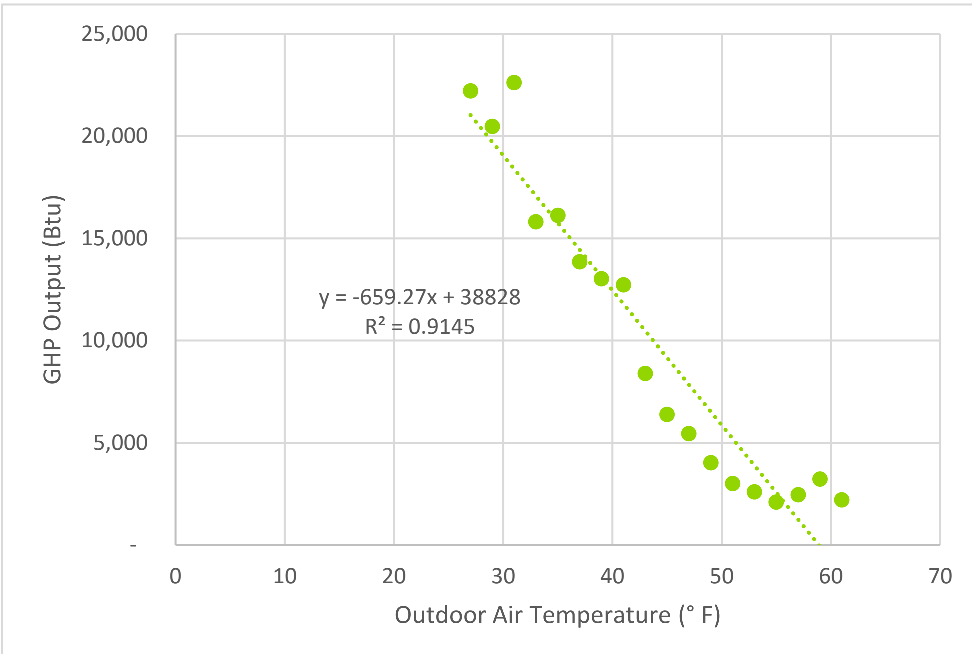
As mentioned in the evaluation plan, Guidehouse conducted an engineering desk review for each of the three sites. Specific site findings were noted in the impact analysis for each site (i.e. baseline model number, nameplate efficiency, etc.). Guidehouse calculated actual baseline data using information submitted and on-site values that were provided by GTI. During the on-site visit to Site 5, the baseline equipment was found to be over 15 years old. Due to this fact, and the equipment being beyond its useful life, Guidehouse adjusted baseline efficiency to meet code minimum baseline of 80% for space heating. For the same site, the water heating baseline efficiency followed guidance from the Mid-Atlantic TRM v11 and inputs used to calculate

[2] Customer interviews were part of the original evaluation plan, however, Guidehouse was unable to reach out to the customers directly. Instead, Guidehouse received responses to the verification questions through the post-installation survey completed by GTI. Guidehouse incorporated the answers to the questions from the survey into the analysis.

efficiency were pulled from billing data data. Site X water heating baseline efficiency followed guidance from Mid-Atlantic TRM v11 code baseline of 80%.

As part of each engineering desk review, Guidehouse calculated the Coefficient of Performance (COP) of each GHP by using an 8760 temperature based bin analysis. Using actual gas consumption and outside air temperature to create a regression model Guidehouse calculated a more accurate COP for each system. In the table below, R^2 was calculated for Site 10 to a value of 0.9145 that proves a very strong correlation between the billing data and actual efficiency. The evaluated COP for the three sites ranged from 0.73 to 1.05, compared to nameplate COP ranging from 1.20 to 1.40.

Figure 1: Site 10 Regression Model



*As a point of reference for a two variable regression model. An acceptable R^2 value should be great than 0.6; anything about that value is preferred.

Guidehouse applied an effective useful life of 15 years[3] and per the Mid-Atlantic TRM a constant emission factor of 0.0083 $MTCO_{2e}$/therm to calculate the lifetime savings and the lifetime GHG emission reductions.

[3] This value is based on the Illinois Technical Reference Manual (TRM) version 11.

Table 3. Evaluated Lifetime Savings and Emissions Reductions

Site Number	End Uses	Annual Savings (therms)	Lifetime Savings (therms)	Lifetime GHG Emission Reductions (MTCO2e)
5	Residential Space Heating and Water Heating	154.2	2,312.6	19.2
10	Residential Space Heating	108.9	1,633.5	13.6
X	Commercial Water Heating	45.9	688.5	5.7

Source: Guidehouse analysis

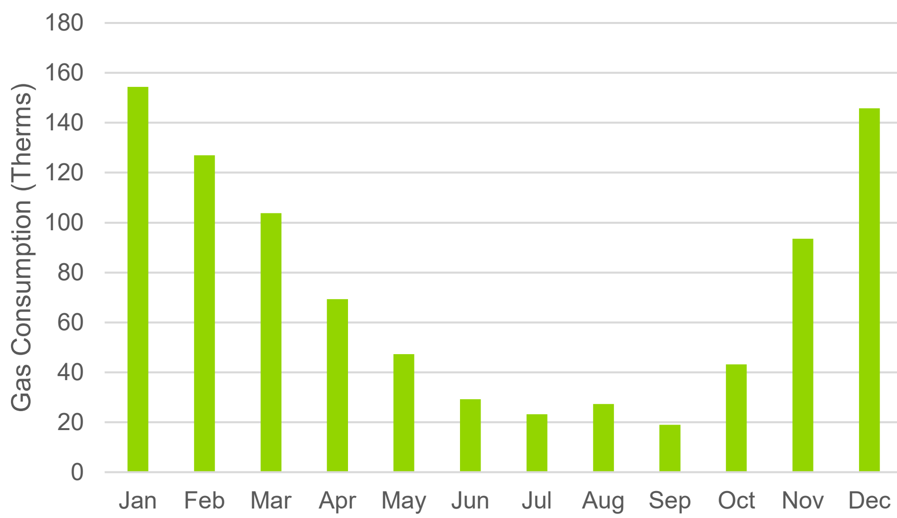
Appendix A. Site-Specific Details

A.1 Site 5

This site is the first residential site to participate in the GHP pilot. The site is a single-family house with a finished basement. In the baseline, the site had a 100,000 BTU gas furnace and 40,000 BTU and 50-gallon gas water heater. At this site, GHP Provided the space and domestic water heating.

Guidehouse analyzed the billing data for the site from October 2021 to February 2023. Figure 1 shows the average gas usage per month for the site in the baseline. From the billing data, Guidehouse observed that natural gas consumption at the site is primarily from space heating during winter months.

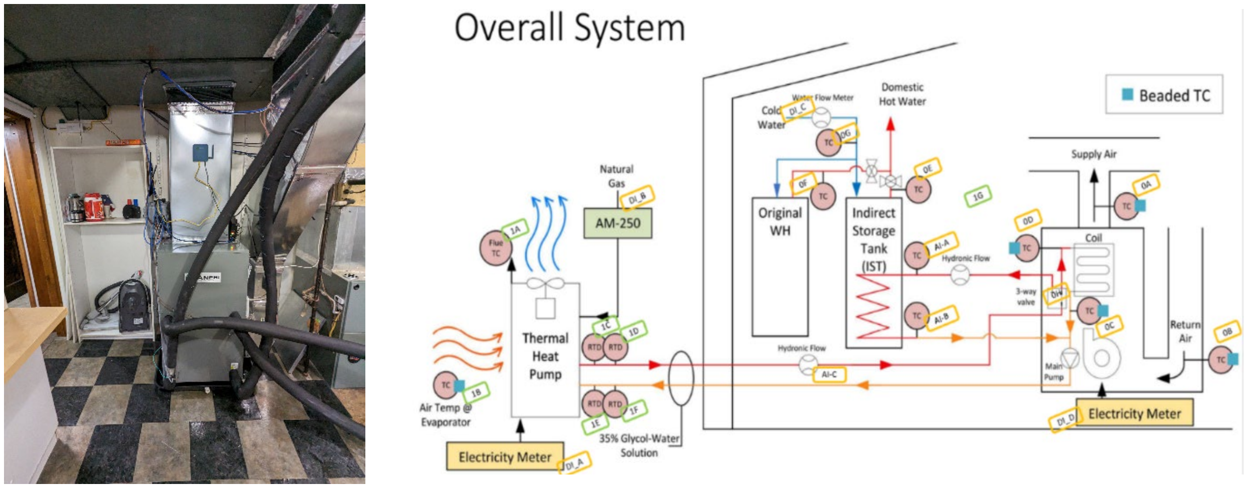
Figure 2. Site 5 – Baseline Gas Consumption – Billing Data



Source: Guidehouse analysis

The implementer installed an 80,000 BTU GHP at the site to provide space heating and water heating needs (make: Anesi, model number: 0801HXANXX). Figure 2 includes a picture of the installed GHP unit and a schematic of the overall system installation.

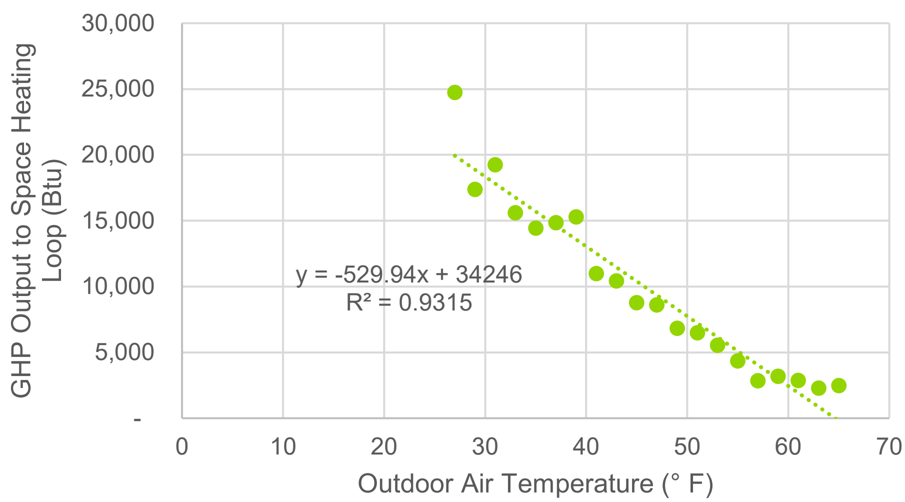
Figure 3. Installed GHP at Site 5 and Site Schematic Diagram



Source: GTI

Guidehouse analyzed the trend data provided for site 5 and developed linear regressions for the GHP output against the outdoor air temperatures. Guidehouse used bin hour analysis to calculate average space heating load versus outdoor temperature for 2°F temperature bins. As the GHP system provides hot water to space heating as well as DHW, Guidehouse calculated heating provided to both the loops and checked for the correlation of heating provided against outdoor air temperature. More details on these steps can be found in the Detailed Evaluation Approach section. Figure 3 shows the GHP output to space heating loop versus outdoor air temperature for site 5.

Figure 4. GHP Output to Space Heating vs. Outdoor Air Temperature

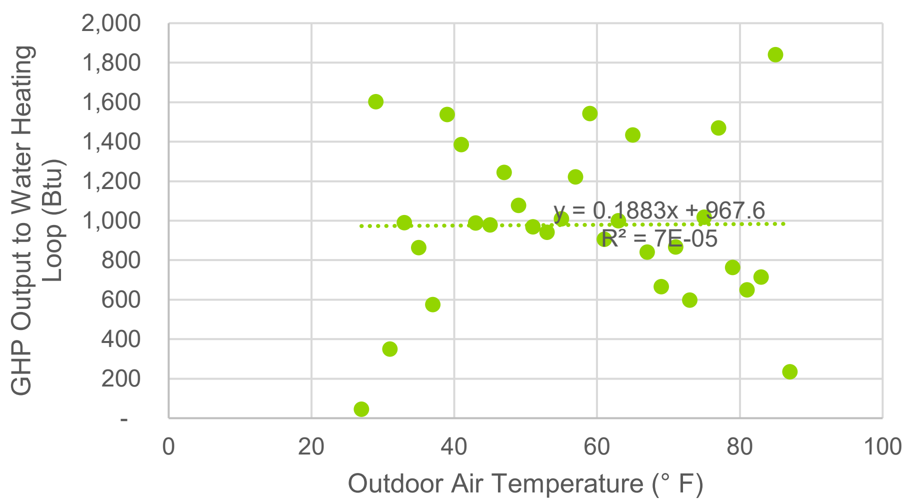


Source: Guidehouse analysis

From Figure 3, Guidehouse observes that GHP output is directly correlated with the outdoor air temperature. Therefore, Guidehouse used the regression equation along with TMY3 weather data to calculate space heating needs for a typical year. Guidehouse used calculated COP from the trend data for outdoor temperature buckets to calculate efficient case consumption and applied an 80% Annual Fuel Utilization Efficiency (AFUE) baseline efficiency. In addition, Guidehouse assumed that space heating occurs below 64°F outdoor air to be on a conservative side when estimating gas savings from the space heating. Overall, Guidehouse evaluated space heating savings for this unit of 104.3 therms per year.

Guidehouse also looked at the heating load from the DHW loop for the site against outdoor air temperatures. Figure 4 shows the GHP output to domestic water heating loop versus outdoor air temperature for site 5.

Figure 5. Site 5 – GHP Output to Water Heating vs. Outdoor Air Temperature



Source: Guidehouse analysis

Guidehouse observed that the GHP output to water heating is not directly correlated with the outdoor air temperature. Therefore, instead of using the regression equation, Guidehouse calculated average load per hour and applied a constant average load throughout the year to calculate gas savings. As this was a replace-on-burnout measure, Guidehouse calculated code baseline value as per Maryland TRM version 11 (Page 43). Guidehouse assumed hot water heater size as 50 gallons (same as baseline) and draw pattern as high (as calculated from the trend data). Calculated baseline efficiency for water heating loop at the site is 62.7%.

Overall, Guidehouse evaluated water heating savings for this unit are 49.9 therms per year.

In summary, Guidehouse evaluated total annual savings for site 5 to be 154.2 therms. Overall COP for the GHP installed at the site was 0.94 as per the Guidehouse analysis.

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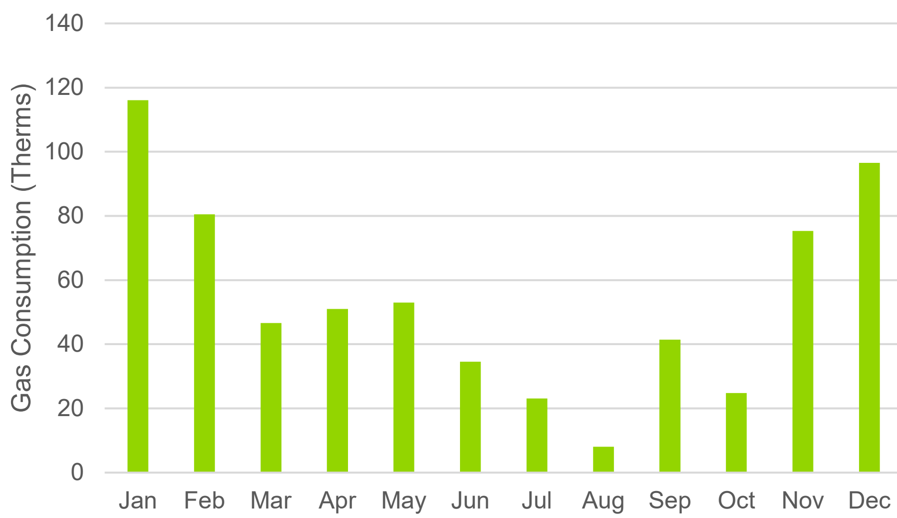
A.2 Site 10

The site is a single-family two-story residential home with an outdoor swimming pool. The site has an 80,000 BTU condensing gas furnace and the pool uses a 400,000 BTU heater. The site has a 90-gallon electric water heater.

The implementer installed an 80,000 BTU GHP (make: Anesi, model number: 0801HXANXX) at the site to address site space heating. Guidehouse analyzed the billing data for the site from October 2021 to February 2023. Figure 5 shows the average gas usage per month for the site prior to the installation of the GHP. Guidehouse observed that the natural gas consumption at the site is primarily driven by space heating during winter months.

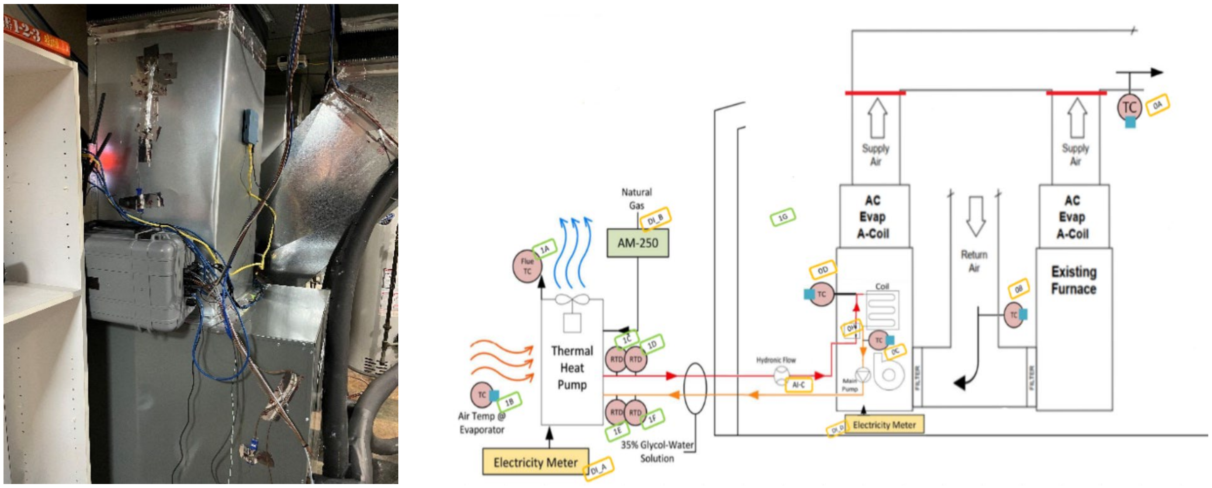
Figure 6. Site 10 – Baseline Gas Consumption – Billing Data



Source: Guidehouse analysis

Figure 6 shows the installed GHP at the site as well as the site schematic.

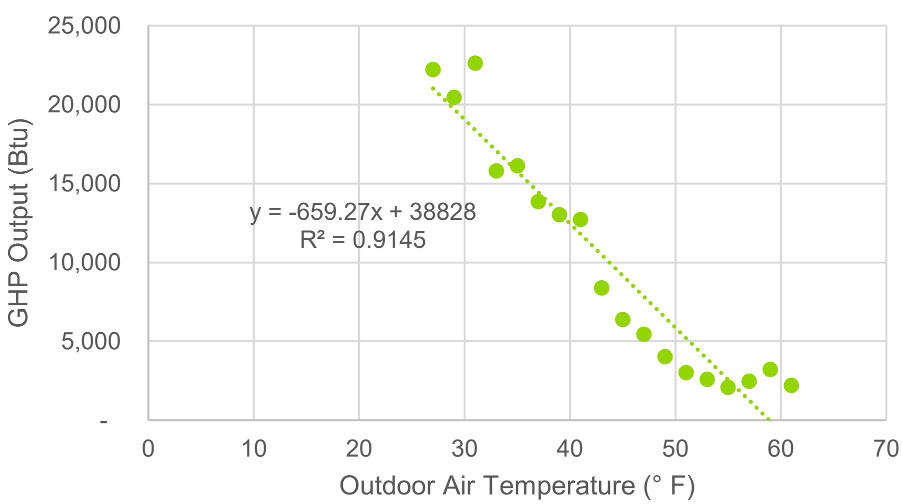
Figure 7. Installed GHP at Site 10 and Site Schematic Diagram



Source: GTI

Guidehouse analyzed the trend data provided for site 10 and developed a linear regression for the GHP output against the outdoor air temperatures. Figure 7 shows the GHP output versus the outdoor air temperature.

Figure 8. Site 10 – GHP Output vs. Outdoor Air Temperature



Source: Guidehouse analysis

Guidehouse observed a strong linear correlation between the GHP output and the outdoor air temperature. Therefore, Guidehouse used the regression equation along with TMY3 weather data to calculate space heating needs for a typical year. Guidehouse used calculated COP from the trend data for outdoor temperature buckets to calculate efficient case consumption and applied an 80% AFUE baseline efficiency. In addition, Guidehouse assumed that space heating occurs below 60°F outdoor air as the trend data obtained from the site shows that for site 10, space heating takes place once the outdoor temperature drops below 60°F. Guidehouse also calibrated savings value with the billing data to calculate the savings for the site.

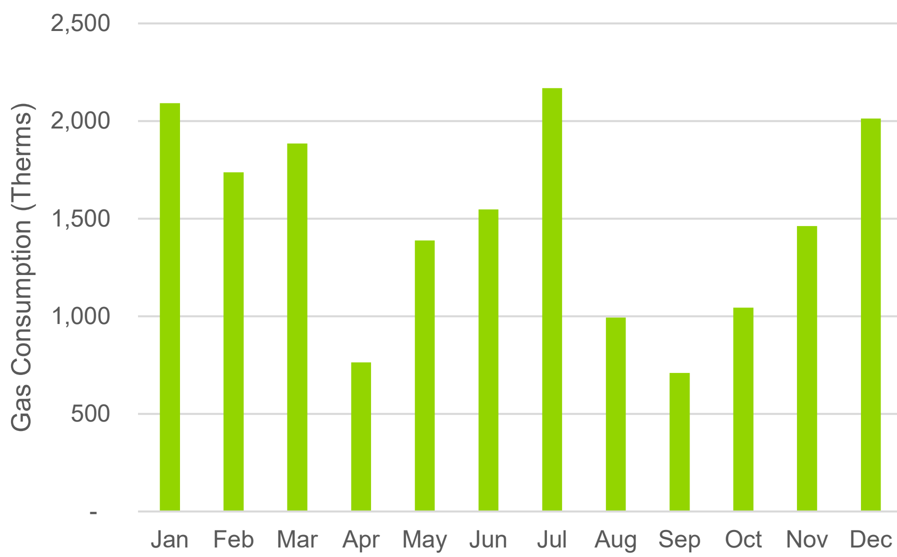
Overall, Guidehouse evaluated space heating savings for this unit of 108.9 therms per year. Overall COP for the GHP installed at the site was 1.05 as per the Guidehouse analysis.

A.3 Site X

Site X is a fitness center, which has an occupancy of about 15-20 personnel on an average day. The site had two 199,900 BTU, 91-gallon circulating tank water heaters that provide the hot water needs at the fitness center. As part of the pilot, GTI installed one GHP of 78,000 BTU output rating to provide pre-heating to the domestic water loop. The GHP replaced one of the two existing water heaters and provides hot water to the pre-heat tank, which is then further heated in the existing water heater to provide hot water to the facility.

Guidehouse analyzed the billing data for the site from June 2021 to December 2023. Figure 8 shows the average gas usage per month for the site in the baseline.

Figure 9. Site X – Baseline Gas Consumption – Billing Data



Source: Guidehouse analysis

Guidehouse observed that gas consumption at the site is dependent on more factors than just the outside weather, as there is significant gas consumption during the summer period. Also, gas consumption at the meter level is significantly higher than the calculated baseline consumption for the GHP hot water loop. This finding indicates that there are other loads on the same gas meter in addition to the hot water system. Guidehouse confirmed with GTI that there is a boiler which is also on the same utility meter. Thus, billing consumption cannot be used to calibrate the baseline consumption for the GHP water loop. As such, Guidehouse proceeded with the calculated baseline consumption for energy savings calculations at this site as a counterfactual baseline consumption based on water heating load for the site and the code baseline efficiency of 0.8 Thermal Efficiency (TE).

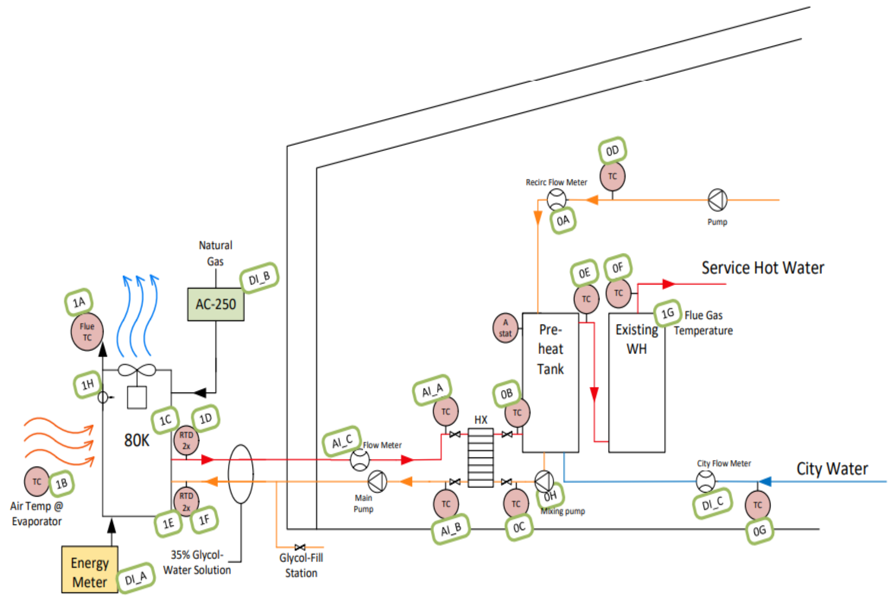
Under the pilot, the implementer, GTI, installed an 80,000 BTU GHP at the site (make: Anesi, model number: 0801HXANXX). GTI also installed an indirect pre-heat tank in place of one of the old water heating units.

Figure 10. Installed GHP and Pre-Heat Tank at Site X

Source: GTI

Figure 10 shows the site schematic drawing for the new hot water system at the site after the GHP installation.

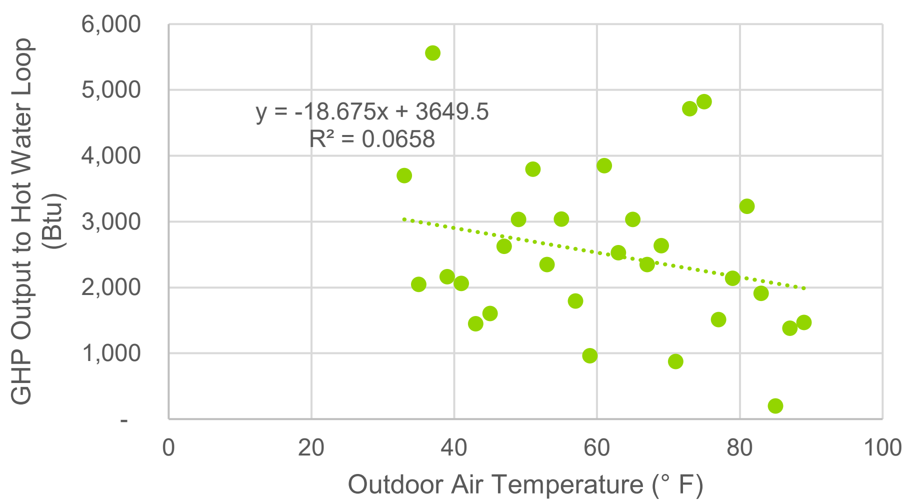
Figure 11. Site Schematic for Site X GHP Installation



Source: GTI

Guidehouse analyzed the heating load from the hot water loop for the site against outdoor air temperatures using 2°F temperature bins. Figure 11 shows the GHP output to hot water loop versus outdoor air temperature for site X.

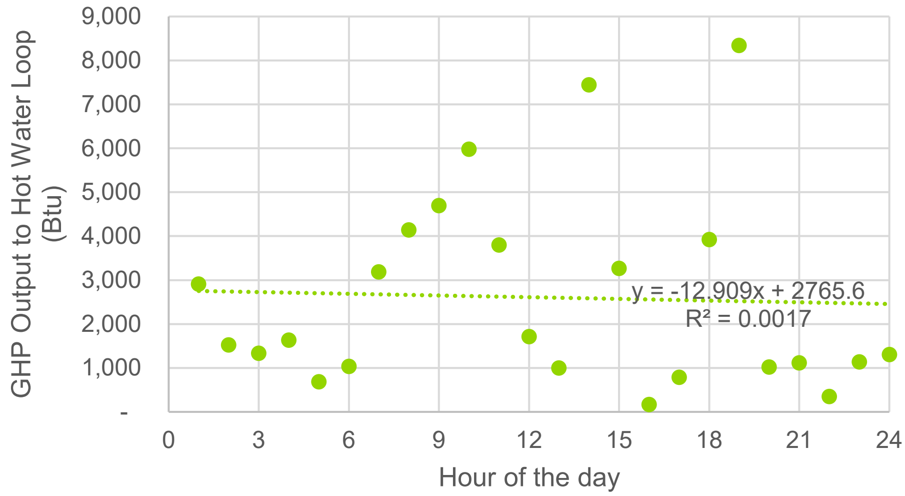
Figure 12. Site X – GHP Output to Hot Water Loop vs Outdoor Air Temperature



Source: Guidehouse analysis

Guidehouse observed that GHP output to the hot water loop is not directly correlated with the outdoor air temperature. Guidehouse also analyzed the average hourly profile for the hot water loop at the site. Figure 12 shows the GHP output versus hour of the day for site X. It is evident from the figure that the GHP output is also not directly correlated with the hour of the day.

Figure 13. Site X – GHP Gas Output vs. Hour of the Day



Source: Guidehouse analysis

As there is no correlation between GHP output and the outdoor air temperature or hour of the day, Guidehouse did not use a regression analysis.[4] Therefore, Guidehouse calculated average hourly load and gas consumption by GHP and used annual hours of use (8,760 hours/year) to determine the efficient case gas consumption.

For baseline gas consumption, Guidehouse followed the same process of using hot water load on the system and baseline TE = 0.8 as per the energy code.

After analyzing the consumption data, Guidehouse determined that the calculated average COP value for the GHP installed at the site is 0.73, based on the Guidehouse analysis of trend data provided by GTI. This COP value was calculated as a ratio of total heat output provided by GHP to the hot water loop to the actual gas consumption of the GHP. This COP value is below the code baseline of 0.8. Thus, there are no gas savings associated with only GHP water heating loop at the site.

However, late in the evaluation, GTI provided one-minute interval trend data for the inefficient baseline water heater and the efficient GHP water heater at the site. The additional information showed that the hot water setpoint for the GHP loop was kept as same as Water Heater 2 at

[4] Regression analysis is suitable when the R^2 value between the variables is 0.9 or above.

130° F. This resulted in lower operational hours for Water Heater 2 as compared to the baseline where both the water heaters were running in tandem. Guidehouse calculated the reduction in the operating hours for the water heater 2 using the flue gas temperature data for water heater 2 from the trend data provided by the site. The trend data analysis confirmed reduced operating hours for the water heater 2 resulting in overall gas savings of 45.9 therms for the site X.

Appendix B. Detailed Evaluation Approach

B.1 Step 1: Review of Utility Bills and Onsite Data

The Guidehouse team reviewed the baseline as well as efficient case billing data to assess the usage pattern of the sites through the year. Guidehouse reviewed more than 12 months of billing data for the three sites to determine the usage pattern.

B.1.1 Other Baseline Considerations

For the purposes of this pilot, Guidehouse used baseline assumptions from the Maryland TRM v11, where applicable to calculate the lifetime savings for this pilot. Table 4 summarizes the key baseline assumptions for this pilot.

Table 4. Baseline Assumptions

Equipment	RUL Baseline	Post-RUL Baseline	RUL* Period	Effective Useful Life**
Residential Furnaces	Calculated in-situ baseline (see below)	AFUE = 80%	Actual – estimated through customer interviews	21 years
Residential Water Heaters	Calculated in-situ baseline (see below)	Calculated based on type (storage/tankless) draw pattern and tank size from Maryland TRM v11	Actual – estimated through customer interviews	13 years
Commercial Water Heaters	Calculated in-situ baseline (see below)	TE = 80%***	Actual – estimated through customer interviews	10-13 years**

*RUL = Remaining Useful Life
**All effective useful lives are sourced from the Maryland TRM v11.
Source: Guidehouse Research

GTI was not able to complete a combustion analyzer test to calculate in-situ efficiency of the baseline equipment at the sites. Thus, Guidehouse adjusted the nameplate efficiency of the in-situ equipment using a degradation factor to account for mechanical wear and tear during the time spent in operation. The adjusted efficiency was calculated as per the following equation:

$$\eta_{Adj} = \eta_{Base} * (1 - M)^{age}$$

Where,

η_{Adj} = Adjusted efficiency of the furnace or gas water heater

η_{Base} = Nameplate efficiency of the furnace or gas water heater

M = Maintenance factor for furnace= 0.015[5]

= Maintenance factor for water heater= 0.010[6]

Age = Age of in-situ equipment

For the post-RUL period, Guidehouse determined the baseline consumption for space heating and DHW using a combination of calculated hourly loads, described in Step 2 and the post-RUL efficiency from Table 4. Table 5 below shows the final baseline assumptions used for the sites for evaluation.

Table 5. Final Baseline Assumptions for Sites

Site	Space Heating Baseline	Water Heater Baseline	RUL Period	Notes
5	Code (80% AFUE)	Code (80%)	0	Both furnace and water heater were beyond useful life.
10	Code (80% AFUE)	NA	0	Furnace was 9 years old. Adjusted efficiency is about 80.6%. Thus, Guidehouse decided to use only code efficiency for the savings calculations.
X	N/A	TE = 80%	0	Age of the water heater not known. However, the units are older, hence Guidehouse assumed code baseline.

Source: Guidehouse analysis

B.2 Step 2: Develop Regression Model

The purpose of this step was to establish a relationship between the hourly loads that were calculated using the onsite data and outside air temperature. This relationship was then used to weather normalize energy savings via a bin analysis using TMY3 data.

In preparation for the bin analysis, Guidehouse calculated the space heating load profiles with respect to outdoor conditions and the hot water consumption statistics including daily draw

[5] The Maintenance factor for gas furnace, natural draft combustion, and standing pilot light in conditioned space from Robert Hendron, National Renewable Energy Laboratory, Building America Performance Analysis Procedures for Existing Homes, May 2006, https://core.ac.uk/download/pdf/71315144.pdf.

[6] The Maintenance factor for gas water heater, 40-gallon tank, pilot light, natural draft combustion, 1-in. insulation, no heat traps, and standard flue baffling from Robert Hendron, National Renewable Energy Laboratory, Building America Performance Analysis Procedures for Existing Homes, May 2006, https://core.ac.uk/download/pdf/71315144.pdf.

volumes and heat provided to the water heating loops of the system where applicable. An overview of the equation used is provided below; all variables relating to flow and temperature measurements were provided by GTI from the trend data captures at the sites.

B.2.1 GHP Hydronic Loop Loads

The Guidehouse team used the following equation to calculate the total load (DHW and space heating) on the GHP for every 1-hour interval:

$$Q_{Hydronic} = \dot{V}_{Flow} C_P \rho (T_{Supply} - T_{Return})$$

Where,

$Q_{Hydronic}$	= BTUh delivered by the GHP loop
V_{flow}	= Flow rate in GPM for the GHP loop
$C_p\rho$	= Specific heat of water adjusted for 35% propylene-glycol concentration
T_{Supply}	= Temperature of supply water for the GHP loop
T_{Return}	= Temperature of return water for the GHP loop

The Guidehouse team correlated the total load with the outside air temperature for the monitoring period by developing a linear regression model.

B.2.2 DHW Load and Draw Pattern

Guidehouse verified the draw patterns/rates for the DHW loop by performing a time series analysis and considering the flow rates and supply and return temperatures for the indirect storage tank and GHP hydronic loop. The following equation was used to determine the energy input into the storage tank from the GHP loop:

$$Q_{ID} = V_{DHW} C_P \rho (T_{SupplyID} - T_{ReturnID})$$

Where,

Q_{ID}	= BTUh delivered by the indirect tank
V_{DHW}	= Flow rate in GPM for the DHW loop
$C_p\rho$	= Specific heat of water adjusted for propylene-glycol concentration
$T_{SupplyID}$	= Temperature of supply water for the indirect tank
$T_{ReturnID}$	= Temperature of the return water from the indirect tank

B.2.3 GHP Space Heating Loop

Guidehouse used the following equation to calculate space heating loads using the difference between the total GHP hydronic loop load and DHW load:

$$Q_{SH} = Q_{Hydronic} - Q_{ID}$$

Where,

Q_{SH}	= BTUh delivered by the GHP loop for space heating
$Q_{Hydronic}$	= BTUh delivered by the GHP loop
Q_{ID}	= BTUh delivered by the indirect tank

B.3 Step 3: Incorporate Customer Interviews

Guidehouse also attempted to confirm the installation and other data points with the customers involved in the pilot as a part of the verification. However, Guidehouse was not able to reach out to the customers directly. Guidehouse received responses to the verification questions through a post-installation survey completed by GTI. Guidehouse incorporated the answers to the questions from the survey in the analysis.

B.4 Step 4: Conduct Bin Analysis

Using site data from GTI, Guidehouse developed the load for the hydronic space heating and DHW loops, as described in Step 2: Develop Regression Model. Guidehouse calculated space heating therms savings for each site using the following steps:

1. First, Guidehouse weather normalized the hourly space heating and DHW loads for the pilot sites by using TMY3 data for the local weather station and the coefficients from the linear regression equation that were created in **Error! Reference source not found.**.

2. Guidehouse used the calculated natural gas consumption for the GHP system to develop a performance curve and establish the relationship between natural gas consumption and space heating loads.

3. The energy consumption for the GHP and the baseline system was calculated by applying the efficiency curves for each system to the hourly load versus outside air temperature regression across the temperature bins for the local weather station. For the GHP system, the Guidehouse team used the performance curve developed in **Error! Reference source not found.** of the bin analysis section. Whereas for the baseline systems, Guidehouse used baseline efficiencies as outlined in Table 5.

4. Guidehouse compared the energy consumption for the GHP and baseline equipment for the outdoor air temperatures where the sites would call for space heating and determined the weather normalized therms savings for each site.

5. For the GHP system that served both space heating and the DHW loop (site 5), Guidehouse separately calculated average DHW load for the site from the trend data.

6. For site X, GHP provided only the water heating, so Guidehouse followed the same process as outlined in Step 5 to calculate the hot water load and actual natural gas consumption of the GHP to develop efficient case natural gas consumption.

7. For the baseline natural gas consumption, Guidehouse used the hourly DHW load from the trend data calculation and baseline efficiencies as outlined in Table 5.

B.5 Step 5: Report Results

With the findings from the bin analysis, Guidehouse calculated first-year and lifetime verified gross savings. From verified lifetime gross energy savings, Guidehouse calculated lifetime GHG emissions reductions using the Avoided Emissions Calculator per MDE Policy taking into consideration the changing emissions from the electric grid over time.

B.6 Data Needs

Guidehouse will request the following data from GTI:

1. In-situ equipment specifications that include:
    a. The age of the in-situ equipment
    b. The design load of each home
    c. Mechanical drawings for all sites
2. List of all other sources of natural gas consumption such as stoves, fireplace, ovens etc., for all sites.
3. A continuous set of data measurements which will be used to calculate the space heating and DHW loop load for the site (see Table 3). These measurements are to be collected for the GHP equipment.

Table 3: List of Continuous Measurement Data Points to be supplied by GTI

Measurement Category	Measured Quantity	Measurement Point(s) and Variable(s)	Units
Natural Gas Flow	Natural Gas Flow	GHP $V_{NG,GHP}$	ft^3

Power Consumption	Power Consumption	Hydronic AHU Q_{Elec_AHU}, Conventional AHU Q_{Elec_AHU}, GHP Q_{Elec_GHP}, Circulation pumps (individually and in aggregate) Q_{Elec_pumps}	Wh
DHW	Water Flow	DHW [VDHW]	gal.
Domestic Hot Water	Temperature	Hot Water Outlet T_{DHW}, Cold Water Inlet T_{CW}	°F
Ambient/ Indoor Air	Temperature	Indoor Mechanical Room T_{Air_Mech}, Outdoor GHP T_{Air_GHP}	°F
Hydronic Loops	Temperature	AHU Loop Supply T_{Supply_AHU}, AHU Loop Return T_{Return_AHU}, DHW Tank Supply $T_{Supply\_Ind\_Tank}$, DHW Tank Return $T_{Return\_Ind\_Tank}$, GHP Supply T_{Supply_GHP}, GHP Return T_{Return_GHP}	°F
Hydronic Loops	Flow Rate	GHP Hydronic Loop $\dot{V}_{GHP}$, AHU Loop $\dot{V}_{AHU}$, Indirect Tank Loop $\dot{V}_{Indirect\ Tank}$	GPM
GHP external	Temperature	GHP Flue Gas Outlet $T_{FG\ GHP}$	°F
Outside Air Temp	Temperature	Outside Air Dry Bulb Temperature	°F

4. A continuous set of measurements that will be used to determine the baseline DHW and space heating loads and energy usage. These measurements are to be collected for the in-situ equipment.

Table 4: List of Measurement Points to be collected by GTI for In-Situ Equipment

Measurement point	Sensor	Logging Device
Storage Water Heater Flue Gas	K-type Thermocouple Probe	HOBO UX100-014M
Furnace Gas Valve	Setra Current Switch	HOBO UX90-001M
Thermostat Ambient Temp	HOBO Temp/RH sensor	HOBO UX100-003
2nd Furnace Air (2) and A/C lines (2)	T-type beaded Thermocouple	HOBO UX120-014M

5. On-site pictures to verify in-situ equipment size, efficiency, and configuration.

APPENDIX C – METHODOLOGY & RESULTS OF COMPARATIVE ANALYSIS OF GAS VERSUS ELECTRIC HEAT PUMPS

Appendix begins on next page.

MEMORANDUM

Date: July 05, 2024

To: Erika Moore, Teagan Gorman, John Richards, Joshua McClelland (Washington Gas)

From: Jason LaFleur, Ram Dharmarajan, Haley Keegan (GTI Energy)

Re: EHP vs GHP Methodology for Washington Gas Maryland Gas Heat Pump Pilot

OBJECTIVE

The following is in regard to the Gas Heat Pump (GHP) Pilot program that was conducted by Washington Gas and implemented by GTI Energy. The Public Service Commission of Maryland stipulated the following asks on the analysis conducted in the GHP Pilot Program –

**Under section 12 of Order number 90663[1]-*

c. The analysis performed on the Pilot Program shall:

i. Utilize Maryland-specific assumptions;

ii. Be over the lifespan of the asset;

iii. Include a comparative analysis between GHPs and EHPs; and

iv. Assume changing emissions from the electric grid over time and assess both current Maryland state policy and zero emissions grid by 2045 for electric emissions, providing both marginal and average emissions results.

This memorandum outlines the methodology that GTI Energy proposes to satisfy 12.c.iii, i.e. complete the comparative analysis between GHPs and Electric Heat Pumps (EHPs).

[1] https://www.psc.state.md.us/wp-content/uploads/Order-No.-90663-2022-Q3Q4-Semi-Annual-Report.pdf

SCOPE AND METHODOLOGY

The comparative GHP vs. EHP analysis covers residential retrofit space heating, cooling, and water heating applications. This analysis does not include commercial applications.

The analysis addresses residential single-family home installations of GHPs, in retrofit settings for both the actual home where the GHP equipment was installed, and homes representative of the Maryland residential building stock. End-use application for GHPs will cover combination space heating and domestic water heating (combi) functionality. Combi GHPs use a heat pump unit (typically installed outdoors) paired with an indoor air handler and an indirect storage tank. Wherever applicable, ENERGY STAR[2] requirements were sought while selecting equipment for any performance rating compliance purposes. GTI Energy used energy modeling tools for the comparative analysis task. For all simulations, climate data using NOAA 15-year normals from 2006 to 2020 for Washington DC were used. This is in accordance with the existing methodology in version 11 of the Maryland TRM.

The analysis followed the process outlined below:

1. Model five equipment scenarios in two DOE reference homes for Maryland and one field pilot study home. The five equipment scenarios are as follows –
    a. GHP Combi Equipment with Central Air Conditioner (CAC)
    b. Federal Minimum Standard Electric Equipment
    c. High Efficiency Electric Equipment
    d. Federal Minimum Standard Gas and CAC equipment
    e. High Efficiency Gas Equipment with CAC

    Please refer to Table 2 for specific equipment efficiencies that were modeled for each scenario.
2. Compile usage data outputs for each scenario in each home.
3. Calculate energy consumption, annual and lifetime energy savings, annual and lifetime operating costs, seasonal performance, annual and lifetime marginal and average CO_2e emissions for each scenario in each home.

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[2]https://www.energystar.gov/sites/default/files/asset/document/National%20Program%20Requirements%20Version%203.1_Rev%2012.pdf

Assumptions and supporting details are described throughout the rest of this memorandum.

MODELING APPROACH

GTI Energy used energy modeling tools developed by the U.S. Department of Energy (DOE) and National Renewable Energy Laboratory (NREL), namely Building Energy Optimization Tool (BEOpt)[3] and EnergyPlus[4] to complete the comparative analysis task. GTI Energy used modeling tools from DOE to analyze electricity consumption and gas consumption for each scenario in two reference homes and a field site home. BEOpt was used to generate the residential energy models with envelope characteristics compliant with applicable International Energy Conservation Code (IECC) baselines for existing homes[5].

Using reference home models provided by DOE via the Pacific Northwest National Laboratory (PNNL)[6], two types of single-family detached home archetypes were modeled (which are 2,420 and 3,300 sq.ft.). Per NREL's Building Stock Analysis[7] on US Residential Building Typology Segmentation, 51% of the single-family detached housing stock in Maryland built after 1980 falls between 2,000 and 4,000 sq.ft in area. NREL's End-Use Load Profiles for the U.S. Building Stock[8] study calibrated and validated the outputs from models of the U.S. residential and commercial building stocks using utility meter data from more than 2.3 million customers and other real-world datasets. The study further binned the floor area for single-family detached homes into different tiers for accurate representation in EnergyPlus. The reference homes cited in this study equal the average floor area in their respective single-family house (detached) bins. Reference home 1 is the representative home in the 2,000 to 2,999 sq.ft floor area bin and Reference home 2 is the representative home in the 3,000 to 3,999 sq.ft. floor area bin. Collectively, these reference homes are intended to represent the predominant existing single-family detached housing stock in Maryland that will serve as the optimum target application for GHPs.

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[3] https://www.nrel.gov/buildings/beopt.html
[4] https://energyplus.net/
[5] https://www.energycodes.gov/status/states/maryland and https://www.energycodes.gov/infographics
IECC 2006 has been selected as the 'baseline' for modeling existing homes
[6] https://www.energycodes.gov/prototype-building-models#Residential
[7] https://public.tableau.com/app/profile/nrel.buildingstock/viz/USBuildingTypologyResidential/Segments
[8] https://www.nrel.gov/docs/fy22osti/80889.pdf

The analysis used these reference homes as the DOE representative building prototypes were specifically developed to analyze the effectiveness of potential energy efficiency improvements in the residential sector[9]. They have detailed building design characteristics including geometry, configuration, HVAC systems, climate, fuel type and energy technologies. Additionally, these models represent fairly realistic buildings and typical construction practices. The reference building models are recommended to be used to assess new technologies; optimize designs; analyze advanced controls; develop energy codes and standards; and to conduct lighting, daylighting, ventilation, and indoor air quality studies[10]. For broad studies of the U.S. residential sector, prototypical designs representing "typical" homes are instrumental to provide the basis for this detailed analysis.

As part of the GHP Pilot program conducted by Washington Gas, GTI Energy implemented two GHP projects in residential settings, with one combi installation and one space heating only. Guidehouse evaluated first-year energy savings, lifetime energy savings, and lifetime gross greenhouse gas (GHG) emission reductions from each GHP project that is installed. For this GHP vs EHP comparison, GTI Energy modeled one of the field site homes where the GHP is being demonstrated in a combi functionality.

Table 1 summarizes the homes that GTI Energy will model -

Table 1. Reference Homes Characteristics

	Reference Home 1	**Reference Home 2**	**Field Site Home**
Name	Model 1	Model 2	(Combi Install Home)
Area (sq.ft.)	2,420	3,300	1,980
Building Energy Code	IECC 2006	IECC 2006	N/A - 1963
Wood Stud	R-13 Fiberglass Batt, 2x4, 16" o.c.	R-13 Fiberglass Batt, 2x4, 16" o.c.	2x4, 16" o.c.
Wall Sheathing	OSB	OSB	Plywood
Exterior Finish	Vinyl, Light	Vinyl, Light	Brick

[9] https://www.osti.gov/biblio/1194327
[10] https://www.osti.gov/biblio/1009264

Interzonal Walls	R-13 Fiberglass Batt, 2x4, 16” o.c.	R-13 Fiberglass Batt, 2x4, 16” o.c.	2x4, 16” o.c.
Ceiling	R-38 Cellulose, Vented	R-38 Cellulose, Vented	R11 batt, Vented
Roof Material	Asphalt Shingles, Medium	Asphalt Shingles, Medium	Asphalt Shingles, Medium
Slab	Under Slab 2ft R10 XPS	Under Slab 2ft R10 XPS	Uninsulated
Interzonal Floor	R-19 Fiberglass Batt	R-19 Fiberglass Batt	Uninsulated
Carpet	20%	20%	20%
Floor Mass	Wood Surface	Wood Surface	Wood surface
Exterior Wall Mass	½ in. Drywall	½ in. Drywall	½ in. Drywall
Partition Wall Mass	½ in. Drywall	½ in. Drywall	½ in. Drywall
Ceiling Mass	½ in. Drywall	½ in. Drywall	½ in. Drywall
Window Material	Low-E, Double, Non-Metal, Arg, M-Gain	Low-E, Double, Non-Metal, Arg, M-Gain	Wood Single Pane with alum storm
Interior Shading	Summer=0.7, Winter=0.7	Summer=0.7, Winter=0.7	Summer=0.7, Winter=0.7
Door Area	20 sqft	20 sqft	40 sqft
Door Material	Fiberglass	Fiberglass	Wood
Eaves	2 ft	2 ft	12”
Air Leakage	3 ACH50	3 ACH50	9 ACH50
Mechanical Ventilation	Exhaust	Exhaust	None
Cooling Setpoint	From MD TRM	From MD TRM	75°F
Heating Setpoint	From MD TRM	From MD TRM	71°F

MODELED SCENARIOS

GTI Energy modeled usage in each of the homes in Table 1 with a combination of space heating, cooling, and water heating equipment to generate usage data necessary to make comparisons between the performance of different types of equipment. To demonstrate the performance of GHP vs. EHP vs traditional gas space conditioning equipment in various configurations, Washington Gas proposed to model multiple scenarios covering baseline and high efficiency gas and electric equipment (Table 2).

Table 2. Proposed Equipment Scenarios

Scenario	Space Heating and Cooling Equipment	Water Heating Equipment	Source
Scenario 1: GHP Combi Equipment with CAC	1.4 COP at rated conditions[11] and 14.3 SEER2 Central AC[12]	1.4 COP at rated conditions	https://stonemountaintechnologies.com/products/gas-heat-pump/
Scenario 2: Federal Minimum Standard Electric Equipment	7.5 HSPF2 EHP (14.3 SEER2)	0.92 UEF electric storage water heater	a) https://www.ecfr.gov/current/title-10/part-430#p-430.32(c)(5) b) Assuming compliance for a 40-gal tank as reference. Federal minimum standard
Scenario 3: High efficiency Electric Equipment	8.9 HSPF2 cold climate EHP (19.3 SEER2) 70% capacity ratio at 5°F/47°F	3.6 UEF Electric HPWH	a) Based on Maryland EmPOWER program data. Average rebated Tier 2 ASHP efficiency rating b) Average efficiency rating for ENERGY STAR compliant 240-volt HPWH models, adjusted with a 2.6% degradation factor
Scenario 4: Federal Minimum Standard	80% AFUE Furnace and 14.3 SEER2 Central AC	0.58 UEF gas storage water heater[13]	a) https://www.ecfr.gov/current/title-10/part-430#p-430.32(e)(1)(ii)

[11] Performance at standard ANSI rating conditions of 47°F ambient air, 95°F return water temperatures
[12] ENERGY STAR Program Requirements. Product Specification for Central Air Conditioner and Heat Pump Equipment.https://www.energystar.gov/sites/default/files/ENERGY%20STAR%20Version%206.1%20CACHP%20Final%20Specification%20and%20Partner%20Commitments%20%28Rev.%20January%20%202022%29_0.pdf . Accessed April 2024.
[13] Assuming compliance for a 40-gal tank as reference

Gas and CAC equipment			b) Assuming compliance for a 40-gal tank, medium draw as reference. Federal minimum standard
Scenario 5: High Efficiency Gas Equipment with CAC	96% AFUE Furnace and 17.1 SEER2 Central AC	0.89 UEF tankless water heater	a) Based on Maryland EmPOWER program data. Average rebated combustion furnace efficiency rating b) Energy Star criteria for certified gas fired instantaneous water heaters. https://www.energystar.gov/products/water_heaters/residential_water_heaters_key_product_criteria

Scenario 1: GHP Combi Equipment with CAC

The GHP scenario modeled usage of homes installing a Gas Absorption Heat Pump (GAHP) system, as that is the most applicable GHP technology to the residential market. One site in the pilot had a GHP installed in a combi scenario, which was modeled as Field Site Home in Table 1.

GTI Energy has developed a standardized peer-reviewed methodology to incorporate GAHP systems into EnergyPlus[14]. The GTI Energy developed GAHP module functionalities were added into DOE's EnergyPlus from version 23.1.0[15]. Metered data from the residential GHP field pilot sites was used to calibrate and validate the energy models. The model will use a control strategy similar to the real GHP system, following a temperature setback curve for heating and operating in DHW priority. The dynamic heating capacity of the GHP was determined from the rated heating capacity and a function of outdoor dry bulb temperature and hydronic return temperature. A publicly available peer reviewed technical paper[16] provides further details on GHP combi modeling, and also highlights results from a similar modeling comparison done previously across the US. Space cooling was provided by a central AC with an efficiency of 14.3 SEEER2.

[14] https://docs.lib.purdue.edu/cgi/viewcontent.cgi?article=1353&context=ihpbc
[15] https://github.com/NREL/EnergyPlus/releases/tag/v23.1.0
[16] https://docs.lib.purdue.edu/cgi/viewcontent.cgi?article=1353&context=ihpbc

Scenario 2: Federal Minimum Standard Electric Equipment

The baseline electric scenario represented homes that install the minimum efficiency electric space and water heating equipment per federal minimum compliant standard EHP (7.5 HSPF2/14.3 SEER2)[17] and an electric resistance tank water heater (0.92 UEF)[18].

For the EHP performance, GTI Energy incorporated EmPOWER provided performance data into these energy models, enabling a comparison based on real-world performance in Maryland across the equipment types. Per footnote 30 listed in Order[19], "There have been multiple EHPs installed in the State of Maryland through the EmPOWER program. WGL shall coordinate with the other EmPOWER utilities to gather the data necessary to perform the comparative analysis." Alternatively, the hourly performance data for EHPs in BEOpt or EnergyPlus or peer-reviewed publications will be used for comparison.

Scenario 3: High efficiency electric equipment

This scenario represents all-electric homes installing high performance electric space and water heating equipment. A higher efficiency-tier EHP scenario with cold climate EHP (8.9 HSPF2/19.3 SEER2)[20] and an electric heat pump water heater (UEF 3.6)[21].

The cold climate EHP will be modeled with modulation capabilities and was sized based on 100% of the maximum heating load, to better reflect how a "cold-climate" heat pump would be sized.

Scenario 4: Federal Minimum Standard Gas and CAC equipment

GTI Energy also compared the GHP vs a standard gas baseline. The federal minimum standard gas equipment scenario represented homes that install the minimum efficiency gas space and water heating equipment per appropriate federal equipment standards[22]. A standard gas baseline with federal minimum compliant non-condensing gas furnace[23]

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[17] https://www.ecfr.gov/current/title-10/chapter-II/subchapter-D/part-430/subpart-C

[18] Assuming compliance for a 40-gal tank as reference. ENERGY STAR Single-Family New Homes National Program Requirements, Version 3.1 (Rev. 12)

[19] https://www.psc.state.md.us/wp-content/uploads/Order-No.-90663-2022-Q3Q4-Semi-Annual-Report.pdf

[20] Based on Maryland EmPOWER program data. Average rebated Tier 2 ASHP efficiency rating

[21] Average efficiency rating for ENERGY STAR compliant 240-volt HPWH models, adjusted with a 2.6% degradation factor

[22] https://www.ecfr.gov/current/title-10/chapter-II/subchapter-D/part-430#430.32

[23] AFUE 80% baseline per federal standards is for retrofit install scenario in an existing home.

(AFUE 80%) and a gas storage water heater (UEF 0.58)[24]. The non-condensing furnace used a part-load efficiency curve[25] to account for cycling efficiency losses. The part-load ratio (PLR) is defined below.

$$Efficiency\_gas = Efficiency\_(steady\ state)*(0.8 + 0.2*PLR)$$

where,

$$PLR = load/capacity$$

$$Efficiency\_(steady\ state) = 0.80$$

Space cooling was provided by a central AC with an efficiency of 14.3 SEEER2.

Scenario 5: High Efficiency Gas Equipment with CAC

Finally, to demonstrate whether GHPs provide incremental improvements over more common high efficiency gas-fired options, the high efficiency gas equipment scenario represented the most commonly installed high efficiency equipment currently rebated through the Washington Gas EmPOWER residential prescriptive program: a condensing gas furnace (AFUE 96%)[26] and a condensing gas tankless water heater (UEF 0.89)[27]. The condensing furnace also used a part-load efficiency curve[28] to account for cycling efficiency losses. The part-load ratio (PLR) is defined below.

$$Efficiency\_gas = Efficiency\_(steady\ state)*(0.9 + 0.1*PLR)$$

where,

$$PLR = load/capacity$$

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[24] MD TRM v11 baseline assuming 40 gallon tank and medium draw

[25] Default EnergyPlus performance curves for non-condensing furnaces. Henderson, Hugh, Huang, Y J, and Parker, D. Residential equipment part load curves for use in DOE-2. United States: N. p., 1999. Web. doi:10.2172/6519.

[26] Based on Maryland EmPOWER program data. Average rebated combustion furnace efficiency rating.

[27] Energy Star criteria for certified gas fired instantaneous water heaters. Water Heater Key Product Criteria | ENERGY STAR

[28] Fridlyand, Aleksandr; Baez Guada, Alejandro; Kumar, Navin; Ahsan, Abbas; Kingston, Tim; and Glanville, Paul, "Load-based Testing of Heating and Cooling Equipment Informed by Detailed Energy Models" (2022). International Refrigeration and Air Conditioning Conference. Paper 2390. https://docs.lib.purdue.edu/iracc/2390

Efficiency_(steady state) = 0.96

Space cooling was provided by a central AC with an efficiency of 17.1 SEEER2.

MODELING OUTPUTS

For all scenarios, both GHP and EHP systems were simulated against the same building energy loads. The analysis covered a total of 15 unique scenarios across 3 home types and 5 space heating and water heating scenarios. The following key data points and metrics were obtained from the annual hourly building energy modeling outputs:

- **Space heating delivered (Btu)**: This metric defines the hourly space heating loads of the modeled home captured from the modeling outputs.
  For the GAHP system, these values along with the GAHP performance curves obtained by GTI Energy from the laboratory and field were used to compute parameters like Coefficient of Performance (COP) and Part-Load Ratio (PLR). The hourly data was used to estimate peak (Btu/hr) and annual space heating (Btu) delivered by the GAHP.
  Additional metrics that were also be calculated are listed below –
  - Btu heat provided (annual heat load)
  - Energy consumption of fan (kWh)
  - Energy consumption (therms) (if applicable)
  - Energy consumption of the heat pump (kWh) (if applicable)
  - Energy consumption of aux heat (kWh) (if applicable)

- **Space cooling delivered (kWh)**: This metric defines the hourly space cooling loads of the modeled home captured from the modeling outputs.
  Additional metrics that were also be calculated are listed below –
  - Energy consumption of the Central AC (kWh) (if applicable)
  - Energy consumption of the heat pump (kWh) (if applicable)
  - Energy consumption of aux heat (kWh) (if applicable)

- **Domestic water heating delivered (Btu):** This metric defines the hourly domestic water heating loads of the modeled home captured from the modeling outputs.
  For the GAHP system, these values along with the GAHP performance curves obtained by GTI Energy from the laboratory and field were used to compute the GAHP parameters inputs like COP and PLR. The hourly data was used to estimate peak (Btu/hr) and annual domestic water heating (Btu) delivered by the GAHP.

- **Site electricity usage (kWh):** Energy usage from the space heating and water heating load

- **Site gas usage (Btu):** Energy usage from the space heating and water heating load

- **Operating costs ($):** The annual electricity and gas usages were multiplied with the gas and electricity prices respectively to determine the operating costs. Latest residential EIA pricing[29] was used for the analysis which is a representative average for multiple utilities in the territory for the residential segment. The annual electric cost used for 2023 was $0.1659/kWh and $1.67/therm for natural gas. Since the prices reflect each state's aggregate of multiple local distribution companies and marketers, a comparison of the aggregate prices may not represent the realized price savings that an individual customer might have obtained. Localized tariff rates, distinct contract/pricing options, and contract timing may affect the price differential between marketers and licensed distribution companies. For example, in 2023, the cost to Washington Gas' Residential Sales & Delivery customers was $1.45 per therm.

  Annual Operating Cost ($) = ((Total Space Heating/DHW Heating Used in kWh)*Price of Electricity) + ((Total Space Heating/DHW Heating Used in Therms)*Price of Natural Gas)

  Lifetime energy costs were calculated using residential electricity and natural gas price projections for MD from 2023 through 2050 based on the Reference Case from EIA's 2023 Annual Energy Outlook[30]. The lifetime average electric energy cost used was $0.1836/kWh and $1.07/therm for natural gas.

- **Installed costs ($):** The equipment and labor costs for each scenario will determine the installed costs.[31]

- **Site Energy Savings (Btu):** The total electricity and natural gas usage by each modeling scenario (HVAC type) were estimated using the formula below

[29] https://www.eia.gov/dnav/ng/ng_pri_sum_a_EPG0_PRS_DMcf_a.htm and https://www.eia.gov/electricity/monthly/epm_table_grapher.php?t=table_5_06_b
[30] https://www.eia.gov/outlooks/aeo/data/browser/
[31] https://www.eia.gov/analysis/studies/buildings/equipcosts/pdf/appendix-a.pdf

Site Energy Savings (Btu) = (Total GHP Site Energy – Baseline Site Energy)

Annual energy savings are assumed to remain constant over the Effective Useful Life (EUL) of each scenario. The Annual Energy Savings were converted to Lifetime Energy Savings by multiplying with the respective EULs. For this analysis, a 15-year EUL term was utilized across all appliances, regardless of actual EUL (stipulated per MD TRM) for ease of comparison. Per the MD TRM, the actual EUL's for each appliance scenario can vary, for example, EUL for the Air Source Heat Pumps is 15 years, EUL for the Gas Heat Pump is 15 years but the EUL for gas furnaces is 21 years.

- **Source Energy Consumption (Source Btu/year):** The total electricity and natural gas usage by each modeling scenario (HVAC type) were converted to source energy using the formula below. Source energy takes into account all the energy used to generate power or to supply fuel for heating or cooling. This includes the full fuel cycle, i.e. all energy required to extract fuel (natural gas, oil, coal, renewables), conversion (e.g. power generation), and distribution (pipelines, power transmission lines). Source energy use and full-fuel-cycle emissions for electricity vary by region depending on the power generation fuel mix. GTI Energy has developed a public tool[32] using EPA eGRID annual grid mix releases[33] to calculate source energy factors for each eGRID subregion. This methodology is approved and incorporated into ANSI/ASHRAE Standard 105-2021[34].

  Source Energy Consumption = (Total Electric Energy consumed at site (Btu))*Site to Source conversion factor + (Total Natural Gas consumed at site (Btu))*Site to Source conversion factor[35]

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[32] https://cmicseeatcalc.gti.energy
[33] https://www.epa.gov/egrid
[34] Standard Methods of Determining, Expressing, and Comparing Building Energy Performance and Greenhouse Gas Emissions. ANSI/ASHRAE Standard 105-2021. American Society of Heating, Refrigeration and Air-Conditioning Engineers, 2021
[35] https://cmicseeatcalc.gti.energy
The Electric site to source conversion factor for Maryland is 2.96 using eGRID 2021 data (latest)
The Natural Gas site to source conversion factor for Maryland is 1.09

Table 3 Site to Source Conversion Factors for MD (eGRID 2021)

	Site to Source Energy Factor for Maryland (EPA eGRID 2021 (latest)) (Btu/Btu)
Electricity	2.96
Natural Gas	1.09

As means of a sensitivity analysis, the source energy consumption computed using the latest EPA eGRID site to source factors were compared with the current year heat rate in the MDE policy case.

- **Average and Marginal Emissions (CO_2e lbs):** The total electricity and natural gas usage by each modeling scenario (HVAC and DHW type) was converted to average and marginal CO_2e emissions. GTI Energy used electric grid projection data and associated emission factors for electricity and natural gas provided by MDE per section 12.c.iv and footnote 31 of the Order. Specifically, MDE developed Avoided Emissions Calculator workbook that was used to calculate the outputs from GHG emissions. The workbook is based on analysis conducted for the GHG emissions reduction plan, the 2030 GGRA Plan[36]. The cited workbook provides the projected annual average emissions intensities until 2050 associated with the electricity generation projected in the MD policy plan. A 4.5% Transmission and Distribution Loss Factor was assumed to calculate the MWh at generation as required by the workbook. The MDE workbook does not provide marginal emissions intensity projections. Therefore, for the purpose of this analysis, a marginal CO2 emission factor of 1,008.5 lb/MWh was used based on the marginal on-peak and off-peak values for PJM region per the table in the README tab of the MDE workbook.

  While the analysis for this metric primarily uses the MDE forecasts as required by Order 90663, Washington Gas withholds judgement on validity of forecasts, especially given that, for current emissions, the MDE forecast seem to be off in the base year. It is stated to be in the order of 600 lbs/MWh per the MDE forecast workbook whereas the observed datasets sourced from eGrid and Wattime are in the order of 800 lb/MWh and above range. For these reasons, GTI Energy also did a sensitivity analysis by comparing the MDE workbook derived results with other sources of emission factors such as:

[36] https://mde.maryland.gov/GGRA

- Marginal and Average Emission factors for Maryland from EPA eGRID 2021 to compute Annual CO_2e emissions.[37] Per the review with the Evaluation Advisory Group, a sensitivity analysis comparison between EPA's eGRID emission factors and MDE developed Avoided Emissions Calculator was encouraged.
- Marginal Emission Factors from WattTime for PJM DC from 2023 to compute Annual CO_2e emissions.[38] WattTime generated Marginal Operating Emissions Rate (MOER) represents the emissions rate of the electricity generator(s) that are responding to changes in load on the local grid at a certain time. The MOER includes the effects of renewable curtailment and import/export between grid regions.
- Levelized Marginal Emission Factors from NREL's Cambium 2023 Workbook for PJM East to compute Lifetime CO_2e emissions.[39] Cambium data sets, which are generated by NREL contain modeled hourly emission, cost, and operational data for a range of possible futures of the U.S. electricity sector through 2050, with metrics designed to be useful for forward-looking analysis and decision support. They are widely used in all ASHRAE standards which project forward looking GHG emissions of the electric grid.

Overall, this comparison study quantified the differences in annual and lifetime site and source energy consumption, operating costs, annual energy savings, average and marginal CO_2e emissions by comparing the GHP system to EHPs and other baseline HVAC scenarios.

COMPARISON ANALYSIS

GTI Energy compared the outputs from Scenario 1 (GHP Combi) to Scenarios 2, 3, 4 and 5 as laid out in Table 4 below.

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[37] https://www.epa.gov/egrid and https://cmicseeatcalc.gti.energy
Using a marginal emissions rate of 2,042.9 lbs/MWh and an average emissions rate of 865.4 lbs/MWh.
[38] https://watttime.org/data-science/data-signals/marginal-co2/ using a Marginal Grid Emissions Rate of 1,243.89 lbs/MWh for PJM DC in 2023.
[39] Gagnon, Pieter. 2024. "Long-run Marginal Emission Rates for Electricity - Workbooks for 2023 Cambium Data." NREL Data Catalog. Golden, CO: National Renewable Energy Laboratory. Last updated: February 16, 2024. DOI: 10.7799/2305481. https://data.nrel.gov/submissions/230
Using a Levelized LRMER emissions rate of 759.71 lbs/MWh for 15 years with a discount rate of 3%

Table 4. Proposed Analysis Outputs

Modeled Home	Output	Scenario				
		1	2	3	4	5
Model 1	Annual Site Electric Energy Consumption (MMBtu)	6.96	26.11	16.16	6.19	4.40
	Annual Site Gas Energy Consumption (MMBtu)	31.76	-	-	51.26	42.25
	Total Annual Site Energy Consumption (MMBtu)	38.72	26.11	16.16	57.45	46.66
	Annual Source Electric Energy Consumption (MMBtu)	20.59	77.28	47.84	18.32	13.03
	Annual Source Gas Energy Consumption (MMBtu)	34.62	-	-	55.87	46.06
	Total Annual Source Energy Consumption (MMBtu)	55.21	77.28	47.84	74.20	59.09
	Annual Electric Operating Costs ($)	$338	$1,269	$786	$301	$214
	Annual Gas Operating Costs ($)	$530	-	-	$856	$706
	Total Annual Operating Costs ($)	$869	$1,269	$786	$1,157	$920
	Lifetime Electric Operating Costs ($)	$5,615	$21,072	$13,044	$4,996	$3,554
	Lifetime Gas Operating Costs ($)	$5,097	-	-	$8,227	$6,782
	Lifetime Total Operating Costs ($)	$10,712	$21,072	$13,044	$13,223	$10,335
	Installed Costs ($)	$27,178	$9,530	$12,952	$9,792	$11,437
	Annual Site Electric Energy Savings (MMBtu)	(0.77)	(19.92)	(9.97)	-	1.79

	Annual Site Gas Energy Savings (MMBtu)	19.50	51.26	51.26	-	9.01
	Annual Source Electric Energy Savings (MMBtu)	(2.27)	(58.96)	(29.51)	-	5.29
	Annual Source Gas Energy Savings (MMBtu)	21.26	55.87	55.87	-	9.82
	Annual Average CO_2e Electric Emissions (lbs) – MD Policy 2023	1,197	4,965	3,074	1,065	758
	Annual CO_2e Gas Emissions (lbs) – MD Policy 2023	4,411	-	-	7,120	5,869
	Total Annual Average CO_2e Emissions (lbs) – MD Policy 2023	5,609	4,965	3,074	8,185	6,627
	Annual Marginal CO_2e Electric Emissions (lbs) – MD Policy 2022	2,149	8,064	4,992	1,912	1,360
	Total Annual Marginal CO_2e Emissions (lbs) – MD Policy 2022	6,560	8,064	4,992	9,032	7,229
	Annual Marginal CO_2e Electric Emissions (lbs) – eGRID 2021	4,165	15,631	9,676	3,706	2,636
	Annual CO_2e Gas Emissions (lbs) – eGRID 2021	4,627	-	-	7,468	6,156
	Total Annual Marginal CO_2e Emissions (lbs) – eGRID 2021	8,792	15,631	9,676	11,173	8,792
	Annual Average CO_2e Electric Emissions (lbs) – eGRID 2021	1,764	6,622	4,099	1,570	1,117
	Total Annual Average CO_2e Emissions (lbs) – eGRID 2021	6,391	6,622	4,099	9,037	7,272

	Annual Marginal CO_2e Electric Emissions (lbs) – WattTime 2023	2,536	9,517	5,892	2,257	1,605
	Total Annual Marginal CO_2e Emissions (lbs) – WattTime 2023	7,163	9,517	5,892	9,724	7,761
	Lifetime Average CO_2e Electric Emissions (lbs) – MD Policy	11,239	53,171	32,914	10,000	7,113
	Lifetime CO_2e Gas Emissions (lbs) – MD Policy	64,739	-	-	104,493	86,134
	Total Lifetime Average CO_2e Emissions (lbs) – MD Policy	75,978	53,171	32,914	114,493	93,247
	NREL Cambium - Lifetime Marginal Electric CO_2e emissions (lbs)	23,234	87,192	53,974	20,673	14,705
	eGRID - Lifetime Gas CO_2e emissions (lbs)	69,398	-	-	112,013	92,333
	NREL Cambium - Total Lifetime Marginal CO_2e emissions (lbs)	92,632	87,192	53,974	132,685	107,038
Model 2	Annual Site Electric Energy Consumption (MMBtu)	7.71	28.44	18.36	6.56	4.62
	Annual Site Gas Energy Consumption (MMBtu)	36.72	-	-	59.33	48.92
	Total Annual Site Energy Consumption (MMBtu)	44.43	28.44	18.36	65.89	53.54
	Annual Source Electric Energy Consumption (MMBtu)	22.83	84.18	54.34	19.43	13.67

	Annual Source Gas Energy Consumption (MMBtu)	40.03	-	-	64.67	53.32
	Total Annual Source Energy Consumption (MMBtu)	62.86	84.18	54.34	84.09	66.99
	Annual Electric Operating Costs ($)	$375	$1,383	$893	$319	$225
	Annual Gas Operating Costs ($)	$613	-	-	$991	$817
	Total Annual Operating Costs ($)	$988	$1,383	$893	$1,310	$1,042
	Lifetime Electric Operating Costs ($)	$6,225	$22,954	$14,816	$5,297	$3,729
	Lifetime Gas Operating Costs ($)	$5,894	-	-	$9,522	$7,851
	Lifetime Total Operating Costs ($)	$12,119	$22,954	$15,276	$14,819	$11,580
	Installed Costs ($)	$28,371	$11,277	$13,871	$11,409	$13,020
	Annual Site Electric Energy Savings (MMBtu)	(1.15)	(21.88)	(11.79)	-	1.94
	Annual Site Gas Energy Savings (MMBtu)	22.60	59.33	59.33	-	10.41
	Annual Source Electric Energy Savings (MMBtu)	(3.40)	(64.76)	(34.91)	-	5.75
	Annual Source Gas Energy Savings (MMBtu)	24.64	64.67	64.67	-	11.35
	Annual Average CO_2e Electric Emissions (lbs) – MD Policy 2023	1,327	5,409	3,491	1,130	795
	Annual CO_2e Gas Emissions (lbs) – MD Policy 2023	5,101	-	-	8,240	6,795
	Total Annual Average CO_2e Emissions (lbs) – MD Policy 2023	6,428	5,409	3,491	9,370	7,590

	Annual Marginal CO_2e Electric Emissions (lbs) – MD Policy 2022	2,382	8,784	5,670	2,027	1,427
	Total Annual Marginal CO_2e Emissions (lbs) – MD Policy 2022	7,483	8,784	5,670	10,267	8,221
	Annual Marginal CO_2e Electric Emissions (lbs) – eGRID 2021	4,618	17,027	10,990	3,929	2,766
	Annual CO_2e Gas Emissions (lbs) – eGRID 2021	5,350	-	-	8,643	7,126
	Total Annual Marginal CO_2e Emissions (lbs) – eGRID 2021	9,967	17,027	10,990	12,572	9,892
	Annual Average CO_2e Electric Emissions (lbs) – eGRID 2021	1,956	7,213	4,656	1,665	1,172
	Total Annual Average CO_2e Emissions (lbs) – eGRID 2021	7,306	7,213	4,656	10,307	8,298
	Annual Marginal CO_2e Electric Emissions (lbs) – WattTime 2023	2,812	10,368	6,692	2,393	1,684
	Total Annual Marginal CO_2e Emissions (lbs) – WattTime 2023	8,161	10,368	6,692	11,035	8,810
	Lifetime Average CO_2e Electric Emissions (lbs) – MD Policy	12,460	57,922	37,386	10,603	7,464
	Lifetime CO_2e Gas Emissions (lbs) – MD Policy	74,856	-	-	120,936	99,717
	Total Lifetime Average CO_2e Emissions (lbs) – MD Policy	87,316	57,922	37,386	131,539	107,180

	NREL Cambium - Lifetime Marginal Electric CO_2e emissions (lbs)	25,758	94,982	61,307	21,919	15,429
	eGRID - Lifetime Gas CO_2e emissions (lbs)	80,243	-	-	129,639	106,893
	NREL Cambium - Total Lifetime Marginal CO_2e emissions (lbs)	106,001	94,982	61,307	151,558	122,322
Field Site Home	Annual Site Electric Energy Consumption (MMBtu)	8.98	29.86	20.84	8.64	5.99
	Annual Site Gas Energy Consumption (MMBtu)	38.02	-	-	68.74	51.80
	Total Annual Site Energy Consumption (MMBtu)	47.00	29.86	20.84	77.38	57.79
	Annual Source Electric Energy Consumption (MMBtu)	26.57	88.38	61.69	25.58	17.73
	Annual Source Gas Energy Consumption (MMBtu)	41.44	-	-	74.93	56.46
	Total Annual Source Energy Consumption (MMBtu)	68.02	88.38	61.69	100.51	74.19
	Annual Electric Operating Costs ($)	$436	$1,452	$1,013	$420	$291
	Annual Gas Operating Costs ($)	$635	-	-	$1,148	$865
	Total Annual Operating Costs ($)	$1,071	$1,452	$1,013	$1,568	$1,156
	Lifetime Electric Operating Costs ($)	$7,246	$24,098	$16,822	$6,975	$4,834
	Lifetime Gas Operating Costs ($)	$6,102	-	-	$11,033	$8,313
	Lifetime Total Operating Costs ($)	$13,348	$24,098	$16,822	$18,008	$13,148

	Installed Costs ($)	$24,263	$6,120	$8,414	$7,172	$9,604
	Annual Site Electric Energy Savings (MMBtu)	(0.34)	(21.21)	(12.20)	-	2.65
	Annual Site Gas Energy Savings (MMBtu)	30.72	68.74	68.74	-	16.94
	Annual Source Electric Energy Savings (MMBtu)	(0.99)	(62.79)	(36.11)	-	7.85
	Annual Source Gas Energy Savings (MMBtu)	33.48	74.93	74.93	-	18.47
	Annual Average CO_2e Electric Emissions (lbs) – MD Policy 2023	1,545	5,678	3,964	1,487	1,031
	Annual CO_2e Gas Emissions (lbs) – MD Policy 2023	5,281	-	-	9,548	7,195
	Total Annual Average CO_2e Emissions (lbs) – MD Policy 2023	6,826	5,678	3,964	11,036	8,226
	Annual Marginal CO_2e Electric Emissions (lbs) – MD Policy 2022	2,773	9,222	6,437	2,669	1,850
	Total Annual Marginal CO_2e Emissions (lbs) – MD Policy 2022	8,054	9,222	6,437	12,217	9,045
	Annual Marginal CO_2e Electric Emissions (lbs) – eGRID 2021	5,375	17,876	12,478	5,174	3,586
	Annual CO_2e Gas Emissions (lbs) – eGRID 2021	5,539	-	-	10,014	7,546
	Total Annual Marginal CO_2e Emissions (lbs) – eGRID 2021	10,914	17,876	12,478	15,188	11,132

	Annual Average CO_2e Electric Emissions (lbs) – eGRID 2021	2,277	7,572	5,286	2,192	1,519
	Total Annual Average CO_2e Emissions (lbs) – eGRID 2021	7,816	7,572	5,286	12,206	9,065
	Annual Marginal CO_2e Electric Emissions (lbs) – WattTime 2023	3,273	10,884	7,598	3,150	2,183
	Total Annual Marginal CO_2e Emissions (lbs) – WattTime 2023	8,812	10,884	7,598	13,165	9,729
	Lifetime Average CO_2e Electric Emissions (lbs) – MD Policy	14,503	60,807	42,447	13,961	9,676
	Lifetime CO_2e Gas Emissions (lbs) – MD Policy	77,506	-	-	140,128	105,588
	Total Lifetime Average CO_2e Emissions (lbs) – MD Policy	92,009	60,807	42,447	154,089	115,264
	NREL Cambium - Lifetime Marginal Electric CO_2e emissions (lbs)	29,983	99,713	69,606	28,862	20,003
	eGRID - Lifetime Gas CO_2e emissions (lbs)	83,083	-	-	150,212	113,187
	NREL Cambium - Total Lifetime Marginal CO_2e emissions (lbs)	113,066	99,713	69,606	179,074	133,190

Exhibit KT-R5
Page 1 of 2

PJM Inside Lines

Emission Rates in PJM Reach All-Time Low

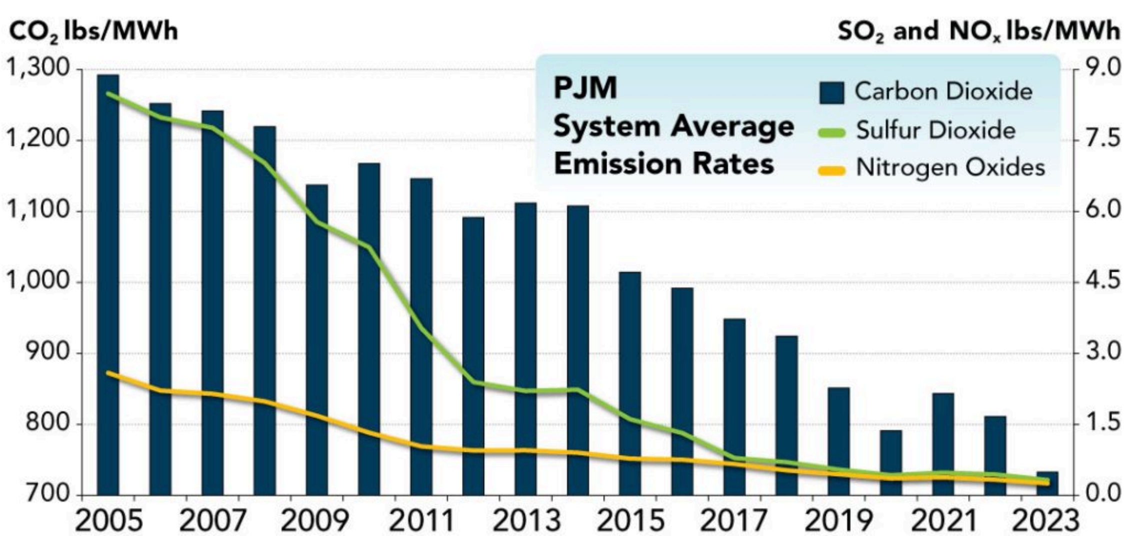
March 28, 2024

The average emission rates for carbon dioxide, nitrogen oxides and sulfur dioxide from generators operating in the PJM footprint dropped to a record low in 2023, having steadily declined for nearly two decades, according to annual data compiled by PJM.

From 2005 to 2023, carbon dioxide emission rates fell 43% across PJM's footprint. Emission rates for nitrogen oxides declined 90%, and the rates for sulfur dioxide dropped 96%.

This decline has occurred as competitive wholesale electricity markets continue to encourage the entry of new technologies, and lower-emitting, more efficient resources replace older, less efficient units.

The PJM system average annual value is a weighted average that accounts for higher loads during the summer and winter months. Emissions are measured in pounds per megawatt-hour (lbs/MWh).



PJM Offers Tracking Tools

PJM's Emissions page and PJM Now app include a visualization of overall average hourly emissions information for the region PJM serves.

PJM also publishes 5-minute marginal emission rates, hourly marginal emission rates and hourly total emissions on Data Miner.

PJM stakeholders have identified potential uses for marginal emission rates to determine the times each day when electricity use can have the least impact on the environment by drawing on lower-emitting resources.

In addition, PJM Environmental Information Services Inc. in March 2023 began providing hourly, time-stamped certificates for PJM generation, answering the growing demand for procuring and tracking carbon-free energy around the clock.

Advocates of the approach maintain that hourly certificates can help electricity consumers, including large government and business customers, tailor their energy consumption to the availability of carbon-free energy at all hours of the day. Such demand expressed through the market could also incent new carbon-free generation resources to serve the hours of the day when renewable energy production is currently lacking.

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	*	

* * * * * * * * * * * * *

PUBLIC DIRECT TESTIMONY

OF

Kenji Takahashi

ON BEHALF OF THE OFFICE OF PEOPLE'S COUNSEL

June 20, 2023

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APPENDIX A: Kenji Takahashi Resume

DIRECT TESTIMONY OF
KENJI TAKAHASHI

I. INTRODUCTION

Q. Please state your name and business address.

A. My name is Kenji Takahashi. 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; 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 Urban Affairs and Public Policy with a concentration in Energy and Environmental Policy from the Biden School of Public Policy and Administration at the University of Delaware. I also recently completed the Massachusetts Institute of Technology's professional program "Sustainable Infrastructure Systems: Planning and Operations." My resume is attached as 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. Over the past 19 years, I have assessed the design, impact, and potential of energy efficiency and distributed energy resources policies and programs in over 40 jurisdictions across North America for a variety of clients. These include environmental groups; municipal, state, and provincial governments; and federal agencies such as U.S. Environmental Protection Agency and U.S. Department of Energy.

Another area of my focus has been technological, resource, economic, and policy assessments of building decarbonization and its impact on gas system planning. I have assessed the potential for building decarbonization in several states including Massachusetts, Rhode Island, Vermont, New York, Maryland, Oregon, and California, as well as in several U.S. regions, including the northeast and the southwest. For example, I led a Synapse team to analyze net zero emissions scenarios for the building sector for Oregon. This project estimated the potential impacts on electric system investments due to electrification, as well as energy bill impacts for residential customers. In 2022, I conducted a heat pump analysis as a part of a project to assess the financial impact of gas system investments in Maryland due to declining sales. Finally, I am currently conducting an electrification impact study on behalf of Maryland OPC, in which we are analyzing the impacts of building and transportation electrification on electric peak loads across six major electric companies in Maryland.

Q. Have you previously testified in regulatory proceedings that concern the relationship between building electrification and the operations of natural gas companies?

A. In 2017, I assessed the potential for natural gas demand savings and electrification measures in connection with Berkshire Gas Company's moratorium on new gas hook-ups, and I testified before the Massachusetts Department of Public Utilities on the matter. More recently, I examined the gas energy efficiency program proposal by New Mexico Gas on behalf of New Mexico's Office of the Attorney General and recommended the discontinuation of rebates for gas equipment efficiency measures and the implementation of building electrification programs.

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

A. Yes. I have also testified and participated in regulatory proceedings before the New York Public Service Commission, Pennsylvania Public Utility Commission, New Jersey Board of Public Utilities, Ontario Energy Board, and Nova Scotia Utility and Review Board.

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 programs presented by Witness Mark D. Case on behalf of the Company. BGE describes these two programs, along with an electrification workforce development proposal, as its customer electrification plan.

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, and responses to discovery requests, public documents, 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.

II. SUMMARY AND RECOMMENDATIONS

Q. Please summarize your primary conclusions concerning BGE's proposed building and non-road electrification programs.

A. My primary conclusions are as follows:

- BGE's electrification program proposal raises various policy and program implementation questions, and any decision by the Commission to approve or modify the proposal would have to address those questions. However, the current Multi-Year Plan ("MYP") base rate case process is not designed for and cannot accommodate adequate discussion and informed resolution of such policy and program questions.

- BGE's electrification program proposal is untimely and premature because the Maryland Building Codes Administration, Maryland Department of Environment ("MDE"), and the Commission, through the EmPOWER Maryland program, are currently investigating and addressing various policy and program questions concerning the promotion of electrification in the building and other sectors.

- BGE's proposal to require program participants to retain their gas furnace as a backup heating system when installing air-source heat pumps (ASHP) (a) is contrary to the state's overarching policy direction as established through the *Climate Solutions Now Act of 2022* ("CSNA") and the major findings in a 2021 report by the Maryland Commission on Climate Change ("MCCC"), (b) ignores the current state and continuing advancement of cold climate heat pump technology, and (c) is not supported or justified by reliable, rigorous studies.

- A study conducted by Energy and Environmental Economics, Inc., or E3 ("E3 study") which BGE commissioned and references to support its electrification program proposal, does not justify BGE's proposal to require the retention of existing heating systems as backup for ASHPs. The E3 study's Limited Gas scenario assumes more extensive building electrification than the other scenarios but is overly biased toward maintaining the existing gas systems in that it assumes no or very little amounts of gas system retirements through 2045. The E3 study also assumes overly high costs for the electric transmission and distribution system and ASHPs. Correcting these errors would likely make the Limited Gas scenario a lower-cost scenario than the other scenarios and would undercut the E3 study's support for BGE's proposal to require the retention of existing heating systems as backup for ASHPs.

- Another study commissioned by BGE and used to support its electrification proposal, an analysis by 1898 & Co. of potential electrification impacts on the electric system, does not support the conclusions that Witness Case draws from it. The analysis contains multiple errors, and a corrected analysis would not show that peak load would "more than triple," and, accordingly, would indicate substantially less need for new electric infrastructure and infrastructure investment.

- Program designs, incentives, and budgets for some of the proposed electrification programs would need to be modified, if the Commission should approve the electrification program. In particular:

    - Per-customer incentive amounts BGE assumed for ASHPs, geothermal heat pumps (GSHP), heat pump water heaters (HPWH), and electrification make-ready measures (e.g., electrical panel upgrades) are too high because they do not take into account available federal tax credits.

- BGE developed per-customer incentive estimates based on cost estimates BGE obtained from California and New York, and from feedback from trade allies in the Baltimore area. However, BGE does not have any Maryland-specific heat pump costs, let alone Baltimore-specific heat pump costs, and as a result it is possible that BGE has overestimated the total cost of ASHPs. If it has, per-customer incentive for ASHPs could be reduced further.
- The proposed program budget for program administration is too high.
- BGE's downstream incentive approach for its building electrification program proposal is inconsistent with EmPOWER's new approach to use midstream incentives for HVAC and HPWH, and also with ongoing efforts to streamline EmPOWER's HVAC and HPWH offerings.
- BGE has not provided sufficient evidence to support and justify its proposed non-road electrification programs.

Q. Please summarize your recommendations.

A. My recommendations on BGE's proposed building and non-road electrification programs include the following:

- The Commission should reject BGE's proposed electrification programs. If BGE then wishes to pursue its electrification programs, the Commission should direct BGE to propose its building and non-road electrification programs within the EmPOWER program.

- The Commission should investigate key policy and program implementation issues concerning electrification in the EmPOWER docket or another policy docket. Among other things, the Commission should investigate program designs, the role of the utilities and other entities, performance incentives, cost-effectiveness analysis framework, goal setting, cost recovery, customer equity and bill impacts, federal incentives, and gas planning.

Q. If the Commission were to approve BGE's electrification programs, do you have recommendations for program modifications?

A. Yes. In such a case, I recommend that the Commission direct BGE to modify some aspects of the proposed programs as follows:

- Remove the requirement to retain gas backup in the Company's building electrification programs;

- Increase the number of participants for residential ASHP, GSHP, HPWH, and make-ready investments (e.g., panel upgrades) using the additional funding that would be freed up by reducing measure incentive levels;

- Conduct a state-specific survey on the costs of building electrification measures—either individually or jointly with other utilities—in order to set appropriate amounts for electrification incentives;
- Offer electrification incentives through a midstream incentive approach instead of a conventional downstream incentive approach;
- Remove the non-road electrification program proposal entirely (approximately $6.6 million); and
- Conduct a market characterization study on commercial and industrial (C&I) non-road measures.

Further, I recommend that the Commission establish guidance on incentive-setting for electrification measures and require BGE to use the guidance to set incentives and develop the total budget for customer incentives. Ideally, such guidance should be developed through a stakeholder process, but I offer the following minimum recommendations: for low-income and moderate-income customers, the total customer incentives that comprise federal rebates, federal tax credits, and utility incentives should not exceed 100 percent of the total installed costs of measures. For the rest of the customers, the total incentives should not exceed 100 percent of the total incremental costs of electrification measures (e.g., the cost difference between an electric heat pump and a gas furnace).

III. OVERVIEW OF BGE'S CUSTOMER ELECTRIFICATION PROGRAMS

Q. Please summarize BGE's proposed customer-side electrification programs.

A. BGE proposes and seeks cost recovery for three new customer-side beneficial electrification programs: a building electrification program ("BE program"), a C&I non-road electrification program ("Non-Road program"), and a workforce development program.[1] BGE estimates the total required funding for these three programs over the current MYP to be $271,517,443.[2] The annual budgets for each program are summarized in Table 1 below. The BE program is the largest component of the programs, with a combined three-year cycle budget of $261,803,512. For context, BGE's EmPOWER Energy Efficiency and Conservation program budget was $120 million in 2022.[3] BGE proposes to defer these expenditures to a regulatory asset to be recovered in base rates over a 12.5-year amortization period.[4]

[1] Direct Testimony of Mark Case at 51.
[2] Company Exhibit MDC-5 11-12 and 20.
[3] BGE Annual EmPOWER MD Report YTD Q4 2022 https://synapseenergyeconomics.box.com/s/012n4j04filccmw4ebh2sci7p8ru71mg.
[4] Direct Testimony of Mark Case at 63.

Table 1: Summary of BGE Proposed Customer Electrification Program Budgets, Excluding Amortization Costs

Total Program Costs	2024	2025	2026	Cycle Total
BE Program: Residential Segment	$26,621,343	$83,786,084	$140,952,865	$251,360,293
BE Program: Commercial Segment	$1,839,299	$3,378,339	$5,225,582	$10,443,219
Non-Road Program	$1,740,006	$2,242,769	$2,637,147	$6,619,921
Workforce Development Program	$1,250,000	$922,500	$922,500	$3,095,000
Total All Programs	$31,450,648	$90,329,692	$149,738,094	$271,518,433

Source: Exhibit MDC-5.

For the proposed BE program, BGE plans to provide a variety of cash and non-cash incentives for both commercial and residential customers. The BE program has three areas:

- **Residential Space Heating and Water Heating**, which includes significant rebates for ASHPs, GSHPs, and HPWHs.
- **Residential Products,** which includes rebates for replacing existing fossil fuel equipment with electric appliances, including cooktops and clothes dryers.[5]
- **Commercial Buildings,** which includes electrification incentives for rooftop ASHP, commercial HPWH, and commercial cooking equipment.[6]

[5] Case Direct Testimony at 53.
[6] Id. at 54.

The BE Program includes fuel-switching rebates ranging from $500 to $7,500 for residential measures and $1,500 to $25,000 for commercial measures.[7] BGE proposes to include a requirement that customers with gas furnaces retain them as a backup heating system in order to be eligible for BGE's heat pump rebates. BGE claims requiring gas furnace backup systems "will prevent higher winter electric peak events than all electric ASHP systems."[8]

For the Non-Road program, BGE plans to provide financial incentives for various electrification measures, targeting several C&I market segments. These include construction equipment, airport group support equipment, port and intermodal equipment, forklifts, and industrial process equipment. The proposed equipment incentives range from as low as $100 per product for golf carts to $80,000 per product for pressing, cutting, and folding machinery.

IV. STUDIES THAT BGE COMMISSIONED TO SUPPORT ITS ELECTRIFICATION PROGRAMS

Q. What studies did BGE commission to support its electrification programs?

A. BGE commissioned two studies that it relies on to support its electrification program proposal: one study by Energy and Environmental Economics

[7] Id. at 52.
[8] Id. at 53.

("E3") and another study by 1898 & Company, a division of Burns & McDonnell Engineering Company, Inc.

Q. Please summarize the study conducted by E3.

A. BGE engaged E3 to analyze decarbonization pathways to achieve Maryland's greenhouse gas ("GHG") emissions reduction targets and identify potential implications for BGE's customers and service territory ("E3 Pathways Study"). The E3 Pathways Study evaluated three potential pathways to achieving the state's decarbonization goals: a "Limited Gas" scenario and two "Integrated Energy System" ("IES") scenarios. (BGE calls one IES scenario a "Hybrid" scenario, the other a "Diverse" scenario). The Limited Gas scenario includes high electrification and a shift away from natural gas used in buildings, while the IES scenarios rely on a combination of electric and gas infrastructure to meet energy demand. The Hybrid scenario includes a significant role for alternative fuels and gas-electric hybrid heating, where 28 percent of homes retain gas heating systems as backup to electric heat pumps.[9] The Diverse scenario includes lower-level electrification as well as gas-powered heat pumps, networked geothermal systems, and a role for alternative fuels. All scenarios include "at least a 60

[9] 2022 E3 Pathways Study at 17, 21.

percent reduction in annual natural gas throughput on BGE's system" by 2045.[10]

The E3 Pathways Study concluded that the two IES scenarios (Hybrid and Diverse) would "achieve Maryland's goals at a significantly lower cost and with less risk for customers and the State's economy" than the Limited Gas scenario by leveraging both existing electric infrastructure and existing natural gas infrastructure.[11]

Q. Please summarize the 1898 & Co study.

A. On page 47 of his direct testimony, BGE Witness Case states that "[p]reliminary analysis conducted in parallel with the E3 work indicates that, under the Limited Gas pathway, demand on the BGE electric system could more than triple with the necessary electrification, requiring significant build out of substations and feeders to provide the required electric grid capacity. This infrastructure would require an enormous financial investment, threatening affordability for customers, and poses an extremely difficult if not impossible siting and permitting challenge in central Maryland's heavily developed regions." As revealed in OPCDR01-01, this "preliminary analysis" that informed BGE's rejection of pathways comparable to the Limited Gas pathway was conducted by 1898 & Co. BGE

[10] Case Direct Testimony at 46.
[11] Id. at 47.

relies upon the 1898 & Co. report to justify its choice to support only hybrid electrification as an approach to decarbonization, rather than full electrification.

V. BGE'S ELECTRIFICATION PROGRAM PROPOSAL DOES NOT BELONG IN THE CURRENT MYP

Q. What is your concern about BGE's proposal to include electrification programs in the MYP?

A. While I agree that building electrification is one of the most important strategies to reduce GHG emissions from buildings in Maryland and recognize that state policies such as the CSNA position electrification as such (see details of the state GHG policies in Section IV of my testimony below), BGE's electrification program proposal should not have been proposed and should not be approved in the MYP for three reasons:

- The electrification programs that BGE proposes are novel and present various policy and program implementation questions, including questions concerning the way existing EmPOWER programs are implemented and evaluated. Base rate cases, including MYP cases, are not an appropriate or adequate setting for the discussion and resolution of such policy questions.

- The state of Maryland, through various administrative agencies including the Commission itself through EmPOWER, is currently working to address program implementation issues to promote building electrification as a key strategy toward the state's climate mandates under the CSNA. Thus, BGE's proposal is untimely and premature.

- The likely outcome of these initiatives by the state agencies is a decarbonization strategy that, consistent with earlier State efforts, features high levels of electrification and very limited usage of gas. BGE's proposal to condition financial incentives for heat pumps on customers' retention of existing gas back-up heating systems is at odds with this strategy. Thus, I am concerned that it would conflict with the implementation of the CSNA.

A. BGE's electrification programs present various policy and program implementation questions. The MYP is not the place to address such questions.

Q. What policy and program questions need to be addressed as part of designing and implementing electrification programs.

A. There are numerous questions concerning electrification programs that need to be vetted by stakeholders and ultimately decided by the Commission. Such questions include, but are not limited to the following:

- **Program designs**: Should backup heating be required? Should whole-home heat pumps be encouraged?

- **The role of the utilities and other entities:** Is the public utility the appropriate provider of broad-based electrification programs? Or are there more suitable non-utility entities that are implementing or could implement electrification programs?

  Funding sources: Is it appropriate to fund electrification programs through electric utility rates, gas utility rates, or both? If so, at what level of funding?

- **Performance incentives:** Should a utility or a third-party administrator receive performance incentives in connection with electrification programs, and if so, how should performance incentives be estimated?

- **Cost-effectiveness analysis framework:** Should any modifications be made to the Maryland Jurisdiction-Specific Test developed in the Commission's EmPOWER docket before it is applied to electrification programs? Are the current avoided costs of capacity, transmission, and distribution appropriate for electrification? What avoided natural gas infrastructure costs are appropriate? What grid emissions rates need to be used?

- **Goal setting**: To the extent that electrification is pursued in EmPOWER, how should the current electricity and gas savings goals be modified? Should fuel-neutral goals (e.g., energy usage in MMBtu or emissions savings) be established?

- **Cost recovery mechanism**: Should the costs of electrification programs be expensed and recovered from ratepayers on a current basis every year in accordance with the direction the Commission recently established for the recovery of EmPOWER program costs?

- **Customer incentive-setting**: How should a program administrator incorporate federal incentives and develop utility customer incentives for electrification measures?

- **Customer equity and bill impacts**: How would building electrification affect customer energy bills? Would the impact differ by customer class or certain customer segments (e.g., low-income customers, disadvantaged communities)? How can we address and mitigate any potential customer equity issues that could arise from building electrification?

- **Gas planning**: How should a gas utility incorporate the impacts of building electrification in its long-term planning?

These are complex questions that cannot be adequately addressed within a base rate case (whether an MYP or a conventional base rate case) due to such cases' constrained statutory timeframes and the resulting lack of opportunities for Commission hearings, working group meetings, and public comments. They need to be addressed in a policy docket that does afford such opportunities and that is statewide in scope, given the statewide need for electrification. Developing electrification policy on a piecemeal, rate-case-by-rate-case basis would require rushed and underinformed decision-making and could create chaos among consumers, contractors, and the market in general.

Q. Is there any example of a regulatory proceeding that discussed policy issues in Maryland before implementing a novel program?

A. Yes. A case in point is Maryland's statewide EV program.

Q. Please explain how the statewide EV program was established.

A. In September 2016, the Commission initiated a public conference (PC44), to begin a "targeted review to ensure that electric distribution systems in Maryland are customer-centered, affordable, reliable and environmentally sustainable."[12] The Commission held public hearings and received numerous comments from over 46 groups on topics including electric vehicles ("EV"), rate design, energy storage, interconnection rules, among others. Through

[12] Maillog # 199669, Notice of Public Conference, at 1 (Sept. 26, 2016) ("PC44 Initiation Notice")

PC44 the Commission established an EV working group which coordinated between utilities, MDE, the Electric Vehicle Infrastructure Council, and addressed actions including EV tariffs and EV supply equipment investment.[13] In January 2018, after a year of EV working group meetings, the leader of the working group filed a petition for a proceeding to consider the implementation of a coordinated statewide EV portfolio, which included BGE's EV program.[14] In February 2018 Commission filed notice of proceeding (Case No. 9478) and request for comments.[15] Over the course of a year the Commission held multiple hearings and opportunities for stakeholder comments.

Q. How do BGE's electrification proposals in the current MYP differ from the process for establishing EV programs in Maryland?

A. BGE is only requesting cost recovery in the MYP for Phase I of its EV pilot program, not Commission approval, because the program was already approved in Case 9478 as described above. The Commission's approval of BGE's EV pilot program came after extensive investigation and public stakeholder input concerning utility engagement in EV charging and market development. This is because utility-administered EV programs posed novel policy questions that required extensive fact-finding, public input, and

[13] Commission. Notice. PC 44. January 31, 2017. Available at: https://webpsc.psc.state.md.us/DMS/pc/PC44
[14] Maillog #218613, Leader of PC44 Electric Vehicle Work Group, Petition for Implementation of a Statewide Electric Vehicle Portfolio (Jan. 22, 2018).
[15] Maillog #218878.

debate. Utility engagement in electrification efforts poses similar novel policy issues that should be addressed through a comparatively robust public stakeholder process. Thus, it is premature for BGE to propose and implement its electrification programs in the current MYP without proper fact-finding and deliberation.

Q. Are there any examples of a regulatory proceeding in other jurisdictions where stakeholders discussed and addressed policy questions concerning building electrification?

A. Yes. I am aware that Colorado and California both opened regulatory proceedings and stakeholder processes to examine how utilities can support building electrification.

Q. Please provide a brief summary of Colorado's regulatory proceedings.

A. Colorado SB 21-246 requires investor-owned electric utilities to develop and implement beneficial electrification (BE) plans every three years. Furthermore, SB 21-264 requires gas distribution utilities to file clean heat plans (CHPs) that must include plans to meet certain GHG emission reduction targets for 2025 and 2030.[16] The bill recognizes the importance of

[16] SB21-264. (1)(a)(II). Available at: https://leg.colorado.gov/bills/sb21-264; the codified bill is found at: https://casetext.com/statute/colorado-revised-statutes/title-40-utilities/public-utilities/general-and-administrative/article-32-air-quality-improvement-costs/part-1-general-provisions/section-40-32-108-clean-heat-targets-legislative-declaration-definitions-plans-rules-reports.

improving energy efficiency of buildings in the state as well as switching from gas space and water heating to high-efficiency electric heating.

The Public Utilities Commission ("PUC") filed a Notice of Proposed Rulemaking on October 1, 2021 to meet the statutory CHP requirements in SB 21-264.[17] However, the PUC went beyond these requirements by incorporating short-term and long-term gas infrastructure planning issues and demand-side management (DSM) rules in the same proceeding,[18] recognizing that CHPs "will not address all of the issues that the gas utilities and its customers will face through the transitions required to meet Colorado's goals."[19] As part of the rulemaking proceeding, the PUC received over 300 public comment filings from stakeholders, held two rounds of oral public comment hearings spanning seven days total, and convened six community meetings in disadvantaged communities around the state. In addition, the PUC held various workshops on topics and issues that arose during the comment process, including GHG emissions accounting methodologies, disadvantaged community definitions, and line extensions. The PUC issued its final decision in December 2022, adopting many of the recommendations and feedback from stakeholders.[20] The first

[17] Colorado PUC. 2021. *Notice of Proposed Rulemaking*. Proceeding No. 21R-0449G. Available at: https://www.dora.state.co.us/pls/efi/EFI_Search_UI.search.
[18] Some of the gas planning issues were already under review in Proceeding No. 21R-0314G.
[19] Colorado PUC. 2021. p. 27.
[20] Colorado PUC. 2022. *Commission Decision Adopting Rules*. Proceeding No. 21R-0449G.

utility CHP plan will be filed in August 2023, after the utility files its BE and DSM plans.

Q. Please provide a brief summary of California's proceeding.

A. In 2017, Sierra Club, Natural Resources Defense Council (NRDC), and others filed a joint motion to reevaluate the "Three-Prong-Test," a test that had impeded fuel switching for many years.[21] The Three Prong Test required that the fuel substitution measures had to pass cost-effectiveness testing at the measure level from the perspectives of both the implementing utility (excluding benefits of other fuel savings) and the total resource (including other fuel savings). [22] That requirement created a barrier for measures that would replace gas fuel with electric fuel because they are not cost-effective as electric efficiency measures from the electric utility's perspective (because they increase electric consumption).

Interested parties were invited to comment on the design and implementation of the test in June 2018.[23] The main opponent of the update to the Three-Prong Test was Southern California Gas (SoCalGas), the

[21] Borgenson et al. 2017. *Motion of The Natural Resources Defense Council (NRDC), Sierra Club, and The California Energy Efficiency Industry Council (The Council) Seeking Review and Modification of The Three-Prong Fuel Substitution Test*. Rulemaking 13-11-005. Available at: https://docs.cpuc.ca.gov/PublishedDocs/Efile/G000/M191/K912/191912103.PDF

[22] CPUC. 2019. *Decision Modifying the Energy Efficiency Three-Prong Test Related to Fuel Substitution*. Rulemaking 13-11-005. Available at: https://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M310/K159/310159146.PDF

[23] CPUC. 2018. *Administrative Law Judge's Ruling Seeking Comments on Three-Prong Test*. June 25, 2018. Rulemaking 13-11-005. Available at: https://docs.cpuc.ca.gov/PublishedDocs/Efile/G000/M216/K775/216775944.PDF

largest gas utility in the state. SoCalGas argued that the amendment removes the cost-effectiveness protections put in place for ratepayers, encourages fuel wars, and impacts energy costs and reliability.[24] In contrast, environmental advocates, including the Sierra Club and NRDC, commented that the unamended test was antiquated and unrepresentative of today's needs.[25,26] The PUC released a proposed decision in June 2018 for comment, and in August, 2019 issued a final decision that replaced the Three-Prong Test with a new Fuel Substitution test and required that the overall energy efficiency portfolio must remain cost-effective.[27]

Q. Are you aware of any jurisdictions that allowed for and approved a fuel switching/electrification program in a rate case?

A. No.

Q. What is your conclusion about key policy and program implementation questions regarding BGE's electrification program proposal?

A. As I discussed above, novel programs like BGE's electrification program would require addressing various policy and program implementation questions as part of designing and implementing a program. Maryland

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[24] Southern California Gas Company. 2019. *Opening Comments Of Southern California Gas Company (U 904 G) To Proposed Decision Modifying The Energy Efficiency Three-Prong Test Related To Fuel Substitution*, Rulemaking 13-11-005. Available at: http://docs.cpuc.ca.gov/PublishedDocs/Efile/G000/M309/K726/309726334.PDF
[25] Seel, A. 2018. "Three Prongs Don't Make a Right." Sierra Club. Available at: https://www.sierraclub.org/planet/2018/04/three-prongs-dont-make-right
[26] UtilityDive. 2019. "California opens $1B in efficiency funding to electrification." Available at: https://www.utilitydive.com/news/california-opens-1b-in-efficiency-funding-to-electrification/560096/
[27] CPUC. 2019.

recently went through a long stakeholder process to discuss and resolve various EV-related topics before implementing an EV pilot program. Other jurisdictions also have spent a fair amount of time sorting out and resolving key policy and program questions before launching building electrification programs. The current MYP, and base rate cases generally, are not designed to discuss and resolve novel and complex policy and program issues. Thus, BGE's electrification program proposal should not be included in the current MYP.

B. BGE's proposal is untimely and premature because BGE's electrification programs presuppose answers to key building electrification policy and program questions that the State is in the process of addressing.

Q. Is EmPOWER Maryland considering incorporating building electrification?

A. Yes.

Q. Please summarize EmPOWER Maryland's recent and ongoing activities to incorporate electrification.

EmPOWER Maryland's initiative concerning building electrification started with the Public Service Commission Order No. 89679, issued December 18, 2020. Order No. 89679 established the Future Programming Work Group (Work Group) and directed the Work Group to consider various topics for EmPOWER's 2021–2023 Plan, including promoting electrification and state climate action plan coordination. The Work Group held 28 meetings over the course of 13 months and stakeholders submitted numerous written comments on various issues.[28] In one of the Work Group meetings, the MDE made a presentation on the recommendations by the MCCC and the State's *2030 Greenhouse Gas Emissions Reduction Act Plan*. Among others, the MCCC recommended that "the General Assembly amend PUA § 7-211 to permit electrification of existing fossil fuel systems through EmPOWER and to direct the Commission to require electric utilities to proactively encourage customers with either natural gas, propane or oil space heating and water heating to replace those systems with electric heat pump technology, especially for LI households."[29] The Work Group discussed a few key issues concerning electrification including whether to discontinue gas appliance rebates, but they did not reach any consensus.

To help the state meet its GHG reduction goals through EmPOWER Maryland's programs, the Work Group commissioned a GHG abatement potential study by AEG ("AEG potential study") in 2022. This study included building electrification measures in a Maximum Achievable scenario in addition to energy efficiency and demand response.[30] On February 2, 2023, the Commission held a hearing regarding goal setting for

[28] Future Programming Work Group Report. April 15, 2022. Case No. 9648. At 2.
[29] Ibid.
[30] AEG. 2023. *EmPOWER Maryland 2024-2029 Greenhouse Gas Abatement Potential Study – Final Report*.

EmPOWER Maryland's 2024–2026 program cycle to review several EmPOWER Maryland-related reports, including the AEG potential study and the Work Group's recommendation report. The Commission then issued an order on March 23, 2023, directing each utility to file three separate program plans that follow three achievable potential scenarios analyzed by the AEG potential study by August 1, 2023.[31] One of the scenarios must follow the Maximum Achievable potential scenario, which includes electrification programs.

Q. Please describe the State's ongoing efforts to address policy questions concerning building or other electrification.

A. In compliance with the CSNA, the MDE is currently developing a state plan that reduces statewide GHG emissions by 60 percent by 2030 and "sets the state on a path" toward achieving net-zero statewide GHG emissions by 2045. The MDE is directed to develop a draft state climate plan by June 30, 2023, convene a series of public workshops, and adopt a final plan by December 31, 2023. This plan will include a set of recommendations for policies to help Maryland meet the CSNA's emission reduction targets.[32]

The CSNA also requires the Building Codes Administration to assess various issues concerning electrification and make recommendations to

[31] Order No. 90546
[32] For more information about MDE's plan, see: https://mde.maryland.gov/programs/Air/ClimateChange/Pages/index.aspx.

satisfy the General Assembly's stated intent "that the State move toward broader electrification of both existing buildings and new construction on completion of the study…"[33] Further, the CSNA requires the Building Codes Administration to develop recommendations "for the fastest and most cost–efficient methods for decarbonizing buildings and other sectors in the State" and "regarding efficient cost–effectiveness measures for the electrification of new and existing buildings"[34]

Q. What is your conclusion about the status of the ongoing policy and program activities concerning electrification in Maryland?

A. In Maryland, the Building Codes Administration, MDE, and the Commission, through EmPOWER Maryland, have been investigating and addressing various policy and program questions related to the promotion of electrification in the building and other sectors, and these efforts are ongoing. Consequently, BGE's electrification program proposal is untimely and premature and thus should not be implemented at this time.

C. BGE's building electrification proposal contradicts the state's climate policy.

Q. What aspects of BGE's building electrification program proposal conflict with the state's climate policy direction?

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[33] CSNA. Section 10. Available at: https://mgaleg.maryland.gov/2022RS/Chapters_noln/CH_38_sb0528e.pdf.
[34] Ibid.

A. BGE's proposed electrification program would require residential customers to keep their existing gas heating systems when they install new electric heat pumps. This requirement does not align with the state's climate policy direction because customers would keep using pipeline gas, whereas the state has established a policy to aggressively promote building electrification to reduce GHG emissions and has found, through the MCCC, that a scenario that pursues aggressive electrification costs less for the society than a scenario that relies on hybrid heating systems.

Q. What are the major findings in the 2021 report by the Maryland Commission on Climate Change?

A. The Mitigation Working Group (MWG) of the MCCC released a *Building Energy Transition Plan* report in 2021. This plan included two major components: (a) major findings from a study conducted by E3 ("the Statewide E3 study") analyzing scenarios for achieving reductions in emissions to near net-zero level for Maryland's residential and commercial buildings by 2045 and (b) recommendations based on the study findings and stakeholder feedback. The Statewide E3 study modeled four scenarios, including the MWG Policy Scenario, as I mentioned in the summary section of my testimony, and found that the MWG Policy Scenario was the lowest-cost scenario of all the decarbonization scenarios. This scenario incorporates the following four core concepts and objectives:

- Ensure an equitable and just transition, especially for low-income households,
- Construct new buildings to meet space and water heating demand without fossil fuels,
- Replace almost all fossil fuel heaters with heat pumps in existing homes by 2045, and
- Implement a flexible Building Emissions Standard for commercial buildings.

Based on these study findings, the MCCC's Building Energy Transition Plan established four core recommendations: (1) Adopt an All-Electric Construction Code; (2) Develop a Clean Heat Retrofit Program; (3) Create a Building Emissions Standard; and (4) Develop Utility Transition Plans. It is also important to note that the second core recommendation, the Clean Heat Retrofit Program, includes (a) encouraging fuel-switching and beneficial electrification through EmPOWER beginning in 2024 and (b) targeting 50 percent of residential heating system, cooling system, and water heater sales to be heat pumps by 2025 and 95 percent by 2030.

Q. What does the Climate Solutions Now Act of 2022 require?

A. The CSNA mandates a 60 percent reduction in the state's GHG emissions by 2031, relative to 2006 levels, and net zero GHG emissions by 2045.

Q. Please characterize the policy direction set by the CSNA.

A. Consistent with the recommendations by the Commission on Climate Change, the CSNA has established a clear policy direction that electrification is the most important strategy in the building sector to help the state meet its aggressive GHG reduction mandates. For example, the Act states "the General Assembly supports moving toward broader electrification of both existing buildings and new construction as a component of decarbonization."[35] The Act also requires the Building Codes Administration to "develop recommendations for an all–electric building code and building energy performance standards for the State" as well as to "develop recommendations regarding efficient cost–effectiveness measures for the electrification of new and existing buildings."[36] These mandates from the CSNA are clear indications that the state intends to aggressively promote electrification while transitioning away from gas infrastructure. BGE's proposal to promote hybrid heating is in conflict with the state's policy direction.

Q. What is your recommendation?

[35] CSNA. Section 10.
[36] Ibid.

A. If BGE wishes to pursue its electrification programs, the Commission should direct BGE to propose its building and non-road electrification programs within the EmPOWER program instead of in this proceeding. The Commission should also investigate key policy and program implementation issues concerning electrification programs in a policy docket. Among other things, the Commission should investigate program designs, the role of the utilities and other entities, funding sources, performance incentives, cost-effectiveness analysis framework, goal setting, cost recovery, customer equity and bill impacts, federal incentives, and gas planning.

VI. BGE'S PROPOSED ELECTRIFICATION PROGRAM DESIGNS ARE FLAWED

Q. What are your main concerns with BGE's proposed building electrification program?

A. As discussed above in the summary section in my testimony, there are numerous issues with BGE's proposed building electrification programs.

- BGE's proposal on gas equipment retention does not align with the state's climate policy direction and ignores technology and market realities. It is also not supported by any rigorous studies, including the studies that BGE commissioned and Mr. Case discussed in his direct testimony.

- Program designs, incentives, and budgets for some of the proposed electrification programs should be modified, if the Commission decides to approve the electrification program. In particular:
    - Per-customer incentive amounts BGE assumed for ASHPs, GSHPs, HPWHs, and electrification make-ready measures (e.g., electrical panel upgrades) are too high because they do not adequately take into account available federal financial incentives. Per customer incentive for ASHPs could be reduced further as BGE's estimates for the total cost of ASHPs could be overstated.
    - The proposed program budget for program administration is too high.
    - BGE's downstream incentive approach for its BE Program proposal is inconsistent with EmPOWER's new approach to use midstream incentives for HVAC and HPWH and with ongoing efforts to streamline EmPOWER's HVAC and HPWH offerings; it creates customer and contractor confusion.

  - BGE has not provided sufficient evidence to support and justify the proposed non-road electrification programs.

A. BGE's building electrification program proposal does not align with policy, technology, and market realities.

Q. What aspects of BGE's building electrification program proposal do you think fail to reflect policy, technology, and market realities?

A. BGE's proposed electrification program would require customers to keep their existing gas heating systems when they install new electric heat pumps. However, as I initially discussed above, this requirement does not align with the state's climate policy direction, ignores the advancement of cold climate ASHPs, and would impose unnecessary costs on ratepayers. Further, this requirement is not supported or justified by reliable, rigorous studies.

Q. What are your concerns about BGE's proposal to require customers to retain existing gas space heating as backup?

A. BGE should not require the retention of existing gas space heating as backup for the following reasons:

- BGE's proposal on gas equipment retention does not align with the state's climate policy direction.

- Backup heaters are not required for cold-climate heat pumps in Maryland's climate, which are widely available in the market.

Q. Please explain why BGE's gas equipment retention proposal does not align with the state's climate policy directions.

A. This hybrid heating approach clearly contradicts (a) the major findings in a 2021 report by the Maryland Commission on Climate Change (MCCC) and (b) the state's overarching policy direction as established through the CSNA, which provides further support for the MCCC findings. Please see my discussions on this topic under Section III above.

Q. How would cold-climate heat pumps perform in Maryland's climate?

A. Cold-climate heat pumps are now widely available in the market. In mild climates like Maryland's, such advanced heat pumps do not require backup heating if sized properly to meet the full heating load. Cold climate heat pumps can provide comfortable heating very efficiently even in frigid temperature conditions. The Northeast Energy Efficiency Partnerships (NEEP) developed and has been maintaining a Cold Climate Air Source Heat Pump (ccASHP) List over the past several years.[37] NEEP establishes minimum requirements for manufacturers to list their heat pumps as ccASHP.[38] One key requirement is a coefficient of performance ("COP") of 1.75 or above at 5°F, which means that heat pumps need to be at least 175 percent efficient at 5°F.[39] Space heating systems are typically sized based on

[37] NEEP's Cold Climate Air Source Heat Pump List. Available at: https://ashp.neep.org/#!/product_list/
[38] Currently the NEEP ccASHP list has over 80,000 models of ccASHPs from over 200 HVAC brands.
[39] Electric resistance heating has a COP of approximately 1; fossil fuel heating systems such as gas furnaces have a COP of approximately 0.7 to 0.9.

design temperatures, which represents weather conditions that meet space heating loads for 99 percent of the hours in a year.[40] The design day temperature in Baltimore, Maryland is 17°F.[41] This means that cold climate heat pumps perform much more efficiently at this temperature and have a higher COP than at the minimum performance condition specified by NEEP's ccASHP requirements.

Q. Have there been any in-field evaluation studies of ccASHP?

A. Yes.

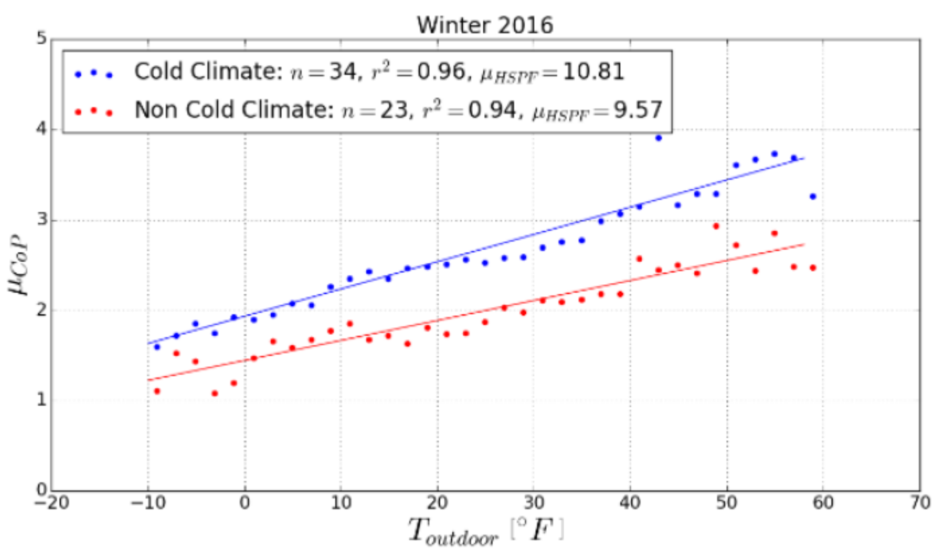
Q. What have those studies found about the actual performance of ccASHPs?

A. Many in-field studies demonstrated the superior performance of cold climate heat pumps over the past several years. For example, a 2016 study conducted by Cadmus Group evaluated the performance of mini-split heat pumps in numerous homes in Massachusetts and Rhode Island.[42] The figure below presents the average COP values (at Y-axis) across varying outdoor temperatures (at X-axis) for 34 cold climate units and 23 regular units

[40] Green Building Advisor. 2021. "Design Temperature vs. Degree Days," Available at: https://www.greenbuildingadvisor.com/article/design-temperature-vs-degree-days; Air Conditioning Contractors of America. 2014. *ACCA Manual J® Residential Load Calculation Eighth Edition*. Available at: https://higherlogicdownload.s3.amazonaws.com/ACCA/8e4cf5b4-e984-4971-bb79-7889082c7cf2/UploadedImages/MJ8-Adden-E-Updated-Weather-Data-11Aug2014.pdf.
[41] U.S. EPA. 2015. *ENERGY STAR Certified Homes County-Level Design Temperature Reference Guide*. Available at: https://www.energystar.gov/ia/partners/bldrs_lenders_raters/downloads/County%20Level%20Design%20Temperature%20Reference%20Guide%20-%202015-06-24.pdf.
[42] Cadmus 2016. *Ductless Mini-Split Heat Pump Impact Evaluation*. Available at: https://ripuc.ri.gov/sites/g/files/xkgbur841/files/eventsactions/docket/4755-TRM-DMSHP-Evaluation-Report-12-30-2016.pdf.

during the winter of 2016. As shown in this figure, the average COP values for cold climate heat pumps are very favorable even in frigid temperatures: a COP of about 2.5 at Baltimore's design temperature of 17°F and a COP of 2 even at 0°F. But regular heat pumps are also very energy efficient at Baltimore's design temperature, especially when compared to gas boilers and furnaces, which tend to be 70 percent to 90 percent efficient (representing a COP of 0.7 to 0.9).

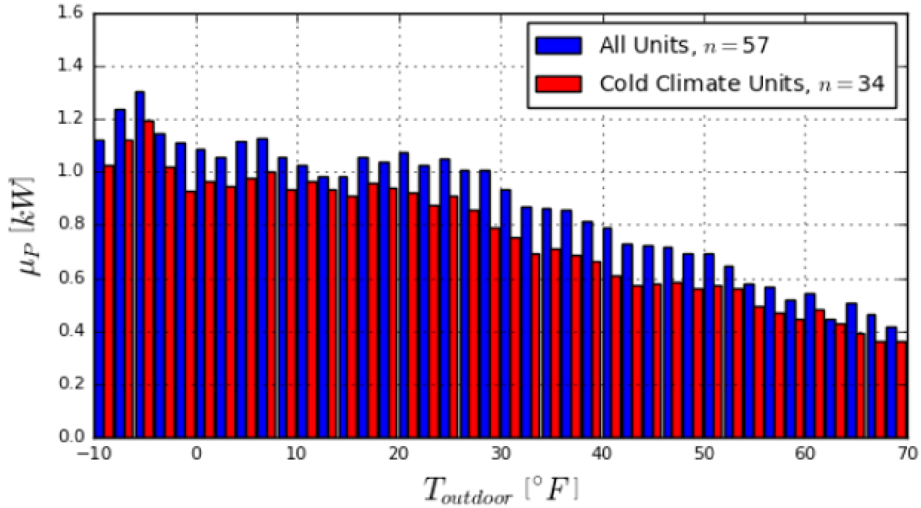
Figure 1. Average Heating COP vs. Outdoor Air Temperature for Cold-Climate and Non-Cold-Climate Systems – Winter 2016



Source: Cadmus 2016. Ductless Mini-Split Heat Pump Impact Evaluation.
Note: µCoP represents the mean COP of the population studied.

The same Cadmus 2016 study also examined electricity demand at varying temperatures and found that little changes in kW usage between 17°F (Baltimore's design temperature) and 0°F, as shown in Figure 2 below.

Figure 2. Winter 2016 Average Power Consumption – Heating kW usage vs. Outdoor Temperature

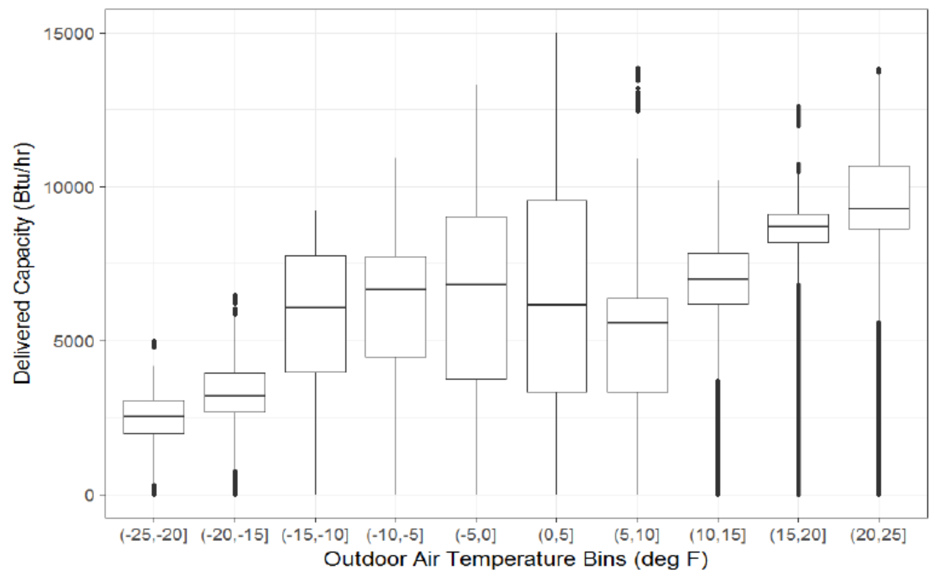


Source: Cadmus 2016. Ductless Mini-Split Heat Pump Impact Evaluation.
Note: μ_P [kW] represents the mean power consumption of the population studied.

While the energy input could be stable in this temperature range, heating capacities could decline as the temperature goes down. However, a 2019 study conducted by the Center for Energy and Environment in Minnesota demonstrated that a mini-split heat pump "delivered a consistent median capacity from 10 ºF to -15 ºF," as shown in Figure 3 below.[43]

[43] Shoenbauer, B. et al. 2018. "Field Assessment of Ducted and Ductless Cold Climate Air Source Heat Pumps." Available at: https://www.mncee.org/field-assessment-ducted-and-ductless-cold-climate-air-source-heat-pumps.

Figure 3. Capacity of a Mini-Split Heat Pumps vs. Outdoor Temperature



Source: Shoenbauer, B. et al. 2018. "Field Assessment of Ducted and Ductless Cold Climate Air Source Heat Pumps."

Q. What do these in-field studies imply about the usage and grid impacts of ccASHPs in Maryland?

A. I draw two main conclusions from these studies: (a) ccASHPs in Maryland do not require fossil fuel back-up heating; and (b) the potential grid impact from ccASHPs is much lower than what BGE and its consultants E3 and 1898 & Co claim.

Q. Do you expect that heat pump technologies will be further improved in the future?

A. Yes. While the efficiencies of fossil-fuel-based heating technologies, such as gas furnaces, haven't seen much technology advancement in the past decade and are not expected to see notable improvement in the future, it is expected that heat pump technologies are going to improve further over the next decade or so. For example, the National Renewable Energy Laboratory ("NREL") conducted a series of Electrification Futures studies; and in one of the studies, NREL projected a range of efficiency advancements for heat pumps and heat pump water heaters through 2050 under three different scenarios.[44] In the most aggressive scenario, the study projects that a COP will increase by 30 to 50 percent in the most aggressive scenario and by 12 to 25 percent in the most conservative scenario by 2030.

Q. How do the costs of ccASHPs compare with the costs of regular ASHPs?

A. A 2018 evaluation study by Navigant Consulting (now Guidehouse) examined the costs of 305 ASHP units, more specifically ductless minisplit heat pump ("DMSHP"), that were part of the Massachusetts Residential Heating and Cooling Program.[45] Figure 4 below shows a summary of this survey. As shown in this figure, the study found that total installed costs of regular and cold-climate (DMSHP) are comparable. At the lower rebate threshold of 18 SEER and 10 HSPF, the total installed cost of cold-climate systems was slightly (3 to 6 percent) higher, except the two largest unit categories, which were 13 to 18 percent more expensive. On the other hand,

[44] NREL. 2017. *Electrification Futures Study: End-Use Electric Technology Cost and Performance Projections through 2050*. Available at: https://www.nrel.gov/analysis/electrification-futures.html.
[45] Navigant. 2018. *Ductless Mini-Split Heat Pump Cost Study (RES 28): Final Report*. Prepared for the Electric Program Administrators of Massachusetts Part of the Residential Evaluation Program Area. Available at: https://ma-eeac.org/wp-content/uploads/RES28_Assembled_Report_2018-10-05.pdf.

at the upper rebate threshold of 20 SEER and 12 HSPF, the study found the total cost of cold-climate systems was consistently lower than the installed cost of regular non-cold-climate systems.

Figure 4. Total Installed Cost of DMSHP Systems at Common SEER-HSPF Combinations

Capacity, kBtu/h	Number of Zones	Base Case 15 SEER, 8.2 HSPF	Lower Rebate Threshold 18 SEER, 10 HSPF		Upper Rebate Threshold 20 SEER, 12 HSPF		Above Current Rebate Levels 28 SEER, 14 HSPF	
		Regular	Regular	Cold Climate	Regular	Cold Climate	Regular	Cold Climate
9 ± 1.5	1	$3,643	$3,860	$3,993	$4,212	$4,035	-*	$4,419
12 ± 1.5	1	$3,717	$3,957	$4,058	$4,407	$4,199	$4,407	$4,515
18†	1	$4,276	$4,475	$4,646	$4,956	$4,812	-‡	-‡
24 ± 3	1	$4,586	$4,811	$5,016	$5,256	$5,176	-*	-*
24 ± 3	2	$6,263	$6,679	$7,060	-*	-*	-*	-*
24 ± 3	3	$7,434	$7,852	$8,202	-*	-*	-*	-*
30 ± 3	3	$7,962	$8,024	$9,049	-*	-*	-*	-*
36 ± 3	4	$8,857	$8,857	$10,438	-*	-*	-*	-*

* The evaluation team could not identify any systems available on the market with this combination of capacity, zones, and efficiency levels.

† The evaluation team estimated the equipment costs for 18 kBtu/h using linear interpolation between the equipment costs at 12 kBtu/h and 24 kBtu/h. Based on contractor survey data, the team assumed that installation costs for 18 kBtu/h systems are the same as for 24 kBtu/h systems.

‡ Since the 18 kBtu/h data was estimated based on data for 12 and 24 kBtu/h systems, it could only be calculated for system configurations that are available at both the 12 and 24 kBtu/h capacities.

Source: Navigant. 2018. Ductless Mini-Split Heat Pump Cost Study (RES 28)

Q. Are there building electrification programs that encourage whole-home electrification of space heating in other jurisdictions?

A. Yes. I am aware of several utility energy efficiency programs that offer large incentives for whole-home heat pumps—more than base level incentives provided to all efficient heat pumps—in order to encourage the installation of whole-home heat pumps and the removal of existing fossil-fuel-based heating systems in colder climate regions than Maryland. I provide a short summary of these programs as follows:

- **Mass Save Residential Whole-Home Heat Pump Rebates**: the statewide energy efficiency provider in Massachusetts, Mass Save, offers larger rebates ($10,000 to $16,000 per home) for "whole-home" heat pumps.[46] To classify as "whole-home," heat pumps must be used as sole source of heating for the heating season and be sized to meet 90 to 120 percent of the total heating load at the outdoor design temperature.[47] To be eligible for these rebates, customers must fill out a verification form confirming that the heat pump will be the sole source of heating and that the pre-existing heating system will be removed or disconnected.

- **New York State Clean Heat Program**: The New York State ("NYS") Clean Heat Program began in 2020 and is one of the largest electrification programs in the country in terms of annual budget and energy savings.[48] The program offers rebates for cold-climate air source heat pumps, with higher incentives for full-load heating heat pumps sized to meet at least 90 percent of the building heat load.[49] In addition, NYS Clean Heat offers specific, higher incentives for

[46] Mass Save. 2023. "Air Source Heat Pump Rebates." Available at: https://www.masssave.com/en/residential/rebates-and-incentives/air-source-heat-pumps.
[47] Mass Save. March 2023. *Heat Pump Program Offers.* Available at: http://ceere.org/MassSave2023HeatPumpProgramOverview.pdf.
[48] Cohn, Charlotte and Nora Wang Esram. February 2022. *Building Electrification: Programs and Best Practices.* Available at: https://www.aceee.org/research-report/b2201.
[49] The Joint Energy Efficiency Providers. September 2022. *NYS Clean Heat: Statewide Heat Pump Program Manual*. Available at: https://cleanheat.ny.gov/assets/pdf/NYS-Clean-Heat-Program-Manual.pdf.

optimizing use of the full-load heat pump system by adding integrated controls or for decommissioning the pre-existing fossil-fuel heating system.[50]

Q. What are the cost implications of the gas heating backup requirement for BGE's customers?

A. I expect that BGE's backup heating requirement could result in unnecessary costs for BGE customers for two reasons: (a) BGE would need to continuously upgrade and maintain many parts of its gas distribution system for use during just a small portion of the year, forcing the Company to raise gas rates significantly in the future; and (b) the customers who were required to maintain their gas heating system as a condition of participating in BGE's heat pump program would also need to replace their old heating system with a new gas heating system in the future once the existing system fails.

B. BGE's studies are flawed and do not support its proposal to require customers to retain existing gas heating systems as backup heating.

Q. Do you have concerns with the studies that BGE commissioned to inform its electrification strategy?

[50] The Joint Energy Efficiency Providers. 2022. *NYS Clean Heat: Statewide Heat Pump Program Manual*. Available at: https://cleanheat.ny.gov/assets/pdf/NYS-Clean-Heat-Program-Manual.pdf.

A. Yes. I have major concerns about both the E3 study and the 1898 & Co study. I found that these studies have many flaws and do not justify BGE's proposal to require the retention of existing gas space heating as backup.

Q. What are the major issues with the E3 Study?

A. As mentioned near the beginning of my testimony, the E3 study analyzed three scenarios: the Limited Gas pathway, the Hybrid pathway, and the Diverse pathway. E3 describes the latter two scenarios as Integrated Energy System ("IES") scenarios. E3 concluded that the IES scenarios "achieve Maryland's goals at a significantly lower cost and with less risk for customers and the State's economy" and that the Limited Gas pathway "would result in a significantly higher cost, more economic and energy system disruption, and a less diverse/resilient system compared to IES scenarios."[51]

Q. Are E3's conclusions justified?

A. No. The E3 study has several major flaws that call into question the study's conclusions. The flaws include the following:

1) The E3 study's analysis of gas asset operation and retirements for the scenario with the highest levels of electrification, the Limited Gas scenario, is overly biased toward maintaining the existing gas

[51] Case direct testimony, at 47.

systems in that it assumes no or very small amounts of gas system retirements through 2045.

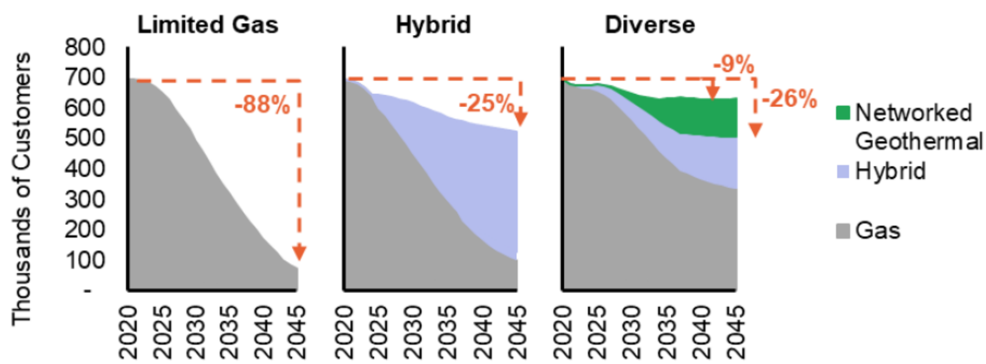
2) The E3 study's estimates for electric system transmission and distribution costs are overly high; and

3) The E3 study's assumptions about the cost of heat pumps are overstated.

Q. Please elaborate on how the E3 study is overly biased toward maintaining BGE's existing gas system.

A. The first flaw is substantially inflating the cost of operating and maintaining the gas system for the Limited Gas pathway. The Limited Gas pathway assumes that the total number of customers declines by 88 percent by 2045; this is substantially more than projected for the other pathways, as shown in the figure below. This steep decline would presumably allow for the retirement of parts of BGE's gas distribution network, but the extent to which the E3 study report assumed and modeled such retirements is not clear. E3 appears to have assumed minimal asset retirements, stating that "opportunities for avoided reinvestments will only be a fraction of the total value of the system between 2022 and 2050" and that "not all gas infrastructure that is up for replacement can be replaced, and ongoing investments will be needed for reasons ranging from safety and reliability to the feasibility challenges inherent in implementing electrification projects at neighborhood scale."[52]

Figure 5. BGE's residential and commercial customer counts by scenario in the E3 study for BGE

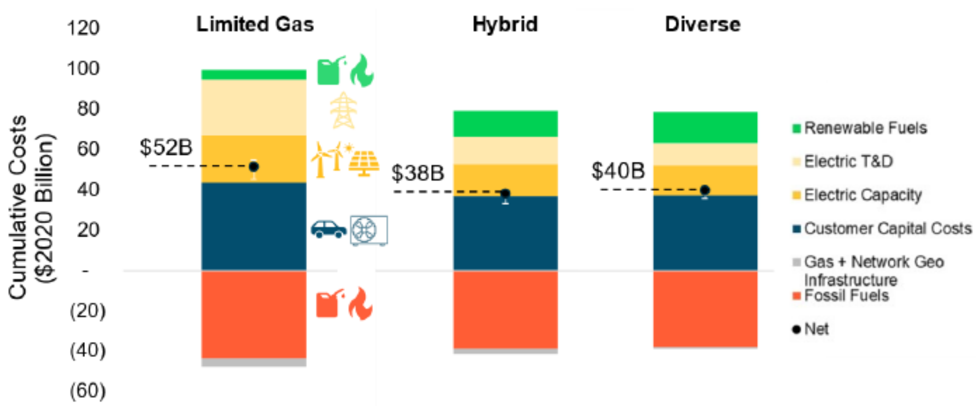


Source: 2022 E3 Pathway Study. Figure 12.

The only apparent quantification of gas system retirements in the E3 study is shown in Figure 6 below. This figure shows that the gas system cost reduction under the Limited Gas pathway (shown as "Gas + Network Geo Infrastructure" in the figure) is extremely small relative to the additional costs for electric capacity and transmission and distribution ("T&D"). This result is surprising given that the E3 study is projecting a nearly 90 percent reduction in customer counts by 2045 under the Limited Gas pathway (see Figure 5).

[52] E3 study at 33.

Figure 6. 2045 Incremental costs by component by scenario relative to Reference Scenario in the E3 study for BGE



Source: 2022 E3 Pathway Study. Figure 17.

BGE provided the actual estimates of gas system costs in its response to OPCDR22-05 CONFIDENTIAL Attachment 1. **BEGIN CONFIDENTIAL** [redacted]. **END CONFIDENTIAL**

Q. Besides E3's arguments for keeping the existing gas system mentioned above, is there any other reason why E3 made such a false assumption?

A. It is possible that this decision was based on the intention and objective of the study itself, stated on page 11 of the study where the study mentioned: "BGE specifically asked E3 to build on its prior efforts in the State by evaluating the implications of decarbonization strategies that achieve the state's newly legislated net-zero targets ***with an intent to understand how BGE's electric and gas businesses and infrastructure could play a supporting role*** [emphasis added]."[53]

Q. Please explain why you find the E3 study's estimates for transmission and distribution costs are overly high.

A. The E3 study used overly high T&D costs of $203/kW-year to $258/kW-year, which were provided by BGE.[54] These values are nearly *eight times higher* than the avoided T&D values of $25.1 to $34.09 per kW-year that BGE's other consultant, Brattle Group, is using to evaluate the cost-effectiveness of its EV fleet programs.[55] Further, BGE stated that Brattle's T&D avoided cost value is consistent with the methodology used for avoided T&D costs in BGE's EmPOWER plan.[56]

Q. Would the results of the E3 study be different if E3 had used the same T&D values used bythe Brattle Group?

A. The E3 study estimated that the total incremental cost of T&D for the Limited Gas pathway is approximately $29 billion in 2045, as is shown in Figure 6 above. If we adjust this value based on the T&D value used by Brattle Group, the total incremental T&D cost would be reduced to just $4

[53] E3 study, at 11.
[54] E3 study, at 79.
[55] A supporting workpaper "Fleet Electrification BCA_Final" filed with Direct Testimony of Witness Case.
[56] BGE response to OPCDR22-14.

billion, representing a reduction of $25 billion relative to E3's estimate. As the net total cost for the Limited Gas pathway is $52 million (see Figure 6), this reduction in T&D costs would reduce the net total cost for the scenario by roughly 50 percent to approximately $27 billion. Applying a similar adjustment to the T&D costs to the other two scenarios, I estimate that the net total cost for the Limited Pathway would be similar to the net costs for the Hybrid and Diverse Pathway scenarios, even taking into account the study's bias towards maintaining the existing gas system. If that bias were eliminated, the Limited Gas pathway would likely be the lowest cost of all the scenarios due to cost savings from retirements of the gas network systems made possible by the projected 88 percent reduction in customer counts.

Q. Please explain why you find that the E3 study's assumptions for the costs of heat pumps are overstated.

[redacted] The E3 study assumes costs (in 2020 dollars) of $12,500 in year 2020 and $13,200 in year 2030 for a hybrid ASHP using a gas heating system as backup heating. For an ASHP using electric resistance as backup heating, the study assumes costs of $14,300 in 2020 and 11,500 in 2030. I converted these values for year 2020 into 2022 dollars based on the recent inflation rates to make them comparable to the cost estimates provided by BGE in the MYP filing (which I assume BGE obtained in 2022). I then estimated the heat pump costs for year 2022 by assuming a linear cost trajectory from 2020 to 2030 based on E3's cost estimates for those two years. The resulting cost estimates for year 2022, in 2022 dollars, are: $15,744 for an ASHP with electric backup and $13,754 for an ASHP with fuel backup, as shown in Table 2 below. ****BEGIN CONFIDENTIAL**** [redacted]

[redacted]

[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	
[redacted]	[redacted]	[redacted]	[redacted]

[redacted]

[57] OPCDR14-08 CONFIDENTIAL Attachment 1.
[58] OPCDR01-01_Attachment1, at 19.

[redacted]. ****END CONFIDENTIAL****

Q. Is the E3 study a reliable basis for drawing conclusions about the impact of electrification on BGE's system?

A. The E3 study is overly biased toward maintaining the existing gas systems under the Limited Gas scenario and assumes overly high costs for both electric transmission and distribution systems and ASHPs. Correcting these errors would likely make the Limited Gas scenario a lower-cost scenario than BGE's IES scenarios. If the Limited Gas scenario is in fact the lowest-cost scenario, as this analysis suggests, there is no basis for BGE's proposal to require the retention of existing gas furnaces as back-up heating for ASHPs.

Q. Do you have concerns with the 1898 & Co. study that BGE used to support the gas equipment retention proposal?

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[59] OPCDR34-02.

[60] The cost of building systems in Baltimore is 94 percent of the national average, according to RS Means. See PDF page 60 of this online document: https://www.rsmeans.com/media/wysiwyg/quarterly_updates/2021-CCI-LocationFactors-V2.pdf.

A. Yes. I found that this study has flaws in some of the assumptions and methodologies it used to estimate peak load and grid impacts of electrification.

Q. Please describe 1898 & Co.'s methods to estimate peak load and the infrastructure impacts of electrification.

A. BGE asked 1898 & Co. to produce an estimate of the peak load—and the distribution system cost to meet that peak load—associated with electrification of the residential and transportation sectors. 1898 & Co.'s approach was to:

- Estimate new electrified loads in each county, based on demographic data and historical growth rates, along with an electrification trajectory toward full electrification in 2045;
- Assume new construction reflects the average of existing buildings, which shifts towards all-electric over time. Assume no change in space or water heating technology in homes heated using electricity today;
- Estimate the peak load impact of each newly electrified space heating, water heating, and EV load;
- Assign those new loads proportionally across the feeders in that county;

- Evaluate whether the new load leads to a peak load in excess of a given feeder's rated capacity;
- If the load exceeds the rated capacity, add the cost to build a new feeder alongside the existing feeder; and
- If the overall load on a substation exceeds that substation's rated load, add the cost to build a new substation.

Q. What are your major concerns with 1898 & Co.'s methods and assumptions?

A. Specifically, 1898 & Co. made unreasonable assumptions and used inaccurate methods in the following areas:

- Peak coincidence
- EV loads
- Heat pump performance
- Efficiency improvements and existing electrically heated buildings
- Cost model

Q. What are your concerns regarding peak coincidence?

A. 1898 & Co. used only the summer peak load for each feeder as the starting point for its calculations. This peak load generally occurs in the afternoon or early evening of a hot summer day. 1898 & Co. adjusted this peak load to account for growth and energy efficiency, then added the assumed peak electric loads from each technology to this starting point. This is nonsensical for multiple reasons. First, it adds the peak new electric *heating* load, which would generally occur on the coldest winter morning, to the summer peak load. For feeders that peak in the summer, this overstates the peak load because the space heating load should be added to the coincident winter load. For feeders that peak in the winter, 1898 & Co. and BGE acknowledged the error of using the summer peak.[61] Because BGE has more summer-peaking feeders than winter-peaking ones, and higher overall load in summer than in winter, the net effect of this error is to overstate the need to add distribution capacity.

Second, 1898 & Co. assumes that the peaks for several different end uses—including space heating, water heating, and vehicle electrification loads—are coincident with the peaks on each feeder. In reality, the respective peaks for those end uses are driven by a wide range of factors and occur at different times of day.

Q. What are your concerns regarding assumed EV loads?

[61] BGE's response to OPCDR10-03(A).

A. 1898 & Co. assumes an unreasonable amount of EV charging load. The 1898 & Co. analysis assumes that 84 percent of EVs charge for two hours at 19.2 kW every night (resulting in a total average nightly energy draw of 38.4 kWh for each EV), and that 20 percent of cars that charge at night are charging at any given time. That is, 1898 & Co. assume five segments of the fleet, each charging for 2 hours, distributed over 10 hours of nighttime. For purposes of grid impacts, this is effectively assuming that each EV charges at 3.84 kW for 10 hours. 1898 & Co. assumes that the remaining 16 percent of EVs charge during the day and that their charging is not peak-coincident.

EVs generally have a fuel economy of about 3 miles per kWh of energy. This means that charging 38.4 kWh every night is enough energy to drive 115 miles per day, or almost 42,000 miles per year. In fact, vehicles in Maryland drive just over 11,000 miles per year.[62] As a result, 1898 & Co. overstates the potential EV load by a factor of about 3.75.[63] This extreme overestimate results in nonsensically high peak loads and resulting infrastructure needs.

Q. What are your concerns regarding assumed heat pump performance?

[62] In 2021, Maryland roads experienced 56.616 billion miles of driving. The state had 5.07 million registered vehicles. The ratio is 11,169 miles per vehicle.
[63] 115 miles per day * 365 days divided by the average per vehicle mile of 11,169 miles in 2021.

A. 1898 & Co. assumes that all ASHPs would be operating at the efficiency of electric resistance heat during peak conditions, which it describes as "polar vortex" conditions. During "polar vortex" conditions in Maryland, temperatures reach as low as 1 degree F according to BGE and E3 (BGE response to OPCDR-22-07). To the extent that cold climate ASHPs are used, this assumption is unreasonable because such heat pumps are designed to maintain adequate capacity and operate very efficiently during such conditions, as I explained in detail in the early part of this section above. Thus, 1898 & Co. is effectively anticipating that no cold climate heat pumps are used in Maryland. However, this assumption is counterbalanced by an assumption that during peak conditions, heat pumps would only be running about half the time (that is, a diversity factor of 50 percent). In practice, during the coldest period for which a heating system is designed, such as a polar vortex, it would be expected to run 100 percent of the time.

The net effect of 1898 & Co.'s underestimating both the efficiency and/or use of cold climate heat pumps and the frequency of heat pump use during peak conditions is that 1898 & Co. assumed the use of ASHPs with an effective efficiency of about 200 percent. While this may be a reasonable assumption at winter peak given improvements in cold climate performance, the errors on which it is based point to a worrisome lack of understanding of heat pump technology and use, which demonstrates how unreliable and inappropriate the study is as a basis for decision-making.

Q. What are your concerns regarding efficiency improvements and electrically heated buildings?

A. 1898 & Co. assumed an annual reduction in peak electric consumption of 0.2 percent as a result of increasing efficiency and a 0.1 percent impact from reducing line losses during peak times. These levels of efficiency improvement are not grounded in any evaluation of Maryland's building stock or the potential for cost-effective efficiency being pursued by the EmPOWER program. 1898 & Co. assumes new construction loads to be equivalent to today's buildings, without accounting for building code improvements. As a result, the starting point load for 1898 & Co.'s analysis is too high. 1898 & Co. also neglected to include the potential impact of market transition (with or without programmatic encouragement) on homes with electric resistance-based water heating and space heating. Homes which upgrade from resistance-based space and water heating to heat-pump-based options will see a reduction in their winter peak load. For water heating, the impact is clear and not weather dependent: a new HPWH reduces electric consumption by a factor of 3 or more relative to a resistance-based starting point. For space heating, peak loads decline after accounting for the real-world cold-climate performance of these technologies, as I discussed above.

Q. What are your concerns regarding 1898 & Co.'s cost model?

A. 1898 & Co. assumed that a new feeder needs to be constructed the moment the peak load on a given feeder passes the maximum load. Most of BGE's feeders have a capacity of 9.9 MVA. This approach builds a new feeder identical to the existing feeder if the load reaches 10.0 MVA. This is true even if the other feeders on the same substation have excess capacity. 1898 & Co's report itself states that the resulting model is "very non-optimized" and not based on reality of engineering, design, or construction.[64] This method ignores the real-world steps that a utility would take, such as shifting load to nearby feeders.

Q. What are your conclusions regarding the suitability of the 1898 & Co. study as a basis for conclusions regarding the impact of electrification on BGE's system?

A. The 1898 & Co. analysis should not be relied upon to draw the conclusions that Witness Case draws from it. A corrected analysis would not show that peak load would "more than triple." Such analysis would likely produce results closer to a forecast recently developed by the New York Independent

[64] Page 10: "Further, the model creates an idealized grid design on one hand and a very non-optimized design on another. Substation design is simplified. If a feeder is overloaded, the model mechanically adds another feeder following the existing right of way. Both are not based in the reality of engineering, design, and construction, but are simplifications for the purposes of 'what-if' modeling."

System Operator (NYISO), which shows a winter peak load increase of just about 60 percent by 2045 due to building and transportation electrification.[65]

C. If the Commission does not remove BGE's Electrification Programs from consideration in the MYP, program designs and incentives for some of the programs would need to be modifed.

Q. Please summarize key issues you identified in BGE's proposal on building and non-road electrification programs.

A. I found the following major issues with BGE's proposal on building and non-road electrification programs.

- Per-customer incentive amounts BGE assumed for heat pumps, HPWHs, and make-ready measures are too high.
- The proposed program administration costs are too high.
- BGE's building electrification proposal relies on a downstream incentive approach instead of a midstream incentive approach.
- BGE has not provided sufficient evidence to support and justify the proposed non-road electrification programs.

Q. Please elaborate on why the per-customer incentive amounts assumed by BGE for certain measures are too high.

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[65] NYISO. 2022. *2022 Load & Capacity Data Gold Book*. Page 22. Available at https://www.nyiso.com/documents/20142/2226333/2022-Gold-Book-Final-Public.pdf.

A. BGE calculated utility incentive levels and the total budget for the incentives in a confidential Excel file OPCDR14-08 CONFIDENTIAL Attachment 1. This file shows that BGE properly incorporated the federal IRA rebates for heat pumps, HPWHs, and electrical panel upgrades. However, BGE confirmed that it did not incorporate the available federal tax credits for these measures and for geothermal heat pumps in its response to OPC's data request.[66] Geothermal heat pumps are now eligible for 30 percent tax credits.[67] Both heat pumps and heat pump waters are eligible for $2,000 federal tax credits, and electrification make-ready investment (i.e., electrical panel upgrades) are eligible for $600 tax credits.[68]

Q. What is your recommendation about how BGE should adjust the utility incentive levels?

A. I recommend that BGE's incentive levels be adjusted downward by the amount of available federal tax credits: the total combined incentives should be no more than the total installed measure costs for low-income households with incomes below 80 percent of the Area Median Income (AMI) and moderate-income households whose incomes are between 80 and 150 percent of the AMI. These households are eligible for the IRA rebates. For

[66] BGE's response to OPCDR34-01, part C.
[67] U.S. EPA. 2022. "Geothermal Heat Pumps Tax Credit." Available at: https://www.energystar.gov/about/federal_tax_credits/geothermal_heat_pumps.
[68] Rewiring America. "25C Residential Energy Efficiency Tax Credit and 25D Residential Clean Energy Tax Credit." Available at: https://www.rewiringamerica.org/ira-fact-sheets.

the rest of the households with income above 150 percent of the AMI, I recommend that BGE's incentives should still be adjusted downward by the amount of federal tax credits; but the total combined incentives should not exceed the total incremental measure costs, which represent the cost premium of electrification measures relative to the cost of standard fossil-based measures (e.g., gas furnace, gas water heater).

Q. How do your recommended incentive adjustments change per-customer utility incentives and the overall incentive budget?

A. Applying the incentive adjustments I mentioned above, I estimated the incentive levels for each of the three income groups that are included in the Excel file OPCDR14-08 CONFIDENTIAL Attachment 1. BGE has its own estimates of the share of customers in these income groups who would participate in BGE's electrification program. Column (2) of the table below presents the weighted average of BGE's proposed incentive levels across the three income groups by measure type. Column (3) shows measure incentives that were revised to take into account federal tax credits. As shown in column (5), incentives were reduced by 20 percent for GSHPs, 53 percent for ASHPs, 44 percent for mini-split ASHPs, 100 percent for HPWHs, and 44 percent for make-ready investments.

Table 3. BGE Per-Customer Incentives for Residential Electrification with Federal Tax Credits

(1) Measure type	(2) BGE average ($)	(3) Revised - average ($)	(4) Difference ($)	(5) Difference (%)
GSHP	$7,500	$5,993	$1,507	20%
ASHP	$4,039	$1,881	$2,159	53%
Mini-Split ASHP	$4,596	$2,590	$2,005	44%
HPWH	$1,367	$0	$1,367	100%
Make Ready	$1,350	$750	$600	44%

Based on these per-customer incentives and BGE's projected participants, I estimated the total incentive budget for each measure type in the table below. I estimate that that the federal tax credits could reduce BGE's estimated incentive budget by approximately $74 million, or 50 percent. Note that these estimates assume no caps on federal IRA rebates.

Table 4. BGE Total Incentive Budget Estimates for Residential Electrification with Federal Tax Credits

	Original - ($)	Revised - ($)	Difference ($)	Difference (%)
GSHP	$733,690	$586,285	-$147,405	-20%
ASHP	$106,091,852	$57,431,208	-$48,660,644	-46%
Mini-Split ASHP	$6,363,229	$4,105,621	-$2,257,608	-35%
HPWH	$15,021,336	$0	-$15,021,336	-100%
Make Ready	$18,534,044	$10,296,691	-$8,237,353	-44%
Total	$146,744,152	$72,419,806	-$74,324,346	-51%

BGE's final incentive budget estimate assumes substantial reductions in federal IRA rebates as each state has its own allocated budget for the IRA rebates. The table below presents BGE's final incentive budget estimate and my revised incentive budget estimate. Overall, I estimate that federal tax credits could reduce the incentive budget by approximately $74 million or by 30 percent, assuming that every homeowner is eligible to receive federal tax credits. However, not every homeowner is eligible for federal tax credits because homeowners can only use it to decrease or eliminate their tax liability.[69] According to the Tax Policy Center, approximately 40 percent of households did not owe federal income taxes.[70] This means that these households would not have been eligible for federal tax credits. Based on this data and to be more conservative, if I assume 50 percent of program participants would not be eligible for federal tax credits, I estimate that BGE could reduce the incentive budget by approximately $37 million (half of $74 million that I estimated above).

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[69] IRA. "Q&A on Tax Credits for Sections 25C and 25D." Available at: https://www.irs.gov/pub/irs-drop/n-13-70.pdf.

[70] Tax Policy Center. 2022. "T22-0132 - Distribution of Tax Units with Zero or Negative Individual Income Tax, By Expanded Cash Income Percentile, 2022." Available at: https://www.taxpolicycenter.org/model-estimates/tax-units-with-zero-or-negative-federal-individual-income-tax-oct-2022/t22-0132.

Table 5. BGE Total Incentive Budget Estimates for Residential Electrification with Federal Tax Credits before Adjusting for Tax credit eligibility

	Original - ($)	Revised - ($)	Difference ($)	Difference (%)
GSHP	$733,690	$586,285	-$147,405	-20%
ASHP	$173,046,874	$124,386,007	-$48,660,867	-28%
Mini-Split ASHP	$10,111,635	$7,854,027	-$2,257,608	-22%
HPWH	$22,902,032	$7,880,696	-$15,021,336	-66%
Make Ready	$37,074,753	$28,837,399	-$8,237,353	-22%
Total	$243,868,983	$169,544,414	-$74,324,570	-30%

Q. Are there any other potential issues with BGE's incentive amounts?

A. Yes. Per-customer incentives for ASHPs could be reduced further as BGE's estimates for the total cost of ASHPs could be potentially overstated. According to OPCDR14-08 CONFIDENTIAL Attachment 1, ****BEGIN CONFIDENTIAL**** [redacted]. ****END CONFIDENTIAL**** BGE stated these costs were estimated using several sources, including SoCalEdison's proposed electrification projects and NY Clean Heat Program performance data and feedback from trade allies in the Baltimore area. However, the 1898 & Co study mentioned national average costs of $7,700 for high efficiency heat pumps and $5,700 for regular heat pumps for single-family residential units.[71] In response to OPCDR34-02, BGE stated that "1898 & Co. also validated these costs through a personal

[71] OPCDR01-01_Attachment1, at 19.

communication with a representative of a national distributor of heat pump systems for the mid-Atlantic zone, which covers the BGE service territory."[72] I expect that the HVAC costs in Baltimore are slightly lower than the national average costs, based on RS Means' location cost factor for Baltimore.[73] This means that BGE's heat pump costs are potentially overstated substantially.

Q. What is your recommendation based on your analysis of customer incentive levels?

A. If the Commission decides to allow the electrification plan (which, as explained above, I recommend against), I recommend that BGE should reduce the incentive levels by the federal tax credits as I described above. However, instead of reducing the total incentive budget, I recommend that BGE should support more program participants with the freed-up budget of approximately $37 million (or potentially more if the total costs of heat pumps are less than what BGE is assuming currently) and further promote building electrification. I also recommend that, if the Commission decides to approve BGE's electrification proposal, the Commission direct BGE to conduct a state-specific survey on the costs of building electrification measures. BGE can use the results to develop the right amount of

[72] OPCDR34-02.
[73] The cost of building systems in Baltimore is 94 percent of the national average, according to RS Means. See PDF page 60 of this online document: https://www.rsmeans.com/media/wysiwyg/quarterly_updates/2021-CCI-LocationFactors-V2.pdf.

electrification incentives per customer since it does not currently possess any Maryland-specific data on heat pump costs, let alone Baltimore-specific data. Furthermore, I recommend the Commission establish guidance on customer incentive setting for electrification measures and require BGE to use the guidance to set incentives and develop the total budget for customer incentives. Ideally, such a guidance should be developed through a stakeholder process, but I offer the following minimum recommendations: for low-income and moderate-income customers, the total incentives that comprise federal rebates, federal tax credits, and utility incentives should not exceed 100 percent of the total measure costs. For the rest of the customers, the total incentives should not exceed 100 percent of the total incremental costs of electrification measures. For example, if a heat pump costs $7,700 and a gas furnace costs $5,700, the total incremental cost for the heat pump is $2,000.

Q. Please elaborate on why BGE's proposed administrative budget is too high.

A. One reasonable approach to assess whether a budget estimate is reasonable is to look at the average budget per program participant. This approach indicates how much money BGE is planning to spend to reach and acquire each program participant and deliver/install measures on average. I compared BGE's residential BE Program non-incentive budget to BGE's reported 2022 residential HVAC EmPOWER budget. I found that on a per-customer basis BGE assumes a much higher program budget for program administration, marketing, and evaluation, measurement, and verification (EM&V), as shown in Table 6 below.

Table 6. Comparison of cost per participant for BGE's residential BE program and EmPOWER residential HVAC program

Budget Category	**BE Residential Program 3-year Cycle Total**	**EmPOWER HVAC 2022 Reported Budget**
Utility Admin	$29.92	$16.28
Outside Services	$198.94	$131.38
Marketing and Median Buys	$175.88	$119.31
EM&V	$23.43	$28.28
Total (excluding incentives)	$428.18	$295.25

Q. If we assume the same per-customer budget estimate based on EmPOWER Maryland's recent spending for BGE's building electrification program, how would this affect the overall budget?

A. Table 7 below shows an estimated budget for BGE's residential BE Program based on the EmPOWER HVAC per-customer budget in Table 6 above. If I assume EmPOWER's cost-per-participant estimate, the total cost of BGE's proposed residential BE Program would be about $7.7 million lower. However, I expect that BGE could reduce the non-incentive budget further if the Company offers its electrification programs within EmPOWER. Thus, I recommend the PSC should direct BGE to combine forces with EmPOWER and develop a revised budget.

Table 7. Adjusted non-incentive budget for BGE residential BE program

Budget Category	Adjusted Non-incentive Budget
Utility Admin	$940,558
Outside Services	$7,589,493
Marketing and Media Buys	$6,892,135
EM&V	$1,633,604
Total Excluding Incentives	**$17,055,790**
Reduction from original non-incentive budget	$7,679,159

Q. Please summarize BGE's incentive approach for the proposed building electrification programs.

A. BGE proposes to provide prescriptive "downstream" incentives offered through the utility to customers, downstream, using EmPOWER delivery channels. The term "downstream" refers to incentives that are targeted towards end-use customers. In contrast, "midstream" incentives are delivered in the middle of the supply chain to vendors or contractors.

Q. What is your concern about BGE's incentive approach?

A. Downstream incentives can be cumbersome for the customer as well as the rebate provider, potentially leading to lower participation and higher overhead costs. Furthermore, the HVAC programs offered through EmPOWER have largely transitioned to a midstream model where incentives are targeted at equipment distributors and installation contractors.[74] If BGE offers other rebates for heat pumps and HPWHs downstream through its BE Program, BGE will be duplicating efforts with the EmPOWER programs and potentially creating confusion for customers and contractors. OPC has previously expressed concerns with the lack of a streamlined approach for EmPOWER HVAC and Appliance Rebates programs.[75] I agree with this concern. Offering incentives outside of EmPOWER is not streamlined and creates greater confusion.

Q. Why do you recommend a midstream incentive approach?

Midstream incentive models provide several benefits. Rather than requiring the customer to claim a rebate, which can take time and effort and may have delayed reimbursement periods, midstream models apply incentives before they reach the customer. Midstream incentives thus require no effort from the customer; rebates are applied "behind the scenes." Distributors pass price discounts directly to contractors, who in turn pass the discounts to customers. Midstream models can also help with market transformation because direct incentives to distributors and retailers will encourage them to keep these newer and more efficient products in stock, rather than having them as special-order items.

[74] VEIC. 2022. *Comments to the Maryland Public Service Commission on EmPOWER Semi-Annual Reports for Q3-Q4 2022*. Prepared for the Office of the People's Counsel. ML#302522.
[75] Ibid.

Efficiency Vermont offers an example of a successful midstream incentive structure. Incentives are applied as an instant discount to contractors at the point of purchase via wholesale distributors, rather than an end-use customer rebate.[76] A study on electrification in the Northeast found that Efficiency Vermont's midstream program model achieves the highest annual installation rate (1.26 percent of homes) out of the 10 programs surveyed, most of which offer downstream incentives.[77]

Q. What is your concern about BGE's non-road electrification program proposal?

A. BGE's non-road electrification program is a very novel program that provides financial incentives to various types of industrial equipment and machines. These include forklifts; golf carts; welders; belt loaders; machinery for pressing, cutting, and folding; injection molding machines; refrigerated rail cars; robots; and ovens.[78] BGE stated that to develop incentives, it relied on incentive benchmarks from utility programs offered by JEA, Salt River Project, Entergy, and CenterPoint Energy and by comparing cost estimates from a few different sources such as manufacturer and dealer interviews. I reviewed these utility incentive programs but was

[76] Nadel, Steven. *Programs to Electrify Space Heating in Homes and Buildings.* ACEEE Topic Brief. June 2020. Available at: https://www.aceee.org/sites/default/files/pdfs/programs_to_electrify_space_heating_brief_final_6-23-20.pdf
[77] Levin, E. 2018. Driving the Heat Pump Market: Lessons Learned from the Northeast. Winooski: VEIC (Vermont Energy Investment Corporation). www.veic.org/clientsresults/reports/driving-the-heat-pump-market-lessons-learned-from-the-northeast.
[78] Exhibit MDC-5, page 10.

not able to find any additional measure information such as market evaluation studies or cost-effectiveness results about the programs offered by the four utilities. I am also not aware of any other utilities that offer electrification incentives for C&I machines. More importantly, I found that BGE has not conducted any market study and does not have any data about the current share of the measures BGE would be promoting under the proposed program.[79] Without such data, I cannot assess how much these measures should be promoted and the level of incentives that should be provided. There may be some measures that may not need any incentives because customers may be already choosing electric machines over fossil-fuel-based machines. Such measures would have a very high number of free riders under BGE's program.

Q. What is your recommendation for the non-road electrification program?

A. I recommend that that the Commission not allow BGE to implement the non-road electrification program proposal entirely (about $6.6 million) because BGE has not provided sufficient evidence to justify the proposed spending.

Q. Have you reviewed the cost-effectiveness results for the proposed customer-side electrification programs? If so, do you have any concerns on the cost-effectiveness results or methodologies?

[79] BGE's response to OPCDR14-06.

A. Yes. BGE has conducted a detailed cost-effectiveness analysis on its proposed building and non-road electrification programs. This is a good start, but we should not take the results of the cost-effectiveness analysis at face value for electrification programs at this point, for a number of reasons. First, electrification programs should be implemented in EmPOWER Maryland and I expect that program designs for such programs will be different from what BGE is proposing in this filing. This means that cost-effectiveness results could be very different for those future programs. Second, there are many issues that need to be addressed before implementing the programs, including how to conduct cost-effectiveness tests on electrification programs; what benefits and costs should be used; and what the appropriate level of benefits and costs are.

Q. Please summarize your key recommendations concerning BGE's customer-side electrification program proposal?

A. My recommendations on BGE's proposed building and non-road electrification programs include the following:

- The Commission should deny approval of BGE's proposed electrification programs in the MYP.
- If BGE wishes to pursue its electrification programs, the Commission should direct BGE to propose its building and non-road electrification

programs within the EmPOWER program instead of in this proceeding.

- The Commission should investigate key policy and program implementation issues concerning electrification programs in in the EmPOWER docket or another policy docket. Among other things, the Commission should investigate program designs, the role of the utilities and other entities, performance incentives, cost-effectiveness analysis framework, goal setting, cost recovery, customer equity and bill impacts, federal incentives, and gas planning.

If the Commission decides to approve BGE's electrification program proposal, or if BGE seeks approval for its electrification programs within EmPOWER later, I recommend that the Commission direct BGE to modify some aspects of the proposed programs as follows:

- Remove the requirement to retain gas backup in the Company's building electrification programs;

- Increase the number of participants for residential ASHP, GSHP, HPWH, and make-ready investments (e.g., panel upgrades) using the additional funding that would be freed up by reducing measure incentive levels;

- Conduct a state-specific survey on the costs of building electrification measures—either individually or jointly with other utilities—in order to set appropriate amounts for electrification incentives;
- Offer electrification incentives through a midstream incentive approach instead of a conventional downstream incentive approach;
- Remove the non-road electrification program proposal entirely (approximately $6.6 million); and
- Conduct a market characterization study on C&I non-road measures.

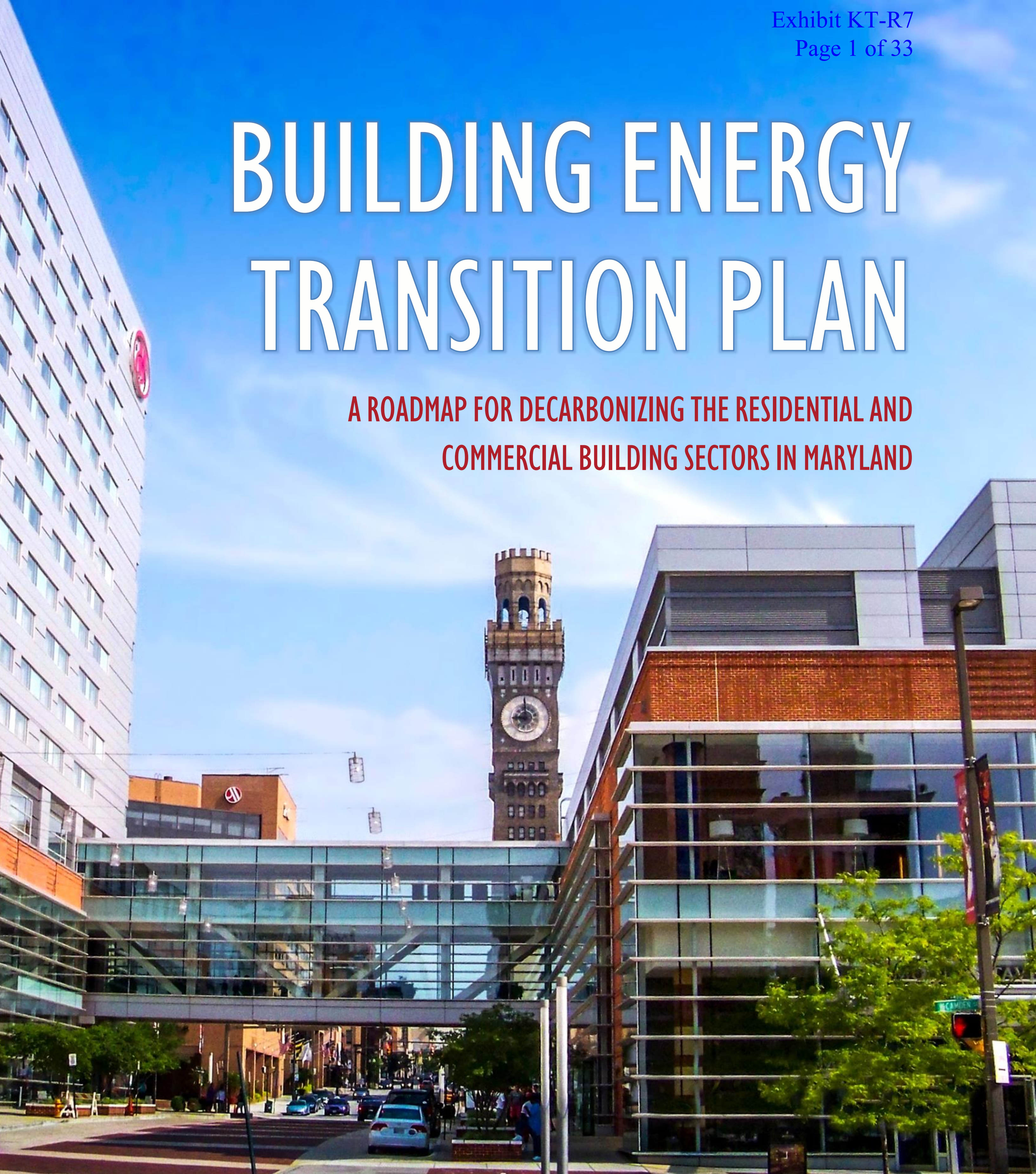
Finally, I recommend that the Commission establish guidance on customer incentive-setting for electrification measures and require BGE to use the guidance to set incentives and develop the total budget for customer incentives. Ideally, such guidance should be developed through a stakeholder process, but I offer the following minimum recommendations: for low-income and moderate-income customers, the total customer incentives that comprise federal rebates, federal tax credits and utility incentives should not exceed 100 percent of the total installed costs of measures. For the rest of the customers, the total incentives should not exceed 100 percent of the total incremental costs of electrification measures (e.g., the cost difference between a heat pump and a gas furnace).

Q. Does this conclude your testimony?

A. Yes.

BUILDING ENERGY TRANSITION PLAN

A ROADMAP FOR DECARBONIZING THE RESIDENTIAL AND COMMERCIAL BUILDING SECTORS IN MARYLAND



MARYLAND COMMISSION on CLIMATE CHANGE

Ben Grumbles, Chair

This is a report by the Maryland Commission on Climate Change, which is charged with advising the Governor and General Assembly on ways to mitigate the causes of, prepare for, and adapt to the consequences of climate change. The Commission is chaired by the Maryland Department of the Environment Secretary Ben Grumbles and consists of members representing state agencies, the Maryland General Assembly, local government, business, environmental non-profit organizations, organized labor, philanthropic interests, and universities in Maryland.

Policy proposals included in this report are supported by the Commission but do not necessarily reflect current state policy. This report is meant to guide Maryland policymakers on decisions related to reducing greenhouse gas emissions from buildings in pursuit of achieving targets in Maryland’s 2030 Greenhouse Gas Reduction Act Plan and the Commission’s recommendation that Maryland achieve net-zero emissions economywide by 2045.

November 2021

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Executive Summary

Direct use of natural gas, heating oil, and propane in buildings – primarily for space heating and water heating – accounted for 13 percent of Maryland's greenhouse gas emissions in 2017. Maryland's 2030 Greenhouse Gas Reduction Act (GGRA) Plan calls for reducing emissions from buildings through energy efficiency and by converting fossil fuel heating systems to electric heat pumps. Heat pumps are essentially air conditioners that can reverse cycle to provide efficient heating and cooling in one system, powered by increasingly clean electricity. They are already the second most common heating system in Maryland.

While the 2030 GGRA Plan sets a goal of electrifying fossil fuel end-uses in buildings, it also calls on the Maryland Commission on Climate Change (MCCC) to develop a Building Energy Transition Plan to identify specific measures and goals to decarbonize the buildings sector.

Energy + Environmental Economics (E3) examined four scenarios that would nearly achieve net-zero emissions for Maryland's residential and commercial buildings sectors by 2045, aligning with the MCCC-recommended target for economywide emissions reductions. E3 found that a "MWG Policy" scenario is the lowest-cost scenario among all that were modeled. E3's findings include estimated future costs and benefits based on a certain set of assumptions; actual results could differ from the findings included in this report.

What is the MWG Policy scenario?

The MCCC's Mitigation Work Group (MWG) formed a Buildings Sub-Group to guide E3's study and craft this Building Energy Transition Plan. A broad and diverse group of stakeholders provided valuable input over seven months and developed the policy recommendations presented herein. E3 modeled an "MWG Policy" scenario to evaluate the impacts of this Plan and recommendations, which are based on four core concepts:

- Ensure an equitable and just transition, especially for low-income households
- Construct new buildings to meet space and water heating demand without fossil fuels
- Replace almost all fossil fuel heaters with heat pumps in existing homes by 2045
- Implement a flexible Building Emissions Standard for commercial buildings

E3 found that implementing this Plan would:

- Reduce emissions from residential and commercial buildings by 95 percent by 2045
- Reduce construction and energy costs for most building types
- Ramp up electricity system investments to around $1B annually by 2045
- Ramp down gas system investments, saving around $1B annually by 2045
- Increase electricity rates by 2 cents per kilowatt-hour by 2045
- Provide the lowest gas rates among all scenarios modeled

Core Recommendations

This Plan includes four Core Recommendations (and 12 additional recommendations) that are designed to achieve a just transition to a decarbonized buildings sector in Maryland.

1. **Adopt an All-Electric Construction Code** – The General Assembly should require the Maryland Building Code Administration to adopt a code that ensures that new buildings meet all water and space heating demand without the use of fossil fuels. A cost-effectiveness test would allow building projects to seek variances to code requirements while maintaining electric-ready standards.

2. **Develop a Clean Heat Retrofit Program** – The General Assembly should require and provide funding to state agencies to implement programs (with the utilities, if applicable) that would:
   a. Retrofit 100 percent of low-income households by 2030
   b. Encourage fuel-switching through EmPOWER beginning in 2024
   c. Encourage beneficial electrification through EmPOWER beginning in 2024
   d. Target 50 percent of residential heating system, cooling system, and water heater sales to be heat pumps by 2025, 95 percent by 2030
   e. Align energy plans, approvals, and funding with the objectives of this Plan

3. **Create a Building Emissions Standard** – The General Assembly should require the Maryland Department of the Environment to develop a Building Emissions Standard that would guide commercial and multifamily residential buildings to net-zero emissions by 2040. State-owned buildings would meet this standard by 2035. The General Assembly should also provide tax incentives and resources to help owners of covered buildings develop and implement emissions reduction measures. An alternative compliance pathway would be available to allow covered buildings to continue using fossil fuels when emissions reduction measures are unnecessarily expensive.

4. **Develop Utility Transition Plans** – The General Assembly should require the Public Service Commission to oversee a process whereby the electric and gas utility companies develop plans for achieving a structured and just transition to a near-zero emissions buildings sector in Maryland.

Background

The combustion of fossil fuels in buildings is a substantial source of greenhouse gas (GHG) emissions in Maryland. Most of this energy use is for space and water heating. Maryland's 2030 Greenhouse Gas Reduction Act (GGRA) Plan calls for reducing GHG emissions from residential and commercial buildings through energy efficiency and by converting fossil fuel heating systems to efficient electric heat pumps that are powered by increasingly clean and renewable electricity. The 2030 GGRA Plan shows a steady transition to heat pump adoption, leading to at least 80 percent of residential space heating systems being heat pumps by 2050.

While the 2030 GGRA Plan sets a goal of electrifying fossil fuel end-uses in buildings, it also calls on the Maryland Commission on Climate Change (MCCC) to develop a Building Energy Transition Plan to identify specific measures and goals to decarbonize the buildings sector. Programs are not yet in place to achieve the building energy transition envisioned by the 2030 GGRA Plan and additional building emissions reductions will be needed for Maryland to achieve post-2030 GGRA targets. More clarity is needed on the levels of efficiency, electrification, and other measures that will be necessary for Maryland to achieve its long-range emissions reduction goals while keeping energy costs affordable for Marylanders.

The MCCC's Mitigation Work Group (MWG) launched a Buildings Sub-Group in 2020 to explore pathways to attain deeper emissions reductions from buildings. The Sub-Group's work led to a report, Decarbonizing Buildings in Maryland, including recommendations for next-step actions. The Sub-Group continued its work in 2021, as called for in the 2030 GGRA Plan, to develop this Building Energy Transition Plan to serve as a roadmap for reaching net-zero emissions from residential and commercial buildings by 2045, aligning with the MCCC's recommendation that Maryland should achieve net-zero emissions economywide by that year.

The Maryland Department of the Environment (MDE) – with funding from the U.S. Climate Alliance and The Nature Conservancy – worked with Energy + Environmental Economics (E3) to conduct a Maryland Building Decarbonization Study, which serves as the foundation for this Building Energy Transition Plan. The Buildings Sub-Group provided guidance and review of E3's work from March through October 2021.

The contents of this Building Energy Transition Plan reflect findings from E3's study, the Sub-Group's proceedings over the past two years, input from various stakeholders, and building decarbonization policies developed by other states.

E3's Building Decarbonization Study

Key Findings

E3 initially modeled three scenarios that were selected by the Buildings Sub-Group in May 2021. Each scenario nearly[1] achieves net-zero emissions by 2045 for the residential and commercial buildings sectors. The initial three scenarios were:

High Electrification – Almost all buildings adopt heat pumps and improve shell performance by 2045. All-electric new construction starting in 2025.

Electrification with Fuel Backup – Existing buildings adopt and use heat pumps for most of the annual heating load by 2045, but existing furnaces and boilers provide backup heating in the coldest hours of the year. Fossil fuels are replaced with low-carbon renewable fuels by 2045. All-electric new construction starting in 2025.

High Decarbonized Methane – Most buildings use fuel for heating and improve shell performance by 2045. Fossil fuels are replaced with low-carbon renewable fuels by 2045.

The initial study uncovered several key findings that informed the Buildings Sub-Group's crafting of policy recommendations. Key findings included:

All-electric new buildings typically have the lowest construction and operating costs

- All-electric buildings produce zero direct emissions[2] and zero indirect emissions when electricity is produced from zero-emissions sources (the 2030 GGRA Plan calls for 100 percent clean electricity generation in Maryland by 2040).
- For single-family homes, all-electric homes cost less to construct than new mixed-fuel homes.
- For multifamily buildings, all-electric buildings cost about the same to construct as mixed-fuel buildings.
- For commercial buildings, all-electric buildings can have higher or lower construction costs than mixed-fuel buildings depending on building type and use.
- All-electric new buildings of all types – residential and commercial – have the lowest total annual costs (including equipment, maintenance, and energy costs) in every net-zero emissions scenario modeled.

[1] Each scenario depends on renewable low-carbon fuels to achieve net-zero direct emissions but methane leaks from in-state gas infrastructure would still produce indirect emissions, estimated to be at the following levels in 2045: 0.02 million metric tons (MMT) of carbon dioxide equivalent (CO2e) in the High Electrification scenario; 0.09 MMT CO2e in the Electrification with Fuel Backup scenario; and 0.19 MMT CO2e in the High Decarbonized Methane scenario. Indirect emissions from electricity consumption in buildings is assumed to be between 5 MMT CO2e and 0 CO2e depending on the pace of electricity sector decarbonization in states that supply power to Maryland.
[2] Excluding refrigerants such as hydrofluorocarbons that can leak from heat pump and air conditioning systems.

Retrofitting existing buildings with heat pumps can reduce equipment, maintenance, and energy costs

- Heat pumps work well in Maryland's climate and are already the second most common heating system used in buildings statewide.
- For single-family homes, the cost to install a heat pump (which provides heating and cooling) is close to the cost of replacing both an air conditioner and a gas furnace. At current utility rates, annual energy costs are comparable between homes with heat pumps and homes with gas furnaces. Annual energy costs are lower for homes with heat pumps than homes heated by electric resistance, oil, or propane.
- For multifamily buildings, the cost of installing heat pumps can be significantly less than the cost of replacing existing air conditioning and gas systems. At current utility rates, annual energy costs are comparable between housing units with heat pumps and units with gas heating.
- For commercial buildings, the cost-effectiveness of replacing heating and cooling systems with heat pumps depends on building type and use.

Electricity system capacity would need to increase to accommodate building and vehicle electrification

- Peak electricity demand could roughly double by 2045 driven by heating demand during the coldest hours of the year.
- New electricity system investments could increase electricity rates gradually, increasing residential electricity rates from 14 cents/kilowatt-hour (kWh) in 2021 to 18 cents/kWh in 2045 in a High Electrification scenario.
- Electricity system costs and rate impacts can be reduced through a variety of demand management measures.
- Annual electricity consumption in Maryland is projected to remain constant as increasing demand from buildings and vehicles is offset by energy efficiency.

Using low-carbon fuels for supplemental heating during the coldest hours of the year could reduce electricity system investments but a dual-fuel approach is complicated

- Replacing natural gas (historic cost around $3/MMBtu) with low-carbon fuels such as biomethane (estimated cost $10-25/MMBtu), hydrogen (estimated cost $15-25/MMBtu), or synthetic natural gas (estimated cost $30-70/MMBtu) could be a cost-effective alternative to building-out the electricity system to handle peak heating demand from a highly electrified building stock.
- An Electrification with Fuel Backup scenario would require sophisticated policy design and utility rate structures to encourage consumers to use fuel backup heating only during the coldest hours of the year.
- Using low-carbon fuels outside of the coldest hours of the year could lead to very high energy costs for consumers using fuel for heating.

Gas consumption is projected to decrease between 62 and 96 percent by 2045

- Gas consumption in buildings would decrease between 62 percent in the Electrification with Fuel Backup scenario and 96 percent in the High Electrification scenario.
- Gas delivery rates could increase more than 20-times the current rate for consumers left on the gas system, leading to significant equity concerns.

Stakeholder Feedback

The Buildings Sub-Group and MWG reviewed and discussed E3's initial findings between July and October 2021 and provided valuable feedback that led to the development of policy recommendations and refinement of E3's modeling. The following summarizes key points of discussion and explains how stakeholder input influenced the development of this Plan.

- **Equity and affordability are top priorities** – There was general agreement that reducing energy burden, making holistic improvements to homes, and ensuring that people are not left behind in the transition are priorities for decarbonization policy. This feedback informed recommendations on implementing holistic retrofits of 100 percent of low-income households by 2030, strengthening incentives for retrofit projects, mandating lowest-cost construction practices to improve housing affordability, and initiating utility transition planning processes to protect consumers from paying higher energy costs.
- **New buildings should be all-electric** – There was general agreement that new buildings should be constructed to all-electric standards but that a cost-effectiveness test should be used to allow buildings, especially commercial buildings, to be constructed with mixed-fuel equipment if all-electric construction is too expensive. This feedback was incorporated into a recommendation to adopt an all-electric construction code.
- **Commercial buildings need flexibility to reduce emissions** – There was general agreement that all-electric solutions are not always the most cost-effective measures for reducing emissions from commercial buildings. Commercial building owners should receive technical and financial support to identify and implement low-cost emissions mitigation measures, which could include offsetting emissions that are too expensive to eliminate. This feedback led to a recommendation to develop a flexible Building Emissions Standard.
- **A fuel-backup approach is problematic** – Several stakeholders raised concerns that implementing an Electrification with Fuel Backup scenario is impractical given utility ratemaking law and consumer behavior. Maryland's Office of People's Counsel wrote in its comments, "*The [Electrification with Fuel Backup scenario] would require coordinating rate setting for not one, but two, utilities. This expectation of precision rate setting is both legally and practically unrealistic... the effort under the [Electrification with Fuel Backup] scenario would require coordinating the price signals of two utilities with competing interests. These utilities will not agree on the proper price signals. Based on our experience, this assumption of efficient rate setting across utilities is not realistic.*"

The Office of People's Counsel added, "*The transition toward a clean energy system will require significant efforts to address equity impacts, but maintaining two systems [electric and gas] will significantly exacerbate inequities. It is undisputed that maintaining the gas system for backup use requires substantial increases in the rates for gas delivery. The high electrification case requires no backup fuels, thus obviating the need for the massive capital investments that have yet to be made to maintain the gas infrastructure.*" Other stakeholders expressed similar concerns. This feedback led to having E3 model a fourth scenario that shows a more practical approach to decarbonizing buildings.

- **Impacts of climate change, methane leaks from gas distribution, competition for low-carbon fuels, and other factors should be included in E3's modeling** – Stakeholders suggested several ways of improving E3's study methodology throughout the process. The U.S. Climate Alliance graciously provided additional funding to allow E3 to run several sensitivity analyses to address most of the improvements requested by stakeholders. The additional analyses refined E3's study results but did not change the key findings mentioned above.

Final Scenario Results

Several rounds of discussion on E3's initial study and draft versions of this Plan helped the Buildings Sub-Group and MWG hone-in on a roadmap and recommendations for decarbonizing buildings in Maryland. The core concepts are to:

- **Ensure an equitable and just transition, especially for low-income households**
- **Construct new buildings to meet space and water heating demand without fossil fuels**
- **Replace almost all fossil fuel heaters with heat pumps in existing homes by 2045**
- **Implement a flexible Building Emissions Standard for commercial buildings**

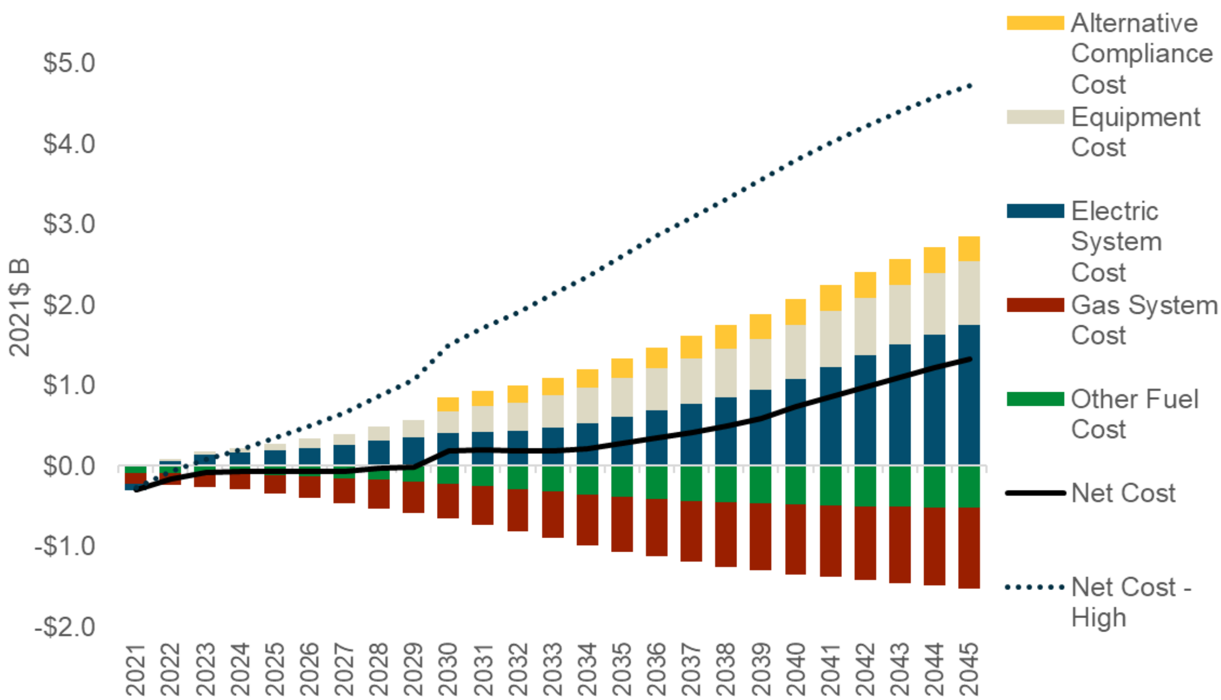
With additional funding from the U.S. Climate Alliance, E3 modeled a fourth scenario, called the "MWG Policy" scenario, to estimate the costs associated with this Plan. **The results show that the MWG Policy scenario has the lowest total cost of all four scenarios while also avoiding the need to maintain backup systems in homes or transitioning to expensive low-carbon fuels**.

Detailed results are included on the following pages.

Total Costs

The MWG Policy scenario requires investments in electricity grid infrastructure (to increase system capacity) and in building equipment (to replace fuel heaters with electric heat pumps). These investments help consumers reduce costs for natural gas, oil, and propane. Annual costs and savings are shown in Figure 1. This represents the lowest-cost scenario of all the decarbonization scenarios modeled.

Figure 1: Annual Incremental Total Resource Costs relative to Reference. Results account for climate change impacts on heating and cooling demand. Building shell improvements are excluded.[3]



In the low-cost scenario, net costs (without accounting for economic benefits such as job creation, health impacts, etc.) would remain around business-as-usual levels through the 2020s. Net costs increase in the 2030s and 2040s as capacity is added to the electricity system and most buildings complete the transition to becoming all-electric. Costs would level off after this period of infrastructure investments.

Alternative compliance costs, which are associated with the Building Emissions Standard proposed in this Plan, could begin in the 2030s for commercial, multifamily, and state-owned buildings that do not meet emissions reduction targets. The alternative compliance costs shown in Figure 1 are based on a modeling exercise assuming that owners of many buildings covered by the Building Emissions Standard would choose to pay a rate of $100 per metric ton of carbon dioxide equivalent (tCO2e) in leu of reducing emissions below target levels. Assumptions here are rough, so these above all other costs should not be taken as certain.

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[3] E3 included deep shell retrofits (wall insulation, roof insulation, glazing, air-tightness, and heat recovery) in its original study but determined that shell improvements are not necessary as cost-control measures in any scenario. E3 removed shell improvements from Figure 1 to illustrate a more likely cost projection for the MWG scenario.

Electricity System Impacts

Electricity system investments – for generation capacity, transmission, and distribution – are significantly lower in the MWG Policy scenario than in the High Electrification scenario. That is because achieving high electrification in Maryland's residential buildings has a small impact on peak electricity demand. E3's work on the MWG Policy scenario uncovered that commercial buildings in Maryland have a much greater impact on peak electricity demand than residential buildings have. As a result, the MWG Policy scenario, which modeled high electrification in the residential sector and modest electrification in the commercial sector, is projected to increase peak electricity demand only 3 gigawatts by 2045.

Figure 2: Incremental Electric System Costs relative to Reference in 2045. Details of the electric sector cost assumptions are documented in E3's Maryland Building Decarbonization Study.

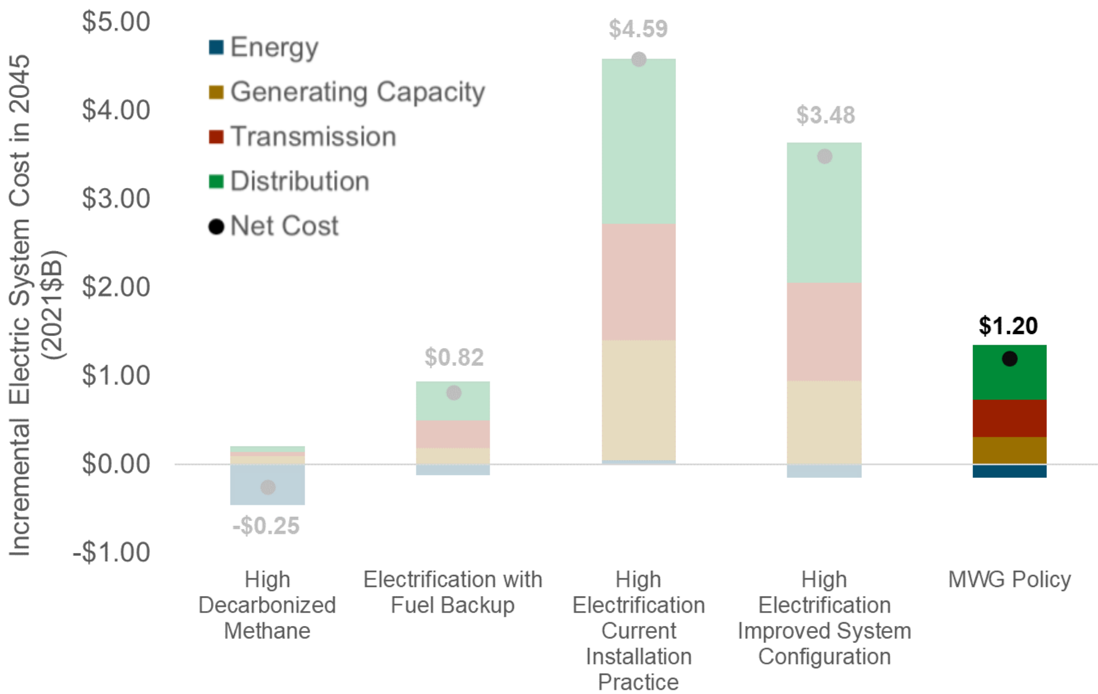
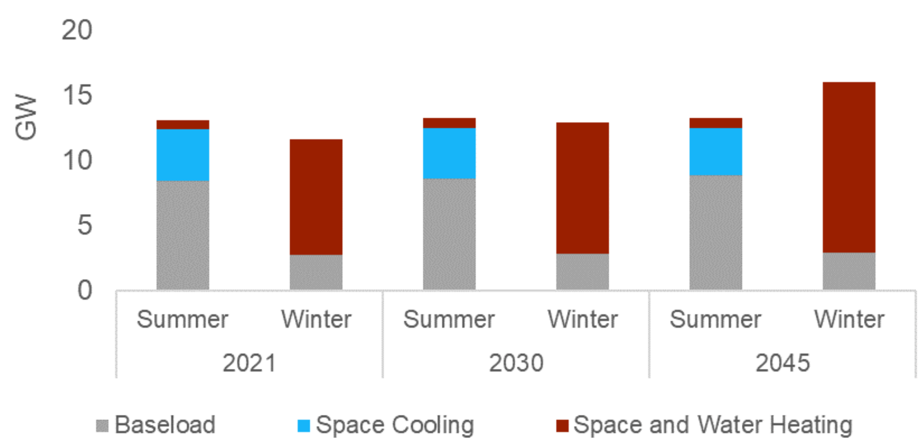


Figure 3: Peak Electricity Load Projections for the MWG Policy scenario. Based on typical summer and winter peak electricity demand.



Gas System Impacts

Gas system throughput decreases 75 percent in the MWG Policy scenario, which results in $1.3B in avoided gas system infrastructure costs and $20.7B in avoided fuel costs from 2021 through 2045. Fuel costs are much lower in the MWG scenario than the Electrification with Fuel Backup or High Decarbonized Methane scenarios because the MWG scenario avoids transitioning to expensive low-carbon fuels.

Figure 4: Incremental Gas System Costs relative to Reference in 2045. Details of the gas sector cost assumptions are documented in E3's Maryland Building Decarbonization Study.

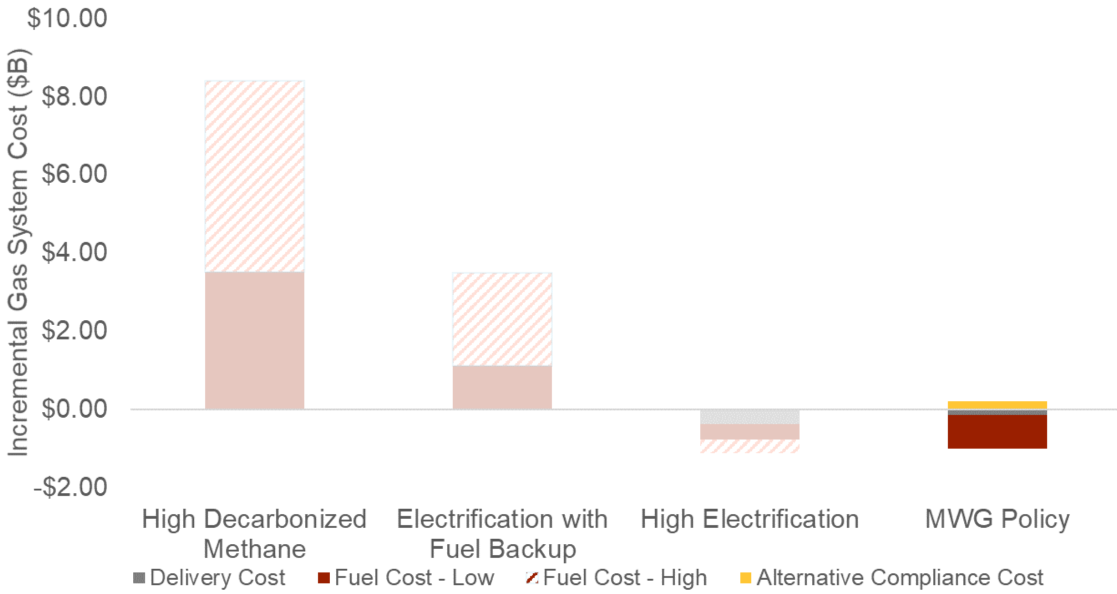
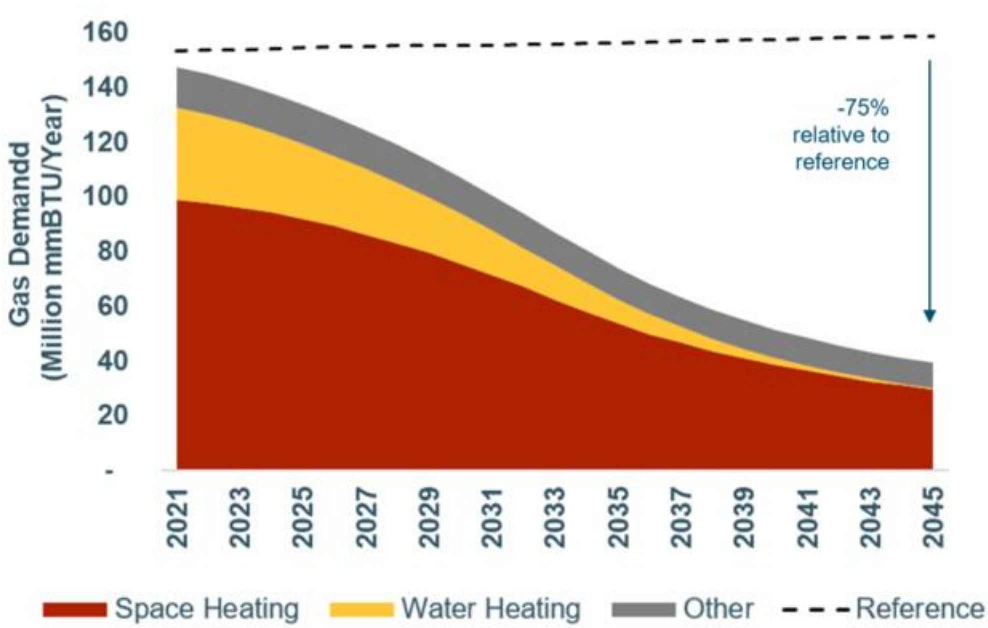


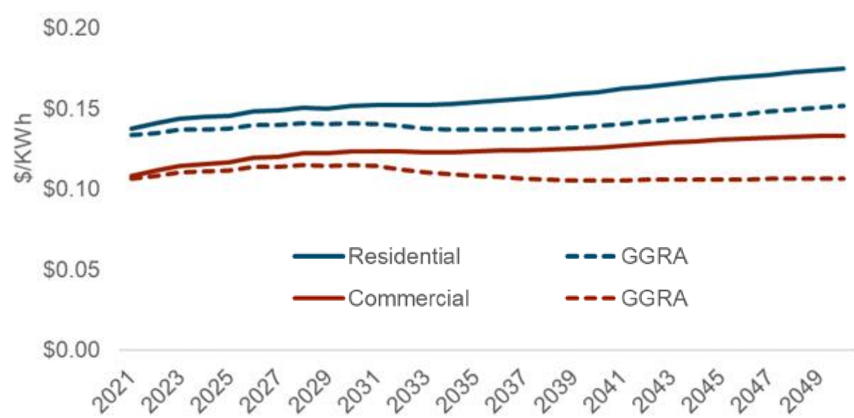
Figure 5: Gas Demand in 2021-2045 in the MWG Policy scenario. Most remaining gas consumption in 2045 would be in commercial buildings. Emissions from gas consumption in commercial buildings would be offset through the proposed Building Emissions Standard alternative compliance path.



Electricity and Gas Rate Impacts

Electricity rates increase gradually in the MWG Policy scenario to pay for the incremental electricity system costs. Rates are projected to increase from around 14 cents/kWh in 2021 to 17 cents/kWh in 2045 for residential customers and from around 11 cents/kWh in 2021 to 13 cents/kWh in 2045 for commercial customers. For both customer classes, rates are projected to increase by 2 cents/kWh by 2045 compared to the reference case.

Figure 6: Electricity Rates in the MWG Policy scenario



Although gas rate impacts are smaller in the MWG Policy scenario than any other scenario modeled, gas rates increase as consumers leave the gas system, leaving fewer consumers to pay for gas system costs. Gas rates remain flat through the 2020s but then climb to the $40-50/MMBtu range by 2045. This Plan recommends transitioning 100 percent of low-income households to heat pumps by 2030 to reduce energy burden for the most vulnerable Marylanders. Heat pump adoption in the commercial sector and the rest of the residential sector would ramp up in the 2030s as the costs of operating gas heating systems increase.

Figure 7: Residential Gas Rates

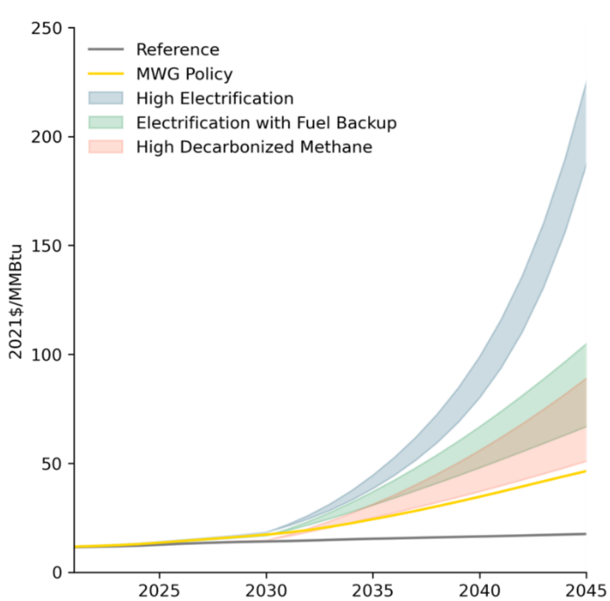
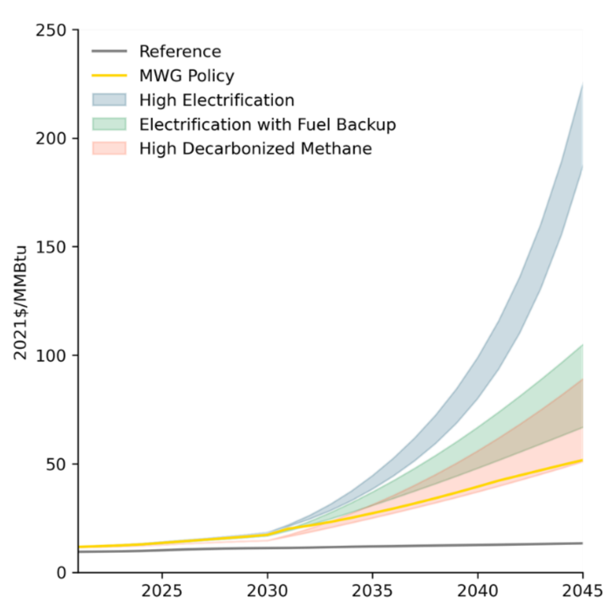


Figure 8: Commercial Gas Rates



Consumer Costs

Much of the heating equipment installed in the 2020s will be operational through the 2030s and into the 2040s, so it is important to consider not only what energy costs are today but what they will be over the lifecycle of equipment. E3 estimated annualized lifecycle consumer costs – including costs for equipment, operations and maintenance, and utility bills – for several types of buildings. Results are summarized in the following table.

Table 1: Annualized Consumer Costs in the MWG Policy scenario. Gas, electricity, and equipment costs are based on 2035 rates. Costs for shell improvements are included but E3 found that many shell improvements are not cost-effective, so actual consumer costs could be lower the costs reflected in this table. "Difference" is the annualized savings (or cost) of all-electric compared with mixed-fuel buildings.

		Mixed-Fuel	All-Electric	Difference
Single-family Residential	New Construction	$5,500	$3,800	$1,700
	Retrofit	$6,100	$5,500	$600
Multifamily Residential	New Construction	$4,100	$3,400	$700
	Retrofit	$3,900	$3,500	$400
Small Commercial	New Construction	$18,400	$15,500	$900
	Retrofit	$17,800	$15,500	$2,300
Large Commercial	New Construction	$150,000	$147,000	$3,000
	Retrofit	$139,000	$147,000	($8,000)

E3 found that, given continued improvement in the cost and performance of electric space and water heating equipment and projected increases in natural gas rates by 2035, most all-electric buildings will have lower lifecycle costs than mixed-fuel alternatives. The exception is an existing, large, mixed-fuel commercial building where the cost to retrofit it into an all-electric building could result in higher annualized costs. This is an example of the type of building that might pursue the Building Emissions Standard alternative compliance path instead of implementing measures to achieve net-zero direct emissions.

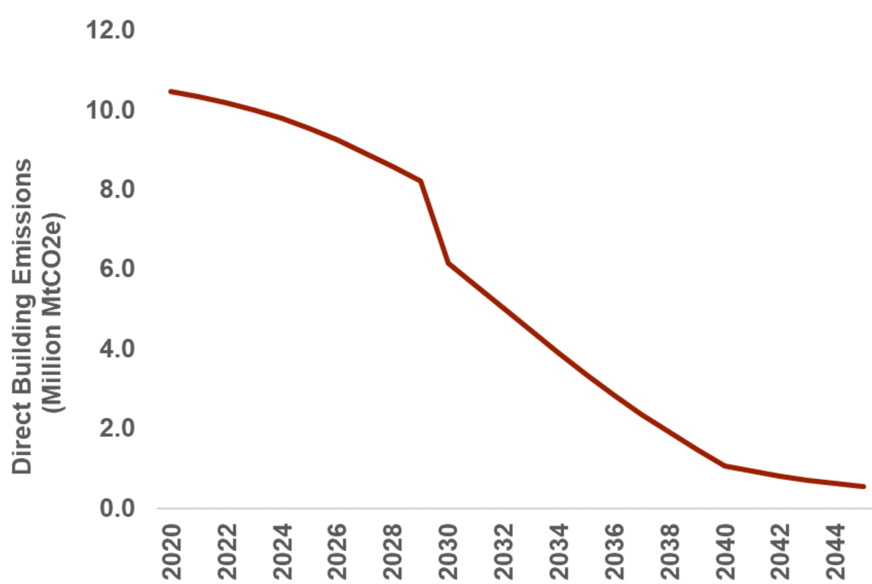
Emissions Reductions

Residential sector emissions reductions are heavily dependent on heat pump adoption rates. If greater than 90 percent of homes adopt heat pumps by 2045, then residential emissions would decrease at least 90 percent. E3's modeling assumes strong heat pump adoption rates, resulting in residential emissions falling around 90 percent, from 5.4 million metric tons of carbon dioxide equivalent (MMT CO2e) in 2017 to around 0.6 MMT CO2e by 2045.

Commercial sector emissions fall less sharply due to continued reliance on fossil fuels in many buildings. E3 estimates that commercial sector emissions could fall from 5.3 MMT CO2e in 2017 to around 3.1 MMT CO2e by 2045. These emissions, however, would be offset through the Building Emissions Standard alternative compliance program. Revenue from the alternative compliance program would be invested in carbon sequestration, negative emissions technologies, or other measures that would net-out remaining emissions from commercial, multifamily, and institutional buildings and allow the state to meet its emerging 2045 net-zero emissions goal.

Overall, E3 estimates that residential and commercial building emissions could decrease around 95 percent by 2045 including offsets from the alternative compliance program.

Figure 9: Greenhouse Gas Emissions in the MWG Policy scenario. Graph shows *net* emissions from residential and commercial buildings (direct emissions less commercial building emissions that are offset through the Building Emissions Standard alternative compliance program).



Roadmap and Recommendations

Building Decarbonization Roadmap for Maryland

Red shading indicates transition time to near-zero emissions

Sector	Measures	Target
New Homes	All-Electric Construction Code [P] Heat pumps for space heating/cooling and water heating Ready for solar, EV charging, and building-grid interaction	Zero direct emissions by 2024
New Commercial	All-Electric Construction Code [P] Heat pumps or other clean energy technologies where practical Ready for solar, EV charging, and building-grid interaction	Zero to low direct emissions by 2024
Existing Homes	Clean Heat Retrofit Program [P] Incentives for holistic efficiency, electrification, comfort, and safety upgrades [E] Gradual transition to an all-electric residential buildings sector	Zero direct emissions by 2045
Existing Commercial	Building Emissions Standard [P] Flexible, technology-neutral program Owners choose the best path for their buildings	Net-zero emissions by 2040
Electricity Supply	Clean and Renewable Energy Standard [L] Renewable Portfolio Standard [S] Regional Greenhouse Gas Initiative [S]	Zero emissions by 2040 [G]
Heating Fuel Supply	Gas Transition Plan [P] Plan for a significant reduction in gas consumption Building Emissions Standard alternative compliance/carbon offset [P]	Low emissions by 2045

Legend: P = Proposed herein E = Existing but should be strengthened G = GGRA Plan target L = Legislation introduced S = In statute

Core Recommendations

Each of the Core Recommendations correspond with a critical component of the Building Decarbonization Roadmap for Maryland (above), which presents a suite of policies that would collectively guide Maryland's residential and commercial building sectors to nearly achieve net-zero emissions by 2045.

1. Adopt an All-Electric Construction Code

The General Assembly should require the Maryland Building Code Administration to adopt a code that ensures that new buildings meet all water and space heating demand without the use of fossil fuels (allowing for the use of electric heat pumps, solar thermal, and other existing and potential clean energy solutions) and are ready for solar, electric vehicle charging, and building-grid interaction. This code shall apply to all new residential, commercial, and state-funded buildings beginning as early as possible but no later than 2024. Legislation should ensure that the Building Code Administration or appropriate local jurisdictions have authority, resources, and direction to effectively enforce compliance with the code. The Building Code Administration shall also develop and implement training courses on the benefits and challenges of all-electric and electric-ready buildings for building developers, realtors, real estate appraisers, and lenders.

The Building Code Administration shall allow exemptions for building types for which compliance with these requirements is not feasible. The Building Code Administration shall also develop a cost-effectiveness test to allow building projects to seek variances to code requirements while maintaining electric-ready standards. The cost-effectiveness test shall include the federal Social Cost of Carbon. If a new commercial building receives a variance and produces greenhouse gas emissions on-site, then it would participate in the Building Emissions Standard (proposed herein) and follow its own tailored plan for reaching net-zero emissions.

Discussion: A recommendation to adopt an all-electric construction code was supported by the MWG in 2020 but the MCCC wanted to receive this Building Energy Transition Plan before voting on the measure. Studies including E3's Maryland Buildings Decarbonization Study and RMI's The New Economics of Electrifying Buildings add to a body of work demonstrating that all-electric new homes have lower construction and energy costs than mixed-fuel homes. This means that all-electric new homes help improve housing affordability and local air quality while reducing greenhouse gas emissions in Maryland.

For commercial construction, all-electric design can increase construction and/or energy costs, which is why a test is proposed to help commercial building developers identify cost-effective clean energy solutions or receive a variance from the all-electric code. Residential building projects would also be able to seek variances using the cost-effectiveness test.

The New Building Institute's Building Decarbonization Code, which is an overlay to the 2021 International Energy Conservation Code (IECC) and compatible with ASHRAE 90.1, includes an all-electric pathway that is one possible solution for code adoption. California and Washington recently adopted building energy efficiency codes and EV infrastructure codes.

2. Develop a Clean Heat Retrofit Program

The General Assembly should require state agencies to develop and implement (with the utilities, if applicable) a Clean Heat Retrofit Program that meets the following targets:

A. **Retrofit 100 percent of low-income households by 2030** – Provide funding to enable the Maryland Energy Administration (MEA), the Department of Housing & Community Development (DHCD), and local governments and organizations to offer little-to-no upfront cost comprehensive retrofits to 100 percent of low-income households by 2030. Holistic retrofits would include weatherization, heat pump installation, and otherwise improve the health and safety of homes statewide. Dedicate funds to address safety-and-health upgrades and electric-panel and wiring improvements, which are commonly needed in low-income households before electrification projects can be completed. Building electrification programs should prioritize low-income customers and be funded and designed to ensure that they do not increase the energy burden of low and moderate-income customers.

   Discussion: It is critical that the state assist households with high energy burden to transition off the gas system before gas rates increase above current levels. Note that gas rates could increase for reasons described in this Plan or for other reasons such as impacts from new regulations, increasing gas supply costs, etc.

B. **Encourage fuel-switching through EmPOWER beginning in 2024** (modified MCCC recommendation from 2020) – Require incentives for the electrification of existing fossil fuel systems through the EmPOWER program and direct the Public Service Commission (PSC) to require the electric utilities to proactively encourage customers with gas, oil, or propane heating systems to replace or supplement those systems with electric heat pumps, especially for low-income households and consumers. State agencies also should modify programs they manage to facilitate fuel-switching if not already allowed.

   Discussion: Gas heating systems are added to this recommendation, which was otherwise approved by the MCCC in 2020. Not yet enacted in state policy. Currently being discussed by the PSC's EmPOWER Future Programming Work Group.

C. **Encourage beneficial electrification through EmPOWER beginning in 2024** (MCCC recommendation from 2020) – Require that the core objective of EmPOWER change from electricity reduction to a portfolio of mutually reinforcing goals, including GHG emissions reduction, energy savings, net customer benefits, and reaching underserved customers. Encourage beneficial electrification, which are strategies that provide three forms of societal benefits: reduced energy consumption (total source BTUs), lower consumer costs, and reduced GHG emissions. Beneficial electrification programs should be prioritized first for low-income households and consumers and should be aligned with other health and safety upgrades to consider a whole-home or whole-building retrofit approach to ensure cost-effectiveness and a focus on benefitting underserved homes and businesses first.

Discussion: Approved by the MCCC in 2020. Not yet enacted in state policy. Currently being discussed by the PSC's EmPOWER Future Programming Work Group.

D. **Target 50 percent of residential HVAC and water heater sales to be heat pumps by 2025, 95 percent by 2030** (modified MCCC recommendation from 2020) – Require that incentives (for consumers, contractors, and manufactures) through EmPOWER and other programs are sufficient to meet a target of 50 percent of HVAC and water heater sales to be heat pumps by 2025 and 95 percent by 2030. Heat pumps (air source or ground source) should be sized to meet all space heating and cooling demand. Heat pump water heaters should be grid-interactive to serve as energy storage devices. Grid-interactive electric resistance water heaters are allowed when heat pump water heaters cannot be installed. Require that electric utilities provide payment options such as on-bill, low-interest financing to spread out upfront costs including electrical upgrades. These targets apply to residential systems but consideration should be given to developing proper incentives and financing options for commercial system electrification.

Discussion: In 2020, the MCCC approved a recommendation that 50 percent of space heater sales should be heat pumps by 2025. The target makes more sense as an HVAC sales target because heat pumps replace heating and cooling systems. Water heaters are added to the recommendation this year. If HVAC and water heater sales reach around 95 percent heat pumps by 2030, then most existing homes would be retrofit with heat pumps by 2045 based on typical equipment replacement schedules.

E. **Align energy plans, approvals, and funding with the objectives of this Plan** – Ensure that the state government's plans, approvals, and funding decisions related to energy align with the objectives of this Building Energy Transition Plan.

Discussion: This recommendation, which previously focused on discontinuing the use of the Strategic Energy Investment Fund to expand fossil fuel use and infrastructure, was broadened to be inclusive of all energy-related decisions.

3. Create a Building Emissions Standard

The General Assembly should require MDE to develop a Building Emissions Standard that shall achieve net-zero emissions from commercial and multifamily residential buildings by 2040. State-owned buildings shall meet this standard by 2035. Historic buildings shall be exempt. The Standard shall give commercial, multifamily, and institutional building owners flexibility in bringing their buildings in line with the state's emissions reduction targets. The Standard shall include measurement and reporting of direct (on-site) emissions and support from the state to implement emissions reduction measures. Emissions reduction measures include but are not limited to:

- Maintaining and retro-commissioning building energy systems
- Implementing HVAC scheduling and other smart control systems
- Making building shell and other energy efficiency improvements
- Replacing fuel burning equipment with efficient electric equipment including air source heat pumps, ground source heat pumps, and induction cooktops
- Installing variable refrigerant flow (VRF) and other systems that capture and utilize waste heat
- Switching fossil fuels with low-carbon renewable fuels
- Installing carbon capture systems (possibly for facilities like larger combined heat and power or district energy plants) if the captured emissions can be stored or utilized in a way that leads to permanent and verifiable emissions reductions

Buildings covered by the Building Emissions Standard shall:

- Measure and report direct emissions to MDE annually starting in 2025
- Achieve net-zero direct emissions by 2040 (2035 for state-owned buildings)

The MCCC's MWG will study and recommend interim targets for covered buildings as part of the MWG's 2022 work plan.

The General Assembly shall provide resources to MEA to offer technical and financial support to help owners of covered buildings develop and implement emissions reduction measures. An alternative compliance pathway should be available to allow commercial building owners to pay a reasonable fee for emissions above target levels. The alternative compliance payment should be reasonable, perhaps corresponding with the cost of implementing additional carbon sequestration or negative emissions technologies in Maryland, but not less than the federal Social Cost of Carbon. The state should create commercial tax credits and direct subsidy payments for upgrades related to building decarbonization projects large enough to reduce the simple payback period to between 3 and 7 years.

Discussion: New York City and Boston are among the U.S. jurisdictions that have implemented building performance standards aimed at guiding commercial buildings to net-zero emissions by mid-century. Building performance standards commonly include interim targets for energy intensity or emissions – thresholds that decrease every five years or so. This proposal previously included just one interim target (50 percent reduction by 2030) in recognition that buildings will not undergo many equipment replacement cycles between now and 2040 (2035 for state-owned buildings). However, the MWG replaced the proposed 2030 target with a plan to study and recommend interim targets in 2022.

The target date is set at 2040 to allow the state time to invest revenue from non-compliance payments into carbon sequestration, negative emissions technologies, or other measures that will help net-out remaining emissions from commercial, multifamily, and institutional buildings and allow the state to meet its emerging 2045 net-zero emissions goal.

4. Develop Utility Transition Plans

The General Assembly should require the PSC to oversee a process whereby the electric and gas utility companies develop plans for achieving a structured and just transition to a near-zero emissions buildings sector in Maryland. Key objectives of those plans include:

<u>Gas Transition Plans</u>

- Appropriate gas system investments/divestments for a shrinking customer base and reductions in gas throughput in the range of 50 to 100 percent by 2045
- Comprehensive equity strategy to enable LMI households to improve energy efficiency and electrify affordably
- Regulatory, legislative, and other policy changes needed for a managed and just transition of the gas system and infrastructure
- Operational practices to meet current customer needs and maintain safe and reliable service while minimizing infrastructure investments
- Assessment of existing gas infrastructure and options for contraction
- Alternative models for the gas utility's long-term role, business model, ownership structure, and regulatory compact, as part of a managed transition

<u>Electric Transition Plans</u>

- Electric system investments for a highly electrified buildings sector
- Ratepayer protections, especially for LMI Marylanders
- Incentives to facilitate the transition to a highly electrified buildings sector
- Demand management solutions to reduce winter peak electricity demand

The PSC shall amend or reject plans that do not meet these objectives. The PSC shall set up a stakeholder process to review the Electric and Gas Transition Plans.

Discussion: E3 estimates that between 2021 and 2045, gas consumption would decrease by 96 percent in a High Electrification scenario, 75 percent in the MWG Policy scenario, and 62 percent by electrifying building heating loads to the point when summer and winter peak electricity demand is roughly equal, which is considered a no-regret action by ICF for decarbonizing buildings. In any scenario, Maryland should expect a significant reduction in gas consumption and should plan for that transition.

California, Colorado, Massachusetts, Minnesota, New York, and Washington are among the states that have opened PSC proceedings on the role of gas distribution companies in a clean energy future.

Additional Recommendations

The recommendations in this section further support building decarbonization in Maryland and are complementary to the Core Recommendations above. Some of the following are MCCC recommendations from 2020 that are not yet enacted by the state, and some are recommendations offered by participants of the Buildings Sub-Group.

5. **Prioritize an equitable level of benefits for all Marylanders** (MCCC recommendation from 2020)

   The Governor, State Agencies, Commissions, and General Assembly should ensure that all policy decisions to reduce GHG emissions from the building sector in Maryland, including those within these recommendations, prioritize an equitable level of benefits to limited income households, the state's affordable and multifamily housing stock, and low-income ratepayers, and concurrently with the benefits provided to others.

   Discussion: Approved by the MCCC in 2020. Not fully enacted in state policy.

6. **Improve interagency coordination for holistic building retrofits** (MCCC recommendation from 2020)

   The Governor, via Executive Order, or General Assembly, via legislation, should revive an Interagency Task Force with the goal of increased and consistent coordination across programs, policies, and funding streams to retrofit Maryland's existing residential and commercial buildings to achieve healthier, safer, more efficient, and climate-friendly homes and businesses. This Green and Healthy Task Force would identify opportunities to align lead, mold, asbestos, and indoor air quality remediation intervention schedules with energy efficiency upgrades and electrification retrofit programs to ensure a more cost-effective, whole-building retrofit program that meets Maryland's various health, safety, affordability, and climate action goals. Progress should be tracked and measured through a public state dashboard. Funding should be provided to make holistic improvements to every limited income and affordable housing unit in the state by 2030.

   Discussion: The last sentence of this recommendation was added based on Buildings Sub-Group participant comments in 2021. The rest was approved by the MCCC in 2020.

7. **Use federal funds for comprehensive retrofits of low-income housing**

   Maryland should prioritize the use of any relevant federal resources coming from the budget reconciliation process, American Rescue Plan Act, and other funding sources to perform comprehensive health, safety, efficiency, and electrification retrofits for affordable housing and should ensure that any new federal funds are not used to support the expansion or installation of new fossil fuel infrastructure or appliances.

Discussion: Proposed by Buildings Sub-group participants.

8. Sunset financial subsidies for fossil fuel appliances within EmPOWER

EmPOWER Maryland and other energy programs in the state should be focused on providing financial assistance only to non-fossil fuel equipment, appliances, and infrastructure associated with the building sector and any and all incentives and subsidies for fossil fuel systems should be eliminated. This should be paired with an increased incentive size for non-fossil appliances and systems installed for limited income consumers.

Discussion: Proposed by Buildings Sub-group participants.

9. Offer incentives for net-zero energy all-electric new buildings (MCCC recommendation from 2020)

The Maryland Building Codes Administration should develop optional codes and standards for efficient all-electric net-zero energy buildings, including allowance of near-site renewable energy systems such as community solar projects, and determine how to incentivize builders to design to those standards. This work should be coordinated with the DHCD in shaping incentive offerings since DHCD already has a Net Zero Loan Program in place and could provide useful insights on program design and existing market gaps to increase the reach of other incentive efforts.

Discussion: Approved by the MCCC in 2020. Not fully enacted in state policy.

10. Lead by example through the electrification and decarbonization of state buildings (modified MCCC recommendation from 2020)

The General Assembly should require that all new state-owned buildings and major renovations to existing state-owned buildings use efficient electric systems for primary space and water heating unless granted an exception based on cost or building characteristics that would make an electric system impractical, including existing use of district heat or combined heat and power. This requirement should apply to projects covered by the Maryland High Performance Building Act.

The General Assembly should require that when existing fossil fueled space and water heating equipment is replaced in State-owned buildings, at least two alternate systems should be proposed, with an Energy Simulation and Life Cycle Cost Analysis of the proposed systems. The Energy Simulation and Life Cycle Cost Analysis should include a cost of carbon equal to the federal Social Cost of Carbon. The State should provide all necessary funds to address any additional costs incurred, net of utility incentives, from switching to zero/low-carbon equipment.

Climate change mitigation, adaptation, and resiliency, including contributing to Maryland's greenhouse gas reduction goals, should be demonstrably central design goals in any building construction or renovation procured with any funds, loans, grants, tax or other benefit from the State of Maryland.

Discussion: The first paragraph was approved by the MCCC in 2020. The second and third paragraphs were offered by Buildings Sub-Group participants.

11. Allow local jurisdictions to set higher fines for non-compliance on building performance

The General Assembly should create enabling legislation to allow local jurisdictions to set higher fines for non-compliance with local building energy/emissions performance standards. The current limit is $500.

Discussion: Montgomery County has proposed to create Building Energy Performance Standards to guide commercial and multi-family buildings to greater energy efficiency and lower emissions. Counties including Montgomery are unable to levy a fine for non-compliance that is sufficient to motivate compliance with the standards.

12. Offer tax credits or other incentives for enhanced energy efficiency in new construction

Several Maryland counties provide property tax credits or other incentives for energy efficient and green buildings. State funding for these incentives in addition to the county support would encourage other counties to act similarly. Montgomery County, which is committed to an 80 percent reduction in greenhouse gas emissions by 2027 and zero emissions by 2035, has property tax credits for new and existing multifamily and commercial buildings based on energy reductions and certifications, and is looking at expanding incentives. Anne Arundel, Baltimore, and Howard Counties offer a tax credit for high performance homes and Anne Arundel and Baltimore Counties award a higher tax credit for a higher performance score.

Discussion: Proposed by Buildings Sub-group participants.

13. Allow above-code green programs to comply with the state-adopted International Energy Conservation Code (IECC)

The State can ease the path to building more energy efficient homes by declaring that residential buildings constructed to above-code green programs comply with the State-adopted IECC. The ANSI-approved ICC 700 National Green Building Standard, Energy Star certifications, and Leadership in Energy and Environmental Design (LEED) rating system are nationally recognized above-code programs. These programs work with experts to ensure that energy and other targets are met and are performing properly. They can help accelerate growth to homes reaching Zero Energy because certifications under above code programs are supported by appraisers and lenders recognizing the greater value of highly efficient buildings. The GSE Fannie Mae has developed Single-Family Green Mortgage-Backed Securities (MBS) that link to Energy Star certifications and is expected to include other green certifications. Fannie Mae already has Multifamily Green MBS that recognize multiple green building certifications.

Discussion: Proposed by Buildings Sub-group participants.

14. Allow a portfolio approach to renewable energy generation

On-site energy generation and sharing of energy among a portfolio of buildings should be incentivized by lifting the limitations on net metering, virtual net metering, and meter aggregation that apply to commercial property. The state should work to address or mitigate the unfavorable Federal tax treatment that limits on-site energy generation by real estate investment trusts.

Discussion: Proposed by Buildings Sub-group participants.

15. Evaluate property tax assessment processes to support decarbonization efforts

Local governments should begin to evaluate and make contingencies for changes to building valuations and tax base resulting from obsolescence or reduced operating income as well as the possible need to increase the use of real estate tax credits to offset the costs and reduce the payback periods of building decarbonization projects.

Discussion: Proposed by Buildings Sub-group participants.

16. Identify locations that need grid upgrades to accommodate new all-electric buildings

Electricity utilities should provide information about locations where the grid is not sufficient to serve new construction of multi-story, all-electric buildings with electric vehicle charging and a method to determine the cost and timetable for necessary upgrades.

Discussion: Proposed by Buildings Sub-group participants.

Appendix: Building Decarbonization Policies in Other States

California

- **New Construction – Heat Pumps and EV-Ready Building Codes**: In August 2021, California adopted its 2022 building energy efficiency standards for new and existing buildings, becoming the first state to establish electric heat pumps as a baseline technology in its building codes.[4] The codes also establish "electric-ready" requirements so homes are able to support EV charging and electric heating and cooking, in addition to expanding standards for onsite solar and battery storage and strengthening ventilation standards.[5] After the code becomes effective in 2023, experts estimate that this combination of standards will lead most new homes and buildings to be built gas-free, which is an already established trend that this code will reinforce. The 2022 code is estimated to provide $1.5 billion in consumer benefits and reduce 10 million metric tons of greenhouse gases over the course of 30 years.[6] California also has the statewide TECH and BUILD initiatives to drive market adoption of heat pumps in existing and new buildings, respectively.

Colorado

- **Building Standards – Statewide Performance Standards**: In June 2021, Colorado became the second state to advance a statewide building performance standard with its passage of legislation that calls for the development of standards that achieve a 7 percent reduction in GHG emissions by 2025 and a 20 percent reduction by 2030, below 2021 levels. This bill also requires annual energy use reporting from owners of buildings larger than 50,000 square feet, beginning in 2022.[7]
- **Energy Efficiency for Gas Utilities**: In June 2021, Colorado adapted their energy efficiency policies to better support greenhouse gas reductions.[8]
  - Senate Bill 21-264 requires gas utilities to file and implement first-in-the-nation "Clean Heat Plans" that may utilize electrification, efficiency, leak reduction, and

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[4] Natural Resources Defense Council. "California Passes Nation's First Building Code that Establishes Pollution-free Electric Heat Pumps as Baseline Technology; Leads Transition Off of Fossil Fuels in New Homes." August 11, 2021. https://www.nrdc.org/media/2021/210811-0.

[5] California Energy Commission. "Energy Commission Adopts Updated Building Standards to Improve Efficiency, Reduce Emissions From Homes and Businesses." August 11, 2021. https://www.energy.ca.gov/news/2021-08/energy-commission-adopts-updated-building-standards-improve-efficiency-reduce-0.

[6] California Energy Commission, 2022 Building Energy Efficiency Standards Summary, https://www.energy.ca.gov/sites/default/files/2021-08/CEC_2022_EnergyCodeUpdateSummary_ADA.pdf

[7] Colorado General Assembly. "HB21-1286: Energy Performance For Buildings." Accessed August 31, 2021. https://leg.colorado.gov/bills/hb21-1286.

[8] Colorado Energy Office. "Colorado adopts nation-leading policies to reduce GHG pollution from buildings." June 8, 2021. https://energyoffice.colorado.gov/press-releases/colorado-adopts-nation-leading-policies-to-reduce-ghg-pollution-from-buildings.

recovered methane or biomethane to reduce GHG emissions 4 percent by 2025 and 22 percent by 2030;

- Senate Bill 21-246 requires electric utilities to file plans that support cost-effective beneficial electrification and directs the Public Utilities Commission (PUC) to include the social cost of carbon and methane emissions in its cost-effectiveness tests; and
- House Bill 21-1238 directs the PUC to set energy savings targets for gas utility demand-side management (DSM) programs, requiring the use of the social cost of carbon and of methane in its cost-effectiveness evaluations. These bills also implemented labor standards for certain commercial electrification and DSM projects. Colorado also passed several bills to finance and fund building transformation, including a bill to fund low-income weatherization assistance grants and another to support low-income energy efficiency, electrification, and renewable energy programs.

Maine

- **Heat Pump Programs**: Maine has set goals to aggressively pursue the installation and use of heat pumps. Between 2013 and 2019, the Efficiency Maine Trust incentivized over 46,000 installations, putting a heat pump in almost 10% of Maine homes. In 2019, the Maine Legislature established the goal to install 100,000 new high-performance heat pumps over five years in Maine through the legislatively enacted LD 1766: An Act to Transform Maine's Heat Pump Market to Advance Economic Security and Climate Objectives. This legislation provides supplementary funding for the Efficiency Maine Trust's incentive programs.[9]

Massachusetts

- **New Construction – Stretch Codes:** In its comprehensive climate bill enacted in March 2021, Massachusetts authorized its energy department to establish, by 2023, a "highly efficient stretch energy code" for new buildings that municipalities may adopt.[10]
    - "Under the Mass Save program, the state's utilities promote new construction meeting Passive House standards. The program was launched in July 2019. As of May 2020, about 50 projects had enrolled in the program, and it hopes to complete more than 4,000 units by 2023. The program began with training for builders in Passive House design and construction techniques. The program will help pay for a project feasibility study (up to $5,000) and for energy modeling

[9] The Efficiency Maine Trust (2019). Beneficial Electrification: Barriers and Opportunities in Maine. https://www.efficiencymaine.com/docs/EMT_BeneficialElectrification-Study_2020_1_31.pdf

[10] Office of Governor Charlie Baker. "Governor Baker Signs Climate Legislation to Reduce Greenhouse Gas Emissions, Protect Environmental Justice Communities." March 26, 2021. https://www.mass.gov/news/governor-baker-signs-climate-legislation-to-reduce-greenhouse-gas-emissions-protect-environmental-justice-communities.

(75% up to $20,000). Financial incentives of $3,000 per unit are offered for meeting Passive House standards. Upon completion of a design that meets program standards, an incentive of $500 per unit is paid. The remaining $2,500 per unit is paid upon completion of construction and a final inspection, including a blower door test. In addition, performance incentives of $0.75 per kilowatt-hour (kWh) and $7.50 per therm are paid for actual first-year energy savings (Mass Save 2020). The feasibility studies have been helpful. Builders appreciate knowing up front the per-unit incentives. And 15 program leaders have found that it is possible to exceed the Passive House standards."[11]

- **Energy Efficiency for Electric and Gas Utilities**: In July 2021, the Baker-Polito Administration established GHG reduction goals for its statewide, three-year energy efficiency plan. The plan, which will cover the years 2022 through 2024 and guide the deployment of ratepayer-funded building efficiency programs, must be designed such that electric and gas utilities reduce 504,000 and 341,000 metric tons of CO_2e, respectively. Investments will include building retrofits and weatherization, building electrification, and equitable workforce development.[12]

New York

- **Heat Pump Programs**: In 2019, New York passed the New York Climate Leadership and Community Protection Act. The Act aims to achieve 40% emissions reductions by 2030. The Act established economy-wide and electric sector targets that includes goals for energy efficiency, renewable energy, and energy storage technology. Notably, New York's Public Service Commission has created incentives and targets for heat pumps under their energy efficiency programs (Wilt 2020[13]; New York PSC 2020[14]).
    - Committed financial incentives: "This Commission order will direct nearly $2 billion in additional utility energy efficiency and electrification actions: $893 million for electric energy efficiency; $553 million for gas energy efficiency; and $454 million for heat pumps through 2025." [15]
    - Energy Savings Targets for Heat Pumps: "New York's electric utilities and NYSERDA are directed to jointly develop a consistent statewide heat pump program framework to be administered by the utilities in their service territories

[11] Nadel, S. 2020. Programs to Promote Zero-Energy New Homes and Buildings. Washington, DC: American Council for an Energy-Efficient Economy. September 2020. https://www.aceee.org/sites/default/files/pdfs/zeb_topic_brief_final_9-29-20.pdf
[12] Massachusetts Executive Office of Energy and Environmental Affairs. "Baker-Polito Administration Sets Ambitious Emissions Reduction Goal for Energy Efficiency Plan." July 15, 2021. https://www.mass.gov/news/baker-polito-administration-sets-ambitious-emissions-reduction-goal-for-energy-efficiency-plan.
[13] The Natural Resources Defense Council, More Efficiency for New York Means More Savings, Carbon & $, January 16, 2020. https://www.nrdc.org/experts/samantha-wilt/win-nyers-new-energy-efficiency-order-saves-ghg.
[14] New York State Clean Heat Program, https://saveenergy.ny.gov/NYScleanheat/
[15] Press Release - Governor Cuomo Announces Additional $2 Billion in Utility Energy Efficiency and Building Electrification Initiatives to Combat Climate Change, January 16, 2020. https://documents.dps.ny.gov/public/MatterManagement/CaseMaster.aspx?MatterCaseNo=18-M-0084&submit=Search.

and combined with LIPA sets a minimum target of 4.6 TBtu for savings from heat pump installations across the state." NYSERDA is seeking to invest $200 million in market development programs to increase consumer awareness of heat pumps, increase skilled workers in the clean heating and cooling industry, provide technical assistance, and increase the benefits for low to moderate income customers

    - Proven Industry Growth: "The contractor industry has grown substantially in New York State since 2017, with 112 ground-source heat pump installers and more than 350 air-source heat pump contractors participating in NYSERDA's heat pump programs as of March 2020. Through 2019, nearly 11,000 program participants received incentives and services under NYSERDA's programs, supporting approximately 21,500 heat pump installations."[16]

- **Carbon Neutral Buildings Roadmap**: To meet the ambitious goals of the Climate Act, the Carbon Neutral Buildings Roadmap was created to identify pathways to decarbonize New York's building stock by 2050.[17]
    - Development of the Roadmap includes analyzing the state's entire building stock, researching critical building decarbonization barriers, modeling various solutions sets, and developing technology and policy recommendations to achieve the Climate Act goals, with a primary focus on four building typologies: Single Family Homes, Multifamily Residential (Low and mid-rise), Commercial Office (Low and mid-rise), and Higher Education.
    - The Roadmap will be updated approximately every 2 – 3 years to account for policy, market, and technological developments, and to analyze additional building typologies. The Roadmap is intended to:
        - Provide cutting-edge research related to building decarbonization
        - Send market signals to the real estate, finance, manufacturing, and construction sectors
        - Spur economic development and the creation of quality clean energy jobs; and raise awareness of the benefits to deep decarbonization, such as: Energy savings; Health & safety, comfort, and productivity; Resilience; and Provide guidance for other state agencies and local governments.
- **New Construction - Buildings of Excellence Competition:** The Buildings of Excellence competition began in 2019 and provides up to $40 million in monetary awards to visionary architects and developers that design and construct low or zero carbon

[16] Nadel, S. 2020. Programs to Electrify Space Heating in Homes and Buildings. Washington, DC: American Council for an Energy-Efficient Economy. June 2020. https://www.aceee.org/sites/default/files/pdfs/programs_to_electrify_space_heating_brief_final_6-23-20.pdf.
[17] New York State Energy Research and Development Authority, Program: Carbon Neutral Buildings, https://www.nyserda.ny.gov/All-Programs/Programs/Carbon-Neutral-Buildings

emitting multifamily buildings. The competition is meant to recognize and encourage best practices for sustainable buildings. [18]

Vermont

- **Heat Pump Programs**: Vermont has extensive heat pump programs supported by both Efficiency Vermont and electric utilities. Tier III of Vermont's renewable energy standard requires electric utilities to acquire fossil fuel savings from energy transformation projects such as building and transportation electrification.

Washington

- **Building Standards – First Statewide Commercial Buildings Performance Standard**: In December 2020, Washington finalized the rules to implement its first-in-the-nation Commercial Clean Buildings Performance Standard, which the state enacted in 2019 legislation. The rules set a state target 15% below the 2009 to 2018 energy use average of commercial buildings larger than 50,000 square feet.[19]

[18] New York State Energy Research and Development Authority, Program: Buildings of Excellence, https://www.nyserda.ny.gov/all-programs/programs/multifamily-buildings-of-excellence
[19] Washington State Department of Commerce. "Clean Buildings Standards." N.d. Accessed August 31, 2021. https://www.commerce.wa.gov/growing-the-economy/energy/buildings/clean-buildings-standards/.

Petition of the Office of People's Counsel for Near-Term, Priority Actions and Comprehensive, Long-Term Planning for Maryland's Gas Companies

Case No. 9707, Phase II

Exhibit KT-R8 – Staff Responses to OPC Data Requests

Staff Responses to OPC DR 1-10

Staff Response to
Office of People's Counsel Data Request No. 1
Case No. 9707, Phase II
July 7, 2026

1-10. Refer to Witness Thomas's testimony at page 4, lines 1–3, where he recommends that rate design should be based on observed system conditions and not speculative assumptions regarding future demand, climate policies, or legislative changes. Please also refer to Witness Thomas's testimony at page 14, line 15 through page 15, line 5, where he states that future climate policies and legislative changes should be considered based on their actual effects on gas demand, customer counts, system utilization, and cost of service once those effects are realized.

(a) Please explain what Witness Thomas means by "speculative assumptions regarding future demand, climate policies, or legislative changes."

Response:

Witness Thomas clarifies that the above-mentioned testimony, specifically page 14, line 15 through page 15, line 5 is on Issue 5. The specific phrase "speculative assumptions regarding future demand, climate policies, or legislative changes" is used in his recommendation, which states:

"I recommend rate design should be based on observed system conditions, established rate design principles, and not speculative assumptions regarding future demand, climate policies, or legislative changes."

By this, Witness Thomas means assumptions about future gas demand, future climate policies, or future legislative changes that are not supported by utility-specific rate design considerations, such as customer usage, billing determinants, cost allocation, bill impacts, or other applicable rate design considerations.

Witness Thomas does not take a position on Issue 1. However, Witness Thomas recognizes that future gas demand, climate policies, and legislative changes may be relevant considerations in planning, before their effects are fully realized. Witness Thomas's testimony should not be read to suggest that such considerations are irrelevant to planning, but rather that rate design changes should be supported by utility-specific evidence and evaluated in base rate proceedings based on the applicable principles of rate design.

(b) Does Witness Thomas consider any of the following to be speculative for purposes of evaluating future gas demand, gas planning, or rate design? If so, please explain why:

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(i) adopted statutes

(ii) final regulations

(iii) executive orders

(iv) PSC orders

(v) utility compliance obligations

(vi) state agency plans

(vii) FERC orders

(viii) PHMSA regulations

Response:

Witness Thomas's testimony concerns Issue 5 and rate design. Witness Thomas does not consider adopted statutes, final regulations, executive orders, PSC orders, utility compliance obligations, state agency plans, FERC orders, or PHMSA regulations to be speculative merely because they concern future conditions. To the extent those items are final, adopted, or legally binding, they may be relevant for consideration of future gas demand or gas planning

Witness Thomas clarifies, however, that his testimony was directed to Issue 5, and not to future gas demand or gas planning generally. Witness Thomas did not offer a position on Issue 1 or on the way future gas demand should be evaluated in a gas planning context.

For purposes of rate design, the speculative element is not the existence of an adopted statute, final regulation, order, compliance obligation, or agency plan. Rather, the speculative element would be an unsupported assumption about how that item will affect utility-specific rate design considerations, such as customer usage, billing determinants, cost allocation, cost recovery, customer bill impacts, or other rate design considerations. Specific rate design changes should be supported by evidence specific to a utility and evaluated in base rate proceedings based on applicable rate design principles.

(c) Please provide multiple examples of evidence Witness Thomas would consider sufficient to determine that future demand changes are reasonably

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foreseeable, rather than speculative, for purposes of gas planning or rate design.

Response:

Witness Thomas clarifies that his testimony concerns Issue 5 and does not offer a general standard for evaluating future demand changes for purposes of gas planning.

For purposes of rate design, evidence that may support a conclusion that future demand changes are reasonably foreseeable, rather than speculative, could include historical customer usage trends, customer count trends, adopted statutes or final regulations that directly affect gas use, or other utility-specific evidence showing a reasonably measurable effect on gas usage, system utilization, cost allocation, cost recovery, customer bill impacts, or other rate design considerations. The existence of such evidence would not necessarily require a rate design change, but it may be relevant to the Commission's evaluation of a specific rate design proposal in a base rate proceeding.

(d) Does Witness Thomas agree that gas utilities should consider expected, non-speculative policy and market changes —such as adopted policies, utility program obligations, observable market trends, and available data on heating equipment adoption or fuel switching—in load forecasts before those changes are fully reflected in historical gas usage data? If not, please explain why not.

Response:

Yes, generally. Witness Thomas agrees that expected, non-speculative policy and market changes may be relevant inputs to gas utility load forecasts before those changes are fully reflected in historical gas usage data. Witness Thomas clarifies, however, that his testimony is focused on Issue 5. His testimony should not be read to provide a complete position on gas planning or load forecasting methodology.

(e) Could waiting until the effects of current or adopted state policies are fully reflected in historical customer counts or usage data before incorporating those effects into gas planning increase the risk of each of the following? If not, please explain why not.

(i) overbuilding gas infrastructure

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(ii) underutilized gas infrastructure

(iii) increased ratepayer costs

Response:

Witness Thomas's testimony addresses Issue 5 and rate design, and does not offer a position on Issue 1 or gas planning methodology. Witness Thomas did not perform an analysis sufficient to determine whether waiting until the effects of current or adopted state policies are fully reflected in historical customer counts or usage data would increase the risk of overbuilding gas infrastructure, underutilized gas infrastructure, or increased ratepayer costs.

Witness Thomas recognizes, however, that expected, non-speculative policy and market changes may be relevant to gas planning before those changes are fully reflected in historical data.

Sponsor:

Evan Thomas