BEFORE THE
MARYLAND 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
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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

[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.

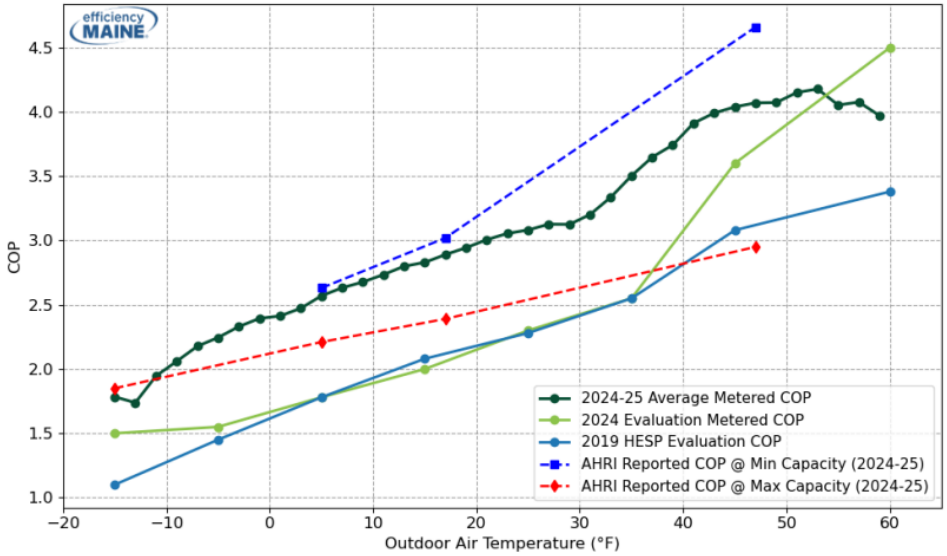
projected winter peak electric demand. More specifically, his analysis relies on ENERGY STAR minimum cold-climate heat pump coefficient of performance ("COP") assumptions at a 5°F design condition—a COP of approximately 1.75—as a basis for converting gas heating loads into electric peak demand.[15] This 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.

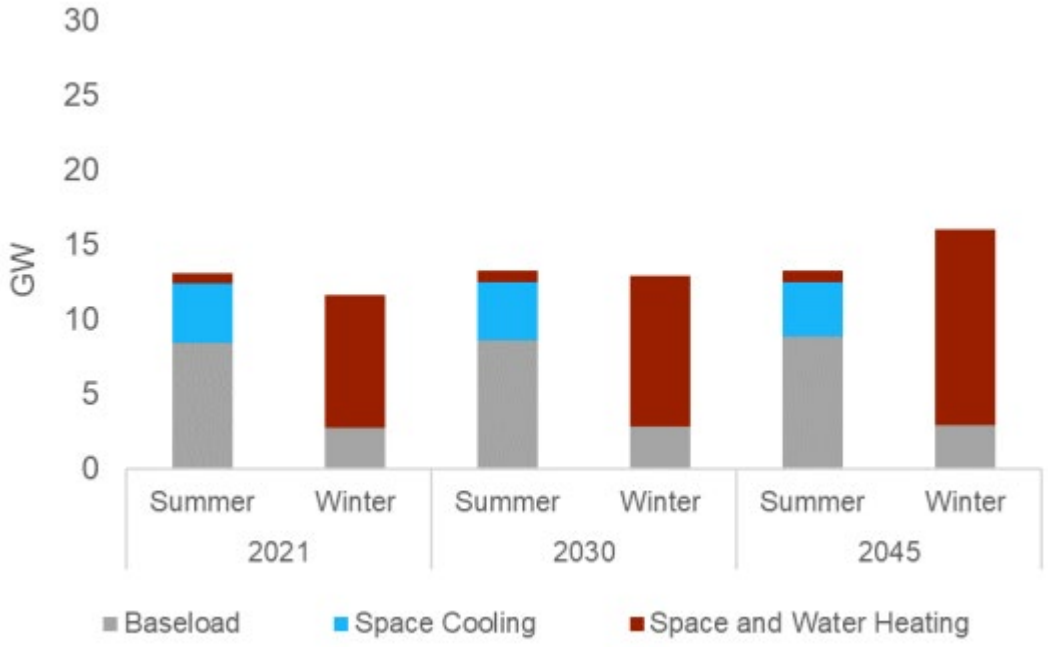
electric peak impacts than those presented by Mr. Wemple, particularly when electrification is modeled as part of policy-driven, phased, and managed transition pathways that also incorporate energy efficiency improvements, building shell upgrades, and other peak-mitigating strategies, rather than as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

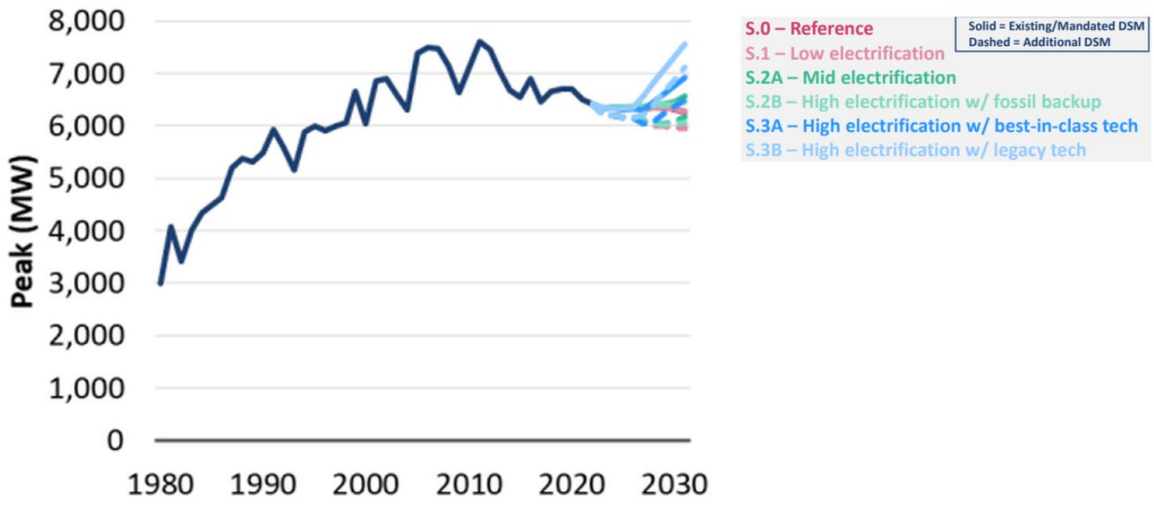
By contrast, Mr. Wemple estimates that statewide electrification of gas heating would increase Maryland's annual system peak by approximately 10.5 GW, or roughly 80 percent relative to Maryland's current summer peak, essentially overnight.[22] The MCCC E3 Study also assumes that improved building shells 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**.

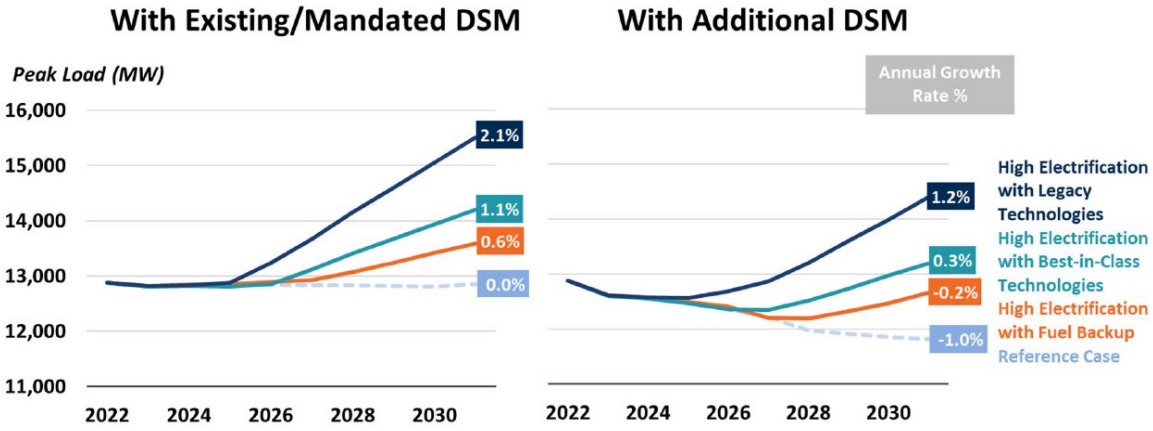
Q. How does the Maryland statewide electrification study prepared by Brattle inform this assessment?

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

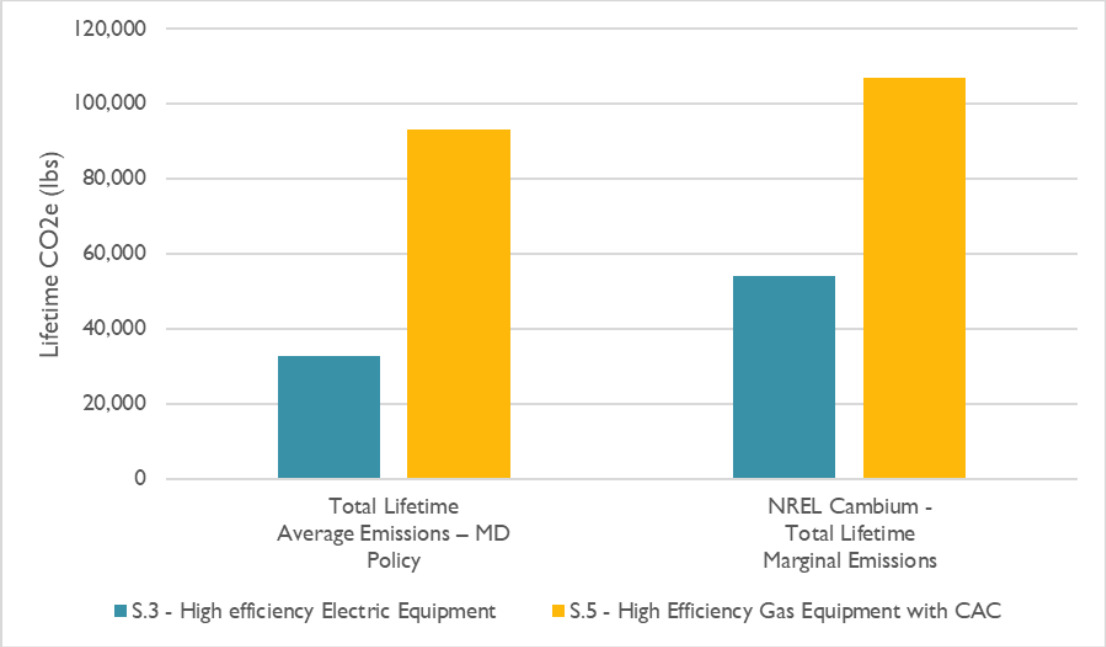
Electric Heat Pumps," Table 4, (filed September 12, 2024, Case No. 9705) (attached as Exhibit KT-R4) ("WGL Heat Pump Report").

[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)



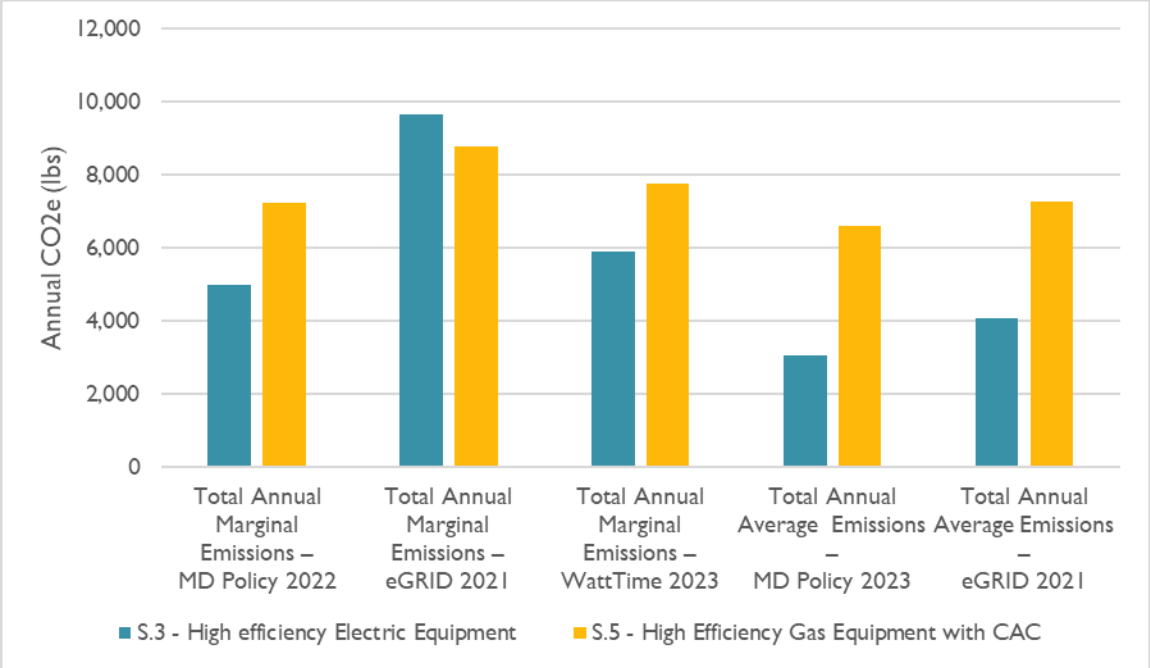
Note: CAC = central air conditioner. Source: WGL Heat Pump Report at Appendix C, Table 4, Exhibit KT-R4 at 68-75.

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]

[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]

[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.

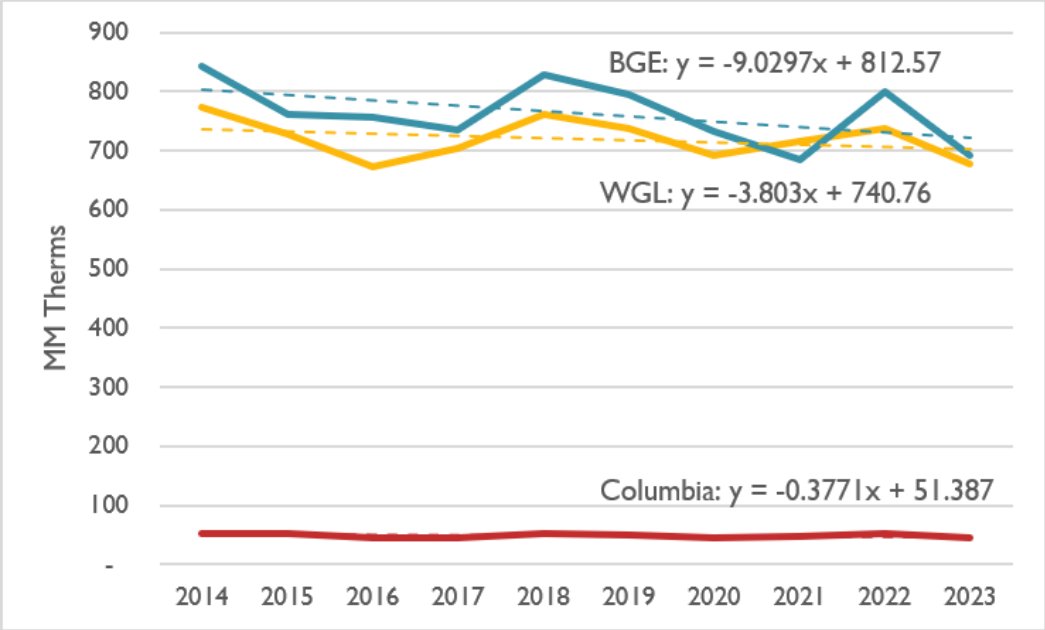
Q. What does a proper historical trend analysis show about recent gas consumption?

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



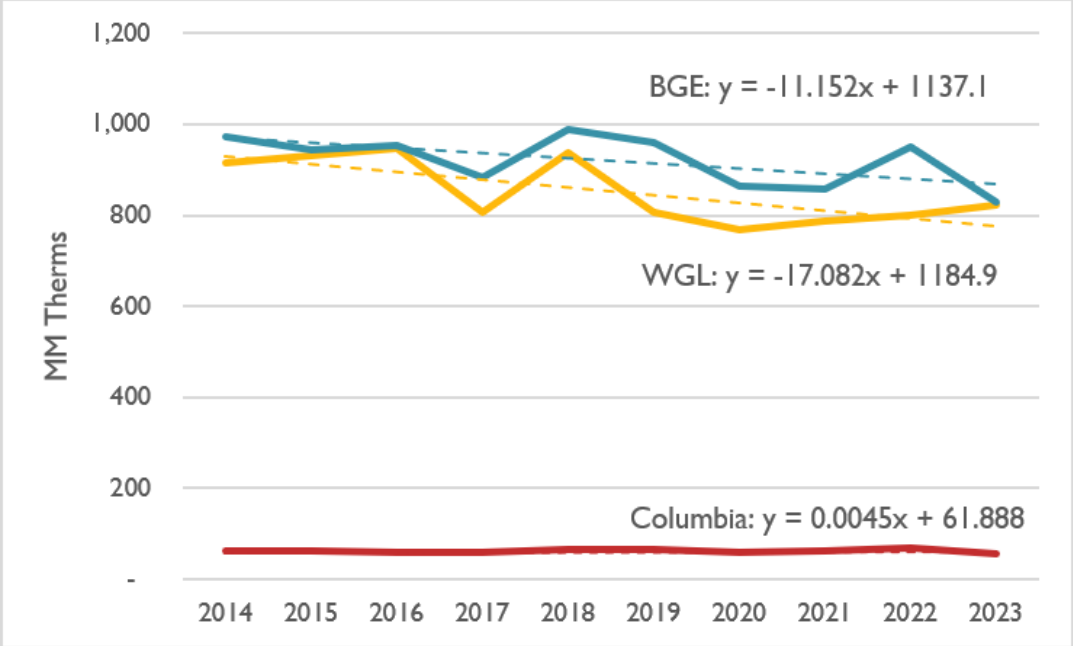
Source: EIA-176 database. Available at: https://www.eia.gov/naturalgas/ngqs/#?year1=2021&year2=2024&company=Name.

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

[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.