UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

MARYLAND OFFICE OF PEOPLE'S COUNSEL	)	
Complainant,	)	
v.	)	DOCKET NO. EL26- -000
PJM INTERCONNECTION, LLC	)	
Respondent.		

COMPLAINT REQUESTING FAST TRACK PROCESSING OF THE MARYLAND OFFICE OF PEOPLE'S COUNSEL

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Pursuant to sections 206 and 306 of the Federal Power Act ("FPA")[1] and Rule 206 of the Federal Energy Regulatory Commission's ("FERC" or the "Commission") Rules of Practice and Procedure,[2] the Maryland of Office of People's Counsel ("OPC") files this complaint against PJM Interconnection, L.L.C. ("PJM"). For the reasons stated here and in the attached Affidavit of Ron Nelson and Andy Eiden, OPC requests, as more particularly described below, that the Commission: (1) establish a refund effective date pursuant to FPA, section 206 as of the date of this complaint; (2) find that PJM's existing cost allocation rules for baseline transmission projects are unjust and unreasonable because they result in the imposition of costs on Maryland electric customers that are not commensurate with any benefits Maryland customers receive; and (3) establish just and reasonable cost allocation rules, as outlined below.

INTRODUCTION

Over the next decade, Maryland customers will pay about $1.6 billion through their electric bills in additional costs for transmission projects driven primarily by the energy needs of data centers located outside of Maryland. These costs result from PJM's hybrid load-ratio share and solutions-based distribution factor ("DFAX") transmission cost allocation methodology for assigning transmission cost responsibility across sub-regions or "zones" of PJM.[3] PJM's hybrid methodology

[1] 16 U.S.C. §§ 824e and 825e.
[2] 18 C.F.R. § 385.206.
[3] PJM divides its footprint into 27 separate areas, each a locational deliverability area ("LDA"), and 21 control "zones," which are aligned with the LDA boundaries (and in some cases reflect nesting of super-imposed larger LDAs). The LDAs and, ultimately, control zones are used for the geographic assignment and allocation of transmission costs, among other matters, pursuant to the PJM hybrid transmission cost allocation methodology. *See generally*, Monitoring Analytics LLC, *2025 State of the Market Report, Vol. 2* (2026) at p. 6 (Figure 1-1). In the subsequent text, "zones" or "transmission zones" are generally used to describe the sub-regions of PJM to which transmission costs are

broadly socializes to all customers costs that data centers, not existing customers, are driving. That result is unjust and unreasonable and violates the cost causation principles that have long governed transmission cost allocation and that this Commission has repeatedly affirmed.

The full scope of this burden is captured in the two tables below, derived from the accompanying Affidavit of Ron Nelson and Andrew Eiden (the "Affidavit") attached to and provided in support of this complaint. Across three successive PJM transmission expansion planning windows, 2022 Regional Transmission Expansion Plan ("RTEP") procurement window 3 ("2022 W3"), 2024 RTEP window 1 ("2024 W1"), and 2025 RTEP W1 ("2025 W1"), PJM's cost allocation rules have assigned Maryland ratepayers $2.0 billion in capital costs—costs that will drive up Maryland customer bills through $1.6 billion in additional revenue requirements over the next ten years—all for transmission infrastructure driven overwhelmingly by data center load growth occurring outside Maryland's borders, but spread to the PJM transmission zones located in Maryland as a result of the PJM tariff's transmission cost allocation methodology.[4] PJM's tariff imposes these costs on Maryland electric customers even though Maryland customers do not meaningfully cause nor benefit from those investments.[5]

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allocated. Four such zones are included wholly or partially within the State of Maryland (the Baltimore Gas and Electric ("BGE"), Potomac Electric Power Company ("Pepco"), Delmarva Power and Light ("DPL") and APS zones.

[4] Total transmission investment in baseline projects resulting from the three RTEPs exceeds $22 billion (2022 W3 – $5.143 billion (*TEAC, Recommendations to the PJM Board White Paper* (Dec. 2023)); 2024 W1 – $5.290 billion (*TEAC Recommendations to the PJM Board White Paper* (Feb. 2025)); and 2025 W1 – $11.840 billion (*TEAC Recommendations to the PJM Board White Paper* (Feb. 2026)). This investment does not include the costs of supplemental projects associated with large-load growth.

[5] *See* Nelson and Eiden Affidavit at 8-12, which is Attachment A to this Complaint.

Table 1: Total 2036 Maryland capital cost allocation for baseline transmission facilities by RTEP procurement window*				
Allocation Method	2022 W3	2024 W1	2025 W1	Total
DFAX	$448,086,246	$371,142,023	$503,294,856	$1,322,523,125
Load Ratio Share	$180,233,197	$162,316,607	$336,131,081	$678,680,885
Total	**$628,319,443**	**$533,458,629**	**$839,425,937**	**$2,001,204,009**

*Note: Differences in summation are due to rounding.

Table 2: 10-year Maryland cumulative revenue requirement allocations by RTEP procurement window*				
Allocation Method	2022 W3	2024 W1	2025 W1	Total
DFAX	$396,776,623	$385,913,686	$298,532,826	$1,081,223,135
Load Ratio Share	$164,633,409	$163,786,865	$211,833,567	$540,253,842
Total	**$561,410,032**	**$549,700,551**	**$510,366,393**	**$1,621,476,976**

*Note: Differences in summation are due to rounding.

Absent Commission action, there is no relief in sight for Maryland ratepayers. A study commissioned by OPC and conducted by Synapse Energy Economics in February 2026 ("Synapse Report") projects that transmission costs will likely continue to increase substantially in the years ahead, driven by data center load increases, and that PJM, using its existing transmission cost allocation rules, could saddle Maryland ratepayers with the responsibility to pay for an additional $5.4 billion in capital costs for transmission projects built between 2031 and 2035—nearly matching in just five

years the entire $7.1 billion in transmission capital costs Maryland ratepayers have borne responsibility for over the preceding 20 years.[6]

Accordingly, OPC files this complaint against PJM.[7] For the reasons stated here and in the Affidavit,[8] OPC requests that the Commission:

> (1) Find that PJM's application of Schedule 12 of its Open Access Transmission Tariff (Tariff)—specifically the hybrid load-ratio share/DFAX transmission cost allocation methodology—to the 2022 RTEP W3, 2024 RTEP W1, and 2025 RTEP W1 projects produces unjust and unreasonable rates by allocating data center-driven transmission costs to Maryland ratepayers who neither materially caused nor materially benefit from those upgrades, rendering the allocation not "roughly commensurate" with the benefits arising from the transmission projects creating these costs, in violation of Commission directives;
>
> (2) Establish a refund effective date of no later than 60 days after the date of this filing and direct PJM to re-study those project windows to determine the proportion of transmission system impacts caused by data center load growth and to credit back to transmission zones the costs attributable to that growth that is collected subsequent to the refund effective date;
>
> (3) Direct PJM to develop an allocation methodology for RTEP baseline reliability costs that results in allocating transmission costs associated with large load interconnections to the zones where those large loads exist or are projected to develop; and

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[6] Synapse Energy Economics, *Rising Transmission Costs: Impacts on Maryland Electricity Customers and Opportunities for Mitigation*, prepared for the Maryland Office of People's Counsel (March 25, 2026) ("Synapse Report") at i. The Synapse Report is Attachment B to this complaint. The Synapse Report focuses on longer-term historic and projected transmission capital expenditures and revenue requirements whereas the Affidavit focuses its quantitative analysis on the three PJM RTEP procurement windows. The Synapse Report summary of the RTEP procurement window projects varies from that set forth in the Affidavit, with the variance attributable to the use of different vintages of PJM's reported cost allocations and different filters for costs included in the summary. For purposes of and in support of this complaint, the Affidavit is the probative, fully updated analysis. The Synapse Report is appended to provide further context and background.

[7] As the Commission previously determined, a complaint is the appropriate vehicle to challenge PJM's cost allocation methodology. *See PJM Interconnection, LLC*, 187 FERC ¶ 61,012 at P 29 (2024) ("The issues raised by the Maryland People's Counsel protest should have been filed as a complaint, rather than as a protest to the instant filing") Comments of Md. Off. of People's Couns., *PJM Interconnection, LLC*, Docket. No. ER25-1811-000 at 5 n.5 (April 28, 2025).

[8] The Nelson and Eiden Affidavit is Attachment A to this Complaint.

> (4) Depending on the outcome of the Commission's advanced notice of proposed rulemaking on large load interconnections, direct PJM to develop a large load interconnection standard modeled on the customer protections embodied in Order No. 2003, but adjusted to address large loads rather than generators, including requiring interconnecting large load customers to fund 100 percent of the upfront network upgrade costs they cause, with appropriate crediting mechanisms.

OPC requests that the Commission process this complaint under its fast-track procedures. Expedited action is essential to protect Maryland electric customers from the affordability crisis they are currently experiencing from high energy bills, including significant recent increases in capacity market costs, and the imminent compounding of unjust costs with each successive PJM RTEP procurement window. That compounding is exemplified by the PJM Board's recent approval and Commission filing of its selections for the 2025 RTEP Window 1, adding $839.4 million in capital cost responsibility to Marylanders for transmission enhancements.[9] The flawed cost allocations of transmission projects are already impacting ratepayers through construction work in progress ("CWIP") incentive awards to and on-going expenditures by developers assigned projects as a result of the PJM RTEP procurements.[10] While the focus of OPC's complaint is on the major adverse and inequitable impacts of PJM's transmission cost allocation methodology on Maryland ratepayers, parallel adverse impacts emanating from the same flawed PJM cost

[9] Attach. A (Nelson and Eiden Aff.), Table 1 at 12.
[10] *See, e.g.*, *Valley Link Transmission Maryland LLC, et al.*, 191 FERC 61,113 (May 13, 2025) (granting three Valley Link LLCs, developers of transmission projects responsive to RTEP 2024 W1, construction work in progress incentives).

allocation methodology are occurring in other states within the PJM footprint due to data center load growth.[11]

Not only are transmission costs increasing on a rapid upward trajectory, but state-level retail large-load tariffs fail to remedy and may exacerbate the misallocation of transmission costs resulting from application of PJM's hybrid transmission cost allocation methodology. Moreover, recent utility filings with the Commission of transmission security agreements ("TSAs") with large-load customers—which are often confidential, highly variable, and fail to protect existing customers—are accelerating.[12] These agreements do not sufficiently address or remedy the infirmities arising from use of the flawed PJM hybrid transmission cost allocation methodology, as further described below and in the accompanying Affidavit; moreover, they carry potential legal consequences that may prove difficult to unravel.

Fast-track processing is necessary (i) to provide meaningful consumer relief before these additional massive costs are allocated under the same defective "hybrid" transmission cost allocation methodology, (ii) to address the gap in allocation of transmission costs not remedied by state-level retail large-load retail tariffs, (iii) to prevent acceptance of TSAs as a default, but inadequate, remedy, and (iv) to avoid or

[11] *See* Institute for Energy Economics and Financial Analysis, *West Virginia Ratepayers Footing the Bill for Infrastructure Build Out, Reform Needed in PJM's Transmission Cost Allocation Process* (2025); Union of Concerned Scientists, *Connection Costs: Loophole Costs Customers over $4 Billion to Connect Data Centers to Power Grid* (2024). These reports analyzed PJM's transmission expansion projects and their rate impacts prior to the most recent 2025 RTEP W1 projects. OPC's complaint, focused on Maryland impacts, updates the impacts to reflect this most recent transmission expansion project procurement round. *See also* Martin and Peskoe, *Extracting Profits from the Public: How Utility Ratepayers are Paying for Big Tech's Power* (2025). This report provides a general analysis of the issue but focuses primarily on better state-level regulation as a partial remedy. OPC's complaint focuses on the inequity that PJM's tariff causes for allocation of transmission costs, particularly at the interstate level, resulting from data centers for which state-level regulation alone is an inadequate and incomplete remedy.

[12] *See* Part II(C) of this complaint and n. 146 below (describing recent TSA filings).

minimize the collection of amounts subject to refund. To accomplish these objectives, the Commission should direct PJM to answer the complaint within 15 days and should grant the complaint on an expedited basis.

BACKGROUND

PJM's cost allocation methodology is being applied to a new paradigm in which it is demonstrably no longer appropriate. Under this new paradigm, concentrated, merchant-scale large-load additions, comprised almost entirely of data centers,[13] located in, or forecasted to be located in discrete, targeted geographic areas, are driving billions of dollars in transmission investment that PJM's tariff broadly socializes to customers throughout the PJM footprint who neither caused nor benefit from these transmission investments.[14]

This background section is organized into three parts that collectively explain how this transmission cost landscape has changed to the detriment of Maryland electric ratepayers and how current efforts to remedy the inequities fail. *First*, data centers in geographically concentrated areas of the PJM footprint—particularly in Virginia, and also in Ohio, Pennsylvania, and Illinois—have reached a scale and pace that was not contemplated when the Commission approved PJM's current hybrid load-ratio share and DFAX cost allocation methodology.[15] *Second*, PJM's hybrid transmission cost allocation methodology is having tremendous impact on Maryland customers even though Maryland customers are not driving the costs nor receiving

[13] Because the large-load customers driving PJM's forecasts and RTEPs are comprised primarily of data centers, this Complaint uses the terms "large load" and "data center" interchangeably.
[14] Attach. A (Nelson and Eiden Aff.) at 8-9 and 46.
[15] *Id.* at 6-8, 18-20 and 24.

material benefits. *Third*, developments purporting to address the inequities posed by data center loads—state large-load retail tariffs and electric utility "self-help" TSAs—are inadequate to shield ratepayers from rising costs due to these developments and, in some cases, have made the regional cost allocation inequities worse.[16]

1. The geographically concentrated data center load growth driving massive transmission expansion.

Data center load growth is driving transmission investments at an unprecedented scale and pace.[17] The following subparts describe the nature and extent of that growth nationally and within PJM.

a. Accelerating national data center growth.

Electricity consumption by U.S. data centers has accelerated at a striking pace, as explained in the Nelson and Eiden Affidavit.[18] Lawrence Berkeley National Laboratory ("LBNL") estimates that data center electricity consumption grew at approximately 4 percent per year from 2010 to 2014, rose to 7 percent per year from 2014 to 2018, and then surged to 18 percent per year from 2018 to 2023.[19] Data centers represented approximately 2 percent of total U.S. electricity demand in 2018. LBNL projects that figure may rise to as high as 12 percent by 2028, with annual energy consumption more than quintupling from less than 100 terawatt-hours ("TWh") to roughly 575 TWh.[20]

[16] *Id*. at 89-90.
[17] *Id.* at 8, 18-21.
[18] *Id*. at 18-19.
[19] *Id.*
[20] *Id.*

The accelerating rate of growth is expected to continue for the foreseeable future.[21] Bloomberg NEF estimates that U.S. data center power demand will rise from roughly 35 GW in 2024 to 78 GW by 2035, representing a doubling of load over the next decade.[22] At the midpoint of LBNL's projections, data center demand would double in just the next four years.[23]

This projected growth has profound consequences for the PJM transmission system. Three of PJM's recent RTEP procurements (2022 W3, 2024 W1 and 2025 W1) total more than $22 billion in transmission capital expenditures for baseline projects, overwhelmingly driven by projected data center load growth.[24]

b. PJM data center load growth concentration: the Virginia epicenter, with forecasts of similar concentrated growth in discrete, limited additional zones.

Amidst national data center growth, Virginia stands as the epicenter. Virginia is the largest data center market in the world, with data center meters serving roughly 50 customers across PJM's Dominion Load-Serving Entity ("DOM-LSE") zone.[25] As of December 2024, data centers represented 3.6 GW of demand in the Dominion zone, reflecting, since 2013, a 660 percent increase in megawatt-hour consumption.[26] Dominion has received approximately 40,000 MW of capacity requests in 2024 alone—more than double the zone's current peak demand of 18,408 MW.[27] As a result, Dominion expects to see a more-than-30-percent increase in peak

[21] *Id*. at 19.
[22] *Id*. at 19-20
[23] *Id.*
[24] *Id.* at 10-11, n. 3 and 59.
[25] *Id.* at 21.
[26] *Id.*
[27] *Id*. at 22.

demand from 2025 to 2030, rising from 24,271 MW to 31,939 MW.[28]

Concentrated load growth accounts for the enormous buildout of transmission infrastructure. In its most recent integrated resource plan, Dominion listed 88 transmission projects driven primarily by data center connections, along with an additional 37 projects attributed to "multi-driver" load growth—which also includes data center growth—in the Dominion transmission zone.[29] The capital costs of these projects total between $2.44 billion (for the 88 data center-driven projects alone) and $5.77 billion (including the multi-driver projects).[30]

Highly concentrated data center load growth in PJM extends beyond Virginia to a few other PJM states. The growth exhibits the same characteristics—highly concentrated location in limited, discrete areas. Although the Dominion zone continues to have the highest impact, 80 percent of the total large-load adjustments, or 38.9 GW, are concentrated in just four PJM zones across Virginia (Dominion), Ohio (AEP), Illinois (Commonwealth Edison), and Pennsylvania (PPL).[31] The 2025 RTEP Window 1 reliability analysis published by PJM notes the "high-impact drivers" for the 2030 and 2032 models were the substantial forecasted data center load in the AEP (OH), PPL (PA) and Dominion (VA) zones plus an additional 3.5 GW of additional data center load in the PPL zone that was added in the 2026 PJM annual load forecast on top of previous increases.[32] Illinois (ComEd) reports a pipeline of over 75 large-load connection requests totaling 28,000 MW of demand—a figure that, if fully built,

[28] *Id.* at 22-23.
[29] *Id.* at 23-24. Multi-driver projects include data center growth and existing load growth, but Dominion did not determine whether the data center growth was the primary cause. *Id.*
[30] *Id.*
[31] *Id*. at 25.
[32] *Id*. at 25-26.

could more than double ComEd's historical system-wide peak demand of just under 24,000 MW.[33]

The data center phenomenon is reshaping load growth, actual and forecasted, across PJM's entire footprint. PJM projects 32 GW of peak load growth across its territory by 2030, of which approximately 30 GW is attributable to data centers.[34] Over the next ten years, utilities within PJM forecast an increase to overall system peak load of 57,212 MW, representing a 3.11 percent compound annual growth rate.[35] The consequences of this growth are already being felt across the system. PJM's Board of Managers has attributed increasing capacity prices and concerns about future resource adequacy to this wave of data center demand,[36] and PJM's Independent Market Monitor has reported that data center load alone raised prices in PJM's most recent capacity auction by more than $6.5 billion and over $23 billion over the last three auctions.[37]

c. The extreme uncertainty of PJM's load forecasts.

While data center load growth is real and significant, the forecasts driving PJM's transmission planning are subject to extreme uncertainty, which PJM itself has acknowledged. PJM has stated that "[t]here is growing uncertainty around the accuracy of forward load forecasts because of the unprecedented nature of data center

[33] *Id.* at 24.
[34] *Id.*
[35] *Id.* at 26.
[36] Letter from Chair of PJM Board Managers to PJM Stakeholders (Aug. 8, 2025) at 1, available at https://www.pjm.com/-/media/DotCom/about-pjm/who-we-are/public-disclosures/2025/20250808-pjm-board-letter-re-implementation-of-critical-issue-fast-path-process-for-large-load-additions.pdf.
[37] Independent Market Monitor for PJM, *Analysis of the 2027/2028 RPM Base Residual Auction – Part A* (Jan. 5, 2026) at 3, https://www.monitoringanalytics.com/reports/Reports/2026/IMM_Analysis_of_the_20272028_RPM_Base_Residual_Auction_Part_A_20260105.pdf.

load growth, and there is the need to examine who should bear the risk of these forecasts being incorrect in either direction."[38] The problem of forecast overstatement is not new. In 2018, Lawrence Berkeley National Laboratory conducted a study comparing forecasting and actual growth for utilities in the Western U.S. and found most overestimated future energy and peak demand growth, with assumptions overstating economic growth as the primary driver.[39] What is new is the scale: The unprecedented surge in data center connection requests has dramatically amplified the consequences of forecast error.

"Phantom" or speculative load requests contribute to much of the uncertainty.[40] Data center developers routinely submit connection requests to multiple utilities across different jurisdictions to evaluate timelines, rates, and incentives before making a final site selection.[41] As a PJM senior manager has acknowledged, data center companies "are pitching the same data centers in different locations."[42] These duplicative requests inflate load forecasts and, by extension, the transmission buildout planned to serve them. Because interconnection requests generally do not require prospective data center customers to make significant financial commitments relative to the upgrade costs they trigger, the economic barriers to speculative queue entry are minimal. As a former commissioner with the Public Utilities Commission of Texas observed, "When it's cheaper to buy a queue position than not use your queue position, you'll buy queue positions all day long."[43]

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[38] Attach A. (Nelson and Eiden Aff.) at 27-28.
[39] *Id.* at 30-31.
[40] *Id*. at 31.
[41] *Id*. at 31-32.
[42] *Id.* at 32.
[43] *Id.* at 33.

Evidence of forecast inflation is substantial. Nelson and Eiden report that load forecasts are highly speculative and up to 30 percent of requests have been cancelled historically.[44] In Ohio, after AEP Ohio implemented a take-or-pay retail large-load tariff with minimum demand charges and exit fees, projected data center load fell from more than 30 GW across 90 sites to 13 GW across 36 sites—a decline of more than half.[45]

Industry participants across the spectrum have voiced similar concerns. Astrid Atkinson, a former senior director of software engineering at Google, stated that there are "five to ten times more interconnection requests than data centers actually being built."[46] The president of a shale gas producer said he expects only 10 percent of announced data center projects to be built.[47] Notably, the data center companies themselves recognize the problem. Microsoft, in testimony before the Georgia Public Service Commission, warned that "over-forecasting demand from data centers could lead to procuring excessive carbon intensive generation," and recommended that the Georgia commission approve near-term resource planning decisions only for "known, mature projects that have made firm commitments."[48]

Even within a single corporate family, forecasts are inconsistent. ComEd reports 28,000 MW of large-load connection requests in its pipeline, while its parent company Exelon submitted half that amount—14,000 MW—to PJM.[49] Exelon explicitly acknowledged the uncertainty in these forecasts, excluding 45 GW of

[44] *Id.*
[45] *Id*. at 35-36.
[46] *Id.* at 29.
[47] *Id*.
[48] *Id.*
[49] *Id.* at 28.

requests in its 2040 forecasts for its four distribution utilities (ComEd, Pepco, BGE, and PECO)—because they are "less certain projects."[50]

Other evidence also indicates that forecasted load growth is overstated. The magnitude of forecasted load growth requires more computing equipment than is possible from existing supply chains.[51] One analysis found that announced U.S. data center projects would require 90 percent of incremental global chip supply through 2030, despite the United States currently holding only a 50 percent market share.[52]

The incentives embedded in the current regulatory framework compound the risk of forecast overstatement. Investor-owned utilities, operating within a cost-of-service regulation model, benefit financially from transmission investments that grow their rate base and increase returns.[53] The costs and benefits are asymmetric: the utility benefits from making investments that expand its rate base but bears few risks of stranded or under-utilized assets, with most risks borne by ratepayers.[54] Because of this, utilities are incentivized to invest in generation and transmission to serve potential load growth, even if it is speculative.[55]

PJM's own efforts to improve the accuracy of forecasts fall short. As Nelson and Eiden explain, PJM's load adjustment implementation document expressly states that PJM "does not specify a particular methodology for forecasting large loads" and that utilities "may utilize any methodology that is reasonable and appropriate"—

[50] *Id*.
[51] *Id*. at 37.
[52] *Id*.
[53] *Id*. at 36.
[54] *Id*.
[55] *Id*.

leaving forecast quality to the discretion of individual utilities.[56] PJM also fails to require standardization in how utilities estimate peak demand impacts relative to capacity requests, meaning a signed commitment from a data center developer may bear little relationship to actual metered demand.[57] Nelson and Eiden conclude that the incentives for both large-load customers and the utilities seeking to serve them exhibit a significant bias toward increasing load forecasts, such that PJM's resulting forecasts likely overstate actual need.[58]

2. PJM's hybrid methodology and its impact on Maryland customers.

PJM's hybrid transmission cost allocation methodology was designed and approved during an era of gradual, diffuse, organic load growth in which no single customer or zone could drive billions of dollars in regional transmission investment within the span of a few years. But when PJM's current methodology was established, the concentrated merchant-scale data center additions described above were not contemplated. The sections below describe how PJM's transmission cost allocation methodology operates and what its application today means for Maryland customers.

a. PJM's current hybrid cost allocation methodology.

PJM allocates costs for RTEP baseline reliability projects through a hybrid methodology described in Schedule 12 of the PJM Open Access Transmission Tariff ("OATT").[59] As the Nelson and Eiden Affidavit explains, projects designated as "regional facilities" (rated at 500 kV or higher) and "necessary lower voltage

[56] *Id*. at 37-38.
[57] *Id*. at 38.
[58] *Id*. at 39.
[59] *Id*. at 40.

facilities" (those rated between 345 kV and 500 kV that involve double-AC circuits and are required to support regional facilities) receive a combined allocation: 50 percent by load-ratio share and 50 percent by solution-based distribution factor analysis ("DFAX"). Projects below these thresholds are allocated entirely through the solution-based DFAX method.[60] Of the $2 billion in transmission capital costs allocated to Maryland, the load-ratio share allocations account for $678,680,885, while solution-based DFAX accounts for $1,322,523,125.[61]

The load-ratio share component assigns each of PJM's transmission zones a proportion of costs based on their relative contribution to PJM's annual coincident peak load during the previous calendar year.[62] Known as "postage stamp" methodology, the load-ratio share allocator assumes that all transmission built will benefit the entire grid—an assumption that has become a "basic fallacy" with concentrated data center load growth, most notably in Virginia and other discrete, limited areas in PJM.[63]

The solution-based DFAX method uses power flow modeling to analyze projected changes in network power flows across a required transmission enhancement, accounting for all resulting flows into a transmission zone from all sources of PJM generation.[64] It models the transfer of power from all generation sources in the PJM region to each transmission zone, measuring the proportion of megawatts transferred over the transmission facility to and from each individual

[60] *Id.*
[61] *Id*. at 12, Table 1.
[62] *Id*. at 40 and n. 75.
[63] *Id*. at 40-42.
[64] *Id*. at 40-41.

transmission zone. PJM then uses the resulting distribution factors as allocation factors for all or part of the costs of the project.[65] The ratio of power flows over a particular transmission facility intends to approximate the benefits accruing to each transmission zone from the project. It makes this approximation by modeling a transfer of power from all generation sources in the PJM region to each transmission zo[66]ne and measuring the proportion of megawatts transferred over the transmission facility to and from each individual transmission zone. PJM then uses the resulting distribution factors as allocation factors for all or part of the costs of the project.

The solution-based DFAX method has a fundamental constraint: Because it is grounded in load-flow modeling, it captures the benefits only of projects that address thermal overloads and static voltage violations. It is not designed to measure stability-related, short-circuit, or dynamic voltage impacts.[67] The Commission has recognized its limitations in prior proceedings, finding that beneficiaries of stability-related and short-circuit projects "are not necessarily captured by the solution-based DFAX method."[68] As explained below, data centers generate non-flow-based reliability impacts that the DFAX methodology was not designed to capture.

b. The financial consequences of PJM's methodology for Maryland customers.

The impact of PJM's hybrid cost allocation methodology translates into concrete financial consequences for Maryland ratepayers that are severe and growing.

[65] *Id*. at 41.
[66] *Id.*
[67] *Id*. at 43-45.
[68] *Id*. at 43 (*citing Del. Pub. Serv. Comm'n v. PJM Interconnection, LLC*, 166 FERC ¶ 61,161 (2019) and *Consolidated Edison Co. of New York, Inc. v. PJM Interconnection, LLC*, 194 FERC ¶ 61,179 at P 73 (2026).)

As documented in detail in the Nelson and Eiden Affidavit, under PJM's current projections, for 2022 RTEP Window 3, 2024 RTEP Window 1, and 2025 RTEP Window 1, PJM's hybrid cost allocation methodology assigns cost responsibility to Maryland customers for $2.0 billion for transmission facilities' capital costs and $1.6 billion in increased total revenue requirements over the first ten years following commercial operation of the transmission facilities.[69] The transmission expansion for each of these RTEP windows is overwhelmingly to support projected data center load growth. Based on the analysis described in the Affidavit, Maryland residential customers will pay an additional $823 million, or $345 per average customer, over the ten-year period analyzed due to these RTEP projects.[70] Maryland commercial customers will pay an additional $146 million, or $673 per average customer.[71] Maryland industrial customers will pay $629 million more for transmission services, or $15,074 per average customer over the same period.[72] Most of these costs are passed through to customers of Baltimore Gas & Electric (BGE) and the Potomac Electric Power Company (Pepco), which together pay an additional $1.2 billion over the next 10 years.[73]

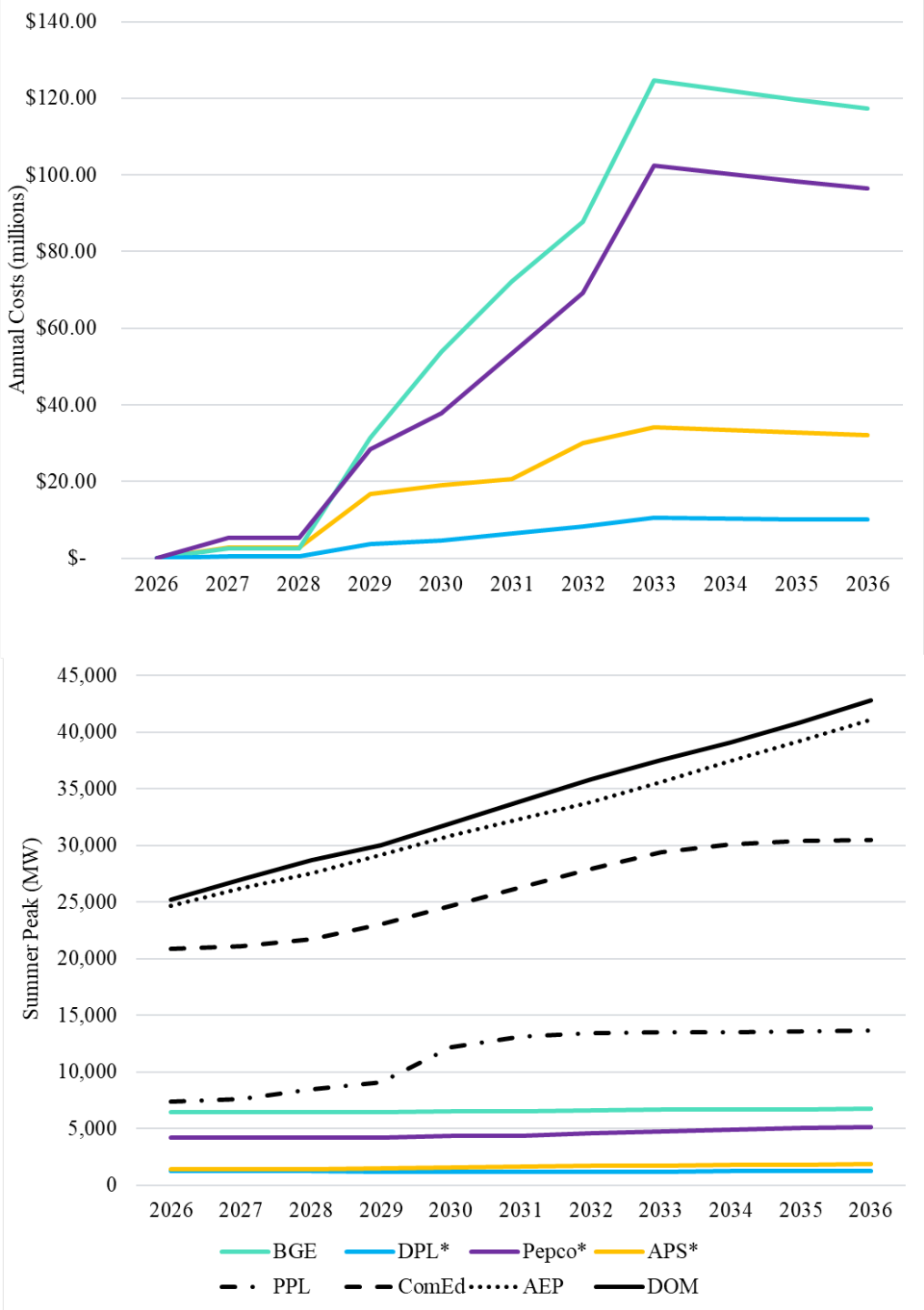
The costs allocated to Maryland customers bear no reasonable relationship to the load growth occurring or currently forecasted to occur in Maryland. The transmission cost increases begin in 2029, peak in 2033, and then gradually decrease

[69] *Id.* at 10-12.
[70] *Id.* at 60-61.
[71] *Id.*
[72] *Id.* and n. 111: Additionally, $23 million are allocated to "other" customer classes, bringing the total to $1.621 billion.
[73] *Id.* at 61-62.

through the end of current projections.[74] Over that period, load projections for transmission zones covering Maryland show only marginal forecasted load growth, while PJM projects the Dominion and AEP transmission zones to substantially increase their current annual load by 2036.[75] Maryland ratepayers are paying substantially for data center-driven transmission buildout by virtue of geographic proximity, not cost causation. Figure 7 in the Affidavit illustrates the relationship between PJM's hybrid transmission cost allocation methodology and the data center load projections.

[74] *Id*. at 62-64 and Figure 7.
[75] *Id*.

Figure 1. Maryland annual revenue requirements from RTEP baseline reliability upgrades compared to summer peak MW growth forecasts[76]



[76] *Id.* at 64.

PJM's cost allocation methodology thus requires Maryland's customers to subsidize data center growth. Most, if not all, transmission network upgrade costs are socialized to existing customers due to PJM's transmission cost allocation methodology. As the Nelson and Eiden Affidavit explains, PJM's cost allocation methodology drives subsidization because the revenue requirements for these large transmission build outs to serve data center growth are being pooled together under the category of "RTEP baseline reliability upgrades" instead of being assigned to those causing the costs.[77]

The fundamental differences between data centers versus non-data centers make subsidization virtually inevitable. A large data center can represent "more load than a mid-size city" and can scale up in a matter of years rather than the decades it would take for load to develop under normal growth patterns.[78] The circumstances driven by massive data center load growth are likely to continue into future, leaving no relief on the horizon for Maryland ratepayers. The Synapse Report projects that PJM could saddle Maryland with the responsibility to pay for an additional $5.4 billion in capital costs for transmission projects built between 2031 and 2035 alone—nearly as much as the $7.1 billion burden Maryland customers paid out over the prior two decades combined.[79]

[77] *Id*. at 69-70.
[78] *Id*. at 75.
[79] Attach. B (Synapse Report) at i and 32.

3. Developments purporting to address the inequities posed by data center loads—state large-load retail tariffs and electric utility "self-help" TSAs.

Two recent developments seek to address the inequities posed by data center loads under PJM's current hybrid methodology for transmission cost allocation. Both are inadequate to resolve the misallocation of costs; in fact, in certain situations, they could exacerbate the unfairness.

First, many states in PJM's footprint have, or are in the process of adopting, state level retail large-load tariffs. These tariffs address elements of the issues posed by data centers, such as requiring greater up-front financial commitments from data centers to mitigate stranded costs in the event the data center load does not show up and to better reveal the full cost of data center interconnection, thereby better aligning data center demand with the costs of serving the demand. However, they remain a partial and inadequate remedy.

Under a large-load retail tariff, a state regulator can allocate a portion of transmission costs to the data center load driving the cost incurrence, but those costs are only those allocated to the state, in that first instance, because of the infirm PJM hybrid cost allocation methodology. Costs allocated to other zones arising from transmission projects driven by the data center load in the hosting state—due to the PJM hybrid cost allocation methodology—are, by definition, not borne by the zone where the data center load is located or by the data center load itself. A state retail large-load tariff is not fully effective in this circumstance. The state large-load tariff, if it attempts to better allocate costs to data center customers, only applies to the costs allocated to the state in the first instance by operation of the PJM tariff. Costs caused by the data center that the PJM tariff allocates to other states in other zones are

effectively ignored by a particular state's large-load tariff and instead paid for by the loads in other zones, creating a subsidy for large-load data centers. Moreover, to the extent the state level retail tariffs are not uniform, the lack of uniformity incents data centers to locate inefficiently, chasing better terms and greater transmission cost subsidies and, in turn, driving inefficient, more expensive transmission expansion chasing the data centers.

Furthermore, if the data center load does not show up in the hosting state at the projected levels, the unnecessary costs incurred to support that unrealized data center load growth are not fully borne by the host state (or, more specifically, the host PJM zone). This asymmetry between host PJM zones and other PJM zones means, as explained in the Affidavit, that the host zone can shield its customers "from stranded transmission upgrade costs for large load customers" by having utilities pay those costs.[80] "If every state commission in PJM's territory uses similar logic, billions of dollars of stranded transmission costs will unnecessarily and inefficiently be spread throughout PJM's territory."[81]

Second, on a self-help basis, utilities have begun making filings of TSAs with the Commission. These voluntary TSAs are also partial and inadequate remedies that may benefit transmission owners but fail to fully protect customers. They share the same deficiency as many large-load retail tariffs—they do not charge the data center load for the full cost of the transmission expansion that the data center load causes due to the allocation under the PJM hybrid methodology of a material portion of those

[80] Attach. A (Nelson and Eiden Affidavit) at 56.
[81] *Id.*

costs to zones other than the one where the data center load is located. Further, under the TSAs, the transmission costs that are allocated to data center customers are "rolled in" costs, which creates the risk of shifting costs to non-data center customers within the utility's service area for even the transmission costs that are allocated to the zone where the data center is located to other retail customers. Due to their filing with the Commission, the utility sponsors of the TSAs may argue that the TSAs have preemptive effect on state-level large-load retail tariffs that seek to prevent cost shifting to non-data center customers.

ARGUMENT

The legal framework governing this complaint is well-established. The Commission may not approve transmission cost allocation methodologies that assign costs without accompanying "roughly commensurate" benefits.[82] Historical acceptance of a cost allocation methodology does not insulate it from challenge when, as here, circumstances have changed.[83] Nor does compliance with Order No. 1000 "necessarily ensure compliance with the cost-causation principle," particularly, as

[82] *Ill. Commerce Comm'n v. FERC.*, 576 F.3d 470, 476 (7th Cir. 2009) ("*ICC I*") (FERC is "not authorized to approve a pricing scheme that requires a group of utilities to pay for facilities from which its members derive no benefits, or benefits that are trivial in relation to the costs sought to be shifted to its members"); *Ill. Commerce Comm'n v. FERC*, 756 F.3d 556, 564 (7th Cir. 2014) ("*ICC II*") ("[T]he basic fallacy … is to assume that the 500-kV lines that have been or will be built in PJM's eastern region are basically for the benefit of the entire regional grid"); *Pub. Serv. Elec. & Gas Co. v. FERC*, 989 F.3d 10, 13 (D.C. Cir. 2021) ("[C]osts assessed against a party must bear some resemblance 'to the burdens imposed or benefits drawn by that party.'") (citing *Midwest ISO Transm'n Owners v. FERC*, 373 F.3d 1361, 1368 (D.C. Cir. 2004)).

[83] *Ill. Commerce Comm'n*, 576 F.3d at 475 ("[T]he fact that these utilities thought it appropriate to share costs in 1967 says nothing about the advantages and disadvantages of such an arrangement in the larger, modern PJM network.").

here, where the factual context anchoring a prior compliance order has materially changed.[84]

The Commission has both the authority and the obligation to act. Section 206(a) of the Federal Power Act ("FPA") authorizes and requires the Commission to correct unjust and unreasonable rates. Although OPC has previously protested PJM's tariff provision for transmission cost allocation in a section 205 proceeding, the Commission itself has recognized that section 206 complaints are the appropriate vehicle for OPC to challenge PJM's transmission cost allocation methodology. [85]

The argument below explains, in three parts, why FPA section 206 relief is necessary to prevent the unjust and unreasonable, and therefore unlawful, allocation resulting from Schedule 12 of PJM's OATT of billions of dollars in transmission expansion costs, which are overwhelmingly driven by projections of data center load growth, to existing customers in Maryland and other PJM states.

> **Part I** explains that PJM's hybrid cost allocation methodology produces unjust and unreasonable rates because it has failed to keep up with the times—specifically the projections of city-sized, geographically concentrated power demands of data centers. Under present circumstances, the methodology violates core cost causation principles, producing cross subsidies and, even worse, it incentivizes the shifting of stranded cost risk from PJM zones with projections of highly concentrated data center growth to other PJM zones.
>
> **Part II** argues that the only effective solution for allocating transmission costs requires PJM to change its existing OATT hybrid cost allocation methodology to establish just and reasonable transmission rates and that state large-load tariffs and

[84] *Old Dominion Elec. Coop. v. FERC*, 898 F.3d 1254, 1265 (D.C. Cir. 2018).
[85] *PJM Interconnection, LLC*, 187 FERC ¶ 61,012 at P 29 (2024) ("The issues raised by the Maryland People's Counsel protest should have been filed as a complaint, rather than as a protest to the instant filing"); Comments of Md. Off. of People's Couns., *PJM Interconnection, LLC*, Docket. No. ER25-1811-000 at 5 n.5 (April 28, 2025).

utility-sponsored TSAs prove inadequate to address the problems created by the OATT.

Part III provides remedies for allocating transmission costs that would result in just and reasonable transmission rates, requesting that the Commission (1) direct PJM to assign RTEP transmission costs caused by concentrated data center load growth to the zones where that load growth is occurring, or (2) depending on its advanced notice of proposed rulemaking,[86] adopt an allocation framework that directly charges upfront transmission network upgrade costs to large loads and fully recovers revenues commensurate with the large loads' ongoing use of the transmission system.

I. PJM's hybrid cost allocation methodology produces unjust and unreasonable rates for Maryland customers because it requires them to pay for regional transmission projects driven primarily by concentrated data center load growth.

A. PJM's allocation of costs must adapt to changing circumstances to adhere to cost causation principles.

The cost causation principle has been the bedrock of transmission rate regulation since the Commission first grappled with how to allocate the costs of regional transmission infrastructure among utilities serving different customer bases: Those who cause transmission costs to be incurred, or who benefit from the investments made, should bear those costs in a manner that is at least roughly commensurate with their contribution or benefit.[87] PJM's hybrid methodology was designed with that principle in mind, but for a fundamentally different world.[88] When the hybrid methodology was developed and approved, load growth across the PJM footprint was gradual, diffuse, and broadly distributed. No single customer, zone, or

[86] Department of Energy, *Sec. of Energy's Direction that the Federal Energy Regulatory Commission Initiate Rulemaking Procedures and Proposal Regarding the Interconnection of Large Loads Purchase to the Secretary's Authority under Section 403 of the Department of Energy Organization Act* (Oct. 25, 2025) (see, esp., P 25, Principle Eight).
[87] *Ill. Commerce Comm'n v. FERC.*, 576 F.3d 470, 476-77 (7th Cir. 2009).
[88] Attach A. (Nelson and Eiden Aff.) at 42-44.

technology could drive billions of dollars in regional transmission investment within the span of a few years. That world no longer exists, and the methodology built for it no longer produces just and reasonable results.

PJM developed its currently approved hybrid cost allocation methodology to address a fundamentally different set of circumstances than those presented by today's unprecedented data center-driven load growth. Its methodology assigns 50 percent of the costs of "regional facilities" and "necessary lower voltage facilities" on a load-ratio share basis and the remaining 50 percent through solution-based DFAX. As applied to the massive transmission build-out necessitated by concentrated data center additions in discrete areas of the PJM footprint, the hybrid methodology fails to satisfy the cost causation principle—the legal and policy principle that requires that costs be allocated to those who cause them to be incurred or who benefit from them in a manner that is at least "roughly commensurate" with estimated benefits.[89]

The PJM OATT implements a framework for allocating regional transmission facilities' costs. Both the courts and Commission Order 1000[90] establish the framework for the cost causation principle. That principle provides:

> When recovering the cost of transmission investments from customers, the costs allocated to certain groups of customers (*i.e.*, in different utility service territories within a region) must be roughly aligned with the benefits received by these customers from the transmission investments. All cost allocation methodologies for transmission projects under FERC jurisdiction

[89] *Pub. Serv. Elec. & Gas Co. v. FERC*, 989 F.3d 10, 13 (D.C. Cir. 2021) (stating that "costs assessed against a party must bear some resemblance 'to the burdens imposed or benefits drawn by that party'"); Order No. 1000, *Transmission Planning and Cost Allocation by Transmission Owning and Operating Public Utilities*, 18 C.F.R. pt. 34, P 622 (July 21, 2011) ("The Commission adopts the following cost allocation principle…Regional Cost Allocation Principle 1: The cost of transmission facilities must be allocated to those within the transmission planning region that benefit from these facilities in a manner at least roughly commensurate with estimated benefits.").

[90] *Transmission Planning and Cost Allocation by Transmission Owning and Operating Public Utilities*, Order No. 1000, 136 FERC ¶ 61,051 (2011).

> have satisfied this requirement, which is known as the cost causation principle. Cost causation requires that all approved rates must reflect some degree of the cost actually caused by the customer who must pay for them.[91]

Adherence to cost causation does not require balancing costs and benefits with "exacting precision," but customer rates must reflect the costs the customer causes.[92]

Critically, cost causation is not a "set it and forget it" proposition. As both the courts and the Commission have found, historical acceptance of a cost allocation methodology does not insulate it from challenges where circumstances have changed. For example, in *Delaware Public Service Commission v. PJM Interconnection, LLC* (the *"Artificial Island"* case), the Commission found that while PJM's solution-based DFAX methodology roughly matched costs to benefits when applied to facilities that resolved flow-based violations, it no longer produced a just and reasonable result when applied to cost allocations for facilities that address stability-related reliability issues.[93] The Commission therefore rejected PJM's proposal to rely solely on the solution-based DFAX method to allocate all costs of lower voltage facilities

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[91] *See* J. DeLosa III, J. Pfeifenberger, P. Joskow, *Regulation of Access, Pricing and Planning of High Voltage Transmission in the U.S.*, MIT Ctr. for Energy & Env't Pol'y Rsch., Working Paper Series, at 9 (Feb 2024) (Hereinafter "MIT CEEPR") (citing *KN Energy, Inc. v. FERC*, 968 F.2d 1295, 1300 (D.C. Cir. 1992)).

[92] *See, e.g., PJM Interconnection*, *LLC,* 193 FERC ¶ 61,217 at P 181 ("The Commission's cost causation principle requires costs to be allocated to those who cause the costs to be incurred and reap the resulting benefits. Courts and the Commission have acknowledged that adherence to the cost causation principle does not require that cost allocation methods balance costs and benefits with 'exacting precision.' Ultimately, the requirement is met so long as 'all approved rates reflect to some degree the costs actually caused by the customer who must pay them[,]' and this apportioning is done by ensuring that costs are 'allocated in a manner that is at least roughly commensurate with benefits.'" (footnotes omitted)).

[93] 164 FERC ¶ 61,035 at P 42 (2018), *aff'd sub nom. Pub. Serv. Elec. & Gas Co. v. FERC*, 989 F.3d 10 (D.C. Cir. 2021).

addressing stability-related reliability issues. The D.C. Circuit affirmed the Commission's rejection of PJM's proposal.[94]

In a recent large-load co-location order, the Commission likewise found PJM's open access tariff unjust and unreasonable in light of changed circumstances.[95] The Commission found that several aspects of the tariff, including rules governing behind-the-meter generation, were "conceived for, and [had] been implemented for, substantially smaller loads (like a warehouse with solar panels)" and were "not designed for large loads and are not a good fit."[96] The Commission accepted PJM's assertion that "20-years later cost causation principles may dictate a different outcome for co-located data center loads that appear to have different customer profile and load characteristics."[97] The Commission thus found that modifications to PJM's tariff were justified based on proliferation of large loads, and it ordered a paper hearing to gather additional evidence on appropriate replacement rates, terms and charges consistent with cost causation principles.[98] All of these decisions support the relief sought by this complaint.

B. PJM's hybrid methodology violates bedrock cost causation principles when it comes to allocating costs driven by massive data center-driven load growth.

Both components of PJM's hybrid methodology violate cost causation principles under the current circumstances of projected rapid, concentrated, and

[94] *Pub. Serv. Elec. & Gas Co.,* 989 F. 3d at 10.
[95] *PJM Interconnection, LLC*,193 FERC ¶ 61,217 at P 186 (2025) ("Co-located Order") ("[C]ircumstances have changed since the Commission approved PJM's retail BTMG rules such that these rules are no longer just and reasonable.").
[96] *Id.* at P 47.
[97] *Id*.
[98] *Id*. at P 219.

massive data center demand growth. *First*, the load-ratio share component broadly socializes costs across the PJM footprint based on each zone's share of system peak load, without regard to the geographic concentration of the load growth driving those costs. *Second*, the solution-based DFAX component is technically ill-suited for allocating costs driven by data center reliability impacts, and it is arbitrary, given the speculative load forecasts on which it depends. Together, these failures will produce more than $2 billion in improper allocation of transmission investment cost recovery responsibility resulting in unjust rates for Maryland customers via massive cross-subsidies in which Maryland customers pay for network upgrades driven by data center demand.

1. The load-ratio share component of PJM's hybrid methodology fails to justly and reasonably allocate costs of concentrated data center load growth.

The load-ratio share component of PJM's hybrid methodology for Maryland imposes substantial costs on Maryland customers. As shown in Tables 1 and 2,[99] the load-ratio share component of PJM's hybrid methodology accounts for $678,680,885 in capital cost allocations to Maryland ratepayers across the three RTEP windows at issue and $540,253,842 in ten-year revenue requirement allocations.

The load-ratio share component of PJM's hybrid methodology assigns 50 percent of transmission project costs on a "postage stamp" basis, allocating costs to each zone in proportion to its share of PJM's annual coincident peak load during the previous calendar year.[100] The theory underlying the load-ratio share allocation is that high-voltage transmission facilities provide broad regional benefits that cannot be

[99] Attach. A (Nelson and Eiden Aff.) at 12; *also supra* at p. 1.
[100] *Id.* at 40.

precisely traced to any individual zone.[101] Both the Commission and at least one court characterized the postage stamp cost allocation methodology as "crude."[102]

In fact, PJM's current hybrid methodology itself was adopted precisely because courts found that a 100 percent postage stamp approach was unjust when applied to geographically concentrated reliability needs. As the Nelson and Eiden Affidavit explains, PJM previously used a 100 percent load-ratio share method to assign costs of 500 kV and greater network upgrades.[103] PJM moved to the hybrid methodology as a direct result of successful challenges by western PJM transmission owners that argued that network upgrades in the eastern PJM region provided no benefit to them.[104] The courts made clear that the issue was "about the allocation of the huge costs of building high-voltage transmission lines that do not provide uniform benefits to all the utilities in the region in which the lines are built," and they identified as a "basic fallacy" the assumption that 500 kV lines built in the eastern region would benefit the entire grid, when in reality those projects addressed specific reliability violations in the eastern part of PJM.[105] It was only as a result of that court remand in *ICC II* that PJM adopted the hybrid methodology.

The same logic that drove adoption of the hybrid methodology now compels the conclusion that the load-ratio share component itself is no longer just and reasonable. As Nelson and Eiden conclude, "the load-ratio share is no longer just and

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[101] *Old Dominion Elec. Coop. v. FERC*, 898 F.3d at 1260-61 (agreeing that the 50 percent postage-stamp component of PJM cost allocation captures regional benefits of high voltage facilities in the pre-data center growth era such as improved reliability, reduced congestion, greater carrying capacity).
[102] *ICC* II, 756 F.3d at 775.
[103] Attach. A (Nelson and Eiden Aff.) at 41-42.
[104] *Id*.
[105] *Id*. at 42.

reasonable under the same logic that justified moving toward the hybrid allocation method in the first place."[106] It is the unprecedented scale of data center growth that is causing substantial increased reliability needs. As was the case when PJM's 100 percent load-ratio share methodology was overturned in the courts because of the "basic fallacy" that assumed 500 kV lines built in the eastern region would benefit the entire PJM system,[107] today's methodology rests on a fallacy that the entire region benefits from massive transmission expansion projects needed to serve data center growth. To the contrary, data-center-driven load growth is geographically concentrated, and massive transmission costs are being allocated using the load-ratio share methodology that are associated with 500 kV lines needed to resolve specific reliability violations caused by that concentrated data center growth occurring in discrete transmission zones in PJM.[108]

Put simply, when the driver of transmission investment is concentrated large load growth in a discrete geographic area, the rationale for the load-ratio share component of PJM's hybrid methodology fails. The load-ratio share method "allocates costs broadly across transmission zones based on each zone's share of system peak load, without regard to the location or drivers of the underlying transmission need," with the result that "projects triggered by concentrated data center growth are socialized across the PJM footprint, including to customers who do not meaningfully contribute to or benefit from those upgrades."[109] In these circumstances, the load-ratio share allocator no longer functions as a rough proxy; it is fundamentally

[106] *Id*.
[107] *Illinois Commerce Commission v. FERC*, 756 F. 3d 556 (7th Cir. 2014).
[108] Attach. A (Nelson and Eiden Affidavit) at 42-43.
[109] *Id*. at 50.

dysfunctional, forcing ratepayers in states like Maryland to absorb billions of dollars in infrastructure costs driven by Virginia's, and a few other states', data center booms, while Maryland customers receive little to no commensurate benefit, contrary to cost causation principles.

2. Solution-based DFAX is unjust and unreasonable due to technical misapplication and speculative load forecasts.

a. DFAX fails to capture stability, short-circuit, and voltage issues.

The solution-based DFAX method is designed to track projected changes in network power flows. It models a transfer of power from all PJM generation sources to each individual transmission zone to measure the proportion of megawatts transferred over a specific transmission facility.[110] Because its basis is load flow, the DFAX method is primarily beneficial for allocating costs associated with steady-state thermal violations and static voltage violations.[111]

The D.C. Circuit has confirmed that the solution-based DFAX method is unsuited for allocating costs of reliability projects that address non-flow-based problems. In the *Artificial Island* case,[112] the court upheld FERC's determination that applying DFAX to stability-related reliability projects is unjust and unreasonable. The court explained that flow-based reliability problems, such as thermal overloads, are solved by bringing power to a constrained region, so "'the beneficiaries of that solution are readily identified based upon those power flows.'"[113] Stability-related issues are "analytically unique": they "arise from the inability of a particular

[110] *Id*. at 41.
[111] *Id*. at 45-46.
[112] *Pub. Serv. Elec. & Gas Co. v. FERC*, 989 F.3d 10 (D.C. Cir. 2021).
[113] *Id.* at 16 (quoting *Del. Pub. Serv. Comm'n*, 164 F.E.R.C. ¶ 61,035 at P 39 (July 19, 2018).

generating unit to maintain synchronism with the grid" and are solved not by bringing power to load but by "providing additional transmission pathways from the generator to the grid."[114] Because the beneficiaries of such a project "are not necessarily captured" by following the flow of electrons—which is what DFAX does—the method fails to align costs with benefits.[115]

The D.C. Circuit extended the *Artificial Island* reasoning to short-circuit projects in *Consolidated Edison Co. of N.Y., Inc. v. FERC*.[116] There, PJM used DFAX to allocate approximately $1.3 billion in costs for upgrades that addressed short-circuit vulnerabilities and storm damage, not flow-based constraints. The court found that it was arbitrary to continue applying DFAX to these projects after directing a different method for the analogous stability project at Artificial Island, noting that the testimony that the Commission relied upon "recognized both 'the short circuit issue and the stability issue' as awkward fits for the DFAX method, because neither are flow-based."[117]

PJM commits the same error here; it applies DFAX to allocate costs driven by reliability needs that DFAX was never designed to measure. As Nelson and Eiden explain in the Affidavit, the solution-based DFAX method is primarily beneficial for allocating costs associated with thermal violations and static voltage violations, but

[114] *Pub. Serv. Elec. & Gas Co.*, 989 F.3d at 18.
[115] Attach. A (Nelson and Eiden Aff.) at 43 n.83 (citing *Del. Pub. Serv. Comm'n*, 169 FERC ¶ 61,161 at P 7).
[116] *Consolidated Edison Co. of N.Y., Inc. v. FERC*, 45 F.4th 265 (D.C. Cir. 2022).
[117] *Id*. at 280. On March 6, 2026, the Commission issued an order on remand in *Consolidated Edison Co. of New York, Inc. v. PJM Interconnection, LLC*, 194 FERC ¶ 61,179 (2026). On the short circuit cost allocation issue, the Commission established paper hearing procedures to develop a further record on whether short circuit projects should be treated similarly to stability projects (for which FERC previously found DFAX inappropriate in *Artificial Island*) or whether there are any differences between the two types of non-flow-based projects that could justify continued use of DFAX for short circuit cost allocation.

large data center interconnections create a far broader range of reliability impacts that DFAX cannot capture.[118] Data center load "poses substantial stability and non-steady state reliability risks which PJM has not adequately studied and are not reflected in its current cost allocation mechanisms."[119] Data centers impose substantial reliability issues not related to load flow. For instance, utilities and system operators globally consider voltage ride-through capability for large loads to be among the most critical system reliability needs, leading to risks of frequency excursions, cascading outages, transient instability, voltage collapse and more.[120]

These risks are not hypothetical. On July 10, 2024, the Eastern Interconnection experienced a sudden drop of 1,500 MW of data center load in Dominion's territory in northern Virginia when a lightning strike caused a transmission-level fault and data centers switched to on-site backup power.[121] A similar significant event occurred in Virginia a few months earlier in February 2025. Roughly 40 data centers, which had been using enough electricity to supply more than one million homes, simultaneously switched to backup power sources in February 2025, when a high-voltage power line malfunctioned. The sudden plunge in electricity demand forced the grid operator to take quick action to avoid potentially serious damage.[122]

Separately, the North American Electric Reliability Corp. ("NERC") has found it critical to have visibility into how large loads operate, "including not just peak demand and interconnection timelines, but also dynamic load models and control and

[118] Attach. A (Nelson and Eiden Aff.) at 45-46.
[119] Attach. A (Nelson and Eiden Aff.) at 46.
[120] *Id.* at 46.
[121] *Id.* at 46-47.
[122] https://www.wsj.com/business/energy-oil/a-new-threat-to-power-grids-data-centers-unplugging-at-once-741f1bda?mod=panda_wsj_section_alert (March 1, 2025).

protection settings."[123] Without visibility into these dynamics, planners and operators cannot assess the full impact of these new loads on the power system which can result in poor planning decisions.[124] On April 21, 2026, NERC confirmed that it is in the "'final stages of preparing to issue a Level 3 essential actions alert' related to large computational loads unexpectedly disconnecting from the grid."[125] Another recent report by Evaluate Energy Consulting further identifies reliability challenges specific to data centers, including "ramping, frequency response, generator cycling, power quality issues, transient stability impacts, and subsynchronous oscillations."[126] As Nelson and Eiden conclude, these system impacts are not adequately reflected in PJM's current modeling assumptions and are simply not understood well enough yet to be captured in the DFAX methodology.[127]

Specific projects from the 2022 RTEP Window 3 provide further evidence of a mismatch between the intended purpose of DFAX and its continued use here. Here, the 2022 RTEP Window 3 includes costs for two types of stability-related projects which are inappropriate for solution-based DFAX cost allocation. According to Nelson and Eiden, PJM may have included costs related to short circuits.[128] In addition, PJM also included $155.82 million for a baseline reliability project classified as "Reactive Power VAR Reinforcements." The $155 million in VAR costs are "not

[123] Attach. A (Nelson and Eiden Affidavit) at 47-48.
[124] *Id*. at 48.
[125] "Sudden data center load losses prompt NERC alert, recommendations," by Richard Walton, *Utility Dive* (April 21, 2026).
[126] Attach. A (Nelson and Eiden Aff.) at 48.
[127] *Id*. at 48 and 49-50.
[128] *Id.* at 44-45. Nelson and Eiden explain that the short-circuit projects may have been included as the result of an initial short-circuit screening step that was subsequently applied to all scenarios, leading to an inclusion of additional projects for this category. *Id*.

due to steady-state-load flow-based project needs and are inappropriately being allocated" under the solution-based DFAX methodology.[129]

b. Speculative load forecasts and phantom requests render DFAX allocations arbitrary.

Even if DFAX were the correct technical tool (which it is not), the methodology is rendered arbitrary by the speculative nature of its inputs. As demonstrated in Part I.D below, the load forecasts driving DFAX allocations are subject to extreme uncertainty, inflated by phantom requests, duplicative applications, and structural incentives to overbuild. PJM has itself acknowledged "there is growing uncertainty around the accuracy of forward load forecasts because of the unprecedented nature of data center load growth, and there is the need to examine who should bear the risk of these forecasts being incorrect in either direction."[130]

The primary mechanism driving forecast inflation is phantom and duplicative interconnection requests.[131] Data center developers routinely submit speculative requests to multiple utilities across multiple jurisdictions.[132] Even PJM's own cross-checking processes cannot catch them: PJM has no way to cross-check whether a data center in, for example, Exelon's service territory has also made the same proposal in Dominion's territory, and both proposals end up in PJM's forecast even though only one will be built. Data center customers themselves have acknowledged that current forecasts "are inaccurate and include double counting issues, speculative loads, and low probability projects."[133]

[129] *Id*. at 45.
[130] *Id*. at 27-28.
[131] *Id*. at 30-31.
[132] *Id*. at 31-32.
[133] *Id*. at 30.

Investor-owned utilities lack incentive to screen out speculative requests. Operating under cost-of-service regulation, utilities benefit financially from growing their rate base but bear few of the risks of stranded or under-utilized assets while ratepayers bear most of the risks.[134] The Nelson and Eiden Affidavit concludes that "the incentives for both large load customers and those seeking to serve them with new generation exhibit a significant bias toward increasing the load forecast, and hence, PJM's resulting forecasts likely overstate the actual need."[135]

The cost allocation consequences are direct and severe. The DFAX allocator is initially calculated based on forecasted power flows and peak loads expected at the time a project enters service.[136] Once the project goes into service, the DFAX is updated annually with actual loads. When forecasted large loads do not materialize, the DFAX allocator shifts costs away from the zone where the load was predicted and redistributes them to other zones that did not cause the upgrade. The result is a systematic transfer of stranded asset risk from the zones that attracted the speculative load growth to ratepayers across the region.[137] As PJM itself has recognized, there is a "need to examine who should bear the risk of these forecasts being incorrect."[138] Under the current methodology, the answer is already known: Ratepayers in non-causal zones like Maryland bear that risk, while the zones and utilities whose speculative forecasts created it do not.

[134] *Id*. at 36.
[135] *Id*. at 39.
[136] *Id*. at 53.
[137] *Id*. at 53-54.
[138] *Id*. at 27-28.

C. The hybrid methodology produces unjust cross-subsidies and creates perverse incentives that compound the harm.

PJM's hybrid methodology does not merely fail to align costs with cost causation. It improperly transfers billions of dollars in costs from the parties that caused them to customers who did not. That transfer takes two forms. The first is direct: Existing customers are forced to subsidize transmission buildouts driven overwhelmingly by data center demand. The second is structural: The methodology creates perverse incentives for utilities and states to compete for large-load development while shifting the risk of stranded assets to ratepayers in neighboring transmission zones, producing a race to the bottom that only federal action can stop.

1. PJM's current cost allocation methodology causes existing customers to unjustly subsidize large loads.

Data center customers are not currently directly allocated transmission network upgrade costs. Instead, the revenue requirements for transmission build-outs driven by data center growth are pooled together under the category of "RTEP baseline reliability upgrades" and socialized to all ratepayers through the hybrid methodology. As the Nelson and Eiden Affidavit explains, "[T]hese costs must be assigned to data centers because without doing so, the costs facing existing ratepayers are not roughly commensurate with the benefits derived."[139] PJM, the Affidavit further states, "is taking insufficient steps to prevent other ratepayers from paying for transmission network upgrade costs caused by new large load customers. Though utilities . . . have proposed reforms to ensure these [large load] customers pay their bills for 10 to 15

[139] *Id.* at 70-71.

years, PJM has not pushed for similar reforms to prevent transmission costs from being paid for by all customers."[140]

The scale of this subsidization is enormous. In Dominion's territory alone, between $2.44 billion and $5.77 billion in transmission projects have been driven primarily or in some part by data center connections.[141] Most of these costs are subsidized by existing customers who did not cause them. As the Affidavit explains, "there are significant differences that set data centers and other large loads apart from existing customers."[142] A single large data center "can represent more load than a mid-size city and can scale up in a matter of years, rather than the decades it would take to develop similar load under more normal growth patterns."[143] The Affidavit concludes that while "significant differences . . . set data centers and other large loads apart from existing customers," there are parallels to merchant generators, including the fact that "speed to grid connection impacts profits."[144] Nelson and Eiden therefore conclude that "[t]he same factors leading to negative market outcomes that the Commission sought to correct by adopting the protections in Order No. 2003 apply equally well, or more, to the case of large loads and data centers."[145]

In Order No. 2003,[146] the Commission implemented two key protections to shield customers from subsidizing merchant generators. *First*, transmission providers can charge interconnecting customers to cover the upfront costs of network upgrades

[140] *Id.* at 69.
[141] *Id.* at 23-24.
[142] *Id.* at 75.
[143] *Id.*
[144] *Id.*
[145] *Id.* at 78.
[146] Order No. 2003, *Standardization of Generator Interconnection Agreements and Procedures*, 104 FERC ¶ 61,103 (2003).

that were not required "but for" their interconnection. Charging interconnecting customers acts as a financing vehicle with credits applied over time to avoid "and" pricing.[147] *Second*, the "higher of" policy allows the transmission provider to charge the "higher of the incremental cost of Network Upgrades required to interconnect the Generating Facility or an embedded cost rate for the entire Transmission System."[148] The Commission has also approved, in the context of a generator seeking interconnection, an arrangement where the generator pays both an embedded rate for use of the existing transmission grid and a separate rate for incremental facilities caused by the generator, with the latter rate cabined by the higher of policy for the incremental service.[149] As the Commission concluded, "this 'higher of' policy ensures that other Transmission Customers, including the Transmission Provider's native load, will not subsidize Network Upgrades required to interconnect merchant generation."[150] No comparable protections exist for large-load interconnections adapted to the context of data centers, even though the system impacts are analogous.[151]

[147] *Id.* at P 704-705.
[148] Order No. 2003-B, *Standardization of Generator Interconnection Agreements and Procedures*, 70 Fed. Reg. 265, 273 (Jan. 4, 2005) (to be codified at 18 C.F.R. pt. 35) ("Order No. 2003-B").
[149] *Northwestern Corp.*, 147 FERC ¶ 61,171 at P 53 (2014).
[150] Order No. 2003-B, 109 FERC ¶ 61,287 at P 54. Attach. A (Nelson and Eiden Aff.) at 72.
[151] The Department of Energy has recognized this gap, laying out a rationale for mirroring the reforms adopted for generators under Order No. 2003 within a near-term large load interconnection reform process, See Attach. A (Nelson and Eiden Aff.) at 75-80; *see also* Letter from Chris Wright, Secretary of Energy to David Rosner, Chairman, Federal Energy Regulatory Commission et. al. (October 23, 2025) (stating "Eighth, load and hybrid facilities should be responsible for 100 percent of the network upgrades that they are assigned through the interconnection studies.").

2. The hybrid methodology's perverse incentive structure independently violates the cost causation principle.

The cross-subsidy documented immediately above in Part C.1 is not the only harm the hybrid transmission cost allocation methodology inflicts. As detailed in Part I.B, the DFAX component creates a structural perverse incentive: Because the allocator is initially calculated on forecasted loads and then updated annually with actual loads, transmission zones that attract large loads that never materialize see their cost share fall while neighboring transmission zones absorb the difference.

State-level large-load retail tariffs worsen this dynamic rather than cure it: Minimum demand charges and long-term commitments insulate the cost-causing transmission zone from bill impacts even when load does not materialize, reducing the utility's downside risk. That risk reduction increases the cost-causing transmission zone's incentive to overbuild transmission to attract speculative large loads in the first place.[152] The DFAX then shifts the resulting stranded costs to neighboring transmission zones.[153] As Nelson and Eiden conclude, individual states cannot fix this dynamic because no state-level remedy can ensure rates reflect cost causation principles so long as the hybrid methodology obscures which transmission costs are caused by expected future data center load growth.[154] A cost allocation methodology that rewards overbuilding and penalizes customers who play no role in the underlying decision independently violates the cost causation principle and provides an additional basis for finding PJM's methodology unjust and unreasonable under Section 206.

[152] *Id*. at 52-54.
[153] *Id*. at 52-57.
[154] *Id*. at 58.

II. PJM must change its existing OATT hybrid cost allocation methodology to establish just and reasonable transmission rates.

These failures of PJM's hybrid cost allocation methodology, causing more than $2 billion in misallocated transmission investment cost responsibility resulting in unjust rates for Maryland customers, are not—and cannot—be addressed without addressing the fundamental flaws in the OATT with respect to data center-driven transmission needs. While state-level efforts are, in many respects, laudatory and may improve outcomes for existing customers, they fall far short and are incapable of addressing the harms of PJM's OATT. Two categories of efforts are currently in play—large-load tariffs and utility-filed TSAs. Both are inadequate. In fact, in some cases these solutions will worsen the plight of existing customers by magnifying utility incentives to overbuild transmission and shifting stranded asset risk from zones with projections of massive data center growth to customers in neighboring zones, including Maryland zones. Each of these issues is addressed in turn below.

A. Retail remedies are not sufficient to solve the inequitable PJM cost allocation problem.

State remedies are inadequate. Most state commissions consistently assign FERC-approved transmission costs to retail customers without sufficient information on cost causation or revisiting traditional cost allocation methodology.[155] But even if they had sufficient information, state commissions can only allocate FERC-approved costs to cost-causers *over which they exercise jurisdiction*. That does not include data center customers in other states. The Maryland legislature just enacted legislation strengthening last year's legislation, all seeking to allocate to data centers all

[155] *Id*. at 69.

transmission costs they cause.[156] Other PJM states have enacted or are considering similar efforts.[157] These efforts reflect genuine attempts to address the problem at the retail level, but they cannot reach the core issue: So long as PJM's hybrid methodology socializes transmission costs to zones that are not the source of expected, massive future data center load growth, no state-level remedy can ensure that rates reflect cost causation.[158]

Worse, state-level large-load tariffs do not merely fail to solve the regional cost allocation problem—they actively exacerbate it. As Nelson and Eiden explain, a large-load tariff that insulates one utility's retail customers from stranded transmission costs magnifies the perverse incentive for that utility to overbuild transmission. The mechanism is straightforward: If large loads do not materialize, the DFAX allocator reduces the cost allocation to the originating transmission zone and shifts those costs to neighboring zones.[159] Nelson and Eiden further note an additional complication: It is unclear how retail large-load tariffs with 10-to-20-year terms interact with RTEP cost allocation.[160] In particular, data centers with contracts that impose minimum transmission charges, but whose load does not materialize, would still pay those charges to the utility.[161] The utility retains those payments, but because the DFAX is updated annually after a transmission project goes into service, the costs associated

[156] Legislation passed by the Maryland General Assembly during the 2026 session, awaiting action by the Governor, "Utility Relief (Reducing Energy Load Inflation for Everyday Families) Act" *HB 1532, amending Md Code, Pub. Utilities Art. § 4-212*.
[157] *See, e.g.*, Pennsylvania (PA PUC Docket No. M-2025-3054271 (large load retail tariff proceeding); Virginia (VA SCC, Case No. PUR-2025-00058 (Dominion large load tariff proceeding); VA SCC, Case No. PUR 2025-00057 (APS large load tariff proceeding)).
[158] Attach. A (Nelson and Eiden Aff.) at 58.
[159] *Id*. at 55-57.
[160] *Id*. at 57.
[161] *Id.*

with that project—built due to the data centers under minimum-charge contracts—are shifted to other zones.[162] Thus, the DFAX mechanism creates the potential for over-collection of transmission revenues by the attracting utility at the expense of everyone else.[163]

This dynamic is not theoretical. In comments filed at the Virginia SCC regarding Appalachian Power Company's ("APCo's") proposed large-load terms and conditions, SCC Staff noted that if a large load customer reduces its capacity, "the reduction may also reduce APCo's share of AEP zonal transmission costs, all else being equal, which could help to partially mitigate cost shifting concern to APCo's remaining customers."[164] As Nelson and Eiden observe, Virginia VCC staff is explicitly suggesting that a partial solution to shielding APCo's customers from stranded transmission costs is for another utility's customers to pay them. If every commission in PJM's territory follows similar logic, billions of dollars of stranded transmission costs will be spread throughout PJM's territory—what Nelson and Eiden aptly describe as "playing hot potato" with stranded transmission costs.[165] FERC, not the states, must address this problem at its source.

B. Transmission security agreements do not cure the harms caused by the hybrid cost allocation methodology.

1. Recent Commission-approved TSAs shift substantial costs and risks to existing customers.

TSAs between transmission owners and large-load customers are gaining utility support as a mechanism purportedly to ensure that data centers contribute to

[162] *Id*.
[163] *Id*.
[164] *Id.* at 56.
[165] *Id*. at 56-57.

transmission costs and to mitigate the risk of stranded costs should a data center project fail to materialize.[166] In the past six months, the Commission approved numerous TSAs filed by PECO and Commonwealth Edison, both affiliates of Exelon, which require the data center customer to make minimum revenue payments (and pay termination fees) if the data center is not built or underperforms its load commitments to offset the transmission costs that the utility will seek to recover through its formula rate from all customers.[167] Transmission owners such as Exelon have urged the Commission to favor their TSA approach over structural reforms that would treat large loads like interconnecting generators for cost allocation purposes. In its comments in Docket No. RM26-4-000, Exelon contends that TSAs "*provide[] valuable early certainty* to large loads regarding their expected transmission costs, which may be critical as they are making complex and cost-sensitive development decisions."[168]

But TSAs do not adequately protect ratepayers. Instead, the TSA model shifts sizable risks to existing customers while providing valuable concessions to large-load

[166] *See Commonwealth Edison Co*., 194 FERC ¶ 61,106 (2026) (Monarch) at P 2 (accepting a bilateral TSA between ComEd and Monarch Rock Air LLC for a new data center in Rockford, Illinois, over protests regarding cost socialization).

[167] *See id.* at PP 3-8; *see also Commonwealth Edison Co.*, 194 FERC ¶ 61,109 (2026) (accepting a transmission security agreement between ComEd and Aligned Data Centers PropCo, LLC for a new data center campus in Coal City, Illinois); *Commonwealth Edison Co.*, 194 FERC ¶ 61,110 (2026) (accepting a TSA between ComEd and Red Energy Partners LLC for a new data center campus in DeKalb, Illinois);
Commonwealth Edison Co., 194 FERC ¶ 61,113 (2026) (accepting a TSA between ComEd and Karis Critical, LLC for a new data center campus in DeKalb, Illinois, finding that cost recovery issues were not yet before the Commission); *PECO Energy Co.*, 193 FERC ¶ 61,148 (2025) (accepting a TSA between PECO and Amazon Data Services, Inc. for a new data center in Falls Township, Pennsylvania). In addition to these Commission-accepted agreements, Commonwealth Edison has filed four more TSAs that are now pending before the Commission. *See* Commonwealth Edison Equinox TSA, Docket No. ER 26-989 (January 9, 2026); Commonwealth Edison QTS TSA, ER26-990 (January 9, 2026); Commonwealth Edison Powerhouse Hillwood TSA, Docket No. ER26-989 (January 13, 2026); Commonwealth Grundy TSA ER26-1031 (January 13, 2026).

[168] Attach. A (Nelson and Eiden Aff.) at 89-90.

customers. Commissioner Judy Chang identified the deficiencies in several concurrences in the Commission orders approving Commonwealth Edison's TSAs.[169]

The TSA approach as advanced by Exelon and others does not establish sufficient protection for existing customers for at least two main reasons. *First*, the only upfront cost responsibility for large-load customers seeking to sign a similar TSA is for the construction of "customer facilities"—including one substation in the case of PECO and Amazon—whereas costs for "transmission facilities" (which are not defined) are the utility's responsibility and will be recovered through formula rates to the extent possible.[170] The precedent of Order No. 2003 standard interconnection rules, however, would allocate both the costs of the interconnection facilities and the upfront costs of the network upgrades that would not be required "but for" the interconnection. As the Nelson and Eiden Affidavit explains, this distinction is not trivial. Applying the Order No. 2003 framework "would result in significantly more near-term costs being assigned to large load customers, compared to the terms under the TSA."[171]

Second, the minimum-charges provision in the TSA meant to protect ratepayers against stranded asset risk is capped at 80 percent of the expected billing determinants and pegged to the transmission rate in place as of TSA's effective date, "regardless of whether such Utility's Network Zonal Service Rate may be greater in the calendar

[169] *Commonwealth* Edison, 194 FERC ¶ 61,106 at P 3 (Chang concurring) ("However, there is a need to protect other customers from potential unjustified cost shifts, and neither the terms of the Agreement nor ComEd demonstrate how these commitments achieve that higher and more essential standard.").
[170] Attach. A (Nelson and Eiden Aff.) at 90.
[171] *Id*.

year in which the Customer Shortfall" occurs.[172] The 20 percent gap fails to fully prevent subsidies from existing customers, and that gap could reach hundreds of megawatts for larger data centers. And further, by fixing the committed revenue contribution to the rate in place at the TSA's effective date, large-load customers are insulated from the risk of future transmission cost increases, which are instead passed on to other customers.[173]

This stands in stark contrast to the Order No. 2003 framework for generator interconnections, which is discussed as a basis for informing a possible remedy in the next section below. Under Order No. 2003, the interconnecting customer is responsible for both the costs of interconnection facilities and the upfront funding of all network upgrades triggered by the interconnection. The Order No. 2003 framework would require the interconnecting customer to pay for the same level of costs as those specified in the TSA, plus any additional network upgrade costs reflected through the interconnection study.[174] The TSA, by contrast, assumes cost socialization as the default which is the very outcome this complaint challenges.

2. Commissioners recognize the limitations of TSAs.

Several Commissioners have expressed concerns regarding the TSA's limitations in the *Commonwealth Edison Company* cases.[175] Commissioner Chang observed that the agreement "does not identify any specific upgrades needed to interconnect the data center" and instead contemplates that all upgrade costs "would

[172] *Id*. at 90-91.
[173] *Id.* at 91.
[174] *Id*. at 91-93.
[175] *Commonwealth Edison*, Order Accepting Transmission Security Agreement (Monarch), 194 FERC ¶ 61,106 (February 17, 2026); *see* other Commonwealth TSA orders, above at n.147.

be added to ComEd's transmission revenue requirements and thereby rolled into transmission rates that all customers pay."[176] Commissioner Chang also demonstrated that if transmission upgrade costs are sufficiently high relative to the load commitments, "the embedded transmission rate paid by other customers will increase."[177] She further noted the durational mismatch: The TSA obligations run for only 8 to 10 years, while the transmission assets have useful lives of 40 years or more, meaning that "if the large load customer ends its service after 10 years, other customers may face increased costs over the long term."[178]

Commissioner Chang concluded that these bilateral arrangements "are not specifically designed to represent the interests of other customers" and "should be treated simply as one piece of a broader package of federal and state measures to protect customers, rather than the primary or exclusive means to do so."[179] She encouraged states and the Commission alike to "proactively explore potential reforms and standards to protect customers against unjustified transmission cost shifts."[180]

Chairman Swett and Commissioner LaCerte, while also concurring in acceptance of the TSA, affirmed that the Commission retains the statutory responsibility to act where circumstances demonstrate serious harm to the public interest, and that "nothing precludes such future examination and action should evidence sufficient to overcome the presumption occur in the future."[181]

[176] *Id.* Chang concurrence at P 4.
[177] *Id.* at P 7.
[178] *Id.*
[179] *Id*. at P 8.
[180] *Id.* at P 10.
[181] *Id. Chang concurrence* at P 2.

Because they are being filed with the Commission, the utility sponsors of the TSAs may argue that they have preemptive effect over state-level large-load retail tariffs. Although the preemptive effect of TSAs has not been resolved, the impact of such preemption would be to lock in the infirmities of the TSAs while overriding state level remedies that are incomplete in nature. The Commission should reject these anticipated arguments of the TSA sponsoring utilities.

TSAs defer the problem while the costs (and their misallocation under current practices) continue to mount; even worse, TSAs would lock in the problem if the sponsoring utilities successfully contend that the TSAs have preemptive effect over state-level large-load retail tariffs due to their filing with the Commission.

What is needed instead of TSAs is a Commission remedy of either allocating large load causing transmission costs to the PJM zones where the large-load customers are located, or, allocating the costs directly to the large loads, as informed by Order No. 2003's upfront funding and "higher of" protections applied to date in the context of generator interconnections for large-load interconnections. Either remedy is necessary to ensure that the large-load customers who cause transmission costs bear those costs rather than shifting them to ratepayers across the PJM footprint.

III. To establish just and reasonable rates, the Commission should direct PJM to adopt a cost allocation framework that assigns transmission costs to the large loads that cause them.

The unjust and unreasonable rates resulting from the PJM OATT stem from a structural gap and, as described in Part II, cannot be addressed by state large-load tariffs nor by TSAs. PJM has no framework for properly assigning transmission costs to the large loads that drive them, so it defaults to existing methodologies like

solution-based DFAX that were never designed for this purpose. The result is unjust. Customers who trigger billions in network upgrades pay a fraction of their costs, while the majority of those costs are socialized to all ratepayers. The Commission must remedy these infirmities by directing PJM to adopt a cost allocation framework that (1) charges transmission costs to the zones where the large load customers that cause these costs are located or (2) directly charges those costs to the large load customers.

The Commission has the simple and immediate ability to address many of the infirmities in PJM's current transmission cost allocation methodology: The Commission can direct PJM to allocate the costs of regional baseline transmission projects constructed to serve incremental data centers directly to the PJM zones where the existing and forecasted data center load is located. As described in subpart A below, this alternative would be a significant step toward ensuring the transmission costs are just and reasonable and do not cause subsidies from zones that are causing the need for the massive transmission investments. By directing the allocation of transmission costs that would not be incurred but for data centers to the PJM zones in which the data centers are located, the Commission would enable the relevant states to allocate those costs to the customers causing the costs. The immediate relief afforded by proper zonal allocation may be followed by further Commission action, depending on the Commission's pending large load advanced notice of proposed rulemaking ("ANOPR") proceeding[182] and resolution of associated jurisdictional issues, that

[182] *Notice Inviting Comments*, Interconnection of Large Loads to the Interstate Transmission System, Docket No. RM26-4 (Oct. 27, 2025); Department of Energy, *Sec. of Energy's Direction that the Federal Energy Regulatory Commission Initiate Rulemaking Procedures and Proposal Regarding the Interconnection of Large Loads Purchase to the Secretary's Authority under Section 403 of the Department of Energy Organization Act* (Oct. 25, 2025) (see, in particular, P 25, Principle Eight).

allocates transmission costs directly to individual large-load data centers that are driving the costs. This methodology, as described in subpart B below, could be informed by the Commission's transmission pricing policies developed for generator interconnections, enhanced to address large-load customers. This remedy would be more precise in allocating costs directly to data centers rather than to the PJM zones in which the projected data centers are located. Importantly, the solution would not require the Commission to completely reinvent the wheel because the Commission has an analogous approach for generation; specifically, Order No. 2003 prevents existing customers from subsidizing merchant-like activity on the grid in Order No. 2003 through generator upfront funding of costs and related protections. Large loads impose similar costs on the system as merchant generation and creates the same risk of cross-subsidization. To ensure adequate cost recovery, data centers would be charged 100 percent of upfront network upgrade costs, with appropriate crediting, and also be charged for ongoing use of the system.

Subparts C and D then discuss how the relief described here is not only required by law; it is necessary to implement the Department of Energy's recommendations pursuant to its ANOPR and the Ratepayer Protection Pledge signed by major hyperscale developers of data centers.[183]

A. The Commission should take immediate action to allocate baseline transmission projects driven by data centers directly to the relevant PJM zones.

The Commission should immediately direct PJM to allocate the costs of regional baseline transmission projects, constructed to serve incremental large

[183] The White House, "Ratepayer Protection Pledge" (March 4, 2026).

load/data centers, directly to the PJM zone(s) where the existing and forecasted data center load is located. This method of allocation would rely on PJM's legacy method for cost allocation by geographic area, utilizing PJM's transmission zones as the basis for allocation. State level large-load retail tariffs could then better and more accurately address the allocation of the transmission costs caused by data centers to final customers within the individual state's jurisdiction. State tariffs would be based on the "up-stream" full allocation of data center caused transmission costs to the zone within the state where the data center load is located. Adoption of this measure would substantially address the current infirmity of the PJM tariff that is not susceptible to remedy by state-level measures because states through their large-load tariffs cannot address transmission costs caused by data center loads outside their jurisdiction.

Put simply, the upstream leakage of a substantial portion of data center driven costs at the regional level to other zones through the current operation of the PJM tariff creates an unjust subsidy for that data center load. The leakage means customers in zones other than the hosting zone pay for data-center driven costs. Removing this leakage would better direct transmission costs to the cost causer, mitigate the undue subsidy and enable individual states, through operation of their large-load retail tariffs, to more effectively address the unjust results of PJM's hybrid methodology.

This approach, however, does not fully eliminate the subsidy problem caused by large loads. Some PJM zones extend over multiple state jurisdictions which leave room for lesser, though still potentially significant subsidies that a state could not address. But zonal allocation would cabin and substantially reduce the problem

currently existing at the PJM footprint wide level, by allocating to the individual multi-jurisdictional zones in which the large-load demand increases are occurring.

B. As a longer-term solution consistent with matters under review in its ANOPR proceeding, the Commission can allocate 100 percent of baseline transmission project costs directly to the data centers causing those costs, and provide, as appropriate, a crediting mechanism.

In its release of the ANOPR on large-load interconnections initiating the Commission's proceeding in docket RM26-4, the Secretary of Energy discussed federal and state authority over the process of interconnecting large loads to the transmission system.[184] Depending on the resolution of the jurisdictional issues, a second alternative for achieving appropriate cost allocation of the network upgrades necessary to interconnect large loads would be to adopt a transmission cost allocation methodology for direct allocation and charging of transmission costs caused by large-load customers to those customers, informed by the Commission's transmission pricing policies developed for generator interconnections. This alternative may be more responsive to the directives and policies embodied in the ANOPR and the Ratepayer Protection Pledge. Further, this alternative would be more closely aligned with the ANOPR and the Ratepayer Protection Pledge in that it more directly tracks cost incurrence and allocates the costs in a more focused manner to beneficiaries, mapping the transmission costs caused by large loads directly to the large load customers. This alternative is more fully described in the sections below.

[184] *Interconnection of Large Loads to the Interstate Transmission System*, Advance Notice of Proposed Rulemaking (Oct. 23, 2025) ("ANOPR"); *see also* Letter from Chris Wright, Sec'y, U.S. Dep't of Energy (Oct. 23, 2025) (Secretary's Letter), PP 2-10, 13-16; FERC, Notice Inviting Comments, *Interconnection of Large Loads to the Interstate Transmission System*, Docket No. 26-4 (Oct. 27, 2025).

1. Order No. 2003 established principles for protections of existing customers against subsidization that should inform and be extended to data centers.

In Order No. 2003, the Commission adopted two key protections to prevent existing customers from bearing the costs of network upgrades caused by interconnecting merchant or independent generators. The first is the "but for" test: transmission providers may charge interconnecting customers to cover the upfront costs of network upgrades that would not have been required "but for" their interconnection. The "but for" requirement is not a penalty; it is a financing mechanism.[185] The interconnecting customer funds the upgrades up front and is then credited back over time with interest based on its use of the transmission system. As the Commission explained, this financing mechanism does not violate the prohibition against "and" pricing because the crediting mechanism reimburses the interconnecting customer for its initial financing of the costs it triggered.[186] The practical effect is that the cost causer pays for the upgrades it causes but is not charged twice for ongoing use of the system, but no less than the embedded cost of the transmission system.

The second component of Order No. 2003 is the "higher of" standard.[187] Under this policy, the transmission provider may charge an interconnecting customer the "higher of the incremental cost rate for Network Upgrades required to interconnect the Generating Facility or an embedded cost rate for the entire transmission system

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[185] Order No. 2003-A, *Standardization of Generator Interconnection Agreements and Procedures*, 69 Fed. Reg. 15,932 (March 26, 2004); FERC Stats. & Regs. Para. 31,160 at P 612 (2004) ("…the Interconnection Customer's upfront payment, with provisions for the payment of interest, credits and reimbursements, serves not as a rate for interconnection or transmission service, but simply as a financing mechanism that is designed to facilitate the efficient construction of Network Upgrades.").
[186] Attach. A (Nelson and Eiden Aff.) at 76.
[187] *Id*. at 77.

(including the cost of the Network Upgrades)."[188] The Commission concluded that "this 'higher of' policy ensures that other Transmission Customers, including the Transmission Provider's native load, will not subsidize Network Upgrades required to interconnect merchant generation."[189] Together, these two protections ensure that the costs of serving new merchant generator entrants are borne by those entrants—not shifted to existing customers.

The Commission has also approved, consistent with the "higher of" policy, charging a generator seeking interconnection one rate for use of the existing transmission grid, at embedded cost, and a separate rate for any additional incremental grid expansion required the generator requires for the interconnection, with the costs of the latter cabined by the "higher of" policy.[190]

No comparable protections for existing customers are in place for new large load interconnections, notwithstanding that the new large loads are both uniquely driving incremental grid expansion and are leaning on and benefiting from the existing transmission grid. PJM's tariff contains no "but for" test for large load-driven upgrades. There is no "higher of" standard that ensures data centers do not harm existing ratepayers. Pro forma large load interconnection agreements do not exist to ensure minimum ratepayer protections, nor does the current patchwork of state-by-state rules shield existing customers from subsidizing data center-induced grid expansions. A single data center "can represent more load than a mid-size city and can scale up in a matter of years, rather than the decades it would take to develop similar

[188] Order No. 2003-B at P 54.
[189] *Id*. at P 11.
[190] *Northwestern Corp.*, 147 FERC ¶ 61,171 at P 53 (2014).

load under more normal growth patterns,"[191] yet it faces none of the cost responsibilities that a comparably sized generator would.

Large loads are much more akin to merchant generators[192] than to native load, and "[t]he same factors leading to negative market outcomes that the Commission sought to correct by adopting the protections in Order No. 2003 apply equally well, or more, to the case of large loads and data centers."[193] In a recent concurrence, Commissioner Chang suggested that "[t]his "higher of" pricing policy could serve as a useful approach for ensuring that the new, discrete large load's demand does not significantly and directly increase the cost of transmission for other customers."[194]

2. To avoid subsidization and ensure adequate cost recovery, data centers should be charged 100 percent of upfront network upgrade costs, with appropriate crediting, and also be charged for ongoing use of the system.

The "but for" and "higher of" protections described above have been successfully applied to the case of merchant generators, and the Commission should adapt their use to the specific circumstances of data centers and large loads seeking interconnection. As Nelson and Eiden have demonstrated, a cost allocation mechanism that assigns 100 percent of the upfront network upgrade costs not required "but for" large load additions, coupled with an appropriate crediting mechanism, would align risks and promote efficient outcomes while also providing for full cost recovery based on the data centers' use of the overall transmission system.[195]

[191] Attach. A (Nelson and Eiden Aff.) at 75.
[192] *Id.* at 75-79.
[193] *Id*. at 78.
[194] *PECO Energy*, 193 FERC ¶ 61,148 at P 5 (Nov. 21, 2025) (Chang, concurring).
[195] Attach. A (Nelson and Eiden Aff.) at 83-84 and 87-88.

i. Commission precedent requires developing new cost allocation methods that charge large loads transmission system expansion costs they cause to avoid negatively impacting other existing customers.

The Commission has already acted in a similar manner that recognizes the necessity of this approach. The Commission recently accepted a tariff framework proposed by Southwest Power Pool ("SPP") that incorporated direct assignment to address the uncertain nature of large load additions, including data centers.[196] The Commission found that "the direct assignment of these Network Upgrades appropriately reflects the uncertain nature of the load and generation additions" and "will therefore protect other transmission customers by limiting cost shifts, particularly if and when the load addition or associated planned Designated Resource are not constructed."[197] The SPP precedent confirms that direct assignment is a logical, Commission-accepted extension of existing cost causation principles to a class of grid participants (large load data centers) that now imposes system impacts comparable to generators.

ii. Objections to direct charging of upgrade costs to large loads ignore established Commission precedent.

Exelon has raised two objections to directly charging large loads network upgrade costs in comments filed in Docket No. RM26-4-000.[198] As Nelson and Eiden explain, both objections are incorrect.

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[196] *See Southwest Power Pool, Inc.*, 193 FERC ¶ 61,018 at P 46 (2025) (approving Provisional Load Process under which the "transmission customer…will be assigned the full annual revenue requirement …of the directly assigned upgrades" until planned generation is designated and remaining undepreciated costs are Base Plan Funded).
[197] *Id.* at P 47.
[198] Attach. A (Nelson and Eiden Aff.) at 80.

Exelon's first objection is that requiring large loads to bear responsibility for 100 percent of network upgrade costs as a condition of interconnection would, under the Commission's longstanding prohibition on "and" pricing, open the door to large loads avoiding any responsibility for the broader transmission system. Specifically, Exelon argues that "if new large loads are made to be responsible for the costs of upgrades as a requirement to interconnect, pursuant to the Commission's prohibition on 'and' pricing and concerns over undue discrimination, those same loads will undoubtedly maintain that they are not required to pay separately for transmission service (i.e., for network integration transmission service or the 'NITS' rate)."[199]

This objection is incorrect. The Commission has already rejected the argument that its pricing policy requiring upfront funding of network upgrades for generator interconnection violates its prohibition on "and" pricing, and courts have upheld that rejection.[200] If, contrary to Commission precedent, large loads make the argument again as Exelon speculates, the Commission should reject it again. Existing customers are further protected because the transmission provider retains the option to charge the "higher of" the incremental cost of the required network upgrades or the embedded cost rate for the whole transmission system, including the cost of those upgrades.[201] As the Commission concluded in Order No. 2003, "this 'higher of' policy ensures that other Transmission Customers, including the Transmission Provider's native load, will not subsidize Network Upgrades required to interconnect merchant generation."[202]

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[199] *Id*.
[200] *Id*. at 81. *See also Entergy Servs. Inc. v. FERC*, 319 F.3d 536, 542-43 (D.C. Cir. 2003) (finding that Commission enforced its prohibition on "and" pricing by requiring credits for upgrades.").
[201] Attach A. (Nelson and Eiden Aff.) at 77 and 81.
[202] *Id*. at 78.

The same protection applies with equal force when extended to large load interconnections.

Exelon also states that when large loads connect to the grid and pay into the overall transmission system, their revenues help lower the average transmission rate for everyone.[203] Therefore, Exelon argues, if large loads are instead required to pay only for their specific network upgrade costs through direct assignment, they will contribute less to the overall system and as a result, other customers will end up paying more.[204]

Exelon presents a false choice. It assumes that a large load must either pay for its specific network upgrades through direct assignment or pay into the broader embedded rate system, but not both.[205] That is not what the Commission's framework requires. When implementing Order No. 2003, the Commission gave transmission providers the flexibility to charge whichever rate—either incremental or embedded—that would be most beneficial to existing customers.[206] Importantly, however, the Commission made clear that choosing the embedded rate to capture those broader benefits for existing customers is "dependent upon an appropriate mechanism for returning any money contributed by the Interconnection Customer related to the initial financing of the necessary upgrades."[207] In other words, the upfront funding requirement and the potential rate reduction benefit for all customers can coexist and are not mutually exclusive. As Nelson and Eiden conclude, "[R]equiring large loads to

[203] *Id*. at 81-82.
[204] *Id*.
[205] *Id*.
[206] *Id*. at 82.
[207] *Id*.

fund 100% of upfront incremental network upgrades, coupled with an appropriate crediting mechanism, would be in alignment with past Commission precedent and would also ensure customer protections through the application of the 'higher of' policy."[208]

Finally, large loads, while analogous in many respects to generators, are like all loads in benefiting from the existence of and services provided by the legacy transmission grid. Unlike generators whose financial responsibilities are limited to the "upgrade" costs required to interconnect their facilities to the grid, loads (including large loads) bear responsibility through embedded rates for the cost recovery of the investment in the integrated grid. Large loads will receive service from and benefit from the legacy grid. Similar to the separate charges approved by FERC in *Northwestern* for different transmission services, large loads should both remain responsible at embedded rates for their use of the legacy grid and, subject to the "higher of" policy, be responsible for the incremental costs of grid expansion caused by the large load.[209]

C. The Department of Energy's initiative, the Ratepayer Protection Pledge, and the actions of other jurisdictions support a new approach.

The Department of Energy ("DOE") has independently reached similar conclusions regarding treatment of transmission costs associated with large loads.

[208] *Id*. at 92. The general remedy of direct charging and crediting for transmission charges caused by large load/data centers, as described in the text, is not intended to exclude consideration of the appropriateness of other possible remedies or methods for cost recovery, including contribution in aid of construction, particularly as applied to a transmission expansion directly related to the physical interconnection and integration into the transmission grid of an individual large load/data center.

[209] *Northwestern Corp.*, 147 FERC ¶ 61,171 at P 53 (2014).

DOE has laid out a rationale for incorporating the reforms similar to those adopted for generators under Order No. 2003 within a near-term large-load interconnection reform process. Specifically, DOE recommends: (1) increasing the cost of entering the queue to deter speculative load requests, through increased deposits on study costs and increased exit fees; (2) developing new methods to study load and hybrid load/generation configurations to identify opportunities to reduce system impacts; and (3) direct assignment of 100 percent of the cost of transmission network upgrades to the interconnecting customer.[210] DOE's recommendations confirm that the remedy proposed here is not novel but rather a logical extension of existing Commission policy to a class of grid participants that now impose system impacts comparable to generators.

The Ratepayer Protection Pledge recently signed by major hyperscale data center developers also embodies these principles. More specifically, the pledge states in relevant part: "[C]ompanies will pay for new power delivery infrastructure upgrades to service their data centers, including adequate network upgrade costs to ensure that these expenses are not passed on to the ordinary household." Adoption of the remedy proposed here is necessary to deliver on this pledge.

Other jurisdictions have already begun implementing reforms to address the problematics raised by large loads. The Alberta Electric System Operator ("AESO") has adopted rules that treat large loads similarly to generators, addressing reliability concerns such as increases in energy emergency alerts during peak demand, dynamic system impacts from steep load ramping, increased reliance on ancillary services, and

[210] Attach. A (Nelson and Eiden Aff.) at 79.

the need for network upgrades.[211] AESO is pursuing a two-stage approach. In the immediate term, AESO has set a 1,200 MW cumulative limit on large load connections through 2028 while it develops technical interconnection standards and modeling requirements.[212] In the second phase, AESO will redesign its interconnection tariff to incorporate new large-load standards, set defined terms for load shedding, demand response, and backup generation supply, and address ancillary service and network upgrade cost causation.[213]

D. Cost allocation reform must be accompanied by planning process reforms to eliminate speculative load forecasts.

Fixing cost allocation alone is insufficient if the planning inputs remain corrupted by the speculative and duplicative forecasts. A remedy must also address these inputs. The Commission's recent Co-located Order provides both the analytical foundation and the mandate for these reforms.[214]

In the Co-located Order, the Commission found PJM's tariff unjust and unreasonable because it failed to: (1) clarify rates, terms, and conditions for customers serving co-located load; (2) reflect co-located customers' ability to limit their energy withdrawals; and (3) address co-located loads' use of the transmission system for ancillary services. The Commission concluded that these gaps allowed large co-located loads to benefit from the grid without contributing to cost recovery, risking that "costs may be allocated entirely to other transmission customers and passed through to residential customers."[215] To remedy this unjust result, the Commission

[211] *Id.* at 48-49.
[212] *Id.* at 49.
[213] *Id*.
[214] *PJM Interconnection, LLC*, 193 FERC ¶ 61,217 (Dec. 18, 2025).
[215] *Id.* at P 159.

directed PJM to establish new transmission services and found that doing so could "potentially avoid costly and inefficient transmission system buildout that may not be necessary."[216]

The Commission's findings in the Co-located Order are not limited to co-located arrangements; they apply to all large loads. *First*, as Nelson and Eiden explain, most modern data centers have substantial on-site backup power capabilities and can effectively operate as a co-located load would behave from the grid's perspective, even under current interconnection tariff rules—meaning the Commission's findings regarding the need to better understand the ancillary service needs of co-located loads applies equally to all data centers.[217]

Second, data centers currently in PJM's planning process, whose loads are incorporated into PJM planning for grid expansion, may later switch to co-located arrangements, meaning the grid will have been expanded at great cost for load that never materializes as firm demand—precisely the "costly and inefficient" buildout the Commission sought to prevent.[218] As Nelson and Eiden conclude, the Commission's logic must be carried "all the way forward to the regional transmission planning process and associated cost allocation methodologies. Otherwise, existing customers will be at significant risk of unjust and unreasonable cost burdens.[219]

Based on these findings, Nelson and Eiden recommend that the Commission direct PJM to remove data center and other large loads completely from the load projections feeding into RTEP reliability modeling and planning workstreams and

[216] *Id.* at P 160.
[217] Attach. A (Nelson and Eiden Aff.) at 95-97.
[218] *Id*.
[219] *Id*. at 97.

develop an alternative planning process that provides the information necessary to assign network upgrade costs to large load customers seeking interconnection.[220] In addition, PJM should be required to develop new reliability standards for studying large load system impacts—including N-1 contingencies for the loss of a large load, which is not studied under current practice—and to integrate operational assumptions about large loads capable of reducing their grid energy demand, consistent with the Commission's December 2025 Co-located Order.

CONCLUSION AND REQUEST FOR RELIEF

Maryland customers are being forced to bear $1.6 billion in added transmission costs in their bills over the next 10 years (due to misallocation to Maryland of $2 billion in transmission investment) from just the three most recent rounds of PJM regional transmission projects—all driven overwhelmingly by data center load growth outside Maryland's borders. Maryland customers neither materially caused nor meaningfully benefit from these transmission expansions. That burden will continue to compound with each successive RTEP planning window absent Commission action.

PJM's hybrid combined load-ratio share and DFAX methodology is unjust and unreasonable as applied to Maryland because it broadly socializes geographically concentrated costs in violation of cost causation principles. The load-ratio share component broadly socializes costs across the PJM footprint based on each zone's share of system peak load, without regard to the geographic concentration of the load growth driving those costs. The DFAX component applies to reliability impacts it was

[220] *Id.* at 98.

never designed to capture, relies on speculative load forecasts that render its allocations arbitrary, and creates perverse incentives that shift stranded asset risks from the zones attracting speculative load growth onto Maryland customers. State-level remedies have proven inadequate, and TSAs as currently structured do not cure the harm to Maryland customers.

Based on the foregoing, the Maryland Office of People's Counsel respectfully requests that the Commission adopt the following measures (Part A):

> 1. Find PJM's hybrid load-ratio share and solution-based DFAX methodology contained in OATT Schedule 12 unjust and unreasonable as applied to the assignment of RTEP baseline reliability upgrade costs driven by large load growth;
>
> 2. Establish a refund effective date of no later than 60 days after the date of this filing, extending to the maximum limit allowed under the Federal Power Act; and
>
> 3. Direct PJM to re-study the baseline reliability projects approved in 2022 RTEP W3, 2024 RTEP W1, and 2025 RTEP W1 to determine the relative proportion in relevant transmission zones of transmission system impacts and costs caused by expected future load growth from data centers versus other causes and, at a minimum and subject to adoption of the additional remedies requested below (in Part B), allocate those costs to the zone where the data center load growth is or is forecasted to be located, with the results used to credit back, effective to the refund effective date of this complaint, to transmission zones that previously collected costs attributable to large load growth under each of those windows; and
>
> 4. Direct PJM to propose a compliance filing within 90 days of the conclusion of the show cause proceeding.

Regarding PJM's broader planning, interconnection, and cost-allocation processes related to large loads and conditioned on or in parallel with the Commission's advancing its review of large load arrangements in the ANOPR proceeding, the Commission should adopt the following remedies (Part B):

1. Find that PJM's planning, interconnection, and cost-allocation processes and associated tariff provisions constitute practices affecting rates within the Commission's authority to remedy under Section 206(a) of the Federal Power Act;

2. Reject PJM's current approach of allocating RTEP baseline reliability costs using the hybrid load-ratio share and DFAX allocation mechanism because it improperly subsidizes speculative and merchant-like activity from data center customers and their developers;

3. Direct PJM to develop a pro forma large load interconnection standard informed by the customer protections embodied in the LGIA pro forma approved under Order No. 2003, including:

a. Requiring interconnecting large load customers to fund 100% of the upfront costs of network upgrades that would not be required "but for" the large load, with appropriate crediting mechanisms;

b. Reaffirming the option for PJM to charge the "higher of" an incremental rate covering the cost of upgrades or the rolled-in embedded system cost inclusive of those upgrades; and

c. Establishing a method for allocating the cost of transmission projects with respect to data centers that ensures zero cross-subsidy potential;

4. Direct PJM to update its RTEP process to remove data center and other large loads completely from the load projections feeding into RTEP reliability modeling and planning workstreams;

5. Direct PJM to develop an alternative planning process to assign network upgrade costs to individual large load customers or groups of customers seeking to interconnect to the transmission system;

6. Direct PJM to develop new reliability standards or modeling approaches to study additional potential system impacts driven by large loads, including N-1 contingencies for loss of a large load in addition to the loss of the largest generator or transmission line; and

7. Direct PJM to integrate operational assumptions about large loads capable of reducing their grid energy demand into the study

process for assessing system impacts of new large load requests, consistent with the Commission's recent Co-location Order, to limit unnecessary and costly transmission network upgrades required to serve large load customers.

RULE 206 COMPLIANCE REQUIREMENTS

To the extent not already provided above, the Maryland Office of People's Counsel provides the following additional information required by Rule 206 of the Commission's Rules of Practice and Procedure.

1. A good faith estimate of financial impact or harm (Rule 206(b)(4))

See Complaint Tables 1 and 2.

2. Practical, operational, or nonfinancial impacts (Rule 206(b)(5))

PJM's current methodology creates perverse incentives that compound the financial injury. By socializing data center-driven transmission costs to all ratepayers, it insulates states and utilities that attract speculative load growth from overbuilding and stranded asset risk while shifting those risks to neighboring states' ratepayers. It also distorts planning incentives: utilities are incentivized to build for speculative load because stranded asset risk falls on ratepayers, not shareholders, and phantom or duplicative load requests inflate forecasts further. Absent regional reform, state-level remedies like large load tariffs may worsen the problem by magnifying the incentive to overbuild while shifting costs to customers elsewhere in PJM.

3. Whether the matters are pending in any other FERC proceeding or other forum (Rule 206(b)(6))

OPC is not aware of any other pending proceedings at the Commission or in any other forum that address the specific cost allocation challenges raised herein.

4. Specific Relief or Remedy Requested (Rule 206(b)(7))

The Complaint sets forth in detail the specific relief requested.

5. Documents supporting the complaint (Rule 206(b)(8))

The Affidavit of Ron Nelson and Andy Eiden, supporting the OPC's Complaint, is included as Attachment A to this Complaint. A report by Synapse Energy Economics, *Rising Transmission Costs: Impacts on Maryland Electricity Customers and Opportunities for Mitigation*, prepared for the Maryland Office of People's Counsel (March 25, 2026) is included as Attachment B.

6. Use of alternative dispute resolution (Rule 206(b)(9))

OPC does not believe that the issues raised herein are amenable to alternative dispute resolution.

7. Request for Fast Track Processing (Rule 206(b)(11))

OPC requests fast track processing of this Complaint to enable the Commission to grant the Complaint and provide relief given the rapidly accelerating transmission costs, the current energy affordability crisis, and the increase in transmission security agreement filings which offer inadequate relief but which threaten to become a default solution. Fast track action is essential to protect Maryland customers from the imminent compounding of unjust costs and to provide meaningful consumer relief as soon as possible.

8. Notice (Rule 206(b)(10))

OPC has appended a form of notice of this filing for publication in the Federal Register in accordance with the specifications in section 385.203(d) of the Commission's rules.

Respectfully submitted,

/s/ David S. Lapp

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UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMITTEE

MARYLAND OFFICE OF PEOPLE'S COUNSEL	)	
Complainant,	)	
	)	DOCKET NO. EL26- -000
v.	)	
	)	
PJM INTERCONNECTION, LLC	)	
Respondent.		

NOTICE OF COMPLAINT
(May 7, 2026)

Take notice that on May 7, 2026 pursuant to sections 206 and 306 of the Federal Power Act (FPA), 16 U.S.C. 824e and 825e, and Rule 206 of the Federal Energy Regulatory Commission's (Commission) Rules of Practice and Procedure, 18 CFR 385.206, Maryland Office of People's Counsel (Complainant) filed a formal complaint against PJM Interconnection, LLC (PJM or Respondent) alleging that PJM's hybrid cost allocation methodology contained in Schedule 12 of its Open Access Transmission Tariff produced unjust and unreasonable results, which the Commission must modify under FPA section 206.

Maryland OPC certifies that copies of the complaint were served on the contacts for PJM as listed on the Commission's list of Corporate Officials.

Any person desiring to intervene or to protest this filing must file in accordance with Rules 211 and 214 of the Commission's Rules of Practice and Procedure (18 CFR 385.211, 385.214). Protests will be considered by the Commission in determining the appropriate action to be taken, but will not serve to make protestants parties to the proceeding. Any person wishing to become a party must file a notice of intervention or motion to intervene, as appropriate. The Respondent's answer and all interventions, or protests must be filed on or before the comment date. The Respondent's answer, motions to intervene, and protests must be served on the Complainants.

The Commission encourages electronic submission of protests and

interventions in lieu of paper using the “eFiling” link at http://www.ferc.gov. Persons unable to file electronically should submit an original and 5 copies of the protest or intervention to the Federal Energy Regulatory Commission, 888 First Street NE., Washington, DC 20426.

This filing is accessible on-line at http://www.ferc.gov, using the “eLibrary” link and is available for electronic review in the Commission’s Public Reference Room in Washington, DC. There is an “eSubscription” link on the Web site that enables subscribers to receive email notification when a document is added to a subscribed docket(s). Forr assistance with any FERC Online service, please email FERCOnlineSupport@ferc.gov, or call (866) 208-3676 (toll free). For TTY, call (202) 502-8659.

Dated: May 7, 2026.

UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

MARYLAND OFFICE OF PEOPLE'S COUNSEL	)	
Complainant,	)	
v.	)	DOCKET NO. EL26- -000
PJM INTERCONNECTION, LLC	)	
Respondent.		

AFFIDAVIT

OF

RON NELSON

AND

ANDY EIDEN

ON BEHALF OF THE MARYLAND OFFICE OF PEOPLE'S COUNSEL

May 7, 2026

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AFFIDAVIT OF
RON NELSON AND ANDY EIDEN

I. Introduction.

Q1. Please state your name and occupation.

A1. **Nelson:** My name is Ron Nelson. I am a Founding Partner of Current Energy Group LLC ("CEG"). My business address is 2900 E Broadway Blvd Ste 100 #780, Tucson, Arizona 85716.

Eiden: My name is Andy Eiden. I am Senior Manager of Distribution System Planning and distributed energy resource ("DER") Integration at CEG, located at 2900 E Broadway Blvd, Ste 100 #780, Tucson, Arizona 85716.

Q2. Please summarize your work experience and educational background.

A2. **Nelson:** I have worked with numerous consumer advocates, nongovernmental organizations, utilities, and public utility commissions on issues related to cost-of-service modeling, rate design, grid modernization, distributed energy resource valuation and integration, large load tariffs, and performance-based regulation. CEG specializes in providing clients regulatory services in the areas of cost-of-service modeling, regulatory innovation, performance-based regulation, distributed energy resources ("DER"), rate design, renewable program development, grid modernization, new grid technologies, integrated resource planning, and electric vehicles ("EVs"). Prior to founding CEG, I briefly worked

for my own sole proprietorship and was at Strategen Consulting in various roles for six years, including as a Senior Director.

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

Eiden: I joined CEG in 2025, where I focus on issues related to large load planning and integration, utility system planning, transmission and distribution rate design and cost allocation, utility line extension policies, DER program design and system integration, Demand Side Management ("DSM") potential studies, DER cost effectiveness, non-wire alternatives ("NWA"), and more. I am currently a member of the Energy Systems Integration Group's Large Load Task Force.[1] Before joining CEG, I was a Senior Principal Planning & Strategy Analyst in Portland General Electric Company's ("PGE") Distributed Resource Planning

[1] See https://www.esig.energy/large-loads-task-force/. The Large Load Task Force helps address challenges to the grid posed by large electrical loads through efforts to "convene stakeholders, identify practical solutions, and develop harmonized practices that ensure reliable and efficient grid integration while supporting industry growth."

team, where I led company-wide DER forecasting and planning efforts, including for EVs and managed charging, distributed solar and battery storage, building electrification, and demand response ("DR"). As part of these job duties, I worked closely with Corporate Load Forecasting, Integrated Resource Planning, Transmission and Distribution Planning, and Power Operations teams surrounding all facets of DER integration into typical utility operations. I also led efforts within PGE to integrate and standardize large customer load requests into distribution planning workstreams and regulatory filings such as the Distribution System Plan.

Prior to joining PGE in 2019, I worked for five years at Energy Trust of Oregon, a statewide non-profit implementer for energy efficiency ("EE") and renewable energy programs, where I participated in or led multiple utility DSM potential studies. I held various roles at Energy Trust, most recently Sr. Project Manager in the Planning department where I specialized in electric system avoided costs, cost-effectiveness analysis of Energy Trust's $200 Million DSM budget, and renewable energy planning. Prior to Energy Trust, I was a consultant with Cadmus Group where I evaluated utility EE and DR programs, including many behavioral pricing, time-of-use ("TOU"), and thermostat-based programs.

I hold dual Bachelor of Science degrees in Economics and Environmental Studies from Portland State University. I have also taught graduate-level courses on smart grid topics, including DER integration for electrical engineering at Oregon State University and energy policy at Portland State University. My curriculum vitae is attached as RN-AE-2.

Q3. Have you testified before other regulatory jurisdictions?

A3. **Nelson:** Yes. I have testified in over 90 proceedings in Alaska, Arizona, Colorado, Florida, Georgia, Illinois, Indiana, Maine, Maryland, Massachusetts, Michigan, Minnesota, Nevada, New Hampshire, New York, North Carolina, North Dakota, Ohio, Oklahoma, Pennsylvania, South Carolina, Utah, Virginia, West Virginia, Wisconsin, and Vermont. The issues covered in these proceedings include marginal and embedded cost of service studies, revenue allocation, rate design, load management, renewable program design, fuel clause adjustments, formula rates, decoupling, performance-based regulation, multi-year rate plans, performance metrics, DER interconnection, flexible interconnection, pre-emptive DER and load upgrades, DER compensation, DER integration, EV infrastructure investments, pilot frameworks, automated metering infrastructure, prudence review, distribution system planning, capital investment plan review, large load tariffs and cost allocation, and smart inverter integration, among other topics.

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

Eiden: I have testified before several other regulatory commissions including the Arizona Commerce Commission in Arizona Public Service's 2025 rate case (docket no. E-01345A-25-0105) regarding large load tariff design and cost of service modeling; the Vermont Public Utility Commission in Green Mountain Power's recent multi-year rate request (case no. Case No. 25-1955-PET) related to

transmission and distribution resilience investments and benefit-cost modeling; the Public Utility Commission of Texas in Oncor Electric Delivery Company's Application for Authority to Change Rates (docket no. 58306**)** that focused on transmission and distribution capital investments and rate design; the Oregon Public Utilities Commission in docket no. UM 2377 regarding changes to PGE's generation marginal cost study necessary to adapt to increasing large load interconnections; the Massachusetts Department of Public Utilities ("D.P.U.") in D.P.U. docket no. 23-51 (National Grid) regarding distribution system Capital Investment Project and DER interconnection, and docket nos. D.P.U. 23-842 (Eversource) and D.P.U. 23-85 (National Grid) regarding EV TOU rate design and policy; the Kentucky Public Service Commission in case no. 2025-00045 regarding Kentucky Utilities Company and Louisville Gas & Electric Company for a Certificate of Public Convenience and Necessity to build new generating facilities to maintain resource adequacy in the face of forecasted data center growth; and the Public Utilities Commission of Colorado in proceeding no. 24A-40442E regarding Public Service Company of Colorado's 2024 Electric Resource Plan, which centered around the need for new generation and transmission to meet forecasted large load growth. In the Colorado case, my testimony explicitly treated large load growth forecasting and transmission and distribution line extension policies. I have also supported clients addressing large load issues in Pennsylvania, Utah, and Virginia by developing analyses of transmission cost allocation and retail rate design, cost of service modeling, and rulemakings around

modernizing transmission cost allocation to address the impacts that large loads and data centers are having on the grid.

Q4. On whose behalf are you testifying in this proceeding?

A4. We are presenting testimony on behalf of Maryland Office of People's Counsel.

Q5. Have you previously testified before FERC?

A5. **Nelson:** Yes, I have. I provided an Affidavit in Docket No. ER24-843.

Eiden: No.

Q6. Have you prepared exhibits to accompany your testimony?

A6. Yes. The following exhibits are provided to support our testimony:

- Exhibit RN-AE-1: Resume of Ron Nelson
- Exhibit RN-AE-2: Resume of Andy Eiden
- Exhibit RN-AE-3: Maryland Rate-Payer Bill Impact Projections

II. Summary and Recommendations.

Q7. What is the purpose of your testimony in this proceeding?

A7. The purpose of our testimony is to assess whether PJM's method of allocating transmission costs approved under the Regional Transmission Expansion Plan ("RTEP") process remains just and reasonable with the advent of large data center loads and the unprecedented impact they have had, and will continue to have, on the transmission system operated by PJM. To substantiate our findings, we

analyze PJM's cost allocation methods as they apply to baseline reliability upgrades included in the 2022 RTEP Window 3, 2024 RTEP Window 1, and 2025 RTEP Window 1 procurement rounds and show that they result in significant increases to costs borne by Maryland ratepayers as a result of data center driven projects in Virginia and other high data center growth zones within PJM.

Our analysis methodology revolves around two primary critiques of PJM's existing method for cost allocation of baseline reliability projects under the RTEP. First, we evaluate the impacts of using the load-ratio share and distribution factor ("DFAX") methods currently approved under the PJM open access transmission tariff ("OATT") and demonstrate why they result in unjust and unreasonable rates in the face of significant development of large loads, which is mostly data centers. Second, we evaluate the broader mechanics and impacts resulting from PJM's decision to allocate transmission network upgrade costs necessary to serve data centers using the same legacy cost allocation methodologies that developed over time to handle widespread and diffuse network load growth. As part of this broader assessment, we provide an overview of the distinctive nature of large data center load growth and the type of system impacts caused by these loads, as well as an analysis of approaches to directly charge costs to the zones where the cost-causing large-load data centers are located to better align cost allocation with cost causation. We also assess alternative cost allocation mechanisms, and associated policy protections, that traditionally have been used for large generator interconnections as an important parallel and potential extension to the cost

allocation reforms needed to protect existing customers, in parallel and consistent with the Commission's implementation of the data center cost allocation principle under consideration in the Commission's pending advanced notice of proposed rulemaking ("ANOPR") proceeding on large load interconnections in docket RM26-04.

Finally, we provide specific recommendations for relief sought to remedy the harms of previous cost allocation decisions impacting State of Maryland ratepayers, as well as the development of new methods to better align cost assignments with benefits received from projects driven by large load growth on a forward-looking basis.

Q8. Please summarize your conclusions.

A8. Our conclusions are as follows:

Our analysis demonstrates that data centers are having an unprecedented impact on the need for baseline reliability upgrades which have resulted in a massive increase in transmission network expansion costs that would not be necessary at the same scale were it not for the expectations of data center load growth. We find that PJM's existing planning study methodology fails to identify the full range of costs that are likely caused by these customers and that the application of PJM's existing cost allocation methodology of the load-ratio share and solution-based DFAX methodology result in unjust outcomes for Maryland ratepayers. Our overall conclusion is that PJM's existing cost allocation methodology, when applied to baseline reliability enhancements to the

transmission system, results in a significant subsidy from residential and other customers to data centers and likely cost and risk shifts between transmission zones, and is therefore unjust and unreasonable.

Regarding the methodologies PJM currently uses to develop and assess the RTEP baseline reliability projects, we find that significant network upgrades can be triggered by a single data center customer, or group of large loads in a concentrated area, and yet are being broadly socialized amongst existing customers using methodologies that were developed and approved by the Commission under a different paradigm of load growth that was much more gradual and spatially diffuse. Given these realities, we conclude that, as a partial remedy, a just and reasonable replacement rate would recognize the inherent differences in terms of upgrade cost magnitude driven by large loads, and the inherent uncertainty in these load requests, and appropriately allocate those costs to the zones in which the data center large loads are located and which are the drivers of the transmission costs. Doing so would better allow state regulatory commissions to implement retail rates that allocate such costs among end-use customer classes according to the specific needs of each state.

Looking at the nature of data center market activity, coupled with the type of system impacts caused by data centers, we conclude that the long-established methods of cost allocation for large interconnecting generators provides another appropriate mechanism to identify the full range of network upgrades triggered by these large loads, and embodies long-established customer protections that should

guide continued development efforts that seek to minimize the risk that existing customers will subsidize data center expansions. This second cost allocation approach should be adopted, as appropriate, assuming that the ANOPR principle for direct cost assignment to large load data centers under consideration in RM26-4 moves forward as envisioned.

Furthermore, the various failures we outline in our testimony regarding PJM's existing cost allocation methodology for RTEP baseline reliability upgrade costs are exacerbated by the very same shortcomings in PJM's OATT recently identified by the Commission in its decision regarding co-location. The Commission recently found PJM's tariff to be unjust and unreasonable due to several shortcomings of PJM's OATT relating to the interconnection of co-located large loads.[2] Our analysis demonstrates that similar cost and system impacts exist for large data center loads whether or not they happen to be in a co-location arrangement, and as a result the Commission must ensure that reforms are made throughout the planning, interconnection, and cost allocation processes to avoid unjust and unreasonable outcomes.

Based on our analysis, we find that between 2022 RTEP Window 3, 2024 RTEP Window 1, and 2025 RTEP Window 1 Maryland ratepayers are assigned

[2] *Large Loads Co-Located at Generating Facilities, Constellation Energy Generation, LLC. v. PJM Interconnection, L.L.C.,* 193 FERC ¶ 61,217 (2025), consolidated with Docket Nos. AD24-11-000 (Large Loads Co-Located at Generating Facilities) and EL25-20-000. (order instituting show cause and directing tariff revisions regarding co-located load) (hereinafter "the co-located order").

$2.0 billion in total capital investment costs for new baseline reliability projects.[3] Table 1 shows the total capital cost allocation to Maryland by RTEP procurement window. As the projects enter service, this $2.0 billion in capital cost assignment translates to $1.6 billion in total revenue requirements by 2036: $1.1 billion through the solution-based DFAX allocation, and $0.5 billion through the load-ratio share method. Table 2 shows total Maryland RTEP revenue allocations over the next ten years by RTEP procurement window.[4]

[3] Total transmission investment in baseline projects resulting from the three RTEPs exceeds $22 billion (2022 W3 - $5.143 billion (*TEAC, Recommendations to the PJM Board White Paper* (Dec. 2023)); 2024 W1 – $5.290 billion (*TEAC Recommendations to the PJM Board White Paper* (Feb. 2025)); and 2025 W1 - $11.840 billion (*TEAC Recommendations to the PJM Board White Paper* (Feb. 2026)). This investment does not include the costs of supplemental projects associated with large load growth.

[4] Data compiled by authors covering the years 2026 through 2036 using PJM's online Transmission Cost Planner tool. *See* https://tcplanner.pjm.com/tcplanner/pages/secure/upgrades-general.jsf, accessed 3/3/2026 (log-in required). Windows include projects approved by the PJM Board during interim months between annual RTEP approvals.

Table 1. Total 2036 Maryland capital cost allocations by RTEP procurement window

Allocation method	2022 W3	2024 W1	2025 W1	Total
DFAX	$448,086,246	$371,142,023	$503,294,856	$1,322,523,125
Load-Ratio Share	$180,233,197	$162,316,607	$336,131,081	$678,680,885
Total	**$628,319,443**	**$533,458,629**	**$839,425,937**	**$2,001,204,009**
Note: Differences in summation are due to rounding				

Table 2. 10-Year Maryland cumulative revenue requirement allocations by RTEP procurement window

Allocation method	2022 W3	2024 W1	2025 W1	Total
DFAX	$396,776,623	$385,913,686	$298,532,826	$1,081,223,135
Load-Ratio Share	$164,633,409	$163,786,865	$211,833,567	$540,253,842
Total	**$561,410,032**	**$549,700,551**	**$510,366,393**	**$1,621,476,976**
Note: Differences in summation are due to rounding.				

Moreover, as we demonstrate in Section III. E, data center growth in PJM is extremely concentrated in a few distinct transmission zones. PJM's currently approved cost allocation mechanisms unjustly allocate costs to Maryland ratepayers whose benefits are not roughly commensurate with said costs. Addressing the flaws that we identify in our testimony with respect to PJM's existing cost allocation methods takes on added urgency, as the undue burden on

existing customers shows no signs of letting up.[5]

Q9. Please summarize your recommendations.

A9. We summarize our recommendations along the two main lines of critique that we described above:

1. Regarding PJM's existing cost-allocation methodology for assigning RTEP Baseline Reliability upgrade costs to transmission zones using the load-ratio share and solution-based DFAX methodology, we recommend that the Commission:
    a. Reject PJM's tariff as unjust and unreasonable.
    b. Initiate a show cause order to determine the just and reasonable replacement cost allocation methodology for handling baseline reliability upgrades driven by large load growth.
    c. Establish a refund effective date of no later than 60 days after the date of this filing that extends to the maximum limit allowed, in recognition of the continued and ongoing cost increases across successive RTEP baseline reliability procurement windows that are primarily driven by large data center load growth as we demonstrate throughout our testimony. In furtherance of the objectives of establishing a refund effective date, we recommend the Commission

[5] Sami Abdulsalam, *Reliability Analysis Update* at 61, PJM Transmission Expansion Advisory Committee (Jan. 6, 2026), https://www.pjm.com/-/media/DotCom/committees-groups/committees/teac/2026/20260106/20260106-item-09---reliability-analysis-update.pdf.

further direct PJM to re-study the baseline reliability projects approved in 2022 RTEP W3, 2024 RTEP W1, and 2025 RTEP W1 to determine the relative proportion of transmission system impacts caused by expected future load growth from data centers versus other causes. The results of this study should be used to credit back to transmission zones any previously collected costs attributable to large load growth included under each of these windows.

d. Direct PJM to propose a compliance filing within 90 days of the conclusion of the show cause hearing.

2. Regarding the broader issue of PJM's existing planning, interconnection, and cost-allocation processes related to large loads, the Commission should find that these broader PJM processes and associated tariffs all amount to practices affecting rates and therefore are within its authority to address in response to this complaint under Section 206(a) of the Federal Power Act. Specifically, with regard to these broader processes and practices, we recommend that the Commission reject PJM's current approach of allocating RTEP baseline reliability costs using the hybrid load-ratio share and DFAX allocation mechanism because it improperly subsidizes speculative and merchant-like activity from large loads, including data center customers, and their developers. In addition, we recommend that the Commission direct PJM to conduct the following activities meant to

capture the full system impact of large load interconnections and protect existing customers:

a. Propose an immediate solution to PJM's cost allocation methodology for baseline transmission reliability upgrades that directly allocates the costs of upgrades driven by large load and data center growth to the zones where the transmission customers are located that are causing these costs through the inclusion of significant data center growth in the electric distribution company load forecasts provided to PJM.

b. In the longer term and in parallel with the Commission's implementation of the data center cost assignment principle under consideration in RM26-4, develop a large load interconnection standard that adopts the cost allocation principles and customer protections embodied in the large generator interconnection agreement ("LGIA") process approved under FERC Order No. 2003, reflecting appropriate modifications to apply those policies to the specific circumstances surrounding large loads instead of generators. These protections should:

    i. Ensure that interconnecting large load customers are required to fund 100% of the upfront costs of network upgrades that would not be required "but for" the large load(s), with

appropriate crediting mechanisms in place to avoid violating the Commission's prohibition on "and" pricing; and

ii. Reaffirm the option for PJM to charge a rate to large load interconnecting customers that is the "higher of" an incremental rate covering the cost of upgrades or the rolled-in rate (i.e., the embedded system cost inclusive of incremental upgrades).

c. Update its RTEP process to remove data center and other large loads completely from the load projections feeding into RTEP reliability modeling and planning workstreams.

d. Develop an alternative planning process that provides the information necessary to assign network upgrade costs to a single large load customer (or group of customers, if under a group study process) seeking to interconnect to the transmission system.

e. Develop new reliability standards or modeling approaches applicable to studying additional potential system impacts driven by large loads, such as studying N-1 contingencies for loss of a large load in addition to the loss of the largest generator or transmission line.

f. Integrate operational assumptions about large loads capable of reducing their grid energy demand based on certain conditions, consistent with the Commission's decision in its recent order on co-location, into the study process for assessing system impacts of new

large load requests. Doing so will limit the amount of unnecessary and costly transmission network upgrades required to serve large load customers.

III. Data center load growth is unprecedented and represents significant risks to existing customers.

Q10. How is this part of your testimony organized?

A10. In subsection A, we first provide an overview of industry growth trends with respect to data centers and other large loads in order to contextualize our analysis of PJM's response to large loads within its footprint.

In subsection B, we describe the data center growth that has dramatically increased over successive recent PJM load forecasts and driven a suite of new baseline reliability projects approved following the 2022 RTEP Window 3, 2024 RTEP Window 1, and 2025 RTEP Window 1 solicitations and Board approvals.

In subsection C, we provide an overview of PJM's transmission cost allocation methodology that the Commission approved in Docket No. ER24-843[6] and PJM used to allocate costs from the RTEP baseline reliability projects that are subject to Maryland OPC's complaint. We discuss reasons that these methods are no longer just and reasonable as currently applied to the types of load growth and system needs reflected in the RTEP Baseline Reliability Project category for the RTEP windows.

[6] PJM Interconnection, L.L.C., 187 FERC ¶ 61,012, at P 28 (Apr. 8, 2024) (Order on Cost Allocation Report and Tariff Revisions), Docket No. ER24-843-000.

In subsection D, we discuss the perverse incentives that can materialize due to the disconnect between transmission cost allocation and state-level actions to attract large load customers.

In subsection E, we analyze the impact of the high concentration of data center growth in northern Virginia and other pockets of data center growth in terms of driving significant increases to transmission system reliability needs. We also demonstrate the disproportionate bill impacts to Maryland customers resulting from baseline reliability projects driven by data center demand in Virginia due to application of PJM's cost allocation methodology.

A. Data center demand is increasing nationwide but still is subject to significant uncertainty in terms of timing and magnitude.

Q11. Please describe how electricity demand from data centers has increased over the past 15 years.

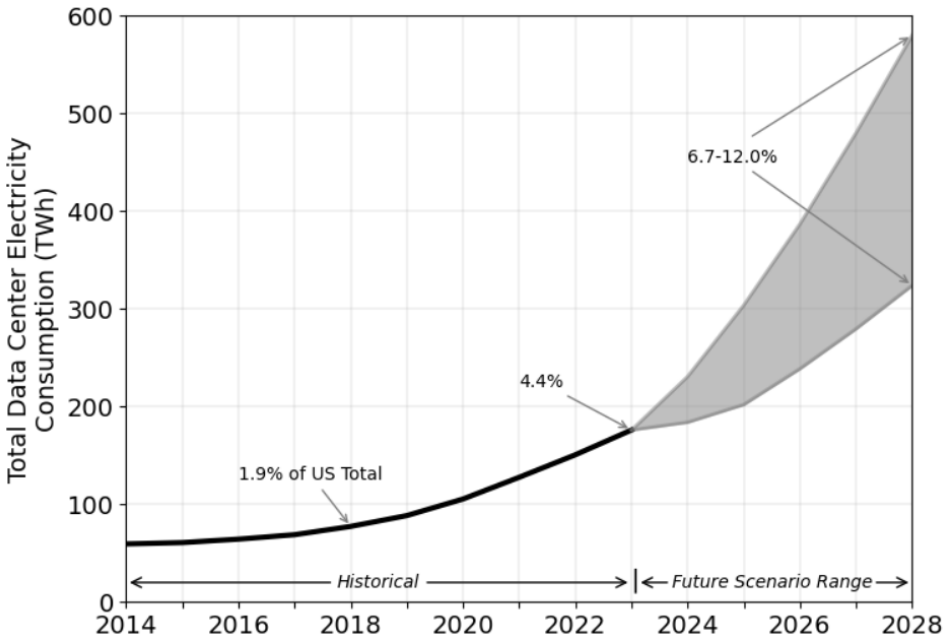
A11. Energy usage from data centers is growing at an accelerating rate. Lawrence Berkeley National Lab ("LBNL") estimates that after increasing by about 4% from 2010-2014,[7] electricity consumption by US data centers rose by 7% per annum from 2014-2018 and 18% per annum from 2018-2023.[8] Data centers represented just under 2% of total US electricity demand in 2018, and LBNL projects that

[7] A. Shehabi, S.J. Smith, D. Sartor, R. Brown, M. Herrlin, J. Koomey, E. Masanet, N. Horner, I. Lima Azevedo & W. Litner, *2016 United States Data Center Energy Usage Report*, Lawrence Berkeley National Laboratory (2016), https://eta.lbl.gov/publications/united-states-data-center-energy.

[8] A. Shehabi, S.J. Smith, A. Hubbard, A. Newkirk, N. Lei, M.A.B. Siddik, B. Holecek, J. Koomey, E. Masanet & D. Sartor, *2024 United States Data Center Energy Usage Report*, Lawrence Berkeley National Laboratory (2024), https://eta.lbl.gov/publications/2024-lbnl-data-center-energy-usage-report.

figure may rise to as high as 12% by 2028, with annual energy usage more than quintupling from less than 100 TWh to roughly 575 TWh (see Figure 1 below).[9]

Figure 1. Total US data center electricity use from 2014 to 2028[10]



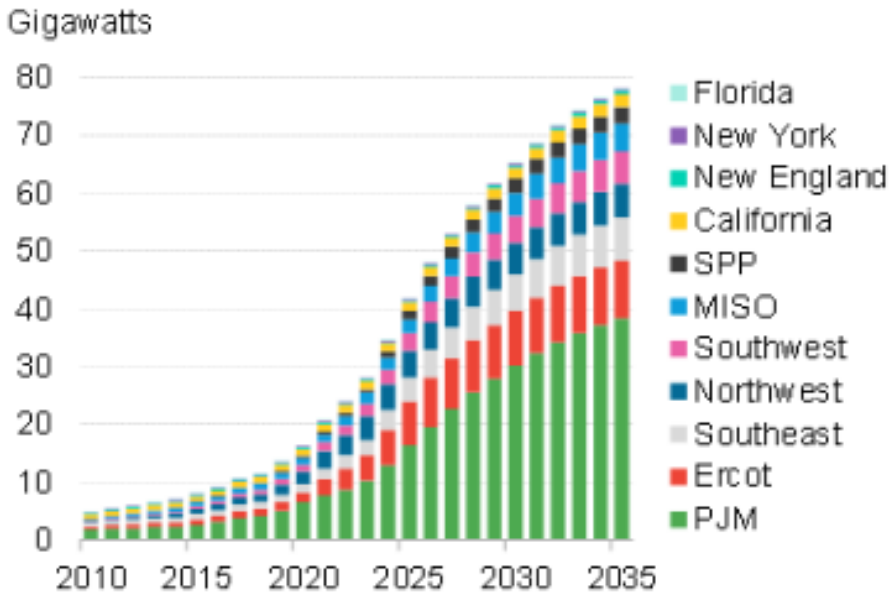
Q12. Is this rate of demand growth from large loads expected to continue?

A12. Yes. While there is a wide range of uncertainty in the actual rate at which demand from large loads will grow, as highlighted in Figure 1 above, numerous industry stakeholders have estimated continued growth in data center power demand. For example, the midpoint of LBNL's estimates would represent a doubling of demand from large loads over the next four years and BloombergNEF estimates

[9] *Id*.
[10] *Id.,* Figure ES-1.

data center power demand will rise from roughly 35 GW in 2024 to 78 GW by 2035, as shown in Figure 2 below.[11]

Figure 2. US data center power load[12]



Q13. How have forecasts of large load growth evolved recently?

A13. Throughout 2024 and 2025, numerous utilities have made significant upwards revisions to their forecast of large load growth in the coming years.[13] As we will discuss in Section III. B, there are several reasons to believe that these updated forecasts have unrealistic expectations for data center demand growth. Nonetheless, it is reasonable to expect demand growth from data centers to be

[11] Helen Kou, *Power for AI: Easier Said Than Built*, BloombergNEF (Apr. 15, 2025), https://about.bnef.com/insights/commodities/power-for-ai-easier-said-than-built/.
[12] *Id*.
[13] Travis Kavulla, *Get Real: Can Policy Approaches Clarify Load Forecasts?*, S&P Global Nodal Trader Conference (Oct. 24, 2025), https://www.nrg.com/assets/documents/energy-policy/kavulla-nodal-traders-conference-10.24.2025.pdf.

unprecedented and to outstrip planned generation additions in key markets like Texas' ERCOT and PJM, even if forecasts are reduced significantly.[14, 15]

Q14. Do the national trends you have just described hold in the PJM territory?

A14. Yes, they do. PJM has experienced significant load growth from data centers in the past decade and has seen significant upwards revisions in its recent load forecast updates.[16] In particular, Virginia is the largest data center market in the world[17] and comprises the majority of the growth underlying these trends in the PJM territory.

Q15. Please describe the nature of the large load growth in Virginia to date.

A15. Virginia is the largest data center market in the world, with 450 data center meters for approximately 50 data center customers across the DOM-LSE footprint.[18] As of December 2024, data centers represented 3.6 GW of aggregated metered demand[19] in Virginia and is growing rapidly. From 2013 to 2024, data centers' MWh consumption grew 660% and metered billing demand grew 676%, from 462

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[14] *Id.*
[15] Mark Thomton, Hla Myat Mon, Chris Boba & Angélica Juárez, *US Utility Large Load Commitments Reach 160 GW amid Unprecedented PJM Demand Surge*, Wood Mackenzie (Oct. 27, 2025), https://www.woodmac.com/press-releases/us-utility-large-load-commitments-reach-160-gw-amid-unprecedented-pjm-demand-surge/.https://www.woodmac.com/press-releases/us-utility-large-load-commitments-reach-160-gw-amid-unprecedented-pjm-demand-surge/.
[16] *2025 Long-Term Load Forecast Report*, PJM Resource Adequacy Planning Department (Jan. 24, 2025), https://www.pjm.com/-/media/DotCom/library/reports-notices/load-forecast/2025-load-report.pdf.
[17] *2025 20-Year Data Center Forecast*, Dominion Energy Virginia (Sept. 16, 2025), https://www.pjm.com/-/media/DotCom/committees-groups/subcommittees/las/2025/20250916/20250916-item-04ai---dominion-data-center-large-load-request.pdf, at 2.
[18] *Application of Virginia Electric & Power Company for a 2025 biennial review of the rates, terms, and conditions for the provision of generation, distribution, and transmission services pursuant to Virginia Code § 56-585*, (Case No. PUR-2025-00058, 2025), Direct Testimony of Stan Blackwell ("Blackwell Direct") at 3.
[19] Blackwell Direct at 4.

to 3,583 MW.[20] In 2024, the new annual connected capacity from data centers reached 977 MW.[21]

Q16. Please describe the nature of large load growth projections in Virginia.

A16. Dominion has already seen rapid large load growth over the past 5 years and projects large load growth to accelerate in the next few years. Dominion reports receiving 40,000 MW of capacity requests in 2024, compared to peak demand for the year of 18,408 MW.[22] Large load growth in Virginia is expected to reach half of the overall peak demand in the DOM Zone by 2028, if not more. As a result of this rapid growth, PJM forecasts the embedded summer peak load growth for the Dominion zone to increase by more than 30% from 2025 to 2030. However, this percentage only captures the influence of the embedded large load growth, which for Dominion is more well represented in the historical baseline years given its relatively longer experience serving this customer segment.[23] Combining both the embedded peak load forecast with the new load adjustments, the summer peak MW in DOM zone is expected to grow by 73% by 2030 over 2025 levels (See Figure 3 below).

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[20] Blackwell Direct at 5 (Figure 1).
[21] *Id*.
[22] Blackwell Direct at 4.
[23] *2026 Long-Term Load Forecast Report* at 4, PJM Resource Adequacy Planning Department (Jan. 14, 2026). https://www.pjm.com/committees-and-groups/subcommittees/las.aspx?p=1. The report states that "[R]esidential, commercial and industrial-sector models were estimated with data from 2015 through 2024."

Figure 3. DOM zone load growth projections, embedded growth plus adjustments[24]

Year	2025	2026	2027	2028	2029	2030
Summer Peak MW - embedded forecast[1]	24,271	25,193	27,008	28,696	29,966	31,939
Summer Peak MW - load adjustments[2]	N/A	3,429	5,266	6,956	8,213	10,135
Total MW	24,271	28,622	32,274	35,652	38,179	42,074
% increase from 2025	N/A	18%	33%	47%	57%	73%

Table footnotes:
1. Source: PJM Load Forecast tables, Table B1.
2. Source: PJM Load Forecast tables, Table B9.

Q17. Have the forecasts of load associated with 'large loads' in Virginia required new or upgraded transmission lines to meet demand?

A17. Yes, the growth of large loads (and forecasted future growth) from data centers has necessitated a number of new transmission lines in Dominion's territory, leading to significant costs for ratepayers. In its most recent integrated resource plan (IRP), Dominion listed 88 transmission projects that were primarily driven by data center connections, along with an additional 37 projects which were attributed to load growth in the Dominion zone. Load growth has primarily been driven by data centers.[25]

Q18. What has been the impact of these projects on transmission costs in Dominion's locational deliverability area?

A18. The capital expenditure for the transmission projects discussed above total between $2.44 billion (the cost of the 88 projects driven primarily by data centers) and $5.77 billion (including the cost of the 37 multi-driver projects, which include

[24] Table produced by authors with data from *PJM 2026 Load Forecast Report.*
[25] *In re: Virginia Electric and Power Company's 2024 Integrated Resource Plan* (Case No. PUR-2024-00184), Appendix 2C-2.

data center growth and existing load growth, but Dominion did not determine whether the data center growth was the primary cause).[26] These projected RTEP costs provided by Dominion illustrate the magnitude of the regional cost impact coming from Virginia.[27]

Q19. Is the nature of Virginia's large load growth unique?

A19. Although Virginia has the largest market for data centers, it is not unique. Other jurisdictions within PJM are already seeing, and will likely continue to see, dramatic increases in large load requests. In Illinois, for example, ComEd reports a pipeline of large load connection requests that "has accelerated at an exponential pace" since 2019[28] and now includes over 75 projects totaling 28,000 MW of demand.[29] If built, these projects could more than double ComEd's historical system-wide peak demand just shy of 24,000 MW.[30] Just last year, PJM was forecasting 32 GW of peak load growth by 2030 across its territory, with 30 GW represented by data centers.[31] PJM's Board of Managers has attributed increasing prices and concerns about future resource adequacy to this rush of demand from

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[26] *Id*.
[27] The referenced projects include some lower-voltage projects which are 100% allocated to Dominion, with the majority being higher voltage projects that are treated as baseline reliability projects and subject to the load-ratio share and DFAX cost allocation methodologies.
[28] *Commonwealth Edison Company Proposal for revisions to Rider Distributed System Extensions (*Docket No. 25-0679), Direct Testimony of Max Leichtman ("Leichtman Direct") at 5, https://icc.illinois.gov/docket/P2025-0679/documents/369551/files/647592.pdf.
[29] Leichtman Direct at 6.
[30] Leichtman Direct at 6.
[31] David Mills, *Letter to PJM Stakeholders*, PJM (Aug. 8, 2025), https://www.pjm.com/-/media/DotCom/about-pjm/who-we-are/public-disclosures/2025/20250808-pjm-board-letter-re-implementation-of-critical-issue-fast-path-process-for-large-load-additions.pdf.

data centers,[32] and PJM's Independent Market Monitor reported that "data center load by itself" raised prices in PJM's most recent capacity auction by approximately $6.5 billion dollars and $23 billion over the last 3 deliverability years.[33] PJM implemented a load adjustment request process in 2025 driven by the need to handle the increases in large load requests coming from different members.[34] While the load adjustment process includes changes for reasons other than data center or large load adjustments, these are negligible compared to the data center adjustments.[35] In its most recent 2026 load forecast update, the adjustments to summer peak in 2030 and 2032 were 33.7 GW and 48.8 GW, respectively.[36] Although Dominion zone continues to have the highest impact, 80% of the total load adjustments (38.9 GW) are concentrated in just four zones by 2032 across Ohio (AEP), Illinois (ComEd), and Pennsylvania (PPL).[37] The 2025 RTEP Window 1 reliability analysis in particular noted the "high-impact drivers" for the 2030 and 2032 model cases were the substantial data center load in AEP, PPL, and Dominion zones, plus an additional 3.5 GW of additional data

[32] *Id*.
[33] *Analysis of the 2027/2028 RPM Base Residual Auction, Part A* ("IMM Report") at 3, The Independent Market Monitor for PJM (Jan. 5, 2026), https://www.monitoringanalytics.com/reports/Reports/2026/IMM_Analysis_of_the_20272028_RPM_Base_Residual_Auction_Part_A_20260105.pdf.
[34] 2026 PJM Load Forecast Report, at 4.
[35] *See id*. at 5, stating that the load adjustments are made to "account for large, unanticipated load changes, market adjustments and peak shaving adjustments…" but the only non-data center load adjustments indicated are a voltage optimization program in Dominion zone, port electrification in PS zone, and a peak shaving program in EKPC zone.
[36] *Id*. at Table B9.
[37] *Id.* These are Dominion (13.9 MW), AEP (10.6 MW), ComEd (8.1 MW), and PPL (6.2 MW).

center load in PPL that was added in the 2026 load forecast on top of the previous increases.[38]

Q20. Are data center customers directly assigned any of the costs of the transmission network upgrade costs?

A20. No. Most, if not all, transmission network upgrades costs are socialized to existing customers, either within the same transmission zone where the data center project is located or to other neighboring transmission zones based on PJM's cost allocation methodology.[39] Large load customers are not currently directly assigned transmission network upgrade costs.[40]

Q21. How does PJM expect demand to change in the next several years?

A21. Over the next 10 years, PJM is forecasting an increase to its overall system peak load of 57,212 MW, or a 3.11% compound annual growth rate. Figure 4 below shows the yearly increases in MW and percentage terms. The increases are overwhelmingly driven by large load additions. Given the market outlook that trends in future expected large load growth will continue for the next decade, it is likely that increasing capacity and transmission costs tied to large loads will also persist.

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[38] *Reliability Analysis Report: 2025 RTEP Window 1* at 4, PJM Interconnection, L.L.C. (Jan. 23, 2025), https://www.pjm.com/-/media/DotCom/committees-groups/committees/teac/2026/20260106/20260106-2025-rtep-window-1-reliability-analysis-report.pdf.

[39] We discuss this issue in more detail in Section III.D of our testimony.

[40] We discuss direct assignment of upgrade costs in Section IV.C of our testimony.

Figure 4. Forecasted change in PJM peak demand[41]

Year	Peak MW	Increase vs. 2025 MW	Increase vs. 2025 %	CAGR
2025	159,660	-	-	
2026	156,373	-3,287	-2.1%	-2.1%
2027	160,451	791	0.5%	0.2%
2028	165,567	5,907	3.7%	1.2%
2029	171,530	11,870	7.4%	1.8%
2030	183,008	23,348	14.6%	2.8%
2031	191,017	31,357	19.6%	3.0%
2032	198,915	39,255	24.6%	3.2%
2033	206,084	46,424	29.1%	3.2%
2034	211,882	52,222	32.7%	3.2%
2035	216,872	57,212	35.8%	3.1%
2036	222,106	62,446	39.1%	3.0%
2037	228,100	68,440	42.9%	3.0%
2038	232,653	72,993	45.7%	2.9%
2039	235,913	76,253	47.8%	2.8%
2040	238,817	79,157	49.6%	2.7%
2041	241,416	81,756	51.2%	2.6%
2042	243,853	84,193	52.7%	2.5%
2043	246,229	86,569	54.2%	2.4%
2044	248,498	88,838	55.6%	2.4%
2045	250,760	91,100	57.1%	2.3%
2046	253,077	93,417	58.5%	2.2%

B. Large load forecasts are highly uncertain in terms of timing and magnitude and present a clear risk of cost shifting to other transmission zones.

Q22. Please explain the uncertainty inherent in large load forecasting.

A22. Data center load growth will continue to be a significant driver, but forecasts of data center projections are subject to extreme uncertainty. This uncertainty in large load forecasts is not just the conclusion of industry observers and analysts; it is also the outlook and perspective of PJM. According to PJM, "[t]here is growing uncertainty around the accuracy of forward load forecasts because of the

[41] PJM 2026 Load Forecast Report.

unprecedented nature of data center load growth, and there is the need to examine who should bear the risk of these forecasts being incorrect in either direction."[42]

Q23. Have any other transmission zones or LSEs within PJM similarly commented on the uncertainty in large load forecasts?

A23. Yes. In its June 2025 filing, ComEd claimed that it had 28,000 MW of new service requests from large load customers in its pipeline. When asked whether ComEd believed all of this demand would materialize, ComEd declined to provide an affirmative response. Instead, ComEd noted that "actual dates of initial service and load ramps could change based on a variety of factors that may not be known until detailed engineering is conducted and connection occurs."[43] ComEd's pipeline is more than double the demand forecast of 14,000 MW that Exelon, its parent company, provided to PJM.[44] In fact, Exelon explicitly acknowledges the uncertainty in these forecasts, excluding 45 GW worth of requests in its 2040 forecast for its four distribution utilities (ComEd, Pepco, BGE, and PECO) because they are "less certain projects."[45] The fact that large load forecasts are being materially adjusted without sufficient transparency even within a single company's own subsidiaries is a clear demonstration of the problem with large

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[42] Manu Asthana, *Prefiled Statement of Manu Asthana on Behalf of PJM Interconnection, L.L.C.*, FERC Resource Adequacy Technical Conference (May 20, 2025), https://www.pjm.com/-/media/DotCom/documents/ferc/filings/2025/20250516-ad25-7-000-manu.pdf.
[43] ComEd, *Response to JNGO-ComEd DR 1.21* (ICC Docket Nos. 25-0077 & 25-0079, Aug. 29, 2025), https://www.icc.illinois.gov/docket/P2025-0677/documents/371138/files/650717.pdf.
[44] *Exelon Large Load Adjustment Proposal – 2026 PJM Load Forecast*, Exelon (Sept. 16, 2025), https://www.pjm.com/-/media/DotCom/committees-groups/subcommittees/las/2025/20250916/20250916-item-04d---exelon-large-load-request.pdf.
[45] *Id.*

load forecasting and the reporting to PJM. And the fact that the magnitude of the difference in Exelon and ComEd's large load forecasts are the size of a large utility's total peak demand requirements demonstrates the cost implications of getting these forecasts wrong.

Q24. Have industry participants voiced similar concerns about the accuracy of forecasts?

A24. Yes, there have been examples of industry participants expressing that forecasts of large load growth are likely overstated. For example, Astrid Atkinson, a former senior director of software engineering at Google, stated that there are "five to 10 times more interconnection requests than data centers actually being built."[46] Similarly, the president of a shale gas producer said he expects only 10% of data center projects that have been announced to be built.[47] Similarly, Microsoft, in testimony on Georgia Power Company's 2023 IRP Update, commented "over-forecasting demand from data centers could lead to procuring excessive carbon intensive generation," and recommended that the Georgia Public Service Commission ("GPSC") only approve near-term resource planning decisions based on "known, mature projects that have made firm commitments to Georgia Power."[48]

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[46] Brian Martucci, *A fraction of proposed data centers will get built. Utilities are wising up.*, Utility Dive (May 15, 2025), https://www.utilitydive.com/news/a-fraction-of-proposed-data-centers-will-get-built-utilities-are-wising-up/748214/.

[47] *US Gas Companies Temper Data Center Demand Expectations*, Energy Intelligence, Natural Gas Week, Vol. 41, No. 11 (Mar. 14, 2025), https://www.energyintel.com/00000195-9503-d464-a7b7-d7bff5ce0000.

[48] Microsoft, *Comments on Georgia Power's 2023 Integrated Resource Plan Update* at 1, 4 (Docket No. 55378, Apr. 1, 2024), https://psc.ga.gov/search/facts-document/?documentId=218199.

Data center customers have suggested that current forecasts are inaccurate and include double counting issues, speculative loads, and low probability projects.[49] While PJM did implement some improvements to its process for incorporating large load adjustments that dampened or delayed some of the anticipated forecast growth included in the 2026 load forecast compared to the 2025 load forecast,[50] PJM's improvements are not sufficient to address the inclusion of past growth trends that were unadjusted and likely duplicative, overstated, or both. PJM has therefore included these questionable large load growth projections into the resource planning underpinning each of the successive RTEP windows covered in our analysis, with the result being that PJM is building transmission for speculative projects and socializing the associated costs to all ratepayers.

Q25. Are concerns related to the accuracy of forecasts a recent phenomenon?

A25. The rapid increase in new large load customers has created additional urgency around these challenges, but they are not new. For example, in 2018, the Lawrence Berkeley National Laboratory conducted a study comparing forecasting and actual growth for utilities in the Western U.S. and found most overestimated future

[49] Amazon, Calpine, Constellation, Google, Microsoft & Talen, *Joint Stakeholder Options PJM CIFP – Large Load Additions*, PJM (Oct. 1, 2025), https://www.pjm.com/-/media/DotCom/committees-groups/cifp-lla/2025/20251001/20251001-item-05d---joint-stakeholder-options---amazon-calpine-constellation-google-microsoft-talen.pdf.

[50] 2026 PJM Load Forecast Report, at 5.

energy and peak demand growth. The researchers found that assumptions overstating economic growth were the primary driver behind this result.[51]

Q26. Why are these forecasts so uncertain, and how do prospective large load customers exacerbate these challenges?

A26. Duplicate or phantom requests are a primary driver, while utilities have little reason to be skeptical because of their economic incentive to build rate base and receive a return on these investments.

Q27. What do you mean by phantom requests?

A27. Phantom requests are speculative and often duplicative requests to connect being submitted by data center customers or developers to multiple utility jurisdictions.

Q28. Why would a prospective data center customer submit requests to connect to multiple utilities?

A28. Data center customers are looking to get connected to the grid faster than new energy infrastructure can be built, which has led developers to submit requests to multiple utilities to understand their timeline, rates, and incentives.[52] Industry participants note that "data center developers consider multiple states as possible

[51] J.P. Carvallo, P. Larsen, A. Sanstad & C. Goldman, *Long Term Load Forecasting Accuracy in Electric Utility Integrated Resource Planning*, Energy Policy, 119: 410-422 (Aug. 2018), https://www.sciencedirect.com/science/article/abs/pii/S0301421518302751?via%3Dihub.
[52] Bianca Giacobone, *Phantom data centers are flooding the load queue*, Latitude Media (Mar. 26, 2025), https://www.latitudemedia.com/news/phantom-data-centers-are-flooding-the-load-queue/.

locations for data centers, and they query multiple utilities simultaneously for electricity rates and incentives prior to making a final selection."[53]

Q29. How common are phantom requests?

A29. It is difficult to precisely identify the rate of phantom requests because load requests are not subject to standardized transparency requirements. However, utilities have seen up to 30% of their applications submitted in 2024 cancelled.[54] Similarly, Public Interest Organizations commented on a recent FERC docket that "… PJM has no way to cross-check whether a data center in, for example, Exelon's service territory has also made the same proposal in Dominion's territory, and both proposals end up in PJM's forecast even though only one will be built. … [I]n a recent presentation at the Pennsylvania Environmental Law Forum, PJM's own Senior Manager of Government Services, Stephen Bennett, stated that data center companies 'are pitching the same data centers in different locations.'"[55]

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[53] J. Koomey, Z. Schmidt & T. Das, *Electricity Demand Growth and Data Centers: A Guide for the Perplexed* at 10, Bipartisan Policy Center (Feb. 2025), https://bipartisanpolicy.org/download/?file=/wp-content/uploads/2025/02/BPC-Report-Electricity-Demand-Growth-and-Data-Centers-A-Guide-for-the-Perplexed.pdf.

[54] Bianca Giacobone, *Phantom data centers are flooding the load queue*, Latitude Media (Mar. 26, 2025), https://www.latitudemedia.com/news/phantom-data-centers-are-flooding-the-load-queue/.

[55] Public Interest Organizations, *Comments of Public Interest Organizations in Response to PJM Interconnection, L.L.C.'s 03/24/2025 Answer to FERC's 02/20/2025 Order under EL25-49* at 16-17 (Docket No. EL25-49-000, Apr. 23, 2025), https://elibrary.ferc.gov/eLibrary/filedownload?fileid=9D23F7BC-5484-CAA9-9030-96645FF00000.

Q30. Do data center customers face costs for submitting phantom requests?

A30. In general, interconnection requests do not require potential data center customers to make significant financial commitments in comparison to the upgrade costs triggered. Reflecting on this, a former commissioner with the Public Utilities Commission of Texas stated, "When it's cheaper to buy a queue position than not use your queue position, you'll buy queue positions all day long."[56] Some jurisdictions are making efforts to introduce more costs into the queue process for large loads, such as ERCOT,[57] Colorado,[58] and Oregon.[59]

Q31. How do phantom requests reduce the accuracy of load forecasts?

A31. Service requests are included in load forecasts, despite the fact that they are known to be highly speculative and up to 30% of such requests have been cancelled historically.[60] The fact that such a large proportion of load requests are speculative makes it difficult to develop an accurate load forecast.

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[56] Brian Martucci, *A fraction of proposed data centers will get built. Utilities are wising up.*, Utility Dive (May 15, 2025), https://www.utilitydive.com/news/a-fraction-of-proposed-data-centers-will-get-built-utilities-are-wising-up/748214/.

[57] Public Utility Commission of Texas, *Project No. 58317, SB 6 Implementation*, https://interchange.puc.texas.gov/Search/Filings?ControlNumber=58317.

[58] Colo. Pub. Utils. Comm'n, *Order Regarding Public Service Company of Colorado's 2024 Electric Resource Plan* (Docket No. 24A-0442E). https://www.dora.state.co.us/pls/efi/EFI.Show_Docket?p_session_id=&p_docket_id=24A-0442E.

[59] Pub. Utils. Comm'n, *In the Matter of Investigation into Marginal Cost Study Treatment and Costs for Large Customers and Further Modifications to Portland General Electric Company's Rule C and Rule I* (Docket No. UM 2377). https://apps.puc.state.or.us/edockets/Docket.asp?DocketID=24470&Child=calendar.

[60] *Uncertainty and Upward Bias Are Inherent in Data Center Electricity Demand Projections* ("LEI Report") at 13, London Economics International (2025), https://www.selc.org/wp-content/uploads/2025/07/LEI-Data-Center-Final-Report-07072025-2.pdf.

Q32. Do utilities take steps to secure commitments from prospective large load customers?

A32. Terms and conditions vary broadly across utilities. Most utilities have some measures in place to secure commitments from prospective large load customers, but the magnitude of these commitments differ significantly. Some utilities have proposed, or have received approval for, large load tariffs that are typically combined with a customer service agreement (CSA) or electric service agreement (ESA) contract. Contract terms and conditions typically include some combination of minimum billing requirements, minimum billing periods, and upfront deposits.[61] Similar mechanisms have been proposed for transmission interconnection under PJM, such as Exelon's Transmission Security Agreement (TSA) that has been approved for use by PECO[62] and ComEd.[63] However, large loads can be in a utility load queues and forecasts for several years prior to signing an ESA or having additional financial obligations.[64] We discuss the shortcomings of the TSA approach in Section IV. B.

[61] *Id.*
[62] *Transmission Security Agreement between PECO Energy Company and Amazon Data Services, Inc.*,193 FERC ¶ 61,148 at P 8 (2025) ("193 FERC ¶ 61,148").
[63] *See* Commonwealth Edison Equinox TSA, Docket No. ER 26-989 (January 9, 2026); Commonwealth Edison QTS TSA, ER26-990 (January 9, 2026); Commonwealth Edison Powerhouse Hillwood TSA, Docket No. ER26-989 (January 13, 2026); Commonwealth Grundy TSA ER26-1031 (January 13, 2026).
[64] See Commonwealth of Virginia State Corporation Commission, Case No. PUR-2026-00011, Direct Testimony of Ron Nelson.

Q33. Do these measures limit phantom requests from prospective large load customers?

A33. The terms of the CSAs and ESAs are often confidential, but publicly available tariffs and terms and conditions suggest that tariff and contract terms are highly variable, and thus their effectiveness is highly variable. For example, the minimum billing periods utilities require vary from as little as one year up to thirty years, and upfront deposits are not widely used at present.[65] Importantly, large loads can be included within the RTEP forecasts several years prior to signing an ESA or other contract that requires a financial obligation for transmission costs.[66]

Q34. Is there evidence that these measures could improve the accuracy of forecasts if implemented more stringently?

A34. Yes, there is some suggestive evidence that measures like take-or-pay requirements, contract minimum terms, and exit fees could reduce the incentive for data center developers to submit phantom requests. For example, after receiving more than 30 GW of connection requests from 50 potential customers, AEP Ohio filed an application for a data center tariff with the Public Utility Commission of Ohio in May 2024. The tariff included take-or-pay requirements including a minimum demand charge, exit fees of 3 years' minimum payments, and a fee for AEP Ohio to study the prospective load. That tariff was approved in July 2025, and from May 2024 to September 2025, AEP Ohio lowered its

[65] LEI Report.
[66] See Commonwealth of Virginia State Corporation Commission, Case No. PUR-2026-00011, Direct Testimony of Ron Nelson.

projected data center load from more than 30 GW across 90 sites to 13 GW across 36 sites.[67]

Q35. Are investor-owned utilities sufficiently incentivized to evaluate load requests that may be speculative?

A35. No, they are not. Investor-owned utilities benefit financially from growing their rate base, which leads to an opportunity to increase returns. Although utilities have processes intended to limit the impact of phantom requests—assigning requests for service probabilities or requiring some financial commitments through ESAs, for example—the costs and benefits for the utility are asymmetric: the utility benefits from making investments that expand its rate base, but bears few of the risks of stranded or under-utilized assets, while most of the risks are borne by ratepayers. Because of this, utilities are incentivized to make investments in generation and transmission to serve potential load growth, even if it is speculative.[68] For example, a large load needs only to pay $250,000 to enter and stay within Dominion's large load transmission queue process indefinitely; Dominion does not remove large load customers for any reason.[69]

[67] Kavulla, 2025, at 15.
[68] LEI Report, at 16.
[69] See Commonwealth of Virginia State Corporation Commission, Case No. PUR-2026-00011, Direct Testimony of Ron Nelson.

Q36. Is there any other evidence that forecasted load growth from data center customers is overstated?

A36. Yes, there is. The magnitude of forecasted load growth requires more computing equipment than is likely possible from existing supply chains. For example, one analysis found that the estimated demand for processing chips from the cumulative announced data centers across the U.S. accounts for 90% of the incremental global chip supply from 2025 to 2030, which is unreasonable given the current U.S. market share of 50% of chips.[70]

Q37. What reforms has PJM put in place to address standardizing its load forecast adjustment process for large load issues?

A37. PJM has updated its process for handling large load adjustments, which is a good start to adding transparency to the process and reducing large load forecast uncertainty. Specifically, PJM lists a number of steps it takes in an attempt to "verify that identified [large load] issue is real and significant," including identifying press announcements, ensuring requesting EDC or LSE has or will include the adjustment in its own forecasting and planning, and asking for a Letter of Agreement or Electric Service Agreement "when appropriate."[71] However, the updated process falls short of creating standards or minimum requirements for including large loads within the forecast, which is prudent given the magnitude and potential for speculative load requests. For instance, PJM's load adjustment

[70] *Id.* at 9.
[71] PJM Interconnection, L.L.C., Manual M-19: Load Forecasting and Analysis, Revision 38, Effective December 17, 2025 (PJM Manual M-19), at 26-27, https://www.pjm.com/-/media/DotCom/documents/manuals/m19.pdf.

implementation document states that "PJM does not specify a particular methodology for forecasting large loads. Electric Distribution Companies ("EDCs") or Load Serving Entities ("LSEs") may utilize any methodology that is reasonable and appropriate."[72] This leaves too much discretion to individual utilities and is ripe for misalignment in the quality of forecasts PJM is receiving from its members.

Q38. Are these reforms sufficient to meaningfully address the potential for over forecasting large load additions in PJM's load forecasting process?

A38. No. Apart from the lack of standardized methodology between EDCs or LSEs as just described, PJM also does not require any standardization around how EDCs or LSEs should estimate peak demand impacts as compared to capacity requests. If an entity submits a forecast with a signed "energy service obligation" or "construction commitment", then the load will be considered in the short-term (three-year) forecast.[73] However, there can be significant differences between capacity commitments reflected in a signed agreement and the level of metered peak demand that ultimately shows up for data centers. PJM states that if an entity supplies a capacity request for large loads without identifying the peak demand

[72] PJM Interconnection, L.L.C., *Load Adjustment Request Implementation*, at 3 (July 1, 2025), https://www.pjm.com/-/media/DotCom/committees-groups/subcommittees/las/postings/load-adjustment-request-implementation.pdf.
[73] *Id.* at 3-4.

level, then it will apply a de-rate, i.e., a reduction to the request, based on historical data either in the same zone or elsewhere in PJM.[74]

Q39. What are your conclusions about the uncertainty exhibited by large loads that are included in utility forecasts, including in the PJM zones impacted by RTEP reliability needs addressed in your testimony?

A39. We conclude that the incentives for both large load customers and those seeking to serve them with new generation exhibit a significant bias toward increasing the load forecast, and hence, PJM's resulting forecasts likely overstate the actual need. In Section IV. C, we discuss recommendations for how to implement protections for existing customers against bearing the costs that result from speculative forecasts and market behavior.

C. PJM's existing cost allocation methods for assigning costs of baseline reliability transmission upgrades are unjust and unreasonable and should be remedied.

Q40. What is the purpose of this section of your testimony?

A40. In this section, we outline the fundamental arguments against continued use of PJM's current cost allocation methods to handle new and unprecedented grid impacts driven by large loads. We explain why PJM's existing regional transmission planning process and associated cost allocation rules developed under the PJM OATT are no longer just and reasonable. In later sections, we will build on this critique by demonstrating how the unprecedented changes stemming

[74] *Id.* at 3. "This factor would be based on observed historical data either in the requestor's area or elsewhere in PJM in the event that no data is available to try and best approximate this relationship."

from large load growth are impacting Maryland ratepayers and causing significant upward pressure on prices, driven overwhelmingly by data centers.

Q41. Please summarize PJM's currently approved cost allocation methodology for baseline reliability projects.

A41. PJM allocates RTEP costs differently for supplemental versus baseline projects, using 100% direct allocation to the causing transmission zone for supplemental projects and a weighted allocation across zones for projects that PJM determines qualify as baseline reliability projects. Baseline reliability project costs are then allocated using a combination of the load-ratio share and solution-based DFAX methods depending on the specifics of the required upgrade. Regional facilities, which are projects rated at 500 kV or higher, and necessary lower voltage facilities, which are between 345 kV and 500 kV and have double-AC circuit and are required transmission enhancements to support regional facilities, receive a hybrid allocation assigning 50% of the costs using the load-ratio share or "postage stamp" method[75] and 50% using the solution-based DFAX method. Projects not designated as either regional facilities or necessary lower voltage facilities are allocated entirely through the solution-based DFAX method.[76] The solution-based DFAX method analyzes the projected changes in network power flows across a required transmission enhancement accounting for all resulting flows into a

[75] A transmission zone's load-ratio share is equal to its proportional contribution to PJM's system-wide coincident peak load during the previous calendar year.
[76] PJM OATT sch. 12, section (b)(i), section (b)(ii).

transmission zone from all sources of PJM generation.[77] The ratio of the resultant power flows over a particular transmission facility that was part of a solution to an identified violation(s) is then used to cost-allocate project costs to approximate the benefits accruing to transmission zones from the project.

Q42. How does the solution-based DFAX method calculate transmission zone cost allocations?

A42. The solution-based DFAX method uses power flow modeling to calculate distribution factors for each transmission zone that determine how much of the power flowing over a particular transmission facility that was part of a given reliability upgrade project is used by the load within that zone as represented by the transmission zone's peak load.[78] It does this by modeling a transfer of power from all generation sources in the PJM region to each transmission zone, and measuring the proportion of megawatts transferred over the transmission facility to and from each individual transmission zone. PJM then uses the resulting distribution factors as allocation factors for all or part of the costs of the project.[79]

Q43. Why does PJM use hybrid allocation for regional facilities and necessary lower voltage facilities?

A43. PJM previously used a 100% load-ratio share cost allocation method to assign 500 kV and greater network upgrade costs. PJM adopted the hybrid cost allocation method for regional facilities and necessary lower voltage facilities as an outcome

[77] PJM OATT sch. 12, section (b)(iii)(B)(1).
[78] PJM Manual 14B, Revision 58 (December 17, 2025), at 65.
[79] PJM OATT, sch. 12, section (b)(iii)(B).

of successful challenges by transmission owners and other parties located in the western PJM region who argued that network upgrades made in the eastern PJM region would provide no benefit to them, and therefore they should not have to bear the costs of these upgrades. The courts made clear that the issue raised in these challenges was "about the allocation of the huge costs of building high-voltage transmission lines that do not provide uniform benefits to all the utilities in the region in which the lines are built."[80] They also highlighted what it called a "basic fallacy" that assumed 500 kV lines built in the eastern region would benefit the entire grid, when in reality those projects were meant to address specific reliability violations in the eastern part of PJM.[81] As a result of this second remand from the court, PJM later agreed to implement the hybrid cost allocation methodology.

Q44. Is the load-ratio share cost allocation methodology just and reasonable given the concentrated load growth driven by data centers in the northern Virginia area?

A44. No, even as part of the hybrid allocation methodology, the load-ratio share is no longer just and reasonable under the same logic that justified moving toward the hybrid allocation method in the first place. This is because of the unprecedented nature of large load growth that is causing substantial increased reliability needs that are geographically concentrated. There are substantial transmission costs

[80] Majority Opinion at 6, *Illinois Commerce Comm'n v. FERC*, Nos. 13-1674, 13-1676, 13-2052, 13-2262 (7th Cir. Jun. 25, 2014).
[81] *Id.*, at 16.

being allocated using the load-ratio share methodology that are associated with 500 kV lines needed to resolve specific reliability violations caused by concentrated data center growth in northern Virginia.

Q45. Is there precedent demonstrating the inadequacy of the solution-based DFAX method for use in allocating certain types of reliability-driven upgrade costs associated with integrating new large loads?

A45. Yes. In *ICC v FERC*, the Commission acknowledged shortcomings of the DFAX method, stating "not all reliability problems can be quantified through the Distribution Factor analysis."[82] More recently, in its Artificial Island Order, FERC has recognized limitations of the solution-based DFAX methodology in capturing certain non-flow-based reliability benefits, particularly in the context of stability-related projects, and has required additional analysis in such circumstances. For example, in *Delaware Public Service Commission v. PJM Interconnection, L.L.C.*, the Commission found that stability-related reliability issues may require additional analysis beyond solution-based DFAX to identify beneficiaries and initially accepted PJM's "stability-deviation method" proposed during the paper hearing.[83] More recently, in the remand proceedings in *Consolidated Edison*

[82] Brief for Respondent at 43, *Illinois Commerce Comm'n v. FERC*, Nos. 13-1674, 13-1676, 13-2052, 13-2262 (7th Cir. Feb. 28, 2014). "Furthermore, the Commission detailed the difficulties of assessing certain reliability benefits, explaining that not all reliability problems can be quantified through the Distribution Factor Analysis. See Remand Order P 46 & n.65 (explaining that "system stability" is unquantifiable), JA 555."

[83] *Del. Pub. Serv. Comm'n v. PJM Interconnection, L.L.C.*, 166 FERC ¶ 61,161 (February 2019 Order), order on reh'g and compliance filing, 169 FERC ¶ 61,234 at P 7 (2019). (The Commission states in relevant part, "[T]he Commission found that the beneficiaries of Regional Facilities, Necessary Lower Voltage Facilities and Lower Voltage Facilities that are solutions to these stability-related reliability issues are not necessarily captured by the solution-based DFAX method, which primarily determines the beneficiaries of flow-based reliability violations. In particular, the Commission found that the record has demonstrated that, given the analytically unique nature of stability-related reliability issues, further analysis of the identification of the beneficiaries is required.") (citations omitted).

Company of New York, Inc. v. PJM Interconnection, L.L.C., the Commission has continued to examine whether DFAX appropriately captures the benefits of certain non-flow-based reliability projects, including short-circuit-related upgrades, and has found the existing record insufficient to reach a definitive conclusion.[84]

Q46. Did PJM allocate any such costs to mitigate stability-related violations using the DFAX cost allocation methodology when assigning RTEP costs to transmission zones?

A46. Yes. The 2022 RTEP window includes costs for two types of stability-related projects which may be inappropriate for solution-based DFAX cost allocation. During modeling of the 2022 RTEP Window 3 projects, PJM first modeled for thermal and voltage violations using steady-state power flow, but also subjected the proposed solutions to an initial screen for short-circuit and stability analyses that identified additional project needs over and above the upgrades required to resolve the thermal and voltage violations. This initial short-circuit screening step applied to all scenarios prior to further evaluation, and may have added additional scope of projects ultimately selected under this window due to breaker replacement, switchyard rebuilds, and potentially whole new substation rebuilds[85] PJM does not specify whether cost increases resulted from scope changes following the short-circuit screening step, but they identify costs due to the more rigorous short-circuit analysis step as well as $155.82 million for a baseline

[84] *Consolidated Edison Co. of New York, Inc. v. PJM Interconnection, L.L.C.*, 194 FERC ¶ 61,179 at P 73 (2026) (finding the record insufficient to determine whether short-circuit-related reliability projects should be treated similarly to stability-related projects for purposes of cost allocation).
[85] PJM Interconnection, L.L.C., *2022 RTEP Window 3 Reliability Analysis Report* (Dec. 8, 2023, rev. R3), at 31.

reliability project titled "Reactive Power VAR Reinforcements."[86] The inclusion of the $155 million to mitigate VAR issues indicates that there are material costs that are not due to steady-state-load flow-based project needs and are inappropriately being allocated to transmission zones using the solution-based DFAX method. This is especially true for projects requiring installation of static synchronous compensators, which are a type of equipment to handle dynamic voltage instability and VAR support, due to the dynamic system impacts caused by data centers.

Q47. Can you elaborate on the potential system impacts attributable to large loads such as data centers that are not well captured by the solution-based DFAX method based on the limitations you described above?

A47. Yes. As discussed above, the solution-based DFAX method is designed to allocate costs associated with thermal and static voltage violations identified through steady-state power flow analysis. It is not appropriate for stability-related impacts. Industry experts have documented several significant risks from data centers that can lead to stability-related reliability challenges and are attributable, as we describe below, to the unique characteristics of these loads. Due to the similarities in terms of the nature of possible system impacts, and the magnitude of impacts stemming from large load concentrations on the grid, these loads are more similar

[86] *Id.*, at 55. PJM's additional short-circuit analysis required an additional 36 new or upgraded circuit breakers to remedy the short-circuit issues identified, totaling $63.27 million in costs. These $63.27 million in costs are directly allocated the transmission zone causing the need, but any potential cost increases resulting from scope changes following the initial short-circuit screening would be allocated using the DFAX method. *See also id.*, at 59. VAR stands for "volt-amp reactive power", which is a type of voltage-related issue not related to steady-state load flow voltage violations. The $155 million for this project is allocated using the DFAX method.

to large generators in terms of the potential system impacts they may cause. For this reason, data centers should be subject to system impact studies and cost assignment methods similar to those applied to generators, rather than the solution-based DFAX method. We discuss this in more detail in Section IV.

Q48. Could you elaborate on what kind of data center related reliability impacts may not be well captured by the DFAX method?

A48. Data center load poses substantial stability and non-steady state reliability risks which PJM has not adequately reflected in its current cost allocation mechanisms. Considering this fact, continued application of the solution-based DFAX cost allocation method results in rates that are unjust and unreasonable. We have two main concerns with continuing to rely on the solution-based DFAX method to allocate costs stemming from data center load growth.

First, there are substantial potential reliability issues posed by data centers on the grid that are not related to load flow, which is the basis of the solution-based DFAX method. For instance, utilities and system operators globally consider voltage ride-through capability for large loads to be among the most critical system reliability needs, leading to risks of frequency excursions, cascading outages, transient instability, voltage collapse and more.[87] The Eastern Interconnection experienced such a situation that resulted in a sudden drop of

[87] Energy Systems Integration Group, *Large Load Performance Requirements: Current Practices and Recommendations* (February 2026), at 5, https://www.esig.energy/wp-content/uploads/2026/03/ESIG-Large-Loads-Performance-Requirements-report-2026b.pdf.

1,500 MW of data center load on July 10, 2024, with no warning to the grid operator, when a lightning strike caused a transmission-level fault.[88] The sudden drop in load was a result of the data centers switching to on-site backup power to avoid damage to their sensitive IT equipment.[89] Industry observers later determined that the location of the 1,500 MW load drop was in Dominion's territory in northern Virginia, but similar issues have been experienced in ERCOT in Texas, which also has substantial data center load.[90] Recent reporting highlights similar incidents occurring in early 2025 in the same region.[91] In response to these challenges, many industry participants are calling for planning and interconnection study reforms to evaluate N-1 reliability not just based on the loss of the largest generator or transmission line, but also on unexpected loss of the largest load. This type of study, to our knowledge, has not been conducted by PJM accessible to the public, and therefore the actual stability challenges and related impacts from such sudden load drops under different conditions are presently unknown and the cost of addressing these issues is unquantified.

Second, grid planners and operators require enhanced visibility into large loads given their unique characteristics. NERC finds that it is critical to have

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[88] NERC. *Incident Review, Considering Simultaneous Voltage-Sensitive Load Reductions*, at 2-3, https://www.nerc.com/pa/rrm/ea/Documents/Incident_Review_Large_Load_Loss.pdf.
[89] *Id.* at 4.
[90] McLaughlin, Tim. *Big Tech's data center boom poses new risk to US grid operators*, Reuters, (March 19, 2025), https://www.reuters.com/technology/big-techs-data-center-boom-poses-new-risk-us-grid-operators-2025-03-19/.
[91] Blunt, Katherine & Jennifer Hiller, *A new threat to power grids: data centers unplugging at once,* Wall Street Journal (March 1, 2026), https://www.wsj.com/business/energy-oil/a-new-threat-to-power-grids-data-centers-unplugging-at-once-741f1bda?msockid=3969fe5be32b65ef0b48eb33e2836438.

visibility into how loads are going to operate, including not just peak demand and interconnection timelines, but also dynamic load models and control and protection settings.[92] Without visibility into these load dynamics, planners and operators cannot assess the full impact of these new loads on the bulk power system and could result in poor planning decisions.[93] A recent report further identifies key reliability challenges specific to data centers, including ramping, frequency response, generator cycling, power quality issues, transient stability impacts, and subsynchronous oscillations.[94] These type of potential system impacts associated with large loads like data centers and crypto mining facilities are very different than the type of predictable and manageable load behaviors that have characterized transmission system planning to date, and share more in common with inverter-based generators like wind and solar plants.[95]

Q49. Has any jurisdiction addressed reliability issues caused by large loads?

A49. Yes. The Alberta Electric System Operator (AESO) has implemented rules that treat large loads similar to generators. The AESO rules address several of the reliability concerns related to large loads, such as an increase in energy emergency

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[92] NERC, Characteristics and Risks of Emerging Large Loads: Large Loads Task Force Whitepaper, at 15 (July 2025), https://www.nerc.com/globalassets/who-we-are/standing-committees/rstc/3_doc_white-paper-characteristics-and-risks-of-emerging-large-loads.pdf.

[93] *Id.*

[94] Elevate Energy Consulting, "Practical Guidance and Considerations for Large Load Interconnections," at 10 (August, 2025), https://www.esig.energy/wp-content/uploads/2025/08/2025-08-20-ESIG-LLTF-Webinar-Large-Load-Interconnection-Report.pdf.

[95] Energy Systems Integration Group, *Large Load Performance Requirements: Current Practices and Recommendations*, at 2 (February 2026), https://www.esig.energy/wp-content/uploads/2026/03/ESIG-Large-Loads-Performance-Requirements-ES-2026a.pdf.

alerts during peak usage hours, dynamic system impacts from steep load ramping, increased reliance on ancillary services, and the need for network upgrades.[96]

Q50. How is AESO proposing to address these issues?

A50. AESO is undergoing a review of cost allocation and recovery for large loads.[97] AESO is implementing a two-stage approach to addressing this issue going forward. In the immediate term, AESO is setting a 1,200 MW cumulative limit on large load connection through 2028 and developing technical interconnection standards and modeling requirements for the industry in the following years. The second phase of this proposal consists of redesigning the interconnection tariff to incorporate new large-load standards from NERC, set defined terms for load shedding, demand response, and backup generation supply, and address ancillary service and network upgrade cost causation.[98] AESO's significant deviation from the status quo to address the unique data center cost causation demonstrates a similar need for PJM to take action and evolve cost allocation approaches.

Q51. What are your conclusions regarding the DFAX method as it is used by PJM to allocate costs of baseline reliability projects related to data centers?

A51. The above examples make clear that there are a number of situations where PJM has applied the DFAX method in areas the Commission has previously found it to

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[96] Alberta Electric System Operator, *Large Load Integration Phase I: Interim Connection Limit and Assignment*, at 12 (June, 2025), https://www.aeso.ca/assets/Phase-I-Large-Load-Intergration-Information-Session-Presentation-posted-June-4-2025.pdf.
[97] Alberta Electric System Operator, *Update on Data Centres*, at 4 (September, 2025), https://www.aeso.ca/assets/Uploads/grid/Data-Centre/AESO-Data-Centre-Update-September-2025.pdf.
[98] Alberta Electric System Operator, *Large Load Integration Phase I*, at 13.

be unsuitable. Further, there are likely to be additional system costs that arise due to the nature of data center demand that are simply not understood well enough yet given PJM's limited modeling assumptions, particularly the type of impacts we note above such as impacts due to fast ramping capability and the impact of large loads on ancillary services like regulating reserves, as well as power quality impacts.

Q52. What are your conclusions regarding the load-ratio share method as it is used by PJM to allocate costs of baseline reliability projects related to data centers?

A52. Our analysis demonstrates that the load-ratio share method is no longer just and reasonable when applied to baseline reliability projects driven by large data center load growth. This method allocates costs broadly across transmission zones based on each zone's share of system peak load, without regard to the location or drivers of the underlying transmission need. As a result, projects triggered by concentrated data center growth are socialized across the PJM footprint, including to customers who do not meaningfully contribute to or benefit from those upgrades.

Q53. What do you recommend?

A53. In recognition of the ongoing harms and unjust subsidization of large loads impacting Maryland's ratepayers, we recommend that the Commission:

- Reject PJM's tariff as unjust and unreasonable due to the shortcomings we addressed in this subsection.

- Initiate a show cause order to determine the just and reasonable replacement cost allocation methodology for handling baseline reliability upgrades driven by large load growth. As part of this hearing, the Commission should require PJM to undertake the steps necessary to build the factual record in order to determine specific costs included in past approved cost assignments that were unjustly applied.
- Establish a refund effective date of no later than 60 days after the date of this filing that extends to the maximum limit allowed, in recognition of the continued and ongoing cost increases across successive RTEP baseline reliability procurement windows that are primarily driven by large data center load growth as we demonstrate throughout our testimony. In furtherance of the objectives of establishing a refund effective date, we recommend the Commission further direct PJM to re-study the baseline reliability projects approved in 2022 RTEP W3, 2024 RTEP W1, and 2025 RTEP W1 to determine the relative proportion of transmission system impacts caused by expected future load growth from data centers versus other causes. The results of this study should be used to credit back to transmission zones any previously collected costs attributable to large load growth included under each of these windows.
- Direct PJM to propose a compliance filing within 90 days of the conclusion of the show cause hearing.

D. PJM's current cost allocation methodology creates perverse economic incentives at the state level that lead to inefficient transmission market outcomes.

Q54. Why is it important to allocate transmission network upgrade costs to cost causers and beneficiaries?

A54. Ultimately, the Commission's rules governing PJM's transmission cost allocation approach under the RTEP are intended to create efficient market outcomes by providing accurate and reasonable price signals. The Commission adopted cost allocation reforms under Order No. 1000, which "requires that all regional and interregional cost allocation methods allocate costs for new transmission facilities in a manner that is at least roughly commensurate with the benefits received by those who will pay those costs."[99] The Commission reiterated in its order on rehearing that one of the prime reasons for the *ex ante* cost allocation mechanisms established under Order No. 1000 was that without them, the result would be "inefficient transmission planning that impedes the development of more efficient and cost effective new transmission facilities, with the result that jurisdictional rates are higher than they would otherwise be."[100] However, as we show in the discussion that follows, PJM's existing cost allocation method can actually distort price signals in the face of overwhelming data center demand and has not demonstrated that the benefits received by Maryland ratepayers are roughly commensurate with the costs imposed by the load ratio share and DFAX

[99] Order No. 1000, *Transmission Planning and Cost Allocation by Transmission Owning and Operating Public Utilities*, 18 CFR Pt. 35 (2011), at P 10.
[100] Order No. 1000-A, *Transmission Planning and Cost Allocation by Transmission Owning and Operating Public Utilities*, 18 CFR Pt. 35 (2012), at P 592.

approaches. Later in Section IV we present alternative cost allocation methods that would provide better price signals and ensure greater ratepayer protections.

Q55. Does PJM's DFAX cost allocation approach result in efficient price signals and market outcomes for transmission?

A55. No. The DFAX cost allocation approach creates a perverse incentive for retail jurisdictions because it reduces the risk associated with stranded transmission asset cost recovery by shifting it to other neighboring zones outside of a given state boundary. The magnitude of transmission upgrades related to large loads makes it a significant issue that needs to be addressed through modifications to cost allocation.

Q56. Please explain the perverse incentive created by the DFAX.

A56. The DFAX cost allocator is initially calculated based on forecasted power flow and peak loads that are expected at the time of assets going into service. This method of timing the calculation embeds large load impacts into the initial DFAX allocator. Once the transmission upgrade project goes into service, the DFAX is updated annually with actual loads.[101] As discussed elsewhere in our testimony, it is almost certain that some significant portion of these large loads will not materialize due to inaccurate load forecasts, speculative market positions, duplicative applications, and economic factors, among other reasons. In instances where large loads do not materialize, the DFAX allocator will not allocate the

[101] PJM OATT, Schedule 12 § (b)(iii)(H)(2).

costs caused to the large load or the transmission zone. However, the transmission upgrade costs still must be collected, and will be shifted to other transmission zones, which is clearly an inefficient market outcome given that the initial benefits estimated through the DFAX to transmission zones will not align with the resulting cost allocation.

Q57. Are states acting to address the potential for stranded transmission assets related to large load customers?

A57. Yes, but with serious limitations, as discussed further below, to the extent that the costs of such stranded assets are allocated to other utilities or states there may be little or nothing that a state can do to protect its customers from costs triggered by actions in another state. States, and retail utilities, are creating separate customer classes and large load tariffs with distinct terms and conditions to better ensure that stranded transmission costs do not impact the utility's other retail customers. For example, Dominion recently proposed a large customer tariff with longer terms of service, minimum demand charges for transmission, collateral requirements, and exit fees.[102] Many of the proposed terms and conditions are intended to better ensure utility transmission, and other, cost recovery for several years beyond when a transmission project would go into service (e.g., a 14 year term).

[102] Virginia Electric and Power Co., Schedule 10 Tariff, § 1(F).

Q58. Do the large load tariffs being proposed and approved by state commissions address the issue of DFAX creating inefficient market outcomes?

A58. No. A large load tariff that insulates one utility's retail customers from stranded transmission costs may magnify the perverse incentive of the utility to overbuild transmission. As noted above, if large loads do not materialize, the DFAX allocator will reduce the allocation of the associated transmission upgrade to the transmission zone where the forecasted load failed to materialize, all else constant. Because many large-load tariffs have minimum transmission demand charges and long-term commitments, they insulate the cost causing transmission zone from bill impacts associated with the transmission upgrades. Specifically, if a large load takes service under such a large load tariff, it is obligated to pay a minimum transmission demand charge even when its load does not fully materialize.[103] If utilities can use large load contract terms and conditions to insulate their own ratepayers from stranded transmission asset risk, they may be more likely to overbuild transmission in an attempt to attract large loads because the downside to them is largely mitigated through lower DFAX allocations and contractual terms that address stranded transmission costs. Additionally, the DFAX fails to assign costs to the causing transmission zone. While the initial load projections from one transmission zone triggered the transmission upgrades, the DFAX assigns those

[103] *See e.g.,* Schedule 10, Large General Service, Virginia Electric Power Co., https://cdn-dominionenergy-prd-001.azureedge.net/-/media/content/rates-and-tariffs/pdfs/virginia/large-business/schedule-10.pdf. *See also* Schedule LLPS, Large Load Power Service, Evergy Kansas Central, Inc., https://www.evergy.com/-/media/documents/billing/kansas-central/commercial-and-industrial/ekc_large-load-power-service.pdf.

costs to another transmission zone, resulting in a need to better track causing transmission zones to prevent unreasonable cost allocation. This result suggests that the DFAX allocator and large load tariff terms can create a perverse incentive to overbuild transmission and misallocated costs because of a reliance on cost shifting to other transmission zones and direct cost recovery from the contracting large load customer.

Q59. Do you have any examples of this perverse incentive?

A59. Yes. Recently, Appalachian Power Company (APCo) filed for approval of large load terms and conditions at the Virginia State Corporation Commission (SCC). In comments, SCC Staff noted that "transmission costs are generally allocated among utilities within American Electric Power transmission zone. Therefore, if a large customer reduces its capacity, the reduction may also reduce APCo's share of these AEP zonal transmission costs, all else being equal, which could help to partially mitigate cost shifting concern to APCo's remaining customers."[104] To be clear, Virginia Staff is suggesting that a partial solution to shield APCo's customers from stranded transmission upgrade costs for large load customers is for another utility's customers to pay for the stranded costs. If every state commission in PJM's territory uses similar logic, billions of dollars of stranded transmission costs will unnecessarily and inefficiently be spread throughout PJM's territory.

[104] Division of Public Utility Regulation, VA SCC, *Staff Report*, Document No. 250740066 (Case No. PUR-2025-00057, July 25, 2025), at 12.

This potential effect clearly demonstrates that states are counting on the flaws within the DFAX allocator to shield ratepayers from the decisions made by their own utility and state commission. The Commission must address the DFAX so that transmission zones are not playing hot potato with stranded transmission costs.

Q60. Are there any other issues related to the incentives created by retail large load tariffs?

A60. Yes. It is unclear how retail large load tariffs with 10-to-20-year terms that include minimum transmission demand charges interact with RTEP and other transmission cost allocation. It is possible that large load customers that sign contracts, but whose load does not materialize, could pay significant minimum transmission demand costs while not having the expected, or any, load. Because the DFAX is updated annually after a project goes into service, the utility could be collecting transmission-related revenues from these customers but not be allocated associated transmission costs through the DFAX. It is possible that this could lead to an over collection of transmission revenues for the associated utility.[105]

[105] It is important to note that while large load tariffs are being proposed and adopted, most large customers sign confidential energy service agreements. Without these agreements being made public, it may not be possible to answer the question of whether the utility is over collecting transmission costs under these circumstances. Additionally, the timing from when the large load enters the load queue, the load enters RTEP and integrated resource planning load forecasts, and when the energy service agreement is signed is not well aligned. Large loads can be in the queue for several years and then only sign energy service agreements approximately one year prior to energization.

Q61. What are your conclusions related to the perverse incentive created by the DFAX with respect to large loads?

A61. It is critical that FERC sends clear direction to PJM and all ISOs/RTOs in order to prevent proliferating state-level issues related to cost allocation of data center driven transmission projects. Many states have enacted legislation to isolate data centers and other large loads as distinct customer classes, and include provisions related to treatment of transmission upgrade costs driven by this customer class. Utah recently enacted legislation requiring that all incremental transmission upgrade costs get allocated to new large load customers.[106] In Oregon, lawmakers passed legislation creating a new customer class for large loads in order to shield existing ratepayers from increases driven by data center expansion.[107] Efforts to mitigate the harms at the local level will continue in a patchwork fashion, leading to market inefficiencies, because they cannot address the core problem of ensuring rates reflect cost causation when the broad regional allocation represented by the hybrid load ratio-share and DFAX methodology obscures which transmission costs are caused by expected future data center load growth.

E. Maryland ratepayers are paying far more for transmission network upgrade costs than the benefits derived due to forecasted data center growth in other transmission zones.

[106] Utah S.B. 132, 2025.
[107] Oregon HB 3546, 2025.

Q62. Can you describe the costs you've modeled as part of your analysis of PJM's RTEP cost allocation methodology?

A62. Overall, across the three RTEP windows studied, PJM approved more than $22 billion in transmission capital expenditures for baseline projects, overwhelmingly driven by projected data center load growth.[108] We analyzed costs from baseline reliability upgrades projects allocated using either the hybrid load-ratio share and DFAX methodology, or the 100% DFAX methodology, from the 2022 RTEP Window 3, 2024 RTEP Window 1, and 2025 RTEP Window 1 procurement rounds using data provided by PJM.[109] We first filtered the data for PJM transmission zones serving Maryland and then applied adjustment factors to approximate Maryland's contribution to the total zonal peak load.[110] We grouped projects approved between each annual RTEP approval with the next upcoming window. Table 3 shows the total capital cost allocation to Maryland by each RTEP procurement window.

[108] *See supra* note 3.
[109] Data compiled by authors covering the years 2026 through 2036 using PJM's online Transmission Cost Planner tool. *See* https://tcplanner.pjm.com/tcplanner/pages/secure/upgrades-general.jsf, accessed 3/3/2026 (log-in required).
[110] We assumed Maryland's share of total zonal peaks as follows: Alleghany Power Systems (APS) 16%, Pepco, 60%, and DPL 30%. We based this conservatively on data covering the earliest window (2022 RTEP Window 3) using Maryland's share of total zonal peak load as reported by PJM in the state level summary from the 2022 RTEP report. *See* PJM Interconnection, L.L.C., *2022 Regional Transmission Expansion Plan Report* (Mar. 14, 2023), at 137, https://www.pjm.com/-/media/DotCom/library/reports-notices/2022-rtep/2022-rtep-report.pdf. For the total zonal peak load (i.e., the denominator of the ratio), we used 2022 summer peak MW reported data for the indicated transmission zones. *See* PJM Interconnection, L.L.C., *Summer 2022 Weather Normalized RTO Coincident Peaks (MW)*, https://www.pjm.com/-/media/DotCom/planning/res-adeq/load-forecast/summer-2022-peaks-and-5cps.pdf.

Table 3. Total 2036 Maryland capital cost allocations by RTEP procurement window.

Allocation method	2022 W3	2024 W1	2025 W1	Total
DFAX	$448,086,246	$371,142,023	$503,294,856	$1,322,523,125
Load-Ratio Share	$180,233,197	$162,316,607	$336,131,081	$678,680,885
Total	**$628,319,443**	**$533,458,629**	**$839,425,937**	**$2,001,204,009**
Note: Differences in summation are due to rounding.				

We then calculated the cumulative bill impacts for Maryland ratepayers by taking the sum of future annual revenue requirements for these projects provided by PJM. Table 4 shows total Maryland RTEP revenue allocations over the next ten years by RTEP procurement window.

Table 4. 10-Year Maryland cumulative revenue requirement allocations by RTEP procurement window.

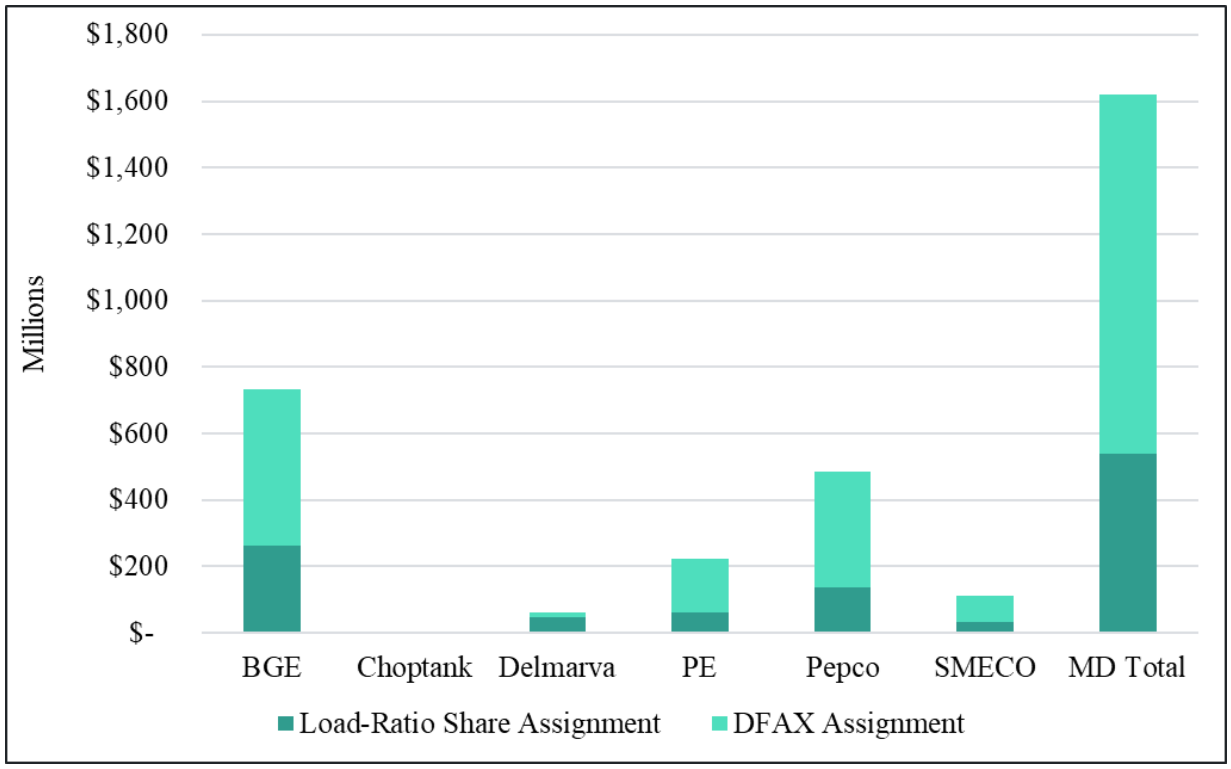
Allocation method	2022 W3	2024 W1	2025 W1	Total
DFAX	$396,776,623	$385,913,686	$298,532,826	$1,081,223,135
Load-Ratio Share	$164,633,409	$163,786,865	$211,833,567	$540,253,842
Total	**$561,410,032**	**$549,700,551**	**$510,366,393**	**$1,621,476,976**
Note: Differences in summation are due to rounding.				

Q63. Have you modeled the current projected bill impacts to Maryland ratepayers resulting from the RTEP cost allocations described above?

A63. Yes. To assign the Maryland zonal cost obligations to individual LSEs, we first compiled customer class transmission rate designs from each LSE's most recent multi-year rate plan (MYRP) or other rate design filing, to calculate overall 2025

LSE transmission cost allocations. Next, we applied those allocations to determine the proportion of each zone's annual RTEP cost obligation allocated to each respective LSE. Figure 5 shows the distribution of the $1.6 billion of total revenue requirements to each Maryland LSE.

Figure 5. 10-Year Maryland cumulative revenue requirement allocations by LSE



Our modeling shows that residential customers will pay an additional $823 million, or $345 per average customer, over this 10-year time period. Commercial customers will pay an additional $146 million, or $673 per average customer. Industrial customers will pay $629 million more for transmission services, or $15,074 per average customer over the same period.[111] Most of these costs are

[111] Additionally, $23 million are allocated to "other" customer classes, bringing the total to $1.621 billion.

passed through to customers of Baltimore Gas & Electric (BGE) and the Potomac Electric Power Company (Pepco), which together pay an additional $1.2 billion over the next 10 years. Due to their proximity to the data center cluster in northern Virginia, Maryland utilities receive significant solution-based DFAX allocations; solution-based DFAX allocated costs make up 67% of the total revenue impacts.

Q64. How concentrated is data center load growth based on PJM's latest load forecast study?

A64. PJM does not publish a separate load forecast specifically for data centers. However, as described above in Section III. A, PJM's load adjustment process is predominantly driven by large load additions and therefore is a good proxy. The top four zones for load adjustments account for 80% of the total load adjustments by 2032, reflecting approximately 38.9 GW of data center demand additions.[112]

Q65. How does the increase in transmission costs allocated to Maryland through the load ratio share and DFAX methods compare with forecasted load growth for Maryland?

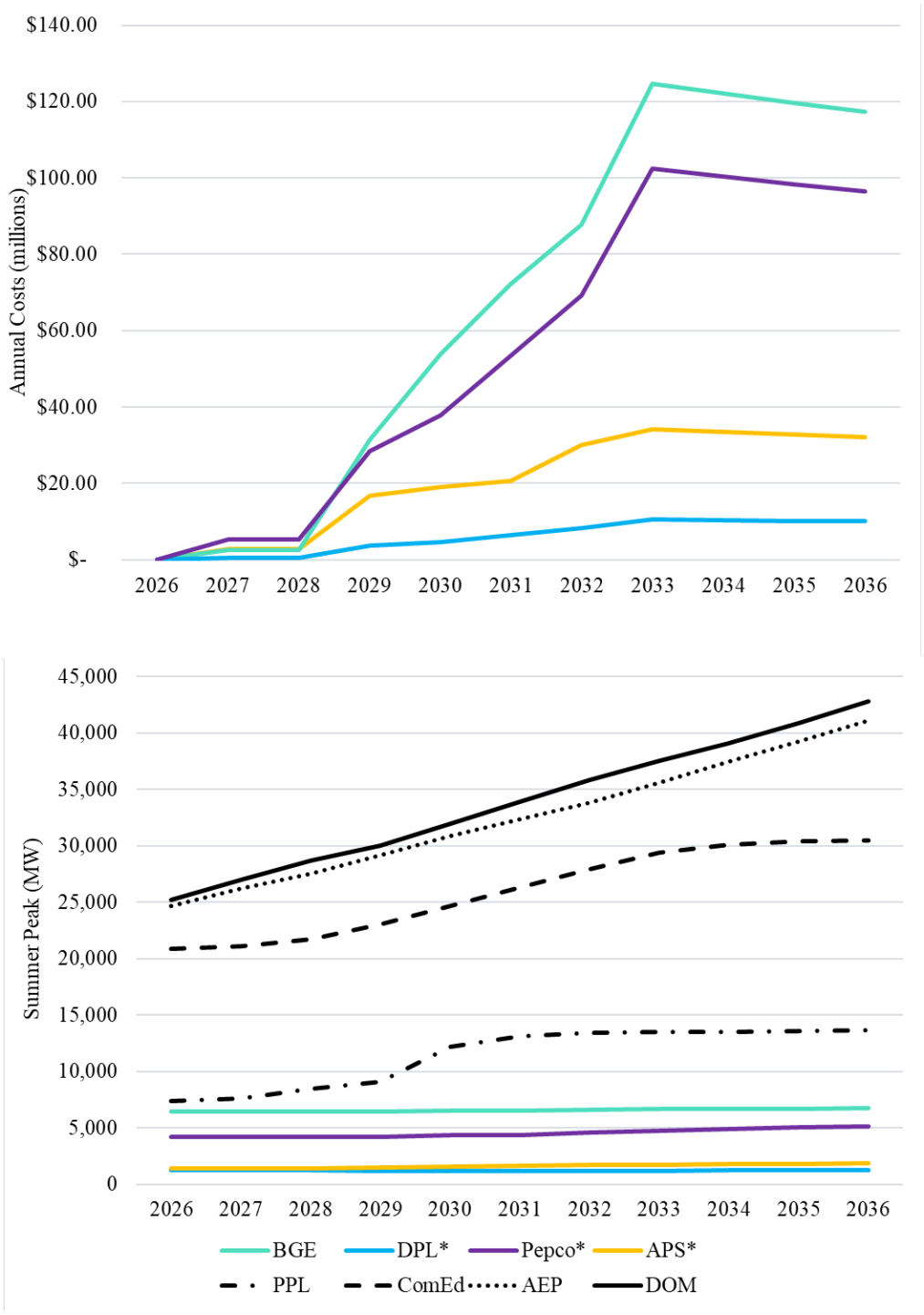
A65. There is a dramatic gap between the costs assigned to Maryland through PJM's current cost allocation methods and the level of load growth occurring in Maryland. The increases in transmission costs allocated to Maryland increase dramatically through 2033, especially for BGE and Pepco, and begin to level out after that. Over that time, there is only a modest rise in load projections for Maryland zones. However, the load projections for Dominion, AEP, ComEd, and

[112] *See supra* note 37.

PPL increase dramatically over the same period, with the cumulative four zones projected to increase their current annual load by 64% by 2036, from 78 GW in 2026 to 128 GW in 2036. Figure 6 shows how the $1.6 billion in cumulative 10-year revenue requirements allocated to Maryland[113] accumulates each year (top half of Figure 6) compared to the respective annual load projections (bottom half of Figure 6). We include the black lines representing the PJM transmission zones with the highest concentrated data center growth to illustrate the disconnect between where this unprecedented growth is occurring versus where costs are being allocated, and therefore underscoring how PJM's cost allocation methodology results in an unjust and unreasonable outcome for Maryland ratepayers.

[113] *See supra* Table 4.

Figure 6. Maryland annual revenue requirements from RTEP baseline reliability upgrades compared to summer peak MW growth forecasts [114]



[114] Load forecast source taken from 2026 PJM Load Forecast Report Tables, Table B1. Zones marked with an asterisk indicate they have been apportioned to reflect the Maryland-specific share based on the ratios described above. *See supra* note 110.

Q66. What are your conclusions regarding data center growth and its impact on Maryland ratepayers due to PJM's current cost allocation methodology?

A66. The substantial amount of data center growth concentrated around northern Virginia under Dominion and APS zones, but also appearing now in a limited few other zones in PJM, is causing continued increases in grid expansion costs that are allocated disproportionately to Maryland customers simply based on their close proximity to Virginia. Even with significant supplemental and "must start" projects to try and meet the growing need that originate in Dominion zone, the issue of local and regional reinforcements and new transmission line buildouts to serve skyrocketing projections of future data center demand is widespread and growing. Our analysis demonstrates that the application of the hybrid DFAX and load-ratio share cost allocation methodology severely impacts Maryland customers, amounting to a subsidy paid by Maryland customers to help fuel data center demand overwhelmingly taking place in Dominion, ComEd, AEP, and PPL Zones.

The issues of cost allocation related to data centers are not limited to PJM's hybrid DFAX and load-ratio share method. An even more systemic problem is the need to shield existing customers from carrying the burden of costs driven by data centers. We discuss this issue in section IV of our testimony.

IV. PJM's cost allocation methodology results in existing customers directly subsidizing the substantial network system upgrades needed to serve data center demand and should be remedied.

Q67. What is the purpose of this section of your testimony?

A67. In this section we outline the mechanisms under which existing customers are subsidizing large data center customers because of the way that PJM has chosen to integrate large loads into its RTEP process and the impact of its cost allocation methodology.

Q68. How are the issues discussed in this section different than the arguments you raised in Section III?

A68. In the previous section, we detailed the flaws within PJM's currently approved OATT methodology for allocating baseline reliability project costs to transmission zones based on the combination of the load-ratio share and solution-based DFAX methods and argued that PJM's existing cost allocation methodology is unjust and unreasonable. In particular we highlighted findings that showed how data center growth was causing disproportionate costs to fall on Maryland ratepayers simply because of their proximity to the growth in Virginia, and that certain costs for non-thermal overload reliability needs (like short circuit replacements to circuit breakers) leads to more than $155 million in costs that are lumped together and inappropriately subjected to the DFAX methodology.[115]

[115] *See* supra, note 86 and related discussion, where we describe PJM's short-circuit screening process and identify $155.82 million for a single project to alleviate VAR issues. We note that this is likely a conservative estimate of the non-flow-based costs included in the RTEP cost assignments using DFAX. This is because the project naming conventions are not consistent and there may be other projects built to address VAR issues.

In this section we expand our critique to cover the more general issue regarding the need to make changes to PJM's cost allocation approach, including changes to the broader RTEP process, to ensure network upgrades triggered by expected future data center demand growth are paid for by those large loads and not socialized across all types of load including residential and other load. We explain that PJM's current cost allocation approach results in a significant subsidy that the Commission should find unjust and unreasonable.

A. PJM's legacy cost allocation methodology is not equipped to handle the dramatic changes stemming from data center growth and results in residential and small commercial customers subsidizing transmission network system upgrades for data centers.

Q69. Should PJM be constrained by previous cost allocation methods if the conditions on the grid have changed substantially?

A69. No. PJM's current cost allocation methodologies that have been applied to the last three RTEP procurement windows reflect previous Commission approvals that were made under wholly different circumstances. Dramatic increases in baseline reliability upgrade needs resulting from data center growth forecasts have forced the issue to the front and must be remedied.

Q70. What was the Commission's decision regarding PJM's request to approve transmission cost allocations from projects resulting from the 2022 RTEP Window 3 solicitation?

A70. The Commission approved the classification of the 2022 RTEP Window 3 transmission projects as "baseline reliability projects" in its final order approving

PJM's OATT update under Docket No. ER24-843-000.[116] In its order, the Commission stated that the Maryland Office of People's Counsel's ("OPC's") protests regarding the cost allocation of these projects should be brought forth under separately filed complaints, since the Commission's scope of review in that matter was the narrow determination of whether PJM followed the provisions of Schedule 12 of the PJM tariff in allocating RTEP transmission costs.[117] As we argue throughout our testimony, historical precedent of relying on continued use of the DFAX method in a new era of unprecedented system transformation stemming from large load growth is no longer just and reasonable.

Q71. Is there precedent to consider revisions to transmission cost allocation rules to reflect changing conditions rather than strict adherence to past precedent?

A71. Yes. Previous court opinions indicate that FERC need not be overly deferential to historical precedent when deciding whether a cost allocation method is just and reasonable if the conditions on the system are substantively different. In its opinion in *ICC v. FERC*, the court's majority stated, that "[t]he eastern utilities that created PJM refer to themselves revealingly as the "classic" PJM utilities, and the fact that these utilities thought it appropriate to share costs in 1967 says nothing about the advantages and disadvantages of such an arrangement in the larger, modern PJM network."[118] Similarly, as we have shown in the discussion

[116] PJM Interconnection, L.L.C., 187 FERC ¶ 61,012, (2024).
[117] *Id.* at PP 28-29.
[118] *Illinois Commerce Comm'n v. FERC*, 576 F.3d 470, 475–76 (7th Cir. 2009).

above, the sudden and dramatic expansion to the overall system caused primarily by data centers is unprecedented, and thus the Commission should not be overly constrained by adherence to previous determinations that it found just and reasonable to allocate costs because those conditions represented a wholly different paradigm of load growth and grid expansion.

Q72. Is PJM taking adequate measures to prevent transmission costs caused by new large load customers being allocated to other ratepayers?

A72. No, PJM is taking insufficient steps to prevent other ratepayers from paying for transmission network upgrade costs caused by new large load customers. Though utilities have recognized the impact new large load customers are having on resource adequacy and have proposed reforms to ensure these customers pay their bills for 10-15 years, PJM has not pushed for similar reforms to prevent transmission costs from being paid for by all customers. State commissions have consistently assigned FERC-approved transmission costs to retail customers without sufficient analysis on cost causation or revisiting traditional cost allocation methods.[119] This analysis needs to be required by FERC to ensure just and reasonable rates. For example, based on a review of the 130 transmission projects in 2024 built to serve large loads (see Figure 4), utilities described just 5% as having no cost impact for other customers. In other words, $4.3 billion in capital

[119] Mike Jacobs, *Connection Costs: Loophole Costs Customers Over $4 Billion to Connect Data Centers to Power Grid* at 3, Union of Concerned Scientists (Sept. 2025), https://www.ucs.org/sites/default/files/2025-09/PJM%20Data%20Center%20Issue%20Brief%20-%20Sep%202025.pdf.

costs for transmission projects needed to serve data center customers were allocated broadly to all customers.[120]

Q73. Explain how existing customers are subsidizing network upgrades that are needed to serve data center demand.

A73. It is important to allocate transmission network upgrade costs to cost causers and beneficiaries of the upgrades. Ultimately, PJM's cost allocation approach is intended to create efficient market outcomes by providing accurate and reasonable price signals by allocating costs roughly commensurate with benefits and reflective of cost causation, which is directly dependent upon the cost allocation approach.

Data centers are rushing to connect to the grid and get sufficient grid power to train valuable AI models, among other uses. This rush has upended the electric industry, causing significant transmission network upgrades, and yet the majority of costs for these new buildouts are being saddled onto existing customers, including residential customers. Existing customers are bearing these costs because PJM's existing RTEP process and associated cost allocation methodology does not distinguish among load types, pooling the revenue requirements for these large transmission build outs to serve data center growth under the category of "RTEP baseline reliability upgrades." Given the magnitude of upgrades needed for data centers, including significant 500+ kV upgrades, these costs must be assigned

[120] *Id*.

to data centers because without doing so, the costs facing existing ratepayers are not roughly commensurate with the benefits derived.

B. The Commission should take immediate action to allocate baseline transmission projects driven by data centers directly to the zones in which they are located served by the relevant wholesale transmission customers that are attempting to serve that load.

Q74. What features must a just and reasonable replacement rate have to overcome the infirmities with using the hybrid load ratio share and DFAX cost allocation methodologies you critiqued in Section III of your testimony?

A74. A just and reasonable replacement rate must ensure that network upgrade costs not needed "but for" large loads such as data centers are paid for by those customers causing the costs to be incurred. The Commission has a simple and immediate remedy to address many of the infirmities in PJM's current transmission cost allocation methodology: The Commission can direct PJM to allocate the costs of regional baseline transmission projects constructed to serve incremental data centers directly to the PJM zone(s) where the existing and forecasted data center load is located. By requiring wholesale transmission customers, at the zonal level, to bear the upfront costs for expanding the grid to serve exponential data center growth, the Commission can remedy in substantial part current shortcomings with how data center upgrade costs are tracked, assigned, and recovered from PJM zones while avoiding jurisdictional challenges.

Q75. Are there instances where state-level retail ratemaking has been frustrated by the fact that transmission upgrade costs driven by data centers are being bundled together with other FERC-approved costs?

A75. Yes. In its most recent rate case, PPL argued that transmission costs were approved by FERC, and therefore the Pennsylvania Commission could not dictate which transmission network upgrade costs were properly assignable to large load customer class. PPL's reasoning for this was that the Pennsylvania Commission only had jurisdiction over retail rates, whereas transmission costs charged to the PPL zone, and recovered from LSE's via the NITS rate, were FERC jurisdictional and therefore not appropriate for debating during the retail ratemaking process.[121] Similar arguments have been made by PG&E.[122]

Q76. Is there precedent for directly charging network upgrade costs to the zones served by transmission customers planning to serve significant data center growth requiring network upgrades?

A76. Yes. The Commission recently approved a tariff change by Southwest Power Pool ("SPP") wherein SPP proposed to temporarily directly assign the costs of network upgrades to the transmission customer seeking to serve large load.[123] Importantly, for the parallels to the points we make in this affidavit, the Commission based its findings, in part, on the recognition that direct assignment of network upgrades to

[121] Pennsylvania PUC Docket No. R-2025-3057164, Nelson Surrebuttal.
[122] Application of Pacific Gas and Electric Company (U 39 E) for Approval of Electric Rule No. 30 for Transmission-Level Retail Electric Service, Cal. Pub. Utils. Comm'n Application No. A.24-11-007 (filed Nov. 21, 2024).
[123] *See Southwest Power Pool, Inc*., 193 FERC ¶ 61,018 at P 46 (2025) ("We further find that SPP's cost allocation proposal is just and reasonable. Under SPP's proposal, the transmission customer, typically the relevant Load Responsible Entity to which the new large load is connecting, will be assigned the full annual revenue requirement (e.g., depreciation, return, and income taxes) of the directly assigned upgrades.") (citations omitted).

the transmission customers that are causing them appropriately reflected the uncertainty posed by these large loads and that SPP's tariff change would prevent improper cost shifting to other customers.[124] In making its determination regarding the SPP proposal, the Commission also distinguished the nature of large load growth from the type of historical load growth associated with network upgrades that have simply been rolled-in to base rates,[125] further justifying the points we present throughout our testimony that unprecedented data center expansions pose a substantial risk that require new approaches to protect existing ratepayers.

Q77. What are your conclusions regarding directly allocating the costs of transmission network upgrades not needed "but for" data center and other large load growth to the zones where that load growth is located?

A77. We conclude that, as an initial remedy to provide immediate relief to Maryland ratepayers in the face of rising costs driven by large load growth occurring outside the state of Maryland, the Commission can use its authority to better map the costs of data center loads causing these network expansions to the data center loads by allocating the full upgrade cost to the zones where these customers are located. This will shield existing customers located in other transmission zones from subsidizing data center expansion occurring outside their boundaries. This method

[124] *Id.* at P 47 ("We find that the direct assignment of these Network Upgrades appropriately reflects the uncertain nature of the load and generation additions contemplated through the Attachment AX study process and will therefore protect other transmission customers by limiting cost shifts, particularly if and when the load addition or associated planned Designated Resource are not constructed.").
[125] *Id.* at P 49 ("We acknowledge that Attachment AX differs from the typical practice of rolling in the cost of transmission upgrades associated with new load…However, given the risk that the requested load addition or planned generation may not materialize, it is reasonable that those transmission customers must agree to accept the obligation to fund Network Upgrade costs for a time until they secure sufficient Designated Resources to serve the requested load addition.").

of allocation would allow state-level large load and other retail tariffs to better and more accurately address the allocation of the transmission costs caused by data centers to end-use customers within the individual state's jurisdiction, having a more transparent picture of the data center caused transmission costs falling on that zone and within the state where the data center load is located. This approach to directly allocating costs to transmission zones would require relatively few changes to existing processes and is well supported by recent Commission precedent, and should therefore be pursued. However, as we discuss in Section IV.C and Section V of our testimony, additional changes will likely be necessary to fully account for the total system impacts, and associated costs, that data centers will have on the grid, particularly if the Commission implements or in parallel with its implementation of the direct assignment of upgrade costs to data center loads consistent with, as discussed further below, the large loads interconnection ANOPR currently pending before the Commission and securing the protections of the Ratepayer Protection Pledge for existing customers.

Q78. What are your recommendations to the Commission?

A78. We recommend that the Commission direct PJM to propose an interim solution to its cost allocation methodology for baseline transmission reliability upgrades that directly allocates the costs of upgrades driven by large load and data center growth to the zones in which transmission customers that are causing them are located by including significant data center growth in their load forecasts provided to PJM. In Section V of our testimony, we further elaborate on changes required to the RTEP

modeling process to ensure sufficient transparency into how data centers are causing system costs and how the overall process needs to be updated to ensure efficient system expansions.

C. Data centers have more in common with merchant generators than with existing customers and the Commission should require PJM, as a longer-term option, to develop cost allocation and interconnection processes that adopt the safeguards included in Order No. 2003 for large generators modified to the specific contexts surrounding large loads.

Q79. What are the differences between data center load and existing customers that require differential treatment?

A79. There are significant differences that set data centers and other large loads apart from existing customers. As an example of the difference, consider that a large data center can represent more load than a mid-size city and can scale up in a matter of years, rather than the decades it would take to develop similar load under more normal growth patterns. These inherent differences justify FERC action to require PJM to update its tariff to include the same type of protections for existing customers that the Commission adopted in Order No. 2003 and has long upheld for interconnecting generators. The parallels with precedent set under Order No. 2003 are even more evident when considering that for data center developers, like merchant generators, speed to grid connection impacts profits.[126]

[126] *See e.g., The cost of compute: A $7 trillion race to scale data centers*, McKinsey Quarterly (April 28, 2025), https://www.mckinsey.com/industries/technology-media-and-telecommunications/our-insights/the-cost-of-compute-a-7-trillion-dollar-race-to-scale-data-centers.

Q80. Can you describe the type of protections FERC created in Order No. 2003 to shield existing customers from subsidizing merchant generators?

A80. Yes, we highlight two key protections that the Commission adopted in Order No. 2003 that can similarly protect non-large load customers from equivalent risks posed by data centers. The first major protection is the ruling that transmission providers can charge interconnecting customers to cover the upfront costs of the network upgrades that would not otherwise be required "but for" their interconnection. Parties to the Order No. 2003 proceeding challenged the Commission's decision, claiming that requiring upfront incremental funding of network upgrades violated the Commission's longstanding prohibition against "and pricing"[127] and raising concerns that only charging for the incremental network upgrades would not cover the full costs of the use of the system.[128]

Q81. How did the Commission respond to the first concern?

A81. Regarding the concern that requiring upfront funding would constitute "and" pricing, the Commission maintained, and the courts later upheld, that assigning upfront costs of network upgrades to interconnecting customers did not violate the Commission's policy prohibiting "and" pricing because of the crediting mechanism that reimburses the interconnecting generator for its upfront financing of the network upgrade costs that it triggered, with interest.[129]

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[127] *Order No. 2003,* 104 FERC ¶ 61,103 at PP 683–692.
[128] *Order No. 2003-B*, 109 FERC ¶ 61,287 at P 48.
[129] *Entergy Servs., Inc. v. FERC*, 319 F.3d 536, 542–43 (D.C. Cir. 2003) (describing and affirming FERC's requirement that Consumers Energy provide transmission credits for certain network upgrades. The court noted that

Q82. How did the Commission respond to the second concern?

A82. The Commission found the second concern regarding potential under recovery of system revenue requirements similarly unconvincing. The Commission reasoned that requiring interconnection customers to provide upfront funding for network upgrades needed solely because of their interconnection did not result in double collection for the same service. This is because upfront funding paired with a crediting mechanism is distinct from a charge for transmission service.[130] The Commission found that requiring interconnecting to fund the upfront costs of Network Upgrades would promote efficient price signals related to siting decisions and reduce speculative interconnection requests.[131]

Q83. Can you elaborate on the second major protection established by the Commission under Order No. 2003?

A83. The second major protection is what is known as the "higher of" policy, in which the Commission provides that the Transmission Provider may charge an interconnecting customer the "higher of the incremental cost of Network Upgrades required to interconnect the Generating Facility or an embedded cost rate for the

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"[t]he Commission ordered Consumers Energy to revise its crediting provisions to allow crediting for network upgrades necessary to remedy short-circuit and stability problems, stating that by requiring credits for these upgrades, 'the Commission was enforcing its prohibition against `and' pricing.'") *Id.* (quoting *Consumers Energy Co.*, 95 FERC ¶ 61,233, at 61,804 (2001)).

[130] *Order No. 2003-A,* 106 FERC ¶ 61,220 at P 612 (2004) (The Commission explained that "…petitioners fail to recognize that the Interconnection Customer's upfront payment, with provisions for the payment of interest, credits and reimbursements, serves not as a rate for interconnection or transmission service, but simply as a financing mechanism that is designed to facilitate the efficient construction of Network Upgrades.").

[131] *Id.* at P 613 ("[T]he purpose of the upfront financial payment is twofold…[S]econd, by placing the Interconnection Customer initially at risk for the full cost of the Network Upgrades, the upfront payment provides the Interconnection Customer with a strong incentive to make efficient siting decisions and, in general, to make good faith requests for Interconnection Service.").

entire Transmission System (including the cost of the Network Upgrades)."[132] The Commission concluded that "this 'higher of' policy ensures that other Transmission Customers, including the Transmission Provider's native load, will not subsidize Network Upgrades required to interconnect merchant generation."[133]

Q84. Would similar protections benefit existing customers if the Commission were to apply them to large loads seeking interconnection to the transmission system?

A84. Yes, the type of protections referenced above and commonly used for shielding existing customers from subsidizing merchant generators are not distinct to generators, and would also yield substantial benefits in terms of reducing or eliminating the subsidy potential of existing customers to data centers and other large loads. The same factors leading to negative market outcomes that the Commission sought to correct by adopting the protections in Order No. 2003 apply equally well, or more, to the case of large loads and data centers. These protections include promoting market efficiency by establishing meaningful price signals that can reduce speculation and interconnection shopping (we discussed phantom large load requests, a result of interconnection queue shopping, in Section III. A above), reducing interconnection process delays due to lack of standardization between jurisdictions, among others. But most important is the need for shielding existing customers from subsidizing new large loads. The

[132] *Order No. 2003-B*, 109 FERC ¶ 61,287 at P 54.
[133] *Id*.

Commission has recognized this principle in connection with large generators and should do the same with respect to large loads.

Q85. Is there broader support for using Order No. 2003 as a framework for establishing ratepayer protections while trying to accelerate connections of large loads?

A85. Yes. The Department of Energy has laid out a rationale for mirroring several of the reforms adopted for large generators under Order No. 2003 within a near-term large load interconnection reform process,[134] including:

- Increasing the cost of entering the queue in an effort to deter speculative load requests (through increased deposits on study costs, increased exit fees, etc.),
- Development of new methods to study load and hybrid load and generation configurations to identify opportunities to reduce system impacts, and
- Requiring large loads to be responsible for 100% of cost of transmission network upgrades to the interconnecting customer, with the possibility for offsetting these costs through crediting mechanisms.[135]

Similarly, four of the world's largest tech companies have recently signed the White House's ratepayer protection pledge, demonstrating broad support for overhauling outdated rules and processes concerning how we pay for grid expansions to accommodate data center power needs.[136] The ratepayer protection

[134] Letter from Chris Wright, Secretary of Energy, to David Rosner, Chairman, Federal Energy Regulatory Commission et al., (Oct. 23, 2025).
[135] *Id.* at 12.
[136] Sonal C. Patel, *"*Hyperscalers Sign White House Pledge to Fund Data Center Power, Grid Upgrades,*"* *POWER Magazine*, March 5, 2026, https://www.powermag.com/hyperscalers-sign-white-house-pledge-to-fund-data-center-power-grid-upgrades/.

pledge provides that, "[C]ompanies will pay for all new power delivery infrastructure upgrades required to service their data centers, including adequate network upgrade costs to ensure that these expenses are not passed on to the ordinary household."[137]

Q86. Have any parties raised concerns about the Department of Energy's recommendation to consider cost allocation approaches requiring large load customers to be responsible for 100% of the network upgrade costs using Order No. 2003 as a precedent?

A86. Yes. Exelon submitted comment in Docket No. RM26-4-000 cautioning against relying on the precedent of assigning upfront network upgrades to generators when considering policy changes for large load interconnections because "doing so opens the door to [large loads] avoiding any responsibility for the entire rest of the transmission system, considering the Commission's prohibition on 'and' pricing."[138] Exelon further states its concern is that "if new large loads are made to be responsible for the costs of upgrades as a requirement to interconnect, pursuant to the Commission's prohibition on 'and' pricing and concerns over undue discrimination, those same loads will undoubtedly maintain that they are not required to pay separately for transmission service (i.e., for network integration transmission service, the 'NITS' rate)."[139] The concerns about violating the Commission's prohibition against "and" pricing are also repeated in supplemental

[137] The White House, "Ratepayer Protection Pledge," March 4, 2026, https://www.whitehouse.gov/releases/2026/03/ratepayer-protection-pledge/.
[138] Comments of Exelon Corporation, Docket No. RM26-4-000, *Interconnection of Large Loads to the Interstate Transmission System* (Nov. 21, 2025), at 7.
[139] *Id.* (additional citations omitted).

comments to Docket No. RM26-4-000, referring to a whitepaper prepared for Exelon by Concentric Energy Advisors.[140]

Q87. Do you agree with Exelon's concern?

A87. No. As we described above, the Commission has previously rejected the notion that its pricing policy for generator interconnection would violate its prohibition against "and" pricing and the courts have upheld the Commission's decision.[141] The Commission has also confirmed that existing load customers are protected because a transmission provider can elect to charge the "higher of" the incremental cost of upgrades, or the embedded cost rate for the whole transmission system, including the cost of the upgrades.[142]

Q88. Are there other aspects of Exelon's comments in Docket No. RM26-4-000 that are relevant to the issues presented here?

A88. Yes, Exelon claims that adopting a policy requiring large loads to bear responsibility for 100% of required network upgrades, as the Department of Energy letter suggests and as we argue here, would lead to a situation wherein, "if [large loads] are only required to pay for incremental investment, they avoid paying for the broader system and that benefit is lost. The more large loads are

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[140] Concentric Energy Advisors, *The Risks of Cost Shifts in Serving Large Loads Under a Framework with Direct Allocation of Transmission Costs*, at 1 (Mar. 30, 2026), attached as Appendix to Supplemental Comments of WIRES, Docket No. RM26-4-000 ('Concentric whitepaper') ("A prohibition on 'and' pricing might allow the same large load customers, having paid for their network upgrades, to argue that they should be exempt from the rates that fund the ongoing development, maintenance, and operation of the broader transmission system, called Network Integration Transmission Service ("NITS") charges. This could result in cost shifts between large load customers and other customers.").

[141] *See supra* note 124 and related discussion.

[142] *See supra* note 127 and related discussion.

carved out to pay separately for certain transmission infrastructure, the less they will pay for the overall grid and the more other customers will pay."[143] Here, again, the concerns Exelon raises are misplaced in that they constrain the choice to an "either-or", wherein a large load would pay the incremental cost of network upgrades or be charged the embedded cost rate.

Q89. Explain how concerns that data center and large load customers may avoid paying future ongoing use of system charges are misplaced.

A89. The Commission recognized the possibility that revenues paid by interconnecting customers could reduce overall systemwide rates when implementing Order No. 2003 and explicitly highlighted that the transmission provider had the flexibility to choose whichever rate would be most beneficial to customers.[144] More importantly, the Commission found that selecting the average embedded rate if it lowers costs to customers is "…dependent upon an appropriate mechanism for returning any money contributed by the Interconnection Customer related to the initial financing of the necessary upgrades."[145] The simple fact that future revenues collected from data centers and other large load customers through the

[143] *Id.* at 9.
[144] *Order No. 2003-A,* 106 FERC ¶ 61,220 at PP 580-581 (2004) (The Commission clarified that "under our interconnection pricing policy, the Transmission Provider continues to have the option to charge a transmission rate that is the higher of the incremental cost rate for network upgrades required to interconnect its generating facility or an embedded cost rate for the entire transmission system (including the cost of the Network Upgrades)…" and went on to explain, "In other words, in most instances, the additional usage of the transmission system by a new Interconnection Customer will generally cause the average embedded cost transmission rate to decline for all remaining customers. Accordingly, we would expect that the Transmission Provider would want to roll-in the costs of any Network Upgrades necessary to interconnect the new generator to enable its existing transmission customers to benefit from this overall lower average embedded cost rate.").
[145] *Id*. at P 581.

rolled-in embedded cost rate (i.e., the NITS charge) *could* yield benefits to all existing customers, it does not follow that this is incompatible with the protections outlined in Order No. 2003.

Indeed, the Commission's articulation of the "higher of" policy, combined with the provisions for funding upfront network upgrades with appropriately designed crediting mechanisms, ensures that upfront siting risks would be appropriately born by interconnecting data centers, and customers could still benefit through reduced overall rates if those data center loads materialize to anticipated levels. This is because, as the Commission has clearly articulated, the provision of upfront funding for incremental network upgrades not required "but for" the interconnecting customer's request simply acts as a financing vehicle, and is meant to appropriately allocate siting risk to the merchant generator in order to protect existing customers from speculative activity.[146] It does not mean that an interconnecting customer does not also pay an embedded cost rate for ongoing use of the system.

Therefore, Exelon's concerns regarding the inability to recover sufficient use of system charges are unfounded. Similarly, the conclusions of the Concentric whitepaper of a supposed potential cost shift to existing customers, should the Commission decide to adopt a policy assigning responsibility of network upgrades to data centers, completely ignores the scenario that would require large load

[146] *See supra* notes 125 through 127.

customers to fund 100% of upfront network upgrade costs, receive credits with interest in proportion to their use of the transmission system, and pay an ongoing use of system charge such as the NITS rate.[147] Not only does the whitepaper fail to quantify the expected benefits of an upfront funding mechanism with an appropriate crediting policy, such as is outlined by the Commission under Order No. 2003, it also erroneously claims that such a mechanism would fail to achieve any intended policy-driven objectives, and would simply amount to a more administratively burdensome way to approximate the same outcomes as under a "status quo" approach where transmission owners fund network upgrades and recover costs through the NITS rate.[148] This disregards the Commission's policy that by requiring interconnecting generators to provide upfront financing, it is effectively enforcing efficient price signals and encouraging good faith interconnection requests. PJM itself, in defending the appropriateness of its "but for" pricing under its generator interconnection transmission pricing policy, highlighted the benefit of promoting efficient siting decisions as showing its compliance with Order No. 2003.[149]

[147] Concentric whitepaper at 17-18 ("In estimating large load contributions to network upgrade costs, the analysis assumes that large loads pay the full network upgrade costs and do not receive any refunds of, or credit for, those payments in the future regardless of the rate design.").
[148] *Id.*
[149] Answer of PJM Interconnection, L.L.C. to Comments and Protests, Docket No. ER04-457-000 (FERC filed Feb. 25, 2004), at 5.

Q90. Explain how the LGIA crediting policy works with respect to reimbursing interconnection customers for upfront financing of network upgrades.

A90. If an interconnection customer provides upfront funding for network upgrades, they are entitled to transmission reimbursement credits, on a dollar-for-dollar basis, up to the total amount paid to the transmission provider for the cost of the network upgrades, plus any tax gross-ups or other tax-related payments.[150] The credit amount is calculated with interest dating from the date of the payment from the interconnection customer through the date of the reimbursement payment.[151] Finally, the credit is to be paid for the non-usage sensitive portion of the interconnection customer's transmission charges, as those payments are made under the transmission provider's tariff for transmission services, with full reimbursement not extending past a period of 20 years.[152]

Q91. Under PJM's existing LGIA, do generators pay for transmission service under the NITS rate?

A91. Not typically. Interconnecting generators pay for network upgrades not needed "but for" their interconnection, and then will typically pay for either Energy Resource Integration Service or Network Resource Integration Service. Therefore, they are not typically assigned the NITS rate, which is charged to network customers in most instances. However, if a generator does connect to the transmission system and obtain point-to-point transmission service, such as for

[150] Federal Energy Regulatory Commission, *Pro Forma Large Generator Interconnection Agreement*, art. 11.4.1. (updated Aug. 20, 2024), https://www.ferc.gov/media/pro-forma-lgia.
[151] *Id.*
[152] *Id.*

sales to a distant customer, then it would pay directly for transmission service, albeit under point-to-point service and not under NITS.

Q92. If interconnecting generators currently do not pay the NITS rate, does that invalidate your claim that protections provided by Order No. 2003 are equally applicable to large loads in terms of preventing under recovery of the revenue requirement?

A92. No. While it is true that under PJM's current transmission pricing and interconnection rules, interconnecting generators do not pay both the cost of upfront network upgrades and for ongoing transmission service through the NITS rate, that fact does not mean that the Commission cannot require data center customers to pay for upfront network upgrades *and* pay a separate charge for ongoing use of the transmission system, without violating the "and" pricing principle. In fact, the Commission explained just such a situation in response to a petitioner request for clarification regarding how the new crediting policy established under Order No. 2003 would apply in situations where interconnecting generators do not pay directly for transmission services.[153] The Commission held that, "the [interconnecting customer] is entitled to full reimbursement for its upfront payment and the period for reimbursement may not be longer than the period *that would be required if the [interconnecting customer] paid for*

[153] *Order No. 2003-B*, 109 FERC ¶ 61,287 at P 21 ("Calpine points out that there are also Transmission Systems where the Interconnection Customer does not directly pay for transmission service. As a result, the Interconnection Customer does not receive a bill for transmission services to which credits can be applied. This is the situation, for example, in the California ISO, where load pays for transmission service. However, under Order No. 2003-A, the dollar-for-dollar offset against transmission service payments is the only way explicitly provided to receive transmission credits, and this might allow someone to argue that credits need not be paid in areas such as California.").

transmission service directly and received credits on a dollar-for-dollar basis, or 20 years, whichever is less."[154] Therefore, the concerns posed by Exelon and the Concentric whitepaper are not well founded because they assume the Commission would not use the tools at its disposal to enforce full revenue collection for ongoing use of the transmission system for data center customers. The Commission's policy allowing transmission providers to charge for upfront network upgrade costs not required "but for" their interconnection, and collect ongoing embedded use of system charges, was explicitly considered and reinforced, and importantly, the Commission showed clear judgment in stating that such a pricing policy does not violate the "and" pricing prohibition even if the ongoing embedded use of system charges are not paid by the interconnecting generator, but by a transmission network customer paying the NITS rate.[155]

Since large loads, like all load, benefit from the existence of the legacy transmission network, they should rightly be charged for the embedded costs of paying for their share of the use of the legacy system. Any upgrades, including

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[154] *Order No. 2003-B*, 109 FERC ¶ 61,287 at P 36 (emphasis added) ("Finally, the change addresses Calpine's concern that, in the absence of a date certain for repayment of Network Upgrade costs, a Transmission Provider could conclude that credits need not be repaid in areas where the Interconnection Customer does not pay directly for transmission service. We further clarify that the Interconnection Customer is entitled to the full reimbursement for its upfront payment and the period for reimbursement may not be longer than the period that would be required if the Interconnection Customer paid for transmission service directly and received credits on a dollar-for-dollar basis, or 20 years, whichever is less.").

[155] *Standardization of Generator Interconnection Agreements & Procedures*, Order No. 2003, III FERC Stats. & Regs. ¶ 31,146, at P 700 (2003). ("Moreover, the Commission concludes that, even if the Interconnection Customer (or its power sales customer) is also required to pay an embedded cost-based charge for transmission service, this is not "and" pricing.") (By recognizing that the policy applies equally to the interconnecting generator or its power sales customer (i.e., a network transmission customer paying NITS), the Commission has explicitly stated that its policy is not dependent on the specific arrangements of *who* pays for the ongoing embedded system costs, and that in any instance, these separate charges do not violate the "and" pricing principle because they are separate charges for separate services.

network upgrades, that are needed to accommodate load interconnection requests that exceed existing capacity, should be charged to those customers that cause them. Similar to the separate charges approved by FERC in *Northwestern* for different transmission services, large loads should both remain responsible at embedded rates for their use of the legacy grid and, subject to the "higher of" policy, be responsible for the incremental costs of grid expansion caused by the large load.[156]

Q93. Are crediting mechanisms used at the retail level to finance distribution system upgrades?

A93. Yes. Several utilities have crediting mechanisms within their line extension tariffs.[157]

Q94. How do crediting mechanisms for distribution line extensions work?

A94. While each utilities line extension terms vary, some line extensions require load customers to pay a refundable advance when a customer triggers a distribution system upgrade. The advance is then credited back as a function of the actual revenue paid through the customers full embedded rate over a specified period. If the advance is not fully credited back over the specified period, the remaining

[156] *Northwestern Corp.*, 147 FERC ¶ 61,171 at P 53 (2014).
[157] See https://www.pge.com/tariffs/assets/pdf/tariffbook/ELEC_RULES_15.pdf. See Also https://www.nvenergy.com/publish/content/dam/nvenergy/brochures_arch/about-nvenergy/rates-regulatory/electric-rules-south/Rule_9_South.pdf. See Also https://nj.pseg.com/-/media/pseg/public-site/documents/current-electric-tariff/electric-tariff-17-egccd-effective-20250701.ashx.

advance balance is forfeited as a cost in aid of construction and applied to reduce rate base.

Q95. Could a crediting mechanism similar to the distribution line extension example above be used for network transmission upgrades?

A95. Yes. While the distribution line extension concept would require adaptation to the material differences present for transmission network upgrades, it is a conceptual starting point for a crediting mechanism that is reasonable. Requiring an upfront advance payment for a portion, or all, of the transmission network upgrades caused by data center customers could be paid upfront by those same customers. The advance could then be credited back through credits over a 10 to 20 year period with any remaining advance contributed to the cost in aid of construction. As on the distribution system, this model would insulate other ratepayers from stranded assets by ensuring that load materializes and contributes to embedded system costs. Additionally, this approach mitigates near term rate pressure for other ratepayers because rate base grows more slowly as the credits are refunded.

Q96. Explain your earlier statement that the five recent TSAs signed by Exelon and approved by the Commission do not furnish adequate ratepayer protections.

A96. In its comments under Docket No. RM26-4-000, Exelon states that "the TSA approach not only recognizes that all load, including large load, benefits from investments in the transmission network, but it also *provides valuable early certainty* to large loads regarding their expected transmission costs, which may be

critical as they are making complex and cost-sensitive development decisions."[158] Exelon's TSA approach seems to give a number of valuable concessions to large loads while shifting substantial cost and risk onto general ratepayers. Two main issues illustrate why the TSA example as advanced by Exelon does not establish sufficient protection for existing customers. First, the only upfront cost responsibility for large load customers seeking to sign a similar TSA are for the construction of "customer facilities", including one substation in the case of PECO and Amazon, whereas costs for "transmission facilities" (not defined) are the utility's responsibility and will be recovered through formula rates to the extent possible.[159] As we have noted, the precedent of Order No. 2003 standard interconnection rules would allocate both the costs of the interconnection facilities and the upfront costs of the network upgrades that would not be required "but for" the interconnection. This would result in significantly more near-term costs being assigned to large load customers, compared to the terms under the TSA required by PECO.

Second, the minimum charges provision in the TSA meant to protect ratepayers against stranded asset risk should a large load customer fail to meet their projected load ramp is capped at 80% and pegged to the transmission rate in place as of the effective date of the TSA "regardless of whether such Utility's

[158] Comments of Exelon Corporation, Docket No. RM26-4-000, *Interconnection of Large Loads to the Interstate Transmission System* (Nov. 21, 2025), at 6. (emphasis added.)
[159] *PECO Energy Co.*, Schedule No. 138, Transmission Security Agreement between PECO Energy Company and Amazon Data Services, Inc., Docket No. ER25-3492-000, at 3 (filed Sept. 23, 2025).

Network Zonal Service Rate may be greater in the calendar year in which the Customer Shortfall Event occurs."[160] By fixing the committed revenue contribution to the transmission rate in place as of the effective date of the TSA, large load customers avoid additional risk of future transmission cost increases that are instead passed on to other customers. Additionally, even if the large load customer ramps to above 80% of its projected loading levels there still remains a 20% gap, which for larger data centers can reach hundreds of MWs that are not subject to the guarantee. Therefore, the type of protections to native load customers demonstrated by Exelon's TSA examples are inferior to the type of remedies and relief to shield existing ratepayers from subsidizing large load customers that we present here.

Q97. What are your conclusions regarding the example of Order No. 2003 precedent as it applies to addressing the issues raised in your testimony?

A97. We conclude that the precedent set by Order No. 2003 is directly relevant to the circumstances surrounding data center interconnection and the issue of allocating costs of network upgrades to protect existing customers. The policies outlined in Order No. 2003, if applied to data centers, would ensure risks associated with potential network upgrades needed to interconnect prospective data center and other large load customers are appropriately allocated to those same commercial

[160] *Id.* at 8-9. The minimum revenue guarantee in the TSA is calculated as the difference between the actual revenues collected in a given month and "80% of the sum that would be paid by a Load Serving Entity…" However, this protection is subject to what PECO calls a "Customer Shortfall Event Liability Cap" which further specifies the large load customer's payment obligation is limited to the 80% monthly load ramp amounts multiplied by the network zonal service rate in place as of the effective date of the TSA.

actors that stand to benefit from their future use of the system. For example, the Commission found it appropriate to tie the crediting back policy to the interconnecting generators' actual future use of the transmission system, as a means of accounting for the potential burden placed on existing transmission customers should the generator not use the system as much as projected, or cease operation early.[161] We have shown how cautions against using Order No. 2003 as precedent, such as those brought forth by Exelon and others, are unconvincing and do not accurately reflect the Commission's policies, reinforced by the courts, regarding incremental upfront funding of network upgrades and associated crediting mechanisms. We have shown that concerns that large loads may not be responsible for paying ongoing use of system charges through the NITS rate if they are required to finance upfront incremental network upgrades are misplaced and not reflective of long held Commission policy and court precedent. Parties suggesting this risk are merely pointing to this potential negative outcome without any substantiation, while ignoring the very real risks posed by these large loads should they fail to materialize. Requiring large loads to fund 100% of upfront incremental network upgrades, coupled with an appropriate crediting mechanism, would be in alignment with past Commission precedent and would also ensure customer protections through the application of the "higher of" policy. Such upfront payment and crediting policies for interconnecting load customers are

[161] *Order No. 2003-A,* 106 FERC ¶ 61,220 at P 615 (2004).

common among distribution utilities and could be adapted by PJM for use in the case of data centers connecting to the transmission system.

Q98. What do you recommend to address the issues of cross-subsidization resulting from PJM's current planning and cost allocation mechanism to pay for large load interconnection?

A98. As we have demonstrated, large load connections have far-reaching impacts on transmission planning and operations, and therefore the costs allocated to all customers. For this reason, the Commission should establish clear and consistent standards which can uniformly address the transmission network upgrade cost allocation and crediting policies that we have described above. Specifically, and building off of the interim solution proposed in Subsection IV.B, and with regard to these broader processes and practices, we recommend that the Commission reject PJM's current approach of allocating RTEP baseline reliability costs using the hybrid load-ratio share and DFAX allocation mechanism because it improperly subsidizes speculative and merchant-like activity from data center customers and their developers. In addition, we recommend that the Commission direct PJM to conduct the following activities meant to capture the full system impact of large load interconnections and protect existing customers:

- In the longer term and dependent on the Commission's progress in implementing the ANOPR under consideration in RM26-4, propose a large load interconnection standard that adopts the cost allocation principles and customer protections embodied in the LGIA process approved under Order No. 2003, reflecting appropriate modifications to apply those policies to the

specific circumstances surrounding large loads instead of generators. These protections should:

- Ensure that interconnecting large load customers are required to fund 100% of the upfront costs of network upgrades that would not be required "but for" the large load(s), with appropriate crediting mechanisms in place to avoid violating the Commission's prohibition on "and" pricing; and
- Reaffirm the option for PJM to charge a rate to large load interconnecting customers that is the "higher of" an incremental rate covering the cost of upgrades or the rolled-in rate (i.e., the embedded system cost inclusive of incremental upgrades).

V. PJM's planning process must adapt more quickly to capture the full range of system impacts posed by large loads and the substantial reliability needs they have already caused.

Q99. What is the purpose of this section of your testimony?

A99. In this section we highlight areas of PJM's planning processes that must be changed to ensure that the changes we have recommended above can have their intended effects. We first discuss the Commission's recent order in the co-located docket and its relevancy to large load transmission planning generally, and then we discuss changes to the RTEP modeling process that could address the issues raised in section III of our testimony.

Q100. What did the Commission find with respect to PJM's tariff in the co-located order?

A100. The Commission found PJM's tariff unjust and unreasonable for three primary reasons:[162]

- The lack of clarity regarding the PJM tariff's rates, terms, and conditions relating to interconnecting customers serving co-located load.
- The tariff does not reflect transmission services for co-located Eligible Customers that are "willing and able" to limit their energy withdrawals from the transmission system under certain conditions.
- The tariff does not address co-located loads' use of the transmission system for ancillary services, including regulation and black start services. The Commission found that because of this, large co-located loads may benefit from the services provided from the transmission grid without contributing to cost recovery and thereby risk pushing all of those costs onto other customers, including residential customers.

Q101. What did the Commission direct PJM to do as a remedy in that case?

A101. To remedy the reasons why the Commission found PJM's tariff unjust and unreasonable, the Commission directed PJM, among other things, to "establish three new transmission services." The services must "reflect that Eligible Customers taking service on behalf of Co-Located Load are willing and able to

[162] PJM Interconnection, L.L.C., 193 FERC ¶ 61,217, at P 159 (2025).

limit their energy withdrawals from the transmission system under certain conditions."[163] In describing its reasoning for this, the Commission found that "[t]hese new transmission service options reflect a Co-Located Load's ability to limit withdrawals from the transmission system and *potentially avoid costly and inefficient transmission system buildout that may not be necessary*."[164]

Q102. Can you explain how the reasoning applied by the Commission in the context of the co-located order also reinforces the need to change how PJM is planning for new large load whether co-located or not?

A102. The Commission's findings described above are relevant to all large loads and data centers seeking interconnection to the transmission grid, whether or not they are situated in a co-located arrangement. There are two main reasons that the Commission's findings are relevant:

- First, as we described above when discussing the NERC incident review of the 1,500 MW of data center load that suddenly tripped offline and switched to backup power, most, if not all, modern data centers have substantial on-site backup power capabilities today and can effectively operate as a co-located load would behave (from the perspective of the grid) even under the current interconnection tariff rules. Therefore, the

[163] *Id.* at P 160.
[164] *Id.* (emphasis added).

Commission finding related to the need to better understand the ancillary service needs of co-located loads also applies to all data centers.[165]

- Second, data center customers that entered the load forecast pipeline by submitting individual interconnection requests to LSEs within the different transmission zones throughout PJM may opt to switch to a co-located arrangement at a later date. In this scenario, the grid would be expanded significantly based on the assumption that the load would materialize and stay on the system, but in reality significant portions of that load may prefer to take service under a co-location arrangement. If a data center(s) is in the planning process as firm capacity, and then opts to switch to non-firm capacity once the pending PJM Tariff update is complete, the transmission system will have been expanded at a great cost when lower cost alternatives could have prevailed. This is precisely the type of outcome that the Commission addresses as an example of the reason for requiring PJM to update its tariff, to enable those future cost savings. However, as our testimony makes clear, there is still the need to carry this logic all the way forward to the regional transmission planning process and associated cost allocation methodologies. Otherwise, existing customers will be at significant risk of unjust and unreasonable cost burdens.

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[165] In addition to large loads tripping unexpectedly offline to protect sensitive equipment, as described in the NERC incident review, large loads can also increase forecast error due to their ability to ramp up or down in response to market or price signals. *See* ERCOT Staff, *Ancillary Services and Large Loads in ERCOT*, Large Load Integration Presentation, at 5-7 (May 6, 2024), https://www.ercot.com/files/docs/2024/05/05/Large%20Loads%20and%20Ancillary%20Services.pdf.

Q103. What do you recommend?

A103. As discussed in section IV.B in our testimony, large loads are substantially more similar to generators in terms of potential impacts on the system than traditional load types. Therefore, we recommend that the Commission require PJM to:

- Update its RTEP process to remove data center and other large loads similarly situated completely from the load projections feeding into RTEP reliability modeling and planning workstreams.
- Develop an alternative planning process that provides the information necessary to identify and track network upgrade costs triggered by interconnection of a single large load customer (or group of customers, if under a group study process). This could be done, for example, by requiring system modeling to occur with and without the addition of the large load(s) and quantifying the resultant differences in system reliability needs and associated costs.
- Develop new reliability standards or modeling approaches applicable to studying additional potential system impacts driven by large loads, such as studying N-1 contingencies for loss of a large load in addition to the loss of the largest generator or transmission line only. Studying contingency scenarios that model sudden loss of large loads is important to better understand the impact large loads have on reserve requirements and operational reliability that are not captured under the current RTEP study process.

- Integrate operational assumptions about large loads capable of reducing their grid energy demand based on certain conditions, consistent with the Commission's decision in the co-located order, into the study process for assessing system impacts of new large load requests. Doing so will limit the amount of unnecessary and costly transmission network upgrades required to serve large load customers.

VI. Conclusion.

Q104. Does this conclude your testimony?

A104. Yes.

Ron Nelson

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Education

MS, Agricultural and Resource Economics
Colorado State University, 2013

BA, Environmental Economics
Western Washington University, 2006

Work Experience

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

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

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

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

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

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

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

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

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Select Publications

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

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

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

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

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

Select Projects

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

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

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

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

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

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

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

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

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

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

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

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

Expert Testimony

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

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

CURRENT ENERGY GROUP

Large Load Tariffs, Flexible Connection, and Cost Allocation

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

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

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

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

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

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

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

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

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Direct

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

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

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

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

81. Petition of NSTAR Electric Company d/b/a Eversource Energy for Approval to Offer Optional Electric Vehicle Time-of-Use Rates. Petition of Massachusetts Electric Company and Nantucket Electric Company each d/b/a National Grid for Approval to offer Optional Electric Vehicle Time-of-Use Rates. On Behalf of the Massachusetts AGO (with Andy Eiden).
EV TOU Rate Design, Submetering
Direct

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

56. Application of Public Service Company of Oklahoma, an Oklahoma Corporation, for an Adjustment in its Rates and Charges and the Electric Service Rules, Regulations, and Conditions of

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Service for Electric Service in the State of Oklahoma and to Approve a Formula Based Rate Proposal . On Behalf of AARP
Cost of Service and Rate Design
Responsive Testimony

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

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

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

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

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

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

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

CURRENT ENERGY GROUP

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

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

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

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

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

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

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

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

Direct | Rebuttal

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

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

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

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

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

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

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

CURRENT ENERGY GROUP

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

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

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

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

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

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

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

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

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Prefiled Direct Testimony

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

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

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

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

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

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

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

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

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

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

Direct | Supplemental | Case link

15. Commonwealth Edison (DKT: 18-0753) On Behalf of the IL AG
Distributed Generation Rebates and Smart Inverter Specifications
Direct | Rebuttal | Case link

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

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

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

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

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

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

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

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

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

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

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Direct | Rebuttal | Surrebuttal | Case link

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

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

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

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

Andy Eiden

Senior Manager, (971) 244-2063, aeiden@currentenergy.group

Education

Bachelor of Science, *magna cum laude,* Economics and Environmental Studies
Portland State University – Portland, OR (2011)

Master's Certificate in Energy Policy and Management
Portland State University – Portland, OR (expected 2026)

Work Experience

Senior Manager, Current Energy Group (January 2025 – Present)

- Subject matter expert in Distribution System Planning (DSP), electrification and DER forecasting, DSM potential studies, DER integration, advanced rate design, large load planning and interconnection issues, cost-effectiveness modeling, and locational value frameworks.
- Designing strategies to advance integrated transmission and distribution planning processes and practices, DER adoption, and other decarbonization strategies before state public utility commissions.

Senior Principal Planning & Strategy Analyst, Portland General Electric (2023-2024)
Principal Planning & Strategy Analyst (2022-2023)
Senior Planning & Strategy Analyst (2020-2022)
Planning & Strategy Analyst (2019-2020)

- Led company-wide DER forecasting efforts to support DSP, IRP, finance, programs, and transmission planning. Responsible for all aspects of analysis and final reports.
- Represented PGE in regulatory proceedings, including DSP and transportation electrification dockets and related technical working groups.
- Designed Python-based DER forecasting tools for circuit-level DER adoption modeling.
- Led team of analysts to deliver sound planning studies to internal clients.
- Managed multiple R&D partnerships with government, industry, and academia.
- Led valuation efforts and non-wire alternative evaluations for grid optimization.

Planning Project Manager, Energy Trust of Oregon (2015-2019)

- Managed electric avoided-cost dockets and targeted non-wire alternative pilots.
- Oversaw cost-effectiveness reporting for a $200M energy efficiency portfolio.
- Maintained TRM database and managed solar and multifamily program evaluations.

Research Analyst, The Cadmus Group (2012-2013)

- Conducted process and impact evaluations for utility clients across the U.S.
- Developed survey instruments to evaluate utility efficiency program offerings
- Delivered actionable recommendations through data-driven insights for client projects.

Publications

Levin et al., Capturing the distribution of costs and benefits in electricity system planning and operations, Joule (2026)

Co-authored peer-reviewed journal article describing the need to incorporate distributional effects and more granular information on customers in utility system planning. The paper presents barriers and opportunities for incorporating better information in utility modeling to inform future regulatory actions around issues such as affordability, energy equity, and locational benefits.
Journal article

"Distribution Capacity Expansion: Current Practice, Opportunities, and Decision Support" (2022)

Co-authored a whitepaper looking at the future evolution of Distribution Planning to evolve toward a more holistic approach encompassing scenario planning, DER penetration, and economic optimization. Worked closely with lead authors to validate existing utility planning practices and identify areas for improvement.
Whitepaper

"KPF-AE-LSTM: A Deep Probabilistic Model for Net-Load Forecasting in High Solar Scenarios" (np., March 2022)

Co-authored a paper on net-load forecasting at the distribution level of aggregation that identified statistically-determined upper- and lower-error bounds for PV production while considering typical end use load patterns. Also presented on the paper topic at 2022 IEEE IGST conference in New Orleans regarding utility load forecasting from a system operations perspective.
Article

Industry Technical Advisory Committees

ESIG Large Load Taskforce Member (2025-present)

Contributor to broad industry effort to understand necessary power system changes stemming from the integration of large loads, especially data centers. Participate in working sessions to gather industry feedback on emerging issues and solutions to large load integration.

ESIG DER and Electrification Impacts Task Force Member (2023-2024)

Invited to serve as Task Force member for Energy Systems Integration Group (ESIG) distribution impacts working group. Primary focus was identifying best practices in utility system planning and necessary regulatory evolution related to EV and DER growth.

NEEA End Use Load Research Steering Committee (2021-2024)

Represented PGE in regional end-use metering study to update end use load profiles. Oversaw overall study objectives to ensure desired outcomes for regional utilities, guided workgroup with feedback about relevant research and analysis, and participated in quarterly meetings.

NREL Technical Advisory Group, Grid-Scale Metrics for GEBs (2022-2023)

Provided technical assistance to the NREL NOVA team related to development of metrics for assessing value of grid-interactive efficient buildings (GEBs) as part of DOE grant work. Participated in TAG meetings to review NREL staff concepts about possible metrics and advised on industry feasibility and usefulness. Reviewed draft study materials about TOU rate designs related to solar and storage, as well as provided data and input for a case study of buildings in the Pacific Northwest.

Industry Presentations

"Planning EV Impacts on the Grid" Presentation at ESIG Spring Technical Workshop (2023)

Presented on utility planning practices to accommodate EV load growth on the grid to conference of international attendees.

EV Load Forecasting and Planning, Western Energy Institute Fall conference (2022)

Gave presentation related to utility practices for forecasting EV load and integration of EV load forecasts with planning studies, with a particular focus on secondary distribution networks and common infrastructure sizing practices.

Expert Testimony

1. Application of Arizona Public Service Company for a hearing to determine the fair value of the utility property of the company for ratemaking purposes, to fix a just and reasonable rate of return thereon, and to approve rate schedules designed to develop such return. Docket No. E-01345A-25-0105. On behalf of Western Resource Advocates. (Mar. 18, 2026)
   Large load tariff design; cost of service modeling; rate design
   Direct (available upon request)

2. Petition of Green Mountain Power for approval of its new multi-year regulation plan. Case No. 25-1955-PET. On behalf of Green Mountain Power. (Jan. 16, 2026).

Resilience BCR modeling; T&D resilience planning
Direct

3. Filing proposing three new tariffs, Rider BYODLR (Bring Your Own Device Load Reduction Program), Rider VPP (Virtual Power Plant Program), and Rider CSS (Community Solar Plus Storage Program. ICC Docket No. 25-0678. On behalf of Environmental Law & Policy Center, Natural Resources Defense Council, and Vote Solar. (Nov. 4, 2025).
DER tariff design; VPPs; demand response
Direct

4. In the Matter of Application of Oncor Electric Delivery Company LLC for Authority to Change Rates. Texas PUC Docket No. 58306. On behalf of Environmental Defense Fund. (Oct. 17, 2025)
Distribution planning, DER interconnection, T&D rate design
Direct

5. Investigation into Marginal Cost Study Treatment and Costs for Large Customers and Further Modifications to Portland General Electric Company's Rule C and Rule I. Docket No. UM 2377. On Behalf of Climate Solutions, Columbia River Keeper, Community Energy Project, Green Energy Institute, and Oregon Environmental Council.
Topics covered: Generation marginal cost study; variable energy resources; large load forecasting; flexible connections.
Direct

6. Petition of Massachusetts Electric Company and Nantucket Electric Company, each d/b/a National Grid, for approval of the Capital Investment Project (CIP) for the Monson-Palmer-Longmeadow (Northwest) DG Group Interconnection Study. Docket No. D.P.U. 25-31. On Behalf of the Massachusetts AGO (with Ron Nelson and Tim Cook).
Distributed generation interconnection and cost allocation
Direct

7. In the Matter of Electronic Application of Kentucky Utilities Company and Louisville Gas & Electric Company for Certificates of Public Convenience and Necessity and Site Certificates. Case No. 2025-00045. On behalf of Joint Intervenors Kentuckians for the Commonwealth, Kentucky Solar Energy Society, Metropolitan Housing Association, and Mountain Association.
DSM potential, S+S resource modeling, VPP design
Direct

8. In the Matter of the Application of Public Service Company of Colorado for Approval of its 2024 Just Transition Solicitation. Docket No. 24A-0442E. On Behalf of Western Resource Advocates and Southwest Energy Efficiency Partnership.
Load and DER forecasting, large load forecasting, interconnection policy
Direct

9. Petition of NSTAR Electric Company d/b/a Eversource Energy for Approval to Offer Optional Electric Vehicle Time-of-Use Rates (Docket No. D.P.U. 23-84). Petition of Massachusetts Electric Company and Nantucket Electric Company each d/b/a National Grid for Approval to offer Optional Electric Vehicle Time-of-Use Rates (Docket No. D.P.U. 23-85). On Behalf of the Massachusetts AGO (with Ron Nelson).
   EV TOU rate design, submetering
   Direct, Surrebuttal

Other Industry Engagement

Smart Grid Graduate Policy Course, Portland State University, adjunct instructor (Spring 2024)

Taught graduate-level Smart Grid course covering policy trends in Smart Grid topics for public administration and policy students, as well as professional development for industry practitioners.

Smart Grid Graduate Course in Electrical Engineering, Oregon State University, adjunct instructor (Spring 2023)

Taught graduate-level Smart Grid course in electrical engineering covering distribution system basics, smart controls, demand-side technologies, transmission and market integration issues.

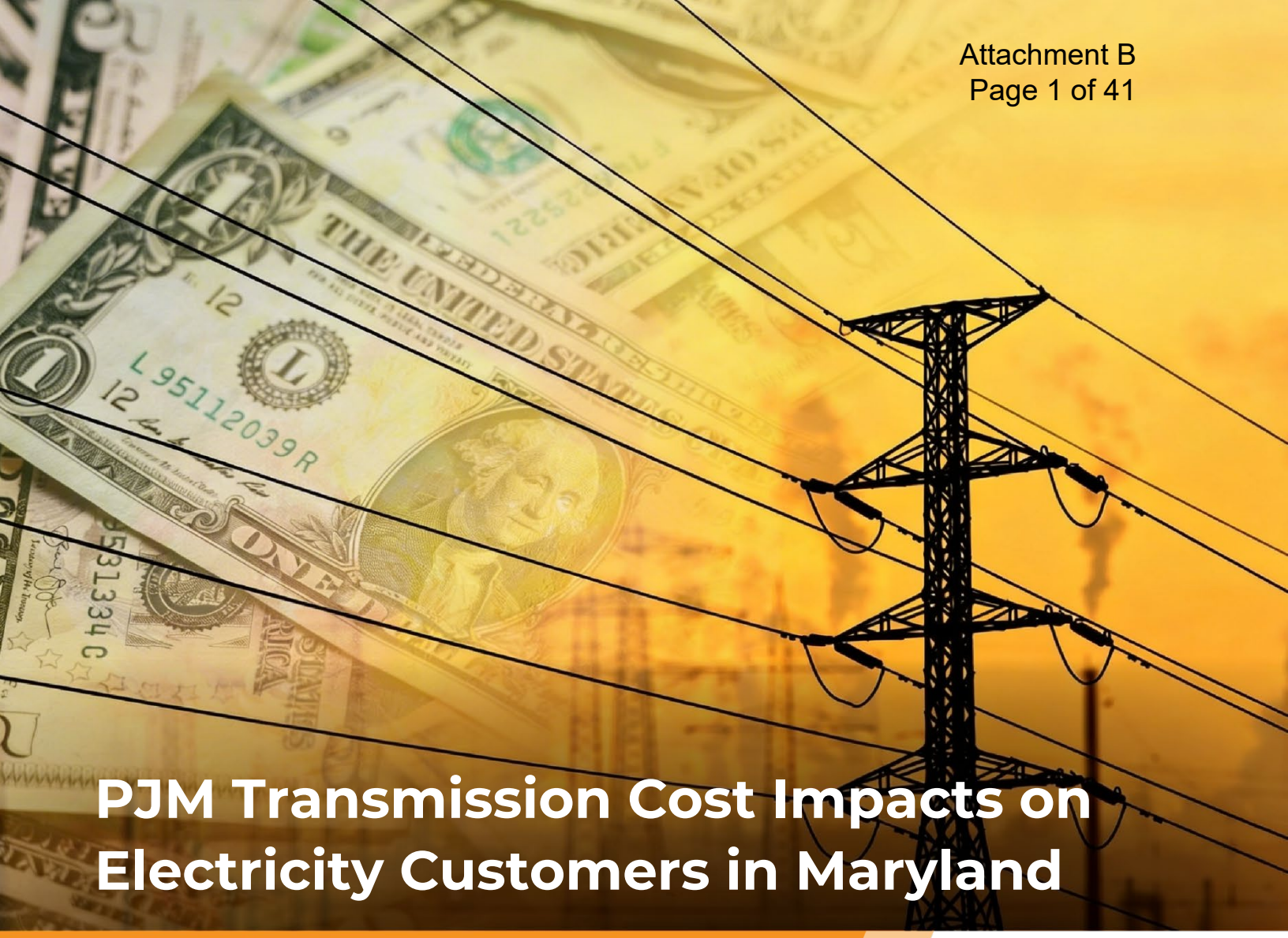
Maryland ratepayer bill impacts projections

Average bill impact per customer, ten-year cumulative revenue requirement

Customer Class	Allocation Method	BGE	Choptank	Delmarva	PE	Pepco	SMECO	Weighted Avg.
Residential	Load Ratio Share	$ 112.87	$ 392.40	$ 158.46	$ 137.20	$ 98.50	$ 126.02	$ 116.93
	DFAX	$ 204.20	$ 115.17	$ 46.51	$ 368.08	$ 253.04	$ 323.74	$ 228.60
	Total Allocation	$ 317.07	$ 507.57	$ 204.97	$ 505.29	$ 351.54	$ 449.76	$ 345.53
Commercial	Load Ratio Share	$ 196.43	$ 1,154.57	$ 391.70	$ 387.75	$ 156.62	$ 226.22	$ 242.54
	DFAX	$ 355.37	$ 338.88	$ 114.97	$ 1,040.26	$ 402.33	$ 581.13	$ 430.72
	Total Allocation	$ 551.80	$ 1,493.45	$ 506.66	$ 1,428.01	$ 558.94	$ 807.35	$ 673.26
Industrial	Load Ratio Share	$ 6,970.02	$ 31,295.31	$ 5,929.63	$ 2,510.02	$ 3,973.23	$ 4,787.45	$ 4,821.09
	DFAX	$ 12,609.74	$ 9,185.58	$ 1,740.42	$ 6,733.85	$ 10,206.78	$ 12,298.44	$ 10,253.25
	Total Allocation	$ 19,579.76	$ 40,480.89	$ 7,670.06	$ 9,243.88	$ 14,180.01	$ 17,085.89	$ 15,074.35

Ten-Year total Maryland cumulative revenue requirement

Customer Class	Allocation Method	BGE	Choptank	Delmarva	PE	Pepco	SMECO	Total
Residential	Load Ratio Share	$ 138,157,203	$ 1,574,963	$ 29,159,897	$ 34,381,641	$ 55,155,478	$ 20,134,437	$ 278,563,619
	DFAX	$ 249,945,576	$ 462,272	$ 8,558,809	$ 92,238,590	$ 141,688,353	$ 51,723,153	$ 544,616,752
	Total Allocation	$ 388,102,779	$ 2,037,235	$ 37,718,706	$ 126,620,231	$ 196,843,830	$ 71,857,589	$ 823,180,370
Commercial	Load Ratio Share	$ 23,193,137	$ 474,431	$ 10,609,002	$ 10,437,114	$ 4,858,249	$ 2,948,238	$ 52,520,171
	DFAX	$ 41,959,608	$ 139,252	$ 3,113,880	$ 28,000,545	$ 12,480,306	$ 7,573,698	$ 93,267,289
	Total Allocation	$ 65,152,745	$ 613,683	$ 13,722,882	$ 38,437,660	$ 17,338,555	$ 10,521,936	$ 145,787,460
Industrial	Load Ratio Share	$ 93,253,682	$ 67,807	$ 8,680,487	$ 15,410,494	$ 75,849,579	$ 8,031,750	$ 201,293,799
	DFAX	$ 168,708,868	$ 19,902	$ 2,547,836	$ 41,343,059	$ 194,849,222	$ 20,632,681	$ 428,101,569
	Total Allocation	$ 261,962,551	$ 87,709	$ 11,228,322	$ 56,753,553	$ 270,698,802	$ 28,664,431	$ 629,395,367
Total	Load Ratio Share	$ 261,297,722	$ 2,117,201	$ 48,449,386	$ 61,018,055	$ 135,863,306	$ 31,508,172	$ 540,253,842
	DFAX	$ 472,723,885	$ 621,426	$ 14,220,524	$ 163,698,391	$ 349,017,881	$ 80,941,027	$ 1,081,223,135
	Total Allocation	$ 734,021,607	$ 2,738,627	$ 62,669,910	$ 224,716,446	$ 484,881,187	$ 112,449,199	$ 1,621,476,976



PJM Transmission Cost Impacts on Electricity Customers in Maryland

An Overview of PJM Transmission Planning and Costs

March 2026
(Corrected 3/25/2026)*

OPC
Office of People's Counsel
State of Maryland

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Report prepared for the Maryland Office of People's Counsel by Synapse Energy Economics, Inc., a research and consulting firm specializing in economic and policy research, modeling, and analysis to provide electric sector solutions.

**This version of the report corrects Figure 2 to show the vertical axis in dollars per year.*

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LIST OF ACRONYMS

Acronym	Term	Definition
APS	Allegheny Power System	A regional transmission area within the PJM grid covering parts of Maryland, Pennsylvania, West Virginia, and Virginia. It is a subsidiary of FirstEnergy.
BGE	Baltimore Gas and Electric Company	A regional transmission area within the PJM grid within Maryland; also refers to the distribution utility serving the same territory. It is a subsidiary of Exelon.
CPCN	Certificate of Public Convenience and Necessity	A CPCN must be issued by the Maryland Public Service Commission (PSC) before a generating station, a qualified generator lead line, an overhead transmission line designed to carry more than 69,000 volts, or certain energy storage devices may be constructed in the State. The CPCN process allows PSC to comprehensively consider the effects of a proposed project. Each proposal is subject to public comment and a public hearing through which various interested parties may provide input. In addition to the public at large, PSC receives input from State agencies with subject matter expertise and representatives of local governments. PSC is then required to weigh the information elicited throughout the application process and make a decision to deny, grant, or, in some cases, conditionally grant a CPCN.
DFAX	Distribution factor analysis	A type of cost allocation for PJM baseline transmission projects. Under this methodology, costs are allocated based on which transmission zones drive power flow on an upgraded transmission facility. This method measures each zone's usage of a transmission line based on changes to its power flow through detailed power flow modeling.
DPL	Delmarva Power & Light	A regional transmission area within the PJM grid serving parts of Maryland and Delaware; also refers to the distribution utility serving the same territory. It is a subsidiary of Exelon.
FERC	Federal Energy Regulatory Commission	The federal agency that regulates wholesale electric power sales and transmission rates.
LSE	Load Serving Entity	A LSE is an entity—such as an electric distirbution company, retail electric supplier, municipal utility, or cooperative—authorized to sell electricity to end-use customers within the PJM region. LSEs must be PJM members and are responsible for procuring adequate supply and transmission to meet their customers' demand.
NERC	North American Electric Reliability Corporation	NERC operates as an electric reliability organization to improve the reliability and security of the bulk power system in North America. To achieve that, NERC develops and enforces reliability standards; monitors the bulk power system; assesses future adequacy; audits owners, operators and users for preparedness; and educates and trains industry personnel.
NITS	Network Integration Transmission Service	NITS charges are the core mechanism through which transmission owners recover the costs of owning, operating, maintaining, and upgrading local transmission projects. They reflect each local project's annual transmission revenue requirement, which includes capital costs, operational and maintenance expenses, depreciation, taxes, and an authorized return on investment.

Acronym	Term	Definition
PE	Potomac Edison Company	A distribution utility serving parts of Maryland. It is a subsidiary of FirstEnergy.
Pepco	Potomac Electric Power Company	A regional transmission area within the PJM grid serving parts of Maryland and the District of Columia; also refers to the distribution utility serving the same territory. It is a subsidiary of Exelon.
PSC	Maryland Public Service Commission	The Maryland PSC is an independent state agency that regulates public utilities—including electric, gas, water, and sewage companies. It ensures safe, reliable service, sets utility rates, and manages consumer complaints.
RMR	Reliability Must-Run	A generating unit slated to be retired by its owners but that is needed for reliability reasons. Typically, PJM requests that the unit remain operational beyond its proposed retirement date until transmission upgrades are completed.
RTEP	Regional Transmission Expansion Plan (or Planning Process)	PJM's comprehensive annual process that examines the three interrelated components of electric power system reliability: load, generation and transmission. The RTEP process employs a range of planning study tools and methodologies to analyze and assess each component to ensure that reliability remains firm. The RTEP process is designed to meet established reliability criteria, keep markets robust and competitive, and ensure stable operations.
RTO	Regional Transmission Organization	The organization that coordinates, controls, and monitors a multi-state electric grid. In this report, RTO refers to PJM Interconnection, LLC (or PJM) which operates a competitive wholesale electricity market and manages the high-voltage electricity grid to ensure reliability in all or parts of Delaware, Illinois, Indiana, Kentucky, Maryland, Michigan, New Jersey, North Carolina, Ohio, Pennsylvania, Tennessee, Virginia, West Virginia, and the District of Columbia.
SOS	Standard Offer Service	SOS is the default electricity supply provided by a local utility to customers who have not chosen a competitive, third-party supplier. It includes the cost of power, transmission, and related services, often procured through state-regulated, competitive bidding processes. It is sometimes referred to as basic service.
TEAC	Transmission Expansion Advisory Committee	The TEAC is a PJM stakeholder group that advises on the development of the RTEP. It acts as the primary public forum for stakeholders to discuss grid study assumptions, system needs, and proposed, cost-effective, or efficient transmission solutions before board approval.
TEC	Transmission Enhancement Charges	TEC in PJM are fees that recover the costs for tranmission owners of building, upgrading, or expanding the regional transmission grid, as approved through the RTEP. They reflect capital costs, operational and maintenance expenses, depreciation, taxes, and the transmission owner’s authorized return on investment.

EXECUTIVE SUMMARY

PJM could saddle Maryland with an additional $5.4 billion in capital costs for transmission projects built in 2031 to 2035.

Transmission infrastructure—the high-voltage system that delivers electricity from power plants to local utilities—is a growing and increasingly significant driver of higher electricity costs for Maryland households and businesses. In the PJM Interconnection (PJM) region, which includes Maryland, 12 other states, and Washington, D.C., transmission rates have roughly doubled over the past decade.[1] In Maryland, transmission now accounts for 10 percent of residential electricity costs (and 16 percent of supply costs).

To understand how transmission costs are impacting Maryland customers and evaluate possible mitigation measures, the Maryland Office of People's Counsel (OPC) commissioned Synapse Energy Economics (Synapse) to conduct this study. We found these transmission costs will likely increase substantially in the years ahead as load growth escalates in PJM. Marylanders are bearing cost responsibility for $7.1 billion in capital costs from transmission projects built and planned over 20 years from 2010 to 2030.[2] We estimate that PJM could saddle Maryland with an additional $5.4 billion in new capital costs for transmission projects built in 2031 to 2035. Of these new costs, regional transmission projects needed for PJM reliability needs (baseline projects) represent 59 percent ($3.2 billion) while local projects—which are driven by the local utilities and are not subject to meaningful cost review—represent 41 percent ($2.2 billion). The $5.4 billion of new transmission costs would be a major increase over five years compared to the $7.1 billion burden over the preceding 20 years. While transmission costs are subject only to federal regulation, state policymakers can take measures to mitigate the impacts skyrocketing prices are having on Marylanders' electricity bills. Identifying those measures requires a better understanding of how transmission planning works and how the related costs end up in customer bills.

Transmission Planning and Project Types

PJM and transmission-owning utilities are responsible for transmission planning for Maryland, 12 other states, and Washington, D.C. Recent increases in transmission costs fall primarily into two categories of transmission projects: baseline projects and supplemental (local) projects.

- PJM oversees regional **"baseline" transmission projects** through its Regional Transmission Expansion Plan (RTEP). In the RTEP process, PJM evaluates long-term reliability needs, load growth, generator retirements, and market efficiency. It identifies projects to address specific transmission constraints or

[1] In nominal terms. Monitoring Analytics. Components of the Total Cost of PJM Wholesale Power. Data retrieved February 17, 2026. Available at: https://www.monitoringanalytics.com/data/pjm_cost.shtml.

[2] PJM and transmission owners plan projects roughly five years ahead of when they are built.

reliability concerns. Baseline projects often cross state lines and utility service territories and, with important exceptions, are subject to competitive solicitations.

- In contrast, transmission owners unilaterally plan **"supplemental" or "local" transmission projects**. These owners are usually local utilities (such as Baltimore Gas and Electric) or their affiliates which identify and address local needs, such as equipment replacement or local reliability concerns. PJM does not assess whether local projects are necessary, nor does it require them to be competitively procured. Local projects are built and owned by the local transmission utility and paid for entirely by the utility's own customers. Federal regulators treat local projects as presumptively prudent, which means they are rarely, if ever, subject to meaningful review for cost-effectiveness.[3] OPC has advocated for closing this regulatory gap for local transmission projects, including filing a complaint, before federal regulators.[4]

Baseline projects: PJM allocated $4.3 billion in transmission capital costs to Maryland from 2010 to 2030, and we estimate it will allocate an additional $3.2 billion to Maryland from 2031-2035 (see Figure 12). Nearly three quarters of transmission spending reflected in Maryland customer bills—recovered in the "supply" portion of the bill—is driven by load growth, most recently from out-of-state data centers. For projects built or planned for construction from 2010–2030, PJM allocated Maryland $2.7 billion dollars of capital costs for load-growth-related projects and an additional $1.6 billion in non-growth-related projects, such as market efficiency projects, for a total of $4.3 billion allocated to Maryland. Over the next 10 years, from 2026 to 2036, PJM forecasts peak electricity demand will grow by 42 percent across the PJM region,

PJM's method of allocating transmission costs has Maryland customers paying a substantial share of the regional transmission projects needed to serve out-of-state load growth.

[3] *See, e.g.*, *Sw. Power Pool, Inc.*, 183 FERC ¶ 61,151 (2023) (Clements, Comm'r, and Christie, Comm'r, concurring at P 4) ("Indeed, the Commission grants formula rate treatment, including a presumption of prudence, to filings from transmission owners seeking cost recovery for transmission projects without regard to whether such projects have been subject to a serious vetting in any proceeding in which both need and prudence of cost must be demonstrated by the transmission developer. We have expressed concerns about this lack of oversight previously, and this filing by SPP illustrates exactly why that is a major problem pertinent to the issue of rising consumer costs for transmission.").

[4] See *Complaint of Industrial Energy Consumers of America, et. al. v. Avista Corporation, et. al.*, Docket No. EL25-44; *see also* Md. Office of People's Counsel, *Costly local transmission projects that avoid competition are causing unlawful rates, OPC tells federal regulators* (Dec. 19, 2024), https://content.govdelivery.com/accounts/MDOPC/bulletins/3c86285; Comments of the Maryland OPC in Support of the Office of the Ohio Consumers' Counsel Complaint, November 11, 2023. FERC Docket No. EL23-105-000. Available at: https://opc.maryland.gov/Portals/0/Files/Publications/Others/OPC%20Comments%20EL23-105%20-%20OCC%20Complaint.pdf.

largely due to the rapid expansion of data centers in Northern Virginia and Ohio and to a lesser extent in Illinois and Pennsylvania.[5]

In contrast to PJM's forecasted 42 percent growth in peak demand across the RTO region (3.6 percent annually), PJM forecasts Maryland's peak demand will grow by only 12 percent during this period (1.1 percent annually). Maryland's share of the region's peak demand will fall from 8 percent to 6 percent over the period. Despite this disparity, PJM's method of allocating transmission costs has Maryland customers paying a substantial share of the regional transmission projects needed to serve out-of-state load growth. And because transmission asset payments span over 30 to 40 years, today's investment decisions will affect customer bills for decades. Furthermore, data center load forecasts are highly uncertain, raising concerns about unnecessary transmission infrastructure. If data center demand throughout PJM is overestimated, Maryland customers face the risk of paying for unnecessary transmission infrastructure that provides limited long-term benefits.

Local projects: Maryland utilities spent (or will spend) $2.8 billion on local transmission projects from 2010 to 2030, and we estimate they will spend $2.2 billion more from 2031-2035. Local transmission projects are also driving considerable increases in transmission costs in customer bills. For projects built or planned for construction from 2010–2030, Maryland's electric utilities spent or will spend $2.8 billion in capital costs for local transmission upgrades. That spending is accelerating. Maryland electricity customers pay for these investments in the supply portion of their bills. Because these local projects face minimal oversight and lack competitive pressure, they present a great risk of excessive or inefficient investment at the expense of electricity customers. As transmission costs rise, these projects will place sustained upward pressure on retail electric rates and exacerbate affordability challenges for households, small businesses, and low-income customers.

Because these local projects face minimal oversight and lack competitive pressure, they present a great risk of excessive or inefficient investment at the expense of electricity customers.

Recommendations for Maryland Policymakers

Maryland can mitigate rising transmission costs and improve accountability in several ways. The following recommendations outline actions policymakers can pursue to protect Maryland customers:

1. **Improve load forecasting and planning assumptions**
   Require greater transparency from its utilities for more rigorous, transparent, and coordinated forecasting of data center demand within the state to reduce the risk of overbuilding transmission infrastructure; advocate for the same at the regional level.

[5] PJM Interconnection. 2026 Long-Term Load Forecast. Data retrieved February 10, 2026. Available at: https://www.pjm.com/planning/resource-adequacy-planning/load-forecast-dev-process.

2. **Advocate for greater oversight of transmission projects at PJM and the Federal Energy Regulatory Commission (FERC)**
   Support reforms such as an independent transmission monitor at PJM that bring local projects into PJM transmission planning processes, expand competitive procurement, and improve access to project data for states and consumer advocates.
3. **Strengthen regulation of transmission projects at the state level**
   Improve the state Certificate of Public Convenience and Necessity (CPCN) process by removing exemptions and waivers and requiring cost-benefit analysis, greater transparency, and evaluation of alternatives for local transmission projects.
4. **Align transmission costs with cost causation**
   Push for federal policies that require new large loads such as data centers to bear the full share of transmission costs directly attributable to their demand.
5. **Promote lower-cost alternatives**
   Encourage the use of grid-enhancing technologies, advanced transmission technologies, and non-wires alternatives that can meet reliability needs at lower cost and with shorter timelines.

Transmission investments made today will shape Maryland electric bills for decades. Without stronger oversight and proactive policy engagement, Maryland customers will continue to bear rising costs—often driven by electricity growth outside the state. Near-term regulatory and policy changes can help ensure future transmission investments are necessary, cost-effective, and fair to Maryland electricity customers.

1. INTRODUCTION

Transmission costs now represent roughly 10 percent of total customer electric bills for most Maryland customers;[6] these rates have been rapidly rising in recent years and will likely continue to increase for the foreseeable future. To understand why costs are going up and what Maryland can do about it, it helps to understand how transmission planning works and how the process allocates costs to Maryland electricity customers.

This report provides an overview of transmission planning and trends in the regional grid system that encompasses Maryland (Section 2). It then details PJM planning, oversight, cost allocation, and cost trends for two different types of transmission projects: regional-level baseline transmission projects (Section 3) and local transmission projects (Section 4). Section 5 lays out the challenges of rising costs and delays specific to network upgrade projects. To connect transmission costs and trends to Marylanders' electricity bills, Section 6 delves into how transmission costs fit into cost recovery and customer rates. And finally, in Section 7, Synapse provides actionable recommendations to help Maryland address the affordability impacts of the region's transmission issues.

2. OVERVIEW OF TRANSMISSION COSTS IN PJM AND MARYLAND

The transmission system is the high-voltage network that transports large amounts of electricity over long distances from power plants to each utility's distribution system. It operates as an interconnected grid that enables the balancing of electricity supply and demand across regions, helping to create an efficient and reliable electricity system.

Several entities are involved in planning, building, and operating the transmission system serving Maryland:

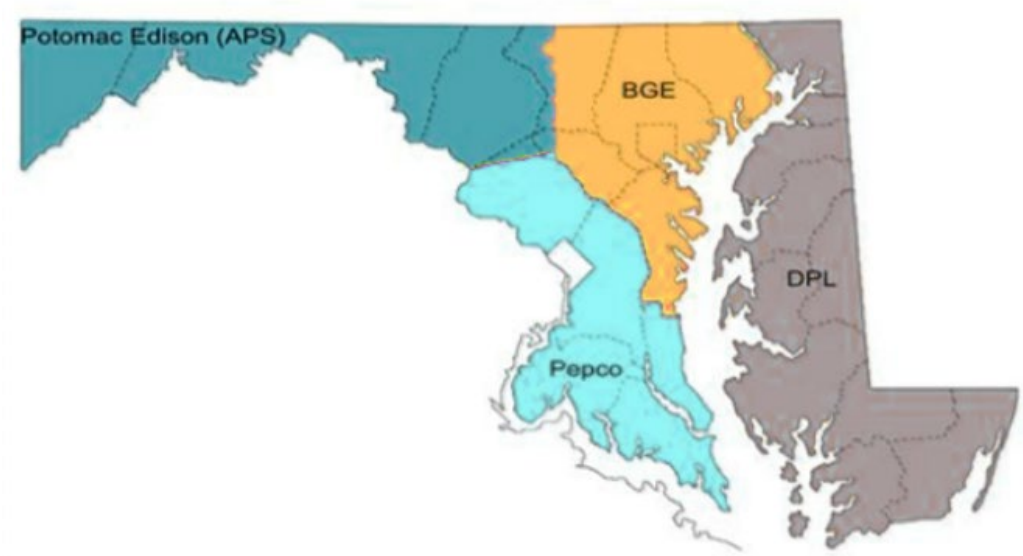
- PJM Interconnection (PJM) is the regional transmission organization (RTO) responsible for regional transmission planning across 13 states and the District of Columbia (DC), including Maryland. While PJM operates transmission lines, it does not own any transmission assets.
- Transmission owning utilities are the entities that own the transmission lines and related equipment within their service territories (transmission zones). These utilities propose, build, and profit from local transmission projects.
- The Federal Energy Regulatory Commission (FERC) regulates PJM and the transmission owners, approves transmission rates and cost allocation

[6] Residential transmission charges relative to total charges. Source: Data collected by the Maryland Office of People's Counsel and provided to Synapse February 19, 2026. For perspective, capacity market costs for 2025 for the Maryland utilities also represent roughly 10 percent of total bills for most customers. Ibid.

methodologies, and determines how much profit the transmission owners can make (i.e., their allowed rate of return).

Maryland has four transmission zones: (1) Pepco, (2) Baltimore Gas and Electric (BGE), (3) Delmarva Power & Light (DPL), and (4) Allegheny Power Systems (APS) (Figure 1). Pepco serves the southern part of Maryland and the DC area, BGE serves Baltimore and the surrounding areas and is located entirely within Maryland, DPL serves both Delaware and portions of the Delmarva Peninsula in Maryland, and APS serves western Maryland[7] along with parts of Pennsylvania, Virginia, and West Virginia.

Figure 1. Map of PJM transmission zones in Maryland



Source: Public Service Commission of Maryland. November 2021. Ten-Year Plan (2021 – 2030) of Electric Companies in Maryland. Prepared for the Maryland Department of Natural Resources. Available at: https://www.psc.state.md.us/wp-content/uploads/2021-2030-Ten-Year-Plan.pdf.

Load growth from data centers, especially those located in Virginia and Ohio, are a primary driver of recent increases in transmission costs.

Across PJM and Maryland's four transmission zones, transmission projects' cost and spending has been increasing rapidly due to load growth unprecedented in timing and scope, aging infrastructure, supply chain issues, inflation, and insufficient regulation of transmission owners. Load growth from data centers, especially those located in Virginia and Ohio, are a primary driver of recent increases in transmission costs. Absent changes in forecasted demand or PJM processes, the PJM grid will require massive transmission expansion projects that will cost electricity customers billions of dollars.

[7] The APS zone in Maryland is served by the Potomac Edison (PE) distribution utility company.

Exelon's winter 2026 investor presentation projects that its transmission spending from 2026 to 2028 will amount to $4.8 billion across its Maryland subsidiaries that include Pepco, BGE, and DPL.[8] These investment levels exceed twofold the transmission investment levels Exelon reported to its investors for the same Exelon subsidiaries for the previous three years, 2023-2025, totaling $2.325 billion.[9] Exelon recently announced that it expects to spend $12 billion to $17 billion on transmission buildout over the next 10 years.[10] In February 2025, the PJM board approved $6.7 billion in baseline transmission projects for projects to be built in the next five years across PJM (2024 Regional Transmission Expansion Plan, or RTEP), many of which are driven by load growth.[11] In February 2026, the PJM board approved the 2025 RTEP which includes $11.8 billion worth of new transmission investments.[12] This amount is nearly double the 2024 RTEP cost.

Exelon recently announced that it expects to spend $12 billion to $17 billion on transmission buildout over the next 10 years.

These ballooning transmission upgrade costs are already impacting retail transmission rates and customer bills, which have steadily increased in Maryland over the past 15 years (Figure 2). Since 2010, transmission rates for Pepco, BGE, and DPL have increased by a factor of five to six, while Potomac Edison's rate has remained flat in nominal terms.[13,14] Figure 2 shows the transmission cost component on the average residential customer's bill in Maryland across Pepco, BGE, DPL, and PE from 2015 to 2025.

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8 Exelon Investor Meetings, Winter 2026 (Jan. 12, 2026). Available at https://investors.exeloncorp.com/static-files/0cd39e2e-ea59-432b-afd7-b432025fe649, slides 40, 43, 44.

9 Exelon Investor Meetings, Summer 2022 (June 21, 2022). Available at https://investors.exeloncorp.com/static-files/8a389a43-ea25-4029-ad8c-8c61b90c64c9, slides 24, 27, 28.

10 Howland, E. February 13, 2026. "Transmission drives Exelon's capital spending plan to $41.3B". Utility Dive. Available at: https://www.utilitydive.com/news/exelon-transmission-data-center-capex-earnings/812200/.

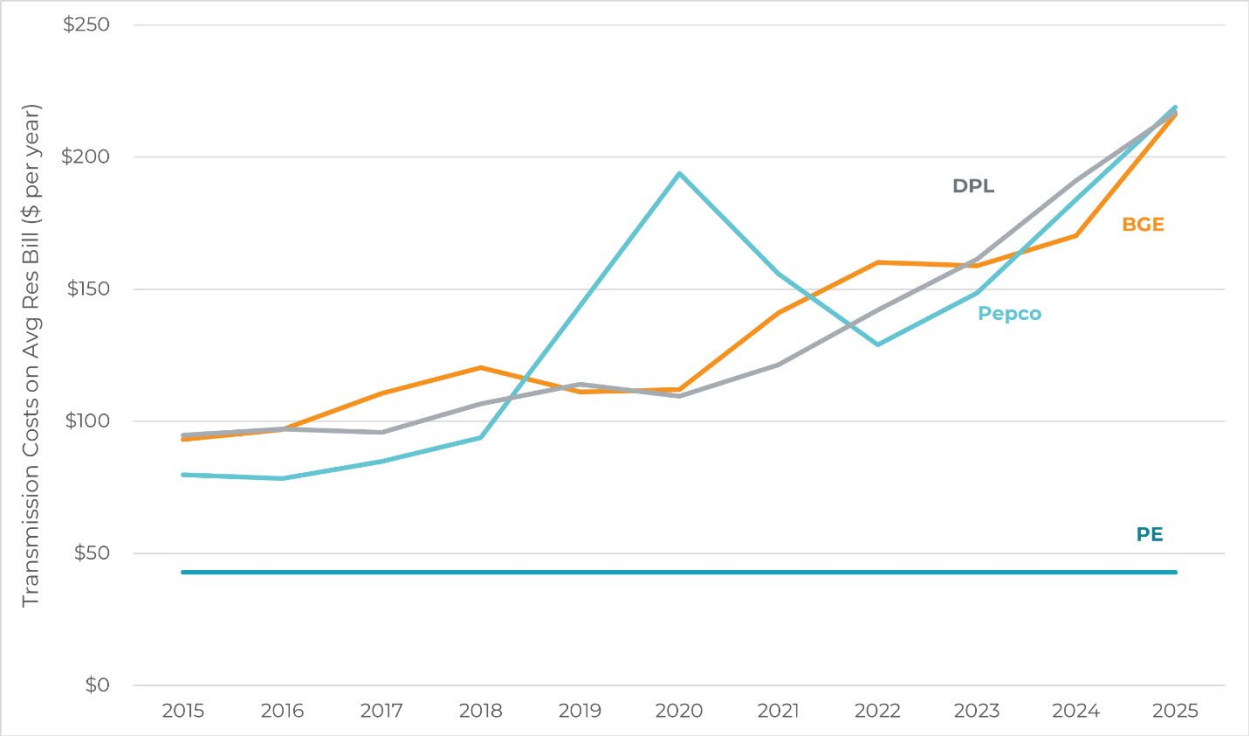
11 PJM Interconnection. February 26, 2025. PJM Board Approves New Transmission Projects to Support Grid Reliability. *PJM Inside Lines*. Available at: https://insidelines.pjm.com/pjm-board-approves-new-transmission-projects-to-support-grid-reliability/.

12 PJM Interconnection. February 13, 2026. "PJM Board Approves Transmission Improvements Needed for Grid Reliability." *PJM Inside Lines*. Available at: https://insidelines.pjm.com/pjm-board-approves-transmission-improvements-needed-for-grid-reliability/ https://www.pjm.com/-/media/DotCom/committees-groups/committees/teac/2025/20251208/20251208-item-11---reliability-analysis-update.pdf.

13 When adjusting for inflation, in real dollar terms, Pepco, BGE, and DPL rates have increased by a factor of four, on average, while PE's rate decreased slightly. Based on rate information provided to Synapse by the OPC in December 2025.

14 The PJM-approved transmission rate that APS charges its transmission customers (such as PE, which converts APS's transmission rate into a retail transmission rate) has remained relatively flat from June 2018 until an uptick in June 2024 (as seen in Figure 10 in Section 5.1). However, APS's capital spending (and thus presumably operations and maintenance costs and other expenditures) has increased from 2010 to 2025. PJM's cost allocation process has also continued to allocate project costs to APS owned by other transmission owners over this same period. This suggests that APS rates, and thus PE's retail transmission rate, should have increased over this period. However, flatness in the PE's retail rate could be explained by load growth in the APS zone (the increase in costs is balanced by an increase in load growth, resulting in a flatter rate). Further analysis is required to fully understand why PE's retail transmission rate has remained flat from 2010 to 2025.

Figure 2. Transmission cost component for the average residential electric bill in Maryland



Source: Data collected by the Maryland Office of People's Counsel, provided to Synapse on February 19, 2026.

2.1. Types of PJM Transmission Projects

There are three types of transmission projects in PJM: (1) baseline projects, (2) supplemental (i.e., local) projects, and (3) network upgrades. Throughout this report, we discuss each of these project types, including their own unique planning and oversight processes, cost drivers, cost allocation methodologies, and cost recovery. We also present trends on project spending for these types of transmission projects and their impact on Maryland electricity customers.

- **Baseline projects** are regional transmission projects primarily required to satisfy reliability standards in the face of new load growth and often span multiple transmission zones or state boundaries. They are also driven by market efficiency, public policy, or operational performance needs such as relieving congestion or mitigating line overloads. PJM identifies and plans baseline projects through its RTEP process, and it subjects most projects to a competitive solicitation process that allows both incumbent utilities that serve the geographic area and non-incumbent developers to propose solutions to a specific PJM-identified need. PJM then evaluates proposals and selects winning projects. The PJM Board ultimately reviews and approves the final set of RTEP projects. Baseline projects are either paid for by electricity customers in the zone where they are located, or more often, are allocated across multiple zones and states.

- **Supplemental projects,** called **local projects** throughout this report, are transmission expansions or enhancements planned and developed by transmission owners to address local system needs such as local load growth and asset replacement. PJM staff does not independently assess the need for these projects, and the Board does not evaluate these projects. Instead, PJM simply ensures the projects will not negatively impact the broader electric system. PJM publicly posts limited data on local projects at its stakeholder forums, such as the Transmission Expansion Advisory Committee (TEAC) and Subregional RTEP Committees, for informational purposes only. Electricity customers in the zones where the projects are located pay for the entirety of the project costs. Federal regulators treat local projects as presumptively prudent, which means they are rarely if ever subject to meaningful review for cost-effectiveness.[15]

- **Network upgrades** are transmission infrastructure upgrades required to accommodate the interconnection of new generation resources. Generator interconnection requests trigger these projects, which ensure that generators can reliably use the PJM transmission system. The interconnecting generators pay for these project costs.

2.2. Recent Trends in PJM Transmission Projects

Across the PJM footprint, annual transmission spending varies, as does the number of approved project types. However, since 2015, total project spending has begun to increase[16] (Figure 3). Across PJM from 2010 to 2030, baseline projects represented 45 percent of costs, local projects represented 48 percent, and network costs made up the remainder (Figure 3).[17]

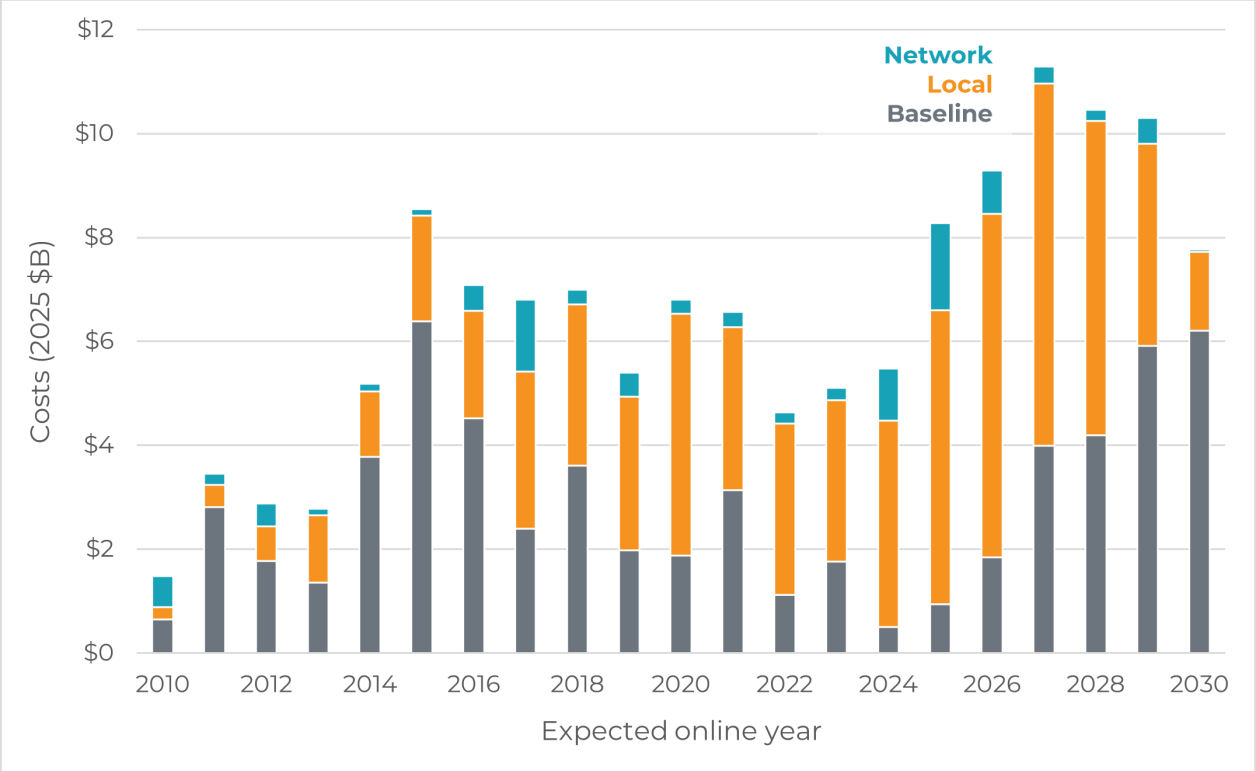
Figure 3 shows the total capital costs of projects by their online or projected online date. Recovery of the costs of baseline and local projects from customers are spread over the project's service life, typically beginning in the year the project comes online.

[15] *See, e.g.*, *Sw. Power Pool, Inc.*, 183 FERC ¶ 61,151 (2023) (Clements, Comm'r, and Christie, Comm'r, concurring at P 4) ("Indeed, the Commission grants formula rate treatment, including a presumption of prudence, to filings from transmission owners seeking cost recovery for transmission projects without regard to whether such projects have been subject to a serious vetting in any proceeding in which both need and prudence of cost must be demonstrated by the transmission developer. We have expressed concerns about this lack of oversight previously, and this filing by SPP illustrates exactly why that is a major problem pertinent to the issue of rising consumer costs for transmission.").

[16] PJM and transmission owners plan projects roughly five years ahead of when they will be built.

[17] For in-service and approved (but not yet online) projects with expected online dates between 2010 and 2030.

Figure 3. Total capital costs of approved and in-service transmission projects in PJM, with expected online dates from 2010 to 2030



Notes: Figure does not include canceled, on-hold, and withdrawn projects. PJM Project Status & Cost Allocation, data as of February 2026. Available at: https://www.pjm.com/planning/m/project-construction.

From 2010 to 2030, PJM-wide baseline capital costs averaged $3 billion per year. This includes the approved $11.8 billion from the 2025 RTEP,[18] which is projected to be built over the next five years. Local project spending during this period averaged $3.3 billion per year, while network upgrades are on average $493 million annually.

Figure 4, below, shows the capital costs of transmission projects allocated to Maryland's four zones from 2010 to 2030.[19] Across all zones, local projects are much more variable across years than baseline projects. Baseline project spending across all zones will increase over the next five years, mostly driven by new load growth outside of Maryland. BGE, in particular, will see a major increase as transmission projects come online that will address a single reliability issue. Two generating stations, called Brandon Shores and Wagner, are under a PJM mandate to continue running despite their operators' request to retire them. This mandate, referred to as "reliability-must-run," or RMR, will be in place until BGE can build enough transmission capacity

[18] PJM Interconnection. February 13, 2026. "PJM Board Approves Transmission Improvements Needed for Grid Reliability." *PJM Inside Lines*. Available at: https://insidelines.pjm.com/pjm-board-approves-transmission-improvements-needed-for-grid-reliability/ https://www.pjm.com/-/media/DotCom/committees-groups/committees/teac/2025/20251208/20251208-item-11---reliability-analysis-update.pdf.

[19] For details on estimating the Maryland portion of baseline transmission costs, see description in Section 2.3.

to bring in electricity from outside the zone or meet local reliability needs.[20] The transmission project, called the Brandon Shores Deactivation Project, is evident in Figure 4, where total costs for BGE in 2028 are almost double the maximum listed on the cost axis. The Brandon Shores Deactivation Project will cost PJM customers over $1.6 billion in capital costs; Maryland will pay for 66 percent of the project, totaling $1.1 billion. Of the four zones in Maryland, BGE is saddled with the largest share, paying over $900 million of the projects' costs.

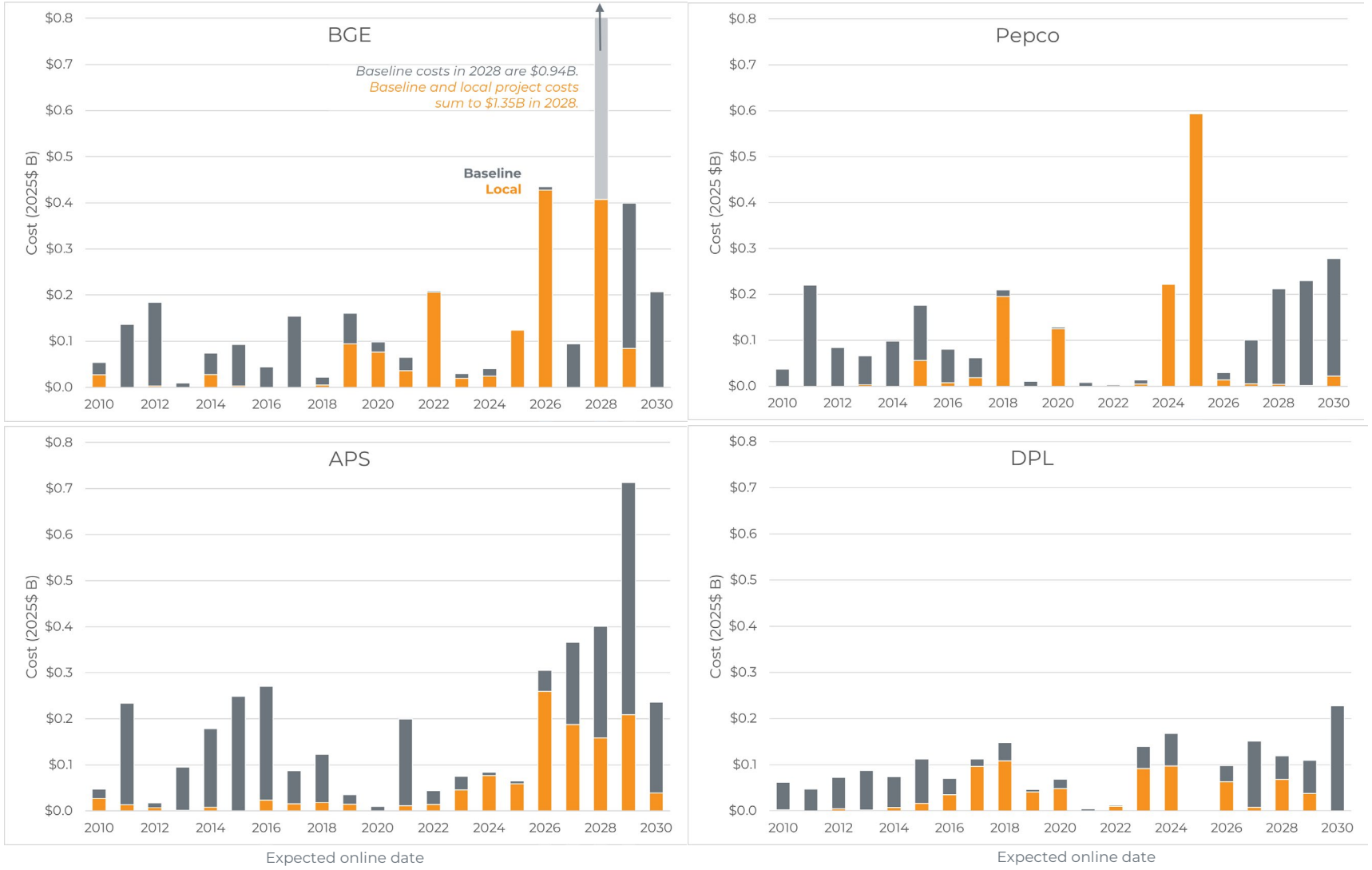
Figure 4 includes approved baseline projects from the 2025 RTEP,[21] with expected in-service dates through 2030. Local and network projects are not included in the RTEP; there will likely be many more local projects in the coming years than those presented in Figure 4.

Project costs are embedded into retail rates over time; they are recovered through depreciation rates and cost recovery mechanisms built into transmission rates. Transmission project depreciation can take over 30 to 40 years, meaning costs are spread across decades of customer bills. For example, a $100 million transmission line with a 3 percent annual depreciation rate would add $3 million per year in depreciation expenses to customer rates until fully depreciated. In addition to depreciation expenses, in the annual revenue requirement used to determine the customer rates that pay for the transmission line customers pay three to four times the project cost of $100 million after including the utility's return, operational and maintenance costs, and for taxes and other charges. For 33 years, these costs will continue to appear in rates, illustrating how long-term infrastructure investments affect electricity bills well beyond the project's online date. The above figures show total transmission project capital costs by expected online date, rather than the period for which customers will pay for these projects.

[20] For more information on the Brandon Shores and Wagner RMRs, see the OPC website's resource adequacy page here: https://opc.maryland.gov/Consumer-Learning/FERC-and-PJM-Issues/Resource-Adequacy

[21] PJM's Board approved the 2025 RTEP in February 2026.

Figure 4. Total capital costs of approved and in-service baseline and local projects that are allocated to Maryland, 2010 to 2030



Source: See description in Section 2.3

2.3. Methodology

Unless otherwise indicated, figures and tables in this report rely on PJM data. They do not include canceled, on-hold, and withdrawn projects as shown in PJM's Project Status & Cost Allocation, data retrieved in February 2026.[22]

For the Pepco, APS, and DPL zones which span multiple jurisdictions, we estimated the Maryland portion of the zone's transmission costs (BGE is located entirely within Maryland). We scaled total zonal capital costs to the Maryland portion using the ratio between Maryland's 2024 peak load[23] and the 2024 zonal peak load from PJM's 2025 Load Forecast Report.[24,25]

3. BASELINE TRANSMISSION PROJECTS

Baseline upgrades are regional transmission projects that PJM determines are necessary to meet reliability standards in the face of load growth, maintain system stability, prevent overloads or voltage violations, and improve market efficiency across the region. These types of projects often span multiple transmission zones or states, and costs are most often allocated to multiple transmission zones, according to how different zones benefit from each project.

3.1. Planning and Oversight Process

PJM plans baseline projects on an annual basis and selects them using its RTEP process through two primary steps: (1) determining transmission needs and (2) identifying specific projects that best meet those needs. This process uses a five-year look-ahead window.

3.1.1. Determining transmission needs

During the RTEP process, PJM conducts transmission system modeling to determine when and where the grid might become constrained. Key inputs include long-term load forecasts, new and retiring generators, and other information about the transmission system. PJM identifies *specific* transmission needs regarding, for example, location, voltage, and project type (e.g., upgrade, new line).

22 PJM Project Status & Cost Allocation, Transmission Cost Planner (TC Cost Planner). Available at: https://www.pjm.com/planning/m/project-construction.

23 PJM Interconnection. June 2025. 2024 Maryland and District of Columbia State Infrastructure Report, slide 21. Available at: https://www.pjm.com/-/media/DotCom/library/reports-notices/state-specific-reports/2024/maryland-and-dc.pdf

24 PJM Interconnection. January 2024. Load Forecast Report. Available at: https://www.pjm.com/-/media/DotCom/library/reports-notices/load-forecast/2024-load-report.pdf

25 As of March 10, 2026, the state-specific reports used for scaling costs to Maryland were not available using PJM's 2025 or 2026 Load Forecast. We expect scaling factors to be similar between 2024 and 2025/2026.

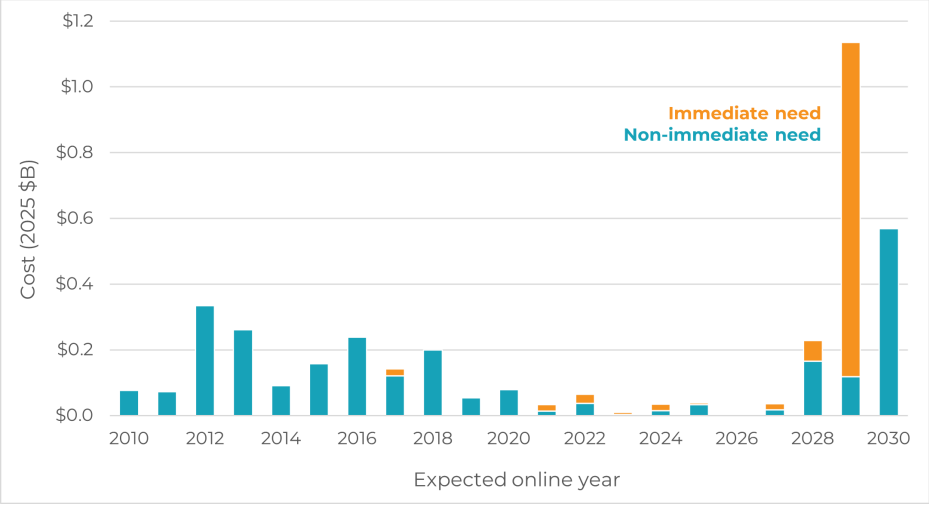
3.1.2. Selecting projects to meet specific transmission needs

After identifying needs, PJM will open an "RTEP Proposal Window" to solicit transmission solutions for each transmission need. PJM identifies most projects through a competitive process where both incumbent and non-incumbent transmission owners can propose a project buildout for a specific need. These types of projects are typically planned and constructed over five years. In some cases, however, PJM will identify "immediate needs," where the need must be addressed in three years or less. Immediate need projects are exempt from PJM's competitive procurement process; PJM selects the incumbent transmission owner to build the project.

Immediate needs projects have been relatively rare over the last 15 years; however, over the next few years they will make up a large portion of the transmission costs for which Maryland electricity customers will pay (Figure 5). Almost 100 percent of the immediate need project costs Marylanders will pay for, and which come online in 2028 and 2029, are part of the Brandon Shores transmission project mentioned above, which addresses the Brandon Shores and Wagner RMRs and their eventual retirements. Furthermore, immediate need projects are typically more costly than non-immediate need projects, as they are not subject to a competitive procurement process. In fact, across the four zones in Maryland, average immediate need project costs are four times more expensive than non-immediate need projects (on a per project basis) (Table 1).[26]

Exempt from competitive procurement requirements, immediate need projects costs across the four Maryland zones are on average four times more expensive than projects competitively procured.

Figure 5. Total capital costs of approved and in-service baseline projects allocated to Maryland, by immediate and non-immediate need, 2010 to 2030



Notes: See description in Section 2.3.

[26] For details on calculation, see description in Section 2.3.

Table 1. Total capital costs, project count, and average dollars in millions of dollars per project, for projects paid for by customers in Pepco, BGE, DPL, and APS zones, from 2010 to 2030

	Immediate Need	Non-Immediate Need
Total Capital Costs (2025$, millions)	$1,658	$6,202
Total Project Count	124	1,832
Average (million dollars (2025$) per project)	$13.4	$3.4

Source: See description in Section 2.3.

3.1.3. Stakeholder involvement and PJM Board approval

PJM's transmission planning and stakeholder involvement process happens at several committee meetings, primarily the TEAC and the subregional RTEP committees (i.e., Mid-Atlantic, Southern, and Western RTEP).[27] PJM allows stakeholder input on submitted proposals in each RTEP Window, but stakeholders cannot vote. Stakeholders participating in these committees and subcommittees can include PJM members (e.g., transmission owners, generation owners, load-serving entities, retail marketers, state consumer advocates, etc.), transmission customers (e.g., large-load customers connected to the transmission system), non-state consumer advocates, and other interested parties (e.g., environmental advocacy organizations). State public service commissions can also participate in the process.

For each RTEP Window, PJM staff selects a final set of projects to meet each identified need and submits them to the PJM Board of Managers for final approval. The final set of recommended projects is meant to include relevant feedback from stakeholders, although multiple stakeholders have pointed out that feedback is not always effectively incorporated. For example in September 2023, the Maryland OPC filed a formal protest with FERC challenging a PJM RTEP baseline project proposal tied to the planned retirement of the Brandon Shores power plant.[28] OPC argued that PJM's planning process lacked rigorous review, transparency, and effective stakeholder engagement, stating that the transmission proposal was not adequately justified and non-transmission alternatives were not discussed. FERC ultimately approved PJM's RTEP transmission solution package associated with the retirement of the Brandon Shores plant, despite protests from stakeholders.

In September 2023, the Maryland OPC filed a formal protest with FERC challenging a PJM RTEP baseline project proposal tied to the planned retirement of the Brandon Shores power plant.

[27] Projects built in Maryland are discussed at the Mid-Atlantic RTEP Committee.

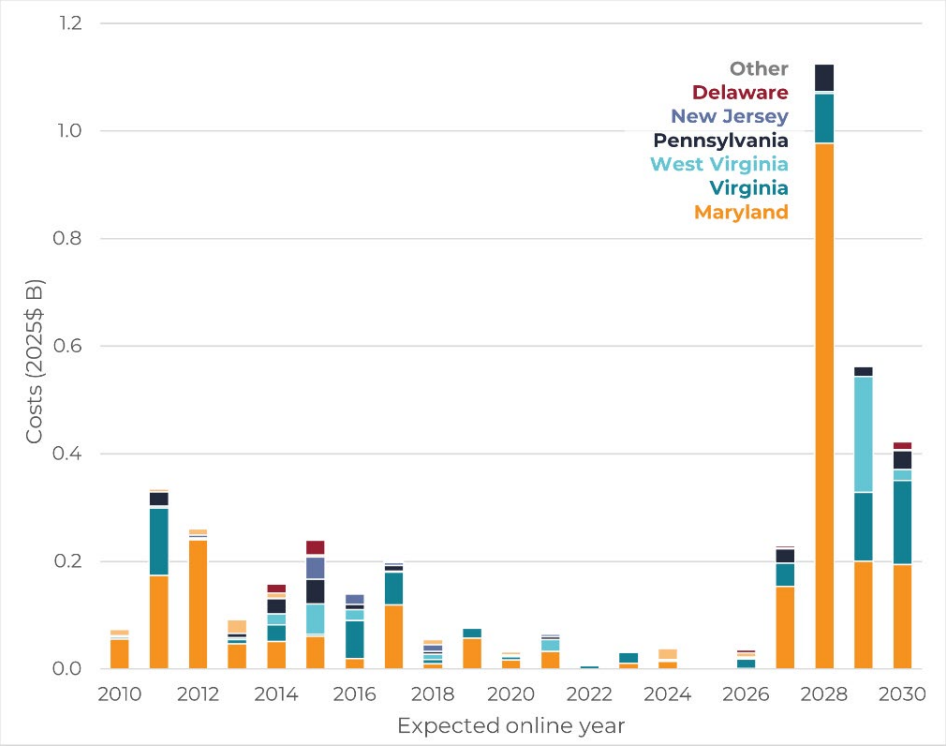
[28] Protest of the Maryland OPC. September 13, 2023. FERC Docket Nos ER23-2612-000, ER23-2612-001. Available at: https://opc.maryland.gov/Portals/0/Files/Publications/Others/Final%20Md%20OPC%20Protest%20ER23-2612%20PJM%20RTEP%20Baseline%20filing.pdf?ver=tgen2T7bSdTQSH44n1SQ6A%3d%3d.

3.2. Cost Allocation Methodology

Because baseline projects address regional reliability needs, PJM usually allocates baseline project costs across multiple zones in the region. Specifically, PJM cost allocation rules require that project costs are allocated to different zones (sometimes across multiple states) based on the share of benefits each zone receives from that project. In some cases, a project's costs are allocated entirely to one zone.[29]

PJM's cost allocation methodology results in Maryland customers paying for transmission projects located both within and outside Maryland. As described below, PJM allocates some, but not all, of the transmission project costs based on how much each zone benefits as determined by a computer simulation of how the new transmission facility changes the flow of power on the system. Figure 6 shows the location of all projects that have costs allocated to Maryland electricity customers. The figure shows that Maryland customers pay significantly for transmission projects located in other states. Over the next five years, the number of projects located in Virginia and West Virginia that Maryland will pay for will increase, mostly driven by data centers located in those states. The large share of costs from projects located in Maryland in 2028 is specifically due to the Brandon Shores Deactivation Project.

Figure 6. Maryland customer cost responsibility for transmission capital costs of approved and in-service baseline projects, by project location, 2010 to 2030



Source:
See description in Section 2.3.

[29] According to *PJM Manual 14B: Attachment A Baseline Reliability Upgrade Cost Allocation Procedures*, lower voltage facilities with an estimated cost below $5 million are allocated 100 percent to the transmission zone in which the upgrade is located, rather than being spread regionally among multiple zones.

PJM has four main cost allocation methodologies for baseline transmission projects:

- *Distribution factor analysis (DFAX)*: Under this methodology, costs are allocated based on which transmission zones drive power flow on an upgraded transmission facility. This method measures each zone's usage of a transmission line based on changes to its power flow through detailed power flow modeling.
- *Load ratio share*: Under this methodology, costs are divided among the benefiting zones based on each zone's non-coincident peak demand.
- *Direct allocation*: 100 percent of the project costs are assigned to the zone where the project is located.
- *State policy approach*: Under this methodology, one or more states will voluntarily pay for the full cost of the project if the upgrade is needed to meet a specific state policy objective, such as offshore wind development or compliance with environmental mandates.

PJM determines the cost-allocation methodologies for baseline projects based on voltage thresholds, usage/load share, and total costs.[30] For higher voltage lines such as double circuit 345 kilovolt (kV) lines, lines greater than or equal to 500 kV, or other regional facilities with estimated costs of $5 million or greater, PJM splits costs evenly between two allocation methods. In such cases, PJM assigns 50 percent of project costs on a load-ratio share basis and the remaining 50 percent using the DFAX methodology.[31] For low-voltage facilities below 500 kV with estimated costs of $5 million or greater, PJM allocates 100 percent of costs using the DFAX methodology.[32] Lastly, for low voltage facilities with estimated costs below $5 million, PJM assigns 100 percent of costs to the local transmission zone (direct allocation).

3.3. Project Cost Drivers for Baseline Projects in Maryland

For projects in service or expected to be in service between 2010 to 2030, PJM allocated $4.3 billion in baseline-project capital costs to Maryland electricity customers (which customers will be paying for well beyond 2030). The $4.3 billion figure includes the recently approved $11.8 billion from the 2025 RTEP.[33] PJM's Transmission Cost Planner categorizes all baseline

[30] PJM Interconnection, "Cost Allocation Education," presentation, September 25, 2020, PJM Planning Committee (Item 04). Available at: https://www.pjm.com/-/media/DotCom/committees-groups/committees/pc/2020/20200925-special/20200925-item-04-cost-allocation-education.ashx.

[31] The stability deviation method is sometimes used in situations when the DFAX method is determined to be unjust and unreasonable (e.g., when the typical DFAX flow-based measure does not align well with engineering drivers of the need). Under the stability methodology, costs are allocated to zones in proportion to how much they benefit from stability improvements. Although this approach is not a routine method, it was developed mainly in context of the Artificial Island project. *169 FERC ¶ 61,234: Delaware Public Service Commission and Maryland Public Service Commission v. PJM Interconnection, L.L.C. and Certain Transmission Owners Designated under CTOA RS.* Issued December 19, 2019. PDF, 14 pp. Washington, DC: Federal Energy Regulatory Commission. May 2020. https://www.ferc.gov/sites/default/files/2020-05/E-28_2.pdf.

[32] Or stability deviation method, as described in the footnote above.

[33] PJM Interconnection. February 13, 2026. "PJM Board Approves Transmission Improvements Needed for Grid Reliability." *PJM Inside Lines*. Available at: https://insidelines.pjm.com/pjm-board-approves-transmission-

projects into six main project driver types, as seen below in Table 2. The table shows the percentage of drivers for all baseline projects with costs allocated to Maryland. From 2010 to 2030, load growth and reliability projects drive an average of 62 percent of Maryland transmission costs across its four zones (Table 2). Nonetheless, an increasing share of this load growth is occurring *outside* Maryland. This load growth will likely only worsen as more data centers located in Virginia and other neighboring areas interconnect to the grid and require transmission upgrades and expansions.

Table 2. Total capital costs of baseline projects allocated to Maryland, and proportion of each cost driver, by zone

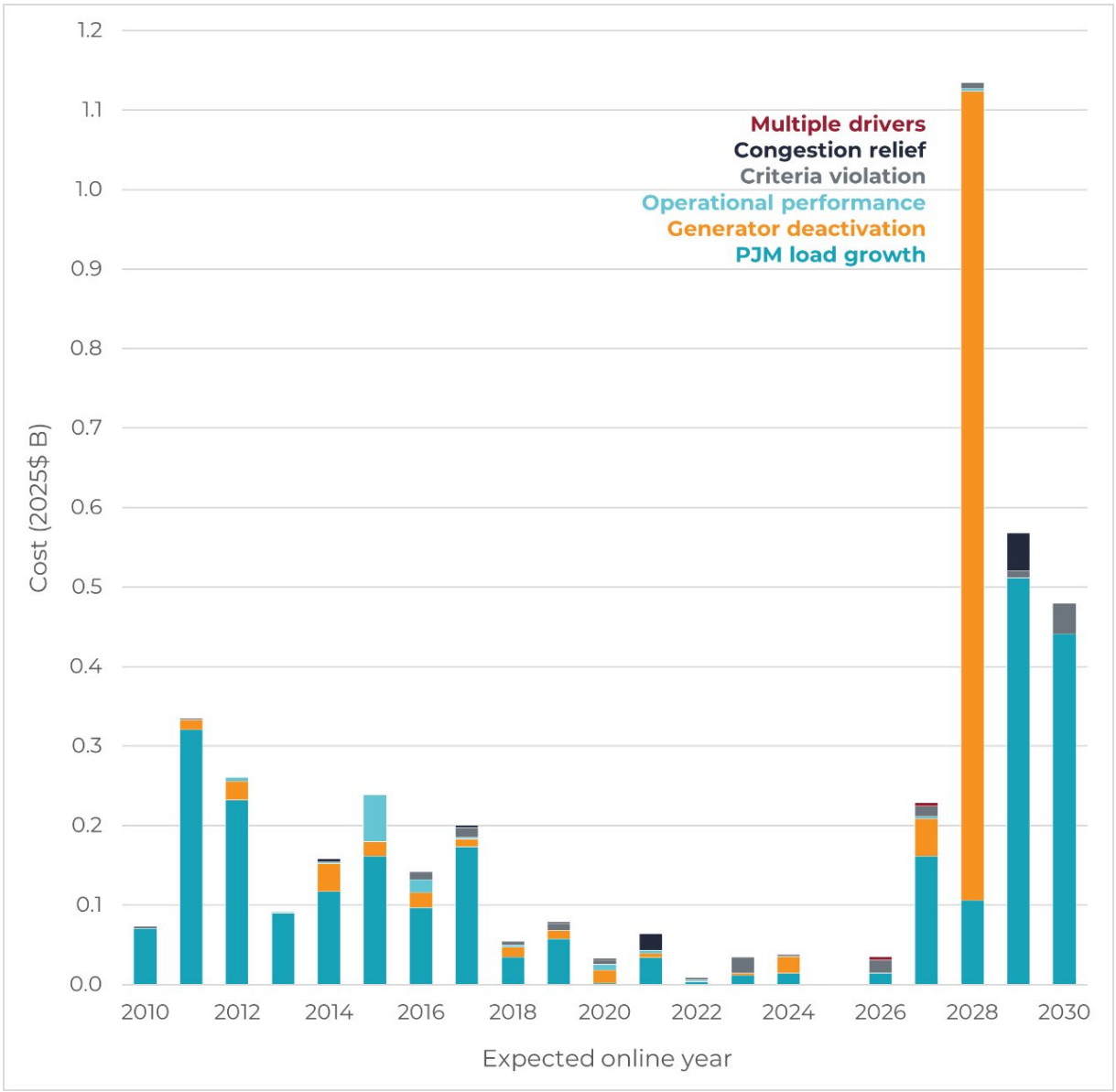
Project Cost Driver	Definition	Pepco	BGE	DPL	APS
Total Baseline Project Capital Costs Allocated to Maryland, 2010-2030 (millions, 2025 dollars)		**$ 1,097**	**$ 2,418**	**$ 352**	**$ 395**
Load Growth & Reliability	Projects needed to maintain compliance with NERC under forecasted system conditions. Includes addressing load growth, thermal/voltage violations, short-circuit issues, and deliverability of resources to load.	75%	53%	66%	81%
Generator Deactivation	Projects triggered by the planned retirement of generation resources that would otherwise result in the system unable to meet reliability or deliverability requirements.	16%	42%	8%	10%
Operational Performance	Projects that address non-NERC reliability issues, which may enhance reliability but may not resolve a formal violation. May include voltage support, dynamic stability, transfer capability, etc.	4%	1%	5%	4%
Transmission Owner Criteria Violation	Upgrades required to satisfy more stringent local reliability standards filed in each transmission owner's FERC Form 715 (beyond PJM's minimum criteria).	3%	2%	20%	4%
Congestion Relief	Projects that reduce congestion and lower overall system production costs. These are identified through PJM's Market Efficiency analysis.	3%	2%	0%	1%
Public Policy	Projects driven by federal, state, or local policy requirements, such as renewable portfolio standards or state-initiated transmission needs. Under PJM's framework, these may be advanced through the State Agreement Approach.	0%	0%	0%	0%
Multiple drivers	More than one of the six drivers above.	<0.5%	<0.5%	<0.5%	<0.5%

Source: See description in Section 2.3.

improvements-needed-for-grid-reliability/ https://www.pjm.com/-/media/DotCom/committees-groups/committees/teac/2025/20251208/20251208-item-11---reliability-analysis-update.pdf.

For Maryland electricity customers, generator deactivation projects are a major cost driver for projects expected to be online in 2028 (Figure 7). This set of projects is associated with the Brandon Shores and Wagner RMRs, where building the transmission projects will enable the eventual retirement of the Brandon Shores and Wagner facilities and end their RMR service. Maryland is saddled with 66 percent of the total Brandon Shores Deactivation Project, with BGE responsible for almost 60 percent of the total. This is on top of the out-of-market RMR costs to keep Brandon Shores and Wagner operating, of which Maryland is also responsible for 66 percent of costs.

Figure 7. Total capital costs of approved and in-service baseline projects allocated to Maryland, by cost driver, 2010 to 2030



Source: See description in Section 2.3.

Figure 7, above, demonstrates how load growth-driven projects are rapidly becoming a major source of new transmission projects and costs, as PJM forecasts accelerating load growth outside of Maryland over the next 15 years. Concerningly, these costs are in addition to other electric system costs associated with data centers, such as rising capacity costs.[34]

Cost allocation is an extremely contentious and challenging aspect of transmission planning. From 2014[35] to 2025, Maryland was responsible for 3 percent of all baseline project capital costs and 6 percent of load growth and reliability project capital costs,[36] while the state represented roughly 9 percent of peak load across the RTO.[37] However, from 2025 to 2030, Maryland is paying for an increasingly greater share of baseline projects (10 and 8 percent in 2029 and 2030, respectively) but is responsible for only 2 percent of the region's total load growth.

Load growth-driven projects are rapidly becoming a major source of new transmission projects and costs, as PJM forecasts accelerating load growth outside of Maryland over the next 15 years.

PJM's 2026 long-term load forecast predicts that across the RTO, peak load will increase by 42 percent from 2026 to 2036, adding an additional 66 gigawatts (GW) to the system peak.[38] Comparatively, PJM expects that Maryland's peak demand will only increase by 12 percent over the same period,[39] indicating that much of the demand growth is occurring outside Maryland. Specifically, across the RTO region, PJM projects that data centers will account for 30 percent (67 GW) of total peak demand by 2036. However, Maryland is projected to account for only 2 percent (1.5 GW) of the total data center peak demand in PJM in that time period (Figure 8).[40] PJM projects that most of the region's data center peak demand growth will occur in the Dominion zone (mostly Virginia) and will account for 30 percent of total data center peak demand growth, followed by the AEP zone (mostly Ohio) making up 25 percent, and the ComEd zone (Illinois) making up 15 percent.[41]

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34 The PJM market monitor estimated that data centers represented 40 percent of capacity market costs in PJM's most recent auction. Monitoring Analytics, January 2026. Analysis of the 2027/2028 RPM Base Residual Auction, Part A. The Independent Market Monitor for PJM. Available at: https://www.monitoringanalytics.com/reports/Reports/2026/IMM_Analysis_of_the_20272028_RPM_Base_Residual_Auction_Part_A_20260105.pdf.

35 Peak load share data is not available from 2010 to 2013.

36 See description in Section 2.3.

37 Based on PJM's 2025 Long-Term Load Forecast and supplemental materials. Available at: https://www.pjm.com/planning/resource-adequacy-planning/load-forecast-dev-process.

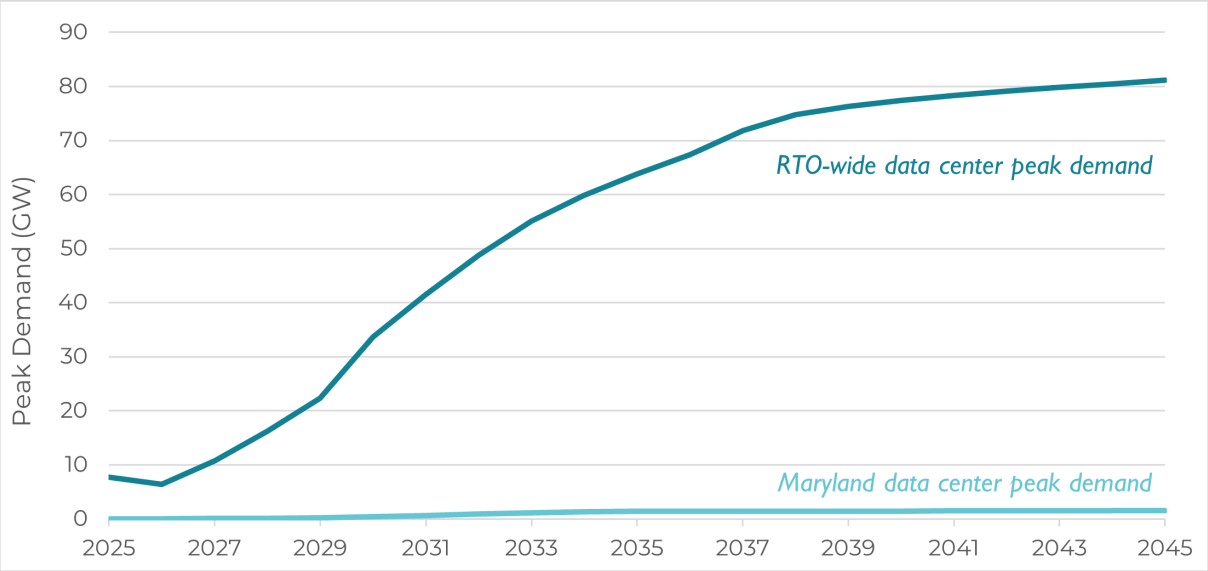
38 PJM Interconnection. 2026 Long-Term Load Forecast. Data retrieved February 10, 2026. Available at: https://www.pjm.com/planning/resource-adequacy-planning/load-forecast-dev-process.

39 Ibid.

40 Ibid.

41 Ibid.

Figure 8. Projected PJM and Maryland data center energy consumption



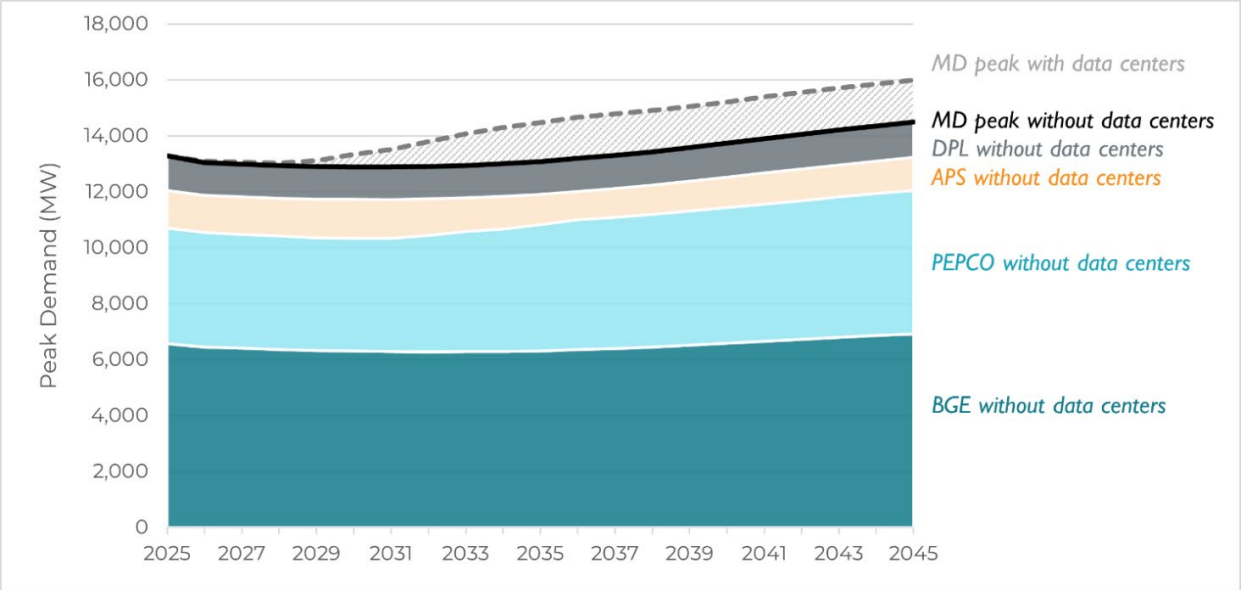
Source: PJM 2026 long-term load forecast. Data retrieved February 10, 2026. Available at: https://www.pjm.com/planning/resource-adequacy-planning/load-forecast-dev-process. See description in Section 2.3 for details on the Maryland portion of demand.

Comparatively, Figure 9 illustrates Maryland's share of projected peak demand across the Pepco, BGE, DPL, and APS zones—excluding data center load. PJM estimates that peak demand from non-data center sources will remain relatively flat in the next 10 to 20 years. Absent data centers, Maryland peak demand increases by only 1 percent by 2036, compared with a 12 percent increase when projected data center demand is included.[42]

PJM estimates that peak demand from non-data center sources will remain relatively flat in the next 10 to 20 years.

[42] Ibid.

Figure 9. Maryland share of projected peak demand by zone with and without data centers



Source: PJM 2026 long-term load forecast. Data retrieved February 10, 2026. Available at: https://www.pjm.com/planning/resource-adequacy-planning/load-forecast-dev-process. Source: See description in Section 2.3 for details on the Maryland portion of demand.

PJM approved $11.8 billion worth of transmission projects in its 2025 RTEP,[43] $6.7 billion in its 2024 RTEP,[44] and $5.1 billion in the 2022 RTEP (window 3 (W3)).[45] A total of $2.3 billion—over $900 million,[46] nearly $800 million,[47] and $551 million of the 2025, 2024, and 2022 W3 RTEP costs, respectively—will be passed on to Maryland electricity customers, mostly for transmission investments due exclusively to out-of-state data center growth. Transmission project costs from out-of-state data center growth have represented a growing share of Maryland electricity costs in recent years. For instance, in the 2022 RTEP, BGE requested financial incentives to build an estimated $634 million of transmission projects to meet reliability needs associated with data centers in Northern Virginia. The transmission projects include multiple new 500 kV transmission lines, substations, transformers and rebuilds, all in BGE's service territory in

43 PJM Interconnection. February 13, 2026. "PJM Board Approves Transmission Improvements Needed for Grid Reliability." PJM Inside Lines. Available at: https://insidelines.pjm.com/pjm-board-approves-transmission-improvements-needed-for-grid-reliability/ https://www.pjm.com/-/media/DotCom/committees-groups/committees/teac/2025/20251208/20251208-item-11---reliability-analysis-update.pdf.

44 Comments of the Maryland OPC. April 28, 2025. FERC Docket No. ER25-1811. Available at: https://opc.maryland.gov/Portals/0/MPC%20Cmts%20ER25-1811%20%5BFinal%5D.pdf?ver=H7cwqPmI1rIghTavBZf1JA%3d%3d.

45 PJM Interconnection. December 2023. Transmission Expansion Advisory Committee (TEAC) Recommendations to the PJM Board, PJM Staff White Paper. Available at: https://www.pjm.com/-/media/DotCom/committees-groups/committees/teac/2023/20231205/20231205-pjm-teac-board-whitepaper-december-2023.ashx

46 For details on estimating the Maryland portion of baseline transmission costs, see description in Section 2.3.

47 Maryland OPC. April 28, 2025. "PJM proposal would unlawfully saddle Maryland customers with nearly $800 million for out-of-state data center growth, OPC tells federal regulators." Press Release. Available at: https://content.govdelivery.com/accounts/MDOPC/bulletins/3de09c9.

central Maryland. Although these data centers are not located in Maryland, they are adding immediate cost burdens to Maryland electricity customers, who are not only paying for these transmission projects, but also the financial incentives granted by PJM to BGE.[48] Under PJM's proposal, Maryland would pay for $551 million, or around 10 percent of total transmission projects from Northern Virgina data centers. On a per-kilowatt basis, Maryland's cost burden would be similar to Virginia's despite Virginia's much larger load growth. OPC protested the cost allocation for these projects in a 2024 filing to FERC, contending that PJM's cost allocation is unjust and unreasonable because it does not align with cost causation principles.[49] OPC argues that these projects should have been treated as multi-driver projects because they address reliability, economic impacts, and public policy requirements (e.g., Virginia's tax incentives for data center development).

Regardless of cost allocation challenges, data center load forecasts are uncertain. It is unclear to what extent projected data center load will materialize, how flexible such load will be (i.e., impact on peak demand), and how efficient the data centers might become in the future (i.e., how much energy will each data center consume when accounting for technological advancement). Nonetheless, these recent PJM forecasts are already informing PJM's transmission planning and driving new transmission projects across the region. If these load forecasts are overblown, PJM risks overbuilding its transmission system. Building projects today that turn out to be unnecessary in the future could lock in millions of dollars of capital and operations expenses, impacting electricity customers for decades to come.

4. LOCAL TRANSMISSION PROJECTS

PJM does not independently assess the need for local transmission projects.

Local transmission projects are local expansion and enhancement projects planned and developed by transmission owners to address local needs such as equipment upgrades or replacement, or local reliability improvements. Since these projects are not needed for regional reliability, PJM does not independently assess the need for these projects. The projects typically have little to no oversight and are paid for by all customers within the project's transmission zone, regardless of whether the project is in a different state within that zone.

[48] Maryland OPC. August 25, 2025. "OPC asks federal regulators to deny BGE financial incentives to build $634 million of transmission projects driven by Virginia data centers." Press Release. Available at: http://content.govdelivery.com/accounts/MDOPC/bulletins/3ef70f4.

[49] Maryland OPC. February 9, 2024. Maryland OPC Protest and Affidavit of R. Nelson. FERC Docket No. ER24-843. Available at: https://opc.maryland.gov/Portals/0/Files/Publications/Others/MdOPC%20Protest%20and%20Affidavit%20of%20R.%20Nelson%20ER24-843%2002-09-24%20%281%29.pdf

4.1. Planning and Oversight Process

Unlike for baseline projects, transmission owners have sole discretion to initiate these projects. Transmission owners plan for these projects outside PJM's RTEP process, yet still in accordance with the Open Access Transmission Tariff (OATT).[50] PJM requires transmission owners to present projects that are 230 kV and above to the TEAC, and projects below 230 kV to the Subregional RTEP Committees. However, PJM does not require transmission owners to submit these projects to the PJM Board for review or approval,[51] nor does PJM require transmission owners to follow its competitive solicitation process.[52] These projects are instead presented as part of the final RTEP report.[53] PJM's role is limited to evaluating whether the proposed local project imposes any adverse impacts on the broader regional grid through a "do-no-harm" study. PJM does not evaluate whether the proposed local project is necessary, cost-effective, or prudent.

Local projects are not subject to substantial state or federal regulatory review.

Furthermore, local projects are not subject to substantial state or federal regulatory review. For some transmission projects, owners must receive a Certificate of Public Convenience and Necessity (CPCN) from the Maryland Public Service Commission (PSC) before beginning construction in the state, but Maryland law includes certain waivers from CPCN requirements and does not require CPCNs for underground transmission lines.[54] Further, Maryland law does not require the PSC to consider cost-effective alternatives to transmission as part of the CPCN process. As a result, local projects have almost no review standards or oversight compared to baseline projects.[55] For baseline projects, PJM rules require validation of project needs, competitive solicitations (thereby incentivizing lower-cost, innovative solutions), cost analyses,[56] and PJM board approval. Though sometimes

50 OATT Attachment M-3. PJM Interconnection. July 2021. PJM Manual 14B: PJM Region Transmission Planning Process, Revision 50, effective July 1, 2021, PJM Transmission Planning Department. Available at: https://www.pjm.com/-/media/DotCom/documents/manuals/archive/m14b/m14bv50-pjm-regional-transmission-planning-process-07-01-2021.pdf.

51 PJM Interconnection. April 17, 2025. RTEP 2024: Regional Transmission Expansion Plan. Available at: https://www.pjm.com/-/media/DotCom/library/reports-notices/2024-rtep/2024-rtep-report.pdf, page 74.

52 Local (Supplemental) projects are presented through the TEAC (230 kV and above facilities) or the Subregional RTEP Committees (below 230 kV facilities).

53 PJM Interconnection. April 17, 2025. RTEP 2024: Regional Transmission Expansion Plan. Available at: https://www.pjm.com/-/media/DotCom/library/reports-notices/2024-rtep/2024-rtep-report.pdf.

54 See Maryland Public Utilities Article § 7-207.

55 Comments of the Maryland OPC in Support of the Office of the Ohio Consumers' Counsel Complaint, November 11, 2023. FERC Docket No. EL23-105-000. Available at: https://opc.maryland.gov/Portals/0/Files/Publications/Others/OPC%20Comments%20EL23-105%20-%20OCC%20Complaint.pdf.

56 As described in the PJM Manual 14C, Section 6.1.2.1 Cost Changes, "Significant cost increases to baseline upgrades can change the analysis done to solve criteria violations and therefore need to be communicated to PJM as they are discovered. PJM will use the new cost data to re-analyze the criteria violation and determine if a different, more economical solution is better suited to solve the issue". PJM Interconnection, L.L.C. *PJM Manual 14C: Interconnection Facilities, and Network Upgrade Construction*. Revision 17, effective July 23, 2025.

flawed, these baseline project review processes serve as safeguards for electricity customers. These safeguards are largely absent in the local project planning process. Although stakeholders may comment on proposed local projects during TEAC and Subregional RTEP subcommittee meetings, transmission owners are not required to incorporate stakeholder feedback before moving forward with a project's development. Furthermore, informational asymmetries often exist, and stakeholders frequently lack time, resources, and the transmission-engineering expertise needed to review proposed projects in their entirety.

Because local projects lack regulatory oversight and are exempt from competition, local projects are often much faster and simpler to advance. This lack of oversight and competition creates a perverse incentive for transmission owners who favor capital-intensive investments to invest more heavily in these projects. In recent years, transmission owners in Maryland have been pursuing these projects at a disproportionate rate.

Consumer advocates, including the OPC and the Consumer Advocates of the PJM States (CAPS), of which the OPC is a member, have raised substantial concerns about the PJM's local transmission project process, stating that it lacks transparency, oversight, and meaningful stakeholder engagement. For instance, OPC has a complaint pending before federal regulators on the regulatory gap that exists for local transmission projects.[57] OPC has argued that PJM rules allow transmission owners to determine whether to classify projects as local, allowing them to bypass regional planning, competitive procurement, and rigorous cost-benefit review.[58] OPC and CAPS have noted that information provided to stakeholders is often minimal or incomplete, with limited access to project justifications, cost drivers, alternative solutions, or reassessments after project approval; this information gap undermines the ability of states and consumer advocates to provide informed feedback.[59] From 2017 to 2022, Maryland utilities spent nearly $1 billion on local transmission projects, a figure that does not include the more than $1.6 billion costs of the non-competitively procured Brandon Shores Deactivation Project associated with the planned retirement of the Brandon Shores coal plant.[60] OPC and CAPS have urged FERC to close these

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Prepared by System Planning Division, PJM Interconnection, L.L.C. https://www.pjm.com/-/media/DotCom/documents/manuals/m14c.pdf.

57 See *Complaint of Industrial Energy Consumers of America, et. al. v. Avista Corporation, et. al.*, Docket No. EL25-44; *see also* Md. Office of People's Counsel, *Costly local transmission projects that avoid competition are causing unlawful rates, OPC tells federal regulators* (Dec. 19, 2024), https://content.govdelivery.com/accounts/MDOPC/bulletins/3c86285

58 Maryland OPC. November 20, 2023. "Maryland Utility Customers Vulnerable to Regulatory Gap in Oversight of Costly Transmission Projects, Office of People's Counsel Tells Federal Regulators." Press Release. Available at: https://content.govdelivery.com/accounts/MDOPC/bulletins/37c005f.

59 Consumer Advocates of the PJM States (CAPS). "*Letter Re: Supplemental Projects*," PJM Public Disclosures, accessed December 30, 2025, https://www.pjm.com/-/media/DotCom/about-pjm/who-we-are/public-disclosures/caps-letter-re-supplemental-projects.

60 PJM Project Status & Cost Allocation, Transmission Cost Planner (TC Cost Planner). Data retrieved February 2026. Available at: https://www.pjm.com/planning/m/project-construction. Brandon Shores Deactivation Projects include baseline projects b3780 and b3781, per PJM Interconnection, February 2025. Transmission Expansion Advisory Committee (TEAC) Recommendations to the PJM Board. PJM Staff White Paper. Available at: https://www.pjm.com/-/media/DotCom/committees-groups/committees/teac/2025/20250204/20250204-pjm-board-whitepaper-february-2025.pdf.

regulatory gaps by expanding regional planning requirements to include local projects and by strengthening and promoting competition as a primary mechanism to increase discipline on costs and protect consumers.

4.2. Cost Allocation Methodology

The cost allocation methodology for local projects differs from that of regional baseline upgrades. Under Schedule 12 of the PJM OATT, 100 percent of the costs for local transmission projects are assigned directly to the local transmission owner's zone and are not regionally allocated. All customers in that zone pay for its local projects, regardless of whether the zone spans multiple states.

4.3. Project Cost Drivers for Local Projects in Maryland

From 2010 to 2030, Maryland has been or will be responsible for $2.8 billion of capital costs for local projects. When combined with the $4.3 billion in baseline projects (described in Section 3, above), Maryland is responsible for a total of $7.1 billion of transmission capital costs from 2010 to 2030. Local project needs and drivers are distinct and separate from the PJM-identified reliability criteria used for baseline projects. Instead, needs are determined at the sole discretion of the transmission owner. Table 3 below shows the percentage of cost drivers for all local projects in the transmission zones within Maryland. "Customer Service" and "Equipment Material Condition, Performance and Risk" represent the largest cost drivers amongst the Maryland transmission zones.

Table 3. Total capital costs of local projects paid for by Maryland, and proportion of driver type, by zone

Project Cost Driver	Definition	Pepco	BGE	DPL	APS
Total Local Project Costs Per Zone, 2010-2030 (millions, 2025 dollars)		$ 872	$ 1,565	$ 217	$ 177
Customer Service	Service to new and existing customers; address localized customer concerns, interconnect new customer load; address customer transmission and distribution load growth, outage exposure, and equipment loading	76%	27%	23%	26%
Equipment Material Condition, Performance and Risk	Projects justified by asset condition assessments, aging infrastructure, performance limitations, or risk mitigation considerations	19%	57%	65%	51%
Operational Flexibility and Efficiency	Optimizing system configuration, equipment duty cycles and restoration capability; minimize outages	2%	6%	5%	5%

Project Cost Driver	Definition	Pepco	BGE	DPL	APS
Infrastructure Resilience	Projects designed to improve system operability, enhance flexibility, or increase system's ability to anticipate, absorb, adapt to, and/or rapidly recover from a potential disruptive event (including severe weather, geo-magnetic disturbances, and physical and cyber security challenges)	0%	0%	0%	<0.5%
Other	Projects supported by miscellaneous or project-specific justifications that do not fall neatly into the categories above including industry recommendations, potential generation retirements, technology pilot projects, governmental/utility commission regulation, and state policy goals	<0.5%	0%	0%	0%
Multiple Drivers	Projects for which transmission owners cite a combination of two or more of the above drivers as the basis for need	4%	11%	7%	17%

Source: See description in Section 2.3.

Data centers are also driving many local projects in Maryland and across PJM. In 2024 alone, utilities in seven PJM states (Maryland, Illinois, New Jersey, Ohio, Pennsylvania, Virginia, and West Virginia) charged their customers more than $4.3 billion in local transmission upgrades to provide transmission services to data centers, and from 2022 through 2024, initiated 130 local transmission projects to connect new data centers.[61] Of the $4.3 billion worth of local transmission upgrades, $108 million were from Maryland data centers in the APS zone.[62]

5. NETWORK UPGRADE PROJECTS

Project developers cover the costs for network upgrades.

Network upgrade projects are transmission infrastructure projects needed to accommodate the interconnection of new service requests to the transmission network. These requests can include new generators, merchant transmission facilities, or new transmission requests in an area with insufficient transmission capacity.[63] Project developers cover the costs for

[61] Jacobs M. Union of Concerned Scientists. 2025. Connection Costs: Loophole Costs Customers Over $4 Billion to Connect Data Centers to Power Grid. Available at: https://www.ucs.org/sites/default/files/2025-09/PJM%20Data%20Center%20Issue%20Brief%20-%20Sep%202025.pdf.

[62] Ibid at Appendix: Compilation of Utility Projects by State. Available at: https://www.ucs.org/sites/default/files/2025-09/PJM%20Data%20Center%20Issue%20Brief%20Appendix%20-%20Sep%202025.pdf.

[63] David Gardiner and Associates. February 2024. Transmission Handbook, Volume IV: Transmission Planning in PJM. Prepared for the Consumer Advocates of the PJM States (CAPS). Available at: https://www.dgardiner.com/wp-content/uploads/2024/03/CAPS-Transmission-Handbook-Volume-4.pdf.

network upgrades; thus, these costs are not direct consumer costs. However, generators recover these costs in the PJM energy and capacity markets, where consumers will pay for these costs indirectly. Planning and oversight process for network upgrade projects happen through the interconnection queue process, including studying upgrade needs and cost development. Network upgrades represent a small percentage of overall transmission spending. Across PJM, they make up 7 percent of total transmission costs.

Network upgrade costs have been increasing in recent years. The PJM interconnection queue has experienced major delays as PJM has sought to overhaul its process. As discussed above, PJM projects data center load will rise at an alarming rate and reach unprecedented levels. In tandem with aging generators nearing retirement, projections of data center growth suggest the PJM system faces resource adequacy risks and needs to bring on more generation. As more resources seek to interconnect to the grid to meet growing demand, total network upgrade costs will continue to rise. Despite PJM's efforts to reform and streamline the interconnection queue process, it is still slow and expensive for resources looking to interconnect.

6. COST RECOVERY, RETAIL RATES, AND LONG-TERM CONSUMER IMPACTS

Transmission charges are the mechanisms by which transmission owners recover the costs of transmission projects. Baseline and local projects are recovered through two different components: Transmission Enhancement Charges (TEC) and Network Integration Transmission Service Charges (NITS), respectively. Utilities ultimately integrate these charges into ratemaking processes and recover them through retail rates.

6.1. Cost Recovery: TEC and NITS

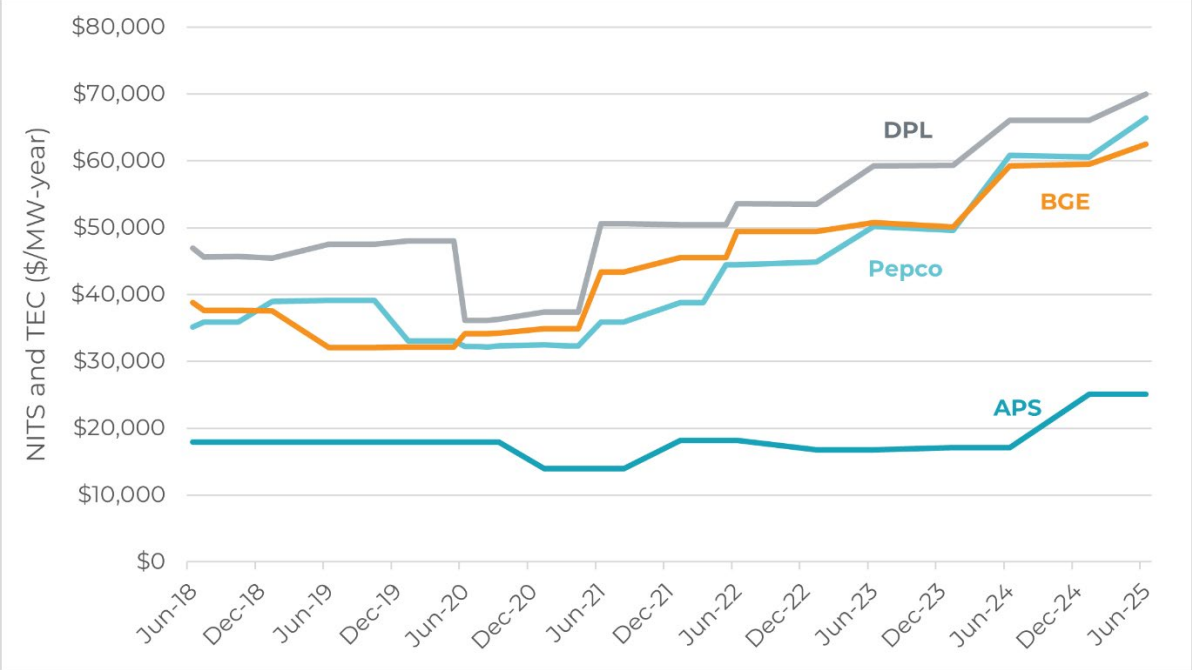
Transmission owners use TEC to recover the costs of baseline projects planned and approved through PJM's RTEP process. Because the benefits of baseline projects are supposed to be regional, PJM cost allocation methodologies assign costs to multiple zones based on which zones benefit from the project. Each benefiting zone is assigned a percentage of the project's annual revenue requirement. The annual revenue requirement includes capital costs, operational and maintenance expenses, depreciation expenses, taxes, and an authorized return on investment. Each zone's allocated share of a baseline project is then converted into a TEC, expressed in dollars per megawatt-month ($/MW-month). Every zone has its own TEC total that PJM charges to its customers, reflecting (1) the allocated share of baseline projects located in that zone that benefit that zone; and (2) the allocated share of baseline projects located in other zones that benefit that zone. For example, for a baseline project built in the Pepco zone, PJM may determine that APS receives 20 percent of the reliability benefit. As a result, APS customers (such as Maryland utility Potomac Edison) pay 20 percent of the project cost through APS's TEC charges, even though the project is physically located in Pepco.

NITS charges are the core mechanism through which transmission owners recover the costs of owning, operating, maintaining, and upgrading local transmission projects. As with TEC, NITS

reflects each project's annual transmission revenue requirement (ATRR), which includes capital costs, operational and maintenance expenses, depreciation, taxes, and an authorized return on investment. For each transmission zone, PJM converts the revenue requirement into a zonal NITS rate, typically expressed in $/MW-Year.

TEC charges for a specific transmission owner are often rolled into a transmission owner's NITS rate. Of the four transmission zones that Maryland is part of, APS is the only zone that does not include its TEC in its NITS rate. Figure 10 shows the combined NITS rate and TEC charges for all four transmission zones in Maryland. The charges have increased over the seven years. Specifically, the combined charges increased by 89 percent for Pepco, 61 percent for BGE, 49 percent for DPL, and 40 percent for APS.[64] The trends in Figure 10 track fairly closely with the residential retail transmission rates shown in Figure 2 (Section 1).

Figure 10. Combined NITS and TEC rates for Pepco, BGE, DPL, and APS (nominal dollars)



Notes: Includes TEC charges and credits, plus NITS charges. PJM Billing, Settlements & Credit. Transmission Enhancement Worksheets and Network Integration Transmission Service Revenue Requirements & Rates. Available at: https://www.pjm.com/markets-and-operations/billing-settlements-and-credit. *Data prior to 2021 from Electricity Transmission Competition Coalition, PJM Network Integration Transmission Service Rates ($/MW-Yr). Available at:* https://electricitytransmissioncompetitioncoalition.org/wp-content/uploads/PJM-Transmission-Rates-History-20215-2024.pdf.

6.2. Retail Rates

Before recovery of TEC and NITS costs begins, rates are filed with FERC. PJM charges each transmission customer its zonal NITS and TEC rates. Transmission customers are typically

[64] When adjusted for inflation, in real dollar terms, the combined charges increased by 51 percent for Pepco, 29 percent for BGE, 19 percent for DPL, and 12 percent for APS.

load-serving entities (LSE), which are distribution utilities (for their standard offer service (SOS) customers) or retail choice suppliers. Under PJM's billing framework, PJM bills the transmission charges to the LSEs in a zone based on their contribution to the zone's maximum peak load on a monthly basis.

LSEs pass these charges down to each of their customer classes using allocation methodologies approved by their state commission. Generally, the allocations are based on each class's contribution to peak load. As a result, retail classes with higher contributions to peak demand bear a proportionally larger share of transmission costs. This allocation methodology ensures that customers with higher demand pay proportionately more for the cost of transmission infrastructure that supports their power needs. Finally, the LSE will then convert the transmission charges for each class into a $/kWh or $/kW charge that appears on customer bills,[65] usually on the supply portion of the bill.

In Maryland, LSEs providing SOS file their retail transmission rates with the PSC before July 1 (or the effective date), along with the allocation calculations for each customer class. These allocations warrant careful examination to ensure that large-load customers are paying for their fair share of transmission costs and that all customers' rates are just and reasonable in this respect.

6.3. Bills and Consumer Impacts

The evolving needs of the grid over the past two decades have led to substantial changes in transmission investments. Even though transmission capital project costs have fluctuated over time, overall spending and the associated rates have entered a sustained period of growth, largely driven by the increase in local projects and more recently from data-center-related baseline projects.

Overall spending and the associated rates have entered a sustained period of growth, largely driven by the increase in local projects and more recently from data-center-related baseline projects.

Transmission project costs are ultimately approved at the federal level and incorporated into utility ratemaking through retail rates. As transmission owners place new projects into service, their associated revenue requirements increase, leading to higher transmission rates. Even if individual project costs appear modest in isolation, the cumulative effect of multiple projects, particularly local upgrades concentrated in certain zones, can increase zonal transmission rates over time. As costs rise, retail rates in Maryland trend upwards, exacerbating the affordability crisis facing residential, small business, and low-income customers. Typically, transmission assets depreciate over 30 to 40 years, meaning that cost

[65] Residential transmission charges typically appear as a $/kWh charge on customer bills.

recovery for an individual asset spans multiple decades.[66] As a result, Maryland customers will continue to see transmission charges for a particular transmission project on their bills over the course of many years.

6.4. Looking Ahead: What to Expect for Future Transmission Costs and Rates

Transmission costs across PJM and for Maryland electricity customers have been rapidly escalating over the last few years, a trend that we expect to continue for the foreseeable future. For example, the 2024 RTEP included $6.7 billion in transmission projects,[67] while the 2025 RTEP is worth $11.8 billion.[68] The following two subsections provide an overview of Synapse's forecast of baseline and local project costs paid for by Marylanders. These forecasts project costs based on the current transmission planning and cost allocation methods used in the PJM region. As discussed elsewhere in this report, OPC has raised objections and challenges to PJM and to FERC regarding these methods.

6.4.1. Baseline project forecasts

Baseline load growth and reliability cost drivers are the largest portion of baseline transmission costs; they represent roughly two-thirds of capital project costs across the PJM footprint and those allocated to Maryland. Although these types of projects are for both reliability and load growth, total project spending for this category tracks closely with peak demand (Figure 11). When peak load is flat, RTO-wide project spending on load growth and reliability projects remains relatively flat and then falls, as can be seen over the last decade from 2014 to 2024. As peak load forecasts have begun to increase at an accelerating pace from 2025 to 2030, approved project costs for load growth and reliability have increased accordingly (Figure 11). We assume that for 2030 to 2035, peak load and reliability projects will continue to track load growth closely, rising at the same annual growth rate as the 10-year peak load forecast from 2025-2035. In reality, costs will be much higher if data center demand continues to grow or could be much smaller if that demand is over-inflated and corrected in the future. Project spending will also likely be much lumpier than appears in Figure 11.

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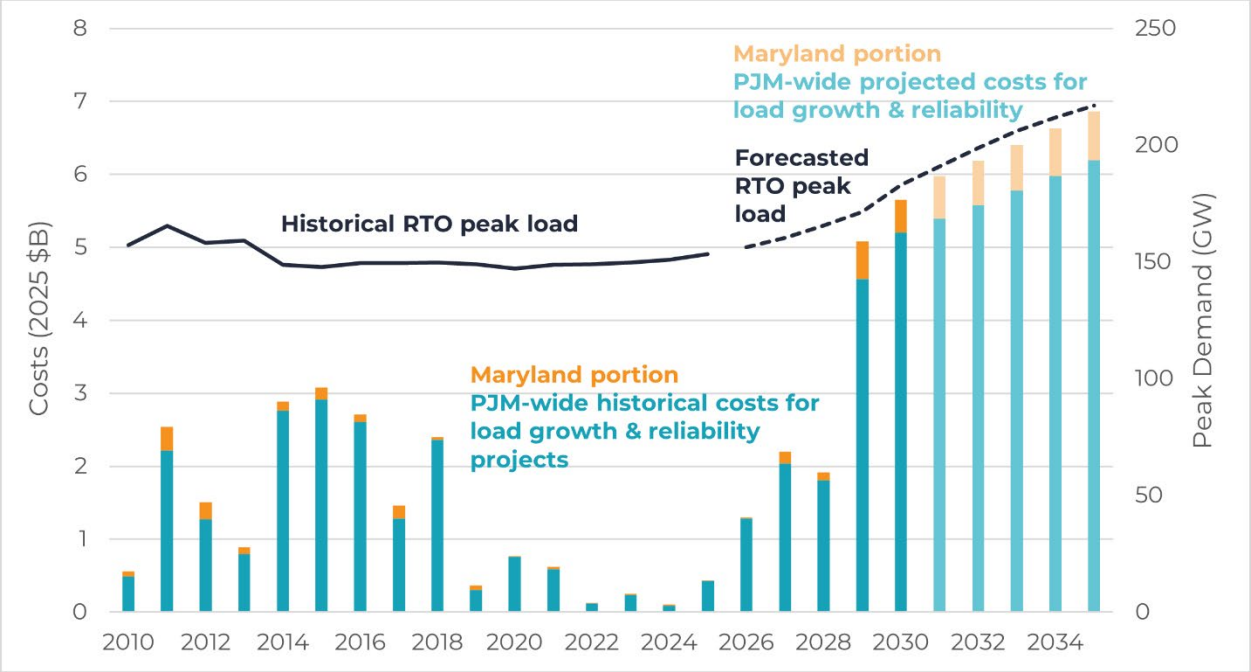
66 Exelon Corporation, *Property, Plant and Equipment – Annual Depreciation Provisions as Percentage of Average Service Life*, SEC Form 10-K XBRL Exhibit R83, Dec. 31, 2021, https://www.sec.gov/Archives/edgar/data/78100/000110935722000076/R83.htm.

67 PJM Interconnection. February 26, 2025. "PJM Board Approves New Transmission Projects to Support Grid Reliability." *PJM Inside Lines*. Available at: https://insidelines.pjm.com/pjm-board-approves-new-transmission-projects-to-support-grid-reliability/.

68 PJM Interconnection. February 13, 2026. "PJM Board Approves Transmission Improvements Needed for Grid Reliability." *PJM Inside Lines*. Available at: https://insidelines.pjm.com/pjm-board-approves-transmission-improvements-needed-for-grid-reliability/ https://www.pjm.com/-/media/DotCom/committees-groups/committees/teac/2025/20251208/20251208-item-11---reliability-analysis-update.pdf.

Figure 11. RTO-wide historical and forecasted peak load, and RTO and Maryland-only portion of baseline capital project costs for load growth and reliability projects, 2010 to 2035



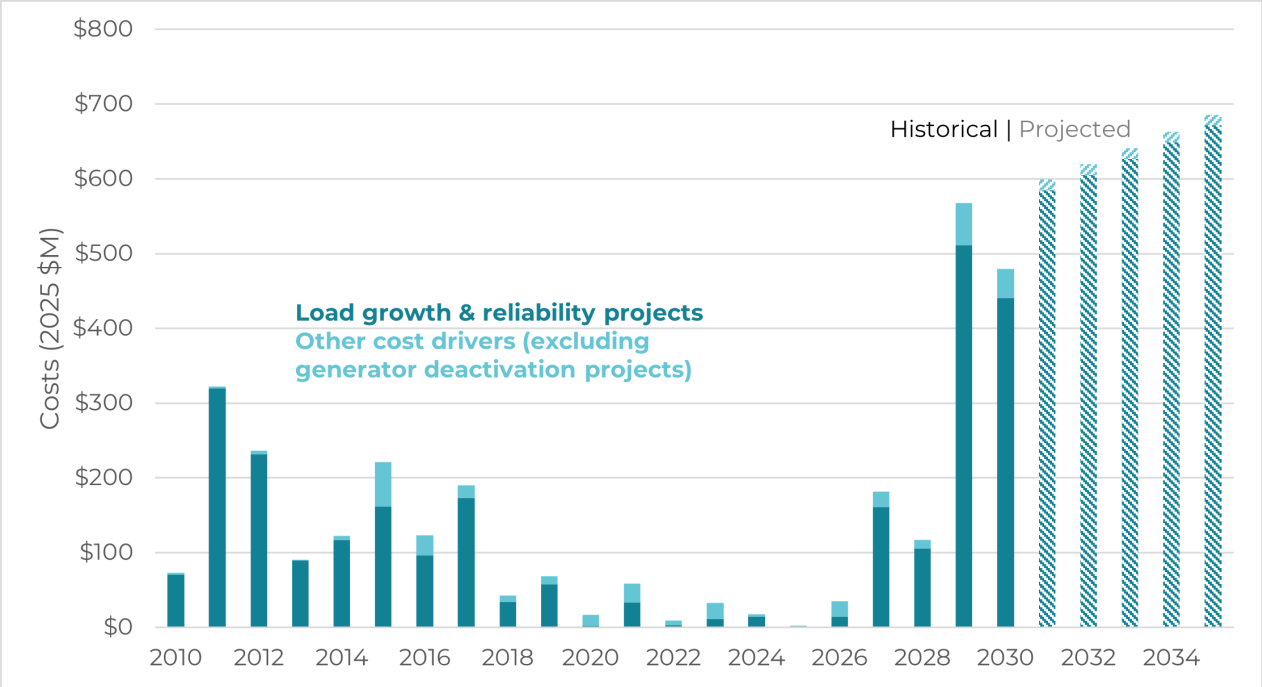
Notes: See description in Section 2.3. Historical and forecasted peak load is from PJM's 2026 Long-Term Load Forecast. Data retrieved February 10, 2026. Available at: https://www.pjm.com/planning/resource-adequacy-planning/load-forecast-dev-process. *For details on forecasted project costs, see description in text.*

Maryland has historically paid for 8 percent of PJM load growth and reliability projects, on average, with substantial variability across years, as can be seen above in the blue bars in Figure 11. From 2025 to 2030, the share of these projects PJM is allocating to Maryland has increased from less than 1 percent to a maximum of 10 percent, mostly driven by data centers being built in Virginia, parts of Maryland, and the neighboring areas. Although Maryland's load growth is comparatively flat, we assume that Maryland will continue paying 10 percent of PJM load growth and reliability projects in the near future, reflecting continued data center development in Virginia and the surrounding regions. Nonetheless, this number could be substantially different depending on where data centers are built and how costs are allocated across zones. Under these assumptions, we estimate that Maryland electricity customers could be allocated an additional $3.1 billion dollars in capital transmission costs for load growth-related projects from 2031 to 2035 (although actual project costs will be paid for over many decades) (yellow bars in Figure 11).

Although load growth and reliability projects represent the largest share of baseline projects, Marylanders also pay for projects due to other cost drivers. Assuming the historical average annual spending and cost allocation to Maryland remains steady—and excluding generator deactivation projects—Maryland electricity customers in the state could incur an additional $72 million dollars for other baseline project types (e.g., congestion relief) during the 2025–2031 period, on top of the $3.1 billion associated with load-growth and reliability-related projects. This

equates to a total of $3.2 billion for 2031 to 2035, a major increase compared to the $4.3 billion of baseline capital costs PJM allocated to Maryland in the proceeding 20 years (Figure 12).

Figure 12. Maryland-only portion of historical (2010 to 2030) and projected (2031-2035) baseline capital project costs



Notes: See description in Section 2.3. For details on forecasted project costs, see description in text.

This forecast does not include generator deactivation projects, as they are difficult to estimate. These types of projects are rare and very lumpy. Moreover, deactivation can occur anywhere in the PJM region. However, it is possible that we will see more generator deactivation-driven transmission projects (such as those addressing RMRs) across PJM, as load continues to grow rapidly and capacity becomes increasingly constrained across the region. For instance, Exelon (the parent company for Pepco, BGE, and DPL) announced that it expects to spend an additional $12 billion to $17 billion on transmission buildout over the next 10 years, which includes generator deactivation projects, among others.[69]

6.4.2. Local project forecasts

Predicting future local projects is much more challenging than for baseline projects because these local projects are not directly tied to load forecasts and other changes on the electric system. Additionally, local projects are highly variable year-over-year and between zones. Nonetheless, assuming historical growth rates of local project spending across the four transmission zones in Maryland, Synapse estimates that the cumulative local project capital

[69] Howland, E. February 13, 2026. "Transmission drives Exelon's capital spending plan to $41.3B." *Utility Dive*. Available at: https://www.utilitydive.com/news/exelon-transmission-data-center-capex-earnings/812200/.

costs from 2031 to 2035 could reach as high as $2.2 billion, in addition to the $3.2 billion of baseline project capital cost forecast discussed above.

In total, we estimate that baseline and local capital costs for Maryland could total $5.4 billion for 2031 to 2035, a major increase compared to the $7.1 billion of transmission costs from the proceeding 20 years.

Lastly, these estimates of near-future spending will be compounded for consumers by existing projects that were built in the previous decades. Customers are still paying for transmission projects built in the 1980s in their electricity rates—any future projects will be added to those existing projects still on the books and will be paid for over decades.

7. RECOMMENDATIONS

7.1. Government Agency Involvement in Transmission Issues

States, regulatory agencies, and consumer advocates should play an important role in transmission planning, cost allocation, and project oversight. These stakeholders, among others, engage in the transmission planning process through multiple PJM committee meetings, federal regulatory processes at FERC, and regional planning organizations. This process allows stakeholders to review proposed transmission projects, provide input on project needs, and influence policy that affects retail customers. The OPC is regularly active in relevant PJM forums. Nonetheless, the PJM stakeholder process remains flawed and is highly resource-intensive. When resources are limited, stakeholders may find it most strategic to focus on key forums, workshops, committee meetings, and docketed cases where stakeholder input can be the most effective.

The PJM stakeholder process remains flawed and is highly resource-intensive.

7.2. Opportunities for Maryland to Mitigate Rising Transmission Costs

Maryland has several avenues to advocate for measures that can mitigate rising transmission costs.

- **Advocate for more accurate load forecasts, especially with respect to data centers**: Given that data centers are the main driver of projected load growth in PJM, and thus transmission costs, it is critical that the large-load adjustments PJM includes in its load forecasts are realistic, based on best available data, and well-vetted. Increased transparency, oversight, and better data overall is needed to improve the accuracy of PJM's data center load forecasts. Improved regional collaboration around data

It is critical that the large-load adjustments PJM includes in its load forecasts are realistic, based on best available data, and well-vetted.

gathering can reduce the potential for double-counting of data center loads across jurisdictions.

- **Establish an Independent Transmission Monitor**: Advocate for the implementation of an independent transmission monitor (ITM), similar to ISO New England's recent creation of an Asset Condition Reviewer,[70] to review and increase transparency of project needs and costs. An ITM in the PJM region could review benefits and costs to evaluate the cost-effectiveness and consider alternatives. The ITM could promote projects that meet multiple needs over a longer planning period (rather than individual projects to meet one specific need) and ensure that projects are rightsized (but without overbuilding) to account for future load growth and electrification. An ITM would not normally set or change rates, reject projects outright, or change cost allocation and allowable rates of return. Real cost containment requires coordinated engagement at the PJM planning, tariff, and FERC regulatory levels. However, an ITM can be a valuable oversight body that supports consumer advocates with Federal Power Act section 206 filings, to lower the burden of proof and advocate for meaningful changes.

- **Strengthen regulation of transmission projects at the state level:** For local transmission projects, the PSC should require cost-benefit evaluation and consideration of alternatives to costly transmission projects during CPCN proceedings, although additional statutory authority or guidance may be required.[71] This would add an additional layer of regulatory oversight to local projects, which would improve transparency and help mitigate costs, project overbuilds, and unnecessary local projects.

- **Reform transmission cost allocation for large load customers**: Stakeholders can advocate at FERC for rules that specifically align cost allocation with cost causation and require large-load customers to pay for the transmission costs that would not be incurred without them. Although transmission service charges are allocated to specific customers based on their share of peak demand, stakeholders

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70 In the ISO New England region, concerns about rising transmission costs have led stakeholders to advocate for the creation of an Asset Condition reviewer to provide unbiased oversight across transmission planning categories and ensure cost-effective project design. The Asset Condition reviewer has been approved by ISO-NE but is still in its initial design phase. It will act independently from ISO-NE and the incumbent transmission owners, with authority to review transmission projects under the Asset Condition Projects (ACP) category. Advocates argue that this oversight would help with rightsizing and inefficient investments and improve the overall process.

71 In a case involving a Potomac Edison supplemental transmission project that would take down an existing transmission line and build a new line along the same route, the PSC rejected OPC's position that the project was a "new" line under the CPCN statute, and therefore, it determined there was no need for the utility to present evidence on alternatives or for the PSC to find that the proposed project was the least-cost solution. Md. Pub. Serv. Comm'n, Order No. 90684, Potomac Edison Company's Application for a Certificate of Public Convenience and Necessity to Rebuild Doubs-Goose Creek Transmission Line (Case No. 9669, June 27, 2023).

can petition for some large-load customers, such as data centers, to pay for a greater share of projects that are driven entirely by their new service requests.

- **Engage in Federal Power Act Section 206 filings**: Advocates should continue to challenge transmission projects of concern at FERC through filings under the Federal Power Act section 206. Cases could involve reviewing the prudency and/or cost allocation of specific projects or could target specific transmission owner rate cases reviewing rates of return, depreciation, and other areas of cost of service. However, direct intervention at FERC is highly resource-intensive due to the information asymmetry between advocates and transmission owners. Although this form of advocacy can sometimes lead to positive outcomes, it shifts the burden to consumer advocates, state agencies, and other intervenors to demonstrate that existing rates or practices are unjust, unreasonable, or unduly discriminatory.
- **Promote cost-reducing technologies**: Stakeholders can support the use of lower-cost Grid Enhancing Technologies and Advanced Transmission Technologies as encouraged by FERC in Order 1920 to lower transmissions costs and network upgrades. They can also advocate for lower-cost alternatives, such as non-wires alternative as opposed to traditional transmission investments. Such advocacy can be take place at all forums and advocacy avenues discussed above.

Overall, Maryland stakeholders should actively pursue all available avenues to mitigate the risk of substantial transmission cost increases. Collaboration with other consumer advocates, state agencies, and regional partners can further strengthen these efforts. Proactive and coordinated engagement across federal, regional, and state processes will be critical to ensure that transmission investments are justified, cost-effective, and aligned with the interests of Maryland electricity customers.

CERTIFICATE OF SERVICE

Pursuant to Commission Rules of Practice and Procedure Nos. 206(c) and 2010, I hereby certify that I have this 7th day of May, 2026 caused the foregoing document to be served upon the Corporate Officials of Respondent PJM Interconnection, LLC that are identified on the Commission's list maintained pursuant to 18 C.F.R. § 385.2010(k).

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