Corporate Energy Buyers Association

April 20, 2026

To:
Wenzheng Qiu
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Emmanuele Bobbio
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PJM Interconnection
2750 Monroe Blvd.
Audubon, PA 19403

Re: Feedback on 2026 RTEP Assumptions (as presented at the April 7, 2026, TEAC)

Via E-mail

Dear Wenzheng and Emmanuele,

CEBA is pleased to submit the following feedback on your presentation at the April 7, 2026, Transmission Expansion Advisory Committee (TEAC) regarding assumptions for the 2026 Regional Transmission Expansion Plan (RTEP). In sum, CEBA supports PJM's proposal to implement capacity expansion modeling in RTEP planning. We also offer detailed feedback on certain technical assumptions.

Capacity expansion modeling in RTEP

CEBA supports PJM's proposal to incorporate capacity expansion modeling into RTEP. This approach aligns with practices in other RTOs and strengthens PJM's ability to proactively plan regional transmission that, in turn, should help ensure that backbone transmission investments are both prudent and deliver savings over time to consumers. CEBA believes that capacity expansion modeling confers several key advantages over current planning assumptions, including:

- Better reflecting how economic generation is deployed to meet expected demand growth plus reserve margin requirements;
- Producing a more realistic view of future generation buildout, by incorporating PJM's own resource characteristics, technology costs and performance, siting constraints, and other commercial factors;
- Leading to more efficient and cost-effective transmission solutions by using more accurate projections of generation type and location; and

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- Building transparency and trust with states on the amount and location of needed transmission.

Feedback on additional technical assumptions

Below, we offer CEBA's feedback on additional technical assumptions as presented to the April 7, 2026, TEAC. For convenience, we have organized our feedback by slide number and topic.

Slide 24: Policy and Planning Inputs

PJM should retain flexibility to consider a broader set of factors—beyond state and federal policies—that may influence the generation mix and reliability needs over the planning horizon. This could include utility-level energy commitments or large energy customer direct procurement trends. CEBA suggests that PJM include additional discretion for consideration of additional factors, consistent with PJM's approach proposed on Order No. 1920 compliance.

Slide 26: Generation Queue Assumptions

PJM should revisit its assumption that *all* queued generation that has not yet received a GIA is built before allowing the capacity expansion model to select new resources. Given historical withdrawal rates in the queue, allowing the model to economically determine buildout, rather than assuming full queue completion, may better reflect likely outcomes, especially for early-stage projects in future planning cycles. This will be particularly relevant in future RTEP studies that consider queued projects beyond TC1 and TC2, which are already commercially advanced.

We also encourage direct engagement with vertically integrated utilities in the footprint to reflect state-approved generation plans.

Slide 26: Sensitivities

PJM should consider a broader set of sensitivities, including natural gas price variations and high/low load growth scenarios, both of which materially impact resource economics and planning outcomes. For reference, MISO took this approach in its recent refresh of planning futures.[1]

Slide 26: Retirement Assumptions

Limiting retirements in the base case to only those units that have announced deactivation may understate future system needs given that the planning horizon is through 2046 (while generation deactivations are commonly announced on a shorter horizon than 8 years out). PJM could instead consider incorporating age-based retirement assumptions, with opportunities for asset owner adjustments, consistent with MISO's approach.

Slides 27 & 34: Storage Technologies

PJM should expand the range of storage durations modeled beyond just 4- and 10-hour systems to better align with the full suite of storage technologies included in PJM's ELCC technology set, including 6- and 8-hour battery storage.

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[1] MISO, *Futures Redesign: Large Load Siting Methodology (*Nov. 18, 2025), Slide # 8, https://cdn.misoenergy.org/20251118%20Workshop%20Item%2001%20Intro%20%20Overview727689.pdf.

Corporate Energy Buyers Association

Slide 34: Nuclear Technologies

PJM should consider including advanced nuclear technologies (e.g., small modular reactors, SMRs) in capacity expansion modeling to reflect a broader set of potential future resources. MISO currently includes nuclear SMRs by relying on 2024 baseline technology assumptions from the U.S. Department of Energy's National Laboratory of the Rockies.

Slide 38: Learning Curves

PJM should expand learning curves to include longer-duration storage technologies, including 6-, 8-, and 10-hour durations to better reflect expected cost trajectories. The 10-hour technology is listed but not depicted on the graph.

Thank you for the opportunity to provide this feedback. We appreciate PJM's thoughtful approach to developing robust RTEP assumptions that increase the likelihood of selecting regional transmission solutions that meet the needs of a rapidly evolving grid. Please do not hesitate to contact our team with any questions.

Sincerely,

John Miller
Director, Transmission Policy
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Comments of FirstEnergy to PJM Planning Staff on
2026 RTEP 8-Year Capacity Expansion Assumptions

April 22, 2026

Submitted via Email

FirstEnergy provides these written comments on the 2026 Regional Transmission Expansion Planning ("RTEP") 8-year capacity expansion modeling and assumptions.[1] FirstEnergy appreciates PJM staff's efforts to share with stakeholders how it is planning to address the 2034 solvability challenge in the RTEP power flow cases, as well as PJM's willingness to discuss results of the capacity expansion modeling at the May 8, 2026 TEAC meeting. It is FirstEnergy's understanding that in this cycle, the 8-year analysis (inclusive of impacts from the capacity expansion modeling) is intended to inform (*i.e.*, affirm or validate) the 5-year power flow modeling results rather than serve as a stand-alone source of transmission needs and therefore would not on its own introduce needs outside of those identified by the 5-year model.

Against that backdrop, FirstEnergy offers the comments below with the goal of supporting the development of a clear problem statement for the 2026 RTEP cycle. This includes seeking clarification and asking questions to enable better interpretation of the modeling assumptions, results, and implications to regional transmission needs. This will help FirstEnergy, PJM and stakeholders understand and apply the 8-year results in a practical and useful manner. FirstEnergy appreciates and encourages PJM's continued stakeholder engagement on this and any future use of capacity expansion modeling in regional transmission planning processes at PJM.

Overview of Comments

As discussed in more detail below, as PJM conducts the initial capacity expansion modeling, FirstEnergy recommends that PJM address the following before or at the May 8 TEAC meeting:

1. Provide confirmation that the capacity expansion modeling and subsequent transmission power flow analysis in both the 5-year model and 8-year model, will not take into account PJM's proposed Connect and Manage framework, or any other additional load flexibility mechanism(s).

2. Provide confirmation regarding which resources from the current interconnection queue will and will not be included in the modeling and how PJM plans to weigh any alternate scenarios; and confirm PJM's modeling assumption concerning the types of resources the model will assume will be constructed.

[1] See *Review of 2026 RTEP Assumptions*, presentation before the Transmission Expansion Advisory Committee, at slide 28 (Apr. 7, 2026), https://www.pjm.com/-/media/DotCom/committees-groups/committees/teac/2026/20260407/20260407-item-10---2026-rtep-assumption-update.pdf.

3. Provide clarification on how new resources and load will be mapped from zonal capacity expansion inputs and portfolios to nodal power flow cases.

1. Confirmation Regarding Load Flexibility

In the current Expedited Critical Issue Fast Path process on the Reliability Backstop Procurement ("RBP"), PJM has proposed two components to address resource adequacy: 1) a voluntary bi-lateral transaction system facilitated by PJM (via Charles River Associates) with eligibility requirements for Bring Your Own New Generation (BYONG) and gating criteria for new load characteristics and 2) a subsequent centralized procurement by PJM for any load needs that are not met by a bilateral contract. It is FirstEnergy's current understanding that if load does not affirmatively participate in one of those two RBP components, PJM is proposing to require the load to interconnect under its "Connect and Manage" approach, meaning the load would be subject to possible curtailment until the region is resource adequate.

If these load flexibility mechanisms, such as the aforementioned Connect and Manage framework, are still in place in 5 or 8 years, this could have a material impact on how much (and where) new capacity is selected in the capacity expansion modeling PJM is conducting in this RTEP cycle, and importantly impacts on subsequent transmission power flow analysis. Given the possible impact of these assumptions, FirstEnergy would appreciate PJM's confirmation of this assumption and modeling choice.

2. Clarification of Interconnection Queue Incorporation

FirstEnergy would appreciate PJM's confirmation regarding how resources from the interconnection queue will be incorporated into the capacity expansion model. At various points, PJM has indicated that all planned resources in the existing interconnection queue would be included in the model as if they will all reach commercial operation. However, PJM's April 7, 2026 TEAC presentation indicates that certain resources in the interconnection queue may be excluded from the capacity expansion modeling effort. For example, Slide 9 of that presentation lists that certain offshore wind projects may not be included. FirstEnergy requests that PJM confirm whether it is, indeed, including "all" projects from the interconnection queue or whether certain resources are being excluded. Additionally, to the extent PJM plans to run any alternate scenarios or sensitivities involving the inclusion or exclusion of resources from the interconnection queue, FirstEnergy believes it would be helpful if PJM shared its planned weighting of these alternatives (*i.e.*, will some scenarios or sensitivities be weighted more heavily in PJM's ultimate decision-making and/or be treated as more credible or likely?).

In addition, FirstEnergy notes that in light of historical completion rate data and the pending RBP effort, the current makeup of the interconnection queue may not accurately reflect the types of resources that will actually come to bear in five or eight years. For example, it seems likely that the RBP will increase the amount of natural gas generation constructed. PJM's base scenario appears to assume that there will be no material differences in transmission location(s) or need(s) based on the potential mismatch between the technologies in the queue and technologies that are more likely to reach commercial operation. Put another way, FirstEnergy understands PJM's base case scenario as assuming that, for transmission planning purposes, the transmission locations and needs will be materially similar regardless of whether, for example, more gas than solar reaches commercial operation in the near and medium term. FirstEnergy would appreciate PJM's confirmation of this assumption and modeling choice.

3. Request for Additional Information on Zonal to Nodal Mapping

Lastly, FirstEnergy requests that PJM provide details on how it will map zonal load and zonal capacity expansion portfolios to nodal power flow cases. It is important for stakeholders to understand this mapping to specific locations on the transmission system for input into the power flow models because these siting assumptions have a material impact on the subsequent examination of transmission needs.[2]

Among peer RTOs, this portfolio mapping process is typically treated explicitly (*e.g.*, via queue-based siting, deliverability zones, or structured allocation methods), and subject to extensive stakeholder input and feedback.[3] Recognizing the compressed nature of the RTEP timeline, additional documentation and transparency on how this mapping is being conducted during this cycle will be valuable to help stakeholders better understand and interpret the transmission system findings.

Conclusion

FirstEnergy offers these comments with appreciation for PJM staff's work on this set of complex and challenging modeling issues, which is driven by the lack of supply in PJM. The suggestions above are intended to help PJM and stakeholders better interpret and apply the 8-year results within the current cycle's stated role for that analysis as way to inform and ideally test the robustness of the 5-year results. FirstEnergy's goal is to establish a clear problem statement in the 2026 RTEP cycle – a benefit to both PJM and all stakeholders and essential for managing reliability in regional planning processes. FirstEnergy looks forward to the May 8 preliminary modeling readout and to any further discussion that may be useful once stakeholders have had an opportunity to review the initial results. FirstEnergy may submit additional comments following the May 8 preliminary modeling readout.

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[2] In future discussions, FirstEnergy may also request additional clarifications of key assumptions that impact the attractiveness and location of resource builds within the capacity expansion model. As one example, it may be helpful to better understand how projected gas prices are translated into generator fuel costs in the capacity expansion analysis, e.g. whether the model relies on a single Henry Hub price path across PJM reflects regional gas price differences, transportation considerations, or other east-west distinctions that may have a material impact on the costs a generator incurs for its fuel.

[3] FirstEnergy is able and willing to provide PJM a briefing and/or materials concerning the practices of other RTOs for similar modeling exercises.

MARYLAND
DEPARTMENT OF
NATURAL RESOURCES

Wes Moore, *Governor*
Aruna Miller, *Lt. Governor*
Josh Kurtz, *Secretary*
David Goshorn, *Deputy Secretary*

April 22, 2026

Maryland DNR Power Plant Research Program Response to 2026 RTEP Assumptions

The Maryland Department of Natural Resources (DNR) Power Plant Research Program (PPRP) appreciates this opportunity to comment on PJM's proposed capacity expansion assumptions for the 8-year (2034) reliability cases under the 2026 Regional Transmission Expansion Plan (RTEP), as presented through the Transmission Expansion Advisory Committee (TEAC) stakeholder process.

PPRP functions to ensure that Maryland meets its electricity demands at a reasonable cost while protecting the State's natural resources. In this role, PPRP coordinates a comprehensive, multi-agency review of proposed generation and transmission projects for the Maryland Public Service Commission's (PSC's) Certificate of Public Convenience and Necessity (CPCN) process. PJM Interconnection's (PJM's) RTEP process informs the transmission projects ultimately submitted to the PJM Board of Managers for approval and subsequently put forth to entities like the Maryland PSC and PPRP for state-jurisdiction siting and permitting. Given PPRP's statutory responsibility to evaluate proposed energy infrastructure in Maryland, PPRP has a strong interest in ensuring that the assumptions underlying the PJM RTEP process are accurate.

On April 7, 2026, PJM, through TEAC, proposed updated modeling assumptions underlying the 8-year (2034) component of the 2026 RTEP, including assumptions related to load forecasts, generation and retirement schedules, and applicable public policy requirements.[1] The 2026 RTEP introduces a substantive methodological departure: the application of capacity expansion modeling to the 8-year (2034) cases.[2] PJM has acknowledged that existing and committed resources are insufficient to satisfy forecasted load across the planning horizon. This finding, in PJM's view, necessitates the endogenous development of additional generation within the model.[3]

A consequence of PJM's proposed approach is that transmission planning outcomes will depend on the novel assumptions regarding resource availability, policy trajectories, and development constraints embedded within the proposed capacity expansion framework. These inputs carry inherent uncertainty and warrant careful evaluation. Ideally, such an evaluation would also give stakeholders an opportunity to substantively engage. PJM provided stakeholders with an initial opportunity to comment on the capacity expansion plan during the April 7 TEAC meeting and requested additional written comments by April 22. PJM's stated intent is to finalize the 2026 RTEP assumptions at the May 8 TEAC meeting.[4]

PPRP is greatly concerned that the timeframe and process proposed for stakeholder review and comment on these proposed assumptions is inadequate. In PPRP's assessment, the proposed application of capacity expansion modeling to the 2026 RTEP represents a significant methodological change with potentially far-reaching implications, yet stakeholders will not be afforded sufficient opportunity to evaluate the underlying assumptions, understand their interaction, and assess their reasonableness if PJM proceeds with its proposed schedule.

PPRP also understands that PJM is undertaking parallel stakeholder processes to evaluate capacity expansion modeling in the context of FERC Order 1920 implementation. This includes PJM's plan to "discuss capacity expansion in more detail as part of Order 1920 manual revisions later this year."[5] Incorporating proposed changes into the 2026 RTEP at this time would preempt important stakeholder engagement that may occur in the coming months. Accordingly, PPRP recommends that PJM not finalize or rely on the proposed capacity expansion assumptions for the 2026 RTEP without providing an additional stakeholder process sufficient to allow meaningful review of the underlying assumptions and methodology.

[1] PJM Planning (April 7, 2026). "Review of 2026 RTEP Assumptions." Transmission Expansion Advisory Committee. PJM Interconnection, LLC.
[2] Id. at 22-28.
[3] Id. at 25.
[4] Id. at 28.
[5] Id. at 25.

Having identified the foregoing concerns and made the above recommendation, PPRP respectfully submits the following questions and comments concerning the assumptions and methodologies presented by PJM:

1. PJM presents two 8-year scenarios (Scenario A and Scenario B) to assess the impact of differing assumptions on resource availability and transmission needs. PPRP seeks additional clarification on the role and interpretation of these scenarios, including:
    a) What are the primary objectives of Scenario A and Scenario B, and how will the results from each scenario be used in identifying and sizing transmission solutions?
    b) What is the rationale for selecting these two scenarios, and were alternative scenario designs considered?
    c) Are Scenario A and Scenario B intended to represent bounding cases (e.g., differing levels of resource availability or development), and how should stakeholders interpret the range of outcomes between them?
    d) Does PJM plan to adopt a consistent and transparent methodology for the treatment of interconnection queue resources across scenarios?

2. PJM applies build limits within the capacity expansion framework that allow generation to scale up to multiples of existing capacity and interconnection queue levels (e.g., up to 2× by 2034 and 3× by 2045, with higher limits on Virginia). What is the basis for the selected build multipliers?

3. PJM proposes utilizing Energy Exemplar's modeling framework for the capacity expansion analysis. Please explain how transmission is represented within the model. In particular:

    a) Does the model incorporate transmission constraints and network topology explicitly, or does it rely on a more simplified representation of the system?
    b) How does the model represent the interaction between transmission expansion and generation additions? Does the model treat transmission and generation as alternative solutions, or are transmission needs determined after generation expansion is modeled?
    c) To what extent are interregional solutions incorporated into the model? PPRP suggests that PJM consider assessing the potential role of expanded external transfer capability in meeting resource adequacy needs, as this could provide additional insight into the value of interregional solutions.

4. Will the capacity expansion model allow for existing resources to be retired and replaced based on economic conditions?

5. Will production cost modeling be conducted to assess system economics in future scenarios? If so, how does the modeling framework represent key drivers such as fuel costs, weather variability, and dispatch dynamics?

6. Does the model evaluate system performance on an hourly (8760) basis to capture reliability and operational constraints, or does it rely on representative time periods (e.g., seasonal or peak load conditions) to approximate system availability?

7. Are ELCC values and the 1-in-10 resource adequacy target treated as dynamic within the modeling framework (i.e., updated as new capacity is added), or are these parameters fixed exogenously at the outset of the analysis?

8. Community solar and other distributed energy resources (DERs) are expected to play an increasing role in Maryland's energy mix. In this context, it is not clear how these resources are represented within the modeling

framework. What assumptions are made regarding the role of community solar and other DERs, and how are their impacts on load and capacity needs reflected in the analysis?

9. SB 937 (Next Generation Energy Act) establishes a policy direction in Maryland to encourage the development of nuclear resources, including small modular reactors, and directs state agencies to pursue related regional and federal arrangements. Why is nuclear not included as an expansion candidate within the capacity expansion framework, especially in the out-years?

10. How does the model account for Regional Greenhouse Gas Initiative (RGGI) compliance costs in resource cost assumptions, and how are these costs reflected in the relative competitiveness of fossil versus non-emitting resources?

11. PJM assumes Henry Hub pricing for natural gas inputs. We suggest the use of index adjustments or basis differentials to account for the diversity of gas supply costs across the PJM footprint.

12. PJM notes that capacity expansion modeling has been used indirectly in prior RTEP cycles to assess expected regional flows. PPRP requests additional clarification on how this approach has been applied in past planning cycles, including any specific examples, and how those applications inform the current modeling framework.

PPRP appreciates PJM's willingness to engage regarding the proposed assumptions. PPRP also wishes to again emphasize that the assumptions being considered, if inaccurate or mischaracterized, may result in planning decisions that materially over- or understate transmission needs, with attendant implications for system reliability and ratepayer costs in Maryland. As such, PPRP again recommends that PJM defer application of capacity expansion modeling in the 2026 RTEP until stakeholders have had a meaningful opportunity to review and respond to the relevant assumptions and methodologies.

Respectively,

Robert Sadzinski

Robert Sadzinski
Director, Power Plant Research Program

Agenda Date: 4/22/26
Agenda Item: LSA

STATE OF NEW JERSEY
Board of Public Utilities
44 South Clinton Avenue, 1st Floor
Trenton, New Jersey 08625-0350
www.nj.gov/bpu/

CLEAN ENERGY

IN THE MATTER OF DECLARING TRANSMISSION TO SUPPORT OFFSHORE WIND A PUBLIC POLICY OF THE STATE OF NEW JERSEY	)	ORDER ON THE STATE AGREEMENT APPROACH (SAA) MUTUAL TERMINATION AGREEMENT
	)	DOCKET NO. QO20100630

Parties of Record:

Brian O. Lipman, Esq., Director, New Jersey Division of Rate Counsel
Susan McGill, PJM Interconnection, L.L.C.
Thomas Donadio, Jersey Central Power & Light Company
Cynthia Holland, Exelon Corporation
Matthew Virant, Mid-Atlantic Offshore Development, LLC
Jason Niven, LS Power Grid Mid-Atlantic, LLC
Shadab Ali, PPL Electric Utilities
Jodi Moskowitz, Public Service Electric and Gas Company
Maria J. Malguarnera, Transource Energy, LLC

BY THE BOARD:

By this Decision and Order, the New Jersey Board of Public Utilities ("Board" or "BPU") considers whether to enter into a Mutual Agreement to Terminate the Amended and Restated State Agreement Approach Agreement with PJM Interconnection, LLC ("PJM") ("Mutual Termination Agreement").

BACKGROUND AND PROCEDURAL HISTORY

By Order dated November 18, 2020, the Board initiated a proceeding for New Jersey to become the first state to integrate its offshore wind ("OSW") transmission goals with its regional electric transmission grid's planning and development process, one of many steps taken to advance timely, effective, and efficient deployment of major in-state energy generation sources.[1] By the November 2020 Order, the Board formally requested the inclusion of the state's plans for OSW generation into PJM's regional transmission expansion plan ("RTEP") through the State Agreement Approach ("SAA"), a first-in-the-nation mechanism that allows a state to pursue its

[1] In the Matter of Declaring Transmission to Support Offshore Wind a Public Policy of the State of New Jersey, BPU Docket No. QO20100630, Order dated November 18, 2020 ("November 2020 Order").

energy priorities within PJM's RTEP if that state agrees to assume cost responsibilities for any transmission projects selected to support the state's public policy goals.[2] On December 18, 2020, PJM submitted to the Federal Energy Regulatory Commission ("FERC") an executed SAA Study Agreement between PJM and the Board to begin implementing the SAA.[3]

In January 2022, PJM filed Rate Schedule 49 at FERC, setting out the agreement between the Board and PJM to implement the SAA process for New Jersey ("SAA Agreement").[4] In the SAA Agreement, PJM committed to preserving transmission capability necessary to realize New Jersey's goals for in-state generation.[5] In exchange, PJM required and New Jersey, through the Board, agreed to accept cost responsibility for the transmission projects that would facilitate that in-state generation, subject to cost-sharing for certain projects that also resolved regional reliability needs.[6] On April 14, 2022, FERC approved the SAA Agreement.[7] The Board and PJM subsequently modified, and on March 6, 2023 FERC approved, the SAA Agreement to expressly incorporate the costs and in-service dates for the selected SAA Projects.[8]

PJM then opened a competitive solicitation to receive project proposals to advance New Jersey's targeted OSW goals. By Order dated October 26, 2022, the Board awarded SAA Projects to nine (9) SAA Developers. These developers proposed to make major investments in New Jersey, upgrading and strengthening the state's electric grid and associated facilities necessary to deliver 4,890 megawatts ("MW") of electricity from New Jersey-built wind projects to New Jersey customers. Taken together, those investments were planned to save ratepayers an estimated $900 million compared to interconnecting OSW generation through a traditional non-SAA

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[2] Amended and Restated Operating Agreement of PJM Interconnection, LLC , Sch. 6, § 1.5.9 ("PJM Operating Agreement"); PJM Open Access Transmission Tariff, Sch. 12(b)(xii) ("PJM Tariff").

[3] PJM Interconnection, L.L.C., 174 FERC ¶ 61,090 at P 1 (2021).

[4] PJM Interconnection, L.L.C., 179 FERC ¶ 61,024 at P 1 (2022).

[5] The provisions of the SAA Agreement formally establish the terms and obligations, under FERC jurisdiction, for the management of the SAA. The SAA Agreement sets forth PJM's ongoing obligation to preserve the transmission capability created by projects selected for the Larabee Collector Solution ("LCS") project, consisting of Mid-Atlantic Offshore Development, LLC's LCS and Jersey Central Power & Light Company's Clean Energy Corridor, for the purpose of enabling New Jersey's OSW generation procurements—referred to as "SAA Capability." See SAA Agreement at § 6.2(c) ("The SAA Capability will be based, modeled and reserved in a manner (i) consistent with PJM's reliability criteria, study assumptions, and modeling processes for offshore wind turbines as detailed in PJM Manuals, and (ii) as described and identified in any subsequent FERC filings, as well as in Appendix B herein (citing PJM Competitive Planning Webpage, 2021 NJ OSW Proposal Overview, at Appendix).") SAA Capability is defined as "all transmission capability created by a SAA Project(s), including but not limited to the capability to integrate resources injecting energy up to the Maximum Facility Output ("MFO"), capability which may become CIRs through the PJM interconnection process, and any other capability or rights under the PJM Tariff, and consistent with the reliability study criteria applied to the evaluation of a SAA Project(s) as set forth in Paragraph 6 [of the SAA Agreement]." SAA Agreement § 1.2.

[6] The SAA Agreement incorporates by reference the provisions of PJM's Tariff that provide for cost-sharing of Multi-Driver Projects that both support state public policies and solve a reliability problem. See SAA Agreement § 15.0; PJM Tariff, Sch. 12(b)(xiv).

[7] Id.

[8] PJM Interconnection, L.L.C., ER23-775 (Mar. 6, 2023).

approach.[9] All projects were planned to be complete and operational by June 1, 2030.[10]

By Presidential Action, in the form of a memorandum issued January 20, 2025 ("PM"), the federal government halted all new OSW leasing and permitting and initiated a comprehensive review of federal wind leasing and permitting practices.[11] Following that Presidential Action, the U.S. offshore wind industry, its investors, the manufacturing, maritime, and construction workers who were actively employed in it, and the ratepayers who looked forward to its promised relief from skyrocketing utility costs have been thrown into turmoil and uncertainty. Repetitive environmental reviews, unnecessary permitting costs, and even stop-work orders on active construction projects, have deeply eroded near-term confidence in the federal regulatory regime for a broad swath of U.S. energy projects, including offshore wind.[12]

In light of this market uncertainty, on May 23, 2025, Jersey Central Power and Light Company ("JCP&L") filed a Motion for Declaratory Guidance in this docket, requesting the Board "either affirm[] the schedule for Movant's development of its project supporting the State's goal of offshore wind development and transmission reliability, or, in the alternative, . . . modify[] said schedule."[13] JCP&L requested "this relief due to the occurrence of new facts and circumstances, primarily at the federal level."[14] As examples, JCP&L's motion cited both the PM and a decision from the United States Environmental Protection Agency's ("EPA") Environmental Appeals Board ("EAB") approving EPA's request for a voluntary remand of the Clean Air Act permit it granted to the Atlantic Shores OSW project.[15] JCP&L explained that under its Designated Entity Agreement ("DEA") with PJM, it would soon need to commence construction on several SAA Projects that had substantial costs.[16] JCP&L thus asked the Board to specifically state whether it should

[9] In re Declaring Transmission to Support Offshore Wind a Public Policy of the State of New Jersey, BPU Docket No. QO20100630, Order dated October 26, 2022 ("October 2022 Order").

[10] Id., App. A.

[11] Presidential Action: Memorandum to Agency Heads, Temporary Withdrawal of All Areas on the Outer Continental Shelf from Offshore Wind Leasing and Review of the Federal Government's Leasing and Permitting Practices for Wind Projects, (Jan, 20, 2025), https://www.whitehouse.gov/presidentialactions/2025/01/temporary-withdrawal-of-all-areas-on-the-outer-continental-shelf-from-offshore-wind-leasing-andreview-of-the-federal-governments-leasing-and-permitting-practices-for-wind-projects/ ("Presidential Memorandum").

[12] See, e.g., Director's Order from Walter D. Cruickshank, Acting Dir., Bureau of Ocean Energy Mgmt, to Matthew Brotmann, Sec'y, Empire Offshore Wind LLC (Apr. 16, 2025), https://www.boem.gov/sites/default/files/documents/renewable-energy/state-activities/BOEM%20Director%26%23039%3Bs%20Order%20Empire%20Wind.pdf; In re Atlantic Shores Offshore Wind, LLC, OCS Appeal No. 24-01, slip op. at 5 (EAB Mar. 14, 2025). https://yosemite.epa.gov/oa/eab_web_docket.nsf/9C7B7CF33923032185258C4D0058F4A7/$File/Atlantic%20Shores%20Order%20Granting%20Motion%20for%20Voluntary%20Remand,%20FINAL.pdf ("EAB Voluntary Remand Order").

[13] Mot. for Decl. Guidance by The Jersey Central Power & Light Company on Current Project Development Schedule, or, Alternatively, for Modification of Current Project Schedule at 1 (May 23, 2025).

[14] Id.

[15] Id. at 3-4 (citing President Memorandum & EAB Voluntary Remand Order).

[16] Id. at 2, 5-6.

proceed with "development as required to meet the current DEA schedule commitments, or should delay near-term commencement of construction pending further OSW development guidance from the Board."[17]

On June 9, 2025, the New Jersey Division of Rate Counsel ("Rate Counsel") filed a letter in response to JCP&L's Motion for Declaratory Guidance and its own Cross-Motion for Rehearing.[18] Rate Counsel stated that it opposed JCP&L's motion "to the extent that motion seeks to affirm the current schedule without further consideration."[19] Through its Cross-Motion for Rehearing, Rate Counsel requested that the Board instead reopen the record to reevaluate costs, prudency, and ratepayer impacts, and further sought a stay of project development pending such review.[20]

By Order dated August 13, 2025, the Board addressed JCP&L's motion and the development schedule of SAA transmission projects previously selected by the Board and incorporated into the RTEP.[21] By the August 2025 Order, the Board found that recent federal policy developments introduced significant uncertainty into the development timeline for the OSW projects the SAA transmission projects were designed to support. To protect New Jersey ratepayers from near-term expenditures and to realign transmission development with generation timelines, the Board (1) directed JCP&L to delay, to the extent practicable, expenditures associated with SAA Projects identified under PJM upgrade identification number b3737 for a period of approximately two-and-one-half years; (2) requested that PJM revise the expected in-service dates for the affected SAA Projects from June 1, 2030 to January 1, 2033; and (3) directed Board Staff ("Staff") to coordinate with PJM and SAA Project developers to defer other SAA related expenditures consistent with the Board's directives.

On August 28, 2025, PJM filed a Request for Clarification, or in the alternative, Motion for Reconsideration of the August 2025 Order.[22] In its filing, PJM asked for clarification of the precise meaning of the Board's request that PJM delay certain SAA Projects, noting that there was an important distinction between "delaying" and "suspending" SAA Projects.[23] PJM further noted that the existing SAA Agreement does not contain provisions authorizing suspension or delay of approved SAA Projects and either a delay or a suspension would require modification of the SAA Agreement.[24]

By letter dated September 22, 2025, Rate Counsel filed a Response to PJM's motion.[25] By its

[17] Id. at 6.

[18] Rate Counsel Resp. to Mot. for Decl. Guidance by the Jersey Central Power & Light Company on Current Project Development Schedule, or, Alternatively, for Modification of Current Project Schedule; and Cross-Motion for Rehearing (June 9, 2025).

[19] Id. at 1.

[20] See id. at 1-3, 7.

[21] In re Declaring Transmission to Support Offshore Wind a Public Policy of the State of New Jersey, BPU Docket No. QO20100630, Order dated August 13, 2025 ("August 2025 Order").

[22] Request for Clarification or, in the Alternative, Mot. for Reconsideration or Rehearing of PJM Interconnection, L.L.C. (August 28, 2025).

[23] Id. at 4-5.

[24] Id.

[25] Rate Counsel Resp. to PJM Mot. for Reconsideration (Sept. 22, 2025).

Response, Rate Counsel urged the Board to deny PJM's request, asserting that PJM failed to demonstrate any legal or factual error in the August 2025 Order and reiterating the importance of ratepayer protection amid uncertainty surround OSW.[26]

Thereafter, on November 21, 2025, PJM submitted a Request for Assurances, asking that the Board in writing: (1) affirm whether the Board's decision was to delay or suspend the SAA Projects and acknowledge modeling and cost implications thereof; (2) affirm the Board's commitment to proceed with the SAA Projects after the two-and-one-half-year delay, including paying 100% of all associated and escalated costs; (3) commit to establish new OSW in-service dates that align with the transmission delay; and (4) commit to fund PJM's own studies necessary to determine which projects can be delayed.[27] PJM made such commitments a condition for its continued cooperation.[28]

For the limited purpose of facilitating continued negotiations for modification to the SAA Agreement necessary to incorporate suspension authority and clarify procedures governing scope, cost, and schedule modifications, on January 3, 2026, the Executive Director of the New Jersey Board of Public Utilities transmitted a Letter of Assurances to PJM pursuant to its request.[29]

Rate Counsel also responded to PJM's Request for Assurances and the Executive Director's Letter of Assurances by letter dated February 20, 2026.[30] In its letter Rate Counsel urged the Board to undertake an updated prudency and cost-benefit analysis before taking further action on the SAA Agreement, because of material changes in the OSW landscape.[31] As such, Rate Counsel opposed any further commitment of ratepayer funds absent stronger evidentiary support and further analysis.[32]

Finally, since the Board's last action in this docket on August 13, 2025, material changes to both the Leading Light Wind Project ("LLW Project") and Attentive Energy Two Project ("Attentive Project") that the Board awarded in January 2024 as part of Offshore Wind Solicitation Three indicate that the projects are unlikely to move forward. Specifically, on November 7, 2025 Invenergy Wind Offshore, LLC ("Invenergy") sent a notice to the Board stating that it "has determined it cannot move forward with the Project under the terms and conditions set out in the Board's January Order,"[33] because of the "economic and regulatory conditions that have made the development of new offshore wind energy projects extremely difficult" discussed above.[34] On

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[26] See id. at 2, 6-10.

[27] Req. for Assurances Regarding State Agreement Approach Agreement at 3-5 (Nov. 21, 2025) ("PJM Demand Assurances Letter").

[28] Id. at 4-5.

[29] Letter from Robert Brabston, Exec. Dir., N.J. Bd. of Pub. Utils., to Stu Bressler, Chief Operating Officer, PJM Interconnection, LLC (Feb. 3, 2026) (on file in BPU Docket No. QO20100630).

[30] Rate Counsel Resp. to PJM Request for Assurances (Feb. 20, 2026).

[31] Id. at 5.

[32] Id.

[33] LLW Project Notice to the BPU at 1, BPU Docket No. QO22080481 (Nov. 7, 2025) (citing In re the Opening of New Jersey's Third Solicitation for Offshore Wind Renewable Energy Certificates (OREC), Order Approving Leading Light Wind 2400 MW Project as a Qualified Offshore Wind Project, BPU Docket No. QO22080481, Order dated January 24, 2024.

[34] Id. at 2.

March 23, 2026, TotalEnergies, the parent company of Attentive Energy, LLC ("Attentive"), announced that in exchange for a nearly $1 billion payment from the federal government,[35] it was "relinquish[ing] its Carolina Long Bay lease (Lease OCS-A 0545) and its New York Bight lease (Lease OCS-A 0538),"[36] the latter of which included the Attentive Project. As the Attentive Project was planned to be built in the New York Bight lease area,[37] TotalEnergies' agreement with the United States Department of the Interior ("Interior") likely means the Attentive Project cannot proceed.

The loss of the LLW Project and the likely loss of the Attentive Project, so long as Interior's agreement with TotalEnergies remains in effect, means there are no viable OSW generation projects with a discernable pathway to commercial operation on the ambitious timeline anticipated both by the state's goals for in-state generation and corresponding investments in the electric grid planned through the SAA.

STAFF RECOMMENDATION

In the months following the August 2025 Order, Staff attempted to work with PJM to limit New Jersey's ratepayers cost exposure during the delay or suspension period. However, PJM stated they were unable to perform more than a preliminary "desktop analysis" absent FERC acceptance of a revised SAA Agreement and a binding commitment on the Board's part to *both* fund the necessary studies *and* force New Jersey ratepayers to pay the costs of suspension before knowing what they would be.[38]

The desktop analysis PJM provided sorted SAA Projects into (1) Category 1 projects that "could be suspended without negatively impacting the transmission system," (2) Category 2 projects "that cannot be terminated, delayed, or suspended without negatively impacting the transmission system," and (3) Category 3 projects "that require further study before PJM can make a determination about whether they can be delayed."[39] PJM's desktop analysis showed that a material amount of projects fell into Category 3, making it difficult to determine the actual benefits delay or suspension might provide to ratepayers. PJM also asserted that effectuating a delay or suspension would be a very lengthy process during which projects would continue as scheduled and costs would continue to mount until at least the latter half of 2026,[40] diminishing the potential value of delay or suspension to ratepayers below what was envisioned at the time of the August 2025 Order.

Moreover, the loss of the LLW Project in November 2025 and TotalEnergies' March 2026

[35] Alex Brown, Trump Administration Will Pay $1B to Block 2 Offshore Wind Farms, N.J. Monitor (Mar. 25, 2026), https://newjerseymonitor.com/2026/03/25/repub/turmp-offshore-wind-farms/.

[36] Press Release, TotalEnergies, United States: TotalEnergies Signs Agreements with U.S. Department of Interior to End its U.S. Offshore Wind Projects (Mar. 23, 2026), https://totalenergies.com/news/press-releases/united-states-totalenergies-signs-agreements-us-department-interior-end-its-us.

[37] In re the Opening of New Jersey's Third Solicitation for Offshore Wind Renewable Energy Certificates (OREC), Order Approving Attentive Energy Two 1342 MW Project as a Qualified Offshore Wind Project, BPU Docket No. QO22080481, Order dated January 24, 2024 at 22, 22 n.88.

[38] PJM Request for Assurances at 4-5.

[39] Id. at 4.

[40] Id.

agreement with the Department of Interior have further eroded the case for continuing with the SAA Agreement. At the time of the August 2025 Order, both the LLW Project and Attentive Project were experiencing significant difficulties, but it remained plausible that they or similar projects could eventually reach commercial operation on a delayed timeline.[41] That is no longer the case in the wake of Invenergy's decision not to proceed with the LLW Project at the approved offshore wind renewable energy credit price, and Attentive' s likely decision to not proceed with the Attentive Project due to Interior's payment to TotalEnergies in exchange for its agreement to cease all US OSW development. Instead, New Jersey is now facing a situation in which there will be no identified, large-scale in-state generation projects under active development that can make use of SAA Capability on the timeline the state and PJM initially envisioned.

Because the SAA Projects and their associated power flows are currently assumed to be part of PJM's transmission system for its RTEP planning process, transmission and interconnection upgrades may be built on top of the SAA Projects. This risks inefficiencies if the power flows assumed to result from the SAA Projects and/or the generation resources they were intended to support do not materialize.

In light of the above, Staff now believes that terminating the SAA Agreement as quickly as possible is in the best interest of New Jersey ratepayers. Staff emphasizes that prompt Board action is essential to avoiding a potentially significant increase in New Jersey ratepayers' cost exposure.

The reasons for this are that (1) PJM will finalize its 2026 RTEP planning assumptions by the start of July 2026, and (2) PJM is legally unable to remove SAA Projects from its RTEP planning assumptions absent FERC approval of a decision to terminate the SAA Agreement. Obtaining such FERC approval will require PJM to make a Federal Power Act Section 205 filing to FERC after the Board agrees to terminate the SAA Agreement. As FERC will have sixty days to issue its ruling,[42] that filing must be made to FERC by the end of April to ensure FERC acts before the beginning of the 2026 RTEP planning cycle. That in turn means the Board must decide to terminate the SAA Agreement before the end of April to prevent SAA Projects from remaining in the 2026 RTEP planning assumptions.

New Jersey ratepayers likely face a significant escalation in cost exposure if all SAA Projects remain in PJM's assumptions for the 2026 RTEP planning cycle. As explained above, new transmission projects may be planned in reliance on SAA Projects if they remain in the model. Once PJM selects new RTEP projects that rely on SAA Projects, it will no longer be possible to terminate the SAA Projects on which the new RTEP projects rely. Conversely, agreeing to terminate the SAA Agreement now will allow PJM to remove the SAA Projects from the 2026 RTEP planning cycle, assuming timely FERC approval. That would minimize further cost exposure to New Jersey under the SAA Agreement by ensuring additional system upgrades are not built in reliance on the SAA Projects. It will also allow PJM to develop a more efficient transmission system, reducing the total amount of transmission costs assessed to ratepayers across the entire PJM region.

To that end, following the announcement of Interior's intent to pay TotalEnergies nearly $1 billion to cancel its leases, Staff began negotiating a draft Mutual Termination Agreement with PJM.

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[41] Attentive Energy LLC's Mot. for a Limited Stay of Order, BPU Docket No. QO22080481 (Jan. 23, 2025); Leading Light Wind's Amended Mot. to Extend the Stay, BPU Docket No. QO22080481 (May 16, 2025).

[42] See 16 U.S.C. § 824d(d).

Under the proposed Mutual Termination Agreement, 52 out of the 58 SAA Projects will be canceled, leaving six SAA Projects to be completed. Based on information provided by PJM and SAA Project developers, Staff estimates that the cost of completing those six SAA Projects plus spend-to-date on SAA Projects amounts to approximately $400 million. As the cost of completing all 58 SAA Projects is estimated to be approximately $1.2 billion,[43] this suggests SAA termination will save New Jersey ratepayers approximately $800 million.[44]

Three of the six SAA Projects, specifically b3737.1, b3737.45, and b3737.60, that will not be canceled are already completed projects. PJM has determined that the remaining three projects, specifically b3737.47, b3737.38, and b3737.39 that have yet to be completed are needed for reliability or the interconnection of non-OSW resources and will therefore be used and useful even in the absence of any OSW projects.

One of these projects, b3737.47, is a Multi-Driver Project that addresses a baseline reliability need in Pennsylvania and as such will have 26.73% of its cost allocated as a Reliability Project, such that only 73.27% of its total cost will be allocated to New Jersey ratepayers as an SAA Project.[45] PJM's public database estimates that the total cost of b3737.47 will be $104.1 million,[46] and New Jersey's share of the Reliability Project component comes to approximately $77.8 million.

New Jersey ratepayers are responsible for any prudently incurred costs of the SAA Project component of b3737.47 due to a FERC-approved provision in PJM's Operating Agreement, which was incorporated into the SAA Agreement by reference.[47] Specifically, it provides that when "a state governmental entity(ies) withdraws its support of the [SAA Project] component of a Multi-Driver Project" but the "Multi-Driver Project must be retained in the Regional Transmission Expansion Plan . . . the withdrawing state governmental entity(ies) shall continue to be responsible for its/their share of the FERC-accepted cost allocations."[48] As b3737.47 must continue to meet the baseline reliability needs of the regional grid, New Jersey ratepayers remain

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[43] The original cost estimate for the entire portfolio of SAA Projects was $1.08 billion. October 2022 Order at 61. However, subsequent adjustments to cost estimates increased the cost estimate by approximately $127 million in June 2023, decreased it by about $29 million in March 2024, and decreased again by about $8 million in December 2024. In re Declaring Transmission to Support Offshore Wind a Public Policy of the State of New Jersey, BPU Docket No. QO20100630, Order dated Dec. 18, 2024 at 4, 6. That produces a revised total cost estimate of approximately $1.17 billion. Given the fluctuation in SAA projects cost and the fact that transmission cost estimates tend to increase over time, Staff believes it is best to round this cost estimate to $1.2 billion.

[44] Staff notes that transmission cost estimates can change significantly during development and construction. Moreover, a portion of the money spent on SAA Projects to date has been spent on parts and equipment that transmission developers can and should redeploy, and reallocate the costs of, to other transmission projects. It is also possible that some of that expenditure could be deemed imprudent and not recoverable from ratepayers, which would further reduce total costs charged to ratepayers. As such, Staff cannot present a precise value of the ultimate savings from terminating the SAA Agreement.

[45] PJM Tariff, Sch. 12, App. C, § 1.

[46] Project Status and Cost Allocation, PJM, https://www.pjm.com/planning/m/project-construction (last visited Apr. 9, 2026).

[47] Amended and Restated State Agreement Approach Agreement § 15.0.

[48] Amended and Restated Operating Agreement of PJM Interconnection, L.L.C., Sch. 6, § 1.5.10(d).

responsible for all prudently incurred cost of its SAA Project component if it ultimately proves to be used and useful.

The other two projects, b3737.38 and b3737.39 are needed to support the interconnection of non-OSW resources, including uprates to two existing New Jersey natural gas plants, and will have 100% of their costs allocated to New Jersey ratepayers.[49] Because of the Board's continued prioritization of in-state generation and capacity resources, New Jersey ratepayers will receive substantially the same benefit from b3737.38 and b3737.39 they would have if OSW development proceeded on the originally envisioned timeline. Project b3737.38 will support two uprates at existing natural gas generating facilities, while project b3737.39 will permit interconnection of the Two Rivers Storage project at the Bergen Generating Station in Ridgefield, which the Board awarded in Tranche 1 of the Garden State Energy Storage Program on March 4, 2026 to help meet New Jersey's statutory storage targets.[50] As such, by paying for the cost of b3737.38 and b3737.39, New Jersey ratepayers are receiving the benefit of facilitating the interconnection of three in-state generation and capacity investments that help achieve New Jersey's policy goals and provide much needed capacity and relief from PJM's market spikes.

The total costs of b3737.38 and b3737.39 are estimated to be $35.3 million and $5.5 million respectively,[51] Thus, the combined cost to New Jersey ratepayers of these three projects amounts to approximately $118.6 million, assuming all costs were prudently incurred.

Because there are generation resources under development that have a substantial reliance interest on project b3737.38, Staff concludes that this cost allocation of b3737.38 is reasonable given the cost savings that will be realized from terminating the SAA agreement and cancelling 52 SAA projects. As shown above, failure to terminate the SAA Agreement could leave New Jersey ratepayers exposed to additional costs of approximately $800 million.

Consequently, Staff believes that on balance the proposed Mutual Termination Agreement dramatically reduces New Jersey ratepayers' cost exposure by effectuating the swift cancellation of 52 of the 58 SAA Projects. Staff therefore recommends that the Board authorize the President to execute the proposed Mutual Termination Agreement on the Board's behalf.

DISCUSSION AND FINDINGS

As discussed above, recent action taken by the federal government, including but not limited to Executive Orders, memoranda, and stop-work orders to individual projects, and payments to foreign energy developers have created significant regulatory uncertainty and disruption in the domestic energy industry. These actions have altered federal permitting and leasing processes and undermined the regulatory framework necessary for New Jersey to continue progress toward investing in certain in-state generation resources and associated transmission planning. The resulting regulatory instability has materially impacted in-state generation projects that formed the basis of the SAA Agreement and New Jersey and PJM's coordinated transmission planning decisions. These federal actions render the investments contemplated by the SAA Agreement

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[50].See In re the Garden State Energy Storage Program ("GSESP") Pursuant to P.L. 2018, C.17, BPU Docket No. QO22080540Order dated March 4, 2026; N.J.S.A. 48:3-87.8(d); N.J.S.A. 48:3-121.3(a)(2).

[51] Id.

infeasible on the timeline envisioned when the SAA Agreement was executed.

While the SAA Capability was not intended to serve any single OSW project, the predictable procurement of OSW projects on the BPU's Solicitation Schedule, included as Appendix A to the SAA Agreement, served as the foundation for the development of the SAA Projects. However, in light of the federal actions described above, the LLW Project is unable to move forward and the Attentive Project will likely not proceed as well. The probable loss of both projects plus the continued federal regulatory block of OSW development—and thus potential replacement OSW capacity—renders the solicitation schedule set forth in the SAA Agreement infeasible. In addition, alternative pathways to coordinated transmission, such as FERC Order 1920,[52] now exist that did not exist at the time of the SAA Agreement. These alternative pathways and mechanisms for coordinated transmission development may serve OSW projects in New Jersey via offshore lease areas, including the area occupied by the Attentive Project.

The Board's August 2025 Order initially looked to delay the SAA Projects by 2.5 years to account for uncertainty in the OSW industry. It is now apparent, based upon the subsequent above-described developments related to the LLW Project and Attentive Project, that such a delay will not be sufficient to ensure SAA Capability will be timely used by awarded OSW projects. In addition, after the August 2025 Order, the Board, through its Staff, learned from PJM that amending the SAA Agreement to limit project expenditures via delay, as envisioned by the August 2025 Order, would entail a lengthy process that would postpone effectuation of the delay until at least the latter half of 2026. During that time, SAA Projects would continue to be constructed and incur costs, contrary to the Board's August 2025 Order goal of pausing costs.

The SAA Agreement's coordinated transmission solution was designed to provide efficiencies and ratepayer savings through reduced upgrade costs, improved siting outcomes, and greater certainty surrounding transmission development. Transmission capability that provides access to the grid at a known cost and on a defined timeline commands meaningful value, particularly in a constrained and competitive development environment. However, this value is dependent on the type, timing, and scale of resources seeking to utilize the capability. The ability to monetize or utilize any SAA Capability that might result from completing the SAA Projects remains uncertain in the absence of a defined procurement framework, fully-studied or identified generation interconnection needs outside of OSW, or committed OSW generation.

Accordingly, there is insufficient value in the SAA Agreement to justify continued ratepayer exposure under recent changed circumstances. As such, the Board **HEREBY FINDS** that continued investment in the SAA Projects is not in the best interest of the State and New Jersey's ratepayers. The Board **FURTHER FINDS** that continuing the SAA Projects as contemplated in the SAA Agreement unduly risks imposing costs on New Jersey ratepayers with little, or no, guarantee of any return on investment. Rate Counsel has similarly emphasized the need to reassess prudency and avoid additional ratepayer exposure under current conditions. Termination of the SAA Agreement addresses these concerns by ensuring that transmission planning remains prudent and aligned with reasonably foreseeable system needs. Prompt termination of the SAA Agreement will also result in the cancellation of the bulk of the SAA Projects, but the Mutual Termination Agreement is designed to continue support for a subset of

[52] *Building for the Future Through Elec. Reg'l Transmission Planning & Cost Allocation*, Order No. 1920, 187 FERC ¶ 61,068 at P 813 (May 13, 2024), (*on reh'g & clarification*, Order No. 1920-A, 189 FERC ¶ 61,126 at P 976 (Nov. 21, 2024) (located at R.976), *on reh'g & clarification*, Order No. 1920-B, 191 FERC ¶ 61,026 at P 1050 (Apr. 11, 2025).

projects necessary to maintain reliability or support interconnection of much needed new capacity resources, including storage resources, that will increase in-state electric generation and capacity. As noted by Staff, cancellation of the remaining SAA Projects will likely save ratepayers well over half the total cost of completing the entire portfolio.

As such, the Board **FURTHER FINDS** that it is appropriate to remove the majority of SAA Projects from the RTEP ahead of the 2026 RTEP and PJM's Cycle 1 interconnection process, retaining only those projects necessary for regional reliability or non-OSW interconnection, in order to limit costs to New Jersey ratepayers. The Board **FURTHER FINDS** that accepting the terms of the Mutual Termination Agreement is necessary for the reasons explained by Staff. As such, the Board **FURTHER FINDS** that executing the proposed Mutual Termination Agreement negotiated by Staff is in the best interest of New Jersey ratepayers.

Therefore, the Board **HEREBY AUTHORIZES** President Christine Guhl-Sadovy to sign the Mutual Termination Agreement on behalf of the Board so that PJM can submit it to FERC for review and approval.

This Order shall be effective on April 22, 2026.

DATED: April 22, 2026

BOARD OF PUBLIC UTILITIES
BY:

CHRISTINE GUHL-SADOVY
PRESIDENT

DR. ZENON CHRISTODOULOU
COMMISSIONER

MICHAEL BANGE
COMMISSIONER

EMMA REBHORN
COMMISSIONER

JOSEPH COVIELLO
COMMISSIONER

ATTEST:

SHERRI L. LEWIS
BOARD SECRETARY

I HEREBY CERTIFY that the within document is a true copy of the original in the files of the Board of Public Utilities.

IN THE MATTER OF DECLARING TRANSMISSION TO SUPPORT OFFSHORE WIND A PUBLIC POLICY OF THE STATE OF NEW JERSEY

DOCKET NO. QO20100630

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April 24, 2026

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The Organization of PJM States, Inc. (OPSI) appreciates PJM's recognition of the role of states in contributing to the assumptions and methods that PJM uses in its transmission planning processes. In recognition of this role, OPSI provides the following feedback on the assumptions in PJM's proposed capacity expansion modeling for the 2026 RTEP 8-year planning cases.[1]

OPSI understands that PJM's 2034 planning models anticipate a generation shortfall of roughly 25 GW in the Summer and 18 GW in the Winter, and that even after adding all queued projects through Transition Cycle 2, PJM will remain roughly 3.5 GW short in both seasons. OPSI recognizes that for PJM's models to be solvable and credible, sufficient generation must be present to cover forecasted load and that capacity expansion modeling is an established industry practice used by utilities, RTOs, and planning organizations across the country. OPSI agrees that PJM must build defensible generation assumptions into its transmission planning models; however, PJM should also thoroughly explain any anticipated reliability challenges identified through its modeling.

Scenario A is a reasonable base case and is most consistent with assumptions from the 2025 RTEP. Running Scenario B as a sensitivity would appear to provide a useful distinction from Scenario A as long as PJM can explain how it decides which projects in the queue it deems to be uneconomic or otherwise unlikely to be built. The language in Scenario A excluding offshore wind and new gas in New Jersey, Maryland, Delaware, Illinois, and eastern Pennsylvania unless backed by an ISA, GIA, or SAA also appears to be PJM making a determination about which generation is feasible. If PJM's concern is that projects in the queue, and especially those that

[1] This letter was approved unanimously by the OPSI Board on April 24, 2026.

have an interconnection agreement, are unlikely to materialize, PJM should apply a generation expansion methodology transparently, and in a way that is rigorous, plausible, and consistent with state policy.

Separately, running a capacity expansion model right before an Interconnection Cycle Application Deadline will not be as informative as if that data from Cycle 01 was included. Therefore, PJM should consider the impact of new generation submitted in Cycle 01.

Lastly, PJM should consider a step in its planning process that informs states of capacity shortfalls and those areas where generation would most cost-effectively meet growing capacity needs considering transmission costs. States with authority to direct generation resource growth should be given the opportunity to evaluate PJM capacity shortfalls and provide input to aid PJM planning.

***

OPSI recognizes the reality of a generation shortfall in the 2034 planning models. However, OPSI supports reflecting that shortfall reasonably in PJM's modeling assumptions and only expanding the capacity mix where generation can realistically be expected to come online. OPSI welcomes further dialogue with PJM on these issues and looks forward to the continued discussion during the May 8 TEAC meeting.

Respectfully submitted,

Dennis P. Deters
President, Organization of PJM States

To: PJM Staff of the PJM Transmission Expansion Advisory Committee (TEAC)

From: Melanie Joy El Atieh, Deputy Consumer Advocate
Zach Teti, Senior Regulatory Analyst
Pennsylvania Office of Consumer Advocate (PA OCA)

Date: April 22, 2026 (Updated May 4, 2026)

RE: **2026 RTEP Assumptions**

1. Request for Delay

At the April 7, 2026 TEAC meeting, PJM informed stakeholders that even when including existing generation, projects in the queue with signed generation interconnection agreements (GIAs), and queue projects without GIAs, PJM cannot solve the 2034 reliability cases due to insufficient generation to meet demand.[1]

At this meeting, PJM proposed to use a capacity expansion model (CEM)[2] to estimate where new generation may be expected to interconnect in 2034 in order to construct its base and sensitivity cases for the 8-year-out cases. PJM said it would take stakeholder input at the prompt 4/7 TEAC meeting and in writing by 4/22, on assumptions to incorporate into the CEM.

The PA OCA requests PJM to not use the CEM and instead delay the base case development for the 2026 RTEP until it can be informed by the completed Cycle 1 interconnection application review process (7/27/2026) and/or the completed Phase 1 decision point (12/24/2026). These new market-based generation queue projects would better inform transmission expansion planning, as opposed to – or as a validation for – theoretical CEM results. We believe the best data will be available after completion of the Phase 1 decision point, where some projects will drop out of the queue based on network upgrade economics and other factors.

We have concerns about the justness and reasonableness of PJM approving billions of dollars of ratepayer costs for transmission expansion projects to solve theoretical reliability violations that are based on a hypothetical system using CEM assumptions about the location of future generation. Delaying the 2026 RTEP by just a few months would provide PJM with real, market-based interconnection queue data to better inform its power flow modeling.

Capacity expansion models (CEM), including those that co-optimize between generation and transmission for least-cost capacity expansion, are industry standards in vertically integrated states that use integrated resource planning (IRP). In these states, CEM results inform real-world,

[1] https://www.pjm.com/-/media/DotCom/committees-groups/committees/teac/2026/20260407/20260407-item-10---2026-rtep-assumption-update.pdf.
[2] PJM proposes to use Energy Exemplar's capacity expansion model.

ratepayer investments in capacity expansion through the IRP and subsequent utility rate cases. In PJM, CEMs are useful to inform long-term planning efforts, such as FERC Order No. 1920 compliance, where the 20-year time horizon requires model-based information. However, even in long-term planning, PJM does not intend to use CEMs to plan the transmission system, rather the CEM will be used to simulate the projected future resource mix based on input assumptions.

CEMs are not consistent with PJM's competitive market-based approach to generation capacity expansion for near term (5-to-8 year) transmission planning. This is because in PJM generation investment decisions are not centrally planned using co-optimization. Rather, these decisions are based on private developer decisions and market dynamics.

CEMs are not consistent with PJM's developing approaches to connect-and-manage, bring your own new generation (BYONG), or reliability backstop central procurement (RBCP), all of which are relevant to the 2034 horizon. For example, BYONG has generation buildout decisions being driven by bilateral negotiations between buyers and sellers, and RBCP is essentially a market-based central procurement.

Beyond the inconsistencies mentioned above, regional CEMs require detailed calibration on a state-by-state basis, considering state and federal policy drivers that impact generation investment decisions. PJM's proposal to give states less than 2 weeks to inform such calibration is woefully insufficient. Once calibrated with detailed assumptions, CEMs require validation to ensure results are robust and dependable. PJM has offered no information on the steps it would take – post assumption input – to validate results. For example, would CEM model runs for past years yield new generator interconnection results consistent with real-world observations?

2. Request for Additional Scenarios

Please refer to Item 10 of the April 7 meeting materials, available here: https://www.pjm.com/-/media/DotCom/committees-groups/committees/teac/2026/20260407/20260407-item-10---2026-rtep-assumption-update.pdf

In addition to Scenarios A&B on P 26, we request PJM to include additional scenarios for purposes of understanding the impact of load growth uncertainty. The requested additional scenarios should include the following:

Additional Scenario #1: Keep load flat at current levels (i.e., do not incorporate Table B9:Adjustments Above Embedded to Summer Peak Load (MW) for Each PJM Zone and RTO (2026-2046)) – to directly compare to Scenarios A & B where we understand peak load is 218,339MW in the Summer and 204,549 in the Winter.

Additional Scenario #2: Cut-off load growth at Summer 2027 (i.e., do not incorporate load growth past Summer 2027 illustrated in Table B9: Adjustments Above Embedded to Summer Peak Load (MW) for Each PJM Zone and RTO (2026 - 2046)).

3. Clarification Questions

In the capacity expansion assumptions for Scenarios A&B on P 26, has PJM included in its assumptions any specific information related to large load BYONG arrangements (whether co-located or not)? We have heard PJM express during the RBP E-CIFP process that they are not privy to the details of data center's decisions to enter into BYONG arrangements with generators; however, this information would seem to be critically important to be included in PJM's assumptions for purposes of determining capacity expansion and transmission needs.

On P 25, "PJM is forecasting 218,339MW of peak load in the Summer and 204,549 in the Winter" – then, during the TEAC it was explained that this was noncoincident peak load; but per Load Report Table B1 Note 1: "All forecast values are non-coincident as estimated by PJM staff." Can you please explain the difference between the amount on P 25 and the amount in the Load Report Table B1?

Conclusion

We appreciate PJM's consideration of this reasonable request to delay development of the 2026 RTEP to ensure real-world data informs system needs and billions of dollars in ratepayer cost recovery.

Input on RTEP 2026 Window 1
April 22, 2026

The undersigned organizations appreciate the opportunity to provide feedback on PJM's 2026 Regional Transmission Expansion Plan (RTEP). We recognize the dilemma that PJM is facing, with a lack of sufficient generation available to meet forecasted load growth. We commend PJM for developing capacity expansion modeling tools to meet the needs of the 2026 RTEP and also comply with FERC Order No. 1920. We believe the following recommendations can enhance PJM's transmission planning to continue to address load growth and other drivers of change in the region.

Incorporate data from the first cycle of PJM's interconnection cluster study into the 2026 RTEP.

The deadline for applicants for PJM's first cluster study is April 27, 2026, and PJM will review and confirm the final list of eligible applicants by July 27, 2026. We believe that the list of confirmed applicants from this initial cluster study could help better inform PJM's capacity expansion modeling assumptions, as well as inputs, with respect to the types and locations of generation. Rather than allow these two study processes to move forward asynchronously, **we urge PJM to incorporate initial application data from the first cycle into the 2026 RTEP inputs and assumptions.** We feel that any perceived time delay imposed by the integration of these cluster study applicants into the capacity expansion modeling assumptions is insignificant to the potential improvements in study accuracy by the use of most-up-to-date data inputs.

Additionally, if not already doing so, PJM should incorporate common, repeating network upgrades that meet the Order 1920 criteria into the 2026 RTEP. These are network upgrades that are > 230 kV, cost more than $30 million, and are associated with generator withdrawals in at least 2 historic interconnection cycles in the last 5 years. Incorporating these repeatedly identified network upgrades offers the opportunity to unlock gigawatts of new capacity.

Ensure RTEP is consistent with PJM's connect and manage decisions.

Connect and manage rules currently under discussion at PJM are likely to place load growth beyond available capacity on some type of interruptable service. This suggests that PJM should consider increasing load management assumptions in RTEP cases with insufficient supply as a sensitivity to adding new generation resources.

Fully incorporate state public policies into capacity expansion model inputs.

Several states in PJM have public policies that impact generation and storage additions. We urge PJM to continue to work with its states through venues such as the Independent State Agencies Committee (ISAC) to incorporate state policies as inputs into the capacity expansion model to ensure the resulting resource additions are accurate and reflective of state priorities.

Increase valuation of storage resources.

PJM's capacity expansion model should consider investments that increase ELCC without requiring CIRs, such as increasing the duration of existing storage and adding storage using surplus interconnection. This can enable demand to be met more affordably.

PJM should also consider 6 hr and 8 hr battery storage resources as expansion candidates. As 4 hour battery storage becomes saturated and grid needs change over time, it is valuable to assess and consider the role of medium duration storage to meet future needs.

Deactiviations

We support PJM's decision to not model deactivations beyond those already announced in the 8-year base case. State policies that require deactivations almost always have a reliability safety valve, and we believe it is reasonable to assume that states will either delay deactivations or create in-place replacements for deactivated units.

Integrate external generation resources into transmission models.

PJM should study the impacts of increasing imports of generation from outside of its own footprint, and specifically the cost benefits that this could provide to ratepayers. Several studies have shown how increasing interregional transfers along PJM's seams with its neighbors could save ratepayers millions of dollars.[1] If PJM finds that it is land- or resource-constrained for new generation in its capacity expansion modeling, incorporating a modest amount of external resources into the model could help it solve at lower cost.

Even if PJM decides not to fully integrate external generation into the capacity expansion model, an increased capacity imports scenario should be included as a sensitivity analysis.

Ensure generator outage rates are treated consistently

PJM's capacity expansion model needs are currently driven by scenarios where gas plants have high outage rates during winter events (slides 49-50). It would be inconsistent to determine supply needs based on this assumption while determining transmission needs based on average EEFORd (slide 17). If PJM is considering ELCCs in the capacity expansion model, it should also treat gas plants in its transmission planning models as having an outage rate based on the outage rate in ELCC model during loss of load hours, at least during winter peak conditions.

Ensure that build limits recognize natural gas pipeline constraints and expansion limitations.

Similar to land availability for wind and solar generation, there are limitations in natural gas pipeline availability and locations. PJM frequently faces limited natural gas capacity during extreme weather due to pipeline restrictions and firm service availability. Therefore, PJM should incorporate appropriate build limits on natural gas CC and CT resources due to those limitations and restrictions.

[1] See, for instance, *Economic, Reliability, and Resilience Benefits of Interregional Transmission Capacity*, GE Consulting, October 2022, https://www.pjm.com/-/media/DotCom/committees-groups/user-groups/pieoug/2022/20221201/item-02-ge-nrdc-interregional-transmission-study.pdf.

Integrate co-optimization into PJM's capacity expansion model, including the transmission value of storage.

Research has shown that a model with co-optimization of supply-side (generation) and transmission solutions can result in the most efficient and cost-effective outcomes for ratepayers.[2] PJM's model today looks only at transmission solutions. We urge PJM to integrate co-optimization methods in a timely fashion to its modeling, recognizing that this requires additional technical resources. In particular, given storage's siting advantages, it is especially important that the capacity expansion model consider avoided transmission costs when deciding between storage and other generation resources (e.g., gas).

Consider shifting to a Consolidated Planning Process (CPP)-style approach.

FERC recently approved SPP's new Consolidated Planning Process (CPP)[3] and commended it for more fully integrating the interconnection queue with the transmission planning process. We urge PJM to consider ways that it could integrate CPP design elements into the RTEP. In addition to further analysis on the opportunity to shift to a CPP model, there are at least two key components of the CPP model study process that PJM could consider immediately including as part of this iteration of RTEP study:

1. Synching interconnection queue submission deadlines with key RTEP dates for finalizing inputs and assumptions (see note above)
2. Using RTEP modeling to determine upfront cost information for interconnecting generators on an annual basis, synchronized with RTEP near-term planning cycles

Shifting to a CPP-style approach can ensure that PJM has adequate resources (including generation, storage, and demand side flexibility to meet load growth and other grid demands for every planning cycle moving forward. This change would also be responsive to inputs that PJM has received from other forums, notably including comments made during a recent Federal Energy Regulatory Commission meeting in spring 2026 after the Commission's approval of SPP's CPP application.[4]

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[2] *Coordinated vs Sequential Transmission Planning*, NYU Institute for Policy Integrity, September 2025, https://arxiv.org/abs/2509.24959

[3] Docket Nos. ER26-414-000 and ER26-414-001. See, e.g., Commissioner Rosner concurrence, https://www.ferc.gov/news-events/news/commissioner-rosners-concurrence-southwest-power-pool-inc

[4] During the meeting, FERC Commissioners David Rosner and Judy Chang urged PJM to look at other regional approaches, specifically highlighting the Southwest Power Pool's (SPP) new Consolidated Planning Process (CPP) as a "better way" to improve interconnection. FERC Open Meeting, March 2026, Meeting recording available at https://www.ferc.gov/news-events/events/march-19-2026-open-meeting-10082025, meeting notes at https://www.ferc.gov/news-events/news/summaries-march-2026-commission-meeting.

Work with Transmission Owners (TOs) to identify ways to reduce costs to ratepayers from data center-driven lines.

Much of the transmission investment in the RTEP today is being driven by data center load growth.[5] The federal government and data center companies have collectively pledged that data centers pay their fair share of necessary grid upgrades.[6] We urge PJM to work with its Transmission Owners to develop methods for ensuring that these pledges and commitments are actionable in the context of transmission rates. This may include changing cost allocation methodologies and/or sharing more project-level data with FERC, NERC, and state utility commissions through the formula ratemaking process. For instance, PJM and its TOs can proactively share annual project-level transmission spend data with states, breaking down which transmission projects are being built explicitly for data centers to allow states to more accurately fulfill their duties as retail rate regulators and implement any large load tariffs they may have. While we recognize that ratemaking and cost allocation is not PJM's responsibility, we believe that PJM can play a critical role as a convenor and communicator between PJM state governments and Transmission Owners in ensuring affordable transmission outcomes for ratepayers.

Signed,

RMI
Sierra Club
NRDC
Southern Environmental Law Center

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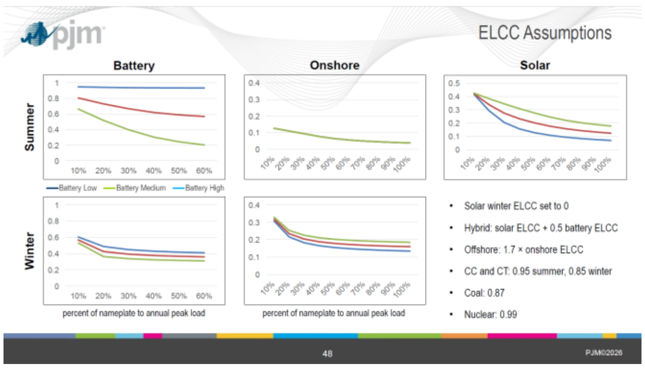
[5] *Drivers of Transmission: Examining Demand Growth and State Clean Energy Policies*, NYU Institute for Policy Integrity, January 2026, https://policyintegrity.org/files/publications/Drivers_of_Transmission_Issue_Brief__1.pdf
[6] *Ratepayer Protection Pledge Proclamation*, White House, March 4, 2026, https://www.whitehouse.gov/presidential-actions/2026/03/ratepayer-protection-pledge-proclamation/

Hi PJM Transmission Planning Team,

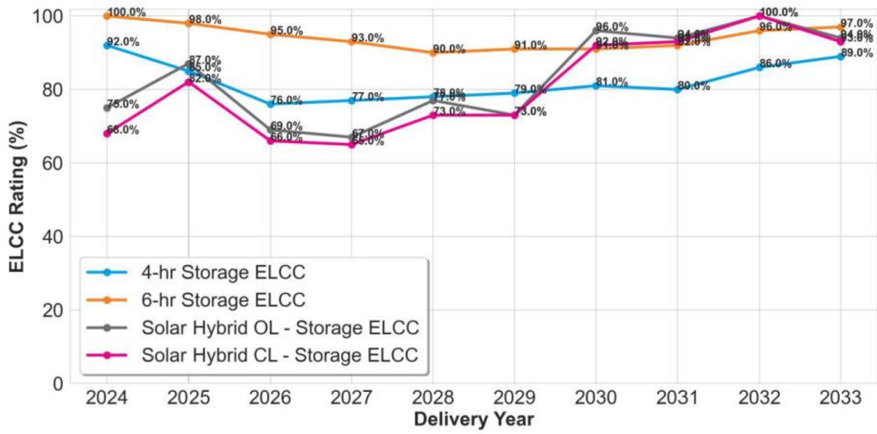
Thank you for presenting your plans for capacity expansion modeling in the latest RTEP and for offering the opportunity to comment on the assumptions for that modeling. Some of our PJMCCC members have questions about some of these assumptions, and we'd appreciate any answers you can offer.

- On the ELCC assumptions (presented on slide 48 of the TEAC presentation, attached and shown below):



1. Could you please explain why hybrid solar+storage resources will only receive half of the ELCC of a battery plus the full ELCC of a solar resource. Why shouldn't the hybrid resource receive the full ELCC credit of a battery? How does the team reconcile this assumption with PJM's 2023 ELCC report, which calculates hybrid solar+storage resources achieving ELCC values between 0.65 and 1 and, especially, increasing over time? See excerpt from PJM's 2023 ELCC report below:

Figure 4: 2024 – 2033 ELCC Class Ratings for 4-hr Storage, 6-hr Storage, Solar Hybrid Open Loop (OL) - Storage Component, Solar Hybrid Closed Loop (CL) - Storage Component



2. Could you please explain why the ELCC of a battery declines with increasing penetration? Why does PJM assume that battery ELCC declines with greater battery penetration in two of three summer scenarios and all three winter scenarios, when NREL modeling shows that battery ELCC stays fairly high (between 0.7 and 1) over various levels of penetration and various weather scenarios (see attached NREL report)? See excerpt from NREL report below:

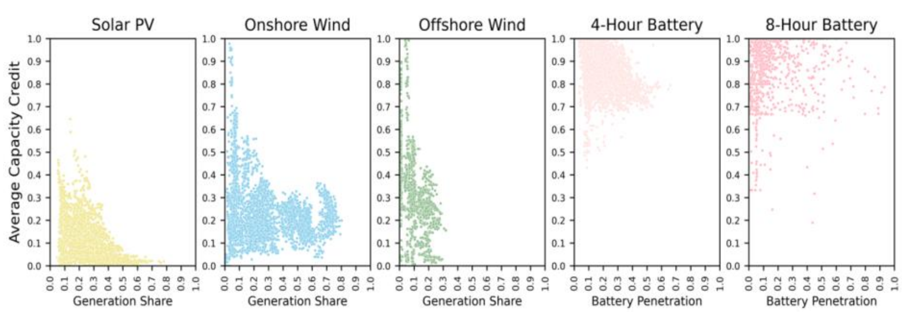


Figure 5: National average capacity credits vs. generation shares across technologies. The x-axes are the ratios of solar PV generation, onshore wind, and offshore wind over total system generation, and ratios of 4-hour and 8-hour battery capacities over total system capacity.

3. Could you please explain why the ELCC of battery resources is consistently much lower in the summer than in the winter? Why does PJM think the ELCC of battery resources will be consistently low (0.6 to 0.3) in the winter scenarios, when NREL's calculations show battery resources achieving such low ELCC values only rarely (see same attached NREL report and same excerpt above)?

- On the assumptions for overnight capital costs (presented on slide 36 of the TEAC presentation, attached - the combined cycle values appear to range from $1,411/kW to $1,649/kW, while the combustion turbine values appear to range from $1,339/kW to $1,495/kW):

Fixed Costs

	Overnight Capital Cost (2028$/kW)	FOM (2028$/kW-year)
Combined Cycle		
EMAAC	1517	41.0
SWMAAC	1411	61.0
Rest of RTO	1419	57.0
WMAAC	1476	48.0
COMED	1649	38.0
Combustion Turbine		
EMAAC	1395	21.0
SWMAAC	1339	33.0
Rest of RTO	1361	25.0
WMAAC	1390	21.0
COMED	1495	21.0
BESS 4-hr		
EMAAC	1832	57.0
SWMAAC	1753	62.0
Rest of RTO	1750	55.0
WMAAC	1784	57.0
COMED	1980	59.0

Brattle 2025 CONE Report for PJM (Quadrennial Review)
https://www.pjm.com/-/media/DotCom/committees-groups/committees/mic/2025/20250411-special/item-01-2-cone-report-final.pdf

36 PJM©2026

1. How does the team reconcile these values with recent reports showing that just the cost of turbines alone have risen to between $2,000/kW to $3,000/kW over the past few months? How does the team reconcile these values with recent modeling by E3 that assumes $2,800/kW for combined cycle and $2,500 for combustion turbine - starting in 2030 and declining closer to the PJM team's values only by 2035 (see attached report from E3)?

2. Given that the team's assumed values come from Brattle's calculations of the costs of a resource that would come online specifically in 2028, as opposed to the time horizon being considered by the team's capacity expansion modeling, how will the values for overnight capital costs change over this time horizon? Does the team assume the overnight capital costs of these technologies to remain constant throughout the modeling time horizon? If so, how does the team reconcile this assumption with recent modeling efforts, such as E3's, that assume changes in resources' overnight capital costs over time?

3. Given that combined cycle resources use two different turbine technologies - combustion turbines and steam turbines - can the team explain why the overnight

capital costs of combined cycle resources are assumed to be so similar to the overnight capital costs of combustion turbines, which use only one turbine technology? If the answer is in Brattle's report, please refer us to the report.

Given that this capacity expansion will model new resource builds in PJM, does the PJM team have any plans to model storage as a transmission asset? If so, how does the team plan to represent this? If not, why not? Does the team have knowledge of ERCOT's successful methods for modeling batteries as transmission assets?

What assumptions does the PJM team plan to use for the time-to-build of each resource type? Does the PJM team have any assumptions that reflect how quickly different resource types can be built in the capacity expansion modeling? Does the PJM team expect the capacity expansion results to show quick-build resources like batteries coming online early vs slow-build resources like combustion turbines coming on later (owing partly to the five-year backlog of turbine orders discussed in the news source linked above)?

Thank you again for entertaining our questions. We look forward to your responses, and please reach out to us with any questions you have.

Best regards,

Alex (on behalf of the PJMCCC)

PPL Comments to PJM on Use of Capacity Expansion Modeling in 2026 RTEP Studies

PPL appreciates the opportunity to provide feedback on this effort. As a general comment, PPL would like to emphasize that incorporating capacity expansion modeling into RTEP study methodology is a significant change, with wide-ranging implications for the results of those studies and subsequent project portfolios. Utilizing this methodology without taking more time to solicit and incorporate feedback significantly increases the likelihood that it will produce inaccurate results that lead PJM to develop the RTEP transmission portfolio in a manner that is neither cost-effective, nor secure from a reliability perspective. To ensure the 2026 RTEP cycle is not delayed, PPL strongly recommends that this cycle focus only on 5-year (2031) reliability needs (postponing 8-year case activities), and that PJM should establish a separate but parallel stakeholder initiative in short order to discuss the capacity expansion scenario selection methodology and/or process for use in long-term assessments in the PJM Order 1000 process. These discussions should also address other potential Order 1000 / Order 1920 process coordination issues in the interest of driving the region towards a more holistic, efficient system planning process.

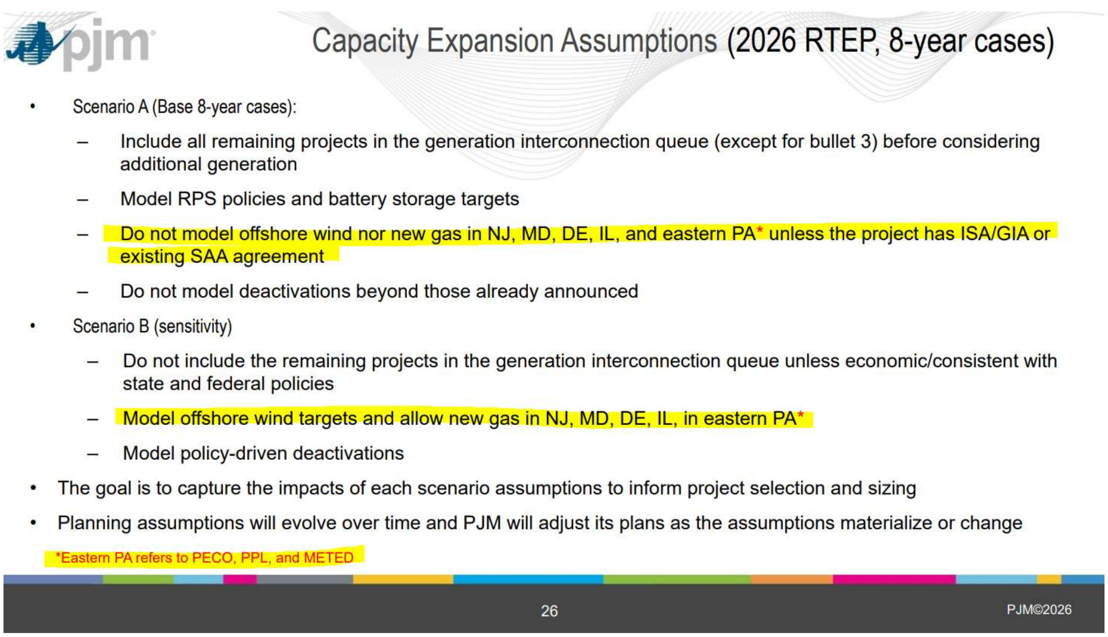
Technical Questions and Concerns

- PPL reiterates its request for access to more detailed capacity expansion modeling data than has been provided to date. For example, during the December 2025 TEAC meeting, PJM provided transfer deltas between the Scenario 5 cases (2032 with policy deactivations) and the Scenario 3 cases (2032 base case). PPL requested that transfer deltas be provided between the Scenario 5 cases and the Scenario 4 cases (2032 with NJ OSW out) that were used to determine the need for significant 765 kV solutions. Such data would have helped PPL and other stakeholders better understand how the Scenario 5 capacity expansion case dispatch and transfers compared to the method used for Scenario 4. However, no transfer deltas were ever provided. PPL is still interested in seeing this data.

- Additionally, PPL would like to see a complete set of capacity expansion modeling data, assumptions, and settings used for the 2025 RTEP Scenario 5 assessment and the same suite of data as presently proposed for the 2026 RTEP Scenarios, to better inform its position on capacity expansion assumptions PJM is proposing for the 2026 cycle.

- Examples of capacity expansion technical details that PPL would like PJM to provide include, but are not limited to:
  - Number/duration of time blocks used and how they are separated (ex. by time of day, day of week, etc.)
  - Reserve requirements and whether they are modeled on a zonal basis or totaled for all of PJM
  - Additional details on transmission expansion considerations
  - Constraints on battery charge/discharge cycles, including hybrid facility and time-of-day considerations
  - Details on modeled external areas, including treatment and proxy flows
  - Particularly for the 2026 RTEP Capacity Expansion effort, confirmation of whether Developers will be able to gain access to the PJM capacity expansion database

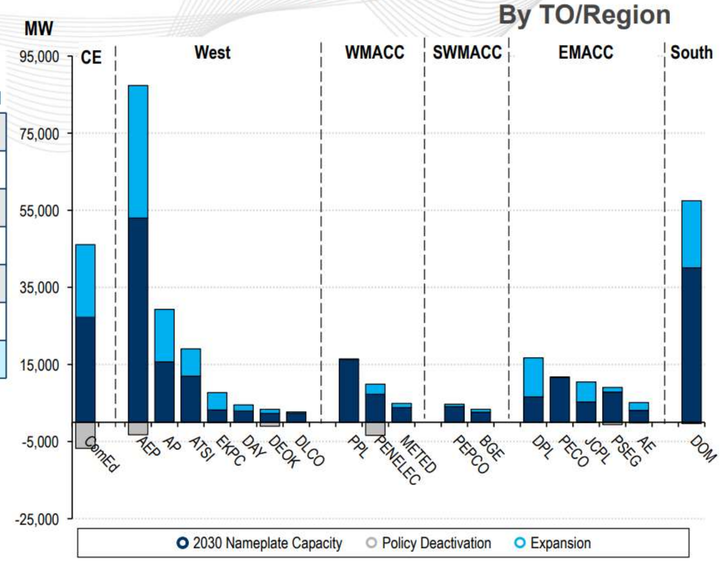
- Referring to the highlighted assumptions and capacity expansion summary on the below slides:



2032 Scenario 5: Capacity Expansion Summary

By TO/Region

Region	2030 Nameplate (MW)	Policy Deactivation (MW)	Capacity Expansion (MW)	Total
ComEd	33,986	-6,762	18,862	46,085
West (W/O CE)	95,799	-4,374	62,554	153,980
WMACC	30,667	-3,400	3,966	31,234
SWMACC	6,672	0	1,399	8,071
EMACC	35,313	-839	18,584	53,057
South	40,405	-331	17,389	57,463
Total	**242,843**	**-15,706**	**122,754**	**349,890**



KEY TAKEAWAY

- ComEd and West accounts for 66% (81 GW) of 123 GW of capacity expansion.
- Most of the expansion is forecasted in AEP (34 GW), CE (19 GW), DOM (17 GW), AP (14 GW) and DPL (10 GW).

- Under Scenario A (Base Case for 2034), PJM does not plan to model new gas generation in NJ, MD, DE, and IL, aligning with those states' clean energy mandates. However, it is unclear why PJM also excludes new gas in eastern Pennsylvania. Unlike NJ and MD, Pennsylvania has not enacted a "Carbon Free" mandate prohibiting gas expansion. In fact, Pennsylvania's policies and tax incentives for energy infrastructure indicate continued support for gas as a transitional resource. Over the past decade, eastern Pennsylvania has been one of the focal points of greenfield gas development in PJM. In particular, the PPL and MetEd zones have seen the highest concentration of new gas builds in PJM's footprint because they sit directly on the edge of the Marcellus Shale production area. Modeling a "hard stop" to this established trend in the 2026 RTEP deviates from geological and economic realities. Given strong demand growth in eastern PA, including new gas generation in this region will better reflect current state policy and avoids overstating transmission needs. PPL also notes that initial applications in PJM's Generation Cycle 01 show significant natural gas submissions in the PPL region, further confirming that PJM's proposed assumptions are inappropriate.
- PPL is concerned that studying only two scenarios that join offshore wind and new gas generation together, as though these fuel types somehow have

conjoined futures, is inappropriate. New gas generation in the PPL footprint is not a conjoined future with new gas generation in other states, let alone offshore wind. Based on slide 150 referenced above, PPL is left to conclude similar assumptions were made for the Scenario 5 assessment last year, resulting in no generation expansion in the PPL footprint in last year's Scenario 5 assessment. To date, PJM has not provided a reasonable justification for this assumption.

  - PPL is concerned that utilizing the 2026 load forecast, with de-rating applied to TO-submitted Large Load Adjustments, does not cover a wide enough range of plausible demand growth outcomes for the 8-year cases. PJM should include, at minimum, one scenario that assumes the TO Large Load Adjustment forecast as provided by the TOs. However, as noted in the beginning of these comments, PPL strongly recommends that the 2026 RTEP cycle should focus only on 5-year (2031) reliability needs, postponing use of the 8-year cases and all window-related activities associated with them until completion of a separate but parallel stakeholder initiative involving discussions on the capacity expansion scenario selection methodology for use in long-term assessments in the PJM Order 1000 process. The recommendation in this bullet is only one example of several in-scope items to be discussed during this separate initiative. The study scenario selection process, and clarity regarding how scenarios will ultimately influence reliability need decision-making are two topics that are paramount to a successful long-term planning process. PPL believes formal and transparent stakeholder discussions focused on these matters and allowed appropriate time for resolution are warranted at this time.

- If PJM chooses to move forward with use of 8-year cases in this window, PPL requests that:

  - PJM concretely defines how it intends to use the 8-year cases to make decisions in the 2026 window. Prior Assumptions slides include use of the term "right-size" to describe how the 8-year cases could potentially impact solutions selected to address 5-year case reliability violations. PPL asks that PJM provide a clear definition of the term "right-size" as it is used by PJM in relationship to this matter, so there is transparency around the range of scope creep that the 8-year cases may introduce after identification of solutions that make the 5-year cases secure from a reliability perspective.

    - PJM utilizes a 120-day solicitation window as noted in the PJM Operating Agreement Schedule 6 Section 1.5.8 (C). If 8-year cases are to be used and reliability violations from such cases are to become involved in the 2026 RTEP reliability window, PPL believes any solutions “right-sized” to resolve violations from 8-year cases constitute Long-lead projects for which a 120-day solicitation window should be used.

- Whether PJM utilizes 8-year cases in the 2026 RTEP window or postpones their use until a separate but parallel initiative concludes, PPL requests that once 8-year case scenarios have been developed, such cases also be used to reassess the need for the “right-sized” portion of the 2025 RTEP upgrade portfolio.

To help us better understand PJM's approach—particularly in the context of scenario development for scenario B—and related items addressed in the recent TEAC presentations, we have compiled the following questions. We hope these questions will help PJM develop talking points and clarifications at the upcoming May TEAC meeting.

1. Gas Generation Assumptions and Siting Considerations

- **Use of Existing Generation Sites:** Does PJM intend to prioritize or leverage existing or retired generation sites (e.g., former coal plant locations) when siting new gas generation in the capacity expansion model?
- **Short Circuit and Fault Current Considerations:** Will PJM account for existing short circuit levels when determining the location of new gas generation? There is concern that new resources could be placed in electrically constrained areas with existing fault current challenges.
- **Gas Infrastructure Dependencies and Risks:**
    - Will PJM consider proximity to existing gas pipelines when siting new gas generation to mitigate risks associated with common-mode failures (e.g., pipeline outages)?
    - Will pipeline outage contingencies be modeled or provided for consideration within the RTEP analysis?
- **Pipeline Capacity and Expansion:**
    - Does the modeling framework account for existing pipeline capacity constraints?
    - If new pipeline infrastructure is required to distribute to gas units, is a cost adder or constraint incorporated into the model?
    - How does PJM represent the relationship between gas generation siting and potential pipeline expansion?
    - It will be important to ensure that sufficient gas infrastructure is developed in parallel with generation expansion, with particular attention to avoiding single points of failure. As the system evolves to meet unprecedented load growth, maintaining fuel supply resilience will be critical to overall grid reliability.

- **Geographic Realism of Gas Buildout:** Will PJM apply any screening to ensure that new gas generation is geographically consistent with plausible pipeline expansion corridors, rather than dispersed in a manner that may not be physically supportable?
- **Capital Cost Assumptions:** The TEAC materials indicate gas generation capital costs of approximately $1,500/kW, while more recent industry sources (e.g., GridLab's 2025 Gas Turbine Cost Report) suggest costs will likely exceed $2,000/kW.
    - How does PJM plan to evaluate sensitivities to higher gas generation capital costs, given that this assumption could significantly influence the level of modeled gas buildout, particularly in Scenario B?

2. Offshore Wind Assumptions (Scenario B)

- **Development Feasibility and Timing:** In Scenario B, how does PJM account for permitting, interconnection, and construction timelines for offshore wind? Specifically, is there an assessment of whether assumed offshore wind capacity can realistically achieve commercial operation within the study horizon?

3. Relationship Between Scenario A and Scenario B

- **Divergent Outcomes Across Scenarios:** Scenario A includes all remaining queue projects, while Scenario B includes only those deemed economic or policy consistent. This could lead to materially different system conditions and identified needs.
    - How does PJM plan to reconcile situations where the two scenarios produce conflicting results?
    - What framework will be used to determine which scenario (or combination of scenarios) should drive project selection and sizing?
- **Reliability Need Identification:** How will PJM treat cases where a reliability need is identified in one scenario (e.g., Scenario A) but not in another (e.g., Scenario B)?
    - What criteria will be used to determine whether a project is ultimately selected?
    - It is imperative that RTEP project selection is grounded in realistic and achievable generation expansion assumptions.

4. Battery Storage Deployment

- **Concentration Risk at Individual Locations:** Will PJM impose any limits on the amount of battery storage that can be modeled at a single point of interconnection (POI) to avoid over-concentration and potential operational or reliability risks associated with large, single-site deployments?

5. Transparency and Stakeholder Review

- **Access to Capacity Expansion Results:** How does PJM plan to share the results of the capacity expansion modeling with stakeholders? Our recommendation is that PJM release the capacity expansion model should be made available to stakeholders, an important way to establish transparency in this effort and future 1920 planning windows.
- **Opportunity for Review:** Will stakeholders have the opportunity to review detailed (e.g., locational and technology-specific) outputs prior to their incorporation into the RTEP planning models?

Exelon's questions and comments:

- Does the RTEP Scenario A attempt to emulate the approach of ISAC Scenario 5?
    - From the 2/3/26 TEAC slides: "PJM will account for the PJM States (ISAC) input towards the development of the 2026 RTEP Scenarios."
- Apart from the year (2034 vs. 2032), what are the differences between the RTEP Scenario A and ISAC Scenario 5? In particular, the OSW?
- How was Scenario B developed?
    - Is Scenario B considered a low west-to-east transfer case?
    - Does it relate to another ISAC scenario?
- How will projects be right-sized against the two scenarios?
- Will the PLEXOS model be released to stakeholders?
- Will short-circuit impacts to the system be considered when siting generation in the model?
- Will NG line capacity be considered when siting NG generation in the model?
    - Will NG line contingencies and associated risk be incorporated as well?
- Exelon is generally supportive of PJM's decision to perform the Capacity Expansion Modeling for the 2034 model and have confidence in the team's ability to make reasonable resource decisions. We do have some questions regarding the two scenarios (A&B), and how the results will be factored into decision making within the window. In addition, how the assumptions and results from these scenarios will be communicated to stakeholders, particularly non-technical stakeholders. The one concern is that these two scenarios have very different assumptions that will likely result in very different outcomes and the messaging will be important to understand the significance for policy and reinforcement decisions. Though a no regrets scenario analysis approach to planning generally makes sense, our concern is that while we support this approach, adding other scenarios can disrupt confidence in PJM's capacity expansion modeling. If PJM is leveraging the interconnection queue, public policy and other data to inform its model, this should be the dominant assumption in analysis.

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Electric Transmission Services

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June 1, 2026

Via Electronic Mail
PJM Interconnection, L.L.C.
Jason Connell
Vice President, Planning
2750 Monroe Boulevard
Audubon, PA 19408
jason.connell@pjm.com

Dear Mr. Connell:

As our industry faces unprecedented demand growth, PJM and its members have invested significant effort in a short time trying to keep the same cadence as the load forecast trajectory. There are two things that are certain. First, the forecast is real, as our operational system peaks are outpacing yearly projections. Second, the Regional Transmission Expansion Planning (RTEP) process is just catching up to the reliability needs of our customers. Now is not the time to slow progress on the task we have in front of us.

We see two paths for PJM to institute now for transmission owners to continue to keep pace with demand.

First, on the supply side, firm generation depends on firm deliverability. We encourage PJM to apply a more practical lens in its Capacity Expansion (CapEx) Model by considering information from Cycle 1 queue entries when selecting the generation resources reflected in the model. PJM ought to select the dispatchable projects (regardless of the developer) that have a high probability of going into commercial operations. Variables like pipeline contracts, site control, identified water sources, backup fuel sources, equipment slots, permitting progress should all be considered when PJM is evaluating which projects are real and executable, and which projects are more speculative in nature.

Second, on the transmission planning approach. PJM should maintain a long-term planning horizon in both the annual RTEP and the FERC Order 1000 process. For the 2026 RTEP, that means evaluating an 8+ year outlook—specifically the 2034 case—when soliciting solutions. The Transmission Expansion Advisory Committee (TEAC) appropriately advanced planning to the 2032 case in 2025, supporting long-term durability and affordability. Stepping back from that progression would risk falling behind load growth, introducing planning inefficiencies, and constraining our ability to execute projects on the timelines required.

We understand that others may have a different perspective on these matters, but the broader system solutions and implementation timelines are no longer debatable. The load growth is not waning, the permitting process is elongating, the outage availability is limited, and the solutions are more complex. This dynamic compels an evolution of the planning process that matches execution realities and best positions us to add value to our customers. Incorporating real generation projects into the models and continuing to plan transmission to the 7- or 8-year case provides the certainty, dependability and predictability that our customers are expecting.

Given the complexity of expanding the grid in the timeframe needed also takes significant partnership with state and local regulators and county officials. Continuing to institute a longer-range planning and build horizon allows for better coordination with these important stakeholders. It also provides visibility and predictability, and most importantly, assurances for meaningful partnership and engagement amongst those that have just as much responsibility to the grid as PJM and its member utilities do.

To reiterate Ed Baine's comments in his February 2, 2026, letter in support of PJM's approval of the Heritage – Mosby HVDC project: "Dominion Energy and PJM are uniquely positioned to meet the needs of one of the fastest growing load regions in the world with the right technology and precise execution, deployed at the right time." We only get there with appropriate planning parameters in place.

Thank you for your consideration,

Joseph A. Woomer
Senior Vice President – Electric Transmission
Dominion Energy

CC:
Eric Hsia, PJM
Joshua Stephenson, PJM
Sami Abdulsalam, PJM

Follow-Up Input on RTEP 2026 Window 1
May 22, 2026

The undersigned organizations appreciate the opportunity to provide a second round of feedback on PJM's 2026 Regional Transmission Expansion Plan (RTEP). Below, we have a series of questions that we would appreciate greater information on from PJM, as well as a comment on scenario framing.

1. Can PJM provide additional detail on how the 1-in-10 resource adequacy target is implemented within the capacity expansion model? Specifically, is adequacy evaluated through a chronological or time-sampled simulation where stress periods emerge endogenously with the resource mix, or is it based on a more static or peak-oriented framework with ELCC approximations?
2. Can PJM clarify the temporal resolution used in the CapEx model (e.g., chronological hourly, representative periods, or time slices) and how that affects ELCC calculation and resource adequacy assessment? Relatedly, can PJM expound on the decision to use 2035 as a static interval? Alternative model runs show that when the time horizon is expanded, the relative cost of some resources fluctuates significantly.[1]
3. Can PJM provide additional detail on how ELCC is calculated within the model?
4. Can PJM clarify how natural gas expansion is constrained in the model? In particular, are there any explicit limits on gas deliverability (e.g., pipeline capacity or regional build constraints), or are gas siting considerations primarily represented through cost assumptions and geographic restrictions?
5. Can PJM provide additional transparency on key outputs, including the total installed capacity of the model and the quantity of retirements by resource type?
6. Does PJM plan to look at associated pipeline infrastructure costs and how that may change model outputs? For instance, a recent Interstate Natural Gas Association of America (INGAA) analysis of pipeline applications shows that the median cost per inch-mile of pipeline construction rose 256.98% from 2006 to 2024 and the median cost per horsepower of compression projects rose 172.76% over the same period, for an average increase of 214.87%.[2]

Regarding scenario framing, we would recommend that PJM change its scenario framing to instead utilize a framework where a policy-based case (currently Scenario B) represents the expected trajectory, with sensitivities exploring deviations from that trajectory (e.g., the current Scenario A). The state policies that PJM is modeling only in Scenario B are legally binding requirements that should be included in any default transmission modeling case, so scenarios that do not include policy mandates such as Scenario A should instead be framed as optional sensitivities rather than scenarios receiving equal weighting.

Signed,

RMI

[1] Domeshek, M., Graf, C., and Unel, B. "Coordinate vs. Sequential Transmission Planning," Cornell University, updated April 28, 2026. Available at https://arxiv.org/abs/2509.24959
[2] See p. 16 of Docket No. RM25-12-001, Notice of Proposed Rulemaking, Federal Energy Regulatory Commission, issued May 21, 2026

NRDC
Sierra Club

PPL Comments to PJM on Use of Capacity Expansion Modeling in 2026 RTEP Studies (Comment Period 2)

Defining a Clear Purpose for the 2026 RTEP 8-Year Case

As the term continues to appear in PJM's May TEAC presentation[1] (slides 4 and 13), PPL reiterates its request from its first round of comments for PJM to provide a clear, unambiguous definition and scope of the term "right-size" as used by PJM in many locations in its TEAC slides about the intended use of the 8-Year case. Absent such a clear definition, PPL requests the removal of all references to this term and the concept of the use of the 8-Year case to impact project selections for problems in the 5-Year case from TEAC slides, and that the term and concept not be included in the 2026 window Problem Statement.

There needs to be objective clarity around how the 8-Year case will affect PJM decision-making if the case is to be used at all in the upcoming window. This means that it is necessary to have a clear definition and scope of "right-sizing" as PJM views it, and a clear methodology for how PJM determines that "right-sizing" is warranted. Additionally, if PJM intends to use the 8-Year case to complete transfer analyses that may impact its decision-making regarding "right-sizing", the target interfaces and transfer levels should be explicitly defined in the Problem Statement. If multiple scenarios/sensitivities exist, PJM should clearly explain the weighting factor for each scenario/sensitivity in its decision-making process.

The vast majority of the points above are contentious matters that PJM should not be deciding independently. PPL reiterates its recommendation from its first set of comments that this RTEP window should only involve 5-year (2031) reliability needs, and that PJM should initiate stakeholder discussions on the capacity expansion scenario selection methodology and/or process for use in long-term assessments in the PJM Order 1000 process. These discussions should also address other potential Order 1000 / Order 1920 process coordination issues in the interest of driving the region towards a more holistic, efficient system planning process.

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[1] 20260508-item-12---2026-rtep---capacity-expansion-scenarios-for-8-year-case-(2034).pdf

Consistent and Complete Data Availability for Participating Developers is Paramount for a Well-Functioning Competitive Process

PJM needs to ensure that Developers have access to all pertinent data that could impact window decision-making early in the window process. Slide 5 of PJM's May TEAC presentation indicates that PJM would utilize data from the Reliability Backstop and/or BRA auctions to influence decision-making during the project selection phase after the window has closed and Developers would have no ability to consider the same data and make appropriate adjustments to their proposal portfolios. PPL views this as inappropriate and adverse to proper competitive process.

Unclear Vision Regarding Use of the SAA Process Within the 8-Year Case Assessment

As referenced on slides 4 and 5 of PJM's May TEAC presentation, where Capacity Expansion scenarios do not identify generation in certain locations, states and/or developers can utilize other methods such as the SAA process or the Reliability Backstop or BRA to ensure appropriate generation is considered. This appears to be a new planning approach, and it is unclear how it specifically complies with PJM's existing RTEP process under FERC Order 1000, and how it would be executed.

PPL has several questions on this concept:

(1) How would a transmission developer be able to influence a SAA, the RBP, or the BRA in a manner that would allow for transparent competition to take place in the 2026 RTEP window while it was still open and accepting solutions?

(2) If a state(s) submits a SAA request, what is the process to officially include it in the 2026 RTEP window? How can PJM ensure such an approach does not adversely impact ongoing cycles in the Generation Cycle process if the same generation is already accounted for there?

(3) The SAA process as described in the Operating Agreement anticipates identification of transmission portfolios to serve prescribed public policy needs. What if the result of a SAA scenario in PJM's postulated new Order 1000 solicitation window step is to reduce the transmission portfolio identified in other 8-Year scenarios (i.e. if the result is negative costs, most particularly when compared to the base scenario)?

Absent clear answers to the questions above, PPL arrives at the same conclusion as previously noted–the 8-Year case should be excluded from the 2026 RTEP window, and a stakeholder process should be initiated to resolve several outstanding process and methodological questions.

Clarity Regarding Capacity Expansion Inputs

PPL requests that the Capacity Expansion model be shared by PJM prior to the conclusion of the Capacity Expansion comment/revision period so that stakeholders can better understand and provide comments on what is actually in the model prior to PJM finalizing the primary 8-Year base cases. Waiting until the cases have been completed and the window is opening is too late to execute this key work activity.

Window Duration

If 8-Year cases are to be used in any way that could influence PJM decision-making on solutions for the 2026 RTEP window, PPL requests that a 120-day window be conducted because, for Developers, the complexity of the required window planning studies and solution scoping and estimation increases dramatically, and producing high-quality proposal portfolios with confident cost containment is likely to be considerably more time-intensive than for a 5-Year assessment.

Additional PPL-Specific Requests Associated with the 8-Year Cases Should an 8-Year Assessment be Included in the 2026 RTEP Window

(1) PPL requests that PJM conduct an 8-Year case scenario assuming use of TC1, TC2, and C1 generation, as is, without selections being made via the Capacity Expansion tool. Consider having generation capacity factor as a primary driving generation selection criteria for this scenario.

(2) Since the Capacity Expansion tool only has one PPL zone, PPL requests that PJM clearly delineate what parts of PPL are considered “eastern PPL” and “western PPL”, as it relates to the “eastern PA” stakeholder comment adoption made for Scenario A on slide 8 of PJM’s May TEAC presentation.

(3) PJM’s May TEAC presentation (slide 11) notes that the model is economic and policy based with no transmission representation. How is resource adequacy ensured at the LDA level within this framework, and what assumptions were made regarding transmission limits in supporting those outcomes? We request that PJM provide detailed assumptions of transmission limits assumed in capacity expansion model, if any.

MARYLAND
DEPARTMENT OF
NATURAL RESOURCES

Wes Moore, *Governor*
Aruna Miller, *Lt. Governor*
Josh Kurtz, *Secretary*
David Goshorn, *Deputy Secretary*

May 22, 2026

Maryland DNR Power Plant Research Program Supplemental Response to 2026 RTEP Assumptions

The Maryland Department of Natural Resources (DNR) Power Plant Research Program (PPRP) appreciates the opportunity to provide additional comments regarding PJM's proposed capacity expansion assumptions for the 8-year (2034) reliability cases under the 2026 Regional Transmission Expansion Plan (RTEP), as presented through the Transmission Expansion Advisory Committee (TEAC) stakeholder process. PPRP previously submitted comments on April 22, 2026, regarding the proposed assumptions and methodologies underlying the 2026 RTEP 8-year reliability cases.[1] The following supplemental comments are intended to address PJM's revised assumptions, feedback from other stakeholders, and the preliminary capacity expansion results presented at the May 8, 2026 TEAC meeting.[2]

PJM indicated that stakeholders may continue to provide feedback on the proposed assumptions, sensitivities, siting methodology, and related modeling inputs through May 22, 2026, and that PJM intends to further discuss its capacity expansion approach in the context of both the 2026 RTEP and future Order 1920 stakeholder processes. After reviewing PJM's updated materials and preliminary results, PPRP respectfully submits the following questions and comments:

1. PJM states that the 8-year CapEx scenarios are "not envisioned to be actionable," but may inform the right-sizing of 5-year solutions and future planning decisions.[3] PPRP requests clarification regarding the intended role of these scenarios within the RTEP framework, including the extent to which the outputs may influence transmission solution selection, sizing, or future planning determinations.

2. PPRP understands PJM's explanation that the model selects resources primarily based on economic competitiveness and that certain technologies and resource types, including new nuclear resources and some distributed and distribution-connected resources, are not currently expected to be selected under prevailing cost assumptions. However, Scenario B appears intended to reflect a more policy-driven future resource mix. In that context, PPRP notes that Maryland has recently adopted and expanded policies supporting or requiring the development of a range of clean energy resources, including advanced nuclear technologies, energy storage, community solar, and other distributed and distribution-connected resources that are designed to increase their

[1] PJM Interconnection, L.L.C., *Review of 2026 RTEP Assumptions: Informational Only – 2026 RTEP Assumptions Feedback*, presented to the Transmission Expansion Advisory Committee (TEAC), May 8, 2026, https://www.pjm.com/-/media/DotCom/committees-groups/committees/teac/2026/20260508/20260508-informational-only---2026-rtep-assumptions-feedback.pdf

[2] PJM Interconnection, L.L.C., *2026 RTEP – Capacity Expansion Scenarios for 8-year cases (2034)*, presented to the Transmission Expansion Advisory Committee (TEAC), May 8, 2026, https://www.pjm.com/-/media/DotCom/committees-groups/committees/teac/2026/20260508/20260508-item-12---2026-rtep---capacity-expansion-scenarios-for-8-year-case-(2034).pdf

[3] Id., p. 4.

cost-competitiveness.[4,5,6,7] PPRP recommends that Scenario B or a sensitivity therein account for Maryland's current statutory requirements, including targets for nuclear generation and distributed energy resources.[8]

3. PJM states that the capacity expansion model is "economic and policy based" and does not include explicit transmission representation.[9] Since the geographic distribution of generation additions strongly influences transfer requirements and transmission needs, PPRP requests additional clarification regarding how stakeholders should interpret transmission planning outcomes derived from generation expansion scenarios that are developed without explicit transmission constraints or transmission-generation co-optimization.

4. PJM states that power flow cases will not be developed for sensitivities A.2–A.5 or for the policy scenario B.1, and that these cases are intended to show the impact of varying assumptions on the resulting CapEx scenarios.[10] Scenario B.1 reflects materially different assumptions regarding resource development, retirements, and state policy targets. To the extent Scenario B.1 is intended to inform stakeholders regarding potential policy-driven future resource conditions, PPRP believes the scenario would provide greater planning value if its transmission implications were also evaluated through corresponding power flow analyses.

5. PJM's updated presentation includes sensitivities evaluating additional retirements, including retirement of the entire coal fleet "to provide indicative results on the effect of additional retirements due to aging infrastructure and economics."[11] PPRP requests clarification regarding whether retirements within the modeling framework are determined endogenously based on economics and operational competitiveness, or whether retirements are represented primarily through externally specified policy and sensitivity assumptions.

6. PJM indicates that new generation in the power flow cases will be placed at selected Extra High Voltage (EHV) buses based on proximity to existing generation and gas infrastructure.[12] PPRP requests clarification regarding how sensitive the resulting transmission flows and identified transmission needs may be to these assumed generation siting locations.

7. Scenario A.1 relies substantially on Transition Cycle 2 and Cycle 1 interconnection queue resources to satisfy future adequacy needs. PPRP requests additional clarification regarding how PJM evaluated expected project attrition and commercial viability within the interconnection queue assumptions used for the capacity expansion scenarios.

8. Does the model evaluate system performance on an hourly (8760) basis to capture reliability and operational constraints, or does it rely on representative time periods (e.g., seasonal or peak load conditions) to approximate system availability?

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[4] Maryland General Assembly, *Electricity and Gas – Emissions Reductions, Rate Regulation, Cost Recovery, Infrastructure, Planning, Renewable Energy Portfolio Standard, and Energy Assistance Programs (Next Generation Energy Act),* Senate Bill 937, Chapter 625. https://mgaleg.maryland.gov/2025RS/Chapters_noln/CH_625_sb0937e.pdf

[5] Maryland General Assembly, *Community Solar Energy Generating Systems Program and Property Taxes*, House Bill 908, https://mgaleg.maryland.gov/2023RS/bills/hb/hb0908E.pdf

[6] Maryland General Assembly, *Public Utilities – Generating Stations – Generation and Siting (Renewable Energy Certainty Act)*, House Bill 1036, Chapter 624. https://mgaleg.maryland.gov/2025RS/bills/hb/hb1036T.pdf

[7] Maryland General Assembly, *Utility RELIEF (Reducing Energy Load Inflation for Everyday Families) Act*, House Bill 1532, Chapter 353, https://mgaleg.maryland.gov/2026RS/bills/hb/hb1532E.pdf

[8] PPRP understands that behind-the-meter distributed energy resources may already be reflected indirectly through the PJM Load Forecast. This recommendation concerns front-of-the meter distributed energy resources interconnected at subtransmission voltages.

[9] PJM Interconnection, L.L.C., 2026 RTEP – Capacity Expansion Scenarios for 8-year cases (2034), presented to the Transmission Expansion Advisory Committee (TEAC), May 8, 2026, https://www.pjm.com/-/media/DotCom/committees-groups/committees/teac/2026/20260508/20260508-item-12---2026-rtep---capacity-expansion-scenarios-for-8-year-case-(2034).pdf, p. 11

[10] Id., p. 16.

[11] Ibid.

[12] Id., p. 18.

PPRP again appreciates PJM's willingness to engage with stakeholders regarding the proposed assumptions and address questions and feedback.

Respectively,

Robert Sadzinski

Robert Sadzinski
Director, Power Plant Research Program