UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

Joint Consumer Advocates, *Complainants*, v. PJM Interconnection, L.L.C., *Respondent.*	Docket No. EL25-18-000

COMPLAINT OF JOINT CONSUMER ADVOCATES

Pursuant to sections 206 and 306 of the Federal Power Act (FPA)[1] and Rule 206 of the Federal Energy Regulatory Commission's (Commission) Rules of Practice and Procedure,[2] the Joint Consumer Advocates[3] hereby file this complaint against PJM Interconnection, L.L.C. (PJM).

For the reasons stated here and in the attached Declaration of Marc D. Montalvo,[4] the Joint Consumer Advocates request that the Commission:

> (1) establish a refund effective date pursuant to section 206 as of the date of this complaint;
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> (2) find that PJM's existing capacity market rules are unjust and unreasonable because they fail to mitigate market power and result in the imposition of excessive capacity charges upon consumers; and
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> (3) establish just and reasonable replacement rates, as outlined below.

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[1] 16 U.S.C. §§ 824e and 825e.

[2] 18 C.F.R. § 385.206.

[3] Joint Consumer Advocates are the Illinois Attorney General's Office; Illinois Citizens Utility Board; Maryland Office of People's Counsel; New Jersey Division of Rate Counsel; Office of the Ohio Consumers' Counsel; and Office of the People's Counsel for the District of Columbia.

[4] The Montalvo Declaration is Attachment A to this Complaint.

I. INTRODUCTION

There is a problem in PJM. Its "Reliability Pricing Model" is not producing just and reasonable prices that comport with market fundamentals. Despite the existence of adequate supply resources, Base Residual Auction (BRA) capacity prices for the 2025/2026 Delivery Year set new records. Prices hit zonal caps of $466.35/MW-day for the Baltimore Gas and Electric zone in Maryland and $444.26/MW-day for the Dominion zone in Virginia and North Carolina, and soared to $269.92/MW-day in the rest of the PJM footprint, up from $28.92/MW-day in the immediate prior auction. From one auction to the next, the total capacity cost to consumers jumped from $2.2 billion to $14.7 billion. Worse, continuing to run BRAs using the current design promises the possibility of future auction clearing prices that are even higher. Absent changes to fix the PJM capacity market's flawed auction rules, some have predicted that the 2026/2027 BRA could clear at the new, higher offer cap ($696/MW-day) regionwide, ballooning charges to PJM ratepayers to $37 billion.

These clearing price outcomes do not match the market facts on the ground. Yes, load is increasing—but PJM has historically overestimated load and appears poised to do so again by exaggerating the likely additions of massive data center loads without firm power supplies. And yes, some supply resources are seeking to retire, but PJM ratepayers will pay hundreds of millions of dollars to forestall some of those retirements without receiving in return anything approaching the full reliability value that these ratepayer-funded resources can provide. Meanwhile, thousands of megawatts of additional capacity resources—non-retiring resources that will operate and support reliability during the delivery year—go unrecognized because current PJM rules allow them to keep their capacity out of the auction. PJM's rules—not market dynamics—short the market, boosting prices artificially.

These market rule flaws (and others discussed below) are particularly problematic because hundreds of thousands of megawatts of potential *new* resources—proposed long ago when capacity auction prices were much lower and whose entry would counteract any legitimate shortage—remain stuck in an interconnection queue traffic jam waiting for PJM to process their applications. While PJM's Independent Market Monitor (IMM) says tariff changes are needed because the capacity market is plagued with market power problems, PJM's glacial interconnection study process (coupled with the currently truncated periods between the conduct of auctions and the start of the Delivery Years) compromises the ability of new resources to enter in a timely manner, thereby blunting the competition that serves as the principal means of mitigating incumbent resource market power. In short, PJM acts as if load increases, supply decreases, and slow entry of new resources are facts of nature when, in fact, PJM has or should have tools to manage all three without sending prices to the roof.

A recent and pending complaint[5] seeks rule changes that would require Reliability Must Run (RMR) units to bid into the BRA. While the complaint should be granted, this relief is inadequate because it will not address adequately the lack of new entry to discipline incumbent generator market power or the market rule flaws that enable potential exercises of market power, including exemptions from must-offer requirements and the absence of a demand response (DR) offer price cap. PJM's rules should be structured to maximize

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[5] Complaint of Sierra Club, Natural Resources Defense Council, Public Citizen, Sustainable FERC Project and Union of Concerned Scientists (Sept. 27, 2024), Docket No. EL24-148-000, eLibrary No. 20240927-5073 (PIO Complaint).

supply participation in the auction, and to prevent physical or economic withholding, because the presence of a relatively few additional megawatts can make the difference between the exorbitant clearing prices in the 2025/2026 BRA and the far lower clearing prices in the 2024/2025 BRA.[6]

There is simply no way around it: significant aspects of the BRA design are unjust and unreasonable because they subject consumers to crushing capacity clearing prices that serve little purpose while incumbent generators reap enormous windfall revenues. As summarized by witness Montalvo:[7]

> Under current market conditions, capacity prices are being driven by the barriers to entry of new supply—including constraints on the time it takes to study interconnection requests and build new transmission to interconnect new resources in the queue—which add to the market power of incumbent suppliers. High prices cannot bring new generation into the market more quickly than it can be interconnected, and, while such prices might retain existing generation, they are substantially above any just-and-reasonable measure of the net going forward costs that existing resources must cover to deliver capacity.

The stark difference in outcomes between two auctions held less than a year apart raises serious questions about the validity of auction inputs, market rules, and resulting prices:[8]

> Side-by-side examination of the results of these two auctions would suggest that, in less than a year, market conditions deteriorated sufficiently that PJM went from an apparent robust surplus with little need for additional capacity to near shortage conditions across the region. While it is possible that this is true, the dramatic change raises questions regarding, at a minimum, the validity of the input assumptions—if not more broadly the structure of the

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[6] Montalvo Decl. ¶ 14.

[7] *Id.* ¶ 10.

[8] *Id.* ¶ 17.

> market—and calls a reasonable person to question the robustness of the results.

Joint Consumer Advocates urge the Commission to fulfill its consumer protection mandate by finding the current BRA construct unjust and unreasonable and by establishing effective, just and reasonable replacement rates.

II. SUMMARY OF REQUESTED RELIEF

We demonstrate here that FERC has a more than sufficient basis to conclude that PJM's capacity market design is unjust and unreasonable and to direct the adoption of just and reasonable replacement design modifications. Witness Montalvo explains, and we review below, that the Commission should require changes to PJM's Tariff to:

- Require that all existing eligible capacity resources participate in BRAs, including those resources that previously were categorically exempt from the must-offer construct that now applies to existing thermal generation. These reforms would impact currently exempted resources, including generation operating under RMR arrangements, intermittent resources, battery storage, and DR;

- Require a longer notice period for generator deactivations and adopt standardized RMR provisions and a *pro forma* RMR Agreement that enable PJM to delay existing resource retirements for as long as the resource remains needed for reliability. Where continued service is mandated, the Tariff should provide compensation at a full cost-of-service rate including a return on investment. In exchange, RMR resources should be required to participate fully in all PJM capacity, energy, and ancillary service markets for which they are eligible, including offering capacity as a price taker in each base residual auction for a delivery period that will occur during the term of the arrangement;

- Determine the capacity value of gas-fired generators using winter capacity ratings that seasonally match the winter risks for which those resources' capacity values are discounted in PJM's Effective Load Carrying Capability (ELCC) calculations;

- Give interconnection study priority to ready-to-study projects that will be sited in Locational Deliverability Areas (LDAs) that are more likely to be constrained;

- Require DR resources that bid into the BRA to submit offers that reflect the maximum dispatchable demand reduction that the resource is making available to PJM and measure as the actual reduction delivered (metered consumption before instruction less metered consumption after instruction) in response to a dispatch instruction during a system stress event; and

- Require the IMM to calculate and PJM to impose an offer cap on DR resources participating in the PJM capacity market when structural market power tests fail.

In addition, the Commission should direct PJM to initiate stakeholder proceedings to evaluate the longer-term issues discussed in section III.G and longer-term reforms presented in section IV.G of this Complaint and the Montalvo Declaration.

III. THE BASE RESIDUAL AUCTION MARKET DESIGN IS UNJUST AND UNREASONABLE.

The central aim of PJM's capacity construct is to "procure the least-cost, competitively-priced combination of resources necessary to meet the region's reliability objectives,"[9] but the existing market design is failing in that mission. As we explain below, it is failing in various ways to protect ratepayers from potential exercises of market power and otherwise to secure the needed resources at just and reasonable prices. Because the Commission's "first and foremost duty" under the Federal Power Act "is to protect consumers from unjust and unreasonable rates,"[10] the Commission should grant this complaint and reform PJM's capacity market rules.

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[9] *N.J. Bd. of Pub. Utils. v. FERC*, 744 F.3d 74, 101 (3d Cir. 2014).

[10] *Morgan Stanley Cap. Grp. Inc. v. Pub. Util. Dist. No. 1 of Snohomish Cty.*, 554 U.S. 527, 551 (2008). See also *Atl. Ref. Co. v. Pub. Serv. Comm'n of N.Y.*, 360 U.S. 378, 388 (1959) (FPA's sister, the Natural Gas Act, was "framed as to afford consumers a complete, permanent and effective bond of protection from excessive rates and charges."); *NAACP v. FPC*, 520 F.2d 432, 438 (D.C. Cir. 1975) ("Commission's primary task . . . is to guard the consumer from exploitation . . . ."), *affirmed,* 425 U.S. 662 (1976).

A. The BRA is rife with market power and PJM's market mitigation protocols are not working as intended.

The primary cause of the BRA price spike is not the interplay of supply and demand. It is the byproduct of a market power problem endemic to the PJM design that the existing mitigation protocols are unable to address.

Part B of the IMM's analysis of the recent BRA results finds that (1) the "market design for capacity leads, almost unavoidably, to structural market power in the capacity market"; (2) the "capacity market is unlikely ever to approach a competitive market structure in the absence of a substantial and unlikely structural change that results in much greater diversity of ownership"; and (3) "[m]arket power is and will remain endemic to the structure of the PJM Capacity Market."[11] The IMM goes on to explain why this is the case, observing that the[12]

> capacity market is, by design, always tight in the sense that total supply is generally only slightly larger than demand.
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> The demand for capacity in the capacity market is almost entirely inelastic because the market rules require loads to purchase their share of the system capacity requirement. The downward sloping portion of the VRR [Variable Resource Requirement] curve[13] is everywhere inelastic. The result is that any supplier that owns more capacity than the typically small difference between total supply and the VRR defined demand is individually pivotal and therefore has structural market power. Any supplier that, jointly with two other suppliers, owns more capacity than the difference between

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[11] Independent Market Monitor for PJM, Analysis of the 2025/2026 RPM Base Residual Auction Part B at 3-4 (Oct. 15, 2024), https://www.monitoringanalytics.com/reports/Reports/2024/IMM_Analysis_of_the_20252026_RPM_Base_Residual_Auction_Part_B_20241015.pdf (IMM Part B Analysis).

[12] *Id.* at 3.

[13] "VRR" refers to the Variable Resource Requirement curve, which is a downward sloping demand curve that relates the maximum price for a given level of capacity resource commitment relative to reliability requirements.

> supply and the VRR defined demand either in aggregate or for a local market is jointly pivotal and therefore has structural market power.

Witness Montalvo similarly observes that the IMM "has found year after year with great consistency, [that] structural market power is endemic to the PJM capacity market—an observation that applies both to the PJM aggregate market structure and to the PJM local market structure."[14] He goes on to explain the "IMM uses the Three Pivotal Supplier (TPS) test to identify potential market power," and:[15]

> In PJM, both at the regional level and at the LDA level for at least some LDAs, in almost every BRA, the IMM has found structural market power.

These findings notwithstanding, the IMM asserts that a "competitive outcome can be assured" so long as there are "appropriate market power mitigation rules" in place:[16]

> Detailed market power mitigation rules are included in the PJM Open Access Transmission Tariff (OATT or Tariff). Reliance on the RPM design for competitive outcomes means reliance on the market power mitigation rules. Attenuation of those rules means that market participants are not able to rely on the competitiveness of the market outcomes.

But PJM's market power mitigation rules were not designed to be the sole bulwark against such structural market power. The Commission's electric industry market-oriented mission is predicated on the need "to remove impediments to competition in the wholesale bulk power marketplace and to bring more efficient, lower cost power to the Nation's

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[14] Montalvo Decl. ¶ 23 (referencing the IMM's 2023 *State of the Market Report for PJM* at 10 (Mar. 14, 2024) (*2023 State of the Market Report*)). The statement, "[s]tructural market power is endemic to the capacity market," has appeared in every *State of the Market Report for PJM* since 2018.

[15] Montalvo Decl. ¶ 24 (footnotes omitted).

[16] *2023 State of the Market Report* at 44.

electricity consumers."[17] And consistent with that objective, the premise of the PJM BRA market design is that potential new resources—which previously were expected to be developed and interconnected during what was then a three-year period between the auction and the Delivery Year—would compete with existing resources and check their market power.[18]

As the Commission has explained, the forward-looking BRA was the product of a settlement with "design features [intended to] discourage the exercise of market power and market manipulation generally. Specific mitigation rules and increased competition from new entry are the most important design elements in this regard."[19] Thus, in approving PJM's Reliability Pricing Model (RPM), FERC found that "[t]he three-year forward market [plays an essential role in market power mitigation because it] permits competitive entry in the event that existing generators are seeking to raise prices above competitive levels."[20] Witness Montalvo similarly observes that a "central feature of the RPM's forward-looking market format is that competition from new entry will discipline the market power of incumbent resources."[21]

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[17] *Promoting Wholesale Competition Through Open Access Non-Discriminatory Transmission Servs. by Pub. Utils.; Recovery of Stranded Costs by Pub. Utils. and Transmitting Utils.*, Order No. 888, 75 FERC ¶ 61,080, P 1, *clarified*, 76 FERC ¶ 61,009 (1996), *modified*, Order No. 888-A, 78 FERC ¶ 61,220, *order on reh'g*, Order No. 888-B, 81 FERC ¶ 61,248 (1997), *order on reh*'g, Order No. 888-C, 82 FERC ¶ 61,046 (1998), *aff'd in part and remanded in part sub nom. Transmission Access Pol'y Study Grp. v. FERC*, 225 F.3d 667 (D.C. Cir. 2000), *aff'd sub nom. New York v. FERC*, 535 U.S. 1 (2002).

[18] "Since 2007, PJM's evolving capacity market has used the power of markets to commit enough resources to meet future reliability targets. The three-year-forward auction allows for competition between existing and new resources while attracting participation from across the PJM region. This design creates a wide scope for the market and provides transparent price signals to attract investment and induce less efficient resources to retire." PJM Capacity Market: Promoting Future Reliability at 1, https://www.pjm.com/-/media/about-pjm/newsroom/fact-sheets/pjm-capacity-market-promoting-future-reliability-fact-sheet.ashx.

[19] *PJM Interconnection L.L.C.*, 117 FERC ¶ 61,331, P 6 (2006), *granting reh'g in part,* 119 FERC ¶ 61,318, *reh'g denied,* 121 FERC ¶ 61,173 (2007).

[20] *Id.* P 101.

[21] Montalvo Decl. ¶ 28 (citation omitted).

Reality no longer comports with that premise, however, and renders the current BRA design unjust and unreasonable. According to PJM, there was a significant decline in supply offered into the capacity market from 148,945.7 MW in the 2024/2025 BRA to 135,692.3 MW in the 2025/2026 BRA.[22] As a result, two LDAs constrained in the 2025/2026 BRA and PJM as a whole failed its Three Pivotal Supplier Test—meaning that *all* existing generation capacity resources have market power.[23] And in fact, consistent with that observation, "[a]ll offered thermal, nuclear, demand response and solar capacity cleared the 2025/26 BRA."[24]

Meanwhile, prices soared—unchecked by new entry. Just 110 megawatts of capacity from new generation cleared the 2025/2026 BRA, which was less than a third of the new capacity that cleared the 2024/2025 BRA and thousands of megawatts less than the new capacity that cleared earlier auctions at much lower prices.[25] PJM nonetheless says that the 2025/2026 BRA results will encourage needed new generation,[26] asserting recently

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[22] *Id.*

[23] PJM, 2025/2026 Base Residual Auction Report at 3, tbl. 1 (July 30, 2024), https://www.pjm.com/-/media/markets-ops/rpm/rpm-auction-info/2025-2026/2025-2026-base-residual-auction-report.ashx (PJM 2025/2026 BRA Report).

[24] Aurora Energy Research, PJM Capacity Market - 2025/2026 BRA results & outlook for upcoming auctions at 13 (Sept. 2024) (Aurora Report). A redacted and publicly available copy of the Aurora Report appears at Attach. B.

[25] PJM 2025/2026 BRA Report at 7 & Fig. 2.

[26] PJM's July 30, 2024, Press Release, entitled, "PJM Capacity Auction Procures Sufficient Resources to Meet RTO Reliability Requirement Tighter Supply/Demand Balance Drives Higher Pricing Across the Region" states:

> The capacity auction has been a valuable tool over time to help PJM competitively secure resources to meet reliability requirements," said President and CEO Manu Asthana. "The significantly higher prices in this auction confirm our concerns that the supply/demand balance is tightening across the [regional transmission organization (RTO]. The market is sending a price signal that should incent investment in resources.

that "high prices are a feature designed to incent the development of more capacity."[27] But lower prices did not deter new entry in earlier auctions. And new entry did not occur in anticipation of sky high prices in the 2025/2026 BRA.[28] The combination of the compressed period between the conduct of the 2025/2026 auction and the start of the delivery period, the backlog of projects stuck in the interconnection queue, and the impediments to development of the relatively few resources that have cleared the queue, have dramatically reduced the potential for new entry to discipline the market power of existing resources. And the same thing is poised to happen in the 2026/2027 BRA.

PJM has acknowledged that while it "continues to execute against the [interconnection] transition plan, concerns are growing that the construction build-out from the volume of applications has not yet materialized[.]"[29] A recent survey of developers with PJM interconnection queue projects found that "PJM's increasingly lengthy interconnection process is exacerbating siting and permitting challenges and leading to knock-on delays in equipment procurement and financing decisions, suggesting the timeline for new generation in this market will likely remain long for the foreseeable future."[30] To that end, developers with projects in the queue are delaying taking essential

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[27] Answer of PJM Interconnection, L.L.C. at 6, Docket No. EL24-148-000 (Oct. 18, 2024), eLibrary No. 20241018-5165 (PJM Answer).

[28] If there were no barriers to entry besides low clearing prices, developers would submit offers for potential new resources that they would be willing to build if prices in the associated auction were to rise high enough to cover the developer's costs. Then, if supplies tightened in the auction and prices climbed, some of the offers would clear—producing significant new entry and moderating the price increase. That did not occur on a meaningful scale in the 2025/2026 BRA.

[29] Ethan Howland, *PJM says 'concerns are growing' after less than 2 GW added this year*, UTILITY DIVE (Sept. 26, 2024), https://www.utilitydive.com/news/pjm-interconnection-capacity-online-construction-shortfall-vc-renewables/728145/.

[30] Abraham Silverman, Dr. Zachary A. Wendling, Kavyaa Rizal, and Devan Samant, *Outlook for Pending Generation in the PJM Interconnection Queue* at 7, Columbia Center on Global Energy Policy (May 8, 2024) (Columbia Study). "Only 10 percent of developers report that any of their projects will come online within 12 months of receiving an interconnection service agreement, and most report their projects will require at

project development steps until they have an executed Interconnection Service Agreement (ISA) in hand; even then, it will still be another two years or more before their projects enter service.[31]

As witness Montalvo observes, "the delays in BRAs and the current PJM interconnection queue issues prevent new entry from performing this [disciplining] role."[32] He goes on to explain that the "lack of competition from new entry to discipline the market power of incumbent generators has . . . immediate and important consequences[,]" including that: (1) "generators can assume that their offers will clear at high prices because all or nearly all incumbent supply is likely to clear the auction";[33] and (2) "incumbent generators who have associated demand response can bid the demand response in at any price—up to the market price cap—unconstrained by a resource offer cap in an effort to set the market clearing price[.]"[34] Likewise, the absence of competition from new entry enables incumbent generators to profit from a strategy of retiring some units on short notice as a means of driving up prices received by their other resources.[35] The lack of competition

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least 24 months from the time they receive such an agreement to reach commercial operation." *Id.* at 7-8. A copy of the Columbia Study is included as Attach. C.

[31] *Id.* at 19.

[32] Montalvo Decl. ¶ 28. *See also id.* ¶ 42 ("Any tightness in the capacity market is not because there is insufficient interest in the market or resources are not actively working to enter the market—the problem is that resources are mired in the interconnection process.").

[33] *Id*. ¶ 28. The 2026/2027 Delivery Year begins June 1, 2026, less than two years from now. Yet, project development in PJM is stagnating, overall project schedules are increasing in length, and "projects entering the queue today have little chance of coming online before 2030." Columbia Study at 7. Consistent with these finding, the Aurora Report identifies only one new resource (an 800 MW gas fired unit) expected to offer into the 2026/2027 BRA. Aurora Report at 26.

[34] Montalvo Decl. ¶ 28

[35] *Id.*

from new entry to discipline the market power of incumbent generators has multiple potential adverse effects:[36]

> Lack of material new entry removes market-based discipline on the exercise of extant market power by existing resources; offer mitigation performed by the IMM is weak sauce. Offer caps are not a substitute for a competitive market where new entry can compete with existing resources. The lack of new entry also increases the risk that resources seeking retirement will be required for reliability and gain RMR agreements. Alternatively, it may be the case that the windfall of super high prices will slow temporarily the pace of resource retirements. But it is cold comfort that exaggerated prices that are inconsistent with expected market conditions is the reason for delaying otherwise rational exit decisions.

B. The BRA design undercounts or allows the withholding of available supplies, which in turn fuels artificial price increases.

The situation described above is made worse by the multiple and categorical BRA participation exemptions afforded to intermittent and capacity storage resources. In analyzing the 2025/2026 BRA, the IMM identifies these resource exemptions as increasing "clearing prices above the competitive level."[37] Witness Montalvo explains:[38]

> There are several aspects of PJM's market design that undercount the resources that contribute to serving load reliably: namely, the treatment of RMR resources, the exemption of some resource categories (including storage and renewables) from must offer requirements, and PJM's treatment of combustion turbines in its ELCC and [unforced capacity (UCAP)] calculations.

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[36] *Id.* ¶ 45.

[37] Independent Market Monitor for PJM, Analysis of the 2025/2026 RPM Base Residual Auction Part A at 3 (Sept. 20, 2024), https://www.monitoringanalytics.com/reports/Reports/2024/IMM_Analysis_of_the_20252026_RPM_Base_Residual_Auction_Part_A_20240920.pdf (IMM Part A Analysis).

[38] Montalvo Decl. ¶ 32.

The result of PJM's choices is to "systematically understate the capacity that is available to serve load."[39] And the quantities of forgone market supply are significant. According to the Aurora Report, PJM excused from participation in the 2025/2026 BRA approximately 9.8 gigawatts of installed capacity (ICAP) of existing resources, including 2.4 gigawatts of units under RMR arrangements, 1.5 gigawatts of other thermal generators that requested deactivation, 3.9 gigawatts of intermittent resources, and 1.3 gigawatts of storage resources.[40] Again, these are existing resources that will produce energy and ancillary services, respond to dispatch instructions, and contribute to system reliability.[41] Their absence from the market was a choice, not an operational requirement.

To be sure, there are legitimate, cost-based business reasons to withhold exempt resources—at least under the current, strict-liability capacity performance construct.[42] But under current circumstances it is impossible to rule out that some withholding decisions constituted an exercise of market power. Entities that control a portfolio of resources have a potentially powerful incentive to withhold some exempt resources strategically in order to boost the clearing price to benefit the balance of their (auction-participating) portfolio. As witness Montalvo observes, "[w]hen supply and demand conditions are tight, even the withholding of a small quantity of eligible supply can be a profitable strategy."[43] While

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[39] *Id.*

[40] Aurora Report at 14.

[41] Intermittent resources like wind and solar have very low operating costs and can be expected to produce electricity whenever their "fuel" is available, whether they have undertaken a capacity supply obligation or not.

[42] We explain below that the capacity performance rules should be modified to avoid penalizing intermittent resources for non-performance under circumstances they cannot control and that are already accounted for in their capacity accreditation ratings.

[43] Montalvo Decl. ¶ 36.

witness Montalvo does not know if parties intentionally engaged in this strategy, there is no doubt that "leaving the market exposed to such strategies is poor market design."[44]

The IMM agrees, pointing out that allowing existing resources to withhold supply from the capacity auction unbalances the market and prevents its proper functioning. He explains: "[t]he capacity market was designed on the basis of a must buy requirement for load and a corresponding must offer requirement for capacity resources," and "[t]he capacity market can work only if both are enforced."[45] But, under PJM's Capacity Performance construct, only the load-side participation requirement remains in place,[46] while supply side must offer requirements have been relaxed. The IMM explains that this "will create increasingly significant market design issues and market power issue issues," which will grow in proportion to the quantity of resources that are exempted.[47]

Moreover, the IMM explains, exempting vast and growing amounts of capacity from the must-offer requirement "could also result in very significant changes in supply from auction to auction which would create price volatility and uncertainty in the capacity market and put PJM's reliability margin at risk."[48] Witness Montalvo points out that price volatility and uncertainty impair the usefulness of high prices as an inducement to new entry. He explains that "[c]apacity prices can be sensitive to small supply changes and administrative adjustments to the design."[49] Prices may rise in one auction because exempt

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[44] *Id.*

[45] IMM Part A Analysis at 5-6.

[46] Under PJM's mandatory centralized auction design, load cannot opt out of the market except through the cumbersome Fixed Resource Requirement mechanism.

[47] IMM Part A Analysis at 6.

[48] *Id.* at 5.

[49] Montalvo Decl. ¶ 14.

resources choose not to participate, but a rational investor "may be skeptical of the longevity and dependability of [that] price signal" because the exempt resources could choose to participate in the next auction.[50] A rational investor would "discount the BRA price as not truly reflective of the supply-demand conditions and consequent revenues that will be available when the resource comes online."[51]

Based on all this, witness Montalvo offers a sobering assessment, explaining that currently:[52]

> [C]apacity prices are being driven by the barriers to entry of new supply—including constraints on the time it takes to study interconnection requests and build new transmission to interconnect new resources in the queue—which add to the market power of incumbent suppliers. High prices cannot bring new generation into the market more quickly than it can be interconnected, and, while such prices might retain existing generation, they are substantially above any just-and-reasonable measure of the net going forward costs that existing resources must cover to deliver capacity.

In these circumstances, the Commission should find the existing market design unjust and unreasonable as it cannot adequately mitigate the potential exercise of market power. In response, the Commission should act promptly to adopt rules that address this artificial supply limitation and instead ensure that all existing resources are obligated to participate in PJM's capacity auction, as explained further in section IV.A and IV.B below.[53]

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[50] *Id.*

[51] *Id.*

[52] *Id.* ¶ 10.

[53] *E.g.*, *Cal. Indep. Sys. Operator Corp.*, 171 FERC ¶ 61,220, PP 17-18 (2020) (rejecting, as not just and reasonable, tariff changes that "create an artificial constraint which raises prices for load and generation"); *Investigation of Terms & Conditions of Pub. Util. Mkt.-Based Rate Authorizations*, 105 FERC ¶ 61,218, PP 37-38 (2003) (actions creating artificial shortages are not consistent with just-and-reasonable rates), *clarified on denial of reh'g*, 107 FERC ¶ 61,175 (2004) ; *PJM Interconnection*, *LLC*, 186 FERC ¶ 61,080, P 266 (2024) (noting importance of "aligning the LDA Reliability Requirement with actual reliability needs"), *set aside in part,* 189 FERC ¶ 61,043 (2024); *San Diego Gas & Elec. Co. v. Sellers of Energy & Ancillary Servs.*, 93 FERC ¶ 61,294, at 61,998 (2000) ("While high prices in and of themselves do not make a rate unjust and

C. The PJM tariff does not give PJM sufficient ability to delay the retirement of needed resources and does not require RMR units to provide the value for which customers pay.

The PIO Complaint challenges PJM's failure to require units under RMR arrangements to offer their capacity into the BRA auctions. Joint Consumer Advocates have answered in support of the PIO Complaint and reiterate that support here. But PJM's response in that proceeding underscores a deeper problem. PJM's tariff fails to enable PJM to ensure that adequate supply remains available to the market, and instead leaves PJM—and its ratepayers—at the mercy of resources opting to retire. As PJM put it in answering the PIO Complaint, "PJM currently has no authority to require generators to stay online past a 90-days' notice period, no Tariff-based authority to dictate how a retained generator may operate, and no control over how the generator may be compensated."[54]

That is both unfair and untenable. The unfairness is revealed by comparing the level of control that PJM exerts over load and the entry of new supply as compared to resource retirements. Load is subject to a must-buy requirement and has little ability to opt of the market. Beyond that, PJM sets the demand curves, which go a long way toward dictating how much capacity is purchased and at what price. Meanwhile, PJM exerts extensive control over the entry of new supply and may delay such entry virtually indefinitely while it studies the reliability implications of new interconnections and the need for transmission upgrades. By comparison, the PJM tariff provisions concerning resource retirement are feckless.

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unreasonable (because, for instance, underlying production prices may be high), if over time rates do not behave as expected in a competitive market, the Commission must step in to correct the situation.") (subsequent history omitted).

[54] PJM Answer at 11.

Unlike other regional transmission organizations, whose tariffs include standardized RMR terms and conditions and a pro forma RMR agreement, PJM retains such resources on an ad hoc basis, leaving PJM and ratepayers helpless in the face of a retiring resource's locational market power. According to PJM, its retirement rules "endow the deactivating generator with the rights to decide: (1) whether the resource elects to remain in operation after the deactivation date to address transmission reliability issues; (2) how the resource may operate during the retained period (in accordance with terms negotiated with PJM); and (3) the means by which the resource may be compensated."[55] Specifically, under PJM's framework, undisturbed since 2006, a generator must provide just 90 days' notice that it will retire.[56] Thereafter, if PJM determines that the generator's continued operation is needed for transmission reliability, it "asks the generator to remain in service" until the reliability issues are resolved.[57] But the generator need not do so. After the 90-day notice period has passed, the generator "is free to retire and cease operations, regardless of the impacts."[58] If the resource elects to continue operating, PJM says, its tariff is "silent on the manner in which PJM may dispatch a retained generator or require it to operate."[59]

Because the PJM tariff lacks a *pro forma* RMR agreement establishing standard operating terms and conditions for RMR resources,[60] each generator negotiates its own arrangements with PJM about when and how it will operate and sets its own compensation

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[55] PJM Answer at 16.

[56] *Id.* at 17.

[57] *Id.* at 17-18.

[58] *Id.* at 18.

[59] *Id.*

[60] *Id.* at 16.

to be filed with the Commission.[61] But the retiring resources hold all the leverage. "Because such units are needed by PJM for reliability reasons, and the provision of the service is voluntary in PJM, owners of units that PJM needs to remain in service after the desired retirement date have significant market power in establishing the terms of this reliability service."[62]

Unsurprisingly, then, PJM has a history of paying full cost of service rates to retain generators that express an intent to retire while obtaining, in return, only meager performance commitments. According to the IMM, just two of eight owners have taken the deactivation avoidable cost rate approach, while the other six owners elected the full cost of service recovery rate.[63] But without bargaining power or standardized terms and conditions, PJM has been unable to obtain significant performance commitments in exchange for that compensation. According to PJM, as its deactivation rules currently stand, they provide "no categorical assurance that RMR resources [will] perform consistent with an obligation to provide capacity" so "PJM cannot categorically rely on such resources to meet the region's resource adequacy needs."[64] In fact, PJM says, RMR resources are "generally not subject to the same, or even similar, obligations as other Capacity Resources

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[61] *Id.* at 19.

[62] Memorandum from IMM to Deactivation Enhancements Senior Task Force (DESTF) at 4 (Oct. 12, 2023), https://www.pjm.com/-/media/committees-groups/task-forces/destf/2023/20231109/20231109-item-03---rmr-som-memo.ashx (IMM Mem.); *see also* PJM Answer at 11 (expressing concern that "encumbering resources seeking to retire with additional performance obligations would act as a disincentive for such resources to accept PJM's request and stay online").

[63] IMM Mem. at 3 & Table 5-29. The IMM adds that: "Companies developing the cost of service recovery rate have ignored the tariff's limitation to the costs of operating the unit during the Part V reliability service period and have included costs incurred prior to the decision to deactivate and costs associated with closing the unit that would have been incurred regardless of the Part V reliability service period. In some cases, the filing included costs that already had been written off, or impaired, on the company's public books. The requested cost of service recovery rates substantially exceed the actual costs of operating to provide the reliability required by PJM." *Id.* at 3 (footnotes omitted).

[64] PJM Answer at 8.

. . . such as a daily energy and reserve market must-offer requirement."[65] For example, PJM observes, the RMR arrangements for the Eddystone 2, Cromby 2, and Cromby diesel units explicitly limit their operation so that PJM may dispatch them only (i) when failure to do so would lead to specific reliability impacts identified in the Deactivation Study or (ii) as a last resort, to alleviate a different Transmission Security Emergency after PJM already has dispatched all other units that may help.[66]

The absence of standardized RMR terms and conditions, allowing PJM to retain units for as long as PJM determines that they are needed to maintain either transmission security or resource adequacy is unjust, unreasonable, and unduly discriminatory. It exposes PJM and ratepayers to the generators' exercise of locational market power. The Commission has "long been aware of the locational market power issues inherent in . . . efforts to contract for RMR service" by generators that a system operator needs for reliability.[67] And it has recognized that preventing the exercise of such market power is important to ensure that wholesale rates are just and reasonable.[68] Because standardized RMR terms and *pro forma* agreements are important both to constraining the exercise of generator market power and to safeguarding PJM's ability to retain needed resources on just and reasonable terms, the Commission has held that "having on file rates, terms and

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[65] *Id.* at 10.

[66] *Id.* at 8-9.

[67] *Pub. Utils. Comm'n of State of Cal. v. FERC*, 254 F.3d 250, 257 (D.C. Cir. 2001).

[68] *N.Y. Indep. Sys. Operator, Inc.*, 155 FERC ¶ 61,076, P 158 (2016); *see also Cities of Anaheim*, *et al. v. Cal. Indep. Sys. Operator Corp*., 107 FERC ¶ 61,070, P 26 n.6 (2004) ("RMR unit owners at those times have location-specific market power and could potentially charge a high price in the absence of an RMR agreement. The RMR agreements prevent RMR unit owners from taking advantage of location-specific market power."), *reh'g denied*, 110 FERC ¶ 61,387, *order denying reconsideration*, 111 FERC ¶ 61,218 , *denying clarification,* 111 FERC ¶ 61,731 (2005), *reversing on reh'g*, 118 FERC ¶ 61,255 (2007), *reh'g denied,* 128 FERC ¶ 61,027 (2009).

conditions for RMR service is fundamental to the proper and efficient operation" of an RTO market.[69]

PJM's tariff is therefore unjust and unreasonable because it lacks standardized RMR provisions and a *pro forma* agreement. While these provisions have been missing for decades, their absence was less harmful when capacity was abundant and new entry was relatively unfettered. The decisions that put in place PJM's existing, generator-led RMR approach do not hold up in light of the evolution of Commission precedent on this topic[70] and the facts on the ground in PJM.

PJM's current inability to retain needed generators on reasonable terms and conditions also is unsustainable when viewed against PJM's throttling of new entry. Both resource exit and new entry are subject to reliability reviews—and should be. But under the current rules, if reliability is threatened, PJM can block only market entry, not exit. That disconnect is unduly discriminatory because it is not based on any relevant substantive difference between the reliability issues created by entry and exit. The disparate approach to resource entry and exit also is unjust and unreasonable because it enables—if not contributes to—the very problem that PJM identifies as the major threat to its markets: existing resources retiring faster than new resources are coming online.[71]

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[69] *New York Indep. Sys. Operator Inc*., 150 FERC ¶ 61,116, P 9 (2015).

[70] *See* section IV.B, *infra*.

[71] *See*, *e.g.*, PJM Answer at 12-13 (decrying the "asymmetrical pace within the energy transition, where resource retirements and load growth exceed the pace of new entry").

D. PJM's continued reliance on an anticipated market response in lieu of immediate rule changes to recognize existing supply is wrong.

PJM has already stated its opposition to relief concerning the necessary BRA participation of RMR resources—and, we assume, will similarly oppose relief as concerns other currently-exempt resources that involves mandating participation. PJM argues in its answer to the PIO Complaint that the current auction design, and the results of the 2025/2026 BRA are "just and reasonable"[72] because the clearing prices reflect market realities of supply and demand[73] and send the correct price signal to incent the entry of new resources.[74] These claims are divorced from market realities; if reiterated here, they should be rejected. The price excursion of the 2025/2026 BRA and the anticipated high prices of the upcoming 2026/2027 BRA will not lead to new entry. New resources cannot respond to these auction prices because there is no scenario in which they can enter the market for the 2026/2027 Delivery Year. Indeed, "absent significant reforms or market innovations, most projects entering PJM's queue today are unlikely to come online before 2030."[75] And the roughly 160,000 MW of new development stuck in the queue demonstrates that the most recent exorbitant BRA clearing prices are not necessary to incent new entry. Developers proposed the projects pending in the queue based upon price (and other) projections made years ago when BRA prices were significantly lower.[76]

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[72] *Id.* at 2.

[73] *Id.* at 6 (the recent auction's "higher clearing prices are the natural result of supply and demand fundamentals.").

[74] *Id.* (the 2025/2026 BRA's higher prices will "incent the development of more capacity.").

[75] Columbia Study at 9.

[76] *See* PJM 2025/2026 BRA Report at 4, tbl.2 (July 30, 2024) (listing BRA auction results from 2015/2016 BRA to 2025/2026 BRA).

While PJM seeks to tout its queue reforms, it cannot identify any substantial amounts of new resources that will enter commercial operation for the 2026/2027 Delivery Year. PJM asserts that "[a]s of September 2024, 448 projects, totaling over 34,000 MW (installed capacity) have graduated the queue and have executed final agreements but are not yet in service, and 111 projects are in construction, 199 in engineering/procurement, while 138 projects have elected to suspend."[77] But PJM does not specify how many megawatts of capacity are expected to come on-line or when they will do so. The Columbia Study referenced above investigated these exact resources—*i.e.*, those that had executed an ISA or were far advanced in the queue process—and found that "[o]nly 10 percent of developers report that any of their projects will come online within 12 months of receiving an interconnection service agreement, and most report their projects will require at least 24 months from the time they receive such an agreement to reach commercial operation."[78] Many of these projects are variable resources and under current market rules are exempt from auction participation. Aurora Energy Research issued a report identifying only one new resource (an 800 MW gas fired unit) expected to offer into the 2026/2027 BRA.[79]

Importantly, these resources (and others languishing in the queue) show that high prices are not necessary to incentivize new entry. The BRA regionwide clearing price of the 2025/2026 BRA exceeded the highest clearing price of any of the ten prior BRA auctions by more than $105 MW per day.[80] Before the 2025/2026 auction, the highest RTO-wide clearing price over the prior ten years prior was the $164.77/MW-day clearing price

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[77] PJM Answer at 14.

[78] Columbia Study at 7-8.

[79] Aurora Report at 26.

[80] *See* PJM 2025/2026 BRA Report at 4, tbl.2.

of the 2018/2019 BRA. Applying that price to the installed capacity that cleared in the 2025/2026 auction (135,684 MWs)[81] would yield a total charge to load of $8.16 billion, some $6.5 billion less in total charges and roughly half the total charges to customers. The extreme prices experienced in the 2025/2026 BRA are simply not needed either to induce new entry or to retain existing resources. A recent IMM report estimates that "a doubling of market revenues [from $28.92 MW-day to just $58 MW-day] could reduce the quantity of resources at risk of retirement from 33,774 MW to 18,957 MW, a reduction of 14,817 MW, or 44 percent."[82]

The only evidence that PJM offers in support of its counterfactual contention that super-high prices are needed to encourage new entry is a Calpine Corporation press release.[83] But that press release (as described in a trade press report) is substance-free and can be accorded no evidentiary value. Calpine has apparently committed to "explore" the development of potential new resources in PJM or the expansion of existing generation within the region.[84] The press release says nothing about what that "exploration" involves; it identifies no concrete steps that Calpine may have undertaken (or plans to undertake) to develop new resources in PJM, and provides no information about contemplated resource

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[81] *Id.*

[82] Protest of Talen Energy Corp., Affidavit of A. Joseph Cavicchi P 25, Docket No. EL24-148-000 (Oct. 21, 2024), eLibrary No. 20241021-5206 .

[83] PJM Answer at 6 n.14 (citing Darren Sweeney, *Calpine signals plans to ramp up generation development in PJM*, S&P Global (Aug. 26, 2024), https://www.spglobal.com/marketintelligence/en/news-insights/latest-news-headlines/calpine-signalsplans-to-ramp-up-generation-development-in-pjm-83064266).

[84] Darren Sweeney, *Calpine signals plans to ramp up generation development in PJM*, S&P Global (Aug. 26, 2024), https://www.spglobal.com/marketintelligence/en/news-insights/latest-news-headlines/calpine-signalsplans-to-ramp-up-generation-development-in-pjm-83064266.

sizes or estimated commercial operation dates. Calpine's response to PIOs' complaint in Docket No. EL24-148 fares little better. Calpine claims that[85]

> We are considering opportunities to bring to market a range of technologies that would add reliable capacity to the region, including natural gas peaker plants, natural gas combined cycle plants (potentially with carbon capture), solar and storage. We are currently in active negotiations for two different development sites, and we are in earlier stages of engagement for a number of other sites. We are also reviewing our existing fleet to determine how we can most efficiently add megawatts to our current portfolio through upgrades and expansions. We are putting real resources behind these efforts, including working closely with equipment vendors, hiring personnel to expand my team, and beginning community and economic development outreach with local partners.

Once again, critical details about the contemplated size and operation date of these resources are lacking. And even if Calpine provided a detailed plan, absent Commission action, any PJM resources Calpine were now to embark on developing would not likely enter commercial operation before 2030. In the meantime—and no matter what new generation "exploration" activities Calpine decides to pursue or what generation is developed as a result of those activities—Calpine's existing, incumbent fleet of PJM resources will reap windfall capacity prices for years to come.[86]

PJM contends that "a significant portion of PJM's historical thermal generation fleet has or is in the process of retiring," in part "in response to recent low clearing price signals."[87] And worse, PJM says, this is happening in an environment "where resource

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[85] Protest of Calpine Corporation and LS Power Development, Ex. 2 (Testimony of Suriyun Sukduang) at 6, Docket No. EL24-148-000 (Oct. 24, 2024), eLibrary No. 20241025-5031.

[86] Calpine currently operates more than 5,000 MW of generation in the PJM footprint. Calpine, *Powering America*, https://www.calpine.com/powering-america/ (last visited Nov. 17, 2024).

[87] PJM Answer at 13.

retirements and [anticipated] load growth exceed the pace of new entry."[88] It takes little imagination to divine PJM's calculus: if low clearing prices are causing retirements, then high prices will keep incumbents in the market. But, as detailed above, PJM is not—or should not be—helpless in the face of these impending or threatened retirements. Rather than seeking tariff changes that would afford PJM the meaningful ability to redress the market power of unit withdrawal by means of retirement, PJM apparently believes—wrongly—that it has no option but to expose ratepayers to extortionate clearing prices. The Commission should reject this notion and direct needed relief.[89]

Witness Montalvo observes that the market "goal" should be to "maximize the eligible supply available to the BRA, making it contestable as the design had intended."[90] Had this goal been realized, the BRA results would have been vastly different. Witness Montalvo points out:[91]

> In a preliminary review of the 2025/2026 BRA, the IMM analyzed the impact of nearly 2,000 MW of RMR resources in [Baltimore Gas & Electric (BGE)] choosing not to offer into the market. The IMM found that inclusion of these resources in the supply curve at $0/MW-day would have reduced BRA costs by $4.3 billion, or 29.2% of the actual $14.7 billion cost. The IMM's sensitivity analysis found that excluding RMR resources from capacity markets resulted in 1,441 MW less cleared UCAP, and by implication the inclusion of RMR resources would have caused the RTO clearing price to drop from about $270/MW-day to

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[88] *Id.*

[89] PJM's RMR specific arguments are specious. PJM contends that the Talen-Sierra Club agreement is a barrier to the Brandon Shores and Wagner units participation in the BRA. But that settlement agreement would have allowed continued operation on oil. The settlement agreement did not compel Talen to abandon its planned coal-to-oil conversion; Talen chose that step on its own. And even taking the conversion cancellation as a given, the settlement agreement still poses no insuperable bar to continued operation since the agreement can be amended and Sierra Club has indicated a willingness to negotiate.

[90] Montalvo Decl. ¶ 77.

[91] *Id.* ¶ 70 (footnotes omitted).

> $167/MW-day (38%) while the BGE LDA price would have dropped from $466/MW-day to $167/MW-day (64%).

E. PJM's decision to tie thermal resource ELCC capacity ratings to summer performance is inconsistent with its modeling of ELCC to meet winter risks.

PJM's market design also unreasonably suppresses available market supply by double discounting the capacity value of gas-fired generation. The IMM explains that "[m]ost of the risk recognized in the ELCC model is winter risk but the ELCC accreditation values for thermal resources are capped at the summer ratings" rather than their winter ratings.[92] This inconsistent approach shorts supplies in the capacity market because PJM disregards that combustion resources like combined cycle generators (CCs) and combustion turbines (CTs) can produce at higher levels during cold weather. As witness Montalvo explains, PJM's choice to use summer ratings "effectively undercounts the contribution these resources can make during the high-risk winter period."[93] Discounting gas resources' ELCC values to account for winter risks but applying that discount to already-lower summer ratings is an unjustified double whammy.

Witness Montalvo addresses the IMM's recent assessment of PJM's ratings choice:[94]

> The IMM's estimate is that, on average, the ELCC accreditation for these resources would have been 8.8 percent higher if winter capability was used. The IMM acknowledges that deliverability, in the form of Capacity Interconnection Rights (CIRs) is currently set to summer capacity levels but suggests that these rights could be re-set to reflect winter levels. PJM's response to the IMM acknowledges that there is likely additional winter thermal capacity, and that "it is likely that some additional winter

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[92] IMM Part A Analysis at 6.

[93] Montalvo Decl. ¶ 39.

[94] IMM Part A Analysis at 5; Montalvo Decl. ¶ 39 (footnotes omitted).

> deliverability would be available," but notes that "there are likely limitations," both in terms of capacity interconnection and potential increases to overall resource adequacy requirements if risk shifts from winter to summer. PJM agrees, however, that this issue should be studied.

While "[a]cknowledging that there is some uncertainty about final numbers," witness Montalvo opines that the "potential impact to [UCAP] if the shift is made to winter ratings is in the thousands of megawatts."[95] PJM's approach means that "gas-fired combined cycle units with 5% forced outage rates, many of which have made incremental hardening investments, are now being discounted by over 20% for the purpose of measuring their reliability contributions."[96] When considered in conjunction with "PJM's exclusion of RMR resources and exempt resources, [PJM's] choice to rate natural gas capacity based on summer performance" means that several thousand megawatts of UCAP are intentionally excluded from BRA consideration.[97]

F. The BRA design fails to constrain the potential exercise of market power through DR resource offers.

The foregoing discussion highlights several ways in which the PJM BRA design either fails to recognize and account appropriately for existing supply or allows that supply to be withheld from (i.e., not offered in) the market. But the market design suffers from another, separate problem: PJM's tariff does not constrain the potential exercise of market power by DR resources that are offered as supply and not subject to an offer cap. Witness Montalvo explains that PJM's rules "incorrectly assume[] that DR is demand and that its natural incentive is to lower the price."[98] However, that is not necessarily or uniformly the

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[95] *Id.* ¶ 40.

[96] *Id.* ¶ 65.

[97] *Id.* ¶ 41.

[98] *Id.* ¶ 38.

case. Just like other resources, some DR resource may be parts of larger resource portfolios that "benefit from higher, not lower, prices."[99] Yet existing PJM market rules fail to constrain the owners of such DR resources from acting on those incentives—either by withholding the resources completely (as discussed above) or by offering them at above-competitive prices to attempt to increase the market clearing price and benefit the larger portfolio.[100]

While Joint Consumer Advocates are not privy to DR resource offers and have no knowledge of whether or to what extent resources engaged in this behavior, it is unjust and unreasonable to allow a significant source of potential market power to go unchecked. DR resources comprise a meaningful part (about 4 percent) of the total capacity participating in the market.[101] When supplies are as (artificially) tight as they were in the 2025/2026 BRA and appear poised to be in the 2026/2027 BRA (absent relief), the physical or economic withholding of even a small amount of capacity can have a large and unjustified price impact.

The IMM explains the problem:[102]

> Demand resources, unlike all other capacity resources, are not subject to market seller offer caps to protect against the exercise of market power. When demand resources are pivotal, as they were for the 2025/2026 BRA, they have structural market power and can and do exercise market

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[99] *Id.*

[100] *Id.* ¶ 28 ("[I]ncumbent generators who have associated DR can bid the demand response in at any price—up to the market price cap—unconstrained by a resource offer cap in an effort to set the market clearing price."); *id.* ¶ 38 ("[T]he owner of a resource portfolio that includes DR can offer that DR strategically in the auction to benefit the balance of the portfolio.").

[101] *Id.* ¶ 38.

[102] Independent Market Monitor for PJM, Analysis of the 2025/2026 RPM Base Residual Auction Part C at 5-6 (Nov. 6, 2024), https://www.monitoringanalytics.com/reports/reports/2024/IMM_Analysis_of_the_20252026_RPM_Base_Residual_Auction_Part_C_20241106.pdf (IMM Part C Analysis).

> power. The result is to increase the clearing prices above the competitive level. If the resources clear, it benefits the resources directly. Even if the resources do not clear, higher prices can benefit the owners of capacity portfolios that include such resources as well as resources with an RPM must offer.

After reviewing the data, the IMM concluded that the 2025/2026 BRA results were "significantly affected" by flawed market design decisions and the exercise of market power, including "the exercise of market power through high offers from demand resources."[103]

G. The BRA market design also suffers from other significant flaws.

There are other significant PJM market design flaws that the Commission should direct PJM to address. Two key issues are that PJM consistently over-forecasts peak demand (thereby causing it to procure more capacity than needed) and overestimates the Net Cost of New Entry (thereby driving prices up unnecessarily). We review each issue briefly below. Each is problematic in its own right and exacerbates the effects of the tariff flaws discussed above.

1. PJM over-forecasts demand, which increases auction prices.

Witness Montalvo asserts that "PJM's peak demand forecast used to set the VRR curve has historically and systematically overestimated the actual capacity need leading to over procurement of capacity and inflated prices."[104] While noting that this was "less of an issue" when the region enjoyed large generation surpluses,[105] that is no longer the case.

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[103] *Id.* at 6.

[104] Montalvo Decl. ¶ 46.

[105] *Id.*

PJM's forecast inflation is apparent upon an assessment of its demand forecasts over the past few years for accuracy and bias. Witness Montalvo finds:[106]

> PJM's forecast has overestimated actual peak demand every year of the last seven and has overestimated the weather normalized peak in all but one year where it was under by 0.1%. Compared to the weather normalized peaks, PJM's forecast shows a mean absolute error (accuracy) of 4.2% (range of 9.8% to 0.1%) and a bias of 4.1%. Compared to the actual peaks, PJM's forecast shows a mean absolute error (accuracy) of 4.6% (range of 11.7% to 1.9%) and a bias of 4.6%. In both cases, the forecast systematically exceeds the actual peaks—if the forecast were unbiased, one would expect that it would produce underestimates and overestimates in a roughly comparable number of instances.

He observes that a "forecast of peak demand that is systematically biased upward results in the market repeatedly procuring more capacity than is necessary to maintain resource adequacy, at an increased cost to consumers."[107]

And while load growth has picked up significantly over the past year, it is important not to accept without scrutiny that all proposed or requested data center interconnections are likely to occur. As witness Montalvo observes, data center load growth is concentrated in areas like northern Virginia and Illinois.[108] "For these data center projects to move forward, either transmission will have been built to relieve the constraints and import capacity into these 'data center alleys,' or these large loads will have taken their own supply needs in hand."[109] That is because "[s]ophisticated developers of new data centers are not likely to go forward with these projects if they are unsure about the availability of electric

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[106] *Id.* ¶ 49.

[107] *Id.* ¶ 50.

[108] *Id.* ¶ 52.

[109] *Id.*

supply necessary to meet project needs."[110] Thus, to the extent that new data centers depend on siting and construction of new transmission or new regional generation currently languishing in the interconnection queue, they will be unlikely to go forward in the near term and should not be included in forecast load.[111]

Witness Montalvo explains that any systematic upward bias in forecasted peak demand can inflate clearing prices significantly.[112] "Because of the inelasticity of capacity market demand curves around the forecasted capacity amount, small changes in demand can lead to relatively large changes in capacity market prices and therefore revenues."[113] As compared to actual weather-normalized peak load requirements over the seven years from 2017/2018 through 2023/2024, use of PJM's higher forecasted peak loads resulted in procurement of 4 percent more capacity than necessary, at an excess cost of roughly $2.2 billion.[114]

2. PJM's Net Cost of New Entry is overstated, which increases auction clearing prices.

The Net Cost of New Entry (Net CONE) is intended to represent the long-run marginal cost of supply in the capacity market. Net CONE ideally approximates the annual capacity market revenues that a new resource needs to ensure viability, in addition to anticipated revenues from other sources such as the energy and ancillary services markets. Net CONE is a key parameter in shaping the VRR curve. The maximum price, inflection point, and zero crossing point are all calculated as a function of Net CONE.

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[110] *Id.*

[111] *Id.*

[112] *Id.* ¶ 53.

[113] *Id.*

[114] *Id.* ¶¶ 53-55.

Despite Net CONE's importance to the PJM BRA design, its computation under current rules likewise suffers from tremendous potential for estimation error and bias. The starting point for calculating Net CONE is developing an estimate of gross CONE (that is, the total cost of new entry without any netting of estimated revenues). As explained by witness Montalvo, there are several inputs needed to determine gross CONE—all of which are themselves estimates that may be inaccurate:[115]

> The determination of CONE depends on all the factors that influence the costs of a new plant, such as plant location, technology, and configuration; engineering, procurement and construction costs; other development costs; and the cost of capital. The detailed approach used to develop CONE estimates belies the reality that the process suffers from false accuracy—the estimates depend on a series of choices, best guesses, and speculation.

The potential for error is unsurprising and by itself might not render the approach unjust and unreasonable if, over time, the over- and under-estimates balanced each other out and the Net CONE estimates were empirically reasonable on average. But that is not the case in PJM. Witness Montalvo explains that, "[i]n theory, if the estimates are sound, the long-term capacity market clearing price should equal the estimated Net CONE,"[116] and "one should not expect market entry when market prices are below Net CONE."[117] In PJM, however, capacity prices are consistently below PJM's estimate of Net CONE.[118] And, in eight of the last eleven auctions, thousands of megawatts of new capacity entered

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[115] *Id.*¶ 58 (footnotes omitted).

[116] *Id.* ¶ 60

[117] *Id.* ¶ 62.

[118] *Id.*

the market and cleared annually despite BRA prices well below PJM's Net CONE estimate.[119]

Witness Montalvo concludes from this that PJM's Net CONE estimates are consistently overstated and excessively costly to load. As discussed in section IV.G.1 below, witness Montalvo suggests that "the value of the Net CONE could be determined more straightforwardly and defensibly by reference to the actual cost of new entry, which is the market clearing price of the auction."[120] Compared to an adjusted demand curve based on an empirically observed Net CONE level, PJM's use of an inflated estimate of Net CONE caused the unnecessary procurement of 2,130 megawatts of capacity and inflated customer costs $4.0 billion.[121]

IV. THE COMMISSION SHOULD ADOPT JUST AND REASONBLE REPLACEMENT RATES

Under the Federal Power Act, the Commission has a statutory duty to reform unlawful rates and establish just and reasonable ones.[122] Although "[i]t is the Commission's job—not the petitioner's—to find a just and reasonable rate,"[123] we here describe changes to the current market design that the Commission should direct PJM to implement.

As explained by witness Montalvo, they are intended to address "two fundamental concerns."[124]

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[119] *Id.*

[120] *Id.* ¶ 63. As discussed below, witness Montalvo recommends calculating Net CONE based on a rolling weighted average of actual market clearing prices plus one half of the range between the highest and lowest prices during the same period. *Id.*

[121] *Id.* ¶ 78.

[122] *Miss. Indus. v. FERC*, 808 F.2d 1525, 1557 (D.C. Cir. 1987) (subsequent history omitted).

[123] *Advanced Energy Mgmt. Alliance v. FERC*, 860 F.3d 656, 663 (D.C. Cir. 2017).

[124] Montalvo Decl. ¶ 13.

> First, PJM has expressed concern that the region is becoming capacity-tight. Yet, the current queue delays and the scope of required transmission upgrades are preventing timely new entry in significant amounts. In addition, the market rules allow thousands of MWs of otherwise qualified resources that do plan to operate and support reliability not to bid into the capacity market. At a minimum, then, the tightening capacity supply condition and the market power of incumbent generators might be mitigated in part through a rule change.

To address these concerns, the Commission should act immediately and before the upcoming auction to "maximize supply participation in the auction," which will "further competition in the BRA and improve pricing performance."[125] The steps to maximize supply participation include: (a) revoking categorical exemptions from must-offer requirements for existing resources; (b) adopting standardized RMR provisions and a *pro forma* agreement that will enable PJM to retain resources needed for reliability and that require retained resources to participate fully in PJM markets; (c) correcting the understatement of capacity values resulting from the use of combustion resources' summer ratings in ELCC accreditation; (d) improving management of PJM's interconnection queue to prioritize processing of ready-to-study projects in LDAs that are more likely to be constrained; and (e) applying offer price caps to DR resources to prevent economic withholding.

As explained below, the Commission should grant this complaint and direct PJM to make these changes before it conducts the 2026/2027 BRA. In addition, the Commission should direct PJM to convene stakeholder discussions to address the potential future changes identified by witness Montalvo, including revisions to reduce the effect of

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[125] *Id.* ¶ 14.

systematic load forecast inflation on BRA results and changes to the method of determining Net CONE.

A. PJM should be directed to revise its rules so that all existing eligible capacity resources that contribute to resource adequacy must participate in the capacity auction.

We have demonstrated that the 2025/2026 BRA results do not reflect current conditions accurately because (among other reasons) there is substantial capacity online in PJM that supports reliability but is exempt from BRA participation. The Commission should direct PJM to change the current exemption structure. Revisions aimed at increasing market supplies are inherently pro-competitive. Whatever the propriety of permitting resource exemptions when the market was long, that resource picture has changed significantly. Given current and anticipated market conditions, requiring the auction participation of eligible but exempt resources is necessary to compensate in part for the lost competition of new entry and to mitigate the market power of incumbent resources through withholding.

The IMM sees the current must-offer exemptions as an "important gap[] in the market power rules for the PJM capacity Market,"[126] the closing of which is pro-competitive and necessary to make the market work:[127]

> There is no reason to exempt intermittent and capacity storage resources, including hydro, from the RPM must offer requirement. The same rules should apply to all capacity resources. The purpose of the RPM must offer rule, which has been in place since the beginning of the capacity market in 1999, is to ensure that the capacity market works based on the inclusion of all demand and all supply, and to prevent the exercise of market power via withholding of supply.

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[126] IMM Part A Analysis at 3.

[127] *Id.* at 5.

In response to these concerns, the IMM "recommends that all capacity resources have a must offer obligation."[128] And witness Montalvo agrees, pointing out that "[n]on-participation in capacity markets by exempt resources means that thousands of MWs of capacity that is actually serving load and contributing to reliability is not competing with other incumbent generation in the BRA."[129] The amount of supply at issue is significant. In addition to the now exempt RMR resources,[130]

> PJM's treatment of other "exempt" resources, namely intermittent resources, battery storage, and DR, likewise undercounts these resources' actual availability to serve load in PJM. PJM reports that in the 2025/2026 BRA, excluded RMR resources, unoffered UCAP MWs from battery, diesel-landfill, hydro, solar, and wind resources, total 1,596 MW.

In these circumstances, witness Montalvo recommends that PJM be directed to:[131]

> adopt revisions to its tariff to require that all existing eligible capacity resources that contribute to resource adequacy in the operating timeframe must participate in the capacity auction under the existing must-offer construct that applies to thermal generation. These reforms would impact currently exempted resources, including RMR, intermittent resources, battery storage, and DR.

This recommendation is supported by the Governors of five states within the PJM footprint, who have recently written to PJM urging that it implement this reform and several others.[132] The Organization of PJM States, Inc. (OPSI) has likewise expressed support,

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[128] *Id.* at 3.

[129] Montalvo Decl. ¶ 68.

[130] *Id.* ¶ 37.

[131] *Id.* ¶ 68.

[132] Letter from the Governors in the states of Delaware, Illinois, Maryland, New Jersey, and Pennsylvania to Mr. Mark Takahashi Chair, PJM Board of Managers, and Mr. Manu Asthana President & CEO at 1-2 (Oct. 25, 2024), https://www.pjm.com/-/media/about-pjm/who-we-are/public-disclosures/2024/20241025-governors-letter-regarding-capacity-auctions.ashx (Governors Letter), which calls upon the PJM Board to "direct PJM staff to . . . [e]nsure that capacity from Reliability Must Run units is included in the next Base

stating that it "agrees" with the IMM "that all capacity resources must participate in PJM's capacity construct to prevent resource owners from not offering some portions of their portfolio to benefit other portions of their portfolio."[133] In support of this position, OPSI observes:[134]

> Exceptions to the must offer requirement for generation resources undermine a key component of the capacity market where consumers must buy capacity no matter how high the price. It is important that PJM consider having all resources that are expected to be online and producing power offer into PJM's capacity auctions. This includes all intermittent and storage resources with capacity interconnection rights, which make up the vast majority of resources waiting to interconnect to PJM's system. OPSI has long been in alignment with these concerns.

Witness Montalvo recommends pairing these changes with revisions to the rules governing capacity nonperformance penalties: [135]

> Requiring RMR, intermittent, and other currently exempt resources to offer into the PJM markets may pose problems without other rule changes because these resources will be fully exposed to [Performance Assessment Interval (PAI)] penalties even though some of them may have no practical way of managing that exposure. RMR and intermittent resources are arguably differently situated from thermal resources and each other as regards the impact of the PAI as a real performance incentive. The performance requirements that apply to an RMR resource should be built into the terms and conditions of the RMR arrangement; the expected performance of an intermittent resource is built into its ELCC value.

Residual Auction [;]" and "[e]liminate the must-offer exemption for intermittent generation resources, while protecting them from performance penalties that discourage participation[.]"

[133] Letter from Organization of PJM States, Inc. to Mr. Mark Takahashi, PJM Board of Managers, and Mr. Manu Asthana, PJM President and CEO at 3 (Sept. 27, 2024), https://www.pjm.com/-/media/about-pjm/who-we-are/public-disclosures/2024/20240927-opsi-letter-re-results-of-the-2025-2026-bra.ashx (OPSI Letter).

[134] *Id*. at 2-3.

[135] Montalvo Decl. ¶ 65.

He recommends that intermittent resources subject to a must offer requirement be treated differently to address their unique circumstances:[136]

> I propose that intermittent and battery storage resources be excused from PAI penalties if they are operating at maximum *possible* output during the PAI event. The output of intermittent resources such as wind, solar, and hydro (as well as shorter duration battery storage) resources is largely determined by nature, and these resources are almost all but guaranteed to operate when the relevant "fuel" source is available[.]
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> * * *
>
> Logically, a solar facility cannot produce energy at night and is not expected to do so under the reliability model, so applying a penalty for the failure to perform at night, for example, provides no incremental incentive and cannot improve performance.

The IMM agrees, stating in his Part A analysis that the "inclusion of a must offer obligation for intermittent and capacity storage resources should be coupled with the removal of PAI penalty liability for such resources when it is not physically possible to perform."[137]

B. The Commission should require PJM to adopt standardized RMR provisions that enable PJM to retain needed resources and should grant the pending complaint concerning the capacity auction participation of RMR resources.

We explained earlier that there is currently a Federal Power Act section 206 complaint pending before the Commission asking that it find that PJM's capacity market rules are unjust and unreasonable because they fail to require a consistent accounting of the resource adequacy contributions of power plants operating under RMR arrangements and lead to excessive costs for consumers, and order appropriate relief.[138] The IMM has

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[136] *Id.* ¶ 73.

[137] IMM Part A Analysis at 6.

[138] PIO Complaint at 1.

filed comments in support of the complaint, asserting that the Commission should "order PJM to reform its capacity market rules to consistently account for RMR units' resource adequacy contributions."[139] Joint Consumer Advocates have likewise urged that the complaint be granted,[140] as have the Governors of five states in the PJM footprint.[141]

The requested relief is justified. Witness Montalvo explains that under the current PJM rules, while a resource is in RMR status:[142]

> [it]must be made available to operate and respond to PJM dispatch instructions per the terms of their RMR agreements to support reliable operations but are exempt from required participation in the capacity market. (If the RMR resource nonetheless chooses to participate in the capacity market, then it is subject to the same performance obligations imposed upon all PJM resources that clear a capacity auction). Given the structure of many RMR contracts that limit operations to emergencies, there is likely a high correlation between RMR unit dispatch and system conditions that might lead to a PAI event. The RMR resource may recover its net going forward costs (default rate) or request a cost of service-based (COS) rate. RMR resources generally request COS treatment, the total cost of which is most often substantially above the prevailing market cost of capacity.

Witness Montalvo similarly observes that[143]

> PJM models the reliability contributions and the impacts on power flows of RMR resources when calculating reserve requirements, irrespective of whether the resource participates in the capacity auction and takes on the performance obligations imposed on cleared resources. PJM includes RMR resources in the set of Internal UCAP resources used to calculate the Capacity Emergency Transfer

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[139] Comments of the Independent Market Monitor for PJM Interconnection, Docket No. EL24-148-000 (Oct. 10, 2024), eLibrary No. 20241010-5217.

[140] Comments and Answer of Consumer Advocates, Docket No. EL24-148-000 (Oct. 17, 2024), eLibrary No. 20241017-5154.

[141] In addition, OPSI has supported this relief. *See also* Governors Letter at 2.

[142] Montalvo Decl. ¶ 34.

[143] *Id.* ¶ 35.

> Objective (CETO) and set the LDA reliability requirement and as part of the system modeled to calculate the Capacity Emergency Transfer Limit (CETL). The LDA binds (meaning that the LDA must rely on internal resources) and there is price separation if the CETO is greater than the CETL. As the modeled treatment of a resource is the same after the RMR as it was before (I have no evidence to suggest that PJM modifies the RMR resource's expected contribution to meeting load during modeled emergency conditions), the reliability requirement is not impacted by a resource's new RMR status. However, the RMR resource is not included as supply for purposes of clearing the capacity market auction. This creates a disconnect between assumed supply for purposes of setting LDA resource requirements and the actual supply—per the IMM, approximately 1,984 MW of nameplate capacity supported through RMR agreements, amounting to 1,440 MW of potential UCAP in the 2025/2026 auction.

The IMM has also noted the "disconnect," explaining in his Part A analysis that "PJM currently includes RMR units in the reliability analysis for RPM auctions but does not include the RMR units in the supply curve."[144]

Thus, while RMR resources are compensated to provide system reliability and can be called on by PJM to do so, they participate in the BRA only if the resource owner chooses to do so. The result is that customers are forced to pay twice to satisfy the same

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[144] IMM Part A Analysis at 6. OPSI has likewise stated its support for a directive that PJM reform its capacity market treatment of RMR resources:

> The PJM Board should direct PJM to consider mandating that capacity of generating units that are under RMR contracts and expected to be operational during the relevant Delivery Year be included as available capacity. Under current auction rules, generating units that are under RMR contracts are not required to offer into PJM's capacity auctions, nor are they included in the bid stack, even if they are contracted to remain online to preserve reliability. While RMR units are included in calculations for local reliability requirements, they are not included in the supply curve. PJM must examine this inconsistency and how the reliability value of RMR units is included in the capacity market and whether adjustments are appropriate. If these units will be available for dispatch during the relevant Delivery Year, the reliability value of these units should be duly reflected when settling the capacity market.

OPSI Letter at 2 (footnotes omitted).

capacity need—i.e., once to compensate the RMR unit, and then again to secure a like amount of replacement capacity in the BRA. While PJM says that's not so—it contends that most RMR units agree to performance requirements far short of what a capacity resource provides—that does not make the situation any more reasonable. In the absence of tariff provisions imposing performance requirements, RMR units in PJM exercise their locational market power to extract full cost of service compensation from ratepayers while providing only meager service in return. Ratepayers still pay twice but get little value in return for the second payment.

The Commission should direct PJM to adopt standardized RMR terms and conditions and a *pro forma* RMR agreement. Doing so will help to ensure that PJM has the tools it needs to maintain reliable system operations while protecting ratepayers from the exercise of market power by resources needed for reliability. The new provisions should allow PJM to delay existing resource retirements for as long as the resource remains needed for reliability. While the Commission at one time may have thought that it lacked authority to approve system operator tariffs with mandatory RMR provisions, that view is outdated.[145] And in today's circumstances, given the massive changes occurring in the region's generation fleet, it is essential that PJM have at least as much ability to delay retirements for reliability reasons as it may delay the interconnection of new resources.

Where continued service is mandated, the tariff should provide for compensation at a full cost-of-service rate.[146] In exchange for such guaranteed cost recovery including a

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[145] *See N.Y. Indep. Sys. Operator Inc*., 150 FERC ¶ 61,116, P 17 (2015) (requiring New York Independent System Operator, Inc. (NYISO) to adopt standardized RMR terms and conditions, which could include either a voluntary or mandatory RMR regime), *on reh'g,* 161 FERC ¶ 61,189 (2017), *on reh'g*, 163 FERC ¶ 61,047 (2018).

[146] *Id.*

return on investment, RMR generators should be required to provide ratepayers all the economic value they are capable of producing. The FPA requires no less; if ratepayers cover all of a generator's costs, they should receive all of the corresponding value.[147]

Among other things, that means that RMR generators on cost-of-service rates should be required to offer their capacity as price takers for any delivery years that will be completed during the term of the agreement. (And the terms of the agreement should be timed to coincide with capacity delivery years). The Commission has made clear that doing so is economically efficient and failing to do so is unjust and unreasonable. In New York, FERC rejected a complaint seeking to require RMR generators to bid above zero. FERC agreed with NYISO's external market monitor that the retained resources[148]

> are economic from the perspective of satisfying the NYISO's reliability requirements. . . . If the reliability needs satisfied by these units were reflected in the capacity market, the units would both clear.

The Commission therefore found that it is economically efficient that the resources clear, and "[any] provisions . . . that would cause them not to clear would be unreasonable."[149]

The Commission affirmed this view in response to a NYISO filing of generic RMR provisions. NYISO proposed to allow RMR generators to participate in capacity auctions as price takers except (i) when the generators were being retained for resource adequacy (as opposed to transmission security, for example) or (ii) when the retained generator is not

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[147] *Citadel FNGE Ltd. v. FERC*, 77 F.4th 842, 856 (D.C. Cir. 2023) ("Citadel does not, and cannot, argue that an increase in rates without any commensurate benefit is in the public's interest, let alone just or reasonable."); *id.* at 855 ("[I]ncreased prices on one side of the balance without any value on the other side of the scale—all pain and no gain—[are] unjust and unreasonable.").

[148] *Indep. Power Producers of N.Y. v. N.Y. Indep. Sys. Operator*, 150 FERC ¶ 61,214, P 66 (2015) (quotation omitted), *reh'g granted in part*, 170 FERC ¶ 61,118 (2020).

[149] *Id.*; *see also id.* P 68 ("Where RMR agreements are necessary, those resources also satisfy the reliability needs of the broader [New York Control Area (NYCA)] footprint, and it would be inefficient to procure other capacity elsewhere in the NYCA footprint to satisfy the NYCA capacity needs met by the RMR capacity.").

the least-cost solution to the identified reliability need. FERC rejected the exceptions, reiterating that it's efficient for retained resources to clear in the capacity market; otherwise, ratepayers would pay twice to meet the same reliability need.[150]

FERC followed this precedent in New England, when it accepted ISO-New England, Inc.'s (ISO-NE) proposal to enter fuel security resources into the Forward Capacity Market (FCM) as price-takers:[151]

> If resources needed for fuel security are not entered into the [Forward Capacity Auction (FCA)] as price-takers, they risk not clearing in the FCA and their resource adequacy contributions to the system would not be counted. As the Commission stated in the 2017 NYISO Order, such an outcome would result in a higher clearing price and a higher procurement quantity, which would create an inefficient and unreasonable market outcome. Even putting aside the price impact, this would result in consumers "pay[ing] twice" for capacity—"once for the cost of the RMR agreement, and again for the generator that otherwise would not have cleared the market." We agree with Potomac Economics that, as long as resources are retained for fuel security purposes, including such resources in the FCA as price takers prevents an artificial and inefficient increase in FCA prices.

And Appellate courts have deferred to this reasoning in related contexts.[152]

The Commission should follow the same course here and bring PJM's tariff into conformance with those of the two other system operators that administer mandatory

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[150] *N.Y. Indep. Sys. Operator Inc*., 155 FERC ¶ 61,076, P 85 (2016).

[151] *ISO New Eng.*, *Inc*., 165 FERC ¶ 61,202, PP 82-88 (2018), *on reh'g,* 173 FERC ¶ 61,204 (2020), (footnotes omitted0. FERC also noted that allowing participation as a price taker "accurately reflects [an RMR resource's] low going-forward costs," after accounting for the RMR revenues the generators would receive. *Id*. P 88.

[152] *NextEra Energy Res., LLC v. FERC*, 898 F.3d 14, 20 (D.C. Cir. 2018) (affirming FERC's acceptance of a minimum offer price rule (MOPR) exemption for some renewable resources because, FERC reasoned, the resources would be developed anyway in response to state policies and it would be inefficient to fail to account for them and to instead buy redundant capacity).

capacity markets.[153] Doing so will help to ensure that PJM has the tools it needs to maintain reliable system operations while protecting ratepayers from the exercise of market power by resources needed for reliability.

C. PJM should be required to accredit combustion resources using winter capacity ratings that seasonally match the winter risks driving those resources' ELCC values.

As explained above, PJM's current ELCC accreditation method inappropriately discounts the capacity value of combustion resources by heavily weighting the winter risks faced by such units while using lower summer capacity ratings that "understate[] the reliability value these resources provide in the winter."[154] To fix this problem, the Commission should require PJM to accredit combustion resources using their winter capacity ratings which correspond seasonally to the winter risks driving those resources' ELCC values.[155] As witness Montalvo explains, the change should be given high priority. "[T]here is potentially a significant amount of unrecognized capacity at stake," perhaps as much as 5,400 megawatts (UCAP value), and "clearing prices that ignore 'real' capacity do not properly represent the available supply and will be artificially inflated, particularly in the foreseeable circumstances where substantial new entry cannot enter the market."[156]

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[153] In its answer to the PIO complaint, PJM contends that it is not an "outlier" among RTOs with capacity markets because the Midcontinent Independent System Operator, Inc. (MISO), like PJM, does not mandate capacity auction participation by RMR resources *See* PJM Answer at 40. But MISO is not a good comparison because its capacity market, unlike PJM's, NYISO's, and ISO-NE's, is voluntary for both generation and load. *See Midcontinent Indep. Sys. Operator*, *Inc*., 183 FERC ¶ 61,112 (2023) (Comm'r Christie, concurring).

[154] Montalvo Decl. ¶ 78.

[155] *Id.* ¶¶ 78, 95.

[156] *Id.* ¶ 78.

D. PJM should be directed to undertake changes to the management of its interconnection queue.

As of October 16, 2024, the PJM interconnection queue contained 159,900 MW in active capacity interconnection requests.[157] Witness Montalvo explains that the evident "tightness" in the capacity market is not due to lack interest, effort, or low capacity prices. The problem instead is, as explained above, that existing resources are undercounted and new resources "are mired in the interconnection process."[158] Indeed, the interconnection process has become so dysfunctional that PJM and market participants have begun "addressing their needs in other ways,"[159] such as planning transmission to import power from central and western PJM in place of "generation projects that were put in the queue some years ago to deliver energy close to the now burgeoning load."[160]

Because of how the interconnection bottleneck adversely affects the competitiveness and functioning of PJM's capacity market, the Commission should (in addition to the other relief requested herein) direct PJM to modify its interconnection study procedures. As recommended by witness Montalvo, PJM should "give study priority to study-ready projects in the interconnection queue that are siting in (likely to be) constrained LDAs."[161] Given the scarcity of study resources,[162] this change would give priority to

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[157] PJM, Serial Service Request status, https://www.pjm.com/planning/service-requests/serial-service-request-status (last visited Nov. 17, 2024).

[158] Montalvo Decl. ¶ 42.

[159] *Id.* ¶ 44.

[160] *Id.* Similarly, witness Montalvo notes that "several companies building large new datacenters, the major driver of load growth in PJM over the next five years, are looking to co-locate with existing generation, bypassing the dysfunctional capacity market and the interconnection morass, in an attempt secure reliable low-cost power." *Id.* (footnotes omitted).

[161] *Id.* ¶ 76.

[162] *Id.* ("This rule change would provide a logical means of offering priority to certain queue projects, rather than forcing them to wait to go through the cluster process.").

resources that are likely to offer consumers the greatest near-term benefit. Accelerating the interconnection studies for such resources is a necessary step to enable such resources to begin participating in PJM capacity auctions as quickly as possible.

E. PJM should be directed to modify the rules concerning provisions relating to demand response resource participation in the auction.

As noted above, demand resources in PJM constitute a meaningful percentage of the total capacity participating in the market but do not have an RPM must-offer requirement and are not subject to market seller offer caps to protect against the exercise of market power. This is problematic because DR resources participate as supply and may be parts of larger portfolios that benefit from higher prices. The IMM confirms that, "[w]hen demand resources are pivotal, as they were for the 2025/2026 BRA, they have structural market power and can and do exercise market power" through submission of offers at prices above competitive levels.[163]

In response, witness Montalvo and the IMM recommend that demand resources have defined and enforced market seller offer caps.[164] To that end, witness Montalvo suggests two changes to the treatment of demand response resource offers. First, he recommends that DR "be required to submit BRA offers that reflect the maximum dispatchable demand reduction that the resource is making available to PJM."[165] He explains:[166]

> The performance of DR would then be measured as the actual reduction delivered (metered consumption before instruction less metered consumption after instruction) in

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[163] IMM Part C Analysis at 5-6.

[164] Montalvo Decl. ¶ 95; IMM Part C Analysis at 5-6.

[165] Montalvo Decl. ¶ 75.

[166] *Id.*

> response to a dispatch instruction during a PAI event. The current treatment compares consumption during a PAI event to the resource's claimed maximum consumption. The DR is credited for this difference, even if during the event DR delivers no reduction in consumption (it would have been consuming at the current level irrespective of system conditions), thus having no impact on the load that must be served.

Adopting this change would "facilitate" witness Montalvo's second recommendation, which is that "the IMM evaluate the opportunity cost of demand reductions and use this to calculate mitigated DR offer prices (offer caps) that PJM would then impose when structural market power tests fail."[167]

F. The need for prompt action is apparent.

The need for prompt action is indisputable. If the 2026/2027 BRA is conducted using the existing, flawed market rules, there is a substantial risk that it will produce even more extreme and unreasonable results than the 2025/2026 BRA. OPSI wrote PJM in September, warning that auction design "flaws [identified by the PJM IMM] could lead to the upcoming auction clearing at the maximum capacity price which would assign a total cost to customers of over $30 billion for the 2026/2027 Delivery Year."[168] Consistent with this warning, one expert energy market consultant has analyzed PJM market supply and demand fundamentals and the auction rules for the 2026/2027 BRA and projected "highly uncertain" outcomes including a "high case" scenario of the entire PJM region clearing at

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[167] *Id.*

[168] OPSI Letter at 2.

the new offer cap of "$696/MW-day."[169] This high case scenario would result in total capacity charges to PJM customers in the range of $37 billion.[170]

In these circumstances, where demand is growing, new entry is blocked, and auction supply is artificially constrained, the need for prompt action—on this complaint, the complaint pending in Docket No. EL24-148, and (perhaps) the upcoming PJM section 205 filing—is beyond dispute. Indeed, PJM has responded to the recent auction results by informing the Commission that it is working on a set of changes to the auction process that it plans to file (likely in December 2024) under section 205, and the Commission has granted PJM's request to delay the auction while the details of that filing are being worked out.[171] But PJM's upcoming section 205 filing may fall short of addressing the region's capacity auction difficulties. To ensure that PJM's 2026/2027 BRA produces just and reasonable rates, the Commission should grant this complaint promptly and direct PJM to make the changes identified above before it conducts the upcoming auction.

G. The Commission should direct PJM to convene a stakeholder process to consider longer-term capacity market changes.

Additionally, the Commission should direct PJM to convene a stakeholder process to address the other, longer-term capacity market problems that witness Montalvo identifies and to consider his recommended solutions.

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[169] Aurora Report at 26.

[170] The new PJM BRA offer cap price of $695.8 x 365 days x the 147,264 MW reliability requirement for the 2026-2027 BRA Delivery Year equals total charges to load of $37,400,196,288. The actual figure would depend on the amount of capacity that clears at the offer cap region wide.

[171] *PJM Interconnection, L.L.C.,* 189 FERC ¶ 61,105, P 5 (2024).

1. PJM should be directed to revise it methodology for calculating Net CONE.

We explained earlier that PJM's CONE calculation systematically overstates the cost of new entry. Witness Montalvo recommends a change, observing that a "better approach would utilize the actual cost of new entry as revealed by the capacity market itself."[172] More specifically, he suggests an example of how this objective could be achieved, proposing that Net CONE be calculated as the sum of two components: (1) a moving weighted average of clearing prices for a rolling 5-year historical reference period (weighted on total new unit capacity clearing in the auction); and (2) one half of the range between the minimum and the maximum clearing price from the same 5-year period.[173] Moving to this methodology would be reasonable because the "first component captures the central tendency of recent auction prices that lead to actual new entry, while the second component conservatively accounts for historical spread in setting VRR curve parameters."[174] Because the proposed approach is "purely mechanical" and would "operate as a formula," it would "replace false precision with an empirical calculation," and avoid "making judgement calls about inputs that produce a number that impacts the wallets of both generators and loads."[175]

Witness Montalvo then offers an example of how his methodology would work, explaining the outcome that would have been obtained had his proposed Net CONE calculation been in place during the 2025/2026 BRA:[176]

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[172] *Id.* ¶ 83.

[173] *Id.*

[174] *Id.*

[175] *Id.* ¶ 84.

[176] *Id.* ¶¶ 85-86.

> I compared the market results of the VRR curve PJM used for the 2025/2026 auction with the modeled results of an adjusted demand curve based on a Net CONE calculated [using my proposed methodology]. I reduce the value of Net CONE to $146.60/MW-day for the RTO-wide and Dominion LDA and *increase* the value of Net CONE for the BGE LDA to $224.24/MW-day as an estimate of the *proper* Net CONE.
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> For the actual 2025/2026 PJM BRA, the equilibrium quantity was 135,684 UCAP MW and the price was $269.92/MW-day, with total capacity market revenues of about $14.7 billion. Using the adjusted demand curve based on a proper net CONE level, rather than the overestimated net CONE, would have decreased quantity cleared by 2,130 MW and total BRA cost to load would have decreased $4.0 billion from $14.7 billion to $10.7 billion.

Witness Montalvo concludes:[177]

> Rather than use arbitrary multiples of CONE values that we know will not match actual new entry and would serve in the interim only to extract rents from load, the empirical net CONE provision could be adjusted by a simple scaling percentage, e.g., a 25% adder, if capacity margins are tightening and no resources are in the interconnection queue that would add supply in a timely way.

2. PJM should be directed to address the systematic inflation of its load forecasts by considering a shift to a prompt or staggered capacity auction design.

We explained above that there is a pattern of PJM load forecast inflation. Joint Consumer Advocates recommend that PJM be directed to consider design changes that reduce forecasting error, which should increase accuracy and reduce bias. Witness Montalvo proposes consideration be given to moving to a prompt auction design, which

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[177] *Id.* ¶ 88.

would involve "reducing the forecast period by adjusting the time between the conduct of the auction and delivery year."[178] He explains:[179]

> Empirically, the improved forecast accuracy observed over the past couple of BRAs suggests that reducing the forecast period may be beneficial.

As an alternative, witness Montalvo suggests that the BRA be used to procure a portion of the regional reliability requirement, with the remainder obtained through an incremental auction, which could be used "to top off if short or shed if long." [180] He explains: [181]

> The idea here is to recognize that the forecast tends to be wrong and biased high, and so to purchase a fraction, say 95% of the capacity that the forecast suggests is required through the BRA, and then to purchase additional capacity through the incremental auctions if it looks like the actual loads are consistent with the forecasted load.

V. RULE 206 REQUIREMENTS

To the extent not already provided above, Consumer Advocates provide the following additional information required by Rule 206 of the Commission's Rules of Practice and Procedure.[182]

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

Absent a Commission order granting the relief sought here, it has been reported that the upcoming BRA (scheduled to be held in early December, though since delayed by six months) may clear at the new offer cap of $696/MW-day for the entire PJM region. If that

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[178] *Id.* ¶ 81.

[179] *Id.*

[180] *Id.* ¶ 82.

[181] *Id.*

[182] 18 C.F.R. § 385.206.

occurs, capacity charges to PJM ratepayers in the 2026/2027 BRA could increase to $37 billion.

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

Joint Consumer Advocates believe that the impacts of PJM's unjust and unreasonable auction rules are primarily financial.

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

The Joint Consumer Advocates are aware of the following pending proceeding identifying one tariff change to prevent a recurrence in the 2026/2027 BRA Delivery Year of excessive auction clearing prices:

- *Sierra Club*, *et. al., v. PJM Interconnection*, *L.L.C.*, FERC Docket No. EL24-148-000

However, Joint Consumer Advocates' complaint both identifies additional changes that should be made before conducting the BRA for the 2026/2027 delivery year and seeks broader reform.

Certain of the Joint Consumer Advocates are also involved in stakeholder processes in PJM that could result in reforms to the current BRA rules. At the present time, however, we have no reason to believe that the process will be resolved in a manner that moots the matters at issue here, let alone within a time frame sufficient to address the next and upcoming PJM capacity auctions.

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

The Complaint sets forth in detail the specific relief requested.

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

The Declaration of Mark D. Montalvo, supporting the Joint Consumer Advocates' complaint, is included as Attachment A to this complaint. Witness Montalvo's workpapers and resume are included as exhibits to Attachment A. The Declaration also lists the materials relied upon by witness Montalvo.

The Aurora Report and Columbia Study are included as Attachments B and C to this complaint, respectively.

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

On August 30, 2024, Joint Consumer Advocates and others wrote the PJM Board, requesting that PJM take immediate action to protect ratepayers throughout the PJM region from unjust and unreasonable capacity market prices. The letter urged PJM to institute a Critical Issue Fast Path process to develop rules requiring the capacity value of RMR units to be considered in the capacity market, effects for the 2026/2027 BRA, and delay the auction, as necessary. On September 19, 2024, the PJM Board responded that it would be counterproductive to try to change the market rules for RMR units prior to the 2026/2027 BRA. In these circumstances, Joint Consumer Advocates have not used the Commission's Enforcement Hotline or Dispute Resolution Services and do not believe at this time that alternative dispute resolution would resolve the issues underlying this Complaint.

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

Assuming PJM makes the section 205 filing it has stated will soon be submitted to address BRA market rules (and potentially other related matters), Joint Consumer Advocates ask that this Complaint be addressed contemporaneously.

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

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

VI. PARTIES AND COMMUNICATIONS

I. Complainants

The complainants are the Illinois Attorney General's Office; Illinois Citizens Utility Board; Maryland Office of People's Counsel; New Jersey Division of Rate Counsel; Office of the Ohio Consumers' Counsel; and Office of the People's Counsel for the District of Columbia.

J. Respondent

The respondent is PJM Interconnection, L.L.C.

K. Communications

All correspondence and communications to the Complainants in this docket should be addressed to the following individuals, whose names should be entered on the official service list maintained by the Secretary in connection with these proceedings:[183]

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[183] The Complainants request a waiver of Rule 203(b)(3), 18 C.F.R. § 385.203(b)(3), to allow the inclusion of more than two persons on the official service list on the grounds that the Complainants comprise separate parties, each represented by their own counsel.

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VII. SERVICE AND NOTICE

In accordance with Rule 206(c), the Complainants have served a copy of this Complaint upon PJM, as Respondent, simultaneously with the filing of the Complaint.

VIII. CONCLUSION

The 2026/2027 BRA cannot lawfully go forward under the current market rules. The combination of limited new entry capable of entering service prior to the commencement of the 2026/2027 Delivery Year, anticipated load growth, the artificial exemption of eligible resources from offering into the BRA, and the risk of market manipulation from resources with market power (including, the withholding and/or submission of artificially high demand response offers by fleet operators) portends—if not guarantees—excessive and artificially high capacity prices in the upcoming 2026/2027 BRA. The Commission should find the existing BRA market design unjust and unreasonable, and should implement the reforms identified here.

Respectfully submitted,

/s/ Eric DeBellis

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November 18, 2024

UNITED STATES OF AMERICA
FEDERAL ENERGY REGULATORY COMMISSION

Joint Consumer Advocates, *Complainants*, v. PJM Interconnection, L.L.C., *Respondent.*	Docket No. EL25-____-000

NOTICE OF COMPLAINT

(November 18, 2024)

Take notice that on November 18, 2024 pursuant to sections 206 and 306 of the Federal Power Act, 16 U.S.C. 824e and 825e, and Rule 206 of the Federal Energy Regulatory Commission's (Commission) Rules of Practice and Procedure, 18 CFR 385.206, Joint Consumer Advocates (Complainants) filed a formal complaint against PJM Interconnection, L.L.C. (PJM or Respondent) alleging that PJM's existing capacity market rules are unjust and unreasonable because they fail to mitigate market power and result in the imposition of excessive capacity charges upon consumers.

Joint Consumer Advocates certify that copies of the complaint were served on the contacts for PJM as listed on the Commission's list of Corporate Officials.

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

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

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

Comment Date: 5:00 p.m. Eastern Time on [December 9, 2024].

Dated: [November 18, 2024].

CERTIFICATE OF SERVICE

Pursuant to Commission Rules of Practice and Procedure Nos. 206(c) and 2010, I hereby certify that I have this 18th day of November, 2024 caused the foregoing document to be served upon the Corporate Officials of Respondent PJM Interconnection L.L.C. that are identified on the Commission's list maintained pursuant to 18 C.F.R. § 385.2010(k).

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ATTACHMENT A

Declaration of Marc D. Montalvo

UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

Joint Consumer Advocates,
Complainants,

v.

PJM Interconnection, L.L.C.,
Respondent.

Docket No. EL25-____-000

DECLARATION OF MARC D. MONTALVO

I. QUALIFICATIONS

1. My name is Marc D. Montalvo. I am President and CEO of Daymark Energy Advisors (Daymark). My business address is 370 Main Street, Worcester, Massachusetts 01608. Daymark is a consultancy that provides transmission planning, economic analysis, and strategic advisory services to the electric power industry.

2. I work with industry and policymakers to design regulatory and market structures that enable the efficient development and deployment of clean energy infrastructure. My principal practice areas are competitive power markets, strategic planning, risk management, and capital budgeting and investment analysis. I have worked on capacity market design issues on behalf of clients in PJM Interconnection, L.L.C. (PJM), New York Independent System Operator, Inc. (NYISO), ISO-New England, Inc. (ISO-NE), and Midcontinent Independent System Operator (MISO). Most recently I advised the East Kentucky Power Cooperative regarding PJM's Effective Load Carrying Capability (ELCC) and associated reforms to the Reliability Pricing Model (RPM). My clients include developers, utilities, and government agencies across North America, and I have appeared as an expert before the Federal Energy Regulatory Commission (FERC

or the Commission), Canadian provincial regulators, and state regulatory agencies. Prior to joining Daymark, I worked ten years at ISO-NE where I held the positions of Director of Market Development, Director of Internal Market Monitoring: Investigation and Market Assessment, and Director of Enterprise Risk Management. Prior to ISO-NE, I was a managing consultant with La Capra Associates. I began my career at New England Power. I taught courses in finance and business analytics at Clark University's School of Management from 2016 to 2020.

II. SUMMARY

3. I was retained by the Joint Consumer Advocates[1] to assess the market conditions that gave rise to the price outcomes experienced in the most recent PJM Base Residual Auction (BRA) (for the 2025/2026 Delivery Year), to diagnose any current market design problems, assess the market conditions of the upcoming BRA, and to identify any necessary market design changes. This declaration presents my findings concerning the capacity market design and highlights design flaws. As I explain, the extraordinarily high prices of the 2025/2026 BRA are not efficient nor needed to signal new entry. Rather, the prices result from market design choices that fail to require participation by or to account for the reliability contributions of all existing qualified supply and that tend to overstate demand. Moreover, PJM's ongoing interconnection queue issues effectively block new resources from responding to those prices in a timely manner. This has the effect of preventing new entry from disciplining prices by contesting the market and limiting the market power of incumbent resources.

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[1] The Joint Consumer Advocates are the Illinois Attorney General's Office; Illinois Citizens Utility Board; Maryland Office of People's Counsel; New Jersey Division of Rate Counsel; Office of the Ohio Consumers' Counsel; and Office of the People's Counsel for the District of Columbia.

4. The declaration is organized as follows: first I provide an overview of the design principles that a capacity market should follow and that guide my analysis; then I review and discuss the existing market design flaws; then I focus on potential market design changes that could be implemented near-term to improve the performance of the capacity market as soon as the next BRA; and finally I suggest design improvements that would require a longer time frame to implement that I urge PJM and FERC to consider.

5. For purpose of my discussion here, I define near-term as reforms that can be made via revisions to the tariff and PJM's business processes and should not require (material, if any) modifications to models or software. The near-term changes I propose are restricted to rule modifications governing resource participation and are principally designed to increase and accurately reflect the amount of supply available to the auction by addressing the existing asymmetry that requires all load to buy capacity through the BRA but does not require all qualified supply (including Demand Response (DR) treated as supply) to sell capacity into the BRA. My review of near-term reforms includes the capacity market treatment of Reliability Must Run (RMR) resources, which was identified by Sierra Club, Natural Resources Defense Council, Public Citizen, Sustainable FERC Project, and the Union of Concerned Scientists (PIOs) in their September 27, 2024, Complaint, which is pending before FERC in Docket No. EL24-148-000. My recommendations concerning near-term changes are conservative, and PJM should be able to implement them prior to the next auction.

6. Long-term changes include structural reforms that would require changes to both rules and models to address:

- how capacity requirements are set, including modifications to load forecasting and the treatment of planned transmission upgrades;
- Net cost of new entry (Net CONE) calculation and maximum price, defining parameters in the Variable Resource Requirement (VRR) curve used to reflect demand in the auction;
- ELCC assumptions;
- retirement notification and consideration of needs leading to RMR; and
- the possible inclusion of transmission as a resource in the RPM.

7. While preparing this declaration I reviewed several documents, including the following:

- *Complaint of Sierra Club, Natural Resources Defense Council, Public Citizen, Sustainable FERC Project and the Union of Concerned Scientists ("PIOs")* filed September 27, 2024, pending before FERC in Docket No. EL24-148-000;
- PJM Internal Market Monitor (IMM), *2023 State of the Market Report*;
- *PJM Response to the 2023 State of the Market Report*;
- IMM, *Analysis of the 2025/2026 RPM Base Residual Auction Part A*, September 20, 2024;
- IMM, *Analysis of the 2025/2026 RP Base Residual Auction Part B*, October 15, 2024;
- *PJM letter response to Ratepayer Advocates*, September 19, 2024;
- *PJM Response to Independent Market Monitor Report on 2025/2026 Base Residual Auction*, October 11, 2024;
- PJM *2025/2026 Base Residual Auction Report*, July 30, 2024;
- *Answer of PJM Interconnection, L.L.C.* filed October 18, 2024, Docket No. EL24-148-000; and
- Silverman, Abraham, Dr. Zachary A. Wendling, Kavyaa Rizal, and Devan Samant, *Outlook for Pending Generation in the PJM Interconnection Queue,* Center on Global Energy Policy at Columbia School of International and Public Affairs, May 2024.

III. RECOMMENDED DESIGN PRINCIPLES

8. Capacity is the planned-for capability of a resource (a physical generation or demand asset) to deliver energy (or reduce consumption) or provide ancillary services to firm

load in each hour.[2] In PJM, the capacity market is called the RPM, and capacity, which is defined broadly by a set of tariff obligations to provide energy or ancillary services to the PJM market to support reliable operations, is procured through an annual BRA originally intended to establish delivery obligations three years forward. Delayed execution of the 2025/2026 BRA and 2026/2027 auctions to July 2024 and June 2025, respectively, has delivery occurring within a year of the respective auction.

9. The purpose of the capacity market is to procure the lowest cost portfolio of capacity that meets the resource adequacy target (the amount of capacity needed to reduce Loss of Load Expectation or Expected Unserved Energy to the targeted level).[3] A good capacity market design supports the efficient allocation of capital and coordinates the timely entry and exit of resources, consistent with maintaining regional reliability, all at the lowest possible cost to load.[4]

10. The PJM RPM design assumed:

    - most resource additions can be made within the three-year time frame in response to the forward price;
    - relatively low barriers to entry and exit; and
    - relatively stable load growth.

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[2] Discussions of capacity often focus on the need to deliver energy and ancillary services in critical hours. Of course, any hour when the amount of energy and reserves falls is expected to fall short of load is a critical hour. Consequently, any hour could be critical if a sufficiently percentage of resources fail to perform. Thus, the goal of the market it to procure a portfolio of capacity resources that in aggregate can serve load in each hour.

[3] *New Jersey Board of Public Utilities v. FERC*, 744 F.3d 74, 101 (3d. Cir. 2014).

[4] As PJM's power grid transforms from a largely fossil-fuel-based system to a more intermittent resource-dependent system, the transmission system is undergoing a major reconfiguration to support the location and operating characteristics of the new resources. The scope of the needed transmission build hampers both the rapid entry of new resources as well as the ability of resources around which the existing transmission was built to retire without requiring new infrastructure to take its place. The capacity market was not designed to coordinate the transition of the generation fleet and transmission system to meet the demand of state and federal clean energy policy and the rapid advancement of large energy intensive data-center loads.

As things stand now, however, none of the assumptions still holds. The RPM's three-year forward market construct was intended to provide price signals in advance of need to allow the market time to respond to expected future supply and demand conditions. The 2025/2026 auction was delayed, however, so at best it reflects conditions expected next year. The 2026/2027 auction schedule also was compressed, with offers initially due by December 4, 2024, to supply capacity beginning June 1, 2026. More recently, FERC has granted PJM's request to delay that auction by another six months leaving just one year between conduct of the auction and the start of the 2026/2027 delivery year.[5] Because project developers cannot respond to these price signals by developing projects within these shortened timeframes, the recent auctions, setting aside any other design issues, do not properly reflect the forward price information the market was expected to provide. Under current market conditions, capacity prices are being driven by the barriers to entry of new supply—including constraints on the time it takes to study interconnection requests and build new transmission to interconnect new resources in the queue—which add to the market power of incumbent suppliers. High prices cannot bring new generation into the market more quickly than it can be interconnected, and, while such prices might retain existing generation, they are substantially above any just-and-reasonable measure of the net going forward costs that existing resources must cover to deliver capacity.

11. The capacity market reforms recommended in this declaration address the following design principles:

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[5] *PJM Interconnection, L.L.C.*, 189 FERC ¶ 61,105 (2024).

- Given competing design options, PJM should prefer those that deliver resource adequacy at the lowest possible cost.[6]
- The capacity market design should provide timely and actionable market signals for the allocation of capital to retain or build new capacity resources (or transmission, if that is more appropriate) to meet reliability targets.
- The market design should present assumptions regarding LDA requirements that reflect the best estimates of the system, including transmission topology, generation additions and load, into which new capacity investments would be made.[7]

12. Largely consistent with these principles, PJM's stated BRA objective is "… to procure a target capacity reserve level for the [regional transmission organization (RTO)] in a least-cost manner while recognizing … reliability-based constraints on the location and type of capacity that can be committed."[8]

13. The reforms I propose address two fundamental concerns consistent with the above principles. First, PJM has expressed concern that the region is becoming capacity-tight. Yet, the current queue delays and the scope of required transmission upgrades are preventing timely new entry in significant amounts. In addition, the market rules allow thousands of MWs of otherwise qualified resources that do plan to operate and support reliability not to bid into the capacity market.[9] At a minimum, then, the tightening

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[6] Criticisms of the methods by which Regional Transmission Organizations have created capacity market demand curves include Wilson (2010) and (2020), Chen (2018), the Regulatory Assistance Project (2018), Gramlich and Goggin (2019), McCullough et al. (2019) and (2020).

[7] Capacity requirements in LDAs within PJM are determined annually by PJM using an analysis that forecasts the load expected in the LDA, the available generation within the LDA, and the ability to import power into the LDA. The current approach for calculating the amount of capacity that might needed to be imported in emergency periods to meet load (Capacity Emergency Transfer Objective (CETO) , and transmission system limits on how much capacity can be imported during emergency periods (Capacity Emergency Transfer Limit (CETL)) are not sufficiently transparent and do not necessarily adequately reflect planned-for changes to the transmission system and resource mix that could have material impacts on need for and price of capacity in an LDA in the future.

[8] PJM, *2025/2026 Base Residual Auction Report* (July 30, 2024), https://www.pjm.com/-/media/markets-ops/rpm/rpm-auction-info/2025-2026/2025-2026-base-residual-auction-report.ashx

[9] Independent Market Monitor of PJM, *Analysis of the 2025/2026 Base Residual Auction, Part B* (2024), p. 12.

capacity supply condition and the market power of incumbent generators might be mitigated in part through a rule change. My proposed reforms would result in all existing qualified resources being recognized in the PJM capacity market.

14. Second, investors may be skeptical of the longevity and dependability of the price signal. Capacity prices can be sensitive to small supply changes and administrative adjustments to the design. The resulting volatility and the disconnect from long-term fundamentals may not induce the anticipated developer market entry. Given this, all efforts to maximize supply participation in the auction will further competition in the BRA and improve pricing performance. Moreover, exempt resources that choose not to participate in a BRA are operating facilities that do impact system performance, including energy and ancillary prices, and may choose to participate in a future BRA. The risk of Performance Assessment Intervals (PAI) occurring is impacted by the performance of all resources in the market, not just capacity resources cleared through the RPM, and even resources without capacity positions are eligible to receive PAI bonuses if operating during a PAI event. Any party considering investing would consider these factors and may rationally discount the BRA price as not truly reflective of the supply-demand conditions and consequent revenues that will be available when the resource comes online.

IV. CONCERNS WITH THE PJM MARKET DESIGN AND THE CAUSES OF HIGH 2025/2026 BRA CLEARING PRICES

A. The extraordinary prices seen in the 2025/2026 BRA have appropriately raised questions about PJM's capacity market design.

15. PJM ran the 2025/2026 BRA in July 2024. The 2025/2026 BRA cleared 135,684 MW (excluding energy efficiency) of unforced capacity (UCAP) against a requirement of

132,056 MW (excluding utilities that supply their required capacity outside of the PJM BRA, under the provisions of the Fixed Resource Requirement (FRR)), realizing an 18.6% (18.5% including FRR) reserve margin against a target reserve margin of 17.8%. The RTO clearing price was $269.92/MW-day. The Baltimore Gas & Electric (BGE) and Dominion (DOM) LDAs were constrained, resulting in locational clearing prices of $466.35/MW-day and $444.26/MW-day, respectively. The 2025/2026 BRA cleared a system-wide surplus of 3,628 MW, meaning that resource participation was more than sufficient to support regional resource adequacy. The two constrained zones, BGE and DOM, fell short of clearing sufficient capacity by 303 MW and 532 MW, respectively. The total capacity market cost to load for the 2025/2026 BRA is $14.7 billion.

16. An immediate observation is the stark difference between the BRA results for the 2024/2025 and 2025/2026 Delivery Years—even though the related auctions were held just months apart. The 2024/2025 BRA RTO clearing price was $28.92/MW-day. The MAAC, BGE, DPL-S, EMAAC and DEOK LDAs were constrained, resulting in locational clearing prices of $49.49/MW-day (MAAC), $73.00/MW-day (BGE), $426.17/MW-day (the DPL-S price outcome was based upon what PJM determined were inaccurate auction assumptions), $53.60/MW-day (EMAAC) and $96.24/MW-day (DEOK), respectively. The total capacity market cost to load for the 2024/2025 BRA is $2.2 billion.

17. Side-by-side examination of the results of these two auctions would suggest that, in less than a year, market conditions deteriorated sufficiently that PJM went from an apparent robust surplus with little need for additional capacity to near shortage conditions across the region. While it is possible that this is true, the dramatic change

raises questions regarding, at a minimum, the validity of the input assumptions—if not more broadly the structure of the market—and calls a reasonable person to question the robustness of the results.

18. There were major changes between the conduct of the 2024/2025 and 2025/2026 BRAs. These include: (1) PJM's adoption of resource ELCC calculations; (2) a 3,242 MW increase in forecasted load; (3) an increase, from 14.7% to 17.8%, in the target installed reserve margin; (4) changes in the portfolios of resources subject to FRR (principally, the choice by Dominion to move from FRR to participation in the BRA); (5) a decrease in cleared new generation; and (6) an increase in exemptions, including 1,596 MW of qualified unforced capacity and the exclusion of some 2,100 MW of RMR resources.[10] This latter value on its own exceeds the shortfall in BGE by more than 1,700 MW.

19. On September 27, 2024, PIOs filed a complaint requesting that the Commission find that "PJM's capacity market rules are unjust and unreasonable because they fail to require a consistent accounting of the resource adequacy contributions of power plants operating under [RMR] arrangements and lead to excessive costs for consumers," and order appropriate relief. The PJM Independent Market Monitor (IMM) has filed comments in support of the complaint, stating that the treatment of RMR resources in the capacity auction is problematic, citing the request of the Complainants in Docket No. EL24-148-000 that the Commission "… order PJM to reform its capacity market

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[10] PJM, 2025/2026 Base Residual Auction Results, Presentation to the Markets & Reliability Committee (August 21, 2024).

rules to consistently account for RMR units' resource adequacy contributions,"[11] comments that the Market Monitor "agrees that the current treatment of resources . . . is unjust and unreasonable."[12]

B. PJM has replied that capacity market prices appropriately reflect market fundamentals, but the high 2025/2026 BRA prices are not effective signals and reflect weaknesses in the PJM market design (as recently modified), not market fundamentals.

20. PJM's response to the PIOs, consistent with earlier PJM comments on the 2025/2026 BRA results, is that the results reflect a combination of a "long-term trend of tightening supply and demand balance that PJM has been forecasting for years" with certain "unique facts and circumstances" involving the two RMR resources identified in the complaint.[13] In PJM's account of the capacity market, the PJM capacity market was long on capacity "for years," resulting in low BRA clearing prices that forced resources out of the market. Recent growth in the demand forecast, combined with these retirements, is offered as the reason for a sudden tightening of net-supply and the corresponding spike in BRA clearing prices.

21. Overall, PJM describes high prices as a "feature designed to incent the development of more capacity."[14] The essence of the story, as PJM explains it, is that the "higher clearing prices are the natural result of supply and demand fundamentals given resource retirements (without timely replacements) and a large increase in expected load growth,

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[11] "Comments of the Independent Market Monitor for PJM," filed October 10, 2024 in Docket No. EL24-148-000, p.1, citing Complaint filed September 27, 2024 by Sierra Club, Natural Resources Defense Council, Public Citizen, Sustainable FERC Project and the Union of Concerned Scientists.

[12] *Id.* at 1-2.

[13] Answer of PJM Interconnection, L.L.C. at 5, Docket No. EL24-148-000 (Oct. 18, 2024), eLibrary No. 20241018-5165 (PJM Answer).

[14] *Id.* at 6.

driven in large part by electrification trends and data center development in the PJM Region."[15] PJM defends the 2025/2026 BRA results as the proper outcomes of the market design, which has been found just and reasonable by the Commission. PJM regards these results as a market feature and not a flaw.

22. I agree that capacity prices should reflect supply and demand fundamentals. A capacity market's primary function is to provide incentives for the coordinated deployment of capital to ensure the timely entry and exit of the supply resources needed to ensure long-term reliability. The 2025/26 BRA results expose two fundamental issues with the RPM: (1) the market can produce extraordinary prices that exceed what is needed to signal the need for new capacity, especially in individual LDAs; and (2) the market design tends to exaggerate supply and demand imbalances, so may not properly reflect actual resource needs.

C. Structural market power is endemic to the PJM capacity market.

23. Structural market power sets the PJM market up to produce extraordinary prices that exceed what is needed to signal the need for new capacity, especially in individual LDAs. As the PJM IMM has found year after year with great consistency, structural market power is endemic to the PJM capacity market[16]—an observation that applies both to the PJM aggregate market structure and to the PJM local market structure. As I explain below, pervasive structural market power limits the usefulness of high prices as a signal for capacity investment, exposes the market to anti-competitive bidding strategies, and puts a heavy burden on the IMM to mitigate offers properly.

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[15] *Id.*

[16] IMM, *2023 State of the Market Report for PJM*: 10. The statement, "Structural market power is endemic to the capacity market," has appeared in all IMM *State of the Market* reports for PJM since 2018.

24. The IMM uses the Three Pivotal Supplier (TPS) test to identify potential market power. For each generation owner, the TPS test measures, both at the PJM region-wide level and for the LDA, whether the capacity of the owner's generation facilities, in combination with the two other largest suppliers in the region, is essential to meeting demand in constrained conditions. In PJM, both at the regional level and at the LDA level for at least some LDAs, in almost every BRA, the IMM has found structural market power.[17] When the TPS test is failed, suppliers in that location are subject to PJM offer caps to mitigate the risk of the exercise of market power. As the IMM has noted, the imposition of properly set offer caps—and the selection of correct cap levels—can help to mitigate market power.[18] As one who used to sit in the market monitoring chair, offer caps are a *Band-Aid*, not a substitute for a truly competitive marketplace. In addition, FERC has found that offer caps are a mitigation measure intended to work in concert with the ability of new entry to compete with and thereby discipline the market power of incumbent resources.[19]

25. As the IMM has reported on the 2025/2026 BRA, "[t]he RTO as a whole failed the Market Structure Test (i.e., the Three-Pivotal Supplier Test,)"[20] and approximately 99%

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[17] The exceptions are rare enough to list in footnote, as the IMM does in footnotes 17 and 18 of the most recent *Quarterly State of the Market Report for PJM: January through June*. For the region as a whole, at least some participants passed in the 2008/2009 RPM Third Incremental Auction, the 2018/2019 RPM Second Incremental Auction, and the 2023/24 RPM Third Incremental Auction. At the LDA level, in EMAAC, at least some participants passed the TPS test in the 2012/2013 RPM BRA and in the 2021/2022 RPM Second Incremental Auction. In MAAC, at least some participants passed the TPS test in the 2021/2022 First Incremental Auction and in the 2023/2024 RPM Third Incremental Auction.

[18] "Offer capping is an effective means of addressing local market power when the rules are designed and implemented properly." IMM *Quarterly State of the Market Report for PJM: January through June*: 24.

[19] *PJM Interconnection L.L.C.*, 117 FERC ¶ 61,331, P 101 (2006), *on reh'g*, 119 FERC ¶ 61, 318, *reh'g denied*, 121 FERC ¶ 61,173 (2007).

[20] *PJM 2025/26 Base Residual Auction Report*: Table 3.

of offered MWs cleared.[21] I find PJM's position that the extraordinary 2025/2026 BRA clearing prices are "consistent with market fundamentals" and therefore somehow both necessary and appropriate to be circular at best. The extraordinary prices are a consequence of the application of the existing design, flaws and all, to a set of assumptions and forecasted values. That capacity prices should be rising given market fundamentals is undoubtedly correct. That the extraordinary prices that came out of the 2025/2026 BRA and are likely to come from future BRAs without meaningful reform are somehow just and reasonable because that's how the formula works, is plainly wrong. Price signals that reflect expected supply and demand conditions are essential to the proper functioning of the BRA framework, however the extant broader market conditions and design flaws prevent the orderly entrance of new resources and exit of existing resources.

D. At the LDA level, high prices are too brittle to serve as incentives for investment.

26. The IMM stated in his *2023 State of the Market* report that "[t]he capacity market is, by design, always tight in the sense that total supply is generally only slightly larger than demand."[22] When supplies are tight, as PJM itself states, "… even relatively small impacts to the supply demand balance can have outsized impacts on clearing prices because of the inelasticity of both supply and demand."[23] In transmission-constrained LDAs, the entry or exit of a single resource can make the difference between clearing at the LDA price cap or clearing at the overall PJM market clearing price. If a new

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[21] *Id.*, p. 6.

[22] IMM 2023 State of the Market Report at page 303.

[23] *PJM Response to Independent Market Monitor Report on 2025/2026 Base Residual Auction,* October 11, 2024: 3.

resource enters and solves the capacity shortage in an LDA, it will receive a lower capacity price, because the high shortage price goes away as soon as the new resource clears the market. Consequently, assuming a rational actor, a new supplier does not expect, nor can it require, the high constrained LDA price to enter, but rather the lower post-entry clearing price. The so-called signal (the shortage price) ends up paying incumbents more than the true market cost of entry, and in most instances substantially more than the cost of remaining in the market (net going forward costs) for not exiting the market.[24] Similarly, in an LDA with an announced plan to relieve a constraint through construction of transmission, potential resource investors will realize that high prices will persist only until the transmission constraint is resolved. Prudent investors will hesitate to enter under these conditions, unless they believe that the prices expected to prevail after the transmission is built will be high enough to support their resource.

27. Consequently, both in existing LDAs (especially in those where a transmission upgrade to relieve a deliverability constraint is planned) and in the RTO as a whole, extraordinary prices do not function as effective price signals for new construction. Of course, this fact is exacerbated where queue constraints prevent resources from timely entering the market irrespective of the price. Instead, consumers are simply making windfall payments to existing capacity resources.

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[24] Independent Market Monitor for PJM, *State of the Market Report for PJM 2023* (March 14, 2024), p.2 “a doubling of market revenues [realized in the 2023/24 BRA from $2.2 billion to $4.4 billion] would reduce the units identified as uneconomic [and hence at risk of retirement] by 14,817 MW or 44 percent.”

E. The market power of existing generators is not being disciplined by new entry, due to queue delays, and generators have several options for exercising market power.

28. A central feature of the RPM's forward-looking market format is that competition from new entry will discipline the market power of incumbent resources.[25] But the delays in BRAs and the current PJM interconnection queue issues prevent new entry from performing this role. The lack of competition from new entry to discipline the market power of incumbent generators has several immediate and important consequences. First, generators can assume that their offers will clear at high prices because all or nearly all incumbent supply is likely to clear the auction.[26] Second, incumbent generators who have associated DR can bid the DR in at any price—up to the market price cap—unconstrained by a resource offer cap in an effort to set the market clearing price. Third, incumbent generators with portfolios of resources can retire some units on short notice to drive up prices received by their other resources. Fourth, fleet operators with units eligible but exempt from participation can exercise their option under the rules to withhold, without retiring, the exempt units from the auction. Again, this contributes to auction supply scarcity and leads to inefficiently high auction prices.

F. Current auctions are more like spot markets than forward auctions.

29. As designed, the RPM is intended to be a three-year forward market, with the BRA held three years before the capacity delivery year—a period that is intended to allow for competition from entrants that can complete construction of new facilities in that

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[25] *PJM Interconnection L.L.C.*, 117 FERC ¶ 61,331, P 101.

[26] According to an Aurora Energy Research report "[a]ll offered thermal, nuclear, demand response and solar capacity cleared the 2025/26 BRA." Aurora Energy Research, PJM Capacity Market - 2025/2026 BRA results & outlook for upcoming auctions at 13 (Sept. 2024)

timeframe, between their offers clearing and the delivery year beginning. As PJM has grappled with various capacity market issues and changes to the market design, the BRA schedule has gotten delayed to the point where it currently is acting more like a spot market—for example, the 2025/2026 BRA was held in July 2024 for a planning year that begins in June 2025—less than a year ahead. It is not reasonable to expect a market mechanism designed to produce three-year forward price signals to work in the same way in this short-term time frame.

30. Under current market conditions, high BRA prices, never mind extraordinarily high prices, cannot plausibly serve their intended function as effective market signals. Fortunately, as I discuss below, there is also good reason to believe that the growing capacity imbalance is overstated and that the prices needed to address it are substantially lower than those produced in the 2025/2026 BRA.

G. High prices in the 2025/2026 BRA reflect market design flaws rather than fundamental supply-demand imbalance.

31. The 2025/2026 BRA results do not reasonably reflect market fundamentals. There are several reasons why this is the case: (1) there are substantial amounts of new resources that want to enter the market but cannot do so; (2) there is more eligible capacity in PJM than is recognized in the capacity market; (3) historically, PJM has systematically over-forecasted load, thus setting capacity requirements too high; (4) the administrative cost of new entry, as represented by Net CONE, exceeds true market entry costs; and (5) the RMR need identification and regional transmission expansion planning (RTEP) processes do not identify in a timely way where transmission upgrades or generation additions might be substitutes, which means—at a minimum—that they miss opportunities to avoid unnecessary RMR contracts.

32. Put plainly, the capacity resource shortage in PJM is overstated. By PJM's account, recent retirements, combined with growth in demand, is the source of a capacity shortage and corresponding sudden spike in BRA clearing prices.[27] But the story PJM tells of the supply-demand condition driving the 2025/2026 BRA results is not complete—the apparent shortage reflects less the available megawatts and more a series of design choices made by PJM. There are several aspects of PJM's market design that undercount the resources that contribute to serving load reliably: namely, the treatment of RMR resources, the exemption of some resource categories (including storage and renewables) from must offer requirements, and PJM's treatment of combustion turbines in its ELCC and UCAP calculations. Taken together, these choices systematically understate the capacity that is available to serve load. Additionally, PJM ignores that there are thousands of megawatts of potential generation that want to enter the market but cannot do so because they are still in the interconnection queue or have only recently executed interconnection agreements. I discuss each of these sources of capacity below.

H. RMR resources and other resources which are available to serve load are not offering in the capacity market.

33. I agree with the PIOs that PJM's exclusion of RMR resources distorts capacity prices by ignoring resources that do contribute to resource adequacy. I recognize that the existing voluntary RMR framework may somewhat tie PJM's hands as regards the obligations it can impose on an RMR resource. However, this constraint reflects a design choice that can and should be changed, if for no other reason than to ensure that

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[27] PJM Answer at 6-7.

the money spent to retain these resources results in the delivery of maximum benefits to ratepayers.

34. When PJM determines that loss of a resource seeking to retire would impact reliability and that there is not an available transmission or market-sourced solution that can be implemented before the target retirement date, PJM and the resource can voluntarily enter an RMR arrangement under Part V of the PJM Open Access Transmission Tariff (OATT). The RMR arrangement is in place until an alternative reliability solution is put into service. A resource with an RMR agreement commits to remain operational beyond its requested deactivation date to mitigate reliability concerns until necessary upgrades are implemented.[28] Such resources must be available to operate and respond to PJM dispatch instructions per the terms of their RMR agreements to support reliable operations but are exempt from required participation in the capacity market. (If the RMR resource nonetheless chooses to participate in the capacity market, then it is subject to the same performance obligations imposed upon all PJM resources that clear a capacity auction). Given the structure of many RMR contracts that limit operations to emergencies, there is likely a high correlation between RMR unit dispatch and system conditions that might lead to a PAI event. The RMR resource may recover its net going forward costs (default rate) or request a cost of service-based (COS) rate. RMR resources generally request COS treatment, the total cost of which is most often substantially above the prevailing market cost of capacity.[29] Customers who are paying

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[28] PJM OATT Part V, Sec 113.2.

[29] The IMM found that since 2022, RMR units that used the cost-of-service recovery rate, "revenues have averaged about 4.1 times the corresponding market price of capacity[.]" Monitoring Analytics, *2024 Quarterly State of the Market Report for PJM*, p. 361.

the full embedded cost of a resource retained for reliability should receive the benefits of all the services that the resource can provide.

35. PJM models the reliability contributions and the impacts on power flows of RMR resources when calculating reserve requirements, irrespective of whether the resource participates in the capacity auction and takes on the performance obligations imposed on cleared resources. PJM includes RMR resources in the set of Internal UCAP resources used to calculate the Capacity Emergency Transfer Objective (CETO) and set the LDA reliability requirement and as part of the system modeled to calculate the Capacity Emergency Transfer Limit (CETL).[30] The LDA binds (meaning that the LDA must rely on internal resources) and there is price separation if the CETO is greater than the CETL. As the modeled treatment of a resource is the same after the RMR as it was before (I have no evidence to suggest that PJM modifies the RMR resource's expected contribution to meeting load during modeled emergency conditions), the reliability requirement is not impacted by a resource's new RMR status. However, the RMR resource is not included as supply for purposes of clearing the capacity market auction. This creates a disconnect between assumed supply for purposes of setting LDA resource requirements and the actual supply—per the IMM, approximately 1,984 MW of nameplate capacity supported through RMR agreements,[31] amounting to an estimated 1,600 MW of UCAP MW at ELCC class ratings in the 2025/2026 auction.[32]

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[30] PJM, *PJM CETO/CETL & Load Deliverability* (2023), https://pjm.com/-/media/committees-groups/task-forces/destf/2023/20231109/20231109-item-05---ceto-cetl-and-load-deliverability-test.ashx

[31] MD Office of People's Counsel, Bill and Rate Impacts of PJM's 2025/2026 Capacity Market Results & Reliability Must-Run Units in Maryland, Prepared by Synapse Energy Economics (August 2024), 13.

[32] The Independent Market Monitor for PJM, *Analysis of the 2025/2026 RPM Base Residual Auction Part A* (September 20, 2024), 13.

PJM has noted that one of the units under an RMR arrangement (Brandon Shores) faces potential constraints on operation. But even setting aside Brandon Shores, another RMR resource, Wagner (now converted from coal to oil), provides a potential 702 MW of nameplate capacity and an estimated 527 MW of UCAP.[33] Of course, my concern extends beyond these specific RMR resources. All resources that are expected to operate during a delivery year should be reflected to provide a proper rendering of the expected supply-demand dynamic to potential new entrants.

36. As the rules are currently structured, resource owners that control a portfolio of resources that include eligible but exempt resources have an incentive to withhold some of their exempt resources strategically to raise the clearing price to the benefit of the balance of their portfolio. When supply and demand conditions are tight, even the withholding of a small quantity of eligible supply can be a profitable strategy. The incentive for withholding is even stronger in the case of an exempt RMR resource receiving cost-of-service through its RMR agreement. In this case, the owner is held economically harmless from withholding that resource's eligible capacity from the auction, and in doing so may realize the upside from higher prices on the balance of its portfolio. While I do not know if parties have intentionally engaged in this strategy, leaving the market exposed to such strategies is poor market design.

37. PJM's treatment of other "exempt" resources, namely intermittent resources, battery storage, and DR, likewise undercounts these resources' actual availability to serve load

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[33] As Sierra Club et al. point out in their October 31, 2024 Response (at 57-58), PJM's position that Brandon Shores cannot operate after the end of 2025 cannot be reconciled with PJM's pursuit of an RMR arrangement that extends beyond that date. Moreover, Sierra Club's Response explains that the alleged constraints are subject to modification. And of course, Brandon Shores could have continued to operate without need for such a modification had Talen completed rather than canceled its planned coal-to-oil conversion. However, to be conservative our analysis of BRA impacts excludes Brandon Shores.

in PJM. PJM reports that in the 2025/2026 BRA, excluded RMR resources, unoffered UCAP MWs from battery, diesel-landfill, hydro, solar, and wind resources, total 1,596 MW.[34] Unlike fossil-fueled RMR units, which may be dispatched infrequently, many of these intermittent resources have very low operating costs and should be expected to run whenever an energy source is available. So, whether they participate in the capacity auction and are compensated for doing so, these resources can be expected to provide resource adequacy in accordance with their accredited values. Given that, the question arises why such resources might choose not to participate in the auction and be compensated for providing capacity. One possibility is that the market rules inefficiently disincentivize participation by subjecting such resources to penalties for non-performance that is outside their control and already reflected in their accredited capacity values. Another possibility is that many owners control fleets of resources and can optimize the values of their portfolios by withholding some supply. Again, I do not know whether individual market participants have done so, but market rules that enable the withholding of qualified supply are poorly designed.

38. Similarly, the owner of a resource portfolio that includes DR can offer that DR strategically in the auction to benefit the balance of the portfolio. DR is categorically exempt from the auction,[35] and DR can opt to participate in one auction and refrain from participation in a subsequent auction without much, if any, scrutiny. DR does comprise a meaningful percentage of the total capacity participating in the market

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[34] PJM. *2025/2026 Base Residual Auction Results.* Presentation to Markets & Reliability Committee, August 21, 2024, Slide 38.

[35] The Independent Market Monitor for PJM. *Analysis of the 2025/2026 RPM Base Residual Auction Part A* (September 20, 2024), 4.

(approximately 4 percent in the 2025/2026 BRA).[36] Mitigation is hampered, as the IMM does not apply mitigated offer prices to DR when the structural market power tests fail.[37] Rather, the market incorrectly assumes that DR is demand and that its natural incentive is to lower the price. However, within the context of the capacity market, DR is not treated like demand, but as supply.[38] The portfolios of some DR providers may benefit from higher, not lower, prices. I contend that rules that give DR providers the ability, through strategic bidding, to raise prices above competitive levels are not just and reasonable.

I. PJM's decision to tie capacity ratings to summer performance understates the capacity available to meet winter events.

39. In the recent *Analysis of the 2025/2026 RPM Base Residual Auction, Part A,* the IMM analyzes the impact of PJM's decision to use "summer ratings rather than winter ratings for combined cycle (CC) and combustion turbine (CT) resources."[39] Combustion resources like CC and CT resources are able to produce at higher levels during cold weather, so the choice of summer ratings effectively undercounts the contribution these resources can make during the high-risk winter period. The IMM's estimate is that, on average, the ELCC accreditation for these resources would have been 8.8 percent higher if winter capability was used.[40] The IMM acknowledges that deliverability, in the form of Capacity Interconnection Rights (CIRs), is currently set to summer capacity

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[36] Calculated from PJM 2025-2026 Base Residual Auction Report, July 30, 2024, Table 8.

[37] The Independent Market Monitor for PJM. *Analysis of the 2025/2026 RPM Base Residual Auction Part A* (September 20, 2024), 4.

[38] PJM Response to Independent Market Monitor Report on 2025/2026 Base Residual Auction (Oct. 11, 2024), 9.

[39] The Independent Market Monitor for PJM. *Analysis of the 2025/2026 RPM Base Residual Auction Part A* (September 20, 2024), 5.

[40] Ibid, 10.

levels but suggests that these rights could be re-set to reflect winter levels. PJM's response to the IMM acknowledges that there is likely additional winter thermal capacity, and that "it is likely that some additional winter deliverability would be available," but notes that "there are likely limitations," both in terms of capacity interconnection and potential increases to overall resource adequacy requirements if risk shifts from winter to summer.[41] PJM agrees, however, that this issue should be studied.[42]

40. The IMM's 2025/2026 BRA analysis includes scenarios that test the impact of using winter rather than lower summer ratings for determining capacity of combined cycle and combustion turbine resources. The IMM's analysis found that such a change would have increased the pool wide accredited UCAP (AUCAP) factor from 79.69 percent to 82.53 percent.[43] Such a change implies an increase of roughly 5,400 of UCAP MW for combined cycle and combustion turbine resources.[44]

J. The exclusions from the capacity market detailed above amount to thousands of MWs of potential UCAP that PJM is currently failing to consider.

41. PJM's exclusion of RMR resources and exempt resources and its choice to rate natural gas capacity based on summer performance adds up to thousands of MWs of UCAP that is excluded from consideration in the BRA, as summarized in the table below.

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[41] PJM. *PJM Response to Independent Market Monitor Report on 2025/2026 Base Residual Auction* (October 11, 2024): 6.

[42] *Id.* at 7.

[43] The Independent Market Monitor for PJM. *Analysis of the 2025/2026 RPM Base Residual Auction Part A* (September 20, 2024), 10.

[44] The AUCAP factor of 76.69 percent is based on pool wide accredited UCAP of 152,765 MW as a share of total ICAP in the model of 191,693 MW. An AUCAP factor of 82.53 percent against the same installed capacity (ICAP) total yields 158,204 UCAP MW, or an increase of 5,439 UCAP MW.

Table 1. Potential UCAP not reflected in 2025/2026 BRA[45]

Exclusion category	**Resource**	**Capacity not offered, UCAP MW**
RMR	Brandon Shores	1,069
RMR	Wagner	527
Exempt Resources	Battery	110
Exempt Resources	Diesel-Landfill	73
Exempt Resources	Hydro	424
Exempt Resources	Solar	533
Exempt Resources	Wind	456
Exempt Resources	Demand Response	Unknown
Winter ratings	Combined cycle/combustion turbines	5,439
	Total potential additional UCAP	**8,631**
	Total potential additional UCAP, excluding Brandon Shores	**7,562**

K. Many MWs of potential capacity already exist in the PJM queue or are in development after receiving interconnection agreements.

42. In *Utility Dive* earlier this year, the IMM was quoted saying that “24 GW to 58 GW of thermal resources—or 12% to 30% of the PJM Interconnection’s installed capacity—are at risk of retiring by 2030 without a clear source of replacement generation.”[46] But there *is* a source of replacement generation. As of October 16, 2024, the PJM interconnection queue contained 159,900 MW in active capacity interconnection requests.[47] Any tightness in the capacity market is not because there is insufficient interest in the market or resources are not actively working to enter the market—the problem is that resources are mired in the interconnection process. The extraordinary

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[45] Sources: RMR resources— See, *supra*, Section IV.H.. Exempt resources— PJM. 2025/2026 Base Residual Auction Results. Presentation to Markets & Reliability Committee, August 21, 2024, Slide 38. Summer vs. winter capacity rating—See Section IV.I.

[46] Ethan Howland, *Up to 58 GW faces retirement in PJM by 2030 without replacement capacity in sight: market monitor*, UTILITY DIVE (Mar. 18, 2024), https://www.utilitydive.com/news/pjm-coal-gas-power-plant-risk-retirement-market-monitor/710518/.

[47] PJM, *Planning: Serial Service Request Status* (2024), https://www.pjm.com/planning/service-requests/serial-service-request-status

time it takes to work through interconnection costs project developers real money and feeds into a cycle of further delay. A recent Columbia University survey of generation in the PJM interconnection queue found that "… developers with projects in the queue are delaying essential steps of project development until they have an Interconnection Service Agreement (ISA), and most anticipate that once they execute an ISA it will be another two years or more before their projects enter service."[48]

43. Some projects have made it through the PJM interconnection process. There are currently, according to PJM, 34,000 MW of generation that have final agreements but have not come on-line yet. These projects' interconnection applications were submitted well before the latest extraordinarily high capacity clearing prices were known, and were of course not submitted in response to these prices. In fact, during the seven-year period during which most of these applications were submitted, average RTO clearing prices have been on a downward trend and averaged just 32% of PJM's calculated Net CONE.[49]

44. Meanwhile, parties are addressing their needs in other ways. For example, PJM has identified substantial load serving needs and, through RTEP23 window 3 and RTEP24 window 1, solicited competitive transmission projects to relieve expected constraints and, among other goals, to deliver power from resources in central and western PJM into the Maryland and Virginia region. Some of these transmission projects will

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[48] *Silverman, Abraham, Dr. Zachary A. Wendling, Kavyaa Rizal, and Devan Samant. Outlook for Pending Generation in the PJM Interconnection Queue (Center on Global Energy Policy at Columbia|SIPA) May 2024: 38. Available online at* https://www.energypolicy.columbia.edu/publications/outlook-for-pending-generation-in-the-pjm-interconnection-queue/

[49] All currently approved projects would have had to enter the PJM queue by September 2021 at the very latest. Projects entering the queue since that date will not be eligible to begin the interconnection process until January 2026, at the earliest. For PJM's transition timeline, see PJM, *Interconnection Process Reform*, Presentation to the Markets and Reliability Committee (April 27, 2022): 62.

compete directly with generation projects that were put in the queue some years ago to deliver energy close to the now burgeoning load. It is somewhat ironic that generation projects seeking market entry may be rendered uneconomic by planned transmission projects receiving rate-based cost recovery developed while they were waiting for interconnection studies and transmission upgrades to be completed. Loads are not being passive, either. Several companies building large new data centers, the major driver of load growth in PJM over the next five years,[50] are looking to co-locate with existing generation, bypassing the dysfunctional capacity market and the interconnection morass, in an attempt to secure reliable low-cost power.[51]

45. Moreover, unconstrained by new entry, existing resources may look to exercise their market power. Lack of material new entry removes market-based discipline on the exercise of extant market power by existing resources; offer mitigation performed by the IMM is weak sauce. Offer caps are not a substitute for a competitive market where new entry can compete with existing resources. The lack of new entry also increases the risk that resources seeking retirement will be required for reliability and gain RMR agreements. Alternatively, it may be the case that the windfall of super high prices will slow temporarily the pace of resource retirements. But it is cold comfort that exaggerated prices that are inconsistent with expected market conditions is the reason for delaying otherwise rational exit decisions.

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[50] PJM Resource Adequacy Planning Department, *PJM Load Forecast Report* (January 2024), available at: chrome-extension://efaidnbmnnnibpcajpcglclefindmkaj/https://www.pjm.com/-/media/library/reports-notices/load-forecast/2024-load-report.ashx

[51] There is significant press coverage on this issue. See, for example, Utility Dive (November 4, 2024), "AEP, others press for FERC guidance on 'gargantuan' issue of data center colocation"; RTO Insider (October 3, 2024) "Exelon, Constellation at Loggerheads over Data Center Co-location." Recognizing the salience of this issue, FERC convened a technical conference on Nov. 1, 2024, focused on co-location of generation and large loads (Docket No. AD24-11-000).

L. PJM's focus on load growth overlooks PJM's history of consistently over-forecasting load.

46. Separately, PJM highlights load growth as another major driver of prices in the 2025/2026 BRA. But its version of events misses some important context. PJM's peak demand forecast used to set the VRR curve has historically and systematically overestimated the actual capacity need, leading to over procurement of capacity and inflated prices. The overstatement of demand was less of an issue when there were substantial generation surpluses in PJM. As surpluses are now declining at the RTO and LDA levels, the consequence of inaccurate forecasting is becoming more pronounced. There is great uncertainty in the magnitude, location, and timing of new loads into PJM's system. Unfortunately, the risk of overestimated load forecasts is asymmetrically borne by load through higher than necessary reserve requirements and capacity costs.

47. PJM forecasts peak demand as a function of historical variables including weather, population, employment, economic output, day of the week, and electric end uses. Once the preferred peak demand forecast is selected (PJM looks at multiple scenarios, and stakeholders offer input into the forecasting process), PJM then adds the Installed Reserve Margin (IRM) to account for resource unavailability, transmission limits, and likelihood of demand exceeding forecasted peak. For delivery year 2025/2026, the forecasted peak was 153,880 MW and the IRM was 17.8%. The IRM adjusted peak forecast is then translated from an ICAP basis to an unforced capacity basis. This translation reflects the aggregate unavailability of the generation fleet (now measured using ELCC). For delivery year 2025/2026, the ELCC adjustment added approximately 1.8 percent to the forecasted peak, for an ICAP capacity requirement of 181,242 MW. Finally, this amount is adjusted to account for load and resources that have chosen to

opt out of the capacity market via the FRR provisions. After accounting for FRR, the final capacity requirement (stated in ICAP) for the 2025/26 BRA was 167,583 MW.

48. Figure 1 compares PJM forecasted peak demand used to set the market demand in the BRA whose delivery years covered the last seven years to actual and weather-normalized peak demand for those years.

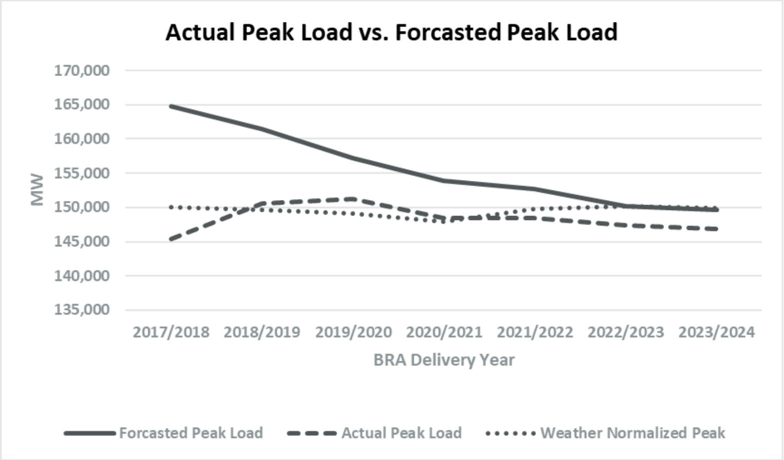

Figure 1. Actual peak load vs. forecasted peak load.[52]

49. I evaluated PJM's peak demand forecast for accuracy and bias. Accuracy measures how well the forecast matches actual outcomes, and bias measures whether the forecast systematically over- or underestimates. I measure accuracy by calculating the mean of the absolute value of the percentage errors of each forecasted value. Bias is measured as the average percentage by which the forecasted values deviate from the actual values. PJM's forecast has overestimated actual peak demand every year of the last seven and has overestimated the weather normalized peak in all but one year where it was under by 0.1%. Compared to the weather normalized peaks, PJM's forecast shows a mean absolute error (accuracy) of 4.2% (range of 9.8% to 0.1%) and a bias of 4.1%.

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[52] Data represented is sourced from annual PJM Base Residual Auction reports, for BRAs from 2017/2018 through 2022/2023 and from PJM Load Forecast Report (January 2024).

Compared to the actual peaks, PJM's forecast shows a mean absolute error (accuracy) of 4.6% (range of 11.7% to 1.9%) and a bias of 4.6%. In both cases, the forecast systematically exceeds the actual peaks—if the forecast were unbiased, one would expect that it would produce underestimates and overestimates in a roughly comparable number of instances.

50. A forecast of peak demand that is systematically biased upward results in the market repeatedly procuring more capacity than is necessary to maintain resource adequacy, at an increased cost to consumers.[53] The timing of PJM's forecasting may explain the inaccuracy of the forecast, though it does less to explain the bias. PJM's BRA nominally takes place three years before the corresponding delivery year. Forecasting demand three years in advance is inherently difficult, so one would reasonably expect such a forecast to be less accurate. However, there is no apparent reason why forecasting three years ahead should lead to a systematic over-forecasting. While the forecast does seem to be improving, there is insufficient data to determine if the last three years are an anomaly or a statistically significant improvement. Any apparent improvement, however, may be an artifact stemming from delays in recent auctions, which has resulted in setting auction parameters, bidding, and conduct of the BRA itself closer to the delivery dates. As such, this might suggest that the use of the three-year forward auction imposes a cost on consumers associated with forecast error.

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[53] In numerous capacity market design cases FERC has pointed to the overriding importance of not over procuring capacity when weighing design trade-offs. See FERC, Order No. 697 & Progeny, online at https://www.ferc.gov/industries-data/electric/overview/electric-market-based-rates/important-orders/order-no-697-progeny.

51. The foregoing suggests that the PJM market might have more accurate peak demand forecasts if it were to eliminate the three-year period between the market auctions and the capacity delivery period but does not cure the issue of bias.

52. PJM adopted the three-year forward design for reasons other than forecast accuracy: to provide more timely signals to the market; allow resources that were not yet built to clear positions and secure financing; improve market contestability; and reduce market power. For much of the past decade load growth in PJM has been slow (around 1% per year or so). Over the past year load growth has picked up dramatically, increasing to about 2.5% per year regionally. Importantly, this growth is concentrated in areas with high data center penetration like northern Virginia and Illinois,[54] and if that load growth is removed, then the regional growth level returns to 1% or so. Suffice it to say, the timing of the data center additions and their impact on RTO-wide and LDA requirements is volatile and uncertain. This is not organic and decentralized load growth. Sophisticated developers of new data centers are not likely to go forward with these projects if they are unsure about the availability of electric supply necessary to meet project needs. As noted above, PJM has sought to address some of this anticipated load growth through the RTEP. Additionally, several companies are looking to co-locate datacenters and generation, bypassing the capacity market, at least in the near-term. Under these conditions, the accuracy of PJM's load forecasting is suspect, and the merits of long-term (i.e., three-year forward) local capacity price are unclear. For these data center projects to move forward, either transmission will have been built to

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[54] Exelon reports that it has 11 gigawatts of "likely data center demand." Reported in Reuters, Laila Kearney, "Exelon data center demand up 80% as utility navigates regulatory fight." (October 31, 2024).

relieve the constraints and import capacity into these “data center alleys,” or these large loads will have taken their own supply needs in hand. Conversely, to the extent that new data centers depend on completion of new regional generation currently languishing in the queue, they will be unable to go forward in the near-term, and the projects should not be treated as forecast load.

53. The VRR curves are anchored to the forecasted peak demand. Because of the inelasticity of capacity market demand curves around the forecasted capacity amount, small changes in demand can lead to relatively large changes in capacity market prices and therefore revenues. Therefore, any systematic upward bias in forecasted peak demand can inflate clearing prices significantly. Using the method described in paragraph 47 to translate peak demand to an overall capacity requirement, I estimate the difference in capacity requirements that has resulted from using higher forecasted peak demands compared to lower actual peak and weather normalized peak demands.

Table 2. Resource requirements calculated using forecast load, actual peak load, and weather-normalized peak load[55]

MW	2017/2018	2018/2019	2019/202O	2020/2021	2021/2022	2022/2023	2023/2024
Resource Requirement using Forecast Peak Load	165,007	160,607	157,092	154,355	153,161	132,257	131,820
Resource Requriement using Actual Peak Load	145,689	149,817	151,210	148,858	148,932	129,732	129,283
Resource Requirement using Weather Normalized Peak Load	150,340	148,908	149,044	148,352	150,284	132,163	132,000

54. If the market had cleared the offered supply against actual (as opposed to forecast) weather-normalized peak load requirements, and assuming a translation of the VRR curve parameters from PJM for the respective auctions and an inelastic supply curve to

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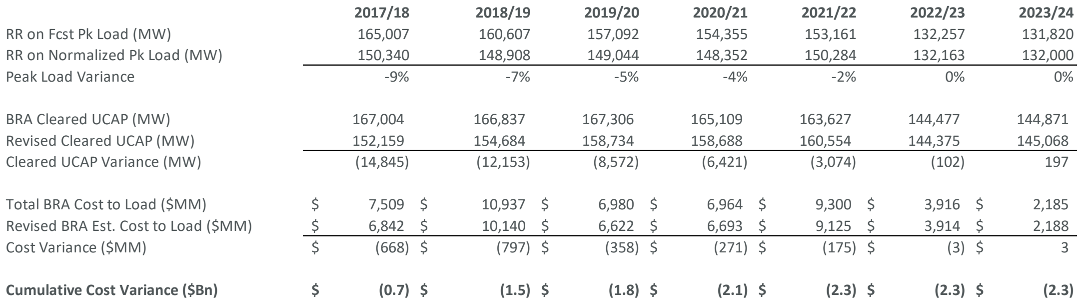
[55] Data sourced from PJM Base Residual Auction Reports for 2017/2018 BRAs through 2023/2024 BRAs and from PJM Load Forecast Report (January 2024).

the left of the original clearing point, the cleared quantities would have been 4% lower over the seven years as follows:

Table 3. Comparison of market clearing MW and costs using requirements based on forecast load and weather-normalized peak load[56]



	2017/18	2018/19	2019/20	2020/21	2021/22	2022/23	2023/24
RR on Fcst Pk Load (MW)	165,007	160,607	157,092	154,355	153,161	132,257	131,820
RR on Normalized Pk Load (MW)	150,340	148,908	149,044	148,352	150,284	132,163	132,000
Peak Load Variance	-9%	-7%	-5%	-4%	-2%	0%	0%
BRA Cleared UCAP (MW)	167,004	166,837	167,306	165,109	163,627	144,477	144,871
Revised Cleared UCAP (MW)	152,159	154,684	158,734	158,688	160,554	144,375	145,068
Cleared UCAP Variance (MW)	(14,845)	(12,153)	(8,572)	(6,421)	(3,074)	(102)	197
Total BRA Cost to Load ($MM)	$ 7,509	$ 10,937	$ 6,980	$ 6,964	$ 9,300	$ 3,916	$ 2,185
Revised BRA Est. Cost to Load ($MM)	$ 6,842	$ 10,140	$ 6,622	$ 6,693	$ 9,125	$ 3,914	$ 2,188
Cost Variance ($MM)	$ (668)	$ (797)	$ (358)	$ (271)	$ (175)	$ (3)	$ 3
Cumulative Cost Variance ($Bn)	**$ (0.7)**	**$ (1.5)**	**$ (1.8)**	**$ (2.1)**	**$ (2.3)**	**$ (2.3)**	**$ (2.3)**

55. Consumers would have saved roughly $2.3 billion over the past seven years on forecast improvements alone. Even if the actual savings are only a fraction of this total, making improvements to the load forecast must be a priority, and I provide recommendations for improving load forecasting in Section V, below.

M. PJM's Net CONE calculation overstates the cost of new capacity.

56. Net CONE is intended to represent the long-run marginal cost of supply in the capacity market. Net CONE ideally approximates the annual revenue that a competitive new resource needs from the capacity market, in addition to revenue from other sources, such as the energy and ancillary services markets, to be financially viable. Net CONE is a key parameter in shaping the VRR curve. The maximum price, inflection point, and zero crossing point are all calculated as a function of Net CONE.[57]

57. As an empirical matter, PJM's Net CONE calculation systematically overstates the cost of new entry.

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[56] Data sourced from PJM Base Residual Auction Reports for 2017/2018 through 2023/2024 BRAs and from PJM Load Forecast Report (January 2024).

[57] PJM, *2026/2027 RPM Base Residual Auction Planning Period Parameters* (August 26, 2024), p. 7.

58. PJM estimates Net CONE administratively by evaluating the costs of constructing and operating a hypothetical new generation resource. The determination of CONE depends on all the factors that influence the costs of a new plant, such as plant location, technology, and configuration; engineering, procurement and construction costs; other development costs; and the cost of capital.[58] The detailed approach used to develop CONE estimates belies the reality that the process suffers from false accuracy—the estimates depend on a series of choices, best guesses, and speculation.

59. Much of the disagreement over CONE estimates centers on the choice of technology for the proxy resource. PJM chose a combustion turbine as its reference technology in 2018, and the reference technology for the 2025/2026 auction is a combined cycle plant. That said, the CONE technology does not often bear much resemblance to the resources that are seeking to enter the market. Approximately 3% of capacity in the current PJM queue is natural gas fired, and only a subset of those resources are combined-cycle units, the current CONE proxy resource.

60. Administratively determined Net CONE estimates should be benchmarked against market results. In theory, if the estimates are sound, the long-term capacity market-clearing price should equal the estimated Net CONE. If the capacity market is meeting its objective of inducing new resources to enter the market with the quantity of capacity necessary to meet capacity requirements, then the capacity price should equal the additional revenue—beyond those earned through other sources—necessary to induce new resources to enter the market.

61. However, capacity prices in PJM have been consistently below Net CONE.

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[58] PJM OATT, Attachment DD, Section 5.10(a)(iv) and PJM Manual 18, Section 3.3.1.

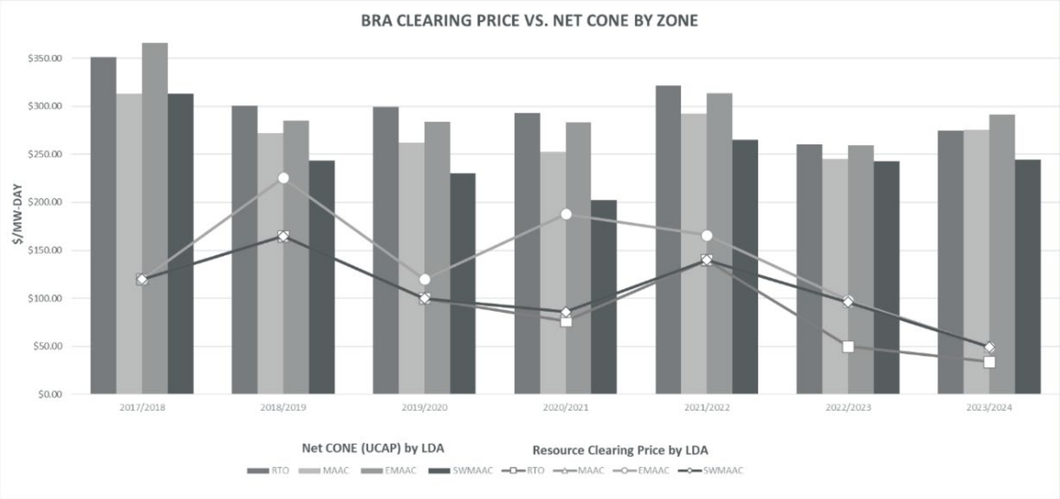

Figure 2. BRA clearing price vs. Net CONE by zone[59]

62. For the 2017/2018 through 2023/2024 time period, RTO-wide market prices averaged only 32 percent of RTO Net CONE values; over the same period, MAAC market prices averaged less than 40 percent of Net CONE values.[60] Because Net CONE is meant to represent the cost of entering the market, one should not expect market entry when market prices are below Net CONE. But the facts are to the contrary. In eight of the last eleven auctions, thousands of megawatts of new capacity cleared the PJM capacity market annually despite BRA auction prices well below Net CONE.[61] Figure 3 below shows this same phenomenon over the period of 2017/2018 through 2023/2024.

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[59] Data sourced from PJM Base Residual Auction Reports for 2017/2018 BRAs through 2023/2024 BRAs and from PJM Load Forecast Report (January 2024).

[60] Net CONE values have been greater than market prices for every market year in both zones since 2010.

[61] PJM 2025/2026 Base Residual Auction Report at 7, fig. 2 (July 30, 2024). The markedly dysfunctional 2024/2025 auction cleared the lowest amount of new generation in this time period. *Id.*

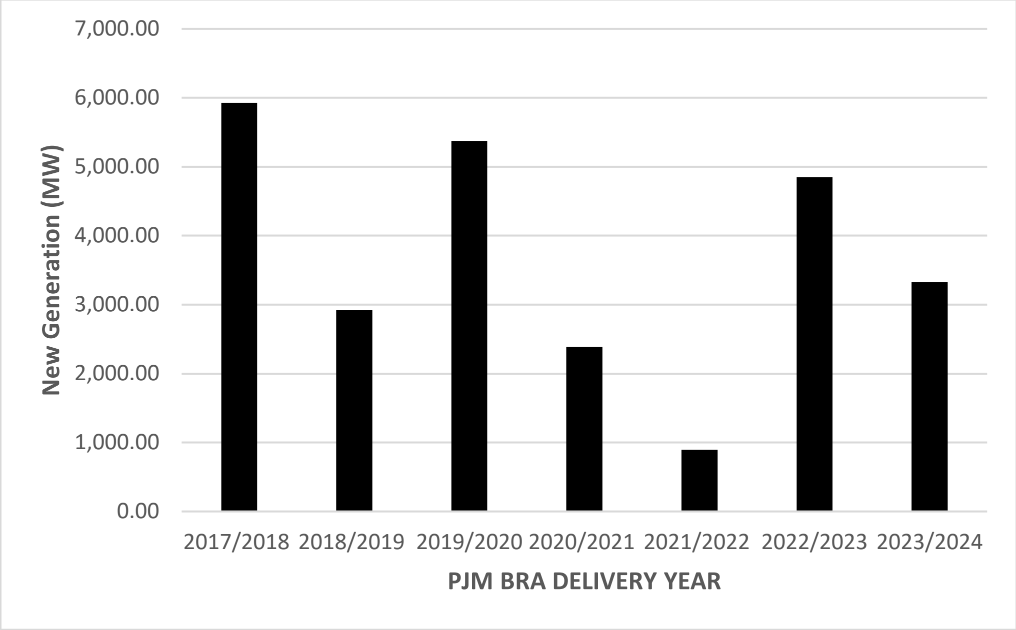

Figure 3. New generation MW entry by PJM BRA delivery year[62]

63. The complex administrative process used to estimate Net CONE is unnecessary and leads to Net CONE values that are inconsistent with the actual cost of new entry as reflected in the auction data evaluated above. Instead, the value of the Net CONE could be determined more straightforwardly and defensibly by reference to the actual cost of new entry, which is the market clearing price of the auction. I provide a detailed explanation of this approach in my long-term recommendations, below.

N. PJM's ELCC approach is a long-term design problem.

64. The adoption of the ELCC accreditation method for all resources in the 2025/2026 BRA is another factor contributing to an alleged new "shortage" of resources in the BRA. According to PJM's estimates, the "supply reduction" resulting from the transition to an ELCC approach for all resources amounted to more than 28,000 MW.

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[62] Data sourced from PJM Base Residual Auction Reports for 2017/2018 through 2023/2024 BRAs.

That reduction needs to be considered in the context of a parallel and related reduction in the BRA Reliability Requirement of approximately 25,000 MW—still, the change in method created an apparent *new* missing 3,000 MW of generation that does not in itself reflect any change to the fleet of resources available to provide capacity.[63]

65. Additionally, PJM's assumptions overweight the impact of winter conditions (including Winter Storm Elliott) on overall resource adequacy. Arguably, at least some of the PAI events during Winter Storm Elliott were due to PJM's operating decisions, and not entirely the failure of generation. The heavy winter weighting of past event-specific performance failures, combined with the assumptions about use of summer ratings for gas-turbine based technology, adversely impacts the natural-gas fleet. As a result of these choices, gas-fired combined cycle units with 5% forced outage rates, many of which have made incremental hardening investments, are now being discounted by over 20% for the purpose of measuring their reliability contributions.

O. PJM's approach to modeling transmission topology does not clearly capture the interaction between the need for local resources and the impact of new transmission.

66. PJM's approach to modeling LDA requirements does not adequately capture how planned transmission upgrades will address criteria violations and how they will impact local capacity requirements in the delivery year or soon thereafter. The goal is to ensure that the impact of a transmission project on the need for local resources to meet resource adequacy requirements is to the greatest extent possible properly reflected in the right timeframe. Doing so will help to make certain that the resulting requirements and prices

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[63] PJM, *2025/2026 Base Residual Auction Results*. Presentation to the Markets & Reliability Committee (August 21, 2024), Slides 23 & 26.

are consistent with the likely conditions a new capacity resource would face upon the in-service date of the transmission facility—even if an RMR resource is retained to cover an interim exposure.

V. RECOMMENDED MARKET REFORMS

67. The discussion above summarizes the problems in the PJM capacity market design that have been highlighted by the 2025/2026 BRA results. In this section, I suggest market reforms that could help to address these design issues.

A. Near-Term Reforms

1. Eliminate Exempt Resources

68. Non-participation in capacity markets by exempt resources means that thousands of MWs of capacity that is actually serving load and contributing to reliability is not competing with other incumbent generation in the BRA. I recommend that PJM adopt revisions to its tariff to require that all existing eligible capacity resources that contribute to resource adequacy in the operating timeframe must participate in the capacity auction under the existing must-offer construct that applies to thermal generation. These reforms would impact currently exempted resources, including RMR, intermittent resources, battery storage, and DR.

69. PJM's Answer to the Complaint filed by Sierra Club and others in Docket No. EL24-148-000 raises objections to the proposal that RMR resources be required to offer into the capacity market. PJM notes that RMR arrangements are often focused on transmission reliability, not resource adequacy; that for the specific resources in question in that docket (Brandon Shores and Wagner), limitations exist on their ability

to provide capacity;[64] that RMR units are not required by their agreements to participate in capacity markets;[65] that PJM has no authority to keep resources on past the 90-day notice period;[66] and that extending capacity market obligations to RMR resources may impose costs on these resources.[67] All of these objections, however, refer to particular agreements, practices, and rules that can be changed. For example, the 90-day retirement notification window could be increased to correspond with the RTEP planning window so that the impact of retirements can be evaluated sufficiently in advance to allow transmission needs to be met through competitive solicitation, and capacity needs to then be addressed through the RPM—thus minimizing the need for an RMR in the first instance.

70. Recall that a retirement decision cannot be wholly private, as it has public impact. The expansion of the transmission system to provide additional firm service and the interconnection of new resources around existing capacity are all made so as to protect the incumbent from adverse impacts and preserve its CIRs. Thus, while it might seem reasonable to allow an existing capacity resource to exit the market when it wants to, the broader, practical impacts on the market, the performance of the integrated power system, and other transmission customers, must be weighed. It is reasonable and proper for PJM to revise its tariff to require resources whose retirements would cause an adverse reliability impact to enter RMR arrangements that will last no longer than the time necessary to implement other measures that will ensure system reliability. It is also

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[64] PJM Answer at 7-11, 21-26.

[65] *Id.* at 20.

[66] *Id.* at 19.

[67] *Id.* at 38.

reasonable and proper to require such resources to provide all services to the market—including RPM participation—in exchange for receiving appropriate, FERC-approved compensation.

71. The IMM and the PIOs have recommended that the capacity associated with an RMR be offered into the BRA as a price taker (at a zero price). It may also be reasonable for the clearing price in the LDA to be set to Net CONE—not the administrative value currently used, but the alternative formulation based on actual results that I recommend below. This approach addresses concerns that the forward price signal would be watered down by a zero offer from the RMR resource. With this approach, if the RMR resource is marginal, it will set a price at the empirically adjusted cost of new entry (not an arbitrarily high number), close to the true cost of new entry. If a new entrant enters at a price below that, it would displace the RMR resource in whole or in part as extra-marginal. The important thing is to reflect this capacity in the market, rather than asking ratepayers to pay for it (as they do now) effectively three times—in the cost of the RMR, the cost of transmission upgrades to address local import constraints, and then again in elevated local capacity market clearing prices—while not recognizing it in the auction.

72. Requiring RMR, intermittent, and other currently exempt resources to offer into the PJM markets may pose problems without other rule changes, because these resources will be fully exposed to PAI penalties even though some of them may have no practical way of managing that exposure. RMR and intermittent resources are arguably differently situated from thermal resources and each other as regards the impact of the PAI as a real performance incentive. The performance requirements that apply to an

RMR resource should be built into the terms and conditions of the RMR arrangement; the expected performance of an intermittent resource is built into its ELCC value.

73. I propose that intermittent and battery storage resources be excused from PAI penalties if they are operating at maximum *possible* output during the PAI event. The output of intermittent resources such as wind, solar, and hydro (as well as shorter duration battery storage) resources is largely determined by nature, and these resources are almost all but guaranteed to operate when the relevant "fuel" source is available.[68] Conversely, they cannot operate without such fuel, regardless of penalties. Importantly, the ELCC calculations already account for these limitations in assessing the probability that intermittent and battery storage resources will not be available during hours when loss of load would be likely, so penalizing them for not performing under conditions contemplated in their accreditation is unnecessary and punitive. Logically, a solar facility cannot produce energy at night and is not expected to do so under the reliability model, so applying a penalty for the failure to perform at night, for example, provides no incremental incentive and cannot improve performance.

74. As regards the feasibility of implementation, the IMM currently calculates mitigated offers for these resource classes, and the provisions to challenge and request a unit-specific offer exist and require no modification.[69]

75. In addition to the generation resources mentioned above, I recommend that PJM modify its tariff to change the way DR participates in the auction in two ways. First, I recommend that DR be required to submit BRA offers that reflect the maximum

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[68] The relevant "fuel" source being system power that is already in the tank. Short duration battery storage will chase high prices, which are most often correlated with—although imperfectly so—high loads.

[69] PJM, *OATT*, Attachment M, Appendix, Section D.

dispatchable demand reduction that the resource is making available to PJM. The performance of DR would then be measured as the actual reduction delivered (metered consumption before instruction less metered consumption after instruction) in response to a dispatch instruction during a PAI event. The current treatment compares consumption during a PAI event to the resource's claimed maximum consumption. The DR is credited for this difference, even if during the event DR delivers no reduction in consumption (it would have been consuming at the current level irrespective of system conditions), thus having no impact on the load that must be served. Adopting this change in the way DR is offered and delivered would facilitate my second recommendation, which is that the IMM evaluate the opportunity cost of demand reductions and use this to calculate mitigated DR offer prices (offer caps) that PJM would then impose when structural market power tests fail.

2. Give Queue Priority to Resources in Constrained LDAs

76. I propose that PJM revise its queue management procedures to give study priority to study-ready projects in the interconnection queue that are siting in (likely to be) constrained LDAs. A project with an ISA in hand would have reasonable confidence, based on the historical time it takes to build interconnection facilities (the most recent Lawrence Berkeley National Lab data finds an average duration from Interconnection Agreement to commercial operation—including completion of required transmission upgrades—of approximately 20 months in PJM in 2023),[70] that the interconnection facilities would be completed and transmission service could begin prior to the delivery

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[70] Lawrence Berkeley National Laboratory. Queued Up: 2024 Edition (April 2024), slide 39.

year as required under the tariff.[71] This rule change would provide a logical means of offering priority to certain queue projects, rather than forcing them to wait to go through the cluster process.[72]

77. The goal of this proposal is to maximize the eligible supply available to the BRA, including within LDAs, making it contestable, as the design intended. In a preliminary review of the 2025/2026 BRA, the IMM analyzed the impact of nearly 2,000 MW of RMR resources in BGE choosing not to offer into the market. The IMM found that inclusion of these resources in the supply curve at $0/MW-day would have reduced BRA costs by $4.3 billion, or 29.2% of the actual $14.7 billion cost.[73] The IMM's sensitivity analysis found that excluding RMR resources from capacity markets resulted in 1,441 MW less cleared UCAP,[74] and by implication the inclusion of RMR resources would have caused the RTO clearing price to drop from about $270/MW-day to $167/MW-day (38%) while the BGE LDA price would have dropped from $466/MW-day to $167/MW-day (64%).[75]

3. Tie unit ratings to winter performance

78. PJM's policy of tying the capacity ratings of CC and CT units to summer performance for the purpose of setting UCAP values understates the reliability value these resources

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[71] PJM, *Manual 18*, Section 4.2.3.

[72] Projects entering the queue since September 2021 will not be eligible to begin the interconnection process until January 2026, at the earliest, which is the target for the first cluster study. For PJM's transition timeline, see PJM, *Interconnection Process Reform*, Presentation to the Markets and Reliability Committee (April 27, 2022): 62.

[73] The Independent Market Monitor for PJM, *Analysis of the 2025/2026 RPM Base Residual Auction Part A* (September 20, 2024), Table 2, p. 12.

[74] The Independent Market Monitor for PJM, *Analysis of the 2025/2026 RPM Base Residual Auction Part A* (September 20, 2024), Table 5, p. 14.

[75] IMM 9/20/24 "Analysis of the 2025/2026 RPM Base Residual Auction Part A", tables 2 (p 12) and 5 (p 14); $168/MW-day Daymark calculated.

provide in the winter. The IMM estimates that limiting CC and CT resources to their summer ratings undercounted their capacity value by about 5,400 UCAP MW in the last BRA.[76] PJM believes these values are overstated, but agrees that there is likely some additional capacity value that could be recognized under different rules, stating that PJM "supports the pursuit of rule changes that could make available additional winter capacity from thermal resources," and that this issue is being considered in PJM's Markets and Reliability Committee.[77] This change should be given a high priority—there is potentially a significant amount of unrecognized capacity at stake, and clearing prices that ignore "real" capacity do not properly represent the available supply and will be artificially inflated, particularly in the foreseeable circumstances where substantial new entry cannot enter the market.

79. In summary, these near-term reform proposals are aligned with addressing two fundamental concerns. First, new entry cannot enter the market in sufficient quantity to discipline the market power of incumbent resources. This is happening at a time when PJM has expressed concern that the capacity situation in the region is becoming ever tighter. Requiring currently eligible but exempt resources to bid into the auction increases auction supply and compensates to some degree for the lack of adequate new entry. In addition, requiring the auction participation of these eligible but currently exempt resources limits the exercise of market power through withholding. And, as there are many thousands of MW of resources that in actual operations support

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[76] The Independent Market Monitor for PJM, *Analysis of the 2025/2026 RPM Base Residual Auction Part A* (September 20, 2024), Table 6, p. 10. UCAP MW value derived in paragraph 41 based on change in AUCAP.

[77] PJM. *PJM Response to Independent Market Monitor Report on 2025/2026 Base Residual Auction* (October 11, 2024), 8.

reliability but sit out of the capacity market, PJM's concern about shortages is likely overstated, perhaps substantially. Second, efforts to recognize the reliability attributes of all eligible resources and bring more supply to the auction will improve auction competition and pricing performance. The difference between a constrained clearing and the extraordinary price outcomes seen in the 2025/2026 BRA and an unconstrained clearing and the substantially lower prices seen in the 2024/2025 BRA is only a few hundred MWs. Moreover, as the exempt resources that did not participate impact system performance and prices, any party looking at the BRA price outcomes would be forced to discount the price as not truly reflective of the conditions that may be in place when the new resource commences operation.

B. Long-Term Reforms

80. Competitive markets are driven by supply and demand, but under current rules demand has no choice as to how it participates in the capacity market. Instead, as is done for all RTO-administered capacity markets, PJM creates demand administratively. PJM's stated objective is to draw a demand curve (i.e., the VRR curve) that produces the "best combination of adequate generation reserves and reliability for reasonable cost."[78] The VRR curve is primarily a function of two parameters: the capacity requirement and the Net CONE. The capacity requirement defines the quantity axis, and Net CONE defines the price axis. However, simple analysis shows that for various reasons PJM's VRR curve procures more capacity at higher cost than needed to meet the reliability requirement.

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[78] PJM Interconnection, L.L.C. Filing in Docket Nos. ER05-1440 and EL05-148-000 requesting FERC approval for the RPM, p. 68.

1. Address Systematic Over-forecasting

81. As discussed above, there is a pattern of repeated load forecast inflation by PJM. I recommend that PJM consider design changes that reduce forecasting error, increase accuracy and reduce bias. Given the difficulty of forecasting out three years for the forward auction, consideration should be given to reducing the forecast period by adjusting the time between the conduct of the auction and delivery year. Empirically, the improved forecast accuracy observed over the past couple of BRAs suggests that reducing the forecast period may be beneficial.

82. To address the timing challenge, rather than procure the entire requirement forward through the BRA, PJM could purchase a portion forward and use the incremental auctions to top off if short or shed if long. The idea here is to recognize that the forecast tends to be wrong and biased high, and so to purchase a fraction, say 95% of the capacity that the forecast suggests is required through the BRA, and then to purchase additional capacity through the incremental auctions if it looks like the actual loads are consistent with the forecasted load. This approach would be the capacity market equivalent to dollar cost averaging in an asset portfolio and would take some of the risk and cost of forecast error off the load.

2. Revise the calculation of Net CONE

83. As discussed above, PJM's CONE calculation systematically overstates the cost of new entry. A better approach would utilize the actual cost of new entry as revealed by the capacity market itself. Consider an example methodology that establishes Net CONE as the sum of two components: 1) a moving weighted average (weighted on total new unit capacity clearing in the auction) of clearing prices for a rolling 5-year historical reference period; and 2) one half of the range between the minimum and the maximum

clearing price from the same 5-year period. The first component captures the central tendency of recent auction prices that lead to actual new entry, while the second component conservatively accounts for historical spread in setting VRR curve parameters. Historical prices are adjusted to inflation-adjusted 2025 dollars using the Commission's oil pipeline index as revised in RM20-14-001. Table 4, below, shows how RTO Net CONE would have been calculated for the 2025/2026 BRA based on this methodology. The Alternative Net CONE value is 64% of the actual Net CONE used in the 2025/2026 BRA ($228.81/MW-day), and 32% of the Gross CONE value ($451.61/MW-day) is used to set the highest point of the VRR curve.

Table 4. Illustration of alternative Net CONE methodology

Row	Item	Source	2020/21	2021/22	2022/23	2023/24	2024/25	2025/26
1	RTO Net CONE ($/MW-day)	BRA Results	$ 292.95	$ 321.57	$ 260.50	$ 274.96	$ 293.19	$ 228.81
2	RTO Clearing Price ($/MW-day)	BRA Results	$ 76.53	$ 140.00	$ 50.00	$ 34.13	$ 28.92	
3	Oil Pipeline chain-type index (2025=1.000)	18 C.F.R. § 342.3	0.769	0.784	0.780	0.856	0.978	1.000
4	RTO Clearing Price (2025$/MW-day)	(2) / (3)	$ 99.53	$ 178.47	$ 64.11	$ 39.89	$ 29.57	
5	Cleared New Gen Unit Capacity (UCAP MW)	BRA Results	2,389	893	4,844	3,330	329	
6	Weightings (thousand 2025$/day)	(4) * (5) / 1,000	238	159	311	133	10	
7	Wgt Avg RTO Clearing Price ($/MW-day)	∑row(6) / ∑row(5) * 1,000						$ 72.15
8	50% of Clearing Price Range ($/MW-day)	50% * { MAX[row(4)] - MIN[row(4)] }						$ 74.45
9	**Alternative Net CONE ($/MW-day)**	**(7) + (8)**						**$ 146.60**

84. This approach would be purely mechanical and operate as a formula. The current method is often controversial, as it involves making judgement calls about inputs that produce a number that impacts the wallets of both generators and loads. Switching to a formulaic Net CONE based on historical market results would replace false precision with an empirical calculation.

85. In other words, the proposed methodology outlined here has merit both because it is empirically grounded in market and developer performance and because the alternative—continuation of the status quo—is so harmful to customers. I have

attempted to estimate the impact of systematically overstating Net CONE. Assuming a fairly inelastic supply and the quantity offered into the auction, I compared the market results of the VRR curve PJM used for the 2025/2026 auction with the modeled results of an adjusted demand curve based on a Net CONE calculated as described above. I reduce the value of Net CONE to $146.60/MW-day for the RTO-wide and DOM LDA and *increase* the value of Net CONE for the BGE LDA to $224.24/MW-day as an estimate of the *proper* Net CONE. The figure below compares the actual VRR curves used in the 2025/2026 BRA to curves adjusted to use my proposed Net CONE values.

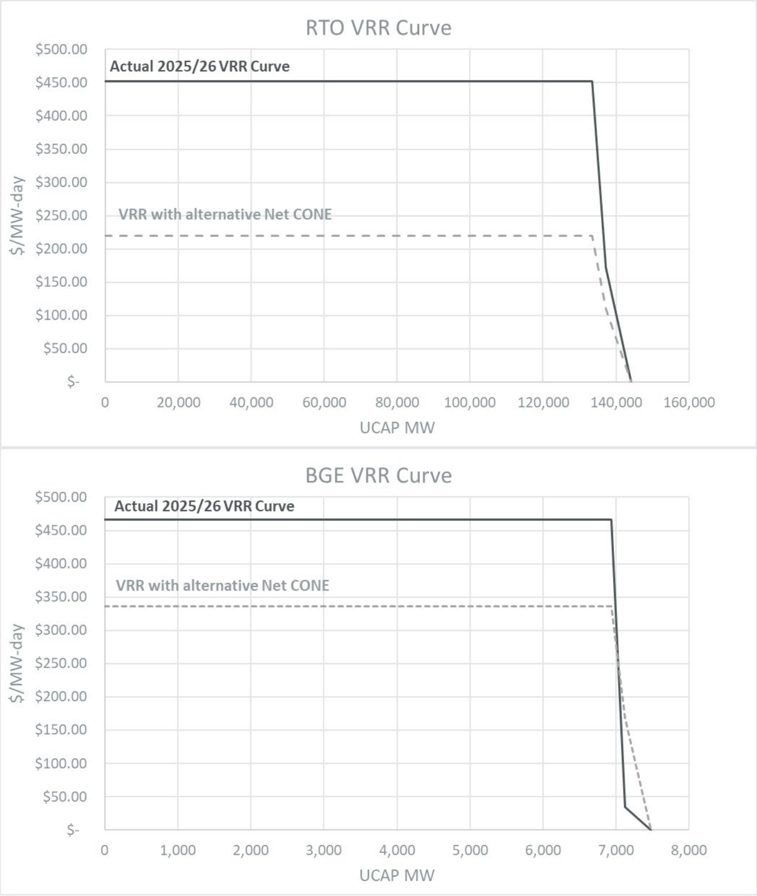

Figure 4.4. Actual and adjusted VRR curves for 2025/2026 BRA

86. For the actual 2025/2026 PJM BRA, the equilibrium quantity was 135,684 UCAP MW and the price was $269.92/MW-day, with total capacity market revenues of about $14.7 billion. Using the adjusted demand curve based on a proper Net CONE level, rather than the overestimated Net CONE, would have decreased quantity cleared by 2,130 MW and total BRA cost to load would have decreased $4.0 billion from $14.7 billion to $10.7 billion.

87. PJM uses a host of historical data in its market planning. Using a rolling average of actual market results to set Net CONE would be consistent with the approach I am suggesting. It has the benefit of linking the cost of new entry to the prices at which real projects have opted to take on capacity obligations, as opposed to a hypothetical project which may never enter the market. The upcoming 2026/2027 auction curves are a ready-made example of the odd impacts on the VRR curves that are experienced when using the current method to administratively set the Net CONE value.

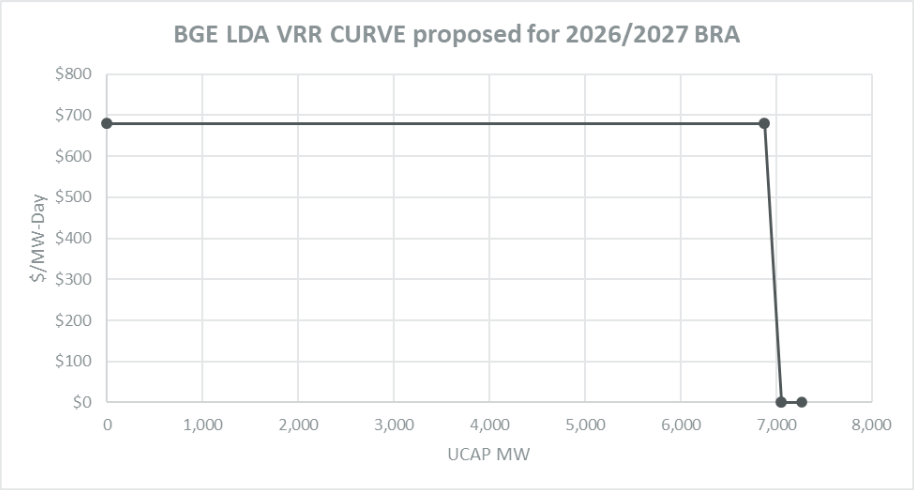

Figure 5.5. BGE LDA VRR curve proposed for 2026/2027 BRA[79]

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[79] PJM, *Planning Period Parameters for 2026/27* BRA (2024). https://www.pjm.com/-/media/markets-ops/rpm/rpm-auction-info/2026-2027/2026-2027-planning-period-parameters-for-base-residual-auction.ashx .

These curves are essentially vertical demand curves that tell the market that, depending on very small differences in supply, the capacity price should either be a multiple of CONE or zero. Suppliers will have a tough time making investment decisions based on such wildly divergent possible outcomes.

88. Rather than use arbitrary multiples of CONE values that we know will not match actual new entry and would serve in the interim only to extract rents from load, the empirical Net CONE provision could be adjusted by a simple scaling percentage, e.g., a 25% adder, if capacity margins are tightening and no resources are in the interconnection queue that would add supply in a timely way.

VI. OTHER REFORM CONSIDERATIONS

1. Revise the ELCC Method

89. Consistent with what I discussed above, I recommend that PJM revise its ELCC calculation methodology to reflect a more complete and accurate set of going forward operating data. I have already recommended tying unit ratings to winter performance as a short-term reform. However, the problems with the ELCC methodology are broader than this. As calculated, the ELCC calculation does not properly measure the expected reliability contribution of each resource in each hour—intermittent resources, such as solar, that cannot operate at night are implicitly and erroneously assumed to contribute to reliability during those hours. Resource performance during historical events, such as Winter Storm Elliott (an event during which gas resources generally under-performed), is over-weighted in the calculations. New resources and investments in dual fuel and other availability enhancements are not properly reflected in ELCC—the class average is assigned. The IMM has quantified the impact on costs of the shift from the old equivalent demand forced outage rate approach to the ELCC approach in

the 2025/2026 BRA and finds that (holding everything else equal) the change to the ELCC approach resulted in increased BRA costs of more than $4.4 billion.[80]

90. At a minimum, the observed reduction in capacity value for gas-fired combined cycle units is material and merits an investigation by FERC to determine if the methods and assumptions are consistent with performance expectation and are not systematically underestimating reliability contributions of these resources. If PJM is systematically underestimating the reliability value of much of the gas-fleet, that may hasten retirements, the exact opposite of the preferred outcome.

2. Modeling Transmission Topology

91. PJM should consider an approach to modeling multi-value transmission upgrades that captures both how they address criteria violations and how they impact local capacity requirements. The important goal is to ensure that to the greatest extent possible, the impact of a transmission project on the need for local resources to meet resource adequacy requirements is properly and timely reflected in resource requirement calculations to ensure that the resulting capacity requirements and prices are consistent with likely conditions upon the in-service date of the transmission facility— even if an RMR resource is retained to cover an interim exposure.

92. For internal consistency, either (1) RMR units should not be included in either PJM's CETO/CETL parameter analysis for capacity auctions, instead using the planned transmission solution, or in the capacity market supply curve; or (2) RMR units should

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[80] The Independent Market Monitor for PJM. *Analysis of the 2025/2026 RPM Base Residual Auction Part A* (September 20, 2024), 8.

be included in both PJM's CETO/CETL parameter analysis for capacity auctions and in the capacity market supply curve.

3. Price Capacity Value of Transmission

93. Transmission needs and resource requirements are connected. Strategic transmission investment can minimize overall capacity requirements and/or address capacity shortages within LDAs by allowing resources to serve a wider load base and avoid curtailment. Currently, as discussed above, in constrained LDAs with RMRs, high capacity prices can be sending signals for capacity investment that are likely to collapse once planned transmission upgrades are completed. There are steps PJM can take to promote synergies. For example, PJM should consider reforms beyond those associated with resource retirements discussed above that better align RTEP competitive windows and/or allow transmission projects that reduce local resource adequacy needs to bid and compete against other resources through the BRA. This approach would explicitly recognize that certain transmission projects can reduce the cost of maintaining resource adequacy, enhance the deliverability of existing resources, and reduce the effects of contingencies. To properly value these multiple attributes and provide incentives to build transmission that lowers the cost of resource adequacy, the reduction in reserve requirement (a transmission *avoided capacity* accreditation amount) should be biddable into the BRA. If that resource clears, it is built out and receives a capacity payment.

VII. CONCLUSION

94. The results of the 2025/2026 BRA illustrate the fundamental dysfunction of the market design. The auction cleared 135,684 UCAP MW of resources at a total cost of almost $14.7 billion, with two LDAs failing to clear minimum local requirements. To address these dysfunctions, PJM should adopt the proposed near-term and long-term reforms.

95. In the near-term, PJM should:

    a. Reform its capacity market rules to require all eligible resources to participate in the BRA for the 2026/2027 Delivery Year, including those resources that previously were categorically exempt from the must-offer requirement.

    b. Modify its Tariff to require a longer notice period for generator deactivations and to adopt standardized RMR tariff provisions and a *pro forma* RMR Agreement that enables PJM to delay existing resource retirements for as long as the resource remains needed for reliability. Where continued service is mandated, the Tariff should provide compensation at a full cost-of-service rate including a return on investment. And in exchange, RMR resources should participate fully in all PJM capacity, energy, and ancillary service markets for which they are eligible, including offering capacity as a price taker in each BRA for a delivery period that will occur during the term of the arrangement.

    c. Impose an offer cap upon DR resources participating in the PJM capacity market when structural market power tests fail.

    d. Require DR resources that bid into the BRA to submit offers that reflect the maximum dispatchable demand reduction that the resource is making available to PJM, and measure performance as the actual reduction delivered (metered consumption before instruction less metered consumption after instruction) in response to a dispatch instruction during a system stress event.

    e. Revise its interconnection queue management approach to give priority to study-ready projects that will be sited in LDAs that are more likely to be constrained.

    f. Determine the capacity value of gas-fired generators using winter capacity ratings that seasonally match the main risks for which those resources' capacity values are discounted in PJM's ELCC calculations.

96. In the long-term, PJM should:

    a. Address systematic over-forecasting to reduce costly over-procurement of capacity.

    b. Revise the calculation of Net CONE to reflect the actual CONE as revealed by capacity market clearing prices.

    c. Revise its ELCC calculation methodology to reflect a more complete and accurate set of going forward operating data.

    d. Consider an approach to modeling multi-value transmission upgrades that captures both how they address criteria violations and how they impact local capacity requirements.

e. Consider reforms to better align RTEP competitive windows and/or allow transmission projects that reduce local resource adequacy needs to bid and compete against other resources through the BRA.

97. To illustrate the potential impact of these proposed reforms, I estimate the impact some of these changes would have had on the 2025/2026 BRA. I do not have detailed bid data from the auction, so make some assumptions and extrapolations to estimate how the auction would have cleared. I derive some information about the original supply curve from scenario results reported by the IMM.[81] Inspection of the smoothed RTO supply curve for the 2025/2026 BRA[82] suggests that at least 75% of supply offers would be price-takers offering at near-zero prices. I then linearly interpolate between the price-takers and the upper end of the supply curve. I make the following adjustments to reflect the specific market reforms proposed in this declaration:

a. Peak load forecast adjusted down 4% to account for persistent forecast bias observed in prior seven-year history (paragraphs 46-55);

b. Net CONE adjusted to $146.60/MW-day for RTO and $224.24/MW-day for BGE; Gross CONE removed from VRR curve formulation (paragraphs 56-63);

c. Wagner (RMR resource) offered in 527 MW (UCAP) at offer price equal to the BGE Net CONE (paragraphs 34-36);

d. 1,596 MW (UCAP) of unoffered exempt resources offered at $0 (paragraph 38);

e. Winter ratings used for capacity ratings of CCs and CTs, increasing UCAP MW by 5,439 MW (UCAP) (paragraphs 40-41).

98. With these changes, the BRA clears 136,812 UCAP MW at a price of $106.31/MW-day. The DOM LDA no longer separates from the RTO. The BGE LDA clears 761 MW

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[81] The Independent Market Monitor for PJM, *Analysis of the 2025/2026 RPM Base Residual Auction Part A* (September 20, 2024). Scenarios 4A-4C involve the same supply curve (including higher winter ratings for CCs and CTs) clearing against 3 slightly different VRR curves. The three clearing points reported in Table 6 can be used to estimate three price/quantity pairs on the supply curve, assuming the scenarios cleared at the intersection of the VRR curve.

[82] PJM, *2025/2026 BRA Supply Curves* (September 13, 2024), at p. 1. https://www.pjm.com/-/media/markets-ops/rpm/rpm-auction-info/2025-2026/2025-2026-bra-supply-curves.ashx.

at a price of $224.24/MW-day. The total BRA cost to load is $5.364 billion,341 million, a reduction of $9.320 billion (63,346 million (64%) from actual BRA results. The example illustrates the tremendous cost burden imposed on load for market design problems in the 2025/2026 BRA that do not improve reliability.

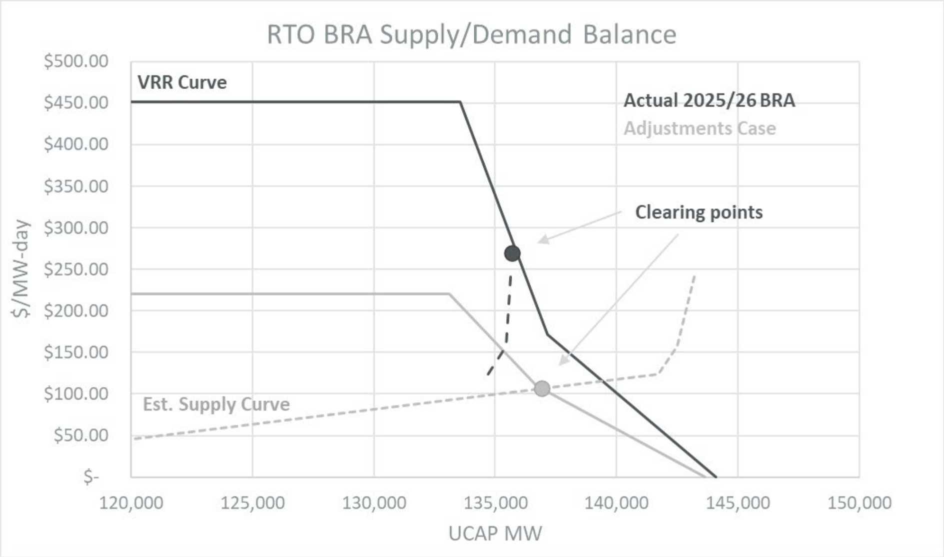


Figure 6.6. Modeled RTO supply/demand balance in 2025/2026 BRA

99. This concludes my declaration. A copy of my workpapers appears at Exhibit 1. I declare under penalty of perjury that the foregoing is true and correct. Executed on November 18, 2024.

/s/ Marc D. Montalvo
Marc D. Montalvo

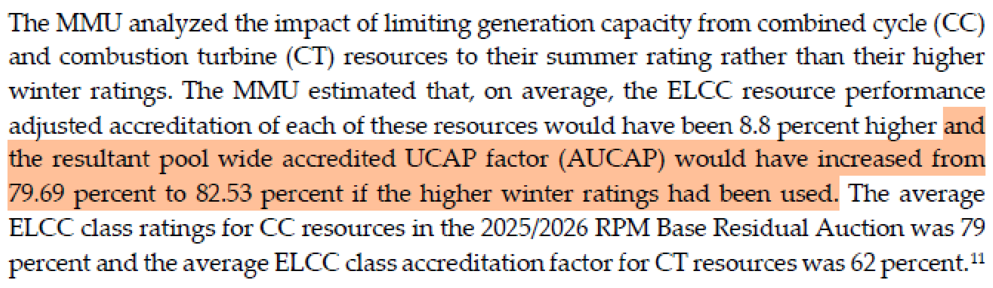
Dated: November 18, 2024

	Value	Source
Pool wide Accredited UCAP MW	152,765	(b)
Total ICAP MW in model	191,693	(b)
Pool wide AUCAP Factor	0.7969	(b)
IMM Est. AUCAP with winter ratings	0.8253	(a)
Implied Accredited UCAP MW with winter ratings	158,204	calc
Increase due to winter ratings (UCAP MW)	**5,439**	calc

Source:	(c) Gas Combined Cycle	Gas Combined Cycle Dual	Gas Combustion Turbine	Gas Combustion Turbine Dual	Total Gas	Source
Existing ICAP MW	55,028	2,435	12,478	12,958	82,900	(c)
Final Class Avg ELCC	79%	79%	62%	79%		(d)
Est. UCAP MW (assume class av	43,472	1,924	7,737	10,237	63,369	calc
Winter rating adj					8.80%	(a)
Est. UCAP MW with winter Adj					68,945.88	calc
Increase due to winter ratings (UCAP MW)					5,577	calc
Existing ICAP - DOM	6,860	2,170	323	3,508	12,861	(c)
Existing ICAP - BGE	-	-	-	249	249	(c)
Est. UCAP - DOM	5,419.24	1,714.46	200.20	2,771.64	10,106	calc
Est. UCAP - BGE	-	-	-	196.55	197	calc
Est. UCAP with Winter Adj - DOM					10,994.82	calc
Est. UCAP with Winter Adj - BGE					213.85	
Increase UCAP from winter ratings - DOM					889.29	
Increase UCAP from winter ratings - BGE					17.30	

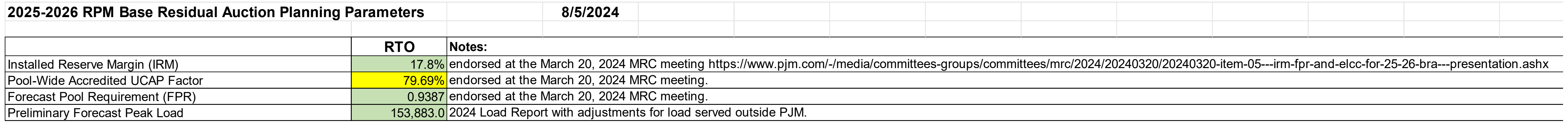
Sourcing:

(a) From IMM, Analysis of the 2025/2026 RPM Base Residual Auction, Part A , p 10



The MMU analyzed the impact of limiting generation capacity from combined cycle (CC) and combustion turbine (CT) resources to their summer rating rather than their higher winter ratings. The MMU estimated that, on average, the ELCC resource performance adjusted accreditation of each of these resources would have been 8.8 percent higher and the resultant pool wide accredited UCAP factor (AUCAP) would have increased from 79.69 percent to 82.53 percent if the higher winter ratings had been used. The average ELCC class ratings for CC resources in the 2025/2026 RPM Base Residual Auction was 79 percent and the average ELCC class accreditation factor for CT resources was 62 percent.[11]

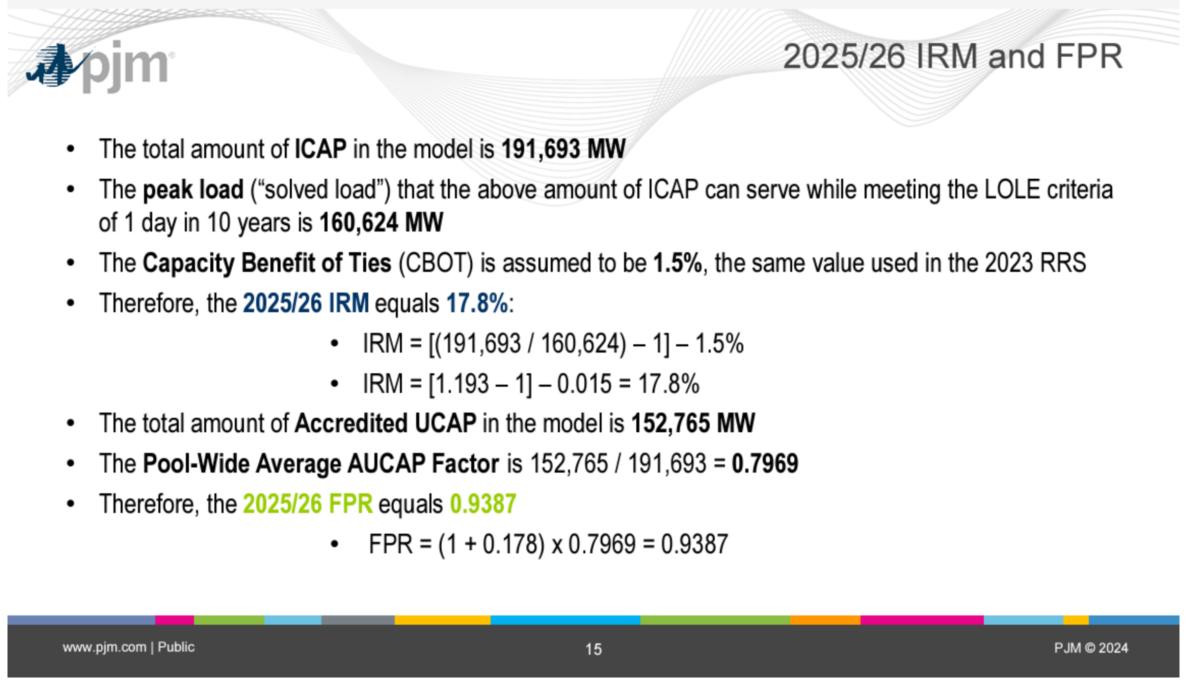
From 2025-2026 RPM Base Residual Auction Planning Parameters
https://www.pjm.com/-/media/markets-ops/rpm/rpm-auction-info/2025-2026/2025-2026-planning-period-parameters-for-base-residual-auction.ashx



2025-2026 RPM Base Residual Auction Planning Parameters **8/5/2024**

	RTO	Notes:
Installed Reserve Margin (IRM)	17.8%	endorsed at the March 20, 2024 MRC meeting https://www.pjm.com/-/media/committees-groups/committees/mrc/2024/20240320/20240320-item-05---irm-fpr-and-elcc-for-25-26-bra---presentation.ashx
Pool-Wide Accredited UCAP Factor	79.69%	endorsed at the March 20, 2024 MRC meeting.
Forecast Pool Requirement (FPR)	0.9387	endorsed at the March 20, 2024 MRC meeting.
Preliminary Forecast Peak Load	153,883.0	2024 Load Report with adjustments for load served outside PJM.

(b) From presentation to the March 20, 2024 Markets & Reliability Committee, slide 15:
https://www.pjm.com/-/media/committees-groups/committees/mrc/2024/20240320/20240320-item-05---irm-fpr-and-elcc-for-25-26-bra---presentation.ashx



2025/26 IRM and FPR

- The total amount of **ICAP** in the model is **191,693 MW**
- The **peak load** ("solved load") that the above amount of ICAP can serve while meeting the LOLE criteria of 1 day in 10 years is **160,624 MW**
- The **Capacity Benefit of Ties** (CBOT) is assumed to be **1.5%**, the same value used in the 2023 RRS
- Therefore, the **2025/26 IRM** equals **17.8%**:
  - IRM = [(191,693 / 160,624) – 1] – 1.5%
  - IRM = [1.193 – 1] – 0.015 = 17.8%
- The total amount of **Accredited UCAP** in the model is **152,765 MW**
- The **Pool-Wide Average AUCAP Factor** is 152,765 / 191,693 = **0.7969**
- Therefore, the **2025/26 FPR** equals **0.9387**
  - FPR = (1 + 0.178) x 0.7969 = 0.9387

www.pjm.com | Public 15 PJM © 2024

(c) 2025/26 RPM Existing Resource List
https://www.pjm.com/-/media/markets-ops/rpm/rpm-auction-info/2025-2026/2025-2026-rpm-existing-resource-list-post.ashx

(d) ELCC Class Ratings for the 2025/2026 Base Residual Auction
https://www.pjm.com/-/media/planning/res-adeq/elcc/2025-26-bra-elcc-class-ratings.ashx

Exhibit 1
Montalvo Workpapers

RESOURCENAME	ICAP	ZONENAME	LDANAME	CLASSTYPE	Class Avg ELCC	Est. UCAP MW (Class Avg ELCC)
BRANDON SHORES 1	635	BGE	BGE	Coal	84%	533.4
BRANDON SHORES 2	638	BGE	BGE	Coal	84%	535.9
Brandon Shores Subto	1273					1,069.3
WAGNER 3	305	BGE	BGE	Steam	75%	228.8
WAGNER 4	397	BGE	BGE	Steam	75%	297.8
Wagner Subtotal	702					526.5
						1,596

Exhibit 1
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Exclusion category	Resource	Capacity not offered, UCAP MW	
RMR	Brandon Shores	1,069	ICAP * Class ELCC (Tab RMR)
RMR	Wagner	527	ICAP * Class ELCC (Tab RMR)
Exempt Resources	Battery	110	Source: PJM. 2025/2026 Base Residual Auction Results
Exempt Resources	Diesel-Landfill	73	Source: PJM. 2025/2026 Base Residual Auction Results
Exempt Resources	Hydro	424	Source: PJM. 2025/2026 Base Residual Auction Results
Exempt Resources	Solar	533	Source: PJM. 2025/2026 Base Residual Auction Results
Exempt Resources	Wind	456	Source: PJM. 2025/2026 Base Residual Auction Results
Exempt Resources	Demand Response	Unknown	
Winter ratings	Combined cycle/combustion turbines	5,439	Tab "CC_CT"
	Total potential additional UCAP	**8,631**	
	Total potential additional UCAP, excluding Brandon Shores	**7,562**	

The AUCAP factor of 76.69 percent is based on pool wide accredited UCAP of 152,765 MW as a share of total ICAP in the model of 191,693 MW. An AUCAP factor of 82.53 percent against th

Exhibit 1
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. Presentation to Markets & Reliability Committee, August 21, 2024, Slide 38.
. Presentation to Markets & Reliability Committee, August 21, 2024, Slide 38.
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. Presentation to Markets & Reliability Committee, August 21, 2024, Slide 38.
. Presentation to Markets & Reliability Committee, August 21, 2024, Slide 38.

e same ICAP total yields 158,204 UCAP MW, or an increase of 5,439 UCAP MW.

Exhibit 1
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AUCTION SUPPLY (MW)

2017/2018	2018/2019	2019/202O	2020/2021	2021/2022	2022/2023	2023/2024
187,473.70	189,579.40	194,243	189,918	192,449.20	172,206.50	160,873.60

TARGET RELIABILITY REQUIREMENT (MW)

2017/2018	2018/2019	2019/202O	2020/2021	2021/2022	2022/2023	2023/2024
179,806	174,896.80	171,037	167,644	166,355	163,269	163,166

PEAK TOTALS

2017/2018	2018/2019	2019/2020	2020/2021	2021/2022	2022/2023	2023/2024
145,434	150,573	151,302	148,433	148,433	147,361	146,799

FORCASTED PEAK LOAD

2017/2018	2018/2019	2019/2020	2020/2021	2021/2022	2022/2023	2023/2024
164,718	161,418	157,188	153,915	152,647	150,229	149,680

PEAK LOAD VALUES (MW)

	2017/2018	2018/2019	2019/2020	2020/2021	2021/2022	2022/2023	2023/2024
Summer Normalized Peak Total	150,076	149,660	149,135	147,929	149,780	150,123	149,884
Winter Normalized Peak Total	131,158	130,265	128,209	130, 005	132, 636	133,059	-
Unrestricted Peak Total Summer	145,434	150,573	151,302	148,433	148,433	147,361	146,799
Unrestricted Peak Total Winter	137,212	137,618	120,272	117,012	128,882	134,951	-

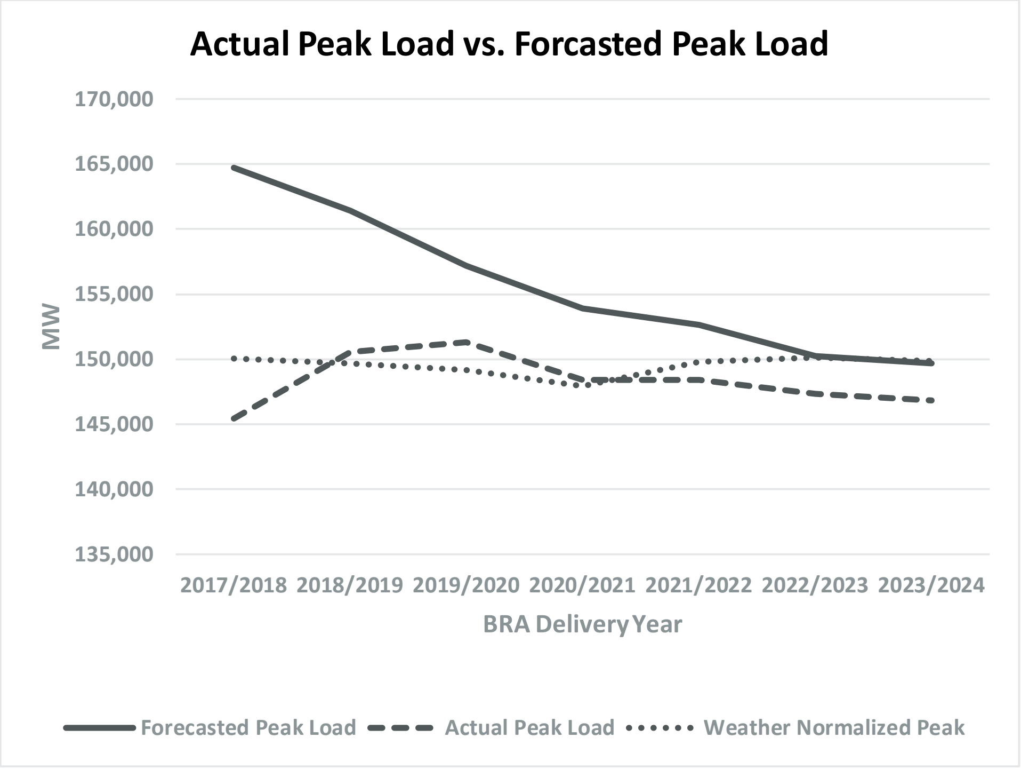

Figure 1: Auction suppy vs. Target Reliability vs. Peak Load Vs. Acutal Peak Load

Forcasted peaks, target reliability, and auction supply

YEAR	**LINK**	**Peak load**	**LINK**
2017/2018	Intro (pjm.com)	**All years**	2024-load-report.ashx (pjm.com)
2018/2019	Intro (pjm.com)		
2019/2020	Intro (pjm.com)		
2020/2021	Intro (pjm.com)		
2021/2022	Intro (pjm.com)		
2022/2023	Intro (pjm.com)		
2023/2024	Intro (pjm.com)		

Act Pks	**2017/2018**	**2018/2019**	**2019/2020**	**2020/2021**	**2021/2022**	**2022/2023**	**2023/2024**
	145,434	150,573	151,302	148,433	148,433	147,361	146,799
	2017/2018	**2018/2019**	**2019/2020**	**2020/2021**	**2021/2022**	**2022/2023**	**2023/2024**
Norm Pks	150,076	149,660	149,135	147,929	149,780	150,123	149,884
	2017/2018	**2018/2019**	**2019/2020**	**2020/2021**	**2021/2022**	**2022/2023**	**2023/2024**
Forecast Pks	164,718	161,418	157,188	153,915	152,647	150,229	149,680

	14642	11758	8053	5986	2867	106	204
	9.76%	7.86%	5.40%	4.05%	1.91%	0.07%	0.14%
	9.76%	7.86%	5.40%	4.05%	1.91%	0.07%	-0.14%
Norm Pks	Abs mean error	4.2%					
		range 0.1% to 9.8%					
	Bias	4.1%					
Act Pks	11.71%	6.72%	3.74%	3.56%	2.76%	1.91%	1.92%
	11.71%	6.72%	3.74%	3.56%	2.76%	1.91%	1.92%
	Abs mean error	4.6%					
		range 1.9% to 11.7%					
	Bias	4.6%					

RR	**2017/2018**	**2018/2019**	**2019/202O**	**2020/2021**	**2021/2022**	**2022/2023**	**2023/2024**
	179,806	174,897	171,037	167,644	166,355	163,269	163,166

Forecast Pool Requirement (FPR)	1.0916	1.0835	1.0881	1.0892	1.0898	1.0868	1.0901	Source: RPM Base Residual Auction Planning Parameters spreadsheets
RR -- Act	158,756	163,146	164,632	161,673	161,762	160,152	160,026	
RR -- WN	163,823	162,157	162,274	161,124	163,230	163,154	163,389	
RR w/FRR	165,007	160,607	157,092	154,355	153,161	132,257	131,820	Source: RPM Base Residual Auction Planning Parameters spreadsheets
	0.92	0.92	0.92	0.92	0.92	0.81	0.81	
ALR FRR ADJ								
RR -- Act	145,689	149,817	151,210	148,858	148,932	129,732	129,283	
RR -- WN	150,340	148,908	149,044	148,352	150,284	132,163	132,000	

Table 2. Resource requirements calculated using forecast load, actual peak load, and weather-normalized peak load

MW	2017/2018	2018/2019	2019/202O	2020/2021	2021/2022	2022/2023	2023/2024
RR Frcst Pk Ld	165,007	160,607	157,092	154,355	153,161	132,257	131,820
RR Act Pk Ld	145,689	149,817	151,210	148,858	148,932	129,732	129,283
RR Norm Pk Ld	150,340	148,908	149,044	148,352	150,284	132,163	132,000

Norm Pk as % of fcst	0.911	0.927	0.949	0.961	0.981	0.999	1.001	0.961

Exhibit 1
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MW	**2017/2018**	**2018/2019**	**2019/2020**	**2020/2021**	**2021/2022**	**2022/2023**	**2023/2024**
RR Frsct Pk Ld	165,007	160,607	157,092	154,355	153,161	132,257	131,820
RR Act Pk Ld	145,689	149,817	151,210	148,858	148,932	129,732	129,283
RR Norm Pk Ld	150,340	148,908	149,044	148,352	150,284	132,163	132,000

Norm Pk as % of fcst	0.911	0.927	0.949	0.961	0.981	0.999	1.001	0.961

Table 3. Comparison of market clearing MW and costs using requirements based on forecast load and weather-normalized peak load

	2017	2018	2019	2020	2021	2022	2023	Avg/Year	Sum (7 yrs)	
	2017/18	**2018/19**	**2019/20**	**2020/21**	**2021/22**	**2022/23**	**2023/24**	**Avg/Year**	**Sum (7 yrs)**	
RR on Fcst Pk Load (MW)	165,007	160,607	157,092	154,355	153,161	132,257	131,820		1,054,300	
RR on Normalized Pk Load (MW)	150,340	148,908	149,044	148,352	150,284	132,163	132,000		1,011,091	
Peak Load Variance	-9%	-7%	-5%	-4%	-2%	0%	0%		(43,209)	-0.040983822
BRA Cleared UCAP (MW)	167,004	166,837	167,306	165,109	163,627	144,477	144,871	159,890	1,119,231	
Revised Cleared UCAP (MW)	152,159	154,684	158,734	158,688	160,554	144,375	145,068	153,466	1,074,261	
Cleared UCAP Variance (MW)	(14,845)	(12,153)	(8,572)	(6,421)	(3,074)	(102)	197	(6,424)	(44,969)	-4.0%
Total BRA Cost to Load ($MM)	$ 7,509	$ 10,937	$ 6,980	$ 6,964	$ 9,300	$ 3,916	$ 2,185	$ 6,827	$ 47,792	
Revised BRA Est. Cost to Load ($MM)	$ 6,842	$ 10,140	$ 6,622	$ 6,693	$ 9,125	$ 3,914	$ 2,188	$ 6,504	$ 45,525	
Cost Variance ($MM)	$ (668)	$ (797)	$ (358)	$ (271)	$ (175)	$ (3)	$ 3	$ (324)	$ (2,267)	
Cumulative Cost Variance ($Bn)	**$ (0.7)**	**$ (1.5)**	**$ (1.8)**	**$ (2.1)**	**$ (2.3)**	**$ (2.3)**	**$ (2.3)**			

[verification to table in 2025/26 BRA Report:]

Total Cost to Load ($Bn) - check	7.5	10.9	7	7	9.3	3.9	2.2
	$ 7.5	**$ 10.9**	**$ 7.0**	**$ 7.0**	**$ 9.3**	**$ 3.9**	**$ 2.2**

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	2017 / 2018	***2018/2019***	***2019/2020***	***2020/2021***	***2021/2022***	***2022/2023***	***2023/2024***
LDA/External Source Zone	**Resource Clearing Price [$/MW-day]**	**Resource Clearing Price [$/MW-day]**	**Resource Clearing Price [$/MW-day]**	**Resource Clearing Price [$/MW-day]**	**Resource Clearing Price [$/MW-day]**	**Resource Clearing Price [$/MW-day]**	**Resource Clearing Price [$/MW-day]**
RTO	$120.00	$164.77	$100.00	$76.53	$140.00	$50.00	$34.13
MAAC	$120.00	$164.77	$100.00	$86.04	$140.00	$95.79	$49.49
EMAAC	$120.00	$225.42	$119.77	$187.87	$165.73	$97.86	$49.49
SWMAAC	$120.00	$164.77	$100.00	$86.04	$140.00	$95.79	$49.49

	2017/2018	**2018/2019**	**2019/2020**	**2020/2021**	**2021/2022**	**2022/2023**	**2023/2024**
LDA/External Source Zone	**Net CONE UCAP TERMS ($/MW-DAY)**	**Net CONE UCAP TERMS ($/MW-DAY)**	**Net CONE UCAP TERMS ($/MW-DAY)**	**Net CONE UCAP TERMS ($/MW-DAY)**	**Net CONE UCAP TERMS ($/MW-DAY)**	**Net CONE UCAP TERMS ($/MW-DAY)**	**Net CONE UCAP TERMS ($/MW-DAY)**
RTO	$351.39	$300.57	$299.30	$292.95	$321.57	$260.50	$274.96
MAAC	$313.00	$271.67	$262.02	$252.40	$292.69	$245.12	$275.08
EMAAC	$365.87	$284.82	$283.63	$283.10	$313.77	$259.36	$291.36
SWMAAC	$313.00	$243.17	$229.93	$202.43	$264.88	$242.95	$244.72

Clearing Price as % of Net CONE

	2017/2018	**2018/2019**	**2019/2020**	**2020/2021**	**2021/2022**	**2022/2023**	**2023/2024**
RTO	34%	55%	33%	26%	44%	19%	12%
MAAC	38%	61%	38%	34%	48%	39%	18%
EMAAC	33%	79%	42%	66%	53%	38%	17%
SWMAAC	38%	68%	43%	43%	53%	39%	20%

Source: BRA results reports

YEAR	**LINK**
2017/2018	Intro (pjm.com)
2018/2019	Intro (pjm.com)
2019/2020	Intro (pjm.com)
2020/2021	Intro (pjm.com)
2021/2022	Intro (pjm.com)
2022/2023	Intro (pjm.com)
2023/2024	Intro (pjm.com)
	https://www.pjm.com/-/media/markets-ops/rpm/rpm-auction-info/2024-2025/2024-2025-base-residual-auction-report.ashx

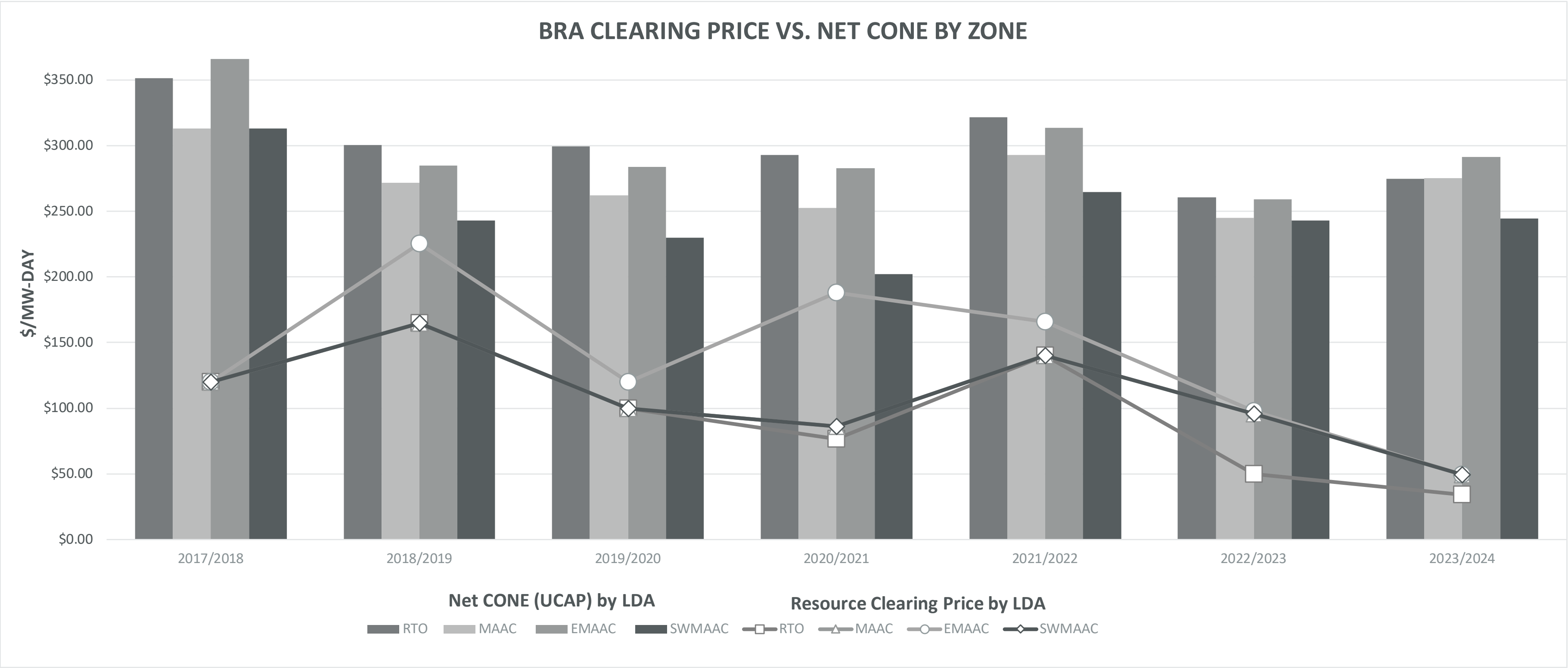

Figure 2: BRA clearing price vs. net CONE by zone

Exhibit 1
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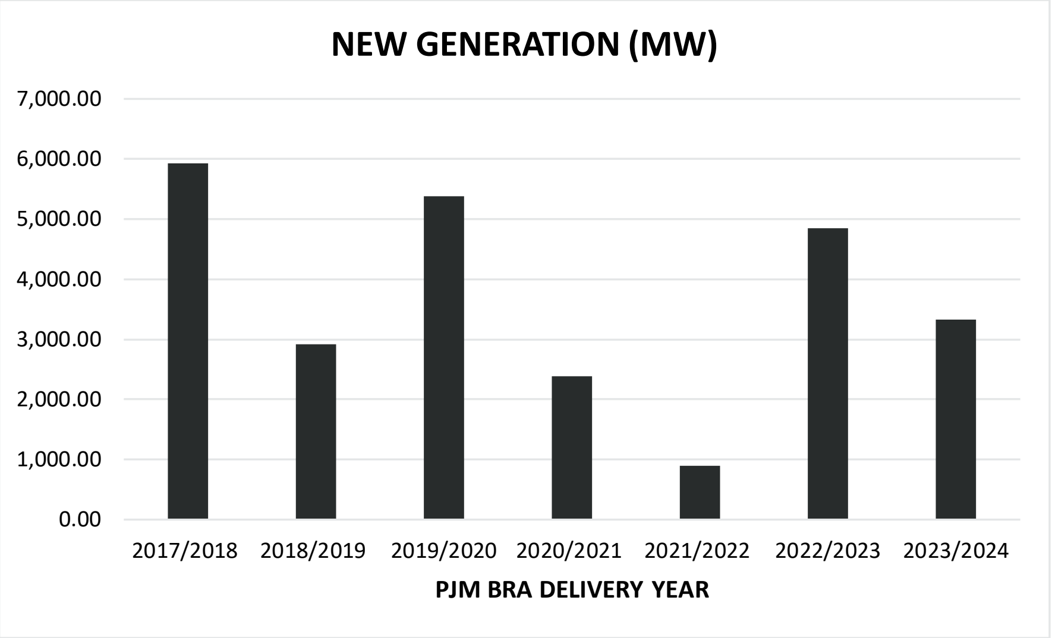
YEAR	**NEW GENERATION (MW)**
2017/2018	5,927.40
2018/2019	2,919.30
2019/2020	5,373.60
2020/2021	2,389.30
2021/2022	893.00
2022/2023	4,848.60
2023/2024	3,329.70



Cleared New Generation (UCAP MW)

		Uprate				New Unit				Total			
		EMAAC	SWMAAC	MAAC	Total RTO	EMAAC	SWMAAC	MAAC	Total RTO	EMAAC	SWMAAC	MAAC	Total RTO
2017	2017/18	65.3		159.2	339.9	1746.4	0	4417.9	**5,927.4**	1811.7	0	4577.1	6267.3
2018	2018/19	79.6		439.6	587.6	561.7		561.7	**2,919.3**	641.3	0	1001.3	3506.9
2019	2019/20	13.5		22.5	155.6	35.6		1843.3	**5,373.6**	49.1	0	1865.8	5529.2
2020	2020/21	86.1		174.2	434.5	7.9		1439	**2,389.3**	94	0	1613.2	2823.8
2021	2021/22	29.3		105.9	508.3	9.6		22.1	**893.0**	38.9	0	128	1401.3
2022	2022/23	128.3		433.1	1210.3	50		193.2	**4,843.6**	178.3	0	626.3	6053.9
2023	2023/24	7.4		100.8	404.8	85.7		103.5	**3,329.7**	93.1	0	204.3	3734.5

YEAR	**LINK**
2017/2018	Intro (pjm.com)
2018/2019	Intro (pjm.com)
2019/2020	Intro (pjm.com)
2020/2021	Intro (pjm.com)
2021/2022	Intro (pjm.com)
2022/2023	Intro (pjm.com)
2023/2024	Intro (pjm.com)

Exhibit 1
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Actual BRA results
https://www.pjm.com/-/media/markets-ops/rpm/rpm-auction-info/2025-2026/2025-2026-base-residual-auction-results.ashx

Actual Clearing Results

LDA	Participant Sell Offers Cleared (UCAP MW)	Resource Clearing Prices [$/MW-Day]
RTO	135,684.0	$269.92
MAAC	51,303.2	$269.92
EMAAC	24,373.3	$269.92
SWMAAC	5,060.8	$269.92
PS	4,390.3	$269.92
PSNORTH	2,507.4	$269.92
DPLSOUTH	956.9	$269.92
PEPCO	2,263.2	$269.92
ATSI	7,764.9	$269.92
TSI-CLEVELAN	1,614.0	$269.92
COMED	21,813.9	$269.92
BGE	606.9	$466.35
PL	8,757.6	$269.92
DAYTON	488.6	$269.92
DEOK	1,633.8	$269.92
DOM	20,049.6	$444.26

RPM Revenue - Actual Results Summary

	MW	$/MW-Day	$Millions
Rest of RTO	115,027.5	$269.92	$11,332.6
BGE	606.9	$466.35	$103.3
DOM	20,049.6	$444.26	$3,251.1
Total RTO	**135,684.0**		**$14,687.0**

IMM Scenario 3: RMR Resources

	MW	$/MW-Day	$Millions	Delta	
Rest of RTO	117,075.0	$167.29	$7,148.7	-38%	
BGE	n/a	$167.29		-64%	Assume RMR resources allow BGE to clear with rest of
DOM	20,049.6	444.3	$3,251.1	0%	No change from actual
Total RTO	**137,124.6**		**$10,399.8**		*Source: IMM Analysis of the 2025/26 BRA, Part A, Tab*

Exhibit 1
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RTO

le 2 & Table 5

Exhibit 1
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	2017	2018	2019	2020	2021	2022	2023	2024	2025	
	2017/18	**2018/19**	**2019/20**	**2020/21**	**2021/22**	**2022/23**	**2023/24**	**2024/25**	**2025/26**	
	Actual Net CONE (UCAP $/MW-day)									
RTO	351.39	300.57	299.3	292.95	321.57	260.5	274.96	293.19	228.81	*Compiled from BRA re*
MAAC	313	271.67	262.02	252.4	292.69	245.12	275.08	294.06	250.98	
EMAAC	365.87	284.82	283.63	283.1	313.77	259.36	291.36	312.39	310.88	
SWMAAC	313	243.17	229.93	202.43	264.88	242.95	244.72	261.07	134.57	
BGE	313.00	235.59	215.62	178.33	244.33	226.37	219.44	234.07	45.34	
DOM									152.69	
	Clearing Price ($/MW-day)									
RTO	120.00	164.77	100.00	76.53	140.00	50.00	34.13	28.92	269.92	*Compiled from BRA re*
MAAC	120.00	164.77	100.00	86.04	140.00	95.79	49.49	28.92	269.92	
EMAAC	120.00	225.42	119.77	187.87	165.73	97.86	49.49	28.92	269.92	
SWMAAC	120.00	164.77	100.00	86.04	140.00	95.79	49.49	28.92	269.92	
BGE	120.00	164.77	100.30	86.04	200.30	126.50	69.95	73.00	466.35	
DOM	120.00	164.77	100.00	76.53	140.00	50.00	34.13	28.92	444.26	
	Clearing Price as % of Net CONE									
RTO	34%	55%	33%	26%	44%	19%	12%	10%	118%	
MAAC	38.3%	60.7%	38.2%	34.1%	47.8%	39.1%	18.0%	10%	108%	
EMAAC	33%	79%	42%	66%	53%	38%	17%	9%	87%	
SWMAAC	38%	68%	43%	43%	53%	39%	20%	11%	201%	
	FERC Oil Pipeline Price Index (RM20-14-001)						https://www.ferc.gov/general-information-1/oil-pipeline-index			
Index Year (7/1/N-1 to 6/30/N)										
Annual Index	0.979865	1.001985	1.044087	1.043108	1.020139	0.994188	1.097007	1.143094	1.022547	
Chain Index (2017=1.000)	1.000	1.0020	1.0462	1.0913	1.1132	1.1068	1.2141	1.3879	1.4192	
	Clearing Price (Real $2025/MW-day)						74.45			
RTO	170.30	233.37	135.65	99.53	178.47	64.11	39.89	29.57	269.92	
MAAC	170.30	233.37	135.65	111.89	178.47	122.83	57.85	29.57	269.92	
EMAAC	170.30	319.27	162.47	244.32	211.27	125.48	57.85	29.57	269.92	
SWMAAC	170.30	233.37	135.65	111.89	178.47	122.83	57.85	29.57	269.92	
BGE	170.30	233.37	136.06	111.89	255.34	162.21	81.76	74.65	466.35	
DOM	170.30	233.37	135.65	99.53	178.47	64.11	39.89	29.57	444.26	
	Cleared Capacity, New Gen Units (UCAP MW)									
RTO	5,927	2,919	5,374	2,389	893	4,844	3,330	329	110	
MAAC	4,418	562	1,843	1,439	22	193	104			
EMAAC	1,746	562	36	8	10	50	86			
SWMAAC	-	-	-	-	-	-	-	-	-	
	Alternative RTO Net CONE ($/MW-day)				New Cap-wgt Avg + 50% of range for n years					
	2017/18	**2018/19**	**2019/20**	**2020/21**	**2021/22**	**2022/23**	**2023/24**	**2024/25**	**2025/26**	
Actual Net CONE - RTO	351.39	300.57	299.3	292.95	321.57	260.5	274.96	293.19	228.81	
RTO Clearing Price	120.00	164.77	100.00	76.53	140.00	50.00	34.13	28.92	269.92	
Alt Net CONE - 3-yr wgt avg				168.41	173.52	132.25	123.43	132.78	70.56	
Alt Net CONE - 4-yr wgt avg					178.00	173.96	139.97	139.52	139.64	
Alt Net CONE - 5-yr wgt avg						177.70	182.76	158.97	146.60	
	Alternative BGE Net CONE ($/MW-day)									
	2017/18	**2018/19**	**2019/20**	**2020/21**	**2021/22**	**2022/23**	**2023/24**	**2024/25**	**2025/26**	
Actual Net CONE - BGE	313.00	235.59	215.62	178.33	244.33	226.37	219.44	234.07	45.34	
BGE Clearing Price	120.00	164.77	100.30	86.04	200.30	126.50	69.95	73.00	466.35	
Alt Net CONE - 3-yr wgt avg				168.37	171.00	166.44	196.23	223.58	171.10	
Alt Net CONE - 4-yr wgt avg					174.65	184.47	188.88	217.48	229.83	
Alt Net CONE - 5-yr wgt avg						185.92	201.71	217.62	224.24	

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eports

eports

Exhibit 1
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Row	Item	Source	2020/21	2021/22	2022/23	2023/24	2024/25	2025/26	
1	RTO Net CONE ($/MW-day)	BRA Results	$ 292.95	$ 321.57	$ 260.50	$ 274.96	$ 293.19	$ 228.81	
2	RTO Clearing Price ($/MW-day)	BRA Results	$ 76.53	$ 140.00	$ 50.00	$ 34.13	$ 28.92		
3	Oil Pipeline chain-type index (2025=1.000)	18 C.F.R. § 342.3	0.769	0.784	0.780	0.856	0.978	1.000	
4	RTO Clearing Price (2025$/MW-day)	(2) / (3)	$ 99.53	$ 178.47	$ 64.11	$ 39.89	$ 29.57		
5	Cleared New Gen Unit Capacity (UCAP MW)	BRA Results	2,389	893	4,844	3,330	329		
6	Weightings (thousand 2025$/day)	(4) * (5) / 1,000	238	159	311	133	10		
7	Wgt Avg RTO Clearing Price ($/MW-day)	∑row(6) / ∑row(5) * 1,000						$ 72.15	
8	50% of Clearing Price Range ($/MW-day)	50% * { MAX[row(4)] - MIN[row(4)] }						$ 74.45	
9	**Alternative Net CONE ($/MW-day)**	**(7) + (8)**						**$ 146.60**	64%
							Gross CONE	$ 451.61	32%

Exhibit 1
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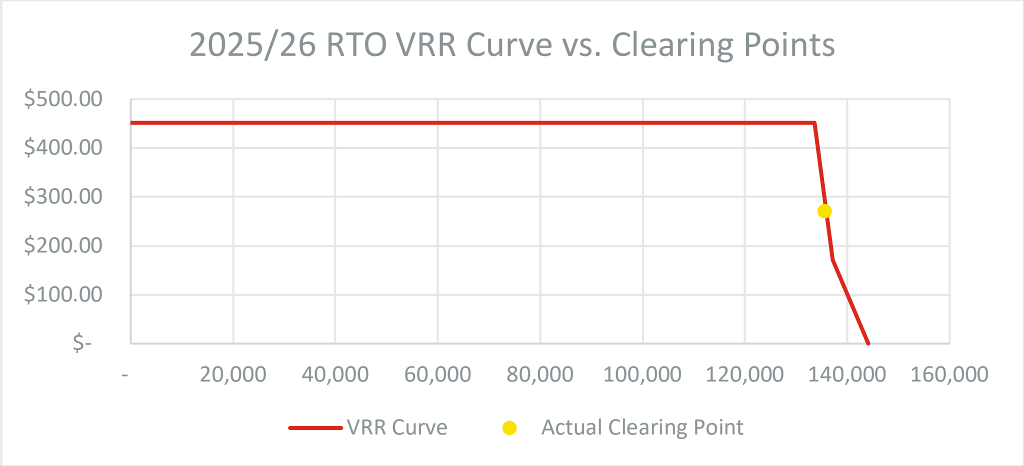
VRR Curve (RTO)

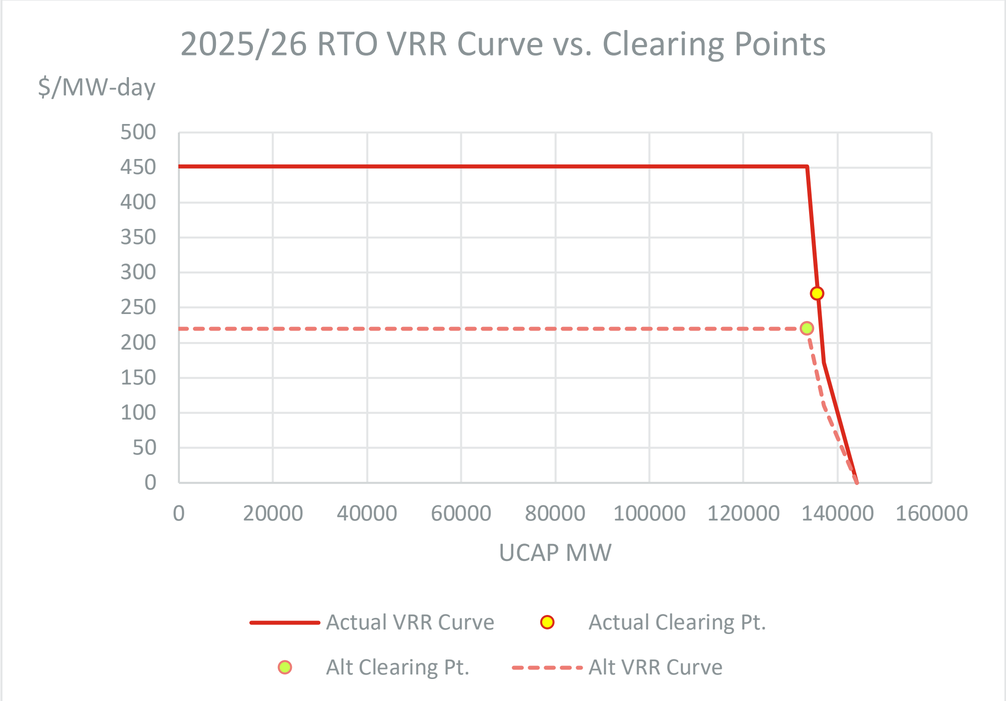
	X (MW)	Y (Price)
Y-intercept	-	$ 451.61
Point (a)	133,554	$ 451.61
Point (b)	137,160	$ 171.61
Point (c)	144,106	$ -
Actual Clearing Point	135,684	$ 269.92

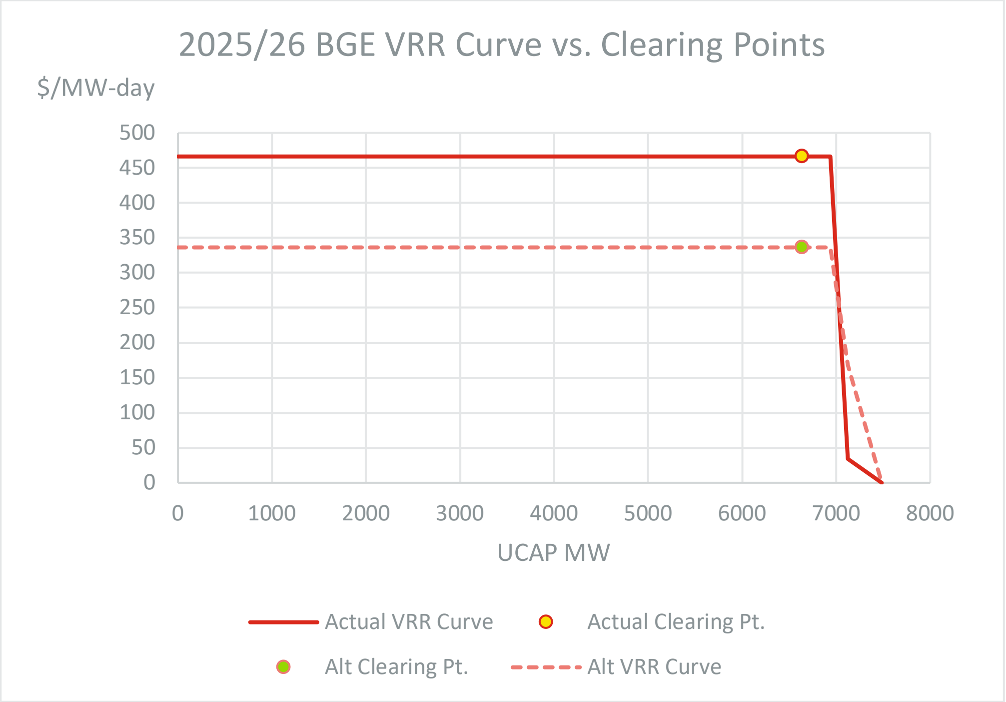


Redrawing VRR with alt Net CONE

	RTO		BGE		DOM	
	MW	$/MW-Day	MW	$/MW-Day	MW	$/MW-Day
Actual Gross CONE		451.61		466.35		444.26
Actual Net CONE		228.81		45.34		152.69
CETL			6,031		5,164	
Actual VRR Curve						
start	-	451.61	-	466.35	-	444.26
pt a	133,554	451.61	6,936	466.35	25,617	444.26
pt b	137,160	171.61	7,124	34.01	26,312	114.52
pt c	144,106	-	7,485	-	27,651	-
Actual Clearing Pt.	135,684	$ 269.92	6,638	466.35	25,214	444.26
Alt Net CONE		146.60		224.24		146.60
Alt VRR Curve						
start	-	219.90	-	336.36	-	219.90
pt a	133,554	219.9	6,936	336.36	25,617	219.9
pt b	137,160	109.95	7,124	168.18	26,312	109.95
pt c	144,106	-	7,485	-	27,651	-
Alt Clearing Pt.	133,554	219.90	6,638	336.36	25,214	219.9

UCAP MW	**$/MW-day**	**$Millions**	**UCAP MW**	**$/MW-day**	
115,028	$ 269.92	$ 11,332.6	112,898	219.90	
607	466.35	$ 103.3	607	336.36	
20,050	444.26	$ 3,251.1	20,050	219.9	
					$Millions
		$ 14,687			$ 10,745
			(2,130)		$ (3,942)





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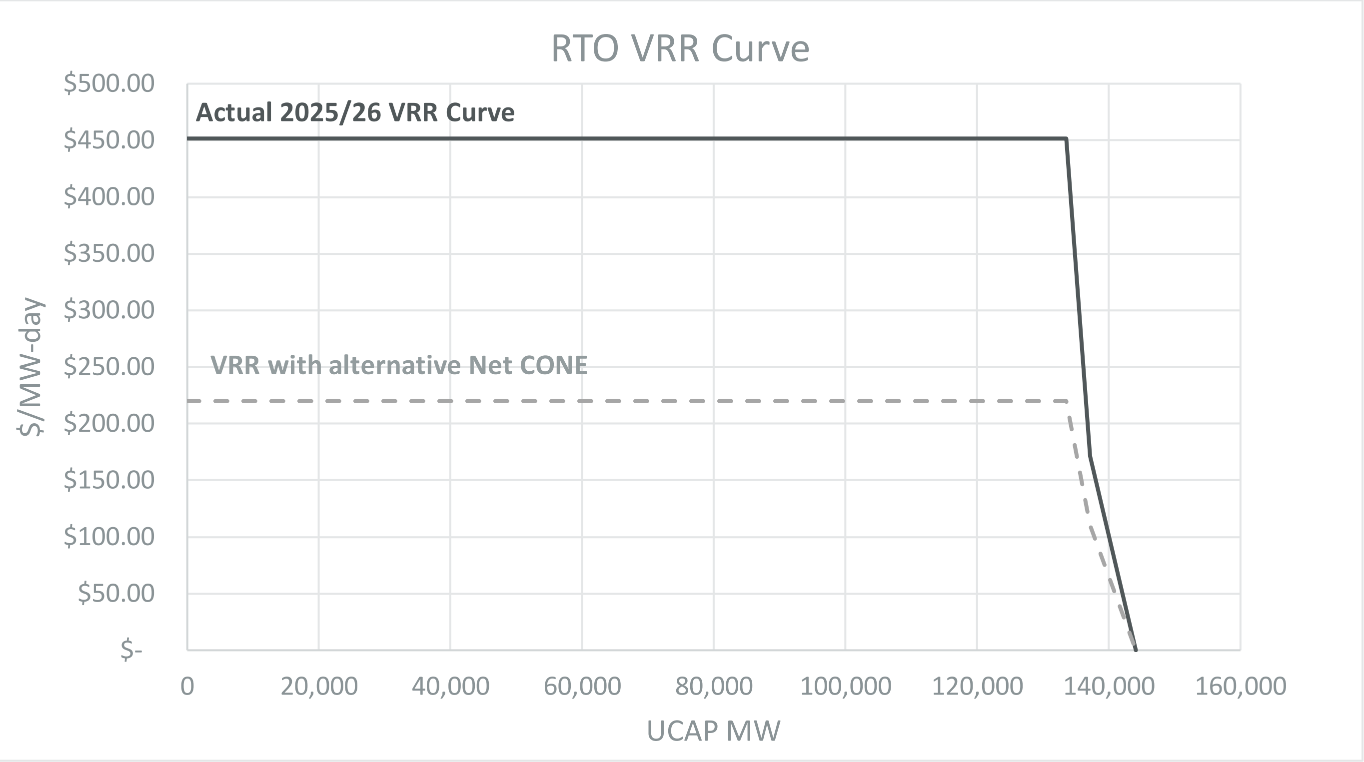

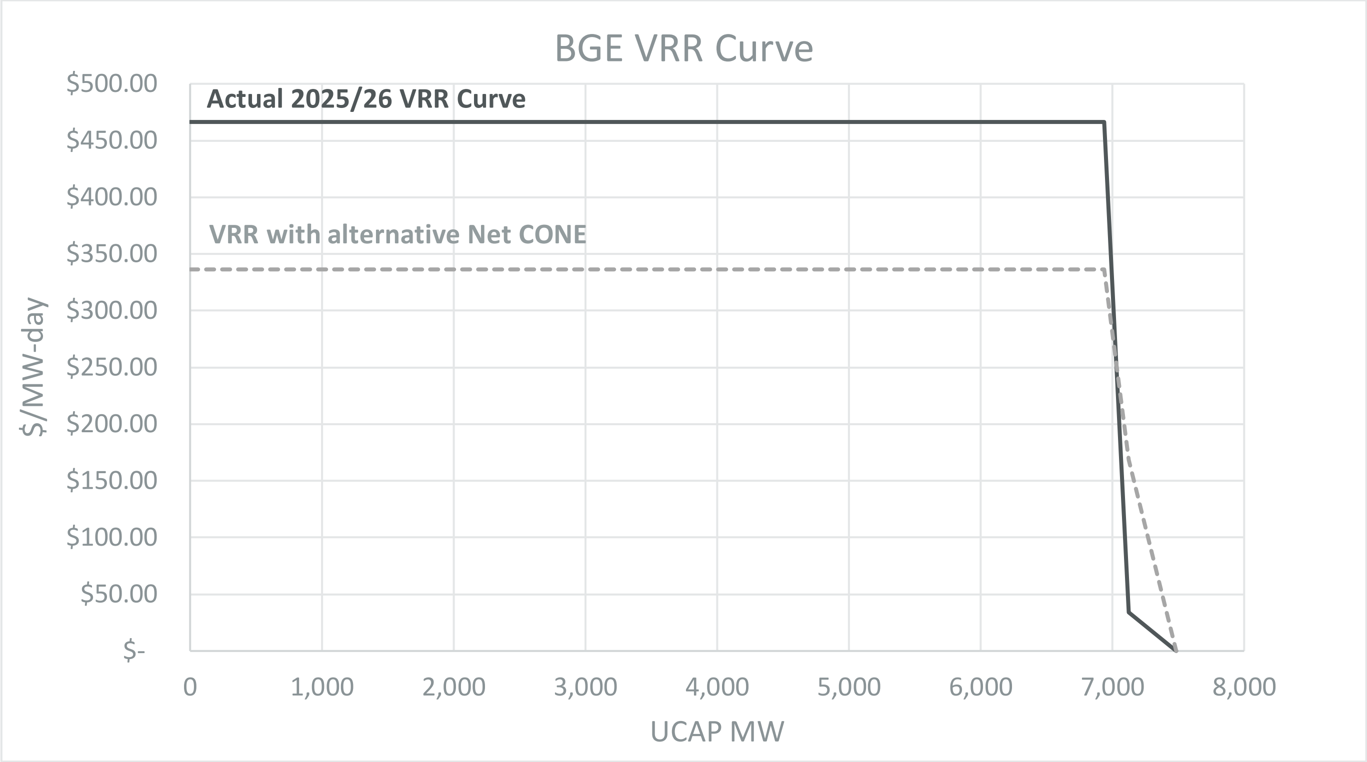

	RTO				BGE			
	Actual VRR Curve		Alt Net CONE VRR		Actual VRR Curve		Alt Net CONE VRR	
	UCAP MW	$/MW-day	UCAP MW	$/MW-day	UCAP MW	$/MW-day	UCAP MW	$/MW-day
y-intercept	0.0	$ 451.61	0.0	$ 219.90	0.0	$ 466.35	0.0	$ 336.36
pt a	133,554.2	$ 451.61	133,554.2	$ 219.90	6,936.2	$ 466.35	6,936.2	$ 336.36
pt b	137,160.4	$ 171.61	137,160.4	$ 109.95	7,123.6	$ 34.01	7,123.6	$ 168.18
pt c	144,105.7	$ -	144,105.7	$ -	7,484.5	$ -	7,484.5	$ -

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BGE 2026/27 VRR Curve

BGE VRR Curve

MW	$/MW Day
0.00	$678.26
6,883.30	$678.26
7,057.10	$0.00
7,265.70	$0.00

Source:

https://www.pjm.com/-/media/markets-ops/ nx

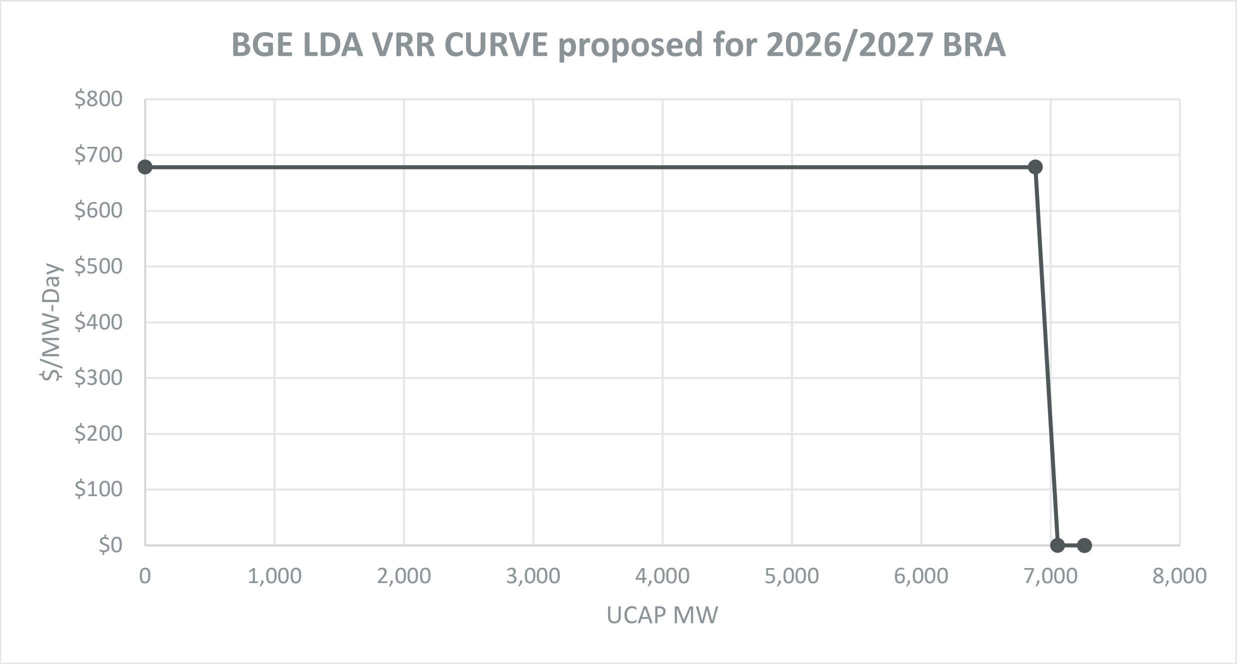

Exhibit 1
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Assumptions needed for adjusted BRA scenario:

Alternative Net CONE - 5-year wgt avg

RTO	146.60	$/MW-day tab: Proposed Net CONE, J50
BGE	224.24	$/MW-day tab: Proposed Net CONE, J59

Load Forecast Adjustment (ratio of adjusted forecast to original)
7-yr avg of normalized peak load to forecast peak load, 2017/18 to 2023/24
Value: 0.961430301

	UCAP MW
Increase UCAP from winter ratings - DOM	889.29
Increase UCAP from winter ratings - BGE	17.30

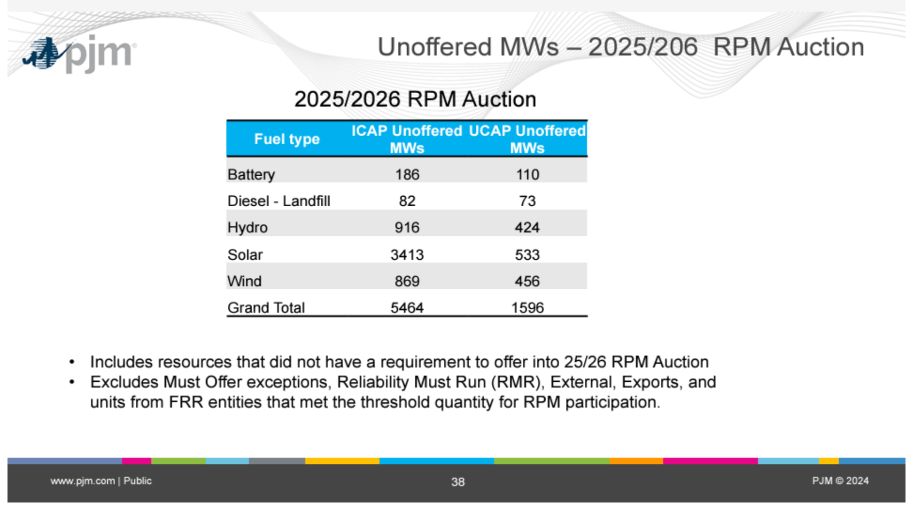
1. Assume at least one of two RMR resources (Wagner) must offer in at Net CONE price

	ICAP	Class Avg ELCC	Est. UCAP	Modeled UCAP MW	Modeled Offer Price ($/MW-day)
Brandon Shores	1273	84%	1069.3	0	$ 224.24
Wagner	702	75%	526.5	526.5	$ 224.24
Total	**1,975**		**1,596**	**527**	

2. Assume other unoffered exempt resources bid in at $0

	ICAP	UCAP	Modeled UCAP	ELCC
Battery	186	110	110	59%
Diesel - landfill	82	73	73	89%
Hydro	916	424	424	46%
Solar	3413	533	533	16%
Wind	869	456	456	52%
Demand Resources	unk	unk		
	5,466	1,596	1,596	

2025/26 Base Residual Auction Results: Aug 21, 2024 Report to the Markets & Reliability Committee
https://pjm.com/-/media/committees-groups/committees/mrc/2024/20240821/20240821-item-08---2025-



Unoffered MWs – 2025/206 RPM Auction

2025/2026 RPM Auction

Fuel type	ICAP Unoffered MWs	UCAP Unoffered MWs
Battery	186	110
Diesel - Landfill	82	73
Hydro	916	424
Solar	3413	533
Wind	869	456
Grand Total	5464	1596

- Includes resources that did not have a requirement to offer into 25/26 RPM Auction
- Excludes Must Offer exceptions, Reliability Must Run (RMR), External, Exports, and units from FRR entities that met the threshold quantity for RPM participation.

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3. Adopt IMM Scenario 4 assumptions that CC/CT resources calculate UCAP from winter ratings
Analysis source: Analysis of IMM Sensitivity Cases.xlsx

Based on visual inspection of past supply curve representations, assume that 75% of supply curve is price taker
Final 3 points on curve derived from IMM scenarios 4A, 4B, 4C

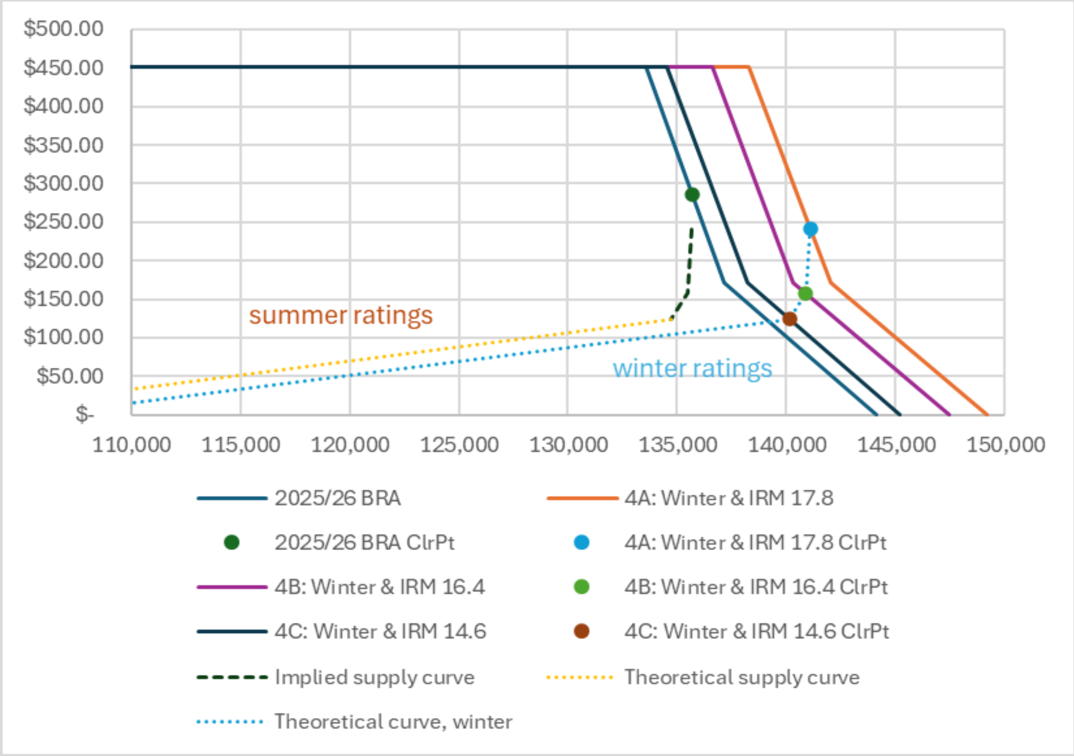
RTO Supply Curve
Supply curve with winter increase and 75% price taker assumption

	UCAP MW	$/MW-day
Top (pt 4A)	141,077	$ 241.03
Pt 4B	140,892	$ 157.96
Pt 4C	140,126	$ 124.06
price taker point (75%)	105,808	$ -

Original supply curve (summer ratings) with 75% price taker assumption

	UCAP MW	$/MW-day
Top (pt 4A)	135,638	$ 241.03
Pt 4B	135,452	$ 157.96
Pt 4C	134,687	$ 124.06
price taker point (75%)	101,015	$ -

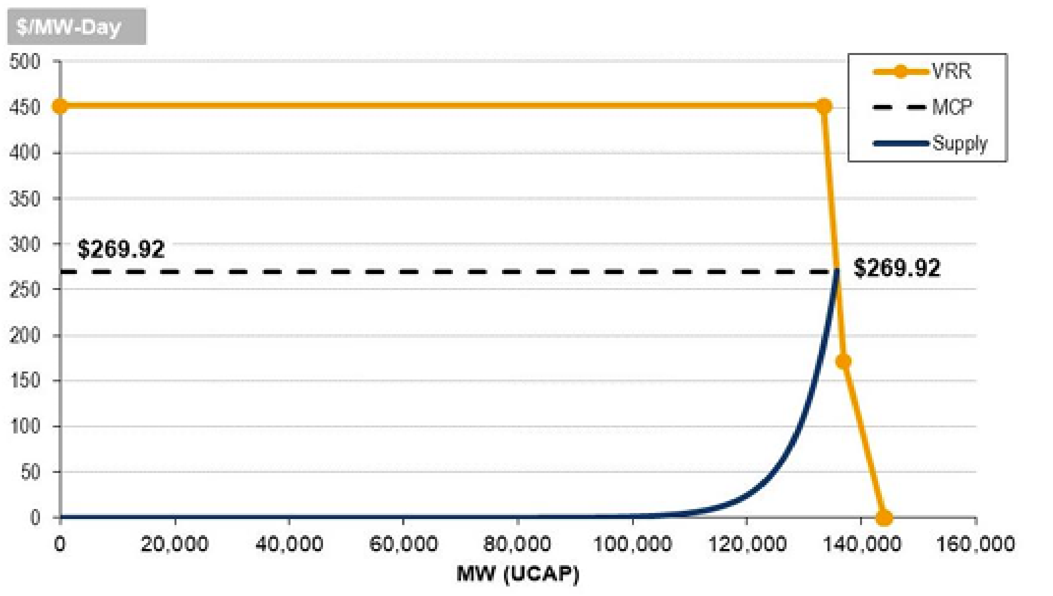
From IMMWinterRatings tab



2025/26 RTO Supply Curve
https://www.pjm.com/-/media/markets-ops/rpm/rpm-auction-info/2025-2026/2025-2026-bra-supply-curves.ashx

Introduction: The graphs below represent a smoothed supply curve of sell offers offered into the RTO and constrained LDAs as described in the OATT Attachment DD Section 5.11(e)

Figure 1. RTO Smoothed Supply (2025/2026 Base Residual Auction RTP Supply Curve)



- RTO supply curve includes sell offers from all LDAs
- The VRR Curve is adjusted for Price Responsive Demand (PRD) in this auction
- Sell offers within Constrained LDAs that cleared at a price higher than the RTO resource clearing price were assumed to be zero in graphing the RTO supply curve

Exhibit 1
Montalvo Workpapers

2026-base-residual-auction---presentation.ashx

Exhibit 1
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This tab uses some of IMM's sensitivity cases to deduce the end of the actual supply curve in BRA 2025/26

		Actual Value	2025/26 BRA	4A: Winter & IRM 17.8	4B: Winter & IRM 16.4	4C: Winter & IRM 14.6	6: Winter+RMR & IRM 17.8	
	Installed Reserve Margin (IRM)	17.8%	17.80%	17.80%	16.40%	14.60%	17.80%	
	Pool-Wide Accredited UCAP Factor	79.69%	79.69%	82.53%	82.53%	82.53%	82.53%	
	Forecast Pool Requirement (FPR)	0.9387	0.9387	0.9722	0.9606	0.9458	0.9722	
	Preliminary Forecast Peak Load	153,883.0	153,883.0	153,883.0	153,883.0	153,883.0	153,883.0	
	Reliability Requirement	144,450.0	144,450.0	149,605.1	147,820.0	145,542.6	149,605.1	
	Total Peak Load of FRR Entities	11,597.3	11,597.3	11,597.3	11,597.3	11,597.3	11,597.3	
	Preliminary FRR Obligation	10,886.4	10,886.4	11,274.9	11,140.4	10,968.7	11,274.9	
	Reliability Requirement adjusted for FRR	133,563.6	133,563.6	138,330.2	136,679.6	134,573.9	138,330.2	
	EE Addback	1,459.8	1,459.8	1,459.8	1,459.8	1,459.8	1,459.8	
	Point (Y-intercept)	0.0	-	0.0	0.0	0.0	0.0	
98.90%	Point (a) UCAP Level, MW	133,554.2	133,554.2	138,268.4	136,636.0	134,553.4	138,268.4	
101.60%	Point (b) UCAP Level, MW	137,160.4	137,160.4	142,003.3	140,326.3	138,186.9	142,003.3	
106.80%	Point (c) UCAP Level, MW	144,105.7	144,105.7	149,196.4	147,433.7	145,184.7	149,196.4	
	Gross CONE, $/MW-Day (UCAP Price)	$451.61	$451.61	$451.61	$451.61	$451.61	$451.61	
	Net CONE, $/MW-Day (UCAP Price)	$228.81	$228.81	$228.81	$228.81	$228.81	$228.81	
	Point (Y-intercept)	$ 451.61	$ 451.61	$ 451.61	$ 451.61	$ 451.61	$ 451.61	
150%	Point (a) UCAP Price, $/MW-Day	$ 451.61	$ 451.61	$ 451.61	$ 451.61	$ 451.61	$ 451.61	
75%	Point (b) UCAP Price, $/MW-Day	$ 171.61	$ 171.61	$ 171.61	$ 171.61	$ 171.61	$ 171.61	
0%	Point (c) UCAP Price, $/MW-Day	$ -	$ -	$ -	$ -	$ -	$ -	
	Clearing Point - input UCAP MW	135,684	135,684	141,077.3	140,891.7	140,126.0	142,527.0	1,635.30
	Solved clearing price ($/MW-Day)	$ 269.92	$ 286.24	$ 241.03	$ 157.96	$ 124.06	$ 159.12	
	Solved clearing UCAP MW	135,684	141,111	141,077.3	140,891.6	140,125.9	141,077.3	
	Clearing Point - input price ($/MW-Day)	$ 269.92	74	241.03	157.96	124.06	241.03	
			2025/26 BRA ClrPt	4A: Winter & IRM 17.8	4B: Winter & IRM 16.4	4C: Winter & IRM 14.6	6: Winter+RM	
	Chart Clearing Point - UCAP MW	135,684	135,684	141,077	140,892	140,126	142,527	
	Chart Clearing Point - Price $/MW-Day	$ 269.92	$ 286.24	$ 241.03	$ 157.96	$ 124.06	$ 159.12	
	RPM Revenue without constrained LDA	13,368	14,176	12,411	8,123	6,345	8,278	
	Actual RPM Revenue (IMM Results)	14,687	14,687	11,966	8,230	6,733	11,966	
	LDA Premium	1,319	511	(446)	107	388	3,688	
	DOM LDA UCAP MW	20,003						
	DOM LDA Premium ($/MW-Day)	$ 174.34						
	DOM LDA Premium ($M)	1,273						
	DOM LDA UCAP MW	607						
	DOM LDA Premium ($/MW-Day)	$ 196.43						
	DOM LDA Premium ($M)	44						
	Total LDA Premium	1,316						

IMPLIED SUPPLY CURVE FROM IMM SCENARIOS 4A-4C

	4A: Winter & IRM 17.8	4B: Winter & IRM 16.4	4C: Winter & IRM 14.6	6: Winter+RMR & IRM 17.8
Gas CC/CT UCAP Increase due to winter ratings	5,439	5,439	5,439	5,439

Implied Supply Curve from 4A	UCAP MW	$/MW-day	
Winter ratings increase	5,439		
Pt 4A without winter increase	135,638	$ 241.03	
Pt 4B without winter increase	135,452	$ 157.96	
Pt 4C without winter increase	134,687	$ 124.06	
RMR Estimated UCAP	1595.82		
Pt 6 without RMR/winter	135,492	$ 159.12	verifies through alt estimate same curve

Theoretical line - assume 75% of supply curve is price taker (from 2024/25 supply curve analysis),

Point A	134,687	$ 124.06
Point B	101,015	$ -

Supply curve with winter increase and 75% price taker assumption

Top (pt 4A)	141,077	$ 241.03
Pt 4B	140,892	$ 157.96
Pt 4C	140,126	$ 124.06
price taker point (75%)	105,808	$ -

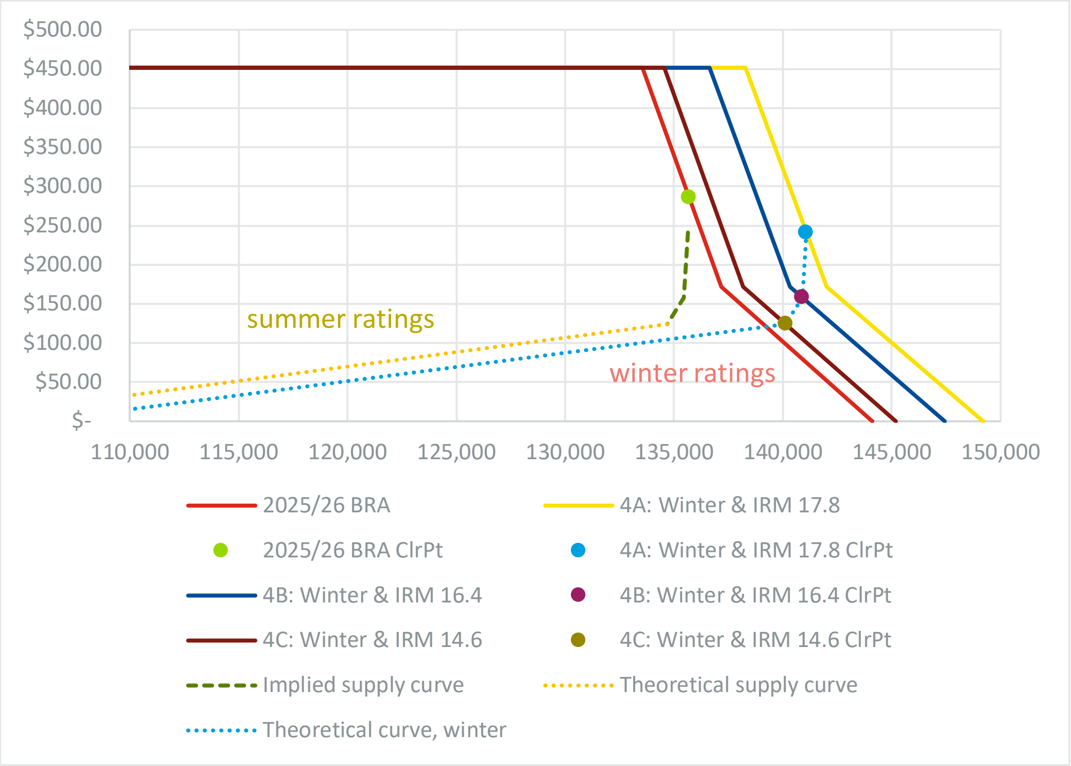

Exhibit 1
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straight line (conservative)

Exhibit 1
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This tab reclears the RTO BRA based on revised assumption, with comparison to actual BRA value

		Actual 2025/2(	2025/26 BRA calculated	All Adjustments
	Installed Reserve Margin (IRM)	17.8%	17.80%	17.80%
	Pool-Wide Accredited UCAP Factor	79.69%	79.69%	82.53%
	Forecast Pool Requirement (FPR)	0.9387	0.9387	0.9722
	Preliminary Forecast Peak Load	153,883.0	153,883.0	147,947.8
	Reliability Requirement	144,450.0	144,450.0	143,834.9
	Total Peak Load of FRR Entities	11,597.3	11,597.3	11,150.0
	Preliminary FRR Obligation	10,886.4	10,886.4	10,840.0
	Reliability Requirement adjusted for FRR	133,563.6	133,563.6	132,994.9
	EE Addback	1,459.8	1,459.8	1,459.8
Demand Curve				
	Point (Y-intercept)	0.0	-	0.0
98.90%	Point (a) UCAP Level, MW	133,554.2	133,554.2	132,991.7
101.60%	Point (b) UCAP Level, MW	137,160.4	137,160.4	136,582.6
106.80%	Point (c) UCAP Level, MW	144,105.7	144,105.7	143,498.3
	Gross CONE, $/MW-Day (UCAP Price)	$451.61	$451.61	$0.00
	Net CONE, $/MW-Day (UCAP Price)	$228.81	$228.81	$146.60
	Point (Y-intercept)	$ 451.61	$ 451.61	$ 219.90
150%	Point (a) UCAP Price, $/MW-Day	$ 451.61	$ 451.61	$ 219.90
75%	Point (b) UCAP Price, $/MW-Day	$ 171.61	$ 171.61	$ 109.95
0%	Point (c) UCAP Price, $/MW-Day	$ -	$ -	$ -
Supply curve				
	Top (pt 4A) UCAP Level, MW		135,638.07	143,200
	Pt 4B UCAP Level, MW		135,452.47	142,488
	Pt 4C UCAP Level, MW		134,686.77	141,722
	price taker point (75%) UCAP Level, MW		101,015.08	107,404
	Top (pt 4A) UCAP Price, $/MW-day		$ 241.03	$ 241.03
	Pt 4B UCAP Price, $/MW-day		$ 157.96	$ 157.96
	Pt 4C UCAP Price, $/MW-day		$ 124.06	$ 124.06
	price taker point (75%) UCAP Price, $/MW-day		$ -	$ -
	Supply Curve - clearing segment			
	Segment (select to meet clearing pt)			3
	Top pt - UCAP		135,684.0	141,722.0
	Bottom pt - UCAP		135,638.1	107,404.0
	Top pt - $/MW-day		$ 269.92	$ 124.06
	Bottom pt - $/MW-day		$ 241.03	$ -
	Slope		0.629	0.004
	Y-intercept		$ (85,067)	$ (388)
	Demand Curve - clearing segment			
	Segment (select to meet clearing pt)			3
	Top pt - UCAP		133,554.2	136,582.6
	Bottom pt - UCAP		137,160.4	143,498.3
	Top pt - $/MW-day		$ 451.61	$ 109.95
	Bottom pt - $/MW-day		$ 171.61	$ -
	Slope		(0.078)	(0.016)
	Y-intercept		$ 10,821	$ 2,281

Exhibit 1
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	Actual 2025/26 BRA ClrPt	2025/26 BRA calculated ClrPt	All Adjustments ClrPt	
Clearing Point				
UCAP	135,684	135,707	136,812	
$/MW-day	$ 269.92	$ 284.45	$ 106.31	
			OK	
RPM Revenue without constrained LDA	13,368	14,090	5,309	
Actual RPM Revenue (IMM Results)	14,687	14,687		
LDA Premium	1,319	597		
DOM LDA UCAP MW	20,003			
DOM LDA Premium ($/MW-Day)	$ 174.34			
DOM LDA Premium ($M)	1,273			
BGE LDA UCAP MW	607		761	
BGE LDA Premium ($/MW-Day)	$ 196.43		$ 117.93	
BGE LDA Premium ($M)	44		33	
Total LDA Premium	1,316	597	33	
TOTAL RPM REVENUE	14,684	14,687	5,341	
			(9,346)	-64%

Exhibit 1
Montalvo Workpapers

This tab reclears the RTO BRA based on revised assumption, with comparison to actual BRA value

		Actual 2025/2(	2025/26 BRA re-modeled	All Adjustments
	Installed Reserve Margin (IRM)	39.2%	39.15%	
	Pool-Wide Accredited UCAP Factor	79.69%	79.69%	
	Forecast Pool Requirement (FPR)	1.1089	1.1089	1.1089
	Preliminary Forecast Peak Load	6,259.0	6,259.0	6,017.6
	Reliability Requirement	6,940.7	6,940.7	6,673.0
	Total Peak Load of FRR Entities	0.0	0.0	0.0
	Preliminary FRR Obligation	0.0	0.0	0.0
	Reliability Requirement adjusted for FRR	6,940.7	6,940.7	6,673.0
	EE Addback	71.8	71.8	71.8
Demand Curve				
	Point (Y-intercept)	0.0	0.0	0.0
98.90%	Point (a) UCAP Level, MW	6,936.2	6,936.2	6,671.4
101.60%	Point (b) UCAP Level, MW	7,123.6	7,123.6	6,851.6
106.80%	Point (c) UCAP Level, MW	7,484.5	7,484.5	7,198.6
	Gross CONE, $/MW-Day (UCAP Price)	$466.35	$466.35	$0.00
	Net CONE, $/MW-Day (UCAP Price)	$45.34	$45.34	$224.24
	Point (Y-intercept)	$ 466.35	$ 466.35	$ 336.36
150%	Point (a) UCAP Price, $/MW-Day	$ 466.35	$ 466.35	$ 336.36
75%	Point (b) UCAP Price, $/MW-Day	$ 34.01	$ 34.01	$ 168.18
0%	Point (c) UCAP Price, $/MW-Day	$ -	$ -	$ -
Supply curve				
	CETL	6,031.0	6,031.0	6,031
	Top (pt 4A) UCAP Level, MW	6,638	6,637.9	7,182
	Pt 4B UCAP Level, MW	6,637	6,636.9	6,654
	Pt 4C UCAP Level, MW	6,627	6,626.9	6,644
	price taker point (75%) UCAP Level, MW	4,970	4,970.2	4,987
	Top (pt 4A) UCAP Price, $/MW-day	$ -	$45.34	$224.24
	Pt 4B UCAP Price, $/MW-day	$ -	$45.34	$224.24
	Pt 4C UCAP Price, $/MW-day	$ -	$45.34	$124.06
	price taker point (75%) UCAP Price, $/MW-day	$ -	$ -	$ -
	Supply Curve - clearing segment			
	Segment (select to meet clearing pt)			1
	Top pt - UCAP		6,626.9	7,182
	Bottom pt - UCAP		4,970.2	6,654.2
	Top pt - $/MW-day		$ -	$ 224.24
	Bottom pt - $/MW-day		$ -	$ 224.24
	Slope		-	-
	Y-intercept		$ -	$ 224
	Demand Curve - clearing segment			
	Segment (select to meet clearing pt)			2
	Top pt - UCAP		-	6,671.4
	Bottom pt - UCAP		6,936.2	6,851.6
	Top pt - $/MW-day		$ 466.35	$ 336.36
	Bottom pt - $/MW-day		$ 466.35	$ 168.18
	Slope		-	(0.933)
	Y-intercept		$ 466	$ 6,563

Exhibit 1
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Clearing Point	Actual 2025/26 BRA ClrPt	2025/26 BRA re-modeled ClrPt	All Adjustments ClrPt
UCAP	6,638	6,638	6,792
$/MW-day	$ 466.35	$ 466.35	$ 224.24
			OK
Local BGE Cleared Capacity (UCAP MW)	606.9	606.9	760.5
Cost of BGE Local capacity ($Millions)	103	103	62

Exhibit 1
Montalvo Workpapers

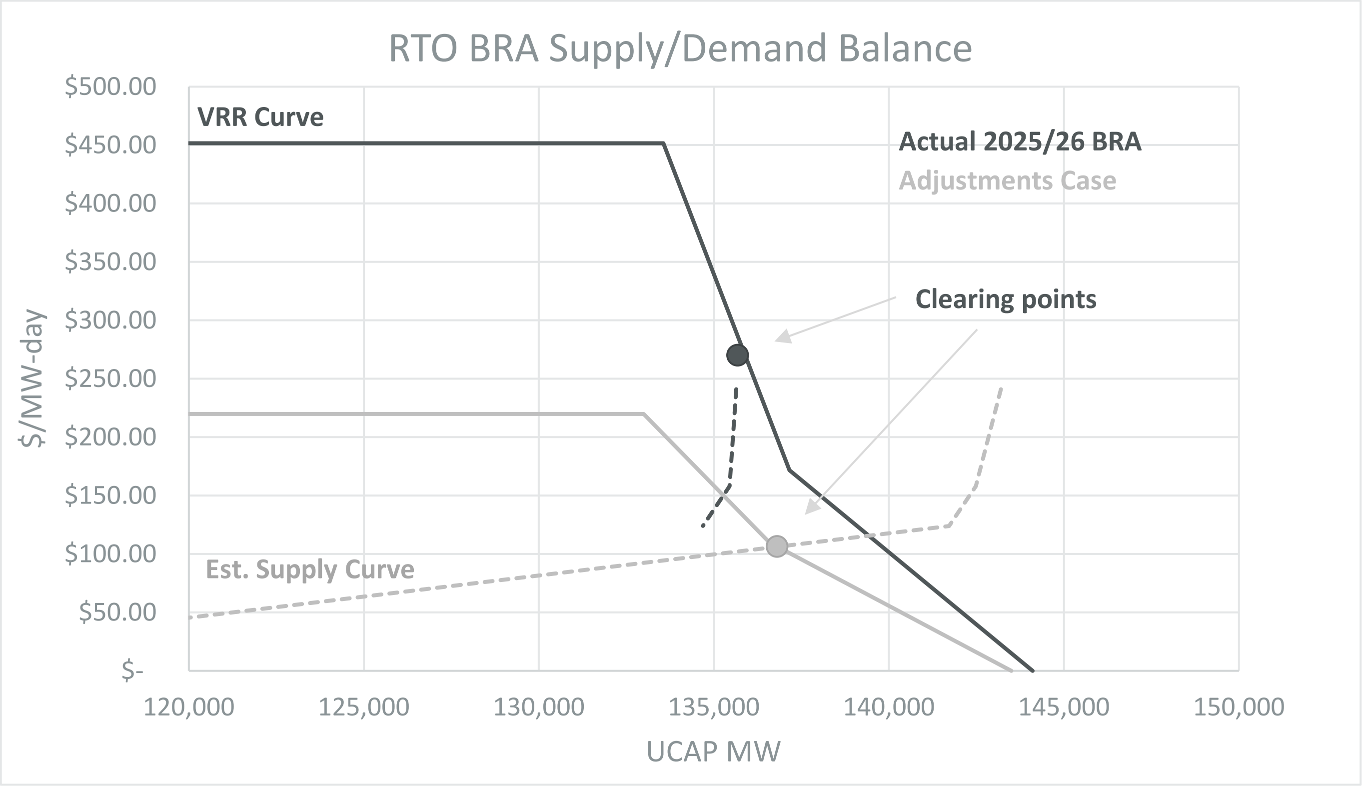

EXHIBIT 2

Resume of Marc D. Montalvo

DAYMARK®
ENERGY ADVISORS

Marc D. Montalvo

President & CEO

For almost 30 years I have worked with industry and policymakers to design effective and efficient market and regulatory structures and to develop and deploy energy infrastructure. My areas of expertise are utility regulation, power markets, and strategic planning. My work has generally focused on problems of regulatory economics, capital planning, cost-benefit analysis, risk management and resilience planning. My consulting engagements frequently require facilitating decision-making processes and negotiating amongst broad sets of interests. I have been invited to present on numerous industry topics and have testified before federal and state regulators. I advise electric utilities, renewable power and transmission project developers, large industrial and commercial end-users, industry and consumer advocacy organizations, and municipal and state government agencies.

INDUSTRY EXPERIENCE

- Transmission & distribution policy: tariff structures, cost recovery and cost allocation mechanisms, revenue requirements, FERC formula rates, capital structure, and ROE analysis
- Capital budgeting and investment analysis
- FERC transmission and market policy
- Cost-benefit analysis, economic impact, and policy evaluation
- Competitive power market design and economics – have addressed market design issues in ISO-NE, NYISO, PJM, MISO, SPP, and ERCOT
- Resource planning and reliability analysis
- Integration of public policy transmission projects, renewables, and storage resources
- Decision-making under uncertainty

Daymark Energy Advisors | www.daymarkea.com Worcester, MA

Daymark Energy Advisors is an employee-owned consulting firm that provides engineering, advisory, and analytical services to companies and policymakers pursuing decarbonization of the electric power sector.

- President & CEO 2015 – Present
  Board of Directors
- V.P. of Business Strategy 2014 – 2015

ISO New England | www.iso-ne.com Holyoke, MA

ISO New England is the FERC-jurisdictional utility responsible for operating the New England power grid, administering the regional wholesale power market, and performing reliability planning.

- Director of Enterprise Risk Management 2012 – 2014
- Director of Market Monitoring 2009 – 2012

- Director of Market Development 2004 – 2009

La Capra Associates (now Daymark Energy Advisors) Boston, MA

- Manger of Market Analytics 2002 – 2004
- Senior Consultant 2000 – 2002
- Energy Market Analyst 1997 – 2000

New England Power Company (NEES) Westborough, MA

- Analyst: generation operations and marketing 1996–1997

TEACHING EXPERIENCE

Clark University, School of Management | www.clarku.edu/gsom Worcester, MA

- Adjunct Professor 2016–2020
  - MIS 5650 Applied Business Analytics | Focus: applications of simulation and optimization methods to managerial decision-making
  - FIN 5417 Financial Consulting Project | Focus: valuation and financing of renewable power project investments

Northeast Energy and Commerce Association | www.necanews.org

- Instructor
  - Electricity 101 Introduction to Wholesale Power Markets, spring 2017
  - Energy Finance 101 Introduction to Asset Valuation, fall 2016 and fall 2017

ISO New England | www.iso-ne.com Holyoke, MA

- Instructor, Human Performance Improvement: Introduction to Concepts and Theory, 2013

EDUCATION

M.S., Finance, Clark University, 2007 Worcester, MA

B.S., Mathematics, Allegheny College, 1995 Meadville, PA

ADDITIONAL EDUCATION AND TRAINING

- *Leadership Development Program,* ISO New England/Rensselaer Polytechnic Institute, 2013
- *Certified Balanced Scorecard Professional,* Balance Scorecard Institute/George Washington University, Alexandria, VA, 2012
- *Executive Certificate: Technology, Operations, and Value Chain Management,* MIT Sloan School of Management Executive Program, Cambridge, MA2008
- *Management Information Systems; Process Modeling and Optimization* (graduate courses), Worcester Polytechnic Institute, Worcester, MA, 2008
- *NERC Power System Operator Certification*, NERC/ISO New England, Holyoke, MA, 2006
- *Total Quality Management: Causal Analysis*, ISO New England, Holyoke, MA, 2006
- *Electric Power System Planning and Operations*, University of Illinois: Continuing Engineering Education, Champaign, IL, 1997

Montalvo Resume Appendix

REFEREED JOURNAL PAPER

J. Zhao, M. Montalvo, B. Brereton, *Gaming-Based Reserve Constraint Penalty Factor Analysis*, IEEE Transactions on Power Systems, volume 26, issue 2, 2011.

SELECTED CONFERENCE PRESENTATIONS

- *HVDC for U.S. Transmission*, 4th Annual Transmission Infrastructure US Conference, June 2024.
- *Leading Through a Changing Energy Landscape*, New England Energy Conference and Exposition, June 2024.
- *Conference Summary: Engaging Stakeholders to Effect Grid Transformation*, NECBC U.S.-Canada Executive Energy Conference, November 2023
- *The expected beneficial impacts of offshore wind on regional wholesale prices and reliability*, RENEW Northeast annual meeting, November 2022.
- *Addressing mechanisms for accelerating clean energy resource deployment*, Massachusetts Energy Markets Business Roundtable with U.S. Senator Ed Markey and staff at Greentown Labs, June 2022.
- *U.S. Electricity Regulator [FERC] Grapples with Barriers to A Clean Grid*, University of Pennsylvania Kleinman Center Energy Policy Now podcast, November 2021.
- *Rethinking Transmission Planning: Meeting the Region's Clean Energy Goals*, NESCOE Transmission Planning Technical Conference, February 2021.
- *Decarbonizing the Electricity Sector: A Strategic View,* 5th Annual Grid Modernization Forum, May 2020.
- *Streamlining Interconnection Procedures in the Northeast*, Solar and Energy Storage Northeast, February 2020.
- *The Green New Deal: A Focus on Decarbonizing the Power Sector*, hosted by the Clark University graduate student chapter of Net Impact, March 2019.
- *Battery Storage: Commercial Opportunities in FERC's Regional Markets*, Energy Storage Summit Americas, February 2019.
- *Carbon Charge: Proposal Evaluation*, NY Integrating Public Policy Task Force, August 2018.
- *System Peaks: Considerations for a Clean Peak Standard or Portfolio Requirement, The Massachusetts Department of Energy Resources Energy Storage Public Stakeholder Forum, May 2018.*

EXPERT TESTIMONY

FORUM	ON BEHALF OF	MATTER
Mass D.P.U.	AEU, NECEC, CCSA, SEIA	Affidavit proposing a preferred framework and guiding principles for an effective proactive distribution planning, cost recovery and cost allocation regime under the Electric System Modernization Planning process. Docket Nos. 24-10, 24-11, 24-12. March 2024.

FORUM	ON BEHALF OF	MATTER
Federal Energy Regulatory Commission (FERC)	New England State Committee on Electricity (NESCOE)	Affidavit addressing the structure of an effective Independent Transmission Monitor within New England's planning and regulatory context. Docket No. AD21-15-000, AD22-8-000. March 2023.
FERC	NY Department of State Utility Intervention Unit (NY UIU)	Affidavit addressing FERC's transmission planning and cost allocation NOPR with particular focus on the impact of its proposals on New York's existing planning processes and policy goals. Docket No. RM21-17-000. August 2022.
New Brunswick Electric Utility Board (NB EUB)	New Brunswick Public Intervener (NB PI)	Examined and recommended modifications to New Brunswick Power's (NBP) proposed OATT update and transmission revenue requirement application; addressed (1) satisfaction of FERC's transmission reciprocity requirements, (2) ancillary service rates, (3) requested target Rate of Return; and (4) load assumptions and supporting data. Matter 513. March 2022.
FERC	NY UIU	Provided a technical affidavit supporting the adoption of the NYISO proposed marginal ELCC-based capacity accreditation method. Docket No. ER22-772-000. February 2022.
FERC	SOO Green HVDC Link ProjectCo, LLC (SOO Green)	Argued that PJM's external capacity participation rules create an unjust and unreasonable barrier to entry for generation seeking to sell capacity into PJM via an HVDC tie line. Docket No. EL21-103. September 2021.
FERC	Joint PJM Cooperatives: East Kentucky Power Cooperative, Buckeye Power, Southern Maryland Electric Cooperative	Argued that PJM's proposed changes to the treatment of Self-Supply entities, specifically the treatment of electric cooperatives, under the MOPR revisions are just and reasonable. Docket No. ER21-2582. August 2021.
FERC	SOO Green	Argued that PJM's interconnection rules create an unjust and unreasonable barrier to entry for merchant transmission projects. Docket No. EL21-85-000. June 2021.
FERC	American Public Power Association (APPA)	Declaration addressing FERC's proposed ROE incentive adder to join an RTO. Supplemental NOPR regarding Electric Transmission Incentives Policy Under Section 219 of the Federal Power Act, Docket No. RM20-10-000. June 2021.
FERC	NY UIU	Argued that Cricket Valley Energy Center and Empire Generating Company's complaint that the NYISO's tariff is unjust an unreasonable and seeking remedy via broad expansion of the MOPR lacked factual and economic foundation and should be rejected. Docket No. EL21-7-000. November 2020.
FERC	American Municipal Power	Argued that ATSI's cost-benefit analysis did not support recovery of the RTO realignment costs requested. Testimony included corrections to the counterfactual and key market assumptions. Docket No. ER20-1740-000. May 2020.

FORUM	ON BEHALF OF	MATTER
FERC	EDF Renewables, EDP Renewables North America, Enel Green Power North America, and Enel North America	Argued that SPP's proposal to eliminate the Z2 revenue credits for Creditable Upgrades was not appropriate and that incremental long-term transmission congestion rights ("ILTCRs") are not a substitute. Docket No. ER20-453-000. May 2020.
New York Public Service Commission (NY PSC)	NY UIU	Submitted responses to questions arguing market mechanisms should be used to cost effectively maintain resource adequacy while achieving state public policy objectives regarding renewable energy resource deployment and power system decarbonization. Case 19-E-0530. November 2019.
FERC	NY UIU	Submitted reply comments arguing that FERC's transmission incentive policy should adopt broader use of competitive processes and market-based incentives. Docket No. PL19-03.
Massachusetts Department of Public Utilities (MA DPU)	Massachusetts Department of Energy Resources (MA DOER)	Reviewed the Performance Base Rate ("PBR") filing of National Grid. Recommended that National Grid expand the set of reliability metrics to increase transparency and incorporate a formal program for addressing resilience into its PBR plan; offered a framework for assessing resilience. No. 18-150.
NB EUB	NB PI	Examined New Brunswick Power's (NBP) revenue requirement application and recommended the company adopt the FERC's pro forma balancing calculation charge methodology. Matter 415. October 2018.
FERC	National Rural Electric Cooperative Association and the American Public Power Association	Argued that FERC exempt public power utilities from PJM's expanded Minimum Offer Price Rule. No. EL18-178. October 2018.
FERC	Central Maine Power	Technical report assessing the potential impacts of the New England Clean Energy Connect Transmission Project on production costs and transmission congestion in New England. No. ER18-2261. August 2018.
NB EUB	NB PI	Examined Algonquin Tinker GenCo's (ATG) revenue requirement application and recommended adjustments to unsupported cost items and to the requested ROE. Matter 385. April 2018.
U.S. 7th Circuit Court of Appeals	*Amici Curiae* (submitted jointly with Mark Cooper, Steven Corneli, Devin Hartman, Andrew Kleit, Robert Michaels, Byron Schlomach, Roy Shanker) in Support of Plaintiffs	Argued that the Illinois ZEC program is an uneconomic subsidy that distorts outcomes and incentives in FERC jurisdictional wholesale markets and may not further the stated goal of reducing long-term green-house-gas emissions. No. 17-2433. September 2017.

FORUM	ON BEHALF OF	MATTER
FERC	NRG Energy	Argued that MISO's proposed Competitive Retail Area Forward Resource Auction design would lead to inefficient pricing and sub-optimal capital allocation. No. ER17-284-000. December 2016.
FERC	NY UIU	Argued that the NYISO demand curve Net CONE assumptions do not align with observed marginal cost of supply and preferences of buyers. No. ER17-386-000. December 2016.
FERC	NY UIU	Regarding NextEra Energy Transmission (NEET) New York's requested base ROE, recommended alternative proxy group and recalculated the ROE using assumptions that better reflected prevailing market risk premium. No. ER16-2719-000. December 2016.
FERC	Dominion, Exelon, Calpine, NRG Energy	Argued that ISO-NE market rules implementing a revised Forward Capacity Market (FCM) demand curve could distort investment incentives due to underestimation of the cost of risk and the value of foregone optionality in the specification of the curve's parameters. No. ER16-1434-000. May 2016.
FERC	NY UIU	FERC Notice of Proposed Rulemaking (NOPR): Offer Caps in Markets Operated by Regional Transmission Organizations and Independent System Operators. Submitted comments addressing the adverse efficiency impact of setting the offer cap too high and of maintaining different caps in adjacent regions. No. RM16-5-000. April 2016.
FERC	NRG Energy	Argued that ISO-NE market rules revising retirement delist bid submission and mitigation rules could restrict exit and raise prices without achieving market power mitigation goals. No. ER16-551-000. January 2016.
FERC	NY UIU	Argued that NYISO's proposed Comprehensive Scarcity Pricing design could lead to less efficient dispatch, increasing fuel costs and reducing overall market efficiency. No. ER16-425-000. December 2015.
FERC	NY UIU	Argued that NYISO market rules regarding Reliability Must Run (RMR) needs assessment and compensation lead to compensation above going-forward costs and create perverse incentives for resources to prefer RMR treatment. No. ER16-120-000. November 2015.
NB EUB	NB PI	Examined Algonquin Tinker GenCo's (ATG) revenue requirement applications and identified methodological and data problems with and recommended changes to ATG's test year assumptions, adjustments, cost normalization, and cost of capital calculations. Matter 256. November 2015.

FORUM	ON BEHALF OF	MATTER
FERC	NY UIU	Negotiated settlement of NY Transco revenues requirement and rate. Matters included ROE, capital structure, formula rate template and protocols. No. ER15-572-000. November 2015.
FERC	NY UIU	Negotiated settlement of Ginna Nuclear RMR agreement. Matters included term and payment structure. No. ER15-1047-000. October 2015.
FERC	PSEG Energy & Trading, NRG Energy, NextEra Energy Resources	Argued that proposed ISO-NE market rule regarding the Dynamic Delist Bid Threshold, Static Delist Bid submission and adjustment process, and the Pivotal Supplier Test creates barriers to exit, raising prices without achieving the market power mitigation goals. No. ER15-1650-000. May 2015.
NB EUB	NB PI	Regarding Algonquin Tinker GenCo's revenue requirement. Evaluated need for requested transformer upgrade and recommended ROE and allocation of common plant to transmission consistent with FERC cost allocation principles. Matter 256. March 2015.
FERC	"Transition Coalition"	Identified design issues and submitted an analysis of the cost of PJM's proposal to transition to the capacity performance-based RPM model and a critique of cost-benefit estimates submitted on behalf of Exelon. No. ER15-623-000. February 2015.
NB EUB	NB PI	Assessed the compliance of the non-rate terms and conditions of New Brunswick Power's proposed OATT with FERC policy and recommended changes to the proposed ancillary services revenue requirements and rates. Matter 256. February 2015.
FERC	ISO New England	Revised Financial Assurance Policy's (FAP) security agreement to perfect the ISO's interest in cash collateral posted by market participants. No. ER14-1448-000. March 2014.
Connecticut Public Utilities Regulatory Authority	Connecticut Public Utilities Regulatory Authority	Fact witness for the PUC regarding People's Power and Gas, LLC's non-compliance with the ISO New England financial assurance and billing policy, leading to suspension and removal from the ISO-NE market. No. 13-12-27. February 2014.
FERC	ISO New England	FAP change that set collateral requirements for resources with capacity supply obligations under the pay-for-performance changes to the FCM rules. No. ER14-1050-000. January 2014.
FERC	ISO New England	Change to FAP provisions regarding the timing and amounts of financial assurance collections for non-commercial capacity cleared through the FCM. No. ER13-525-000. December 2013.

FORUM	ON BEHALF OF	MATTER
FERC	ISO New England	FAP, Billing Policy, and Information Policy changes to comply with the Commodity Futures Trading Commission (CFTC) order that only "Appropriate Persons" participate in the ISO markets. No. ER13-1875-000. July 2013.
FERC	ISO New England	FAP change to the timing of suspension in case of default and introduction of a collateral requirement ratchet to address multiple defaults. No. ER13-1257-000. April 2013.
FERC	ISO New England	FAP change that provide a limited opportunity for participants with under-collateralized internal bilateral transactions to cure prior to rejection. No. ER12-2575-000. September 2012.
FERC	ISO New England	Market rule change that established a Minimum Offer Price (MOPR) based mitigation mechanism in the FCM. No. ER12-953-001. December 2012.
FERC	ISO New England	Market rule change that provides a methodology for (1) the submission and evaluation of delist bids from resources at stations with common costs and (2) the compensation of resources at stations with common costs retained for reliability. No. ER10-750-000. February 2010.
FERC	ISO New England	Market rule change increasing the local Thirty Minute Operating Reserve constraint penalty factor from $50/MWh to $250/MWh. No. ER10-97-000. October 2009.
FERC	ISO New England	Market rule changes revising allocation of uplift costs associated with transactions cleared at external nodes in the day-ahead energy market. No. ER09-547-000. January 2009.
FERC	ISO New England	Answer to a Maine PUC complaint regarding the appropriateness of making OATT Schedule 2 VAR capability payments to generating Resources receiving forward capacity market payments. No. EL07-38-000. October 2008.
FERC	ISO New England	Market rule change to reject self-schedules submitted to the Day-Ahead Energy Market that would result in security violations based on production cost impact rather than time stamp. No. ER08-1221-000. July 2008.
FERC	ISO New England	Market rule changes to day-ahead energy market compensation of priced transactions cleared at external nodes. Nos. ER08-61-001,002 & ER08-1222-000. July 2008.
FERC	ISO New England	Market rule changes revising rules for submission and scheduling of dispatchable capacity transactions in the day-ahead and real-time market systems. No. ER08-697-000. March 2008.

FORUM	ON BEHALF OF	MATTER
FERC	ISO New England	Market rule changes revising the forward reserve and real-time reserve market settlement rules and the capacity market penalty rate used in the transition period. No. ER08-474-000. January 2008.
FERC	ISO New England	Administrative rule changes to accommodate the in-service of the NRI facility and the retirement of the Phase 1 HVDC facility. No. ER08-111-000. October 2007.
FERC	ISO New England	Market rule change to make financially offsetting positions at an external trading node by a Market Participant and/or its affiliates ineligible for receipt of day-ahead economic uplift payments when the external transmission is binding. No. ER08-61-000. October 2007.
FERC	ISO New England	Clarifications and enhancements to fast-start (CLAIM_10/30) parameter auditing and performance-based testing procedures. No. ER07-1234-000. August 2007.
FERC	ISO New England	The long-term Financial Transmission Rights market design package. No. RM06-08-000. January 2007.
FERC	ISO New England	Real-time dispatch and pricing methodology that jointly optimizes energy and operating reserves; inclusion of location requirements and other enhancements to the forward reserve market; the creation of Asset Related Demand, a demand asset class that participates directly in the wholesale market. No. ER06-613-000. February 2006.
FERC	ISO New England	Redesign of the regulation market to improve reservation and mileage payments. Energy market changes to allow all resources revise incremental energy offers prior to the operating day and to allow external dispatchable contracts set the ex-ante dispatch rate. No. ER05-795-000. March 2005.
FERC	ISO New England	Technical Conference. The status of the ancillary services market project and a discussion of the key design features of the proposed regulation and reserves markets. March 2005.
Connecticut Siting Council	Connecticut Office of Consumer Council	Evaluation of CL&P and UI's application for a certificate of environmental compatibility and public need for a 345-kV electric transmission line and associated facilities in southwest CT. Assessed compliance with statutory requirements, basis of need, and recommended alternatives that the companies study. No. 272. March 2004.

FORUM	ON BEHALF OF	MATTER
Pennsylvania Public Utility Commission	Pennsylvania Office of Consumer Advocate (PA OCA)	Evaluated the reasonableness and argued revisions to the supply portfolio plan and generation rates proposed by Duquesne Light Co. for the supply of provider of last resort (POLR) service to residential customers through 2010. No. P-00032071. February 2004.
Vermont Public Service Board (VT PSB)	Vermont Electric Power Company (VELCO)	Regarding VELCO's petition for a Certificate of Public Good authorizing the construction of the Northwest Reliability Project, evaluated the economic and technical merits of wires and non-wires alternatives to VELCO's proposed transmission project as a means of addressing Vermont's reliability need. No. 6860. May 2003.
VT PSB	VELCO	Fact witness regarding (1) the design of ISO New England's congestion management system, (2) congestion in the bulk power system and how it affects system operations and the cost of power, and (3) the implications of the design for Vermont. No. 6860. May 2003.
FERC	PA OCA	Argued that Reliant Energy Mid-Atlantic Power Holdings, LLC's had market power and RMR services in PJM should be capped at the going-forward costs of the resources in question. No. EL03-116-000. April 2003.
Arkansas Public Service Commission (AR PSC)	General Staff of the Arkansas Commission	Report: The adequacy of the generation and transmission infrastructure in Arkansas to support wholesale and retail competition. No. 00-190-U. October 2001.
AR PSC	AR Commission Staff	Report: The status of wholesale market development in Arkansas and the outlook for wholesale electric market prices in the region. No. 00-190-U. September 2001.

LIST OF CLIENTS (2014-PRESENT)

AbleGrid Energy Solutions, Algonquin Power & Utilities Corp, Ameresco, American Municipal Power, American Public Power Association (APPA), Anbaric Development Partners, Avangrid Networks, Town of Bar Harbor, Bay State Wind, Borrego Solar, Braintree Electric Light Department, Burlington Electric Department, Calpine Corp, Carlyle Group, Cayman Islands National Energy Policy Committee of the Electricity Regulatory Authority, Cell Signal Technologies, Central Maine Power, Chicopee Electric Light Department, Chugoku Electric Power, Clearway Energy, Clean Energy Buyers Association, Coalition for Community Solar Access, ConnectGen, Connecticut Municipal Electric Energy Cooperative (CMEEC), Connecticut Office of Consumer Council, Connecticut Public Utilities Regulatory Authority (PURA), Constant Energy Capital, Direct Connect Development Company, Dominion Resources, East Kentucky Power Cooperative, EDF Renewables, EDP Renewables North America, Enel Green Power North America, Enel North America, Equinor, Exelon, FirstLight Power, Florida Reliability Coordinating Council (FRCC), General Staff of the Arkansas Commission, City of Gloucester, Green Mountain Power, Highview Power, Hudson Energy Development, ISO New England, Jupiter Power, Massachusetts Department of Energy Resources (DOER), Massachusetts Water Resources Authority (MWRA), Middleborough Gas & Electric Department, National Grid US, National Grid Ventures, National Rural Electric Cooperative Association (NRECA), New Brunswick Public Intervener, New England Clean Energy Council, New England States Committee on Electricity, New York Department of State Utility Intervention Unit, New York State Energy Research and Development Authority (NYSERDA), Nexamp, NextEra Energy Resources, Norwood Light & Broadband Department, NRG Energy, Osaka Gas, Pennsylvania Office of Consumer Advocate, Pine Gate Renewables, Phase I/II Transmission Interconnection Rights Holders (IRH), PSEG Energy & Trading, PSEG Long Island, Reading Municipal Light Department, RENEW Northeast, Seaport Global, Strata Solar, Syncarpha Capital, Taunton Municipal Lighting Plant, Town of Wallingford Electric Division, Vermont Electric Power Company (VELCO), Vermont Weather Analytics Center (VWEC), Vineyard Wind, The World Bank

ATTACHMENT B

Aurora Energy Research

PJM Capacity Market -2025/2026 BRA results & outlook for upcoming auction

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ENERGY RESEARCH

PJM Capacity Market—
2025/2026 BRA results & outlook for upcoming auctions

September 2024

Aurora provides global market leading forecasts & data-driven intelligence to advance the energy transition

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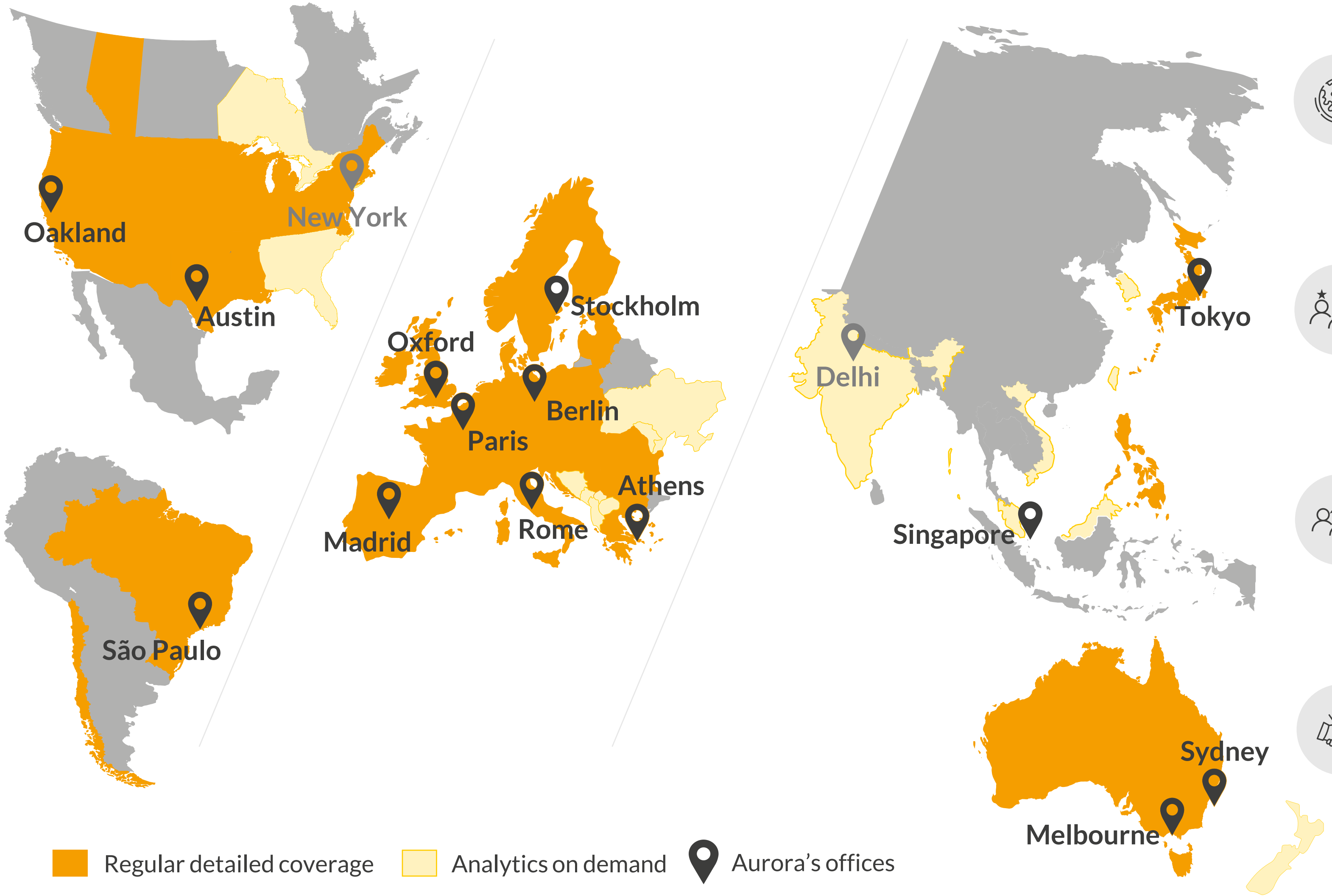
- Natural gas



🟧 Regular detailed coverage 🟨 Analytics on demand Aurora's offices

14 offices and two more coming soon

700+ market experts

850+ subscribing companies

150+ transactions supported in 2023

Source: Aurora Energy Research

Our market-leading models underpin a comprehensive range of seamlessly integrated services to best suit your needs

AURORA

Customization of services

Advisory

Access tailored expert advice and analytics for your crucial projects. Dedicated support for strategy, investments, transactions and policy engagements. **1400+ projects globally**

- **Trusted advisory service** for strategy, investments, transactions and policy engagements

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Make standard analysis bespoke with direct access to our models. Unique SaaS subscriptions to create your own scenarios and asset-specific investment cases. **100+ company licenses**

- **Scenario Forecast:** Forecast scenario comparisons
- **Nodal Explorer:** Nodal granularity visualization interface
- **Chronos:** Bespoke battery valuation forecast

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Receive quarterly outlook reports, bankable price forecasts, **sample investment cases and timely strategic insights** for power and commodities. **700+ subscribing companies**

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- **Bankable battery storage analysis** with detailed costs and revenue for investment cases
- **Bankable nodal basis forecasts,** spatial analysis & nodal trends based on bottom-up power flow modelling

Models & Data

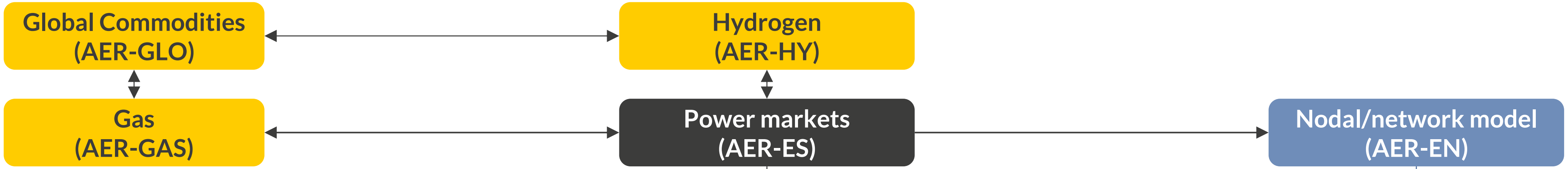
Proprietary, in-house modelling capabilities underpin Aurora's integrated models for power, gas, hydrogen, carbon, oil & coal markets

- Proprietary and continuously updated cutting-edge models populated with highest quality curated datasets
- **Developed over 10 years, 70+ dedicated modellers**

Source: Aurora Energy Research

Unique, proprietary, in-house modelling capabilities underpin Aurora's superior analysis

5 Integrated Models



INPUTS

- Technology
- Policy
- Demand
- Commodity prices[1]
- Weather patterns

Dispatch model

- ½ hourly or hourly
- Iterative modelling
- Dynamic dispatch of plant
- Endogenous interconnector flows

Continuous iteration until an equilibrium is reached

Investment decisions module

- Capacity market modelling
- Capacity build / exit / mothballing
- IRR / NPV driven
- Detailed technology assessments

OUTPUTS

- Capacity mix
- Generation mix
- Wholesale & imbalance prices
- Capacity market prices
- Profit / Loss and NPV
- Electric vehicle charging

ADDITIONAL INPUTS

- Network snapshot - existing & future
- Nodal load map
- Nodal generation map

OUTPUTS

- Power flows & losses
- Nodal prices / loss factors

Up to 70
specifications modelled for each plant

c. 85k
investment hours on modelling capabilities

~15k
model runs per week

50+
strength of modelling team globally

Quarterly updates
through subscription research

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1) Gas, coal, oil and carbon prices fundamentally modelled in-house with fully integrated commodities and gas market model

Source: Aurora Energy Research

Aurora is the market leader in complex transaction support involving flexible and renewable assets accessing multiple revenue streams

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Non-comprehensive project examples

Battery generation

- Buy-side advisor for Engie's successful acquisition of Broad Reach Power
- Sell-side advisor for Black Mountain on ~1.5 GW asset sales to UBS Asset Management, Cypress Creek Renewables, Brookfield Renewable, & East Point Energy
- Siting strategy analysis for battery developer to inform build locations and project valuation
- Buy-side advisor on multiple equity transactions for over 1.5 GW of battery storage projects across ERCOT and CAISO, including nodal modelling, ancillary service price forecasts, and solar/wind + storage co-location analysis

Strategic

- Debt case scenario analysis for large pension fund to inform investing and lending decisions
- Downside scenario modelling for international bank to inform debt sizing
- Pricing and PPA analysis for publicly listed data center company

Renewable generation

- Buy-side advisor for Boralex's acquisition of 840 MW of onshore wind from Blackrock, including nodal pricing, basis risk, and curtailment
- Buy-side financing for 470 MW solar project in ERCOT by SocGen
- Asset-specific valuation of two wind and solar projects totalling 540 MW for infrastructure fund including nodal forecasting and curtailment
- Asset valuation for a large pumped hydro plant participating in the CAISO wholesale and ancillary markets

Thermal generation

- Modelling of proposed ERCOT market reforms (e.g. dispatchable energy credits) for project developer
- Asset valuation for lender for two existing CCGT projects in ERCOT and WECC
- Sell-side advisory for 400 MW OCGT peaking plant in West Texas for large utility
- Analysis of Biden's Clean Electricity Standard design for one of US largest utilities, to engage with White House on the role of gas CCS in the energy transition

Source: Aurora Energy Research

Get in touch with us!

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Reach out for any follow-up questions or to continue the conversation!

Executive Summary

- PJM's **2025/26 BRA** took place in July 2024 and cleared at historically high levels: **$270/MW-day** for the RTO and MAAC; the auction cap for BGE (**$466/MW-day**) and Dominion (**$444/MW-day**)—which rejoined the capacity market after four delivery years as an FRR region, and was modeled as an LDA for the first time.
- These high prices were driven by:
  - Higher demand: +8GW ICAP[1] reliability requirement (compared to the 2024/25 BRA)
  - Lower supply: -4GW ICAP[1] offered (compared to the 2024/25 BRA)
  - PJM's CIFP reforms, implemented for the first time, which raised individual bids by lowering capacity accreditation
- For the **2026/27 BRA**, taking place in December 2024, Aurora considers the outcome highly uncertain: from $100/MW-day (low case) to $696/MW-day (high case), with ~$250/MW-day a p50 expectation. Key factors impacting the 2026/27 BRA relative to the previous auction include:
  - A significantly steeper VRR curve, causing sharply increased price sensitivity compared to previous auctions, raising outcome uncertainty.
  - Higher demand: +3GW UCAP reliability requirement, which could cause a $696/MW-day clearing price (barring supply increases).
  - A strong incentive for increased supply, due to (i) expected higher clearing prices and (ii) effectively removed capacity performance penalties in >50% of PJM, due to a $0/MW-day Net CONE. The extent of supply increases is highly uncertain, but could come from withheld capacity in the 2025/26 BRA (~6GW), DR additions, bidders switching from seasonal to annual bids, or new capacity.

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1) Installed capacity. Structural changes between the 2024/25 and 2025/26 BRAs make a comparison in GW UCAP (unforced capacity)—the market's native unit—meaningless.

Sources: Aurora Energy Research, PJM

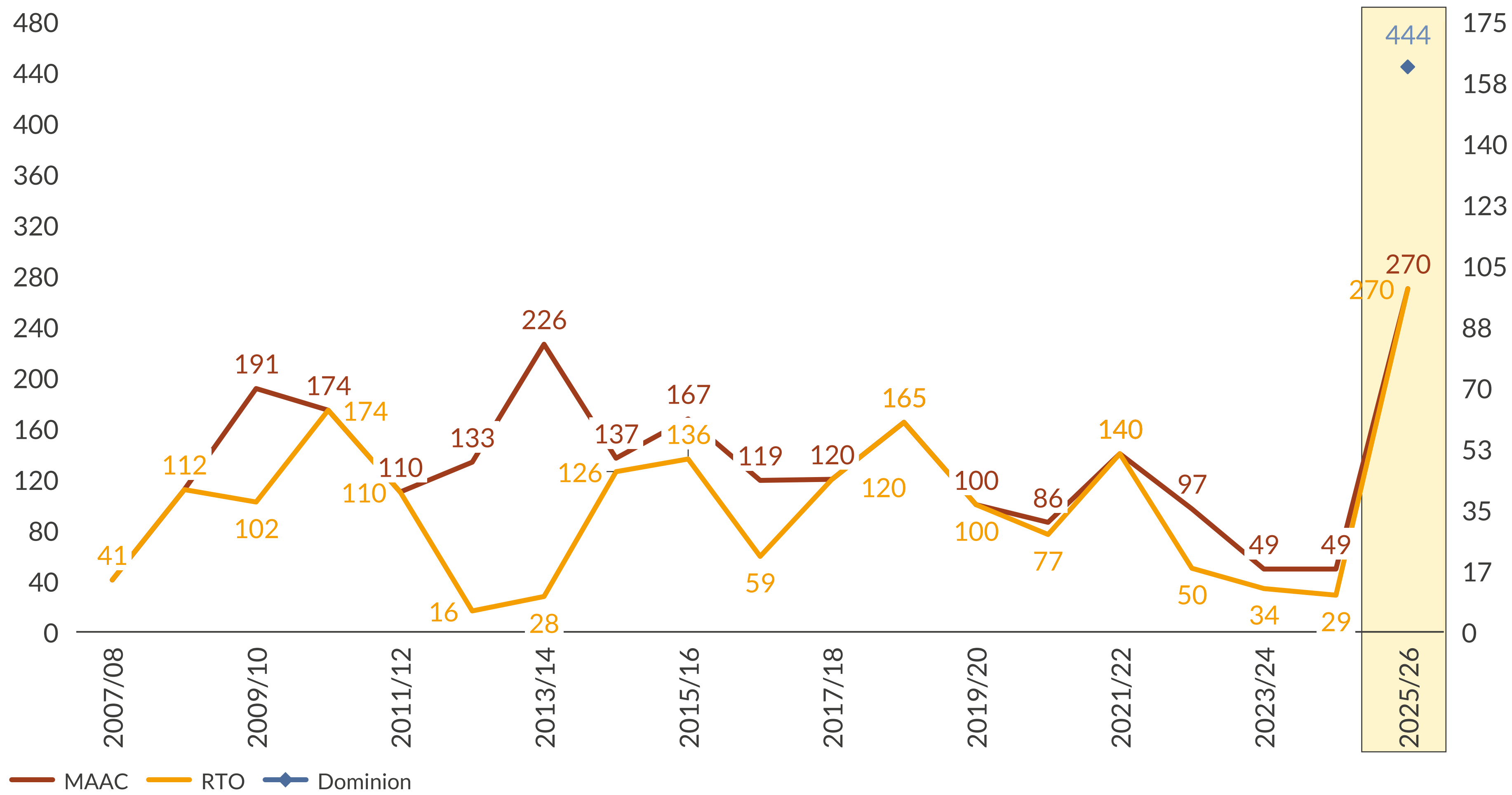
Agenda

Results | The 2025/26 BRA cleared at $270/MW-day, a record for PJM's capacity market, with Dom clearing at its $444 price cap

PJM Base Residual Auction (BRA) clearing price for RTO and selected LDAs

$/MW-day (nominal)

$/kW-year (nominal)



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1) The first delivery year for which PJM held a capacity auction was 2007/08. 2) LDA auction target capacities take existing capacity and capacity transfer objectives (CETO) into account.

Sources: Aurora Energy Research, PJM

RTO

- The Base Residual Auction (BRA) for the 2025/26 delivery year cleared RTO-wide at **$269.92/MW-day**, the highest in the 19-year history of PJM's capacity market.[1]

Dominion

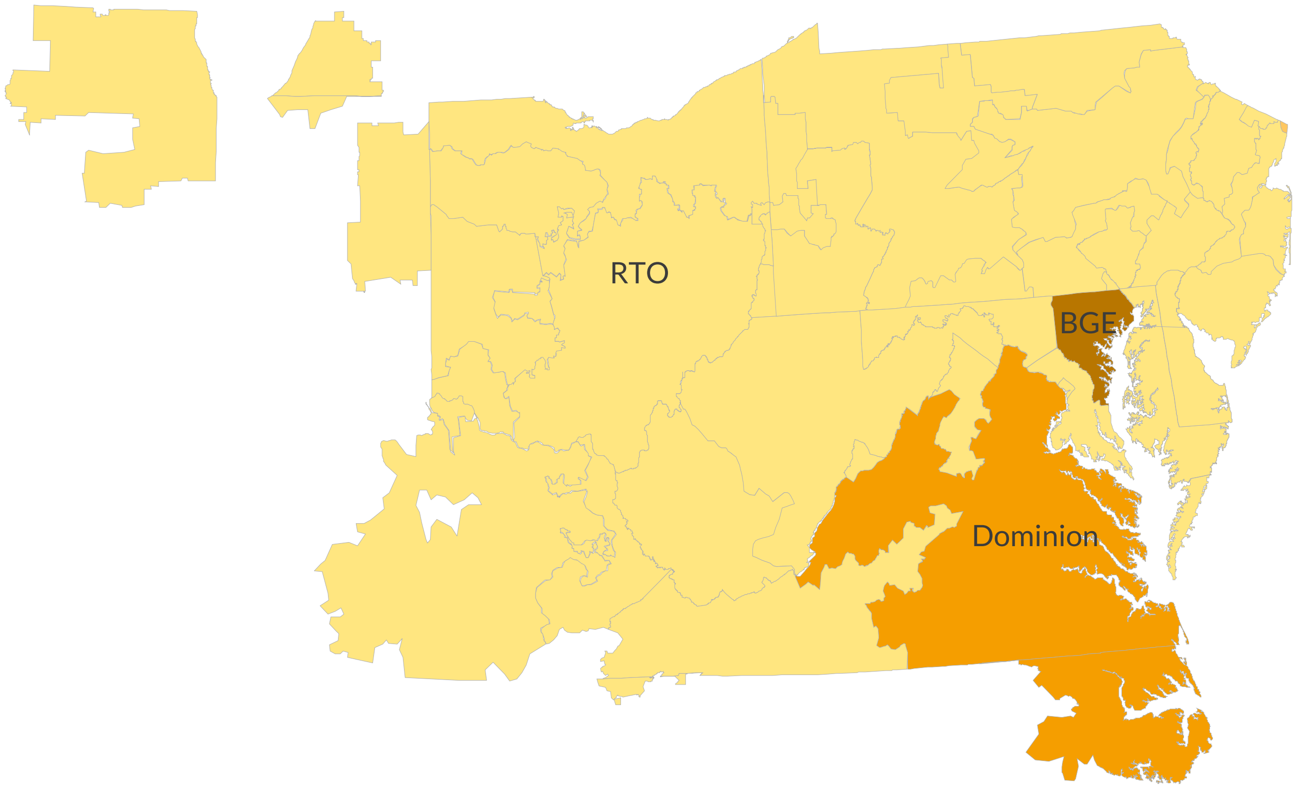
- Dominion, which re-entered the capacity market for the 2025/26 BRA, is one of the two constrained Locational Deliverability Areas (LDAs) in the 2025/26 BRA, clearing well above the RTO at **$444.26/MW-day.**
- LDAs account for transmission constraints across PJM and have individual procurement targets.[2]

MAAC

- MAAC, which has historically been a constrained LDA, cleared at the same level as the rest of the RTO in the 2025/26 BRA.

Results | Nearly all of PJM-RTO cleared at $270/MW-day—10x the last BRA's price—with BGE rising to $466 and Dominion to $444/MW-day

2025/26 BRA clearing prices and constrained LDAs



2025/26 BRA clearing price	RTO	Above RTO (constrained LDA)	
	●	●	●
$/MW-day	269.92	444.26	466.35
($/kW-year)	(98.87)	(162.15)	(170.21)

Parent-child LDA relationship[2]

Clearing price for RTO and all constrained LDAs[1]

$/MW-day

	2024/25 BRA	2025/26 BRA
Rest of RTO	$28.92	$269.92
DEOK	$96.24	$269.92
Dominion	-	$444.26
MAAC	$49.49	$269.92
EMAAC	$54.95	$269.92
BGE	$73.00	$466.35
DPL-South	$90.64	$269.92
Total cost	$2.2bn	$14.7bn

- The RTO clearing price was ~10x higher in the 2025/26 BRA than the 2024/25 BRA.
- 2 LDAs, Dominion and BGE, were constrained in this BRA, down from 5 in the previous auction. Although MAAC cleared at the same price as the rest of RTO, it still cleared at a substantially higher price than in the last BRA.
- Total cost increased by ~$12.5bn from the last auction, primarily due to the significant increase in RTO clearing price.

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1) Constrained LDAs are those with a price above their immediate region parent. For example, BGE was constrained in the 2025/26 BRA because it cleared above the RTO price. 2) Shown for each constrained LDA is the (grand)parent region responsible for all intermediate regions' prices.

Sources: Aurora Energy Research, PJM

Drivers | Supply decreases, load growth, Dominion's capacity market re-entry, and CIFP rule changes all contributed to record-high clearing prices

Factors contributing to the 2025/26 BRA's high clearing prices

		Impact on Clearing Prices
Supply decreases	▪ Due to retirements and modestly lower Demand Response participation, supply eligible to offer into the capacity market declined by 6.5GW[1] from the 2024/25 BRA to the 2025/26 BRA. ▪ Extremely limited new generation is expected to come online prior to the start of the 2025/26 delivery year, particularly for resource types with higher ELCCs, such as dispatchable generation and offshore wind. In total, only 110MW of unforced capacity (UCAP) from new generation cleared the 2025/26 BRA.	↑↑
Demand growth	▪ Driven by data center demand, PJM forecasted peak load increased by 2.2% from 2024/25 to 2025/26, from 150.6GW to 153.9GW.	↑
Dominion rejoining the capacity market	▪ Prior to the 2025/26 BRA, the Dominion LDA primarily satisfied its capacity obligation through an FRR[2] plan outside of the PJM capacity market. Its entry into the capacity market for the 2025/26 delivery year added ~22GW to the RTO UCAP reliability requirement.[3] ▪ However, the generation resources previously used to satisfy Dominion's FRR obligations contributed only ~17GW UCAP of supply, 5 GW below the amount added to the reliability requirement.[3] With Dominion back in the capacity market, this imbalance contributed to the RTO-level supply-demand tightness.	↑
CIFP rule changes	▪ The introduction of a marginal capacity accreditation methodology decreased ELCCs[4] for most resource classes, and therefore UCAP supply. However, the impact of this change was partially offset by a corresponding reduction in the UCAP reliability requirement. ▪ Updates to PJM's approach to modeling reliability risk contributed to an increase in the Installed Reserve Margin (IRM) from 14.7% in the 2024/25 BRA to 17.8% in the 2025/26 BRA.	↓/↑

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1) Measured in ICAP (Installed Capacity) terms. 2) Fixed Resource Requirement. 3) Aurora estimate based on data released by PJM. 4) Effective Load Carrying Capability.

Sources: Aurora Energy Research, PJM

Supply-demand | 2025/26 BRA conditions were much tighter than the previous auction: excess supply offered fell from 16 to 3GW ICAP

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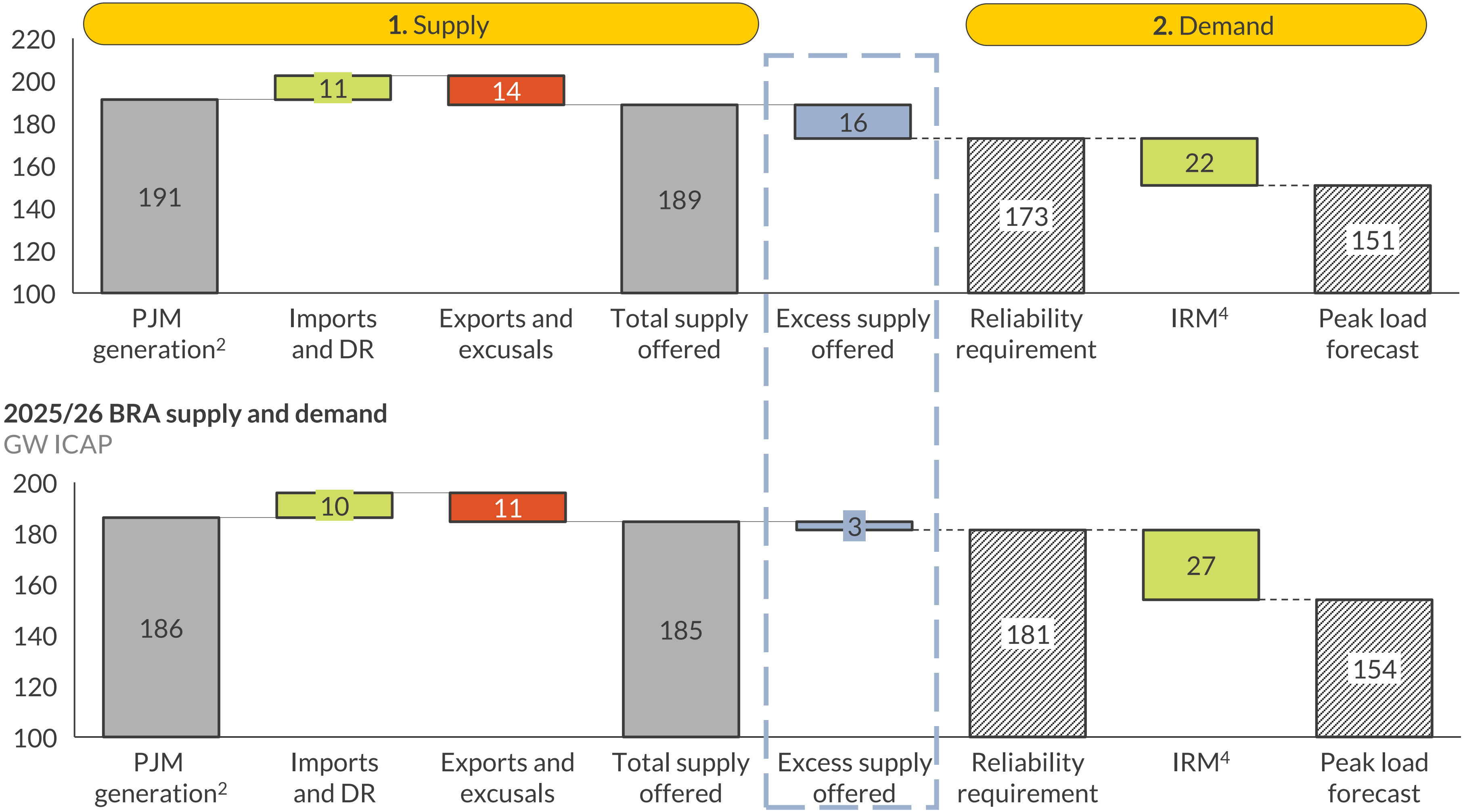
2024/25 BRA supply and demand
GW ICAP



2025/26 BRA supply and demand
GW ICAP

- Given the dramatic change in calculation of UCAP between the 2024/25 and 2025/26 BRA, ICAP[1] values provide the most apt comparison between supply and demand conditions between auctions.

① Total supply offered into the BRA (or committed via an FRR plan) declined from 189GW to 185GW, driven by retirements and modestly lower DR[3] participation.

② Total demand, as reflected by the reliability requirement, increased from 173GW to 181GW, due to:

  - Peak load growth from 151GW to 154GW, driven primarily by data center demand.
  - IRM[4] increase from 14.7% to 17.8%, driven primarily by changes to PJM's reliability risk modeling.

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1) Installed capacity. While PJM's capacity market procures Unforced Capacity (UCAP), results are presented in ICAP terms due to substantial changes in PJM's computation of UCAP between the 2024/25 and 2025/26 auctions. 2) Including Fixed Resource Requirement (FRR) capacity. 3) Demand response. 4) Installed Reserve Margin.

Sources: Aurora Energy Research, PJM

Supply-demand | All offered thermal, nuclear, demand response and solar capacity cleared the 2025/26 BRA

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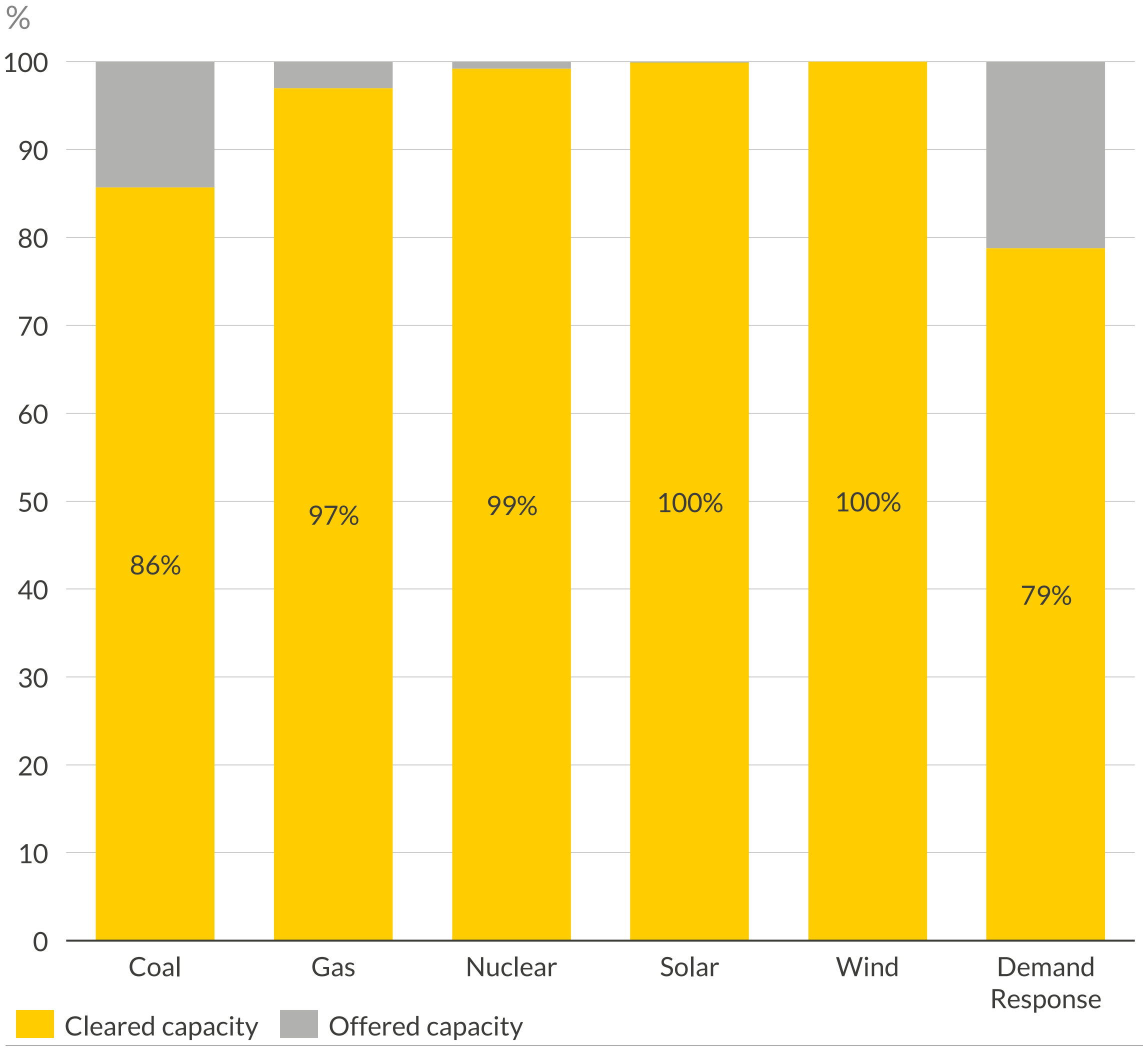
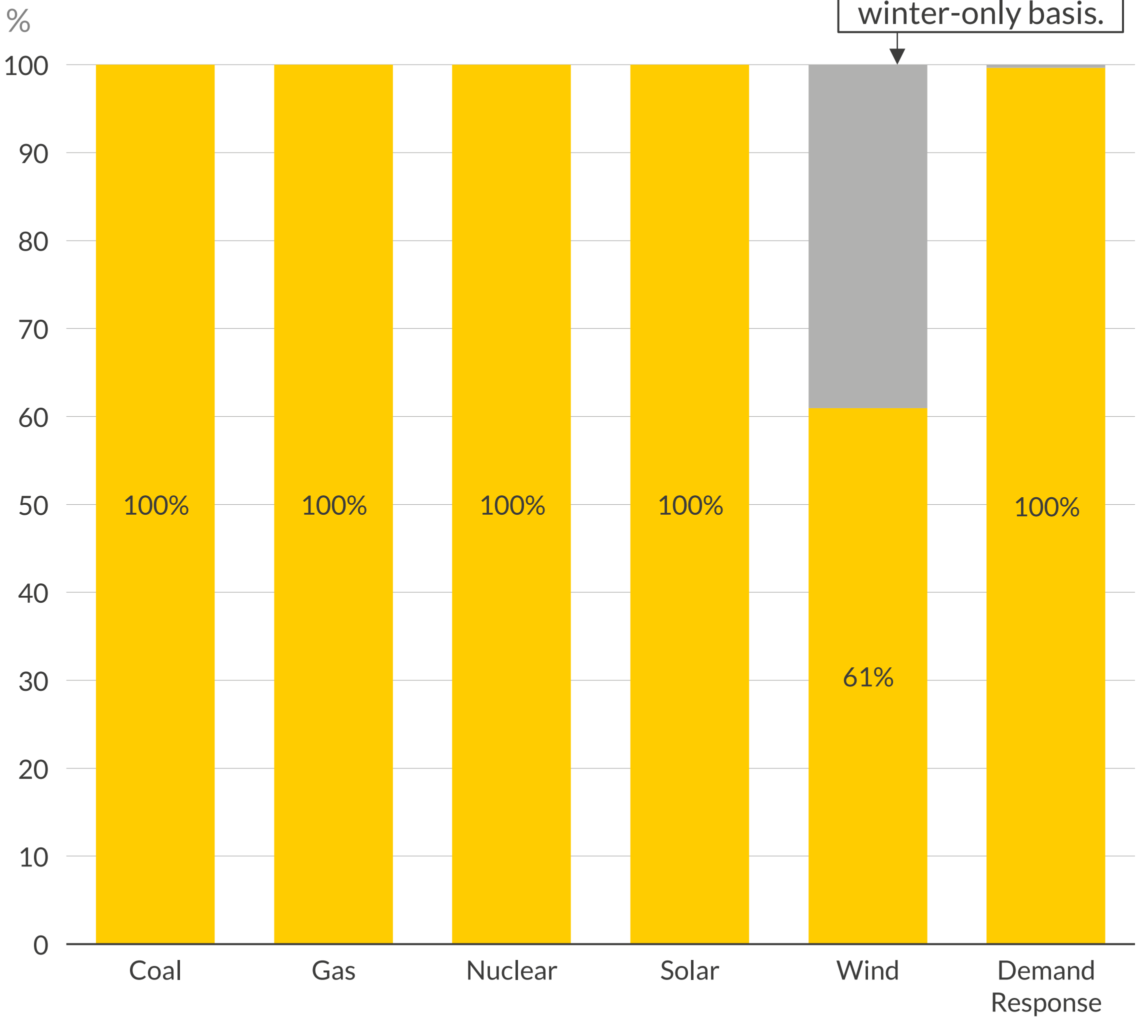
Percent of offered capacity that cleared, 2024/25 BRA



Percent of offered capacity that cleared, 2025/26 BRA

Wind that did not clear likely offered into the RPM on a winter-only basis.



Sources: PJM, Aurora Energy Research

Supply | PJM reported 9.8GW ICAP as "excused" from the 25/26 BRA, comprising categorically exempt resources and retiring thermal plants

Resources "excused" from 2025/26 BRA

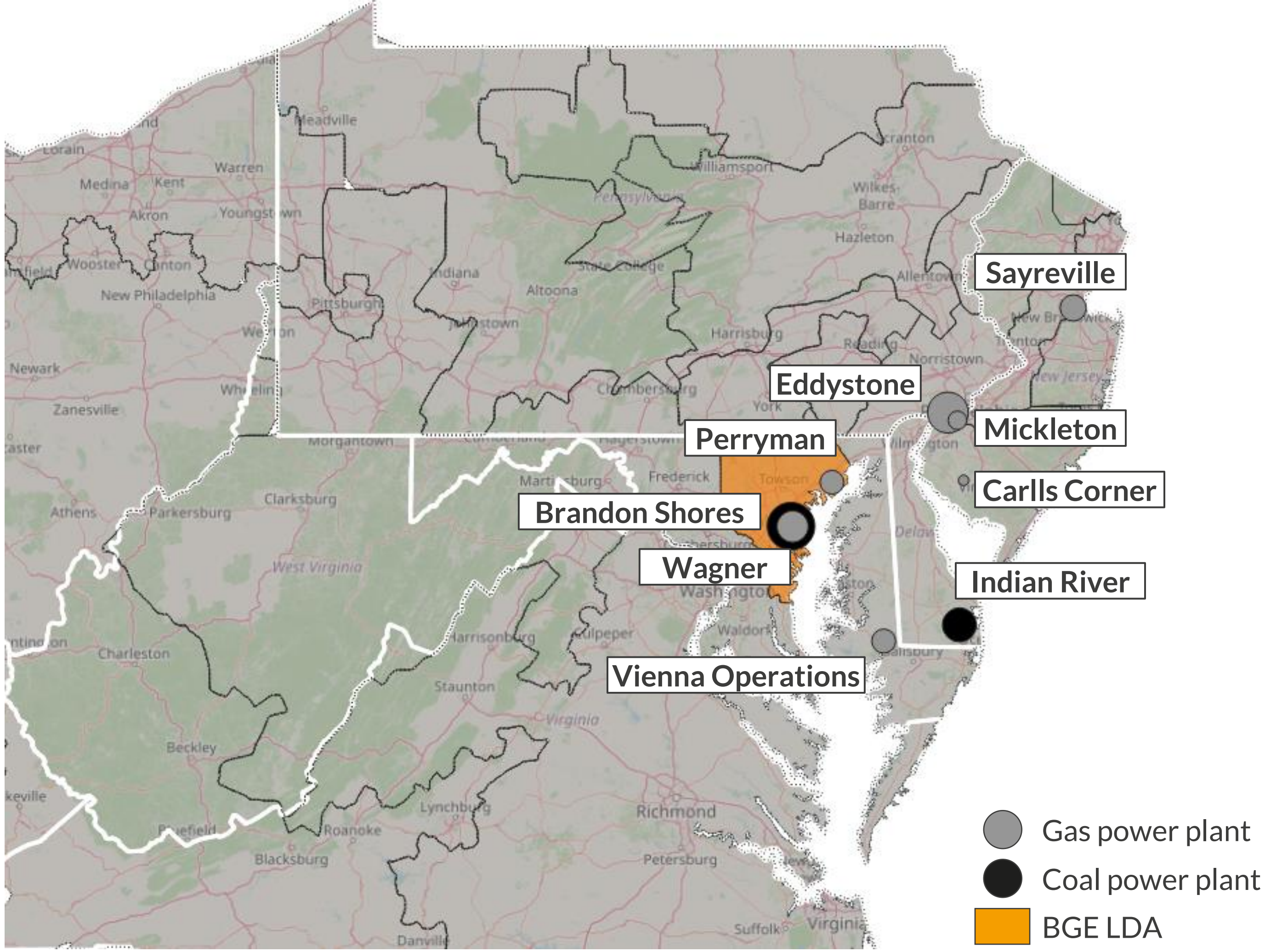
	Total ICAP GW	Associated plants MW ICAP	Likelihood of re-entering capacity market
Reliability must run (RMR) plants	2.4	Brandon Shores (1,282); Wagner units 3-4 (702); Indian River (412)	**Very unlikely:** these plants have already confirmed retirement dates and secured revenue through retirement via the RMR agreements.
Other thermal deactivation requests	1.5	Eddystone (760); Sayreville (217); Vienna (167); Carlls Corner (75); Mickleton (57); Perryman 6 Unit 1 (55); Wagner units 1, CT 1 (139)	**Unlikely:** Withdrawn deactivation requests are precedented, but rare. Certain of these plants (Carlls Corner, Mickleton, and Sayreville) formally retired in June 2024.
Categorically exempt resources	~6	Not available, but the IMM reported that 3.9GW ICAP of intermittent resources and 1.3GW ICAP of storage resources elected not to offer into the 2024/25 BRA.	**Unclear; moderately likely that a portion will re-enter:** ▪ Information on why these resources did not participate is not publicly available, but avoiding of capacity performance penalties is likely a key factor. ▪ High clearing prices and a lack of CP penalties in much of the RTO for the 2026/27 delivery year (due to $0 net CONE) may incentivize capacity to return.

- **Methodology note:** PJM does not publish the data shown here explicitly, except for total excused capacity. The capacities and generators listed are the result of Aurora's analysis, based on the best available data.
- **Almost all resource classes are subject to capacity market must-offer requirement**, and PJM only grants exemptions under specific circumstances:
  - If the resource has submitted a deactivation request to PJM.
  - If the resource has "significant physical operational restrictions" or is "under major repair."
  - If the resource has committed to provide capacity to a region outside PJM.
- Intermittent, Demand Response, and storage (including hydroelectric pumped storage) resources are **categorically exempt** from the capacity market must-offer requirement.

Sources: Aurora Energy Research, PJM

Supply | Thermal plants that did not participate in the 2025/26 BRA due to planned retirements are concentrated in Eastern PJM, particularly BGE

Resources "excused" from 2025/26 BRA due to planned deactivation



The retiring thermal plants that PJM excused from the 2025/26 BRA were concentrated in the eastern portion of PJM, particularly in the Baltimore Gas & Electric (BGE) LDA in Maryland.

- The 1.3GW ICAP Brandon Shores plant and 0.7GW ICAP Wagner plant, both of which are operating through 2028 on Reliability-Must-Run (RMR) contracts, did not participate in the 2025/26 BRA.
- The loss of these plants from the 2025/26 BRA left BGE with only 0.6GW UCAP of internal capacity, resulting in the BGE LDA clearing at its price cap of $444.26/MW-day.
- Prompted by concerns over the impact of capacity market prices on consumer energy bills, ratepayer advocates in several PJM states (including Maryland) have urged PJM to account for the RMR units in the capacity market, even if that requires delaying the 2026/27 BRA.

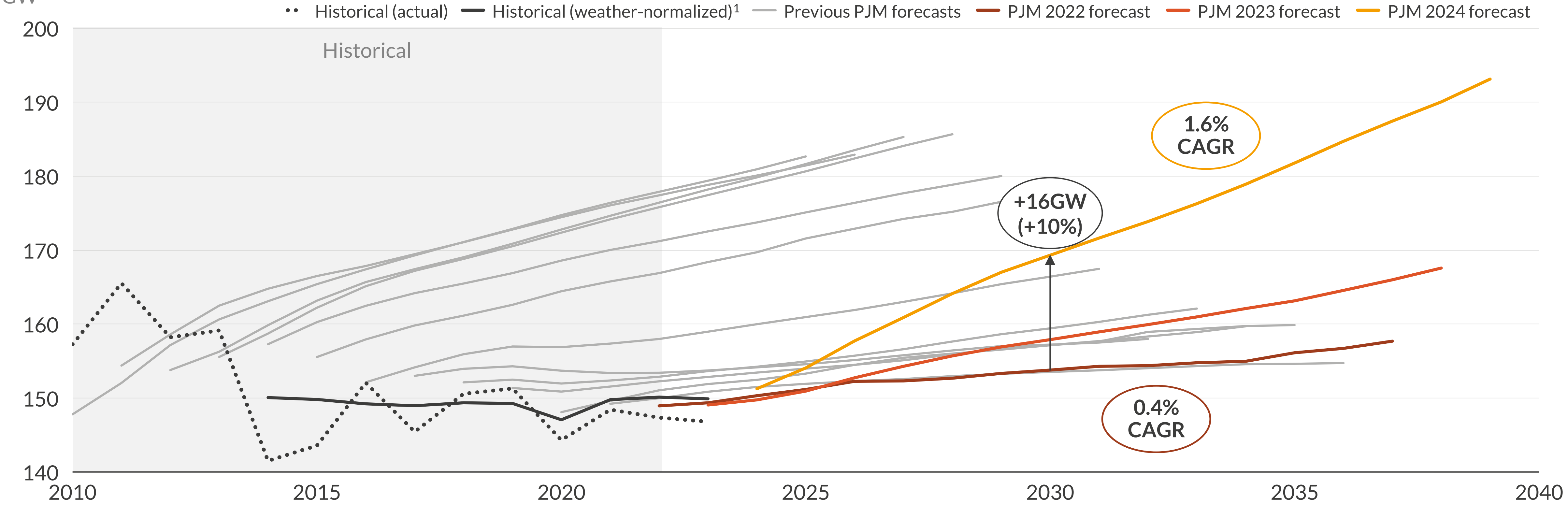
Methodology note: PJM does not publish the plants shown here explicitly, except for total excused capacity. The power plants listed are the result of Aurora's analysis, based on the best available data.

Sources: Aurora Energy Research, PJM, UtilityDive

Demand | 2025/26 BRA demand rose sharply compared to previous auctions primarily due to PJM's 2024 peak load forecast increase

Historical and forecasted RTO coincident peak load

GW



- PJM has consistently overpredicted peak and total annual load, repeatedly shifting its forecast back year-on-year during the last decade.
- Despite PJM's expectations of load growth, peak load in PJM has generally decreased since 2010, primarily due to efficiency improvements.
- Between its 2022 and 2024 load forecasts, PJM raised its 2030 expectations for coincident peak load by 16GW (10%), primarily due to increased expectations of data center and EV growth.

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1) As reported by PJM.

Sources: Aurora Energy Research, PJM

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I. 2025/26 BRA: results & drivers

II. CIFP capacity market reforms

III. 2026/27 BRA: parameters, drivers, & expectations

IV. Long-term forecast

CIFP reform | On Jan 30th, 2024, FERC approved one of PJM's CIFP capacity market reform filings, rejecting the other on Feb 6th

On Jan 30, 2024, FERC conditionally accepted PJM's proposal to reform risk modeling and capacity accreditation within its capacity market, based on PJM's "CIFP"[1] fast-track process.

The 2025/26 BRA was the first auction held under PJM's CFP reform rules.

PJM CIFP capacity market reform timeline

Feb 2023

Feb 24: **PJM's board initiated the Critical Issue Fast Path ("CIFP")** stakeholder process to "address resource adequacy challenges" in the capacity market.

Aug 2023

Aug 23: In final stakeholder vote on CIFP Capacity Market reform proposals, no proposal passed sector-weighted endorsement threshold. The non-binding vote left the final decision to PJM's board. Stakeholders' favored option would only reduce CP[3] penalties, with PJM's annual CIFP proposal coming in second.

Oct 13: **PJM submitted its "CIFP" capacity market reform proposals** to FERC,[2] significantly reducing capacity accreditation, imposing stricter reliability testing, and increasing MSOC[4] to include CPQR[5] costs.

Nov 17: FERC issued deficiency notices for PJM's CIFP capacity market reform filings.

Dec 1, Dec 8: PJM filed replies to FERC's deficiency notices, resetting FERC's 60-day window to issue a ruling.

Jan 2024

Jan 30, Feb 6: **FERC conditionally approved PJM's filing ER24-99** (updating PJM's risk modeling & capacity accreditation), pending another compliance filing; **and rejected filing ER24-98** (to reform MSOC), citing insufficient detail and explanation.

Feb 16: PJM submitted FERC's requested compliance filing.

Feb 26: FERC granted PJM's request to delay the 2025/26 BRA[6] by 35 days, to Jul 17, along with associated pre-auction deadlines.

Apr 2024

Apr 25: FERC accepted PJM's compliance filing, officially finalizing approval for PJM's reforms.

Jul 2024

Jul 23: The auction window closed for the 2025/26 BRA—the first auction running under PJM's CIFP reform rules. PJM published results on **Jul 30**.

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1) Critical Issue Fast Path 2) Federal Energy Regulatory Commission 3) Capacity Performance. 4) Market Seller Offer Cap, a bid cap in PJM's capacity market. 5) Capacity Performance Quantifiable Risk. 6) Base Residual Auction.

Sources: Aurora Energy Research, PJM

CIFP reform | The 25/26 BRA is the first to reflect PJM's updates to risk modeling and capacity accreditation through its CIFP process

PJM's filed capacity market reforms following its CIFP stakeholder process

	Docket No. ER24-98	Docket No. ER24-99	Expected BRA Impact			
	Rejected by FERC (but PJM may still refile)	Implemented in 2025/26 BRA	Resource accred.	Amount procured	Bids	Clear. Price
Capacity Accreditation		▪ Move all resources (incl. demand) to **marginal ELCC**[1] ▪ Include separate **"dual-fuel" class categories** for natural gas resources	↓	↓/↑[2]	↑	↑
Risk modelling		▪ Adopt **Expected Unserved Energy (EUE) as key metric** (replacing current LOLE[3]) ▪ Model risk on hourly level with more weather years				
Market Seller Offer Cap (MSOC)	▪ **Include Capacity Performance Quantifiable Risk (CPQR) cost in MSOC** (PJM's bid cap) ▪ Clarify CPQR definition		-	(↓)	↑	↑
Capacity Performance	▪ Performance payments only for cleared resources ▪ Exclude resources excused from non-performance charges from Balancing Ratio calculation	▪ **Reduce penalty cap** ("stop-loss limit") ▪ Capacity testing required in summer & winter ▪ Add generation operational testing	-	-	↓/↑	↓/↑
E&AS offset	▪ **Forward-looking Energy & Ancillary Services (E&AS) offset** for MSOC, MOPR		-	-	-	-
FRR[4] alignment	▪ Apply Capacity Performance incentive revisions to FRR rules	▪ Align FRR rules with capacity market, e.g. capacity shortfall charges	-	-	-	-
Participation rules		▪ Require **binding notice of participation intent** from planned generation resources ▪ Revisions to sell offer requirements	-	-	-	-

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1) Effective Load Carrying Capacity (ELCC) is a measure of a resource's contribution to reliability. 2) Reduced ELCCs indirectly increase procurement targets. However, PJM modeling determines that under stricter ELCC derating, less UCAP is required to meet reliability targets. 3) Loss of load expected. 4) The Fixed Resource Requirement (FRR) alternative is an option for load-serving entities to meet resource adequacy requirements outside the capacity market, e.g. via internal resource planning.

Sources: Aurora Energy Research, PJM

CIFP reform | Lower capacity accreditation is driven by a shift of all asset types to marginal ELCCs[1] and a focus on winter risk

Drivers of the CIFP reforms' decrease in capacity accreditation

	Driver	Impact
Thermal to ELCC[1]	**All resource types moved to using ELCC for conversion to UCAP[2].** ▪ Thermal resources previously used "EFORd[3]" metric, defined by historical probability of a forced outage, uncorrelated to system risk. ELCC does capture such risk correlation and is thus typically lower. ▪ Renewable, intermittent, and duration-limited (e.g. storage) resources already used ELCC.	**Higher thermal bids, raising clearing prices because thermal usually price-setting.** ▪ As bids are per MW UCAP, assets must raise bids when capacity accreditation falls, to keep their effective bid per MW nameplate constant.
Marginal ELCC	**Move from "average ELCCs" to "marginal ELCCs", which are typically lower.** ▪ Average ELCCs measure the average contribution of any MW within a class to system reliability. ▪ Marginal ELCCs measure the contribution of an additional MW to reliability, which is typically below the average due to correlated outage risks and cannibalization within a technology type.	**Renewables, batteries, and natural gas ELCCs most affected.** ▪ These technologies have stronger correlations (between assets of same type) in their ability to reduce system risk than some others (coal, nuclear). E.g. solar assets typically generate at roughly the same time; natural gas outages are often caused by regional fuel deliverability issues. The technologies' ability to contribute to system reliability thus saturates as more MW are built, lowering marginal ELCCs.
Winter risk	**Shift in focus from primarily summer risk to primarily winter risk, resulting from updated risk modelling methodology.** ▪ Capacity market previously focused on summer risk, when peak load occurs. ▪ A key driver in this shift has been the move to Expected Unserved Energy ("EUE", in MWh) as the metric for outages, rather than Loss of Load Expected ("LOLE", in event-days per year). ▪ PJM has also increased the granularity of its risk modelling and extended it to more historical years.	**Lower ELCCs for assets with lower reliability contribution during winter risk, and vice versa for assets with higher winter reliability.** ▪ Solar and battery reliability contributions lower, because winter system stress events are generally longer than summer events. ▪ Gas ELCCs lower due to risk of weather-driven mechanical failure and correlation between winter storms and natural gas deliverability issues. ▪ Wind ELCCs higher, as wind typically generates more in winter.

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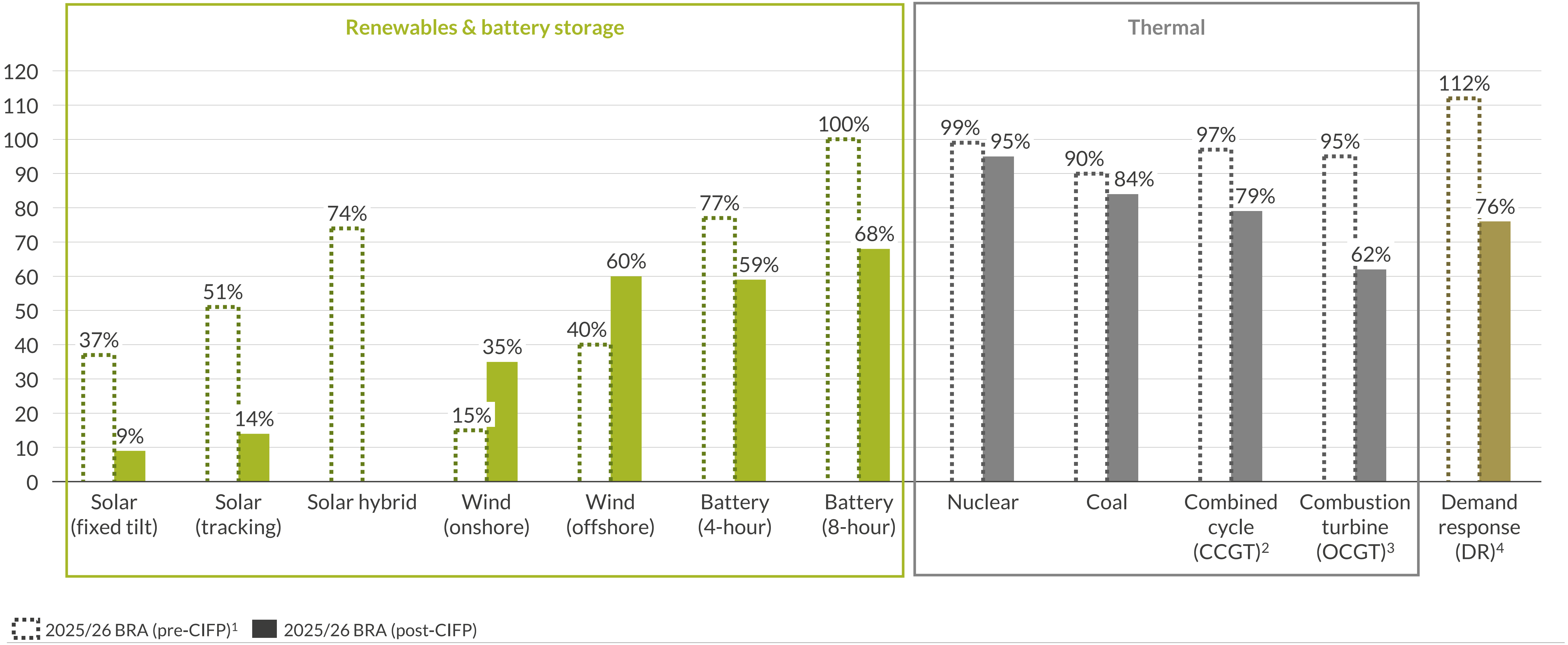
1) Effective Load Carrying Capability. 2) Unforced Capacity—i.e., capacity after accreditation adjustment. PJM's capacity market uses MW UCAP as its native unit for capacity. 3) Equivalent Demand Forced Outage Rate.

Sources: Aurora Energy Research, PJM

CIFP reform | Capacity accreditation decreased for most technologies in the 2025/26 BRA, with solar, batteries, gas, and DR most affected

ELCC values by technology for the 2025/26 BRA[1]

%



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1)"Pre-CIFP" values for thermal plants reflect historical average of [1 - EFORd] per technology class. 2) Combined cycle gas turbine. 3) Open cycle gas turbine.

4) Before CIFP, Demand Response resources were effectively awarded a value equal to the Forecast Pool Requirement (FPR), which PJM recommended be set at 1.1171 for the 2025/26 delivery year in its October 2023 Reserve Requirement Study.

Sources: Aurora Energy Research, PJM

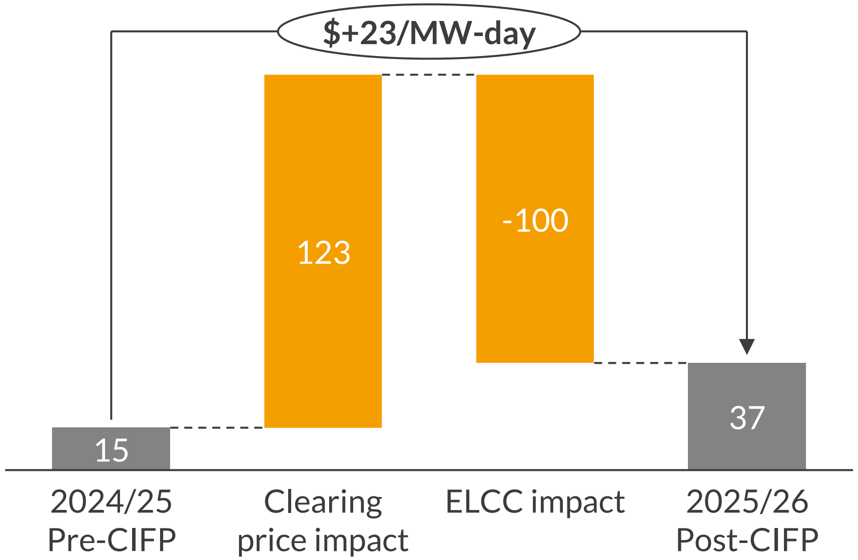
Revenues | Solar PV and onshore wind see opposite ELCC impacts from CIFP reform, but capacity revenues increase for both due to a high clearing price

AURORA

Capacity revenue change from 2024/25 to 2025/26 BRA (RTO-level clearing price)

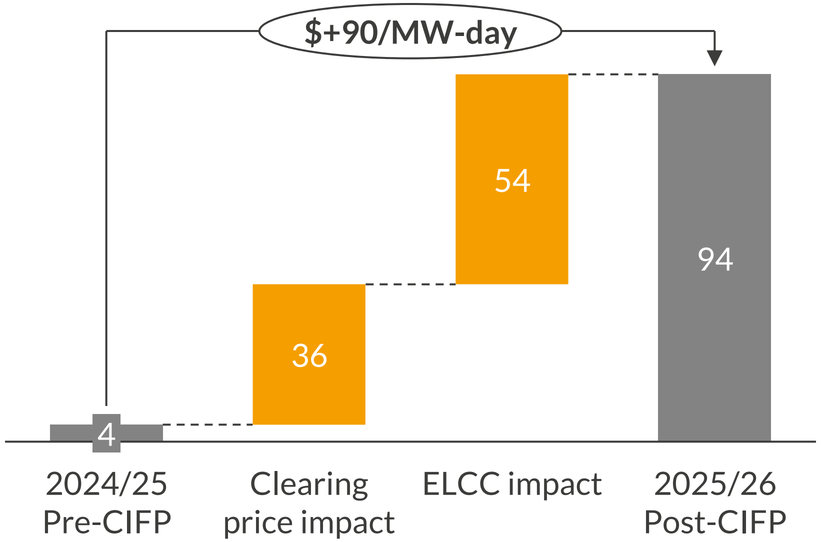
$/MW-day

Solar PV (single-axis tracking)



- Capacity revenues for tracking solar PV see a $23/MW-day increase between the 2024/25 and 2025/26 BRAs due to a rise in clearing price.
- The impact of the large reduction in tracking solar's ELCCs —down from 51% pre-CIFP to just 14% post-CIFP—is mitigated by the $123/MW-day impact due to the change in clearing price.

Onshore wind



- Post CIFP reform, onshore wind capacity revenues increased by ~$90/MW-day, with the increased ELCC values—15% to 35%—contributing $54/MW-day. Onshore wind ELCCs were adjusted in May 2023 after PJM's ELCC methodology update capping modeled output at CIR.
- Wind's higher ELCCs are due to PJM's risk modeling improvements shifting significant perceived reliability risk to winter months, when wind output is generally higher and more stable.

▨ Total 🟧 Impact

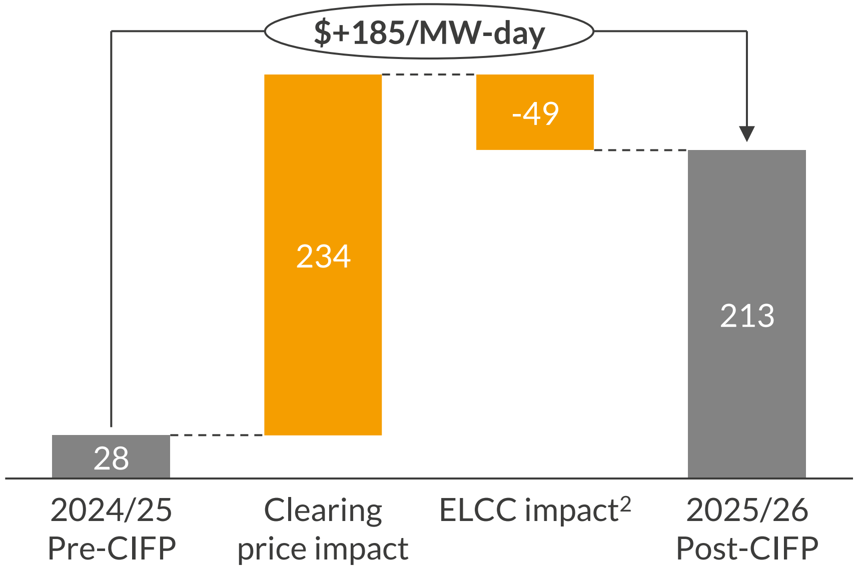
Source: Aurora Energy Research

Revenues | Natural gas assets can expect an overall increase in capacity revenues, despite lower ELCCs

Capacity revenue change from 2024/25 to 2025/26 BRA (RTO-level clearing price)

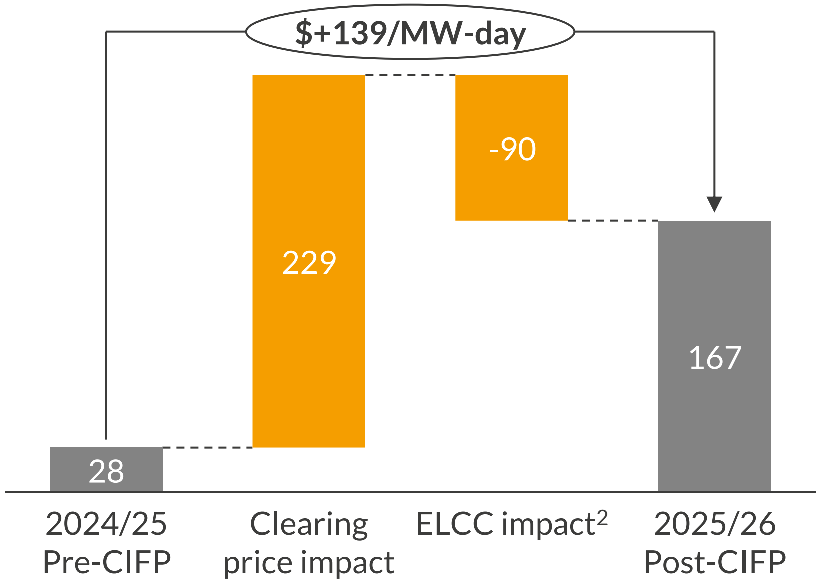
$/MW-day

Natural gas CC (CCGT)



- Capacity revenues for a CCGT in PJM could rise by $185/MW-day due to clearing price impact, despite its capacity accreditation falling from 97% to 79%.[1]
- $234/MW-day impact due to the price mitigates all the $49/MW-day downside from the accreditation decrease.

Natural gas CT (OCGT)



- Combustion turbines take a stronger hit to capacity accreditation due to CIFP—falling from 95% to 62%[1]—which results in a higher decrease in capacity revenues of $90/MW-day.
- However, this decrease is once again mitigated by the $229/MW-day impact of the rising clearing price.

■ Total ■ Impact

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[1] Based on Aurora estimate of "status quo" EFORd values and CIFP ELCC values published by PJM.

Source: Aurora Energy Research

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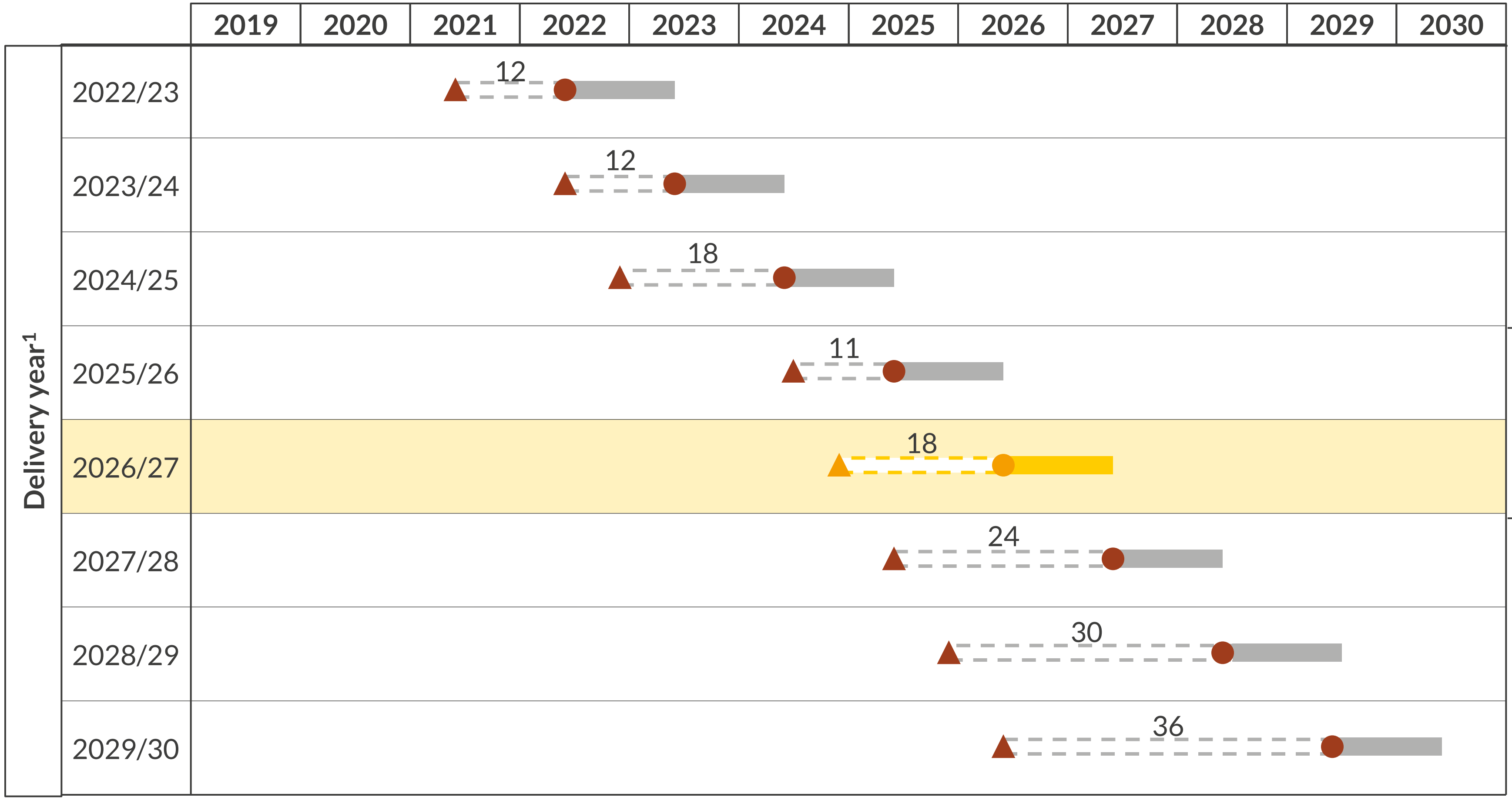
Timeline | The 2026/27 BRA will take place 18 months before the delivery year, with a return to 36 months planned for the 2029/30 BRA

AURORA

PJM's Base Residual Auction (BRA) schedule



The BRA schedule—typically 36 months ahead of each delivery year—was significantly delayed for the 2022/23 delivery year, due to several FERC rulings and related stakeholder management and counterproposals by PJM, most importantly concerning changes to PJM's Minimum Offer Price Rule (MOPR)

PJM also delayed the 2025/26 BRA, due to its CIFP capacity market reforms and changes to the capacity performance construct, reducing the auction lead time to 11 months.

PJM has published a schedule for incrementally increasing the time between BRA and delivery year starts, returning to their original schedule by the 2029/30 BRA, with 2028/29 BRA having a shorter 30-month lead time.

▲ Base Residual Auction (BRA) ● Start of delivery year[1] ⌐⌐ Months delay between BRA and delivery year ■ Delivery year

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[1] Delivery years run from June 1 through May 31.

Sources: Aurora Energy Research, PJM

Drivers | Demand has risen by 3GW compared to the previous BRA, while changes in supply are highly uncertain—with >3GW additions feasible

AURORA

	Factor	Key changes from 25/26 BRA, GW UCAP	Price impact	Explanation
Supply	**New entrants**	+ 0.8-5.5	↓	▪ Trumbull CC (0.8GW UCAP) expected to participate for first time. ▪ Additional capacity possible due to new batteries, renewables, DR, and imports; incentivized by high expected clearing prices and low capacity performance penalties (due to the $0 Net CONE in many regions, yielding a $0 penalty rate).
	Re-entry of exempt resources	+ 0-2.0	↓	▪ Up to ~6GW ICAP available that withheld from 2025/26 BRA. ▪ Incentivized by abovementioned high clearing prices and low capacity performance penalties, but unclear how much will re-enter, if any.
	ELCC changes	- 1.2	↑	▪ Lower ELCCs for renewables and batteries will reduce effective supply (partially offset by higher ELCCs for combustion turbines).
	Retirements	- 0-1.5	↑	▪ New retirements possible despite expected high capacity prices, e.g. due to environmental regulations.
Demand	**Reliability requirement**	RTO: +2.8 DOM: +0.9	RTO: ↑ DOM: ↑	▪ Strong increase in forecasted RTO-wide and Dominion peak load driven primarily by data center additions, raising reliability requirements.
	VRR curve shape	*Significantly steeper*	↑/↓	▪ Caused by updated VRR parameters and a switch to a gas CC as PJM's reference generator, significantly raising Gross CONE (which sets the VRR's upper bound) and lowering Net CONE (to $0/MW-day for much of the RTO).
LDAs	**CETL**	EMAAC: -1.1 SWMAAC: -1.2 DOM: +1.5	EMAAC: ↑ SWMAAC: ↑ DOM: ↓	▪ Significantly lower CETL in EMAAC and SWMAAC may constrain capacity imports, potentially causing price separation in these LDAs. ▪ Dominion's CETL increase more than offsets its higher reliability requirement, potentially lowering its clearing price compared to the 2025/26 BRA.

Sources: Aurora Energy Research, PJM

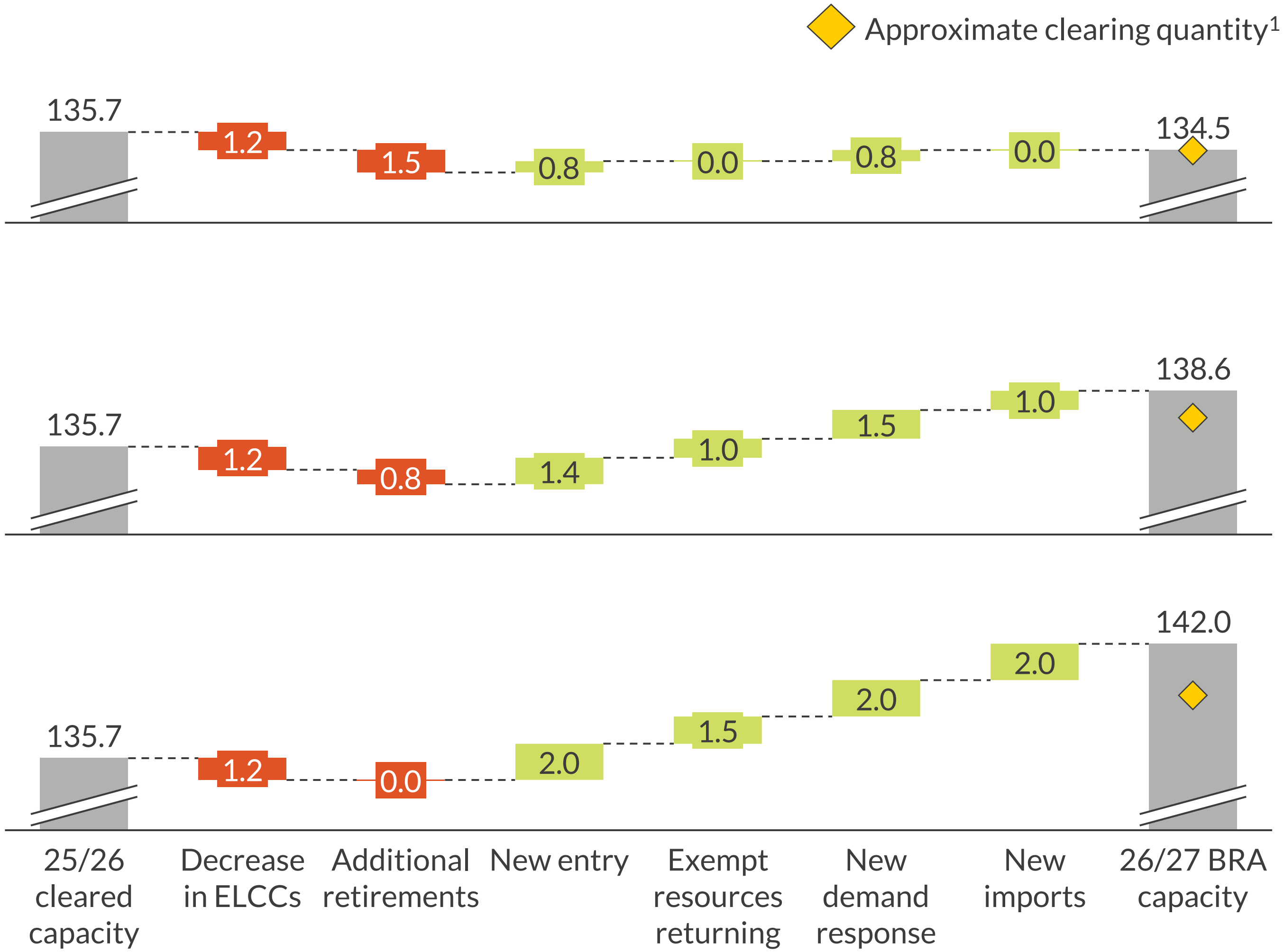
Supply | 2026/27 BRA prices could range from $100 to $700/MW-day, depending on supply—with a $200-$300 Central expectation

Sources of capacity supply shifts for 2026/2027 BRA, GW UCAP

High case
- Clearing price: **$696/MW-day**
- Price setter: RPM price limit

Central case
- Clearing price: **$200-300/MW-day**
- Price setter: New unit or higher-cost DR[2]

Low case
- Clearing price: **~$100/MW-day**
- Price setter: Existing unit or lower-cost DR



- The amount of supply anticipated to participate in the 2026/27 BRA ranges from 134.5 to 142.0GW UCAP.
  - Supply decreases, relative to the 2025/26 BRA, range from 1.2GW UCAP to 2.7GW UCAP, depending on additional retirements.
  - Supply increases range from 1.6GW to 7.5GW UCAP, depending on new entry, exempt resources re-entering the capacity market, and incremental demand response and import participation.
- Small changes in supply could drive large differences in clearing prices—the "Low supply" case would result in clearing at the price cap, while the "High supply" case would likely see a clearing price set by an existing unit or lower-cost demand response resource.

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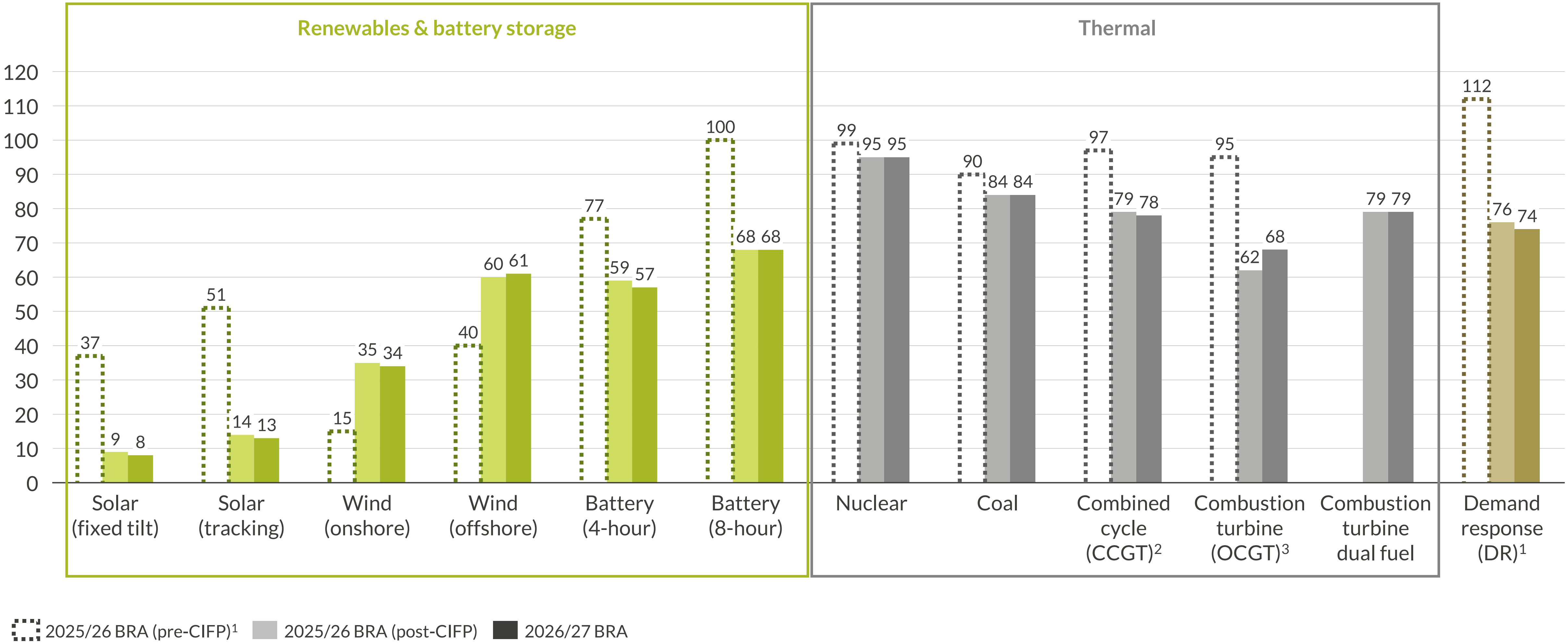
1) 2026/27 BRA capacity reflects total capacity offering into the auction. The quantity of cleared capacity depends on the amount of offered capacity, bid levels, and the shape of the VRR curve. 2) Demand response.

Sources: Aurora Energy Research, PJM

Supply | 2026/27 ELCCs increased by 6p.p. for combustion turbines but decreased slightly for most renewables and batteries, relative to 2025/26

Capacity accreditation by technology[1]

%



	2025/26 BRA (pre-CIFP)[1]	2025/26 BRA (post-CIFP)	2026/27 BRA
Solar (fixed tilt)	37	9	8
Solar (tracking)	51	14	13
Wind (onshore)	15	35	34
Wind (offshore)	40	60	61
Battery (4-hour)	77	59	57
Battery (8-hour)	100	68	68
Nuclear	99	95	95
Coal	90	84	84
Combined cycle (CCGT)[2]	97	79	78
Combustion turbine (OCGT)[3]	95	62	68
Combustion turbine dual fuel		79	79
Demand response (DR)[1]	112	76	74

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1)"Pre-CIFP" values for thermal plants reflect historical average of [1 - EFORd] per technology class; for DR, "pre-CIFP" values are effective, as implied by PJM's parameters through the 2025/26 BRA's FPR. All other values are ELCCs. 2) Combined cycle gas turbine. 3) Open cycle gas turbine.

Sources: Aurora Energy Research, PJM

Supply | Much of PJM has $0 Net CONE for 2026/27, removing Capacity Performance penalty risk and potentially incentivizing more supply

Many areas of PJM will have effectively no capacity performance penalty for the 2026/27 delivery year, due to their Net CONE[1] dropping to $0/MW-day.

- **This could incentivize additional supply to (re-)enter the capacity market that previously may have withheld due to penalty risk**—e.g. renewables, which are exempt from must-offer obligations and susceptible to penalty risk, having little control over output during system stress events.
- Because the capacity performance penalty rate for each 5-minute interval is proportional to Net CONE, performance penalties are null when Net CONE falls to $0:

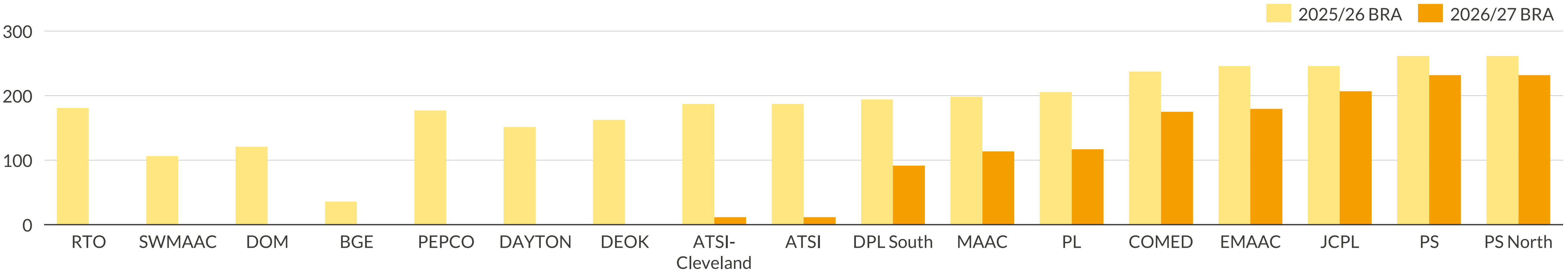
$$Charge\ Rate_{LDA} = \frac{Net\ CONE\ (ICAP)_{\ LDA}}{360}$$

Risks:

- Even with a $0 Net CONE, capacity generators will be subject to capability testing and penalties for test failure. Intermittent resources are exempt from such tests, however.
- This may increase penalty risk for LDAs with a non-zero Net CONE, as (i) much of the RTO has little incentive to perform, potentially triggering drawn-out PAIs[2] and (ii) the total penalty cap is proportional to the BRA clearing price, which could be as high as $700/MW-day.
- Although it has not stated any plans to do so, PJM could reform its capacity performance penalties to ensure a non-zero penalty rate.

Net CONE for PJM RTO and LDAs

$/MW-day ICAP



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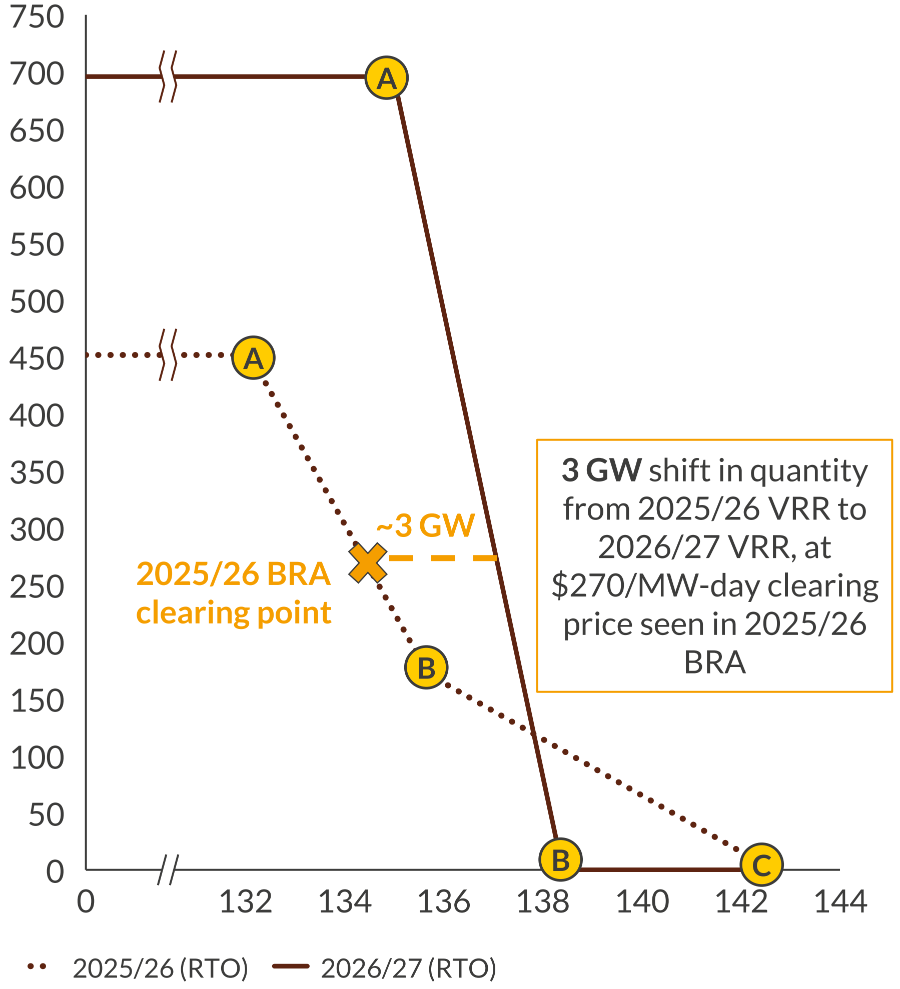
1) Net cost of new entry—an annualized estimate of the revenue required to cover fixed and capital costs, net of margins earned from energy and ancillary services. 2) Performance Assessment Intervals.

Sources: Aurora Energy Research, PJM

Demand | The 2026/27 BRA's VRR curve is much steeper than previously, making price outcomes significantly more volatile

RTO-wide VRR curve[1], incl. point definitions

$/MW-day (nominal), GW UCAP



3 GW shift in quantity from 2025/26 VRR to 2026/27 VRR, at $270/MW-day clearing price seen in 2025/26 BRA

Key impacts of VRR curve changes

1. The steeper shape of the 2026/27 VRR curve—resulting from changes to the parameters underlying the VRR—increases clearing price uncertainty and volatility.
2. The outward shift of the 2026/27 VRR curve—resulting from increases to PJM's Reliability Requirement—implies that at least 3GW of additional supply is necessary to maintain a clearing price at or below the $270/MW-day seen in the 2025/26 BRA.

Key parameter changes for the 2025/26 BRA relative to the previous auction

Parameter	**2025/26 BRA** (prev. auction)	**2026/27 BRA** (next auction)	Driver(s)
Reliability Requirement	144,450MW	147,246MW	▪ Increase in forecasted RTO peak load of 3.3GW
Gross CONE (determines point A)	$451.6/MW-day UCAP	$695.8/MW-day UCAP	▪ Shift in the VRR reference resource from a combustion turbine to a combined cycle, which is both more capital intensive (increasing Gross CONE) and more lucrative in energy and ancillary services markets (decreasing Net CONE).
Net CONE (determines point B)	$228.8/MW-day UCAP	$0/MW-day UCAP	

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1) Variable Resource Requirement—PJM's capacity demand curve, defined by 3 points. 2) VRR curves are net of FRR demand. As PJM has not yet released FRR designations for the 2026/27 BRA, the values here assume identical FRR participation from the 2025/26 BRA.

Sources: Aurora Energy Research, PJM

LDAs | SWMAAC, JCPL, DPL South, BGE, & EMAAC all have higher likelihood of price separation, due to tighter CETO:CETL ratios

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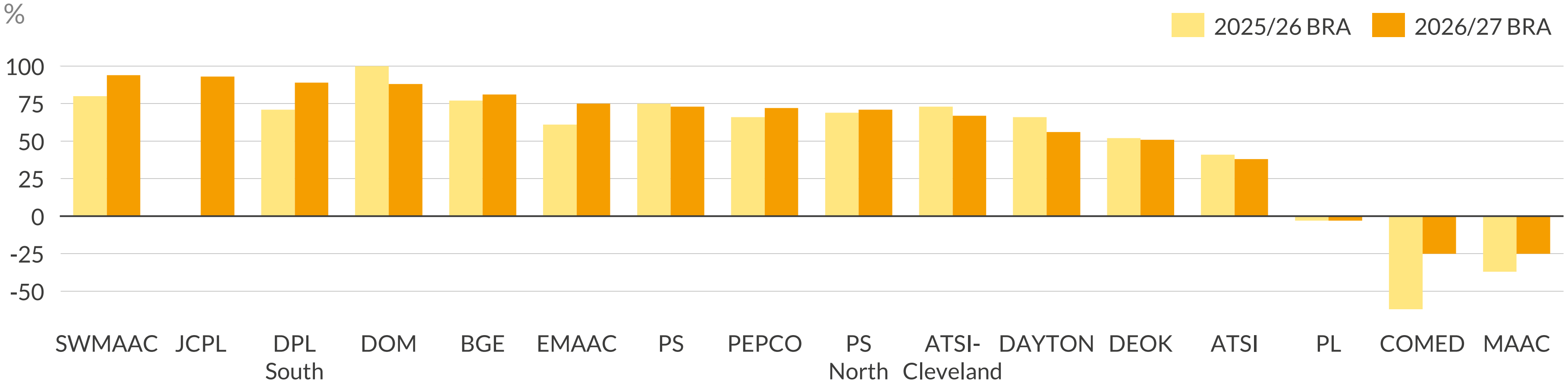
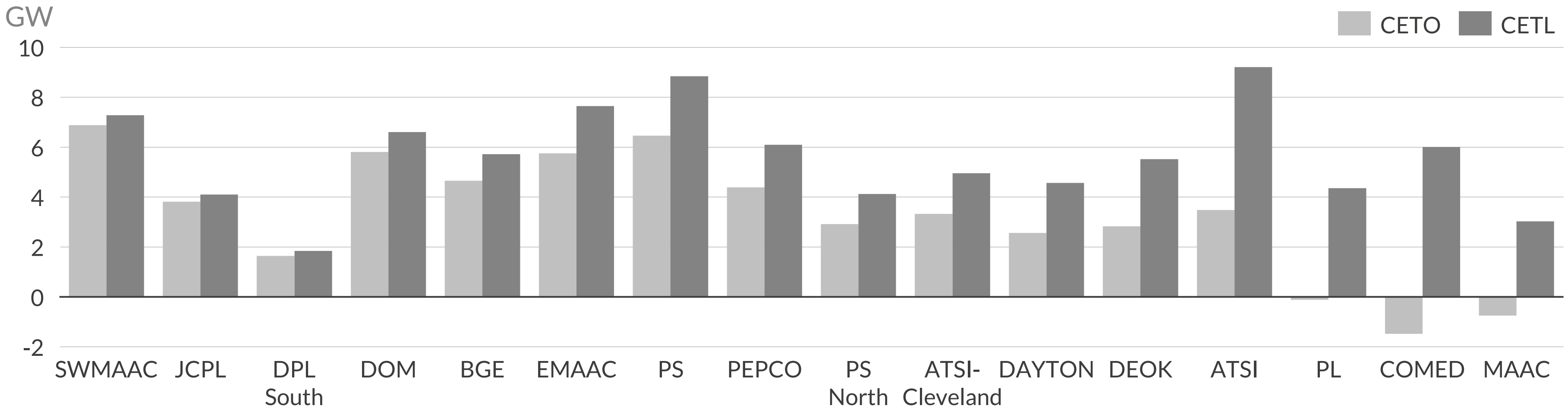
CETO:CETL ratio by LDA



← ***Higher ratio:*** *more likely to clear above parent region*

Lower ratio: *less likely to clear above parent region* →

CETO and CETL by LDA (2026/27 BRA)



Sources: Aurora Energy Research, PJM

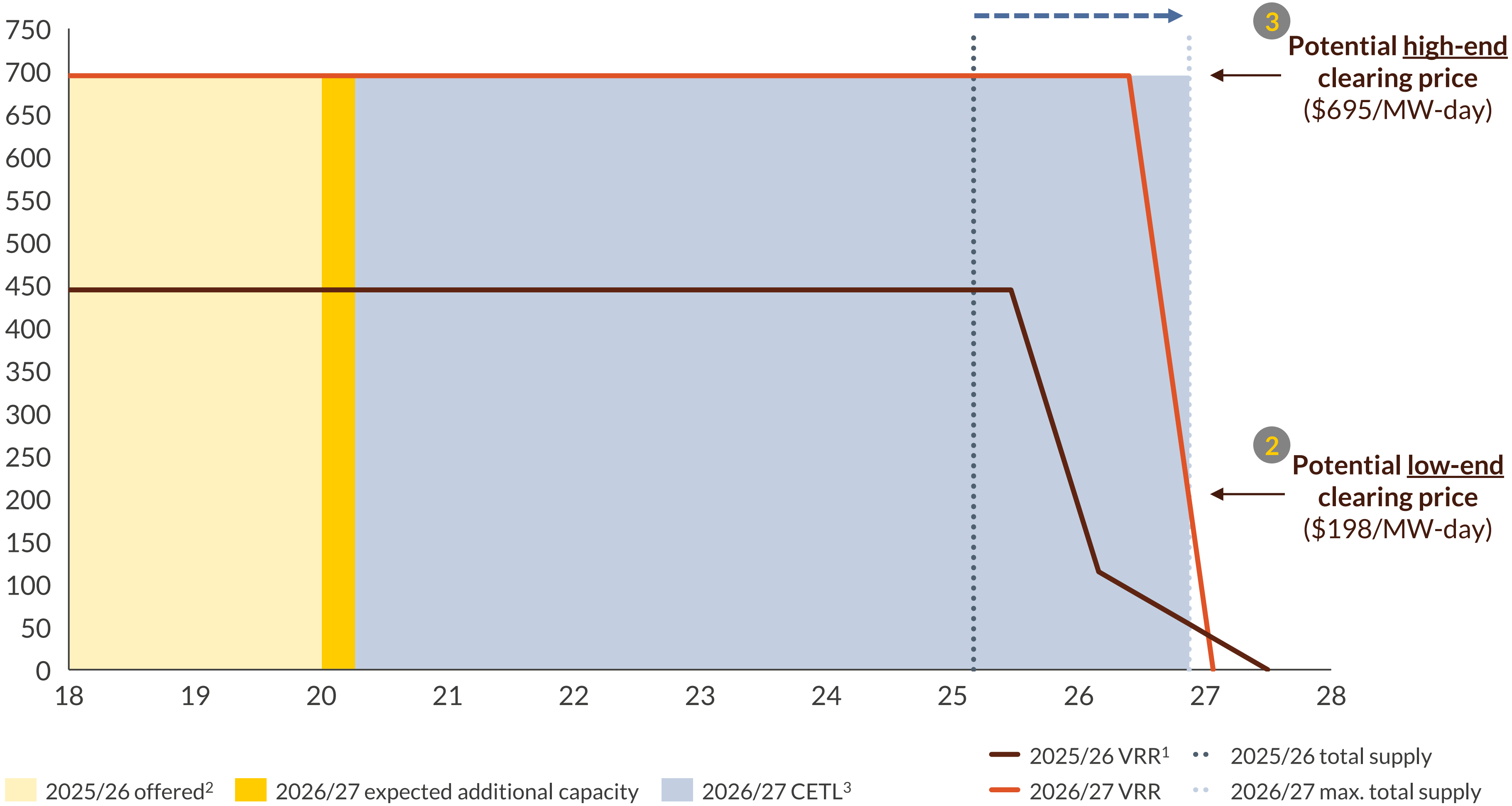
- **Capacity Emergency Transfer Limits** (CETLs) determine how much capacity can be imported into an LDA during peak system stress moments, thus acting as constraints on PJM's cost optimization of the BRA.
- An LDA's **Capacity Emergency Transfer Objective** (CETO) is PJM's estimate of the capacity import necessary to satisfy loss of load expectation requirements.
- The closer CETO is to CETL, generally the more likely that LDA will clear above its parent price ("price separation").
- SWMAAC, JCPL, DPL South, Dominion, BGE, and EMAAC all have a relatively high likelihood of price separation, due to tight CETO:CETL ratios (≥75%).
- Of the above LDAs, only Dominion's CETO:CETL ratio is lower than the previous BRA.

LDAs | Dominion's large CETL increase could bring its clearing price as low as $198/MW-day, although $695 is still feasible

Dominion LDA "VRR[1]" demand curve and potential supply

$/MW-day (y-axis); GW UCAP (x-axis)

① **Potentially available capacity increase** (+1.7GW UCAP)



③ **Potential high-end clearing price** ($695/MW-day)

② **Potential low-end clearing price** ($198/MW-day)

1) Variable Resource Requirement. 2) Excl. (estimated) capacity offered as winter-only but not cleared because no summer-only counterpart available. 3) Capacity Emergency Transfer Limit/ Objective. 4) Estimated from BRA parameters via [reliability requirement] - [CETO]. 4) Also assuming RTO does not clear >$198/MW-day; but in that case CETL would likely not be fully utilized.

Sources: Aurora Energy Research, PJM

① The total available capacity in Dominion—as indicated by PJM's auction parameters—has risen by 1.7GW compared the last auction, primarily due to its 1.4GW CETL[3] increase.

- PJM expects net additional 0.3GW UCAP of capacity bidding within the LDA.

② As a result, Dominion's price could clear as low as $198/MW-day, if the entire extent of the LDA's CETL is utilized and no participants bid above that level.[4]

③ However, neither of the abovementioned criteria are guaranteed—as underscored by CETO[3]<CETL, i.e. PJM's expectation that not all of CETL will be used—and Dominion could still feasibly clear at its auction cap of $695/MW-day if supply falls ≥0.5GW short of the 26.9GW available.

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Outlook | Aurora's Central case expects clearing prices at $XX/MW-day levels

5-year rolling average clearing prices for PJM's Base Residual Auction (BRA)

$/MW-day (real 2023)

Redacted

2026-2030

Prices around the $XX/MW-day level, as tight supply-demand conditions are expected to persist:

- PJM forecasts continued short-term peak load growth.
- Additional thermal resources (particularly coal plants) have announced retirements before 2030.

2031-2050

Sustained prices of $XX/MW-day, as newbuild is required almost every year:

- Retirements from gas plants built in the ~20s reaching end of life, new capacity needed.
- Gas capacity factors driven down by continued renewables growth and flexible demand (e.g., EVs); higher CM revenue needed.

Sources: Aurora Energy Research, PJM

Drivers | Peak load growth and retirements will persist until at least 2030, partially offset by potential new build, DR, and imports

Drivers of capacity price developments through 2029

	Factor	Expected change from 25/26 to 29/30 BRA GW UCAP	Price impact	Explanation
Supply	**New entrants**	+11	↓	▪ New resources primarily comprise solar, wind, and battery storage resources in the interconnection queue, with a small amount of additional thermal capacity possible.
	Other new sources of capacity	Imports: +4 Demand response: +4	↓	▪ The 2025/26 BRA saw low demand response and capacity import participation by historical standards. Higher RPM clearing prices will likely incentivize further participation from these resources.
	Retirements	-10	↑	▪ Coal plants totaling 7GW UCAP have announced retirements by 2029.[1] Some additional peaking capacity may also retire; though higher RPM clearing prices will incentivize these units to remain online.
Demand	**Peak load**	+12	↑	▪ PJM's 2024 load forecast sees peak load rising from **153.5GW** in 2025 to **165.7GW** in 2029. Because PJM uses its own forecasting to assess peak load for the RPM, this forecast provides a basis for near-term auctions.
	VRR curve shape	*Uncertain*	↑/↓	▪ PJM refreshes the parameters underlying the VRR curve annually. An increase in the Net CONE parameter above the $0/MW-day used for the 2026/27 BRA would result in a less steep VRR curve.

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1) Rockport, Kincaid, Miami Fort, Keystone, Conemaugh.

Sources: Aurora Energy Research, PJM

Risks | Structural changes to PJM's capacity market or state policy could lower the price outlook, but most have low probability of occurring

Potential measures PJM or its member states may take that could reduce capacity market prices

Measure	Relevant areas	Estimated likelihood	Explanation
Interconnection queue fast-track process	PJM	◕	▪ PJM is considering implementing a process that would allow "shovel-ready projects" to fast-track their interconnection and construction process, to benefit system reliability.[1] ▪ PJM's planning committee is also considering ways for new projects to bypass the interconnection queue by taking over retiring resources' capacity interconnection rights and physical locations.
Policy hindering impact of data centers on power grid	OH, VA	◑	▪ Legislators in both OH and VA proposed multiple bills in 2023 and 2024 to regulate data centers' impacts on power costs, environment, and local land use. If successful, such bills could slow data center additions or oblige operators to source and pay for power in ways that minimizes impacts on PJM rates.
State subsidies for new generation	MD, PA	◔	▪ State Delegates of MD—the state containing BGE, which cleared at $466/MW-day in the 2025/26 BRA—have announced potential plans to introduce bills to (i) add energy storage to the state's distribution grid and (ii) provide additional REC support to advanced-stage solar projects. ▪ PA Sen. Gene Yaw (R) has announced plans to introduce bills to (i) create a fund to support power plant construction (akin to the Texas Energy Fund) and (ii) increase certainty within the state's permitting process.
Include RMR plants in capacity auction	DE, DC, IL, MD, NJ, OH	◔	▪ Ratepayer advocates from 6 states urged PJM in an August 30 open letter to include RMR units in the capacity auction. ▪ However, PJM uses RMR primarily to guarantee transmission security (rather than resource adequacy), and their inclusion in the capacity auction could distort the necessary price signals to replace the retiring plants.
State or LSE exit as FRR region to lower costs	-	◔	▪ Although no states or utilities have announced intentions to opt out of PJM's capacity market, multiple entities including MD, NJ, and Dominion VA threatened to do so (with Dominion following through) around 2020 when PJM expanded its bid floor ("MOPR") to apply to subsidized renewables. ▪ Such exits could provide feasible pathways for states and utilities to lower costs to ratepayers, should PJM see continued high capacity clearing prices.

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1) According to PJM executive vice president for market services and strategy Stu Bresler.

Sources: Aurora Energy Research, UtilityDive

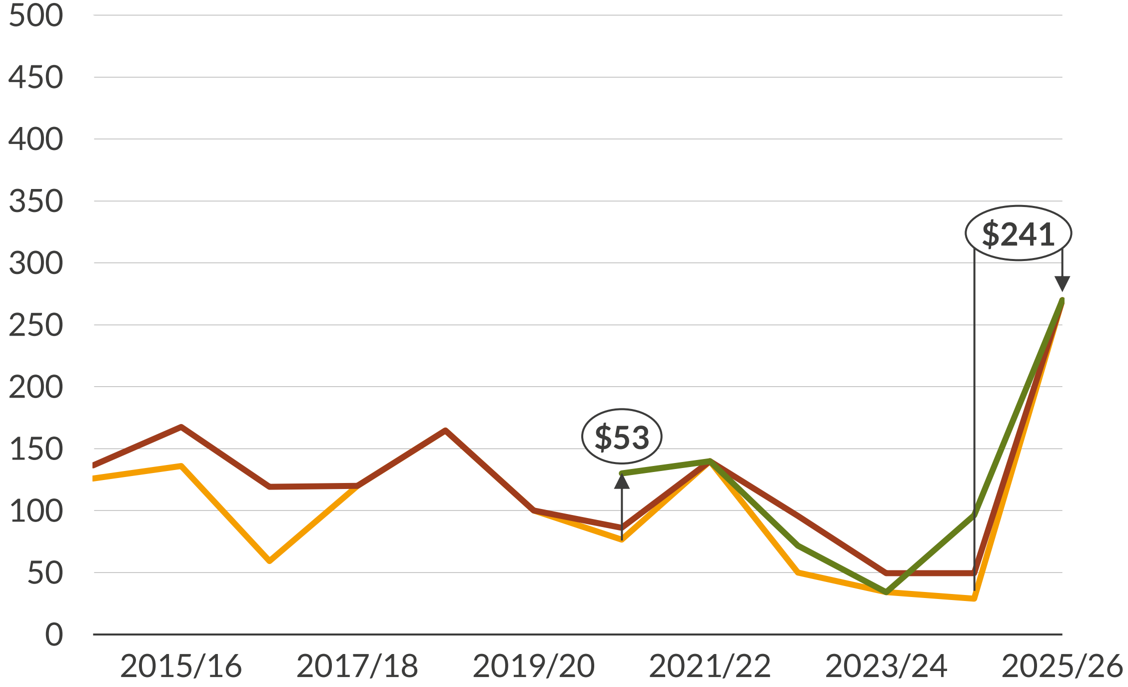
Agenda

I. Appendix

2025/26 BRA | 2 LDAs cleared above their parent price, down from 5 in the previous auction

Clearing prices within RTO (for selected LDAs in 2025/26 BRA)

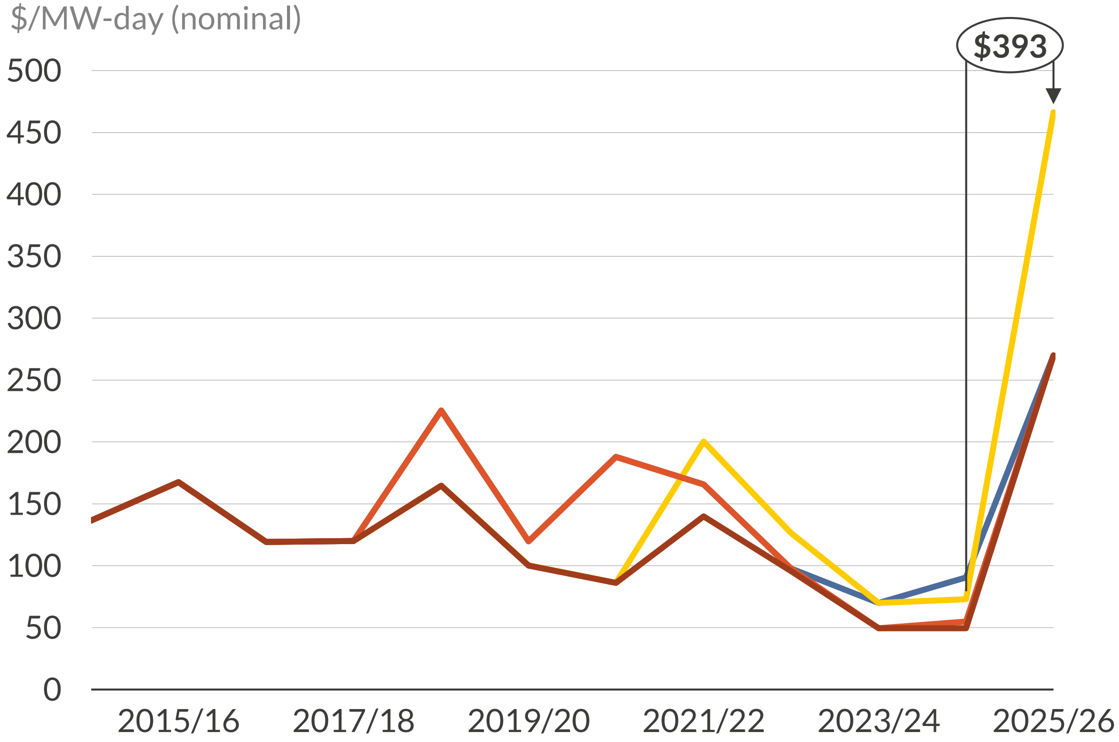
$/MW-day (nominal)



- The 2025/26 BRA saw the largest delta between consecutive RTO clearing prices to date, at $241/MW-day.
- DEOK—modelled as an LDA since the 2020/21 BRA—has cleared above RTO level in 3 out of the 5 prior auctions; however, both DEOK and MAAC cleared at the same level as RTO this time, largely due to RTO's high clearing price.

Clearing prices within MAAC for 2025/26 BRA

$/MW-day (nominal)



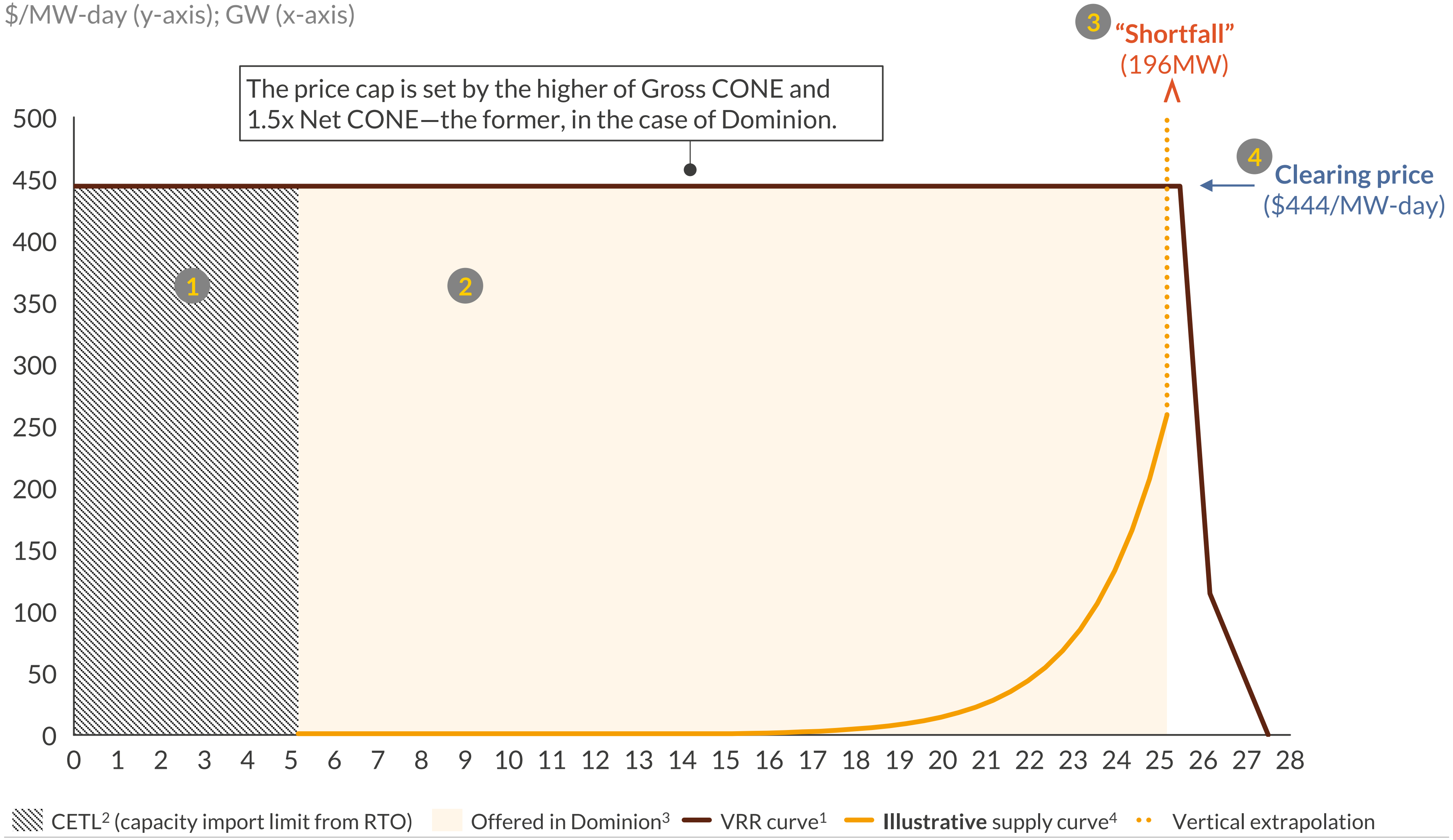
- BGE cleared above the MAAC level in the past 5 auctions, and the trend continued in the 2025/26 BRA too, with BGE clearing $393/MW-day higher than its previous clearing price and $196/MW-day higher than the MAAC clearing price.

Sources: Aurora Energy Research, PJM

2025/26 BRA | Dominion and BGE cleared at their price cap, with total available capacity below any point on the sloped demand curve

Dominion LDA "VRR¹" demand curve and representative supply stack

$/MW-day (y-axis); GW (x-axis)



- Available capacity in Dominion LDA can come from two sources:
  - ① Capacity imported from elsewhere in the RTO, limited by CETL;
  - ② Capacity offered within Dominion (including DR and non-PJM imports).
- ③ The total available capacity (25,167MW) fell nearly 300MW short of the highest point on the sloped portion of the LDA's demand curve, point A (25,463MW).
- ④ As a result, the LDA's price automatically cleared at the LDA's price cap, at $444/MW-day.
- BGE showed analogous shortfall, clearing at its LDA price cap of $466/MW-day.

---

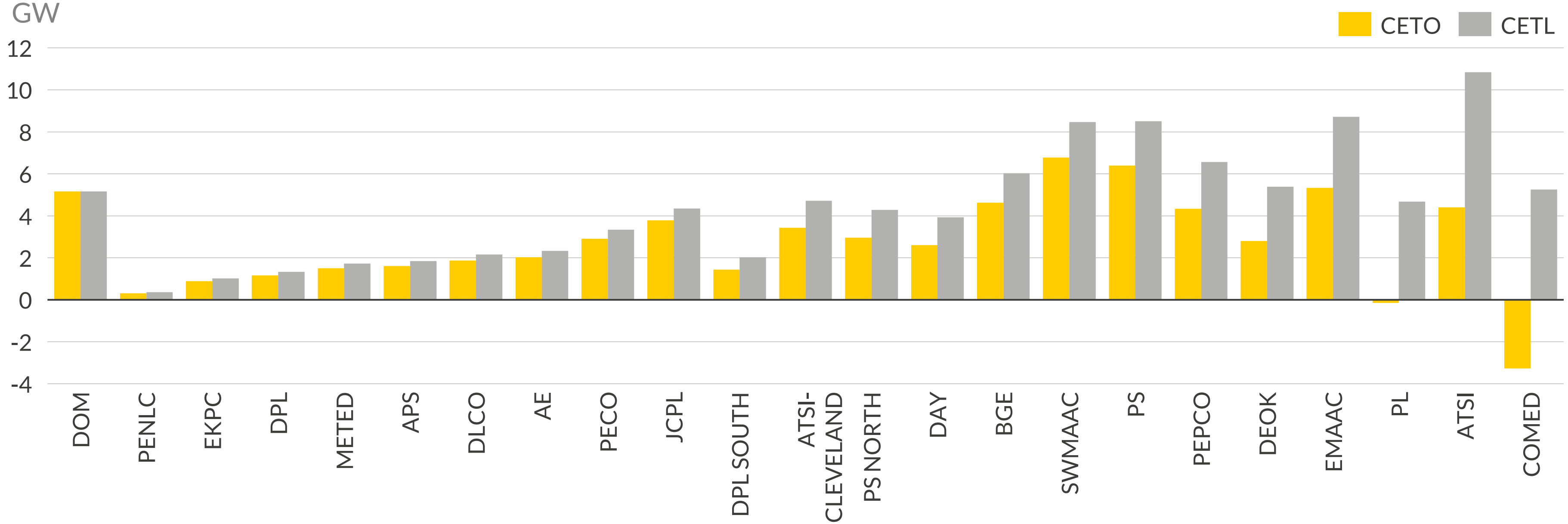
1) Variable Resource Requirement: PJM's capacity demand curve. 2) Capacity Emergency Transfer Limit. 3) Excluding estimated capacity offered but unavailable to clear because offered as winter-only and no summer-only capacity counterpart was available. 4) X-extent is true to auction results; rest of curve is illustrative, as PJM does not publish bid levels or individual bidder info.

Sources: Aurora Energy Research, PJM

2025/26 BRA | PJM expected Dominion LDA to be highly constrained, assigning it a CETO value nearly identical to its CETL

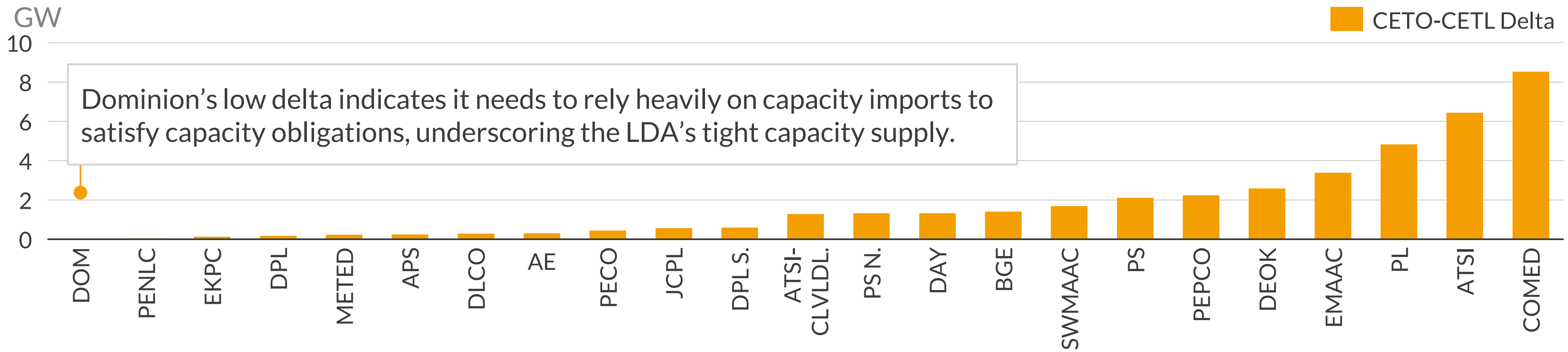
CETL and CETO by LDA

GW



CETL-CETO delta by LDA

GW



Dominion's low delta indicates it needs to rely heavily on capacity imports to satisfy capacity obligations, underscoring the LDA's tight capacity supply.

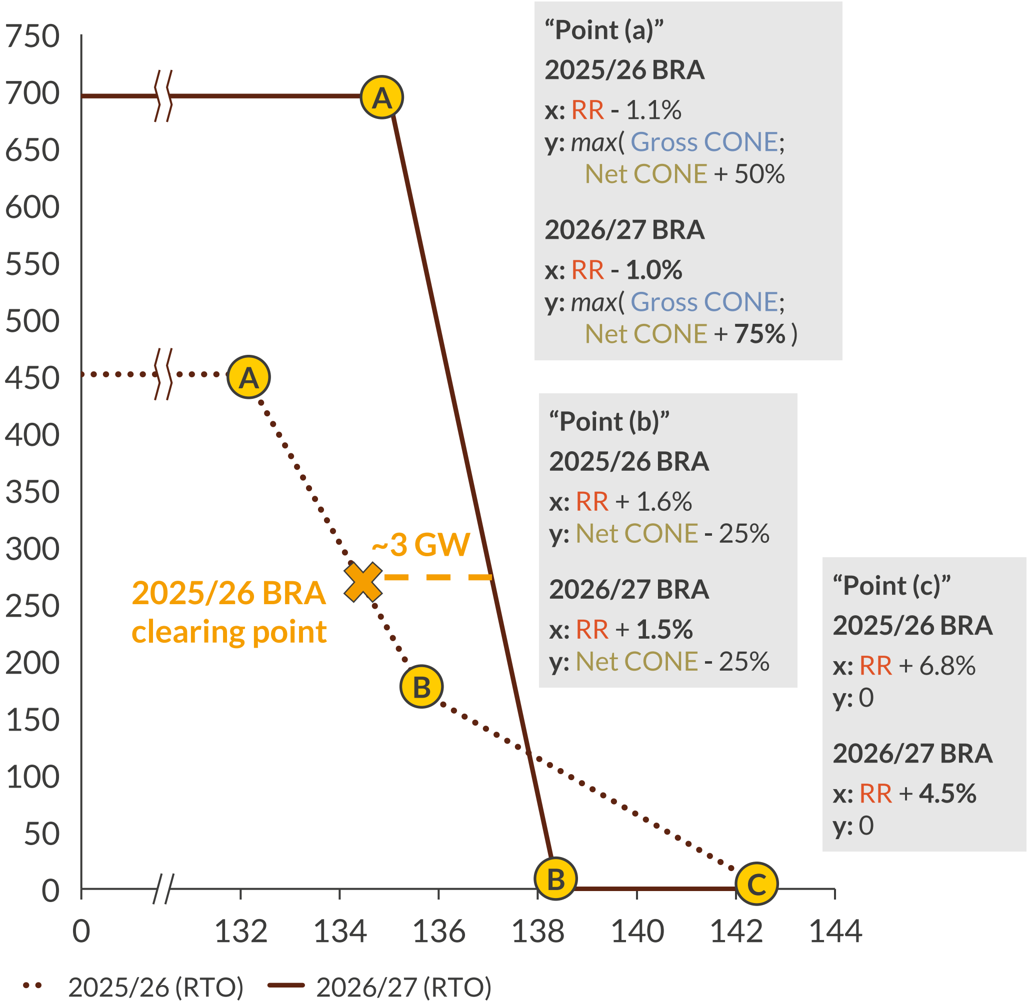
Sources: Aurora Energy Research, PJM

- Capacity Emergency Transfer Limits (CETLs) determine how much capacity can be imported into an LDA during peak system stress moments, thus acting as constraints on PJM's cost optimization of the BRA outcome
- An LDA's Capacity Emergency Transfer Objective (CETO) represents the capacity import amount necessary to satisfy loss of load expectation requirements, according to PJM's studies
- Dominion's CETO was nearly identical to its CETL, indicating the LDA's tight capacity supply and resulting need for capacity imports.

Demand deep-dive | VRR shifted out & more vertical; roughly 3 GW UCAP more demand at 2025/26 BRA's $270/MW-day price point

RTO-wide VRR curve[1], incl. point definitions

$/MW-day (nominal), GW UCAP



"Point (a)"

2025/26 BRA

x: RR - 1.1%
y: *max*(Gross CONE; Net CONE + 50%

2026/27 BRA

x: RR - **1.0%**
y: *max*(Gross CONE; Net CONE + **75%**)

"Point (b)"

2025/26 BRA

x: RR + 1.6%
y: Net CONE - 25%

2026/27 BRA

x: RR + **1.5%**
y: Net CONE - 25%

"Point (c)"

2025/26 BRA

x: RR + 6.8%
y: 0

2026/27 BRA

x: RR + **4.5%**
y: 0

Key parameter changes for the 2025/26 BRA relative to the previous auction

Parameter	2025/26 BRA (prev. auction)	2026/27 BRA (next auction)	Driver(s)
Reliability Requirement (RR)[2]	144,450MW (133,564MW excl. FRR)	147,246MW (136,360MW excl. FRR)	▪ Increase in forecasted RTO peak load of 3.3GW ▪ Increase in Installed Reserve Margin (IRM) from 17.8% to 18.6%.
Gross CONE	$451.6/MW-day UCAP	$695.8/MW-day UCAP	▪ Shift in the VRR reference resource from combustion turbine to combined cycle. Relative to combustion turbines, combined cycle units are both more capital intensive (increasing Gross CONE) and more lucrative in energy and ancillary services markets (decreasing Net CONE).
Net CONE	$228.8/MW-day UCAP[9]	$0/MW-day UCAP	

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1) Variable Resource Requirement—PJM's capacity demand curve, defined by 3 points.

Sources: Aurora Energy Research, PJM

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ENERGY RESEARCH

ATTACHMENT C

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Outlook for Pending Generation in the PJM Interconnection Queue

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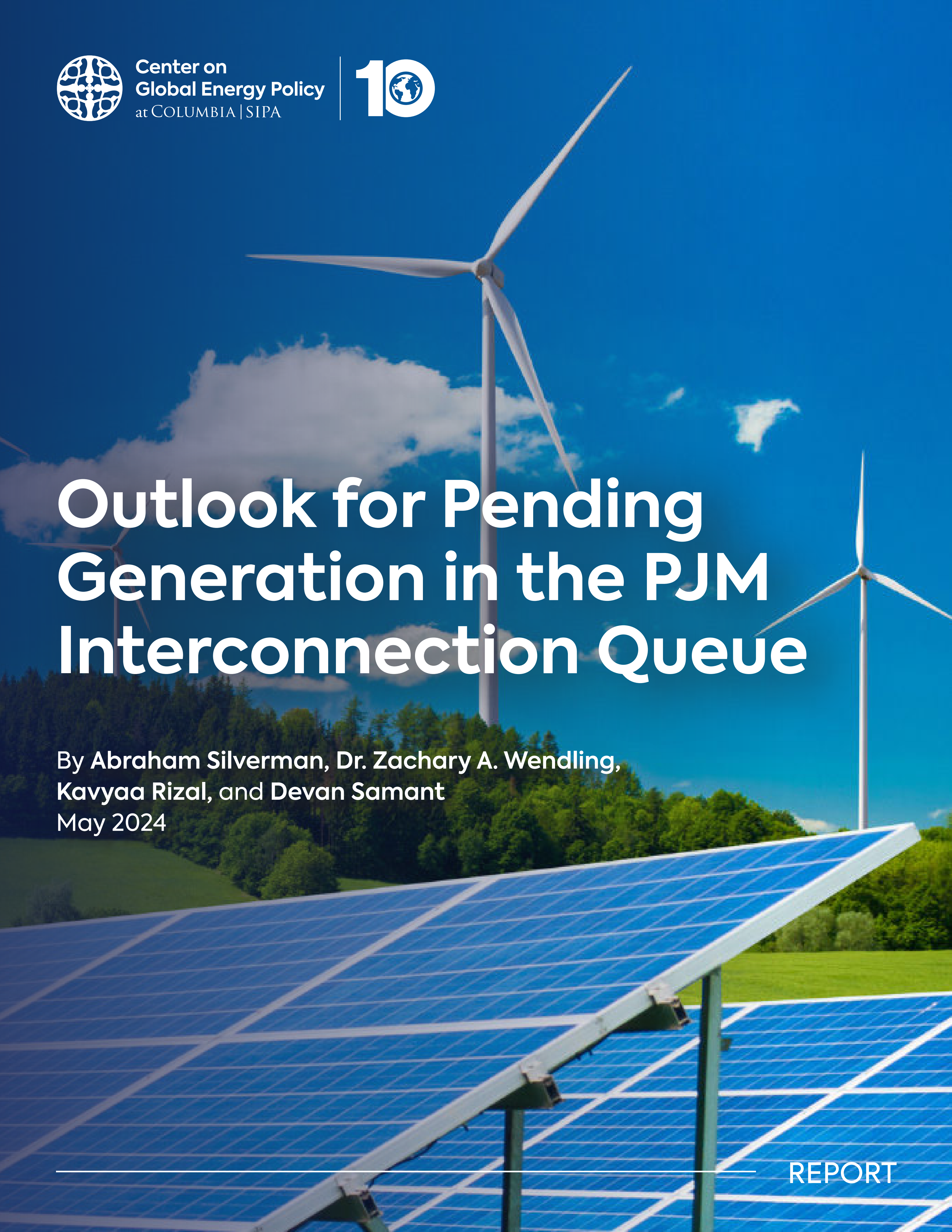

Outlook for Pending Generation in the PJM Interconnection Queue

By **Abraham Silverman**, **Dr. Zachary A. Wendling**,
Kavyaa Rizal, and **Devan Samant**
May 2024

REPORT

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Acknowledgements

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About the Authors

Abraham Silverman joined the Center as the Director of the Non-Technical Barriers to the Clean Energy Transition initiative. The Non-Technical Barriers initiative is designed to identify major legal and regulatory bottlenecks to the clean energy transition and then provide state and federal policy makers pragmatic solutions to address those challenges. Major focus areas include Legal and Regulatory Barriers at the state and federal level, Market Rules and Economic Incentives, and Social Acceptance & Just Deployment of Infrastructure.

Before joining the Center, Abe served at the New Jersey Board of Public Utilities as the General Counsel and Executive Policy Counsel. Abe's portfolio included developing offshore wind, solar, electric vehicle, energy storage, and interconnection reform programs, along with quantifying and managing ratepayer impacts of the clean energy transition. Abe also led the State's engagement with PJM Interconnection, the regional grid operator for New Jersey, on topics such as implementing New Jersey's first-in-the-nation offshore wind transmission solicitation, resource adequacy, clean energy market design, and transmission policy.

Previously, Abe spent more than a decade at NRG Energy, Inc., as the Deputy General Counsel & Vice President of Regulatory Affairs. Abe supported NRG's power markets team, power plant operations group, renewable development and state retail electricity market programs. Abe also led the company's advocacy at the Federal Energy Regulatory Commission, as well as anti-trust compliance work at the Department of Justice/Federal Trade Commission. Abe has also worked as an associate at Perkins Coie LLP and as a staff attorney at FERC. Abe has a Bachelor's Degree from the University of Maryland and a JD from the George Washington University Law School.

Abe has testified before the United States Senate's Energy & Commerce Committee, the Federal Energy Regulatory Commission, the New Jersey Senate, and is the author of numerous pleadings at the state and federal level, including before the U.S. Supreme Court and various U.S. Courts of Appeals.

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Devan Samant is a data scientist and master's student in Columbia Engineering. His prior experiences in regulation and analytics in risk consulting are being applied to research in clean energy generation and climate modeling. Devan works on the Non-Technical Barriers initiative.

Executive Summary

The United States is witnessing rapidly growing interest in clean electricity generation, driven by soaring consumer demand for clean energy and the country's goal to reduce greenhouse gas emissions. In parallel, the time it takes for new, clean generation projects to move from design to execution in the US has lengthened, meaning that the rising interest has not been matched by supply. The country's largest grid operator, PJM Interconnection (PJM), has experienced the most severe delays and backlog in new generation—projects entering the queue today have little chance of coming online before 2030.

It is widely understood that an increasingly lengthy interconnection process, which involves a series of studies and upgrades grid operators must take to ensure projects can connect to the grid safely and reliably, is responsible for this state of affairs. It is not clear how this longer process interacts with other known project development challenges—such as siting and permitting issues, supply chain constraints, and inflationary pressures—and to what extent such interactions may lengthen the timeline for bringing projects online. Understanding these dynamics can help answer critical questions about grid reliability going forward, including whether it will be necessary to delay or cancel the planned retirement of aging fossil fuel-fired generation resources that the new generation is intended to replace.

This report attempts to fill this knowledge gap. It presents results of an author-developed survey of those best positioned to understand the impacts of interconnection process delays: project developers in the PJM market. The key finding from the survey is that PJM's increasingly lengthy interconnection process is exacerbating siting and permitting challenges and leading to knock-on delays in equipment procurement and financing decisions, suggesting the timeline for new generation in this market will likely remain long for the foreseeable future. Given the importance of new entry to keeping prices competitive and maintaining reliability amid the retirement of older fossil resources, PJM will need to find ways to reduce interconnection delays or reconsider when those fossil resources should be retired.

Other notable findings include the following:

- Most developers expect to delay construction milestones or suspend some or all of their development efforts.
- Only 10 percent of developers report that any of their projects will come online within 12 months of receiving an interconnection service agreement, and most report their projects

will require at least 24 months from the time they receive such an agreement to reach commercial operation.

- Developers report very few duplicative interconnection requests, potentially calling into question the conventional wisdom that such projects are a major cause of interconnection delays.
- Over half of the developers who reported withdrawing, suspending, or pausing projects identified interconnection upgrade costs as a significant concern.
- Solar developers report that an outlook of lower value for renewable energy attributes (such as renewable energy credits) was a key factor in their decision to cancel or delay projects, while forward energy prices were less important.
- Offshore wind developers noted that the federal permitting process may require them to consider alternative points of interconnection or alternative turbine sizes, which can create late-stage changes to a project that may not qualify for PJM's traditional process for amending interconnection requests.

Introduction

The Inflation Reduction Act of 2022 and consumer demand for clean energy is driving record interest in new clean generation in the United States. But the time it takes for new clean generation resources to move from design to execution has increased markedly over the past five years, with the median project *completed* in 2023 taking five years from interconnection request to commercial operation.[1] These timelines are only increasing as the interconnection process—that is, the process grid operators go through to ensure that a new generator can connect to the grid safely and reliably—has itself grown from approximately two years in length to five.[2]

The backlog of new generation is particularly severe in the 13-state, plus the District of Columbia, region overseen by PJM Interconnection LLC (PJM), the largest grid operator in the United States, where an influx of new projects, increasing numbers of late-stage project withdrawals, and spiraling numbers of restudies[3] have overwhelmed the queue process, leading to multi-year delays and a freeze in processing new interconnection studies.[4] In consequence, absent significant reforms or market innovations, most projects entering PJM's queue today are unlikely to come online before 2030—and certainly not in the quantities necessary to satisfy demand for clean energy across the region that PJM serves, leading PJM to question whether it can maintain grid reliability.[5]

While experts broadly agree that interconnection delays are hampering the clean energy transition,[6] there is a relatively poor understanding of how these delays are interacting with other recognized development challenges, such as siting and permitting issues, supply chain constraints, and inflationary pressures, and how those interactions affect the timeline for developers to bring projects online.[7] As policymakers debate whether to delay or cancel the planned retirement of aging fossil fuel-fired generation resources due to concerns that new generation will not be ready to take their place,[8] having a grasp of these relationships and the commercial outlook for how long it takes to bring new resources to market could prove critical.

In an attempt to address this knowledge gap, the authors conducted a survey of developers with projects in the PJM interconnection queue. Responses were received from 30 independent developers representing 69 total projects across a range of generator technology types that entered the queue between 2017 and 2023 and reached an advanced stage of the interconnection process by June 2023. The authors also conducted limited follow-up interviews with developers.

The report begins by contextualizing the PJM backlog and explaining its implications for grid reliability. It then introduces the survey of developers and presents the survey results. The report concludes by analyzing the policy implications of the findings and offering a set of recommendations to policymakers and other stakeholders should they wish to resolve the delays caused by the interconnection process in the regions PJM serves and beyond.

The PJM Backlog and Its Implications for Reliability

Explaining the PJM Interconnection Queue

At the end of 2023, 2,600 gigawatts (GW) of generation and energy storage were waiting to connect to the grid nationwide—more gigawatts of generation than currently operate in the entire United States.[9] Zero-carbon resources, including wind, solar, and energy storage, comprised more than 90% of this capacity.[10] Increasing delays in the timeline for interconnection of new resources are well documented, with the average project now taking approximately five years to get through the study process, complete any necessary grid upgrades, and reach commercial operation.[11] These delays strongly impede the deployment of clean energy resources, harming economic competition, market efficiency, and reliability. They also blunt the impact of the Inflation Reduction Act of 2022, which provides incentives for new projects to reach commercial operation within a decade. The availability of these incentives is expected to drive significant reductions in greenhouse gas emissions through the remainder of the decade, but will only do so if generation is actually able to come online.[12]

Efforts to accelerate the interconnection study process are well underway at the Federal Energy Regulatory Commission (FERC). FERC's landmark Order No. 2023,[13] for instance, required all FERC-jurisdictional utilities to adopt new interconnection queuing rules into their tariffs. Regional electricity market operators, including PJM, are provided additional flexibility to propose rules tailored to their specific needs. PJM's compliance filing, along with that of the nation's other independent system operators (ISOs) and regional transmission organizations (RTOs), are due in late spring 2024.

The interconnection queue in PJM mirrors the national trend, where over 2,600 gigawatts of new generation is stuck in a queue. The number of new projects entering the PJM queue tripled between 2018 and 2021, and the total capacity of pending projects is now over 200 GW.[14] The surge in projects led PJM to freeze its interconnection queue in May 2022.[15] According to PJM's Independent Market Monitor, the FERC-recognized independent auditor for the PJM market, "as of December 31, 2023, 268,472.8 [megawatts] were in generation request queues in the status of active, under construction or suspended."[16] This represents "a decrease of 19,019.9 MW (6.6 percent) from the 287,492.7 MW at the end of 2022."[17] Approximately 75% of the generation awaiting study is zero-carbon,[18] compared to the current approximately 160 GW capacity of the entire existing PJM system. Just over 4,400 MW of new generation entered service in 2023. Of that generation, 70% was combined cycle or combustion turbine gas-fired resources, 20% was solar, 6.5% was wind, and the remainder was battery and solar as well as storage units.[19] Although PJM is implementing emergency reforms to its interconnection program, it expects that alleviating the backlog will take several years.

In late 2023, PJM stated that it “expected to clear 300 new generation projects totaling [26 GW] in 2024” and that “another [46 GW] of nameplate generation capacity in projects…should clear PJM’s study process and be ready for construction by mid-2025, for a total of [72 GW] of projects.”[20] Thus, even completing tens of gigawatts of interconnection studies annually still leaves PJM significantly behind the voracious consumer demand for clean energy.

Implications for Reliability

The speed at which projects move through the PJM interconnection queue and the rate at which those projects come online have major implications for the reliability of the electric grid. It is an electrical industry axiom that a reliable electric grid requires the availability of sufficient generation resources to meet electricity demand on peak days, plus an appropriate reserve margin. In practical terms, this “balance sheet” approach to reliability means that as existing generation resources retire, they must be replaced with resources of comparable capacity.

In 2023, PJM officials expressed concern that new resources may not reach commercial operation in sufficient quantities to replace retirements in the existing fleet.[21] As PJM put it, “the amount of generation retirements appears to be more certain than the timely arrival of replacement generation resources, given that the quantity of retirements is codified in various policy objectives, while the impacts to the pace of new entry of the Inflation Reduction Act, post-pandemic supply chain issues, and other externalities are still not fully understood.”[22] PJM’s Independent Market Monitor likewise stated that “the markets face a challenge from potentially high levels of expected thermal generator retirements, with no clear source of replacement capacity or the fuel required for that capacity.”[23]

One of the complicating factors identified in PJM’s Energy Transition Report is that the reliability value of a new generator is a function of both the size (or nameplate) of the generator and how it is likely to operate during periods of stress on the grid. PJM notes that it would take just over 107 GW (nameplate) of new renewable and battery resources to provide 30 GW of reliability value.[24] The reliability value (or “capacity accreditation” in PJM lingo) of a resource is set by PJM based on complicated probabilistic models conducted by PJM,[25] often referred to as Expected Load Carrying Capability (ELCC).[26] The ELCC value is intended to reflect the likelihood that any given generation resource will be available when needed and accounts for factors such as correlated outages of natural gas resources during cold weather[27] or correlated output of solar resources. The result is that PJM's balance sheet reliability analysis is likely to evolve over time as system conditions change, which makes long-term estimates of grid reliability challenging.

Currently, PJM relies on a mix of largely fossil fuel-fired and nuclear generators to meet its reliability needs. However, PJM forecasts that 40 GW, or 21% of its total installed capacity, will retire by 2030.[28] This estimate includes 12 GW of previously announced retirements, 25 GW of retirements driven by federal and state environmental policies, and 3 GW of projected economic retirements.[29] PJM's Independent Market Monitor puts the potential retirement figure even higher, noting that "although the exact numbers may vary, an estimated total of between 24,000 MW and 58,000 MW of thermal resources are at risk of retirement."[30]

Among the policies driving these retirements, several are notable:

- Illinois's Climate and Equitable Jobs Act mandates the retirement of 5.8 GW[31] of coal-fired and high-emitting gas resources.[32]
- A trio of rules from the US Environmental Protection Agency (EPA), namely, the Coal Combustion Residuals, Effluent Limitations, and Good Neighbor Rules, will result in the retirement of approximately 10 GW of generation retirements.
- New Jersey's Carbon Dioxide Rules will result in approximately 3 GW of generation retirements.[33]

While PJM has weathered similar scale retirements in the past (particularly during the mid-2010s, in response to Obama-era EPA rules), the expected replacement schedule is one of the more substantial transitions away from fossil generation in its history.[34]

PJM has highlighted the two dominant drivers of uncertainty about future reliability: the speed at which new generators are proposed and the rate of success for generators currently in the interconnection queue. PJM selected several different measures of the volume of new generation currently in the queue that is likely to reach commercial operation, and made additional assumptions about how much new generation is likely to enter the queue between 2023 and 2030. PJM's "High New Entry" scenario projects sufficient new entry to offset resources anticipated to retire.[35] However, PJM's "Low New Entry" scenario reaches the opposite conclusion, namely, that insufficient new generation will come online to keep up with anticipated retirements. The result would be either higher prices for consumers or a reliability crisis. Only PJM's "High New Entry" scenario adds enough new generation to almost entirely offset the anticipated retirements of fossil resources, even after applying PJM's new ELCC methodology.[36] In its December 21, 2023, update, PJM stated that "at the end of 2023, about [40 GW] of projects that had completed the

PJM study process had yet to move through construction, due to issues including siting, supply chain and financing."[37]

While numerous parties have identified concerns with PJM's analysis—in some cases, calling into question its key conclusion[38]—the specter of a reliability crisis continues to drive sharp energy policy debates. Surveying developers with projects currently in the interconnection queue sheds new light on the dynamics behind this uncertainty.

Study Design

Generation developers have a unique perspective on the challenges of bringing new resources to market, including elongated interconnection study processes, siting and permitting, inflationary pressures, market outlook, and delayed supply chains. The authors identified a range of possible project challenges based on their experiences and conversations with developers and PJM, and then prepared a survey of 27 questions to assess which, if any, developers saw as most salient in the development process.

When respondents designated challenges as highly significant to their projects, the survey prompted them with more specific questions about those challenges. The survey also included questions about how the hurdles presented by atypical events, such as the COVID-19 pandemic and related supply chain and inflationary issues, compared with the more typical aforementioned challenges. Several questions allowed respondents to identify other challenges not identified in the survey. Finally, survey participants were invited to participate in informal follow-up interviews.

Sample

Because the authors were interested in projects that could potentially come online in the next several years, the survey focused on projects that entered PJM's interconnection queue between January 1, 2017, and May 16, 2023. The sample was then further narrowed down to projects at an "advanced stage" of the interconnection process as of June 1, 2023, meaning those that had just started the Facilities Study process, completed a Facilities Study, or tendered or executed an Interconnection Service Agreement (ISA) or the equivalent.[39] Throughout the analysis, the term "project" is used to refer to a single proposed generation project or generator uprate that was assigned a queue position by PJM.[40] The term "developer" or "project sponsor" refers to the ultimate upstream corporate parent. Each developer's parent was identified by cross-matching the name of the specific development project with the upstream parent in FERC filings, interconnection agreements, and/or general web searches. In cases where two upstream owners are partners for a project, both were invited to participate in the survey.

Data on projects was obtained from PJM's New Services Queue. The latter includes project technology, location, and progress through the interconnection queue,[41] as well as links to ISAs and the interconnection studies performed by PJM, which provide additional information not available in the database itself. While these study documents are a mix of machine-readable and non-machine-readable data, web scraping techniques, optical character recognition, and independent research were used to identify developer names and contact information. The survey team also worked with PJM and a variety of business- and policy-oriented trade associations to alert developers to the existence of the survey and solicit participation.

Table 1 contains a description of the projects in PJM's interconnection queue and those in the sample. In total, 496 projects listed in the New Services Queue met the survey qualifications. Of those, project-level data could be extracted for 412 projects and email addresses obtained for 332 projects across 89 developers. The 412 projects had an estimated nameplate capacity of 30 GW. In total, 30 developers representing separate corporate parents substantially completed the survey, divided evenly between two outreach methods. One method involved sending the survey via email to 224 distinct email addresses that had been compiled. One hundred of the emails were opened, and 15 surveys were substantially completed. The second method involved sharing a generic link to the survey to other developers that met the survey qualifications through webinars and informal communications. Fifteen respondents substantially completed the survey using the generic link.

Table 1: Description of sample size and participation

Criteria	Description	Projects	Developers	Nameplate capacity (GW)
Eligible	Entered queue January 1, 2017–May 16, 2023 *and* As of June 1, 2023, either (1) started or completed Facilities Study, *or* (2) tendered or executed Interconnection Service Agreement	496	–	–
Described	Project-level information available from PJM's New Services Queue databases and online sources	412	–	30
Contacted	Discernable email contact information available	332	89	26.4
Responses	Completed survey	69	30	7.1

Respondents to the generic survey were included in the data set if they stated that they had a project that met the survey qualifications. In total, 30 responses in which at least one substantive portion of the survey was completed were received, including from both developers who responded via email and those who used the generic version. Respondents spanned 69 projects that could be tied to specific queue positions, totaling 7.1 GW of generation or storage, or approximately 24%

of the nameplate capacity and 17% of the projects meeting the qualifications for participation in the survey.[42] The 69 project tally likely undercounts total project participation given that some developers represent projects that were not captured by the authors' automated electronic scraping.[43] When asked to self-report the number of eligible projects they represent, developers reported additional projects. The lower, more conservative figure was used to calculate the total survey participation rate. Some questions directly asked the respondent how many projects they were developing. In such cases, the number of projects identified by the developer was used.

Survey

The online survey[44] asked questions about the following topics:

- Siting or permitting considerations at the federal, state, and local levels.
- Length of the interconnection process, both including and excluding new transmission construction.
- Expectations for commercial operation dates.
- Supply chains.
- Tariffs.
- Labor issues.
- Commercial outlook, including for energy, capacity, and environmental attributes.
- Implications of inflation on market conditions related to cost of capital, financing, tax equity, or other financing metrics.
- Regulatory changes related to Effective Load Carrying Capability rules.

The survey asked developers to identify challenges associated with projects that were "actively in development" as well as projects that were "withdrawn from the PJM queue, put into suspension, or for which your firm paused or ceased development." Unstructured follow-up interviews were also conducted with personnel from selected firms to better understand the challenges they are facing and obtain additional context.

Interviews

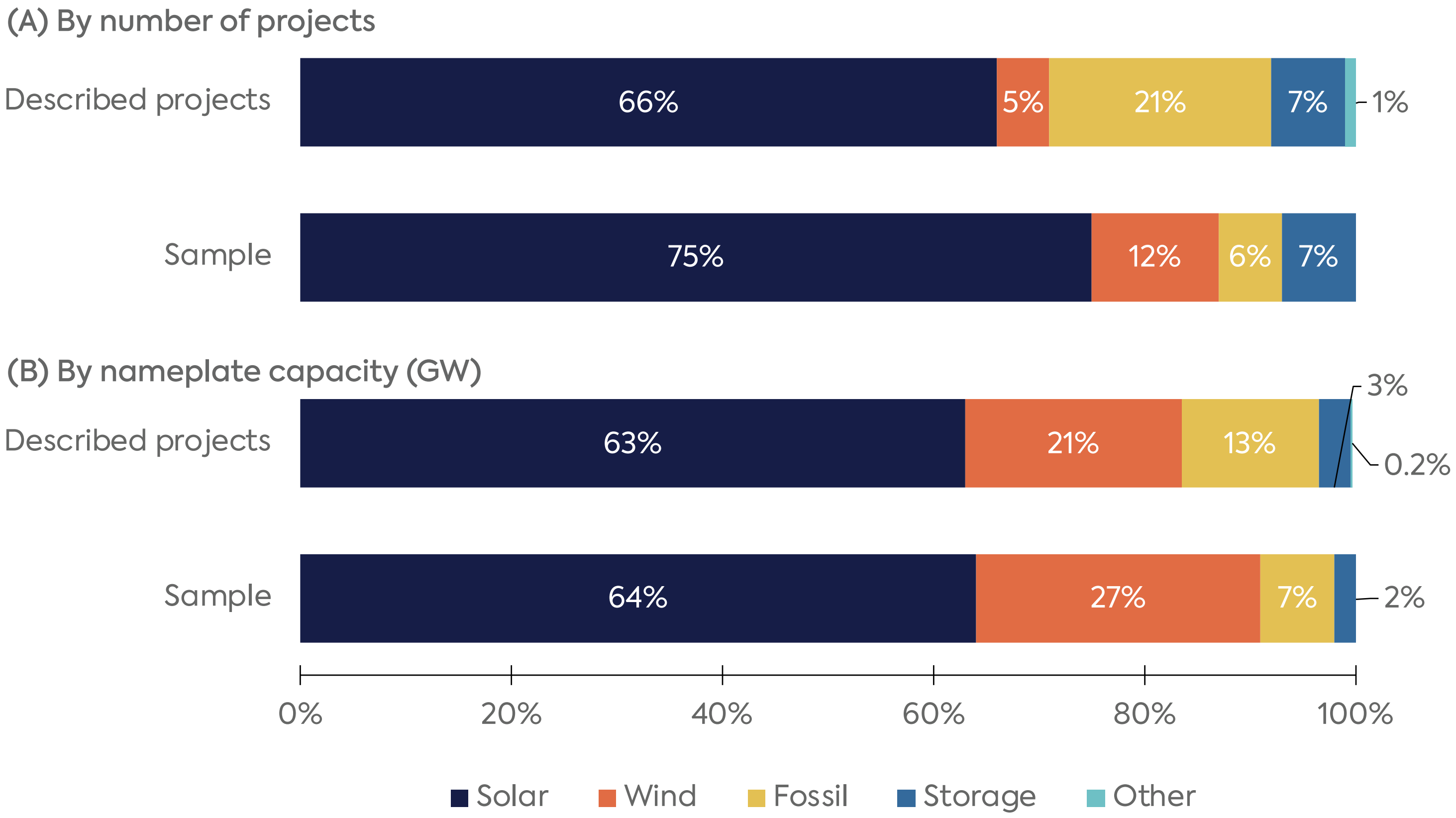
Developers with eligible projects were also invited to participate in unstructured interviews. Six total interviews were conducted. Most interview participants also participated in the survey process, although one firm with eligible projects participated only in the interview process. The interviewees provided additional context for as well as explanations of their experience with the interconnection process.

Results

Descriptive Statistics

Figure 1 shows that the population of described projects (see Table 1) is largely solar or hybrid solar with storage (66%), compared with 75% in the sample, which underrepresents fossil fuel projects and overrepresents wind projects. Likewise, by nameplate capacity, 63% of described projects in the interconnection queue are solar or solar with storage, compared with 64% of the capacity in the sample. The sample contains more wind (27% vs. 20%) and less fossil fuel (7% vs. 13%) than the population's capacity.

Figure 1: Comparison of percentage composition of the sample (*n* = 69, 7.1 GW) to all described projects (*N* = 412, 30 GW) by number of projects and nameplate capacity



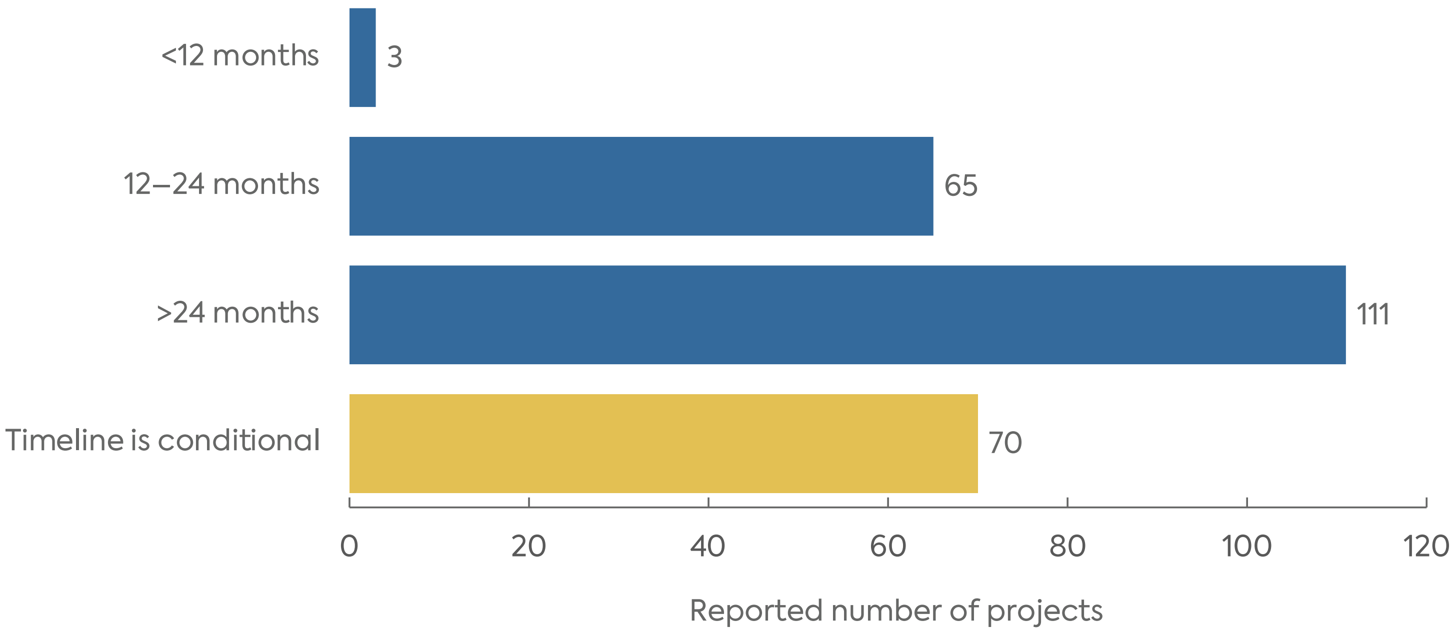
Note: Solar and wind projects include those with and without storage.
Source: Authors' analysis.

Timeline for Bringing Projects Online

The rate at which new interconnection projects make it through the queue and eventually reach commercial operation represents the difference between a reliability crisis with sub-10% reserve margins and a healthy grid.[45] To better understand the developers' outlook on timing, the survey asked how long it would take for each of their projects to reach commercial operation from the time they received an ISA. Eighteen developers responded to this portion of the survey (Figure 2).

Figure 2: Expected timeline for projects if developers received an Interconnection Services Agreement today, based on 18 respondents

"If all your projects received an Interconnection Services Agreement today, how many would reach commercial operation in the following time frames?"



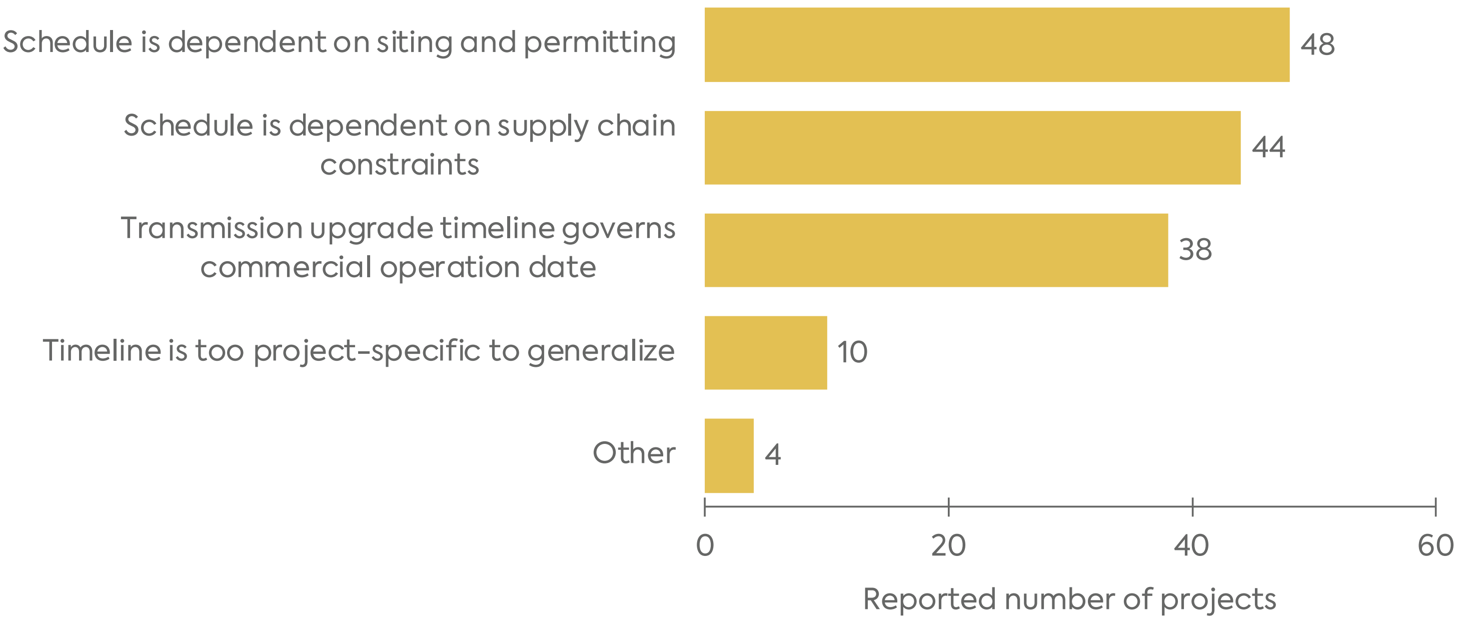
Source: Authors' analysis.

Note that the number of projects was self-identified by the developers, which resulted in a higher number of projects. The three projects with the fastest timelines were an uprate to a natural gas facility, a wind farm, and a solar farm. Medium-term projects included wind, solar, and natural gas resources. Projects expected to take longer than 24 months spanned multiple technologies.

Numerous respondents also said that timeline estimates were "conditional" on project-specific factors. To explore this aspect, the survey asked them to indicate how many of their projects depended on five different factors that were purposefully selected to explore the relative role of siting and permitting, supply chain, and network upgrade timelines (Figure 3).

Figure 3: Factors affecting projects with conditional completion timelines, based on 8 responses

"Thinking about your projects that have uncertain timelines, upon which of the following factors does the schedule depend?"



Source: Authors' analysis.

Siting and permitting was the largest source of uncertainty, followed closely by supply chain constraints and transmission upgrades. Developers who selected "other" or added commentary to their responses identified state renewable energy incentives and the ability to comply with Ohio's Domiciled Worker Rule as major sources of uncertainty, while another identified state policy changes.[46]

Expected In-Service Dates

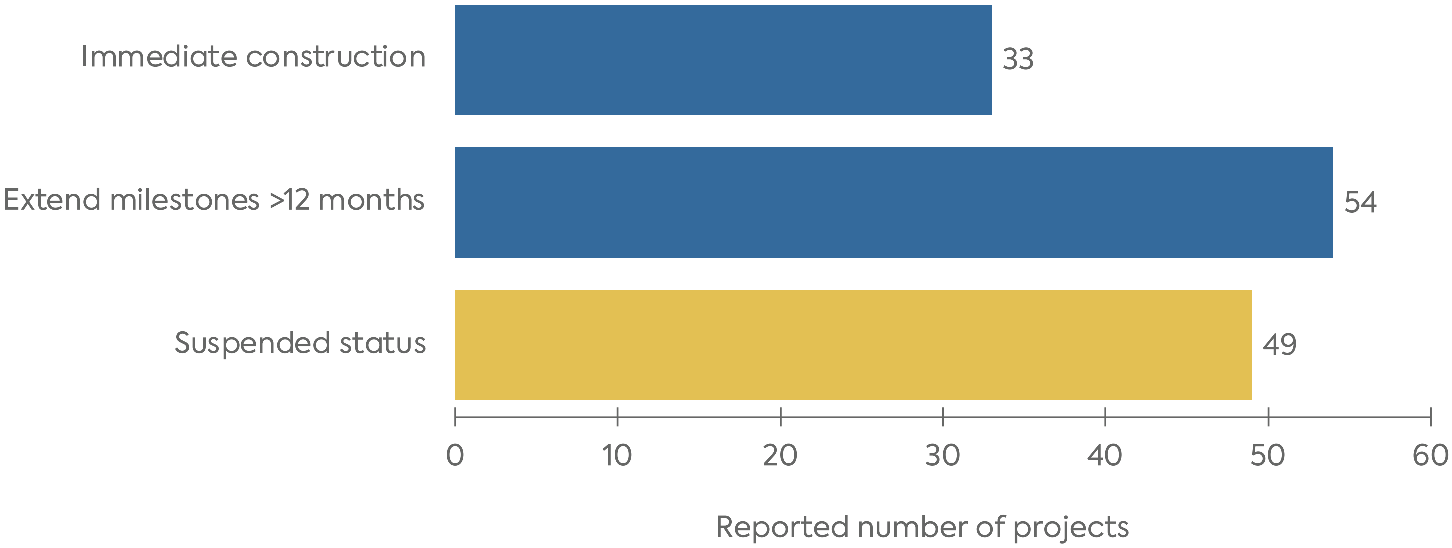
Expected in-service date is an important metric of the health of projects in the PJM queue. In-service dates are a function of two different but highly interrelated processes: the developer's construction of the facility itself; and the construction of network upgrades, or the grid enhancements necessary for the interconnecting utility to receive the power onto its transmission system. Generally, these upgrades must be completed before unrestricted commercial operations can commence. Each ISA issued by PJM includes a set of "construction milestones," applicable to both the developer and the interconnecting utility, that describe when each entity expects to complete its work.[47] If a developer misses its milestones, PJM can remove the project from its interconnection queue.

Because utility and developer construction activities often overlap or are dependent on each other, the PJM process allows developers to extend the milestones, which simply postpones their obligation to meet them, or to request that PJM put their project into "suspension," which allows the developer to pause construction activities until the project is restarted or canceled. In each case, the utility's milestones are revised accordingly. Milestones can also be extended by the transmission-owning utility to reflect delays in procurement of equipment, such as high-voltage transformers, or construction of network upgrades.

To explore how quickly developers expect to be able to begin construction on their projects, the survey asked whether they would commence construction of new facilities or take another action that would delay construction (Figure 4).

Figure 4: Next steps for projects receiving an Interconnection Services Agreement today, based on 27 respondents

"If you were to receive an Interconnection Services Agreement today, which of the following next steps would you be most likely to take?"



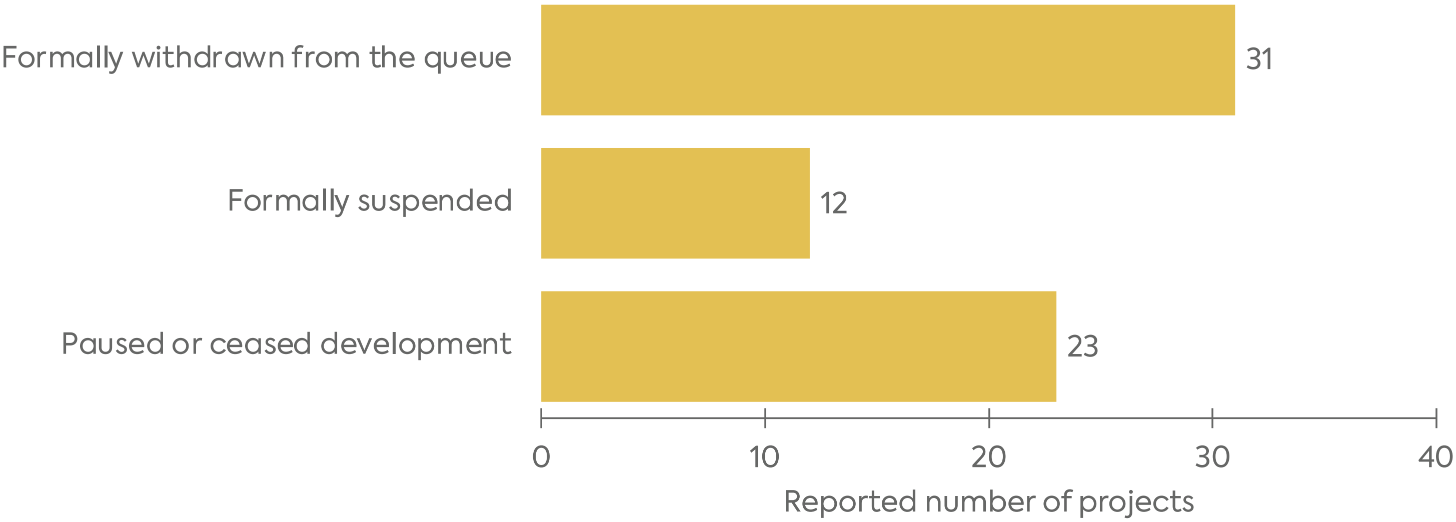
Source: Authors' analysis.

Eleven developers identified a total of 33 projects on which they anticipate commencing construction immediately after receiving an ISA, including uprates to existing natural gas facilities and solar resources. Eight developers representing 54 projects stated that their next step would be to extend milestones by more than 12 months. Another eight developers representing 49 projects across only wind and solar technology types indicated that they would put projects into suspended status. Several developers indicated that they would extend milestones and then likely put the project into suspension. During interviews, some developers indicated that projects would immediately proceed to final engineering. One developer explained, for instance, that once an ISA is received, the project would go to either a senior executive or the board of directors for a Final Investment Decision. The developer cautioned that taking a project to Final Investment Decision can be a lengthy process, as it typically requires identifying equipment and third-party financing arrangements before any determination can be made.

Another significant issue is the fate of projects that received construction milestone extensions or were suspended. Historically, such projects have remained in the interconnection queue despite not being under active development. Because studying a project consumes PJM resources regardless of its commercial prospects, PJM recently reformed its interconnection rules to remove these stalled projects from its queue by inserting two new requirements: increased maturity and financial security postings.[48] The survey asked developers how many of their projects were currently formally suspended, informally paused, or withdrawn from the queue. Developers report that approximately half were formally withdrawn from the queue (31/66) and 12 were formally suspended, in accordance with the new PJM rules. Twenty-three projects were informally paused by the developer (Figure 5).

Figure 5: Status of projects that received milestone extensions or were suspended, based on responses from 18 developers

"How many of your projects were withdrawn from the interconnection queue, put into suspension, or for which your firm paused or ceased development?"



Source: Authors' analysis.

The survey also provides insight into the question of how often developers submit multiple, marginally different interconnection queue requests for the same project. The extent to which these duplicative requests slow down PJM's efforts to complete interconnection studies has been hotly debated,[49] and several of PJM's recent queue reforms were designed to eliminate them. In the sample, only one developer identified an interconnection queue request that had been suspended or paused because it was extremely similar to another project with a separate queue position. Given this issue has been a major theme in PJM discourse, it was surprising to find only a single instance of it among the all the projects in the survey,[50] though it is possible that developers are unwilling to self-report filing a duplicative or speculative interconnection request.

Evaluating Major Challenges

Projects may face a variety of major challenges to successful completion. The authors identified challenges to be included in the survey based on their experience with interconnection challenges, review of ongoing interconnection reforms, and informal discussions with developers. Challenges were divided into two categories: non-financial barriers and financial and business barriers (Table

2). The survey also allowed developers to highlight specific aspects of these challenges and identify other challenges that were not included in the survey.

Table 2: Major challenges to projects in the interconnection queue

Non-financial barriers	Financial and business barriers
• Siting or permitting considerations at the federal, state, or local level. • Length of the interconnection study process (not including construction of network upgrades or interconnection facilities). • Length of the construction timeline for network upgrades or interconnection facilities or uncertainty around that timeline. • Supply chain concerns unrelated to solar tariffs or import restrictions. • Supply chain concerns related to solar tariffs or import restrictions. • Ability to establish site control. • Workforce or labor shortages. • Other (please describe).	• Ability to win a competitive solicitation or comparable process. • Lack of an offtake agreement. • Inflationary pressures related to equipment procurement costs. • Change in anticipated revenues from the capacity and/or energy market. • Change in financial market conditions related to cost of capital, financing, tax equity, or other financing metrics (separate from equipment procurement costs). • Change to state regulatory policy that affected value of environmental attribute or incentive programs. • Change in corporate strategy or risk appetite unrelated to a specific project. • Other (please describe).

Developers were asked to rate these major challenges on a five-point scale:

1 = The factor has no impact on the development of project(s)
2 = The factor has a small impact on the development of project(s)
3 = The factor has a moderate impact on the development of project(s)
4 = The factor has a major impact on the development of project(s)
5 = The factor has a decisive impact on the development of project(s)

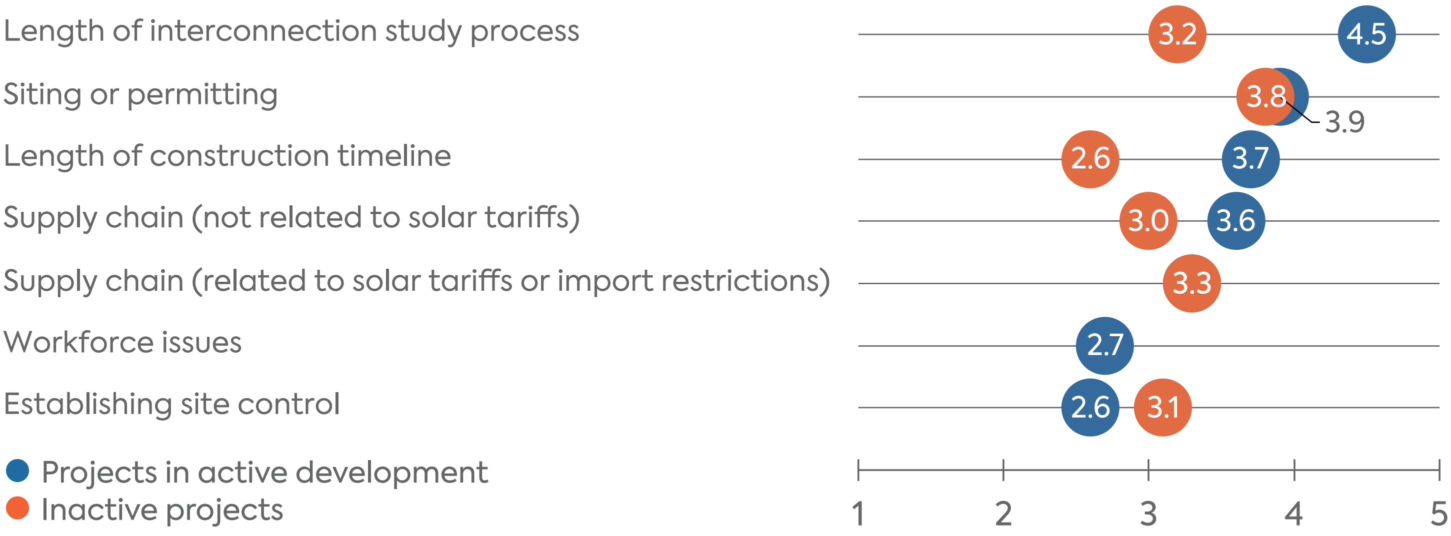
Developers repeated this rating separately for two kinds of projects: (1) those in active development, which were defined as "your company's project or projects that reached the Facilities Study phase or that were tendered an Interconnection Service Agreement or the equivalent"; and (2) projects that have "been withdrawn from the PJM queue, put into suspension, or for which your firm paused or ceased development."

Non-Financial Barriers to Project Development

To assess non-financial barriers, the survey asked respondents to think generally about projects that were actively in development as well as those that are inactive (i.e., withdrawn from the queue or put into suspension by PJM, or paused or ceased development by a firm). In general, respondents rated non-financial barriers as more significant for projects in active development than for those that are inactive, potentially because projects that did not pencil out financially never reached the stage where non-financial barriers were relevant. The greatest difference between these project types related to length of construction timeline, which developers of active projects rated 3.7 out of 5 and developers of inactive projects rated 2.6, the lowest of any factor. For active projects, length of interconnection study process led with an average rating of 4.5 out of 5, indicating a significant burden on the rate of deployment for new energy resources. Respondents rated workforce issues (2.7) and establishment of site control (2.6) as the lowest barriers for active projects (Figure 6).

Figure 6: Average ratings on a five-point scale (5 = decisive impact, 1 = no impact) of non-financial barriers to projects in active development or inactive projects, based 23 respondents for active projects and 15 respondents for inactive projects

> *"Thinking about your projects that are {inactive / actively in development}, please rate the following factors associated with the interconnection process, siting, permitting, or supply chains on {your decision(s) / how much of a challenge they are to the project(s)}."*



Note: "Inactive" includes projects that PJM has withdrawn from its queue or put into suspension, or that the firm has paused or ceased development on. Respondents with inactive projects were not asked about workforce issues.
Source: Authors' analysis.

Length of Interconnection Process

During the interview process, and in response to the open-ended survey questions, several developers explained that uncertainty over the length of the study process was leading to longer siting and permitting timelines. Specifically, developers noted that local siting approvals and permits often lapse after a year or two and that many permits require that the developer start construction within a specified amount of time and then "make continuous progress" for that permit to be maintained. They further noted that when the length of the interconnection study process is knowable, they typically synchronize it with the permitting/siting process, but the uncertainty associated with the current interconnection process has led them to wait to submit new permitting or siting applications until they receive an Interconnection Services Agreement from PJM. As one developer stated during the interview process, "The permitting aspect is an issue. Some people start on both permitting and interconnection at the same time. But we've taken the approach that we're going to wait and see and start permitting at the end."

In the interviews, other respondents identified difficulties in maintaining "site control during extended and uncertain interconnection processes," explaining that options, which give the developer the exclusive right to purchase the property in the future, or other long-term property arrangements were expensive to maintain. One developer also expressed concerns about PJM's approach to deadline enforcement, asserting that "tariff compliance is one-sided; projects sit in limbo for 18 months, and then PJM finally gets in touch on a Friday afternoon and gives you three business days [to make major commercial decisions]."

Concerns about interconnection timelines applied to all technology types, with solar developers slightly more concerned (average score of 4.8) than fossil fuel developers (average score of 4.0). Concerns about the length of the interconnection process were likewise cited as a "major" or "decisive" factor by almost half of developers with paused, suspended, or withdrawn projects.

Siting and Permitting

Seven of the 10 developers who identified siting and permitting as a major non-financial barrier (covering a total of 47 projects) deemed siting concerns as a "decisive" or "major" factor in the cancellation of one or more projects, with many citing county-level siting and permitting challenges as the primary factor in either commentary or during the interview process. Other developers specifically identified siting and permitting concerns with "local communities," "mostly county and township jurisdictions," or "multiple townships and counties." State and local siting and permitting challenges were identified in virtually every state where projects are located, including Virginia, Ohio, Pennsylvania, Maryland, Kentucky, New Jersey, Delaware, West Virginia, and Indiana.

Developers also pointed to regulatory requirements at the state level as major challenges. Several identified the Certificate of Public Convenience and Necessity process in West Virginia as very challenging, particularly given that the state has relatively few areas that are topologically suitable for solar. One developer called out New Jersey's limits on the use of agricultural land for solar arrays.

During the interview process, one developer highlighted what they referred to as "a bit of a chicken and an egg problem—ideally you would time these things so [permitting and construction] would come together, but until you have some kind of certainty that you are going to get an interconnection, we've been unwilling to make massive spending on permitting." Several developers reported that, as a result, they must wait until they receive the ISA before they start the permitting process. This effectively delays the siting and permitting process until the end of the interconnection process instead of conducting these processes in parallel.

Developers also noted that the numerous restudies were leading them to delay both siting and permitting and investment decisions. For example, one developer noted that "PJM likes to think that the interconnection is the last thing that people need, but honestly, when the timelines were better known and adhered to, you could get through the [system impact study], and then you can start making investments, so long as you don't get a surprise in the facilities study phase. But now, you get repeated facilities study delays."

One of the major points that came up across the survey responses is that siting and permitting can be a time-consuming, expensive, and potentially risky investment of funds. As one developer wrote, "state[s] and their associated agencies have competing goals that are not aligned. Local jurisdictional approval[s] are highly subjective and again don't align with intentions and goals." Another noted that a single local siting entity "can tie up project approval through a never-ending appeals process." A different developer identified "litigation of permits" as a key challenge. In each case, developers are having to delay initiating siting and permitting activities.

Relatively few survey respondents for terrestrial projects identified the National Environmental Policy Act or other federal siting or permitting statutes as significant challenges, which likely relates to the fact that federal lands play a smaller role in energy siting decisions in the eastern portion of the United States. During the interview process, several developers did, however, identify concerns about the impact of projects on the habitat of a bat species that had recently been added to the endangered species list.

One offshore wind developer noted that the federal permitting process can propel them to consider alternative points of interconnection or alternative turbine sizes, both of which can trigger a material modification process at PJM, which requires PJM to formally determine whether the change is significant enough to require the generator to restart the interconnection process.

As they put it, the "interconnection process wants a definite design/certainty, while [federal regulators] want flexibility." These developers suggested that better coordination between PJM, FERC, and federal permitting agencies may be warranted. In Europe, by contrast, the Transmission System Operation (the PJM equivalent) identifies points of interconnection at the beginning of the process and starts the permitting process even before the contract is awarded.

Length of Construction Timeline

In general, solar projects appear to be more impacted than fossil projects by long network upgrade construction timelines, potentially because many of the fossil projects involve uprates to existing projects where the interconnection infrastructure largely exists already. While length of construction was cited as a major concern for projects in active development, it was cited far less prominently as a reason for project failure, with only one developer stating that it was a "decisive" reason for a project withdrawal/suspension or pause.

Supply Chain Concerns Unrelated to Solar Tariffs or Import Restrictions

Several developers noted that the length of the interconnection study process was complicating their efforts to address equipment procurement and supply chain issues. Equipment procurement decisions are typically made as late in the construction process as possible to ensure that the project incorporates the most state-of-the-art technology available and to minimize expenses associated with storing equipment. Several developers reported delaying their equipment procurement until after receiving an ISA to avoid the risk of locking in obsolete technology or ordering equipment that they would not be able to immediately deploy. Developers also report that the lack of certainty in interconnection timelines exacerbated their ability to deal with unexpected problems in the equipment pipeline, including as a result of solar tariffs and other pandemic-related supply chain challenges.

Supply Chain Issues Related to Solar Tariffs and Import Restrictions

Respondents were asked to rank the impact of supply chain considerations in general and those related to solar tariffs and import restrictions in particular.[51] When asked to rate the relative impact of all the challenges they previously rated as "major" or "decisive," developers tended to rank tariff/import considerations lower than other challenges, suggesting they were less of a concern than siting and permitting as well as the overall length of the interconnection process. Even firms that ranked tariffs/import considerations as "decisive" said that they were only the third or fourth most significant challenge they faced. Trade issues, however, have the potential to evolve very quickly, and remain a focus for clean energy developers. This shows the complexity of project development and how multiple issues can be decisive to a project's long-term success.

Establishing Site Control

Over the past several years, numerous ISOs and RTOs, including PJM, have ratcheted up site control requirements significantly in an effort to drive down the number of projects in the interconnection queue that have little chance of reaching commercial operation (often colorfully referred to as "zombie projects").

Several developers, whether in their written comments or during the interview process, noted that maintaining site control throughout a lengthy interconnection study process was a challenge. Developers noted that site control is often demonstrated through options agreements, which typically involve an option payment to the property owner, who then agrees not to sell the property to another buyer for a fixed period. Generally, option agreements need to be renewed annually, with larger premiums charged for longer-term tie-ups. Renewing these options can involve expensive and time-consuming negotiations. Solar and wind developers cited site control as a significant challenge, whereas fossil fuel developers did not. As noted above, many of the developers of natural gas-fired projects involve uprates to existing facilities. Because the developer already owns the land on which the existing power plant was sited, they would not experience any issues with site control.

Workforce Issues

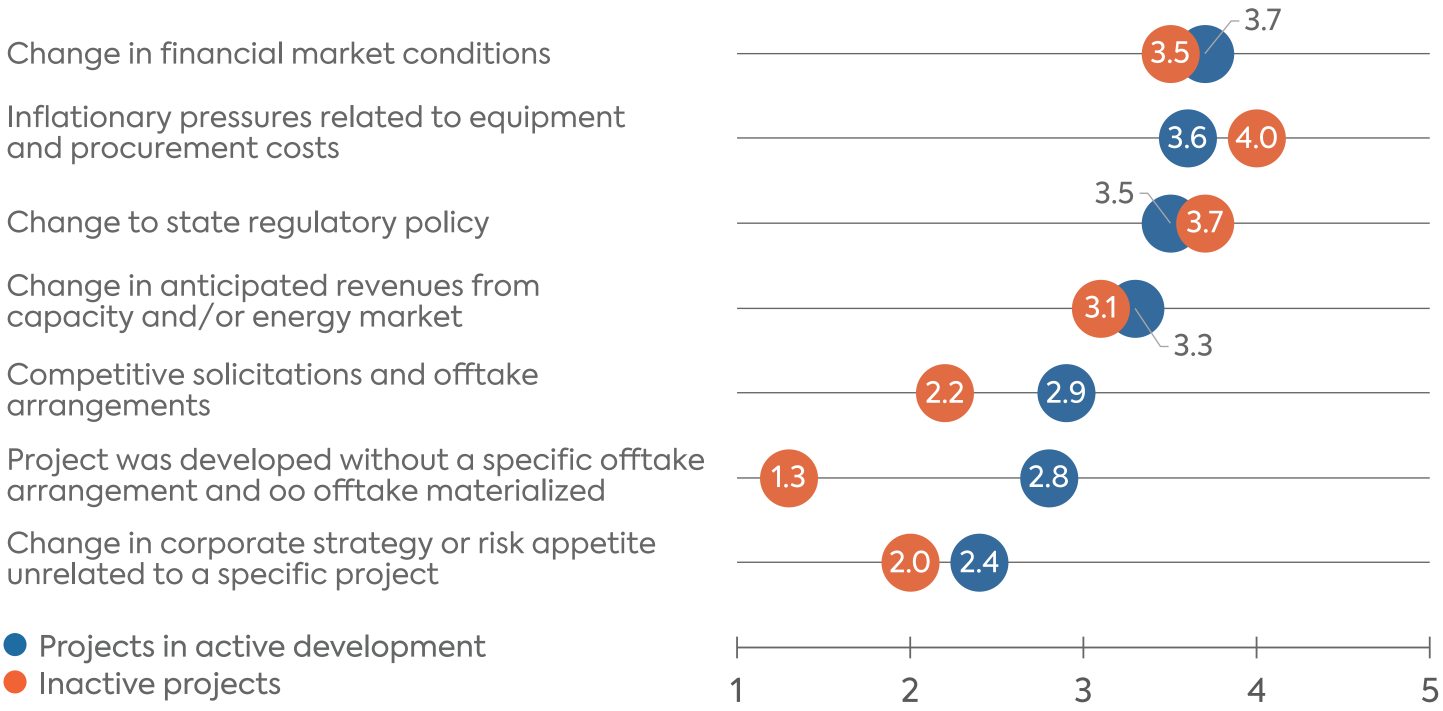
While concerns about workforce Issues were generally not highly ranked, during the interview process several developers referenced Ohio's restrictions on domiciled workers as a key challenge.

Financial and Business Barriers to Project Development

Among the five financial and business barriers included in the survey, respondents identified three as most significant to active and inactive projects alike: changes to financial market conditions, inflation-driven increases in equipment procurement costs, and changed outlook on state incentives. They deemed the two remaining challenges—absence of an offtake agreement and changes in corporate strategy or risk appetite—as less impactful, though more important for projects in active development than for inactive projects (Figure 7).

Figure 7: Average ratings on a five-point scale (5 = decisive impact, 1 = no impact) of financial and business barriers to both projects in active development and inactive projects, based on 19 respondents for active projects and 13 for inactive projects

"Thinking about your projects that are {inactive / actively in development}, please rate the following factors associated with project finance or economics on {your decision(s) / how much of a challenge they are to the project(s)}"



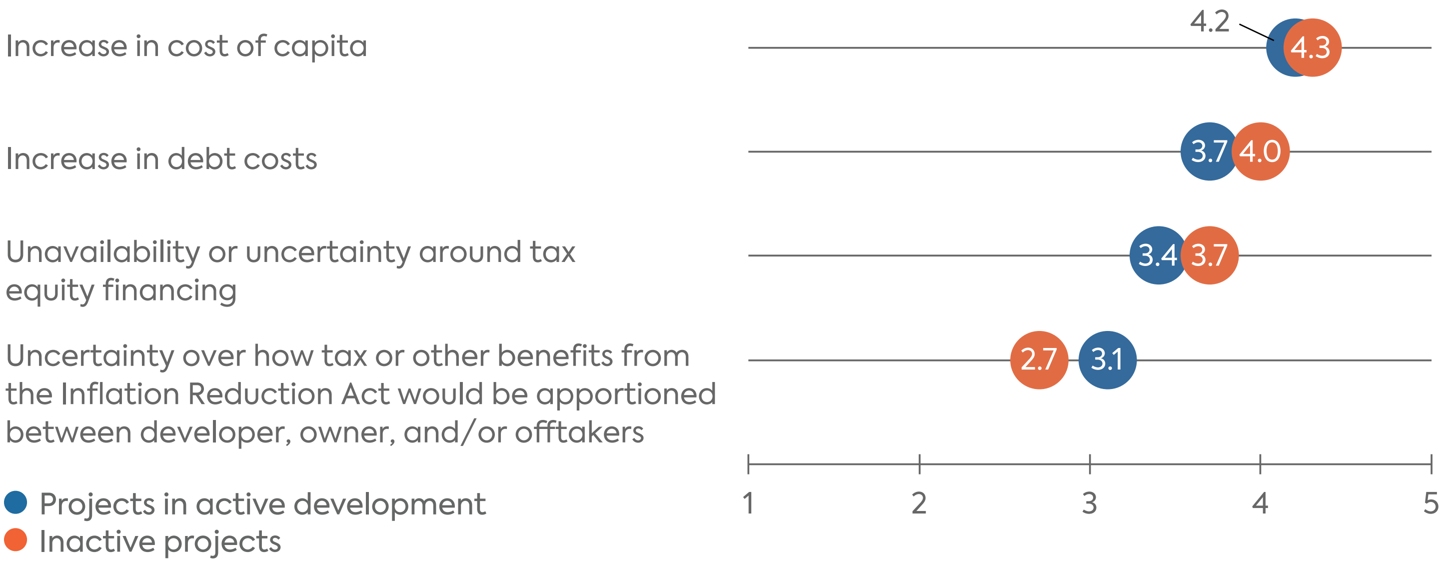
Note: The "Inactive" category includes projects that PJM has withdrawn from its queue or put into suspension, or that a firm has paused or ceased development on.
Source: Authors' analysis.

Change in Financial Market Conditions Related to Cost of Capital, Financing, Tax Equity, or Other Financing Metrics (Separate from Equipment Procurement Costs)

Developers identified changes in financial market conditions related to cost of capital, tax equity, and other financing metrics as a top concern for both active and canceled or paused projects, suggesting that macroeconomic factors related to cost of capital are top of mind for developers. One developer also identified access to tax equity as a significant challenge.

Respondents were also asked to rate four financial market conditions on the same five-point scale for both active and canceled or suspended (Figure 8).

Figure 8: Average ratings on a five-point scale (5 = decisive impact, 1 = no impact) for impact of financial market conditions on active and inactive projects, based on 11 respondents for active projects and 4 respondents for inactive projects



Source: Authors' analysis.

Notably, developers of natural gas-fired projects ranked changing financial conditions fourth, behind state incentives policies, changes in anticipated energy and capacity revenues, and inflationary pressure on equipment, likely reflecting the longer development timeframes associated with fossil units.

Inflationary Pressures Related to Equipment Procurement Costs

Inflationary pressures on equipment procurement were identified as a significant challenge to projects in active development and as a predominant cause of the suspension, pausing, or withdrawal of inactive projects, with approximately three-fourths of respondents citing inflation as the most severe challenge their projects faced. Solar developers rated this issue as slightly less significant than did developers of natural gas-fired and wind generation resources. This discrepancy may reflect the fact that steel and other commodities greatly affected by inflation over the past several years are a larger component of wind turbine and natural gas projects than they are of solar projects.

Change to State Regulatory Policy that Affected the Value of Environmental Attribute or Incentive Programs

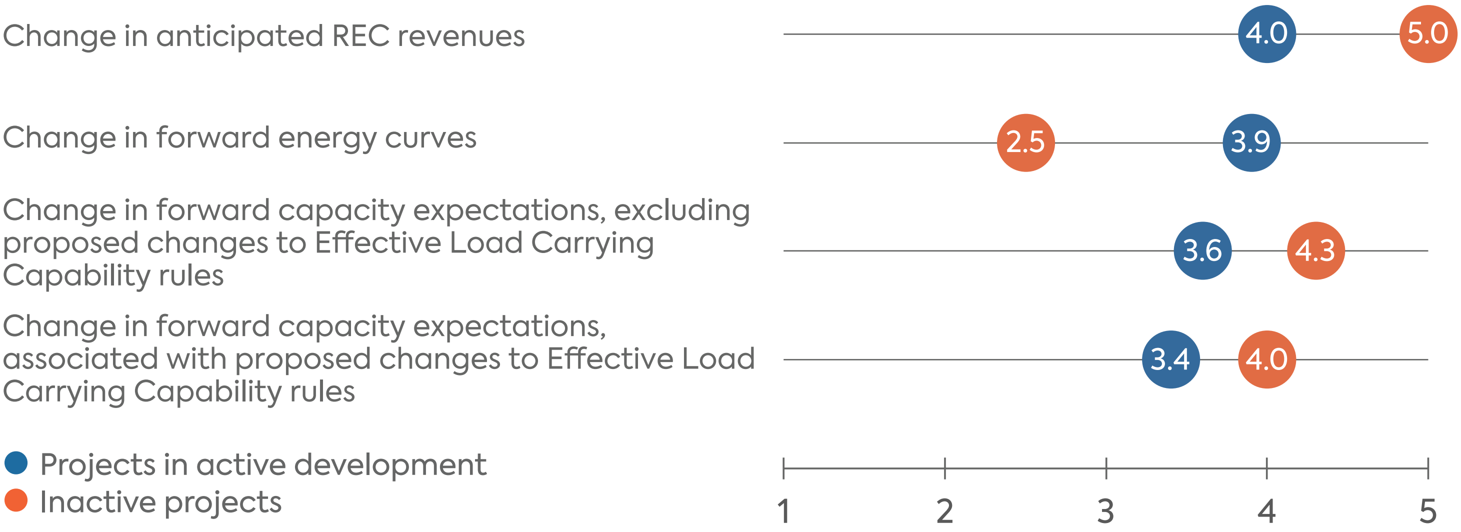
Fossil fuel developers identified state policies as "decisive," likely because of the impact of those policies on new renewable generation, which could have a depressive effect on energy and capacity market revenues. Solar developers appeared to be less concerned with changes to state incentive policies, giving it an average score of 2.8 out of 5, suggesting that they are either comfortable with the regulatory risk associated with solar incentives or are successfully hedging that risk through their sales of environmental attributes of power purchase agreement structures.

Change to Anticipated Revenues from the Capacity and/or Energy Market

Solar and wind developers appeared less concerned about changes to wholesale market revenues, giving it an average score of 3.1 out of 5, perhaps because they are utilizing power purchase agreements or other contractual structures to minimize exposure to fluctuations in wholesale revenues. If so, these results suggest that relatively few solar projects are built on a merchant basis, and that capacity makes up a smaller slice of total project revenues than it does for natural gas facilities.

Firms identifying wholesale revenues as "major" or "decisive" impacts were asked to rate on the same five-point scale a series of factors related to future revenue expectations (Figure 9).

Figure 9: Average ratings on a five-point scale (5 = decisive impact, 1 = no impact) of the importance of changes in anticipated revenues from the capacity and energy markets to projects, based on responses from 8 developers with active projects and 3 with inactive projects



Source: Authors' analysis.

Solar developers (who comprised a significant portion of the pool) were nearly evenly divided between the four options. Developers of natural gas-fired generation resources identified forward energy curves as the most significant factor, which comports with the general expectation that natural gas resources earn most of their revenue from the energy market. The second most significant factor for these fossil developers was capacity market expectations (excluding changes in ELCC rules), followed by changes in anticipated REC revenues and ELCC-driven capacity market changes.

Competitive Solicitations and Offtake Arrangements

Respondents were asked to address their experiences with offtake arrangements in two separate questions, one focused on competitive solicitation processes and the other on whether they developed projects without a specific offtake arrangement in place.

In general, the ability to win a competitive solicitation or comparable process received an average score of 2.9 out of 5, with the small number of wind developers rating this challenge significantly higher (4.3 out of 5) than solar (2.3 out of 5) or natural gas developers (2.0 out of 5). Rankings for the question about offtake arrangements were similar, with an average score of 2.8 out of 5, and a similar trend between technology types.

Two developers indicated that the lack of a specific offtake arrangement was a “decisive” factor in their project development plans. An additional developer indicated that lack of offtake was a “major” factor, while the remaining developers ranked this issue lower. One developer identified the inability to win a competitive solicitation as a “major” reason for the suspension, withdrawal, or pausing of a project. However, the relatively small number of developers who identified lack of offtake or inability to win a competitive solicitation tended to regard that challenge as a significant barrier (either the biggest or the second biggest).

The binary ratings on this topic are likely the result of differing business risk appetites. Developers who highlighted challenges associated with arranging an offtake agreement or winning a competitive solicitation also tended to rate changes in forward energy curves as significant issues. This suggests that, similar to fossil developers, developers with more merchant exposure were more concerned about long-term energy price forecasts. Natural gas developers also fall into this category, since they typically develop on a merchant basis and do not rely on offtake agreements

Change in Corporate Strategy or Risk Appetite Unrelated to a Specific Project

One developer stated that changes in corporate strategy or risk appetite represented a “major” issue for their development efforts, while a separate developer cited this factor as a “major” reason for the cancellation of one or more projects. However, this view was not widely shared, as most developers across technology classes rated this challenge as having “no,” a “small,” or a “moderate” impact on their development efforts.

Interconnection Upgrade Costs

While the survey did not focus on interconnection upgrade costs, eight of the 15 developers that reported withdrawing, suspending, or pausing one or more projects cited interconnection upgrade costs as a key issue.

Outlook on Future Development Efforts

Unlike other questions that focused on existing projects under development, this section of the survey asked about the developer’s general outlook on development. Provided a list of potential issues that included solar tariffs and supply chain constraints, developers were asked, “Thinking about 12 months into the future, which of these factors do you anticipate will continue to negatively affect your development efforts?” The summary of the responses is in Table 3.

Table 3: Percentage of respondents who identified factors anticipated to negatively affect future development efforts, based on 16 total responses

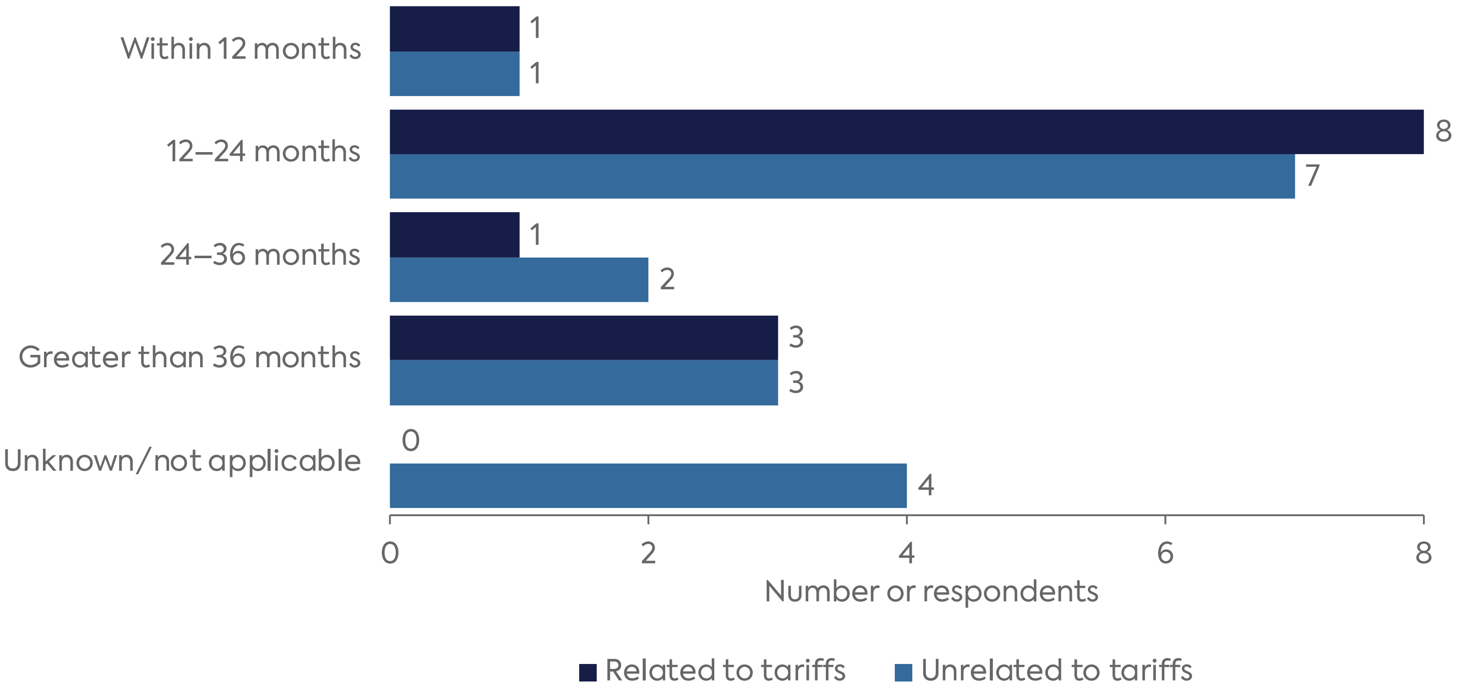
Factor	%
Length of the construction timeline for network upgrades or interconnection facilities or uncertainty around that timeline.	90%
Supply chain concerns unrelated to solar tariffs or import restrictions	81%
Siting or permitting considerations at the federal, state, or local level	57%
Inflationary pressures related to equipment procurement costs	57%
Change in financial market conditions related to cost of capital, financing, tax equity, or other financing metrics (separate from equipment procurement costs)	57%
Length of construction timeline for network upgrades or interconnection facilities or uncertainty around that timeline	57%
Supply chain concerns related to solar tariffs or import restrictions	43%
Change to state regulatory policy that affected value of environmental attribute or incentive programs	38%
Change in anticipated revenues from the capacity, energy, and/or REC market	29%
Ability to establish site control	24%
Other, please describe	19%
Ability to win a competitive solicitation or comparable process	14%
Potential inability to line up an off-take arrangement	14%
Reallocation of resources to another project	14%
Change in corporate strategy or risk appetite unrelated to a specific project	14%

In their outlook for the year ahead, developers expressed many of the same concerns they expressed for past periods, with interconnection timelines continuing to be at the top of the list, followed by macroeconomic factors such as supply chain and cost of capital as well as network upgrade construction timelines and siting and permitting. Several developers called out interconnection costs, pressure from PJM around milestone dates, availability of labor for equipment procurement and construction, and the prospect that high demand for skilled labor could result in higher costs.

In response to the question "When do you estimate that supply chain issues for solar panels {*related*

/ not related} to solar tariffs are likely to be resolved?," most respondents estimated 12–24 months, though nearly a quarter stated "unknown" or "not applicable" when considering issues unrelated to tariffs (Figure 10).

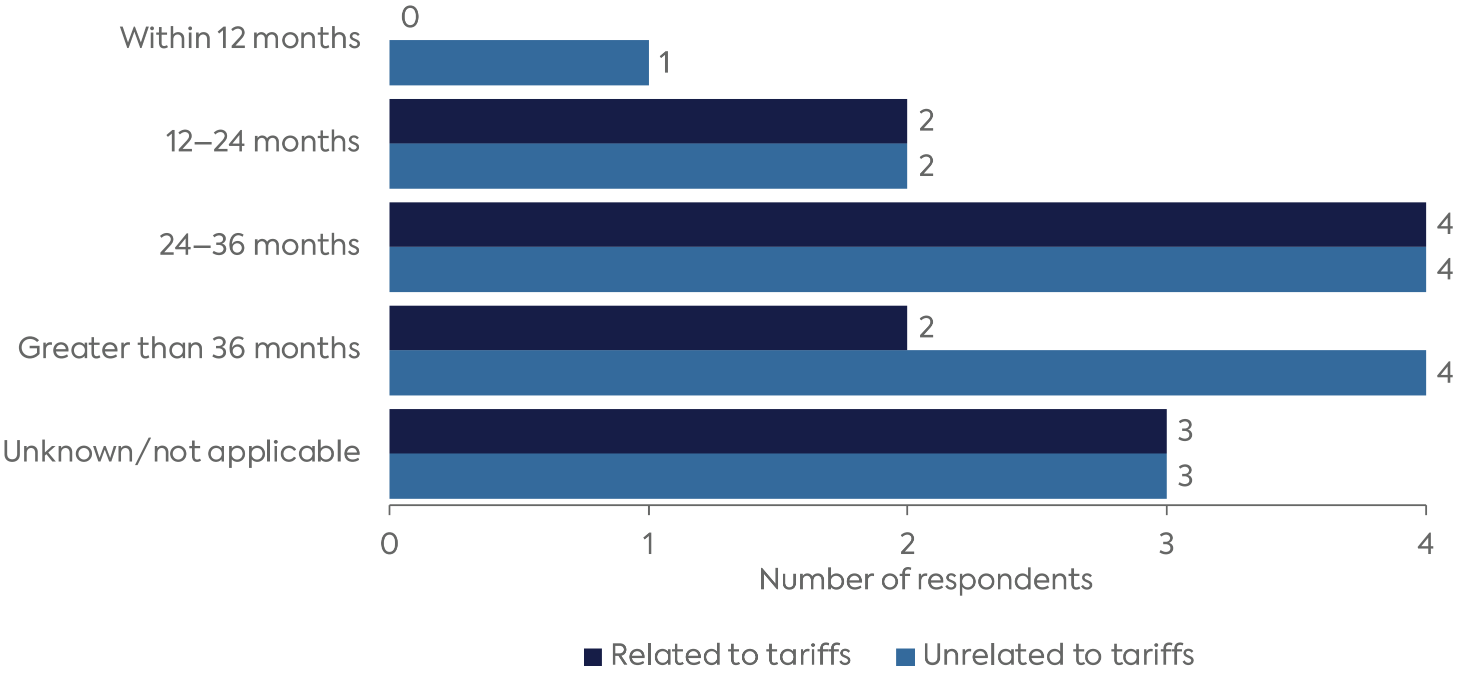
Figure 10: Estimated timeframe for solar panel supply chain issues to be resolved, based on 17 responses.



Source: Authors' analysis.

Developers have also struggled with supply chain issues limiting the availability of transformers. In response to the question "What is your outlook on when supply chain issues for transformers or other issues {*related / not related*} to solar tariffs are likely to be resolved?," developers expressed that, unlike supply chain issues related to solar panels, they expect it will take a long time, with approximately 30% saying either 24–36 or more than 36 months and only one saying within 12 months (Figure 11).

Figure 11: Estimated timeframe for supply chain issues related to transformers to be resolved, based on 14 responses.



Source: Authors' analysis.

During the interview process, several developers noted that it is typically the utility's responsibility to procure high-voltage breakers and transformers. One developer noted that it was currently taking transmission owners over two years to procure high-voltage circuit breakers, and they had recently been told that procuring a 345 kilovolt circuit breaker would take four years in another market region. The data reflect this pessimism, with developers reporting extended delays in transformer supply.

Conclusion

The idea that the interconnection process is fundamentally broken is not new. Nor is the idea that additional reforms will be necessary to fix the process.[52] Interconnection delays are fundamentally caused by a transmission grid that is not sized to meet the amount of new clean generation that is being brought to market and an overly lengthy process for identifying how to grow the grid.

The survey highlights that stakeholders, including PJM, may need to adjust their expectations of how quickly new generation resources can come online. Developers report that most of their projects will take two or more years to reach commercial operation, even after they complete the interconnection process. Survey respondents repeatedly highlighted the pernicious interplay between interconnection delays and siting and permitting challenges—in particular, the fact that site-specific permits and siting approvals expire after a period of inactivity that is typically shorter than the interconnection queue process. Further, the wide range of potential interconnection study times is leading developers to delay high-risk siting and permitting activities,[53] which can be the most contentious and risky part of the development process, until the end of the study process, potentially adding years to commercial operation timelines. This is a troubling sign, suggesting that delays and project cancellations will continue to occur at high levels for the foreseeable future.

This lengthy timeline also underlines the role that interconnection plays in PJM's competitive markets. New generation has the power to displace more expensive resources and discipline the exercise of supply-side market power. But Interconnection queue delays blunt the ability of PJM to ensure effective competition in its markets since even relatively inefficient generators (or those exercising market power) are more difficult to displace with new, lower-cost resources.

Solving the interconnection crisis will likely require two changes: creating effective planning processes that identify where new transmission headroom is likely to be needed; and expanding the transmission system to meet that need. The path to a transmission grid that is "fit for purpose" is long, however, involving difficult questions around cost causation and allocation. PJM is currently considering reforms to its long-range transmission planning process, which lags behind that of other regions in the US.[54] The new reforms are designed to identify proactively the transmission needed to meet future queue needs and address the reliability needs of the grid.[55] FERC is also expected to issue a regional transmission rule in the near future focused on transmission planning reforms on the national level.[56]

Beyond these measures, a significant overhaul of interconnection processing policies will likely be needed. FERC's recent interconnection reforms in Order No. 2023 are an important step forward but are unlikely to fully resolve the problem.[57] FERC may want to consider a range of fixes, from technical reforms that can increase access to the grid in the short term[58] to wholesale revisions to the existing interconnection study framework.[59] Given the immediate needs of the grid, interconnection solutions will likely need to be pursued in parallel with longer-term grid reform efforts. Some that policymakers may wish to consider include:

- Allowing retiring generators to be replaced with new resources at the same location.[60]
- Increasing the use of advanced technologies, such as Grid Enhancing Technologies, that allow more power to flow over existing transmission lines.[61]
- Transitioning from today's study-intensive "invest and connect" model to a study-light "connect and manage" model.[62]

State regulators and other policymakers will also be wise to manage the phaseout of existing resources carefully. One way of doing so is to build "reliability safety valves" into environmentally driven retirement schedules. This safety valve could dynamically adjust retirement dates based on PJM's expected reserve margin or success in bringing on replacement generation. While the PJM market structure sends higher price signals during times of supply scarcity to attract new resources, there may be a lag in new entry, particularly given the lengthy interconnection process.

Notes

1. Joseph Rand et al., "Queued Up: 2024 Edition – Characteristics of Power Plants Seeking Transmission Interconnection As of the End of 2023," Lawrence Berkeley National Laboratory, April 2024, https://emp.lbl.gov/publications/queued-2024-edition-characteristics; and Joseph Rand et al., "Queued Up: Characteristics of Power Plants Seeking Transmission Interconnection As of the End of 2022," Lawrence Berkeley National Laboratory, April 2023, https://doi.org/10.2172/1969977.

2. Federal Energy Regulatory Commission, "Order No. 2023: Improvements to Generator Interconnection Procedures and Agreements," 184 FERC ¶ 61,054 (2023) at P 39–40, https://www.ferc.gov/media/order-no-2023 (finding that "[f]or generating facilities built in 2022, wait times in the interconnection queue saw a marked increase to now roughly five years").

3. See FERC, Order No. 2023 at P 49 (noting that "a withdrawal can trigger costly restudies and create uncertainty in the interconnection process for interconnection customers and transmission providers alike").

4. Rand et al., "Queued Up: 2024 Edition" (noting that PJM completed zero interconnection service agreements in 2023).

5. See PJM, "Energy Transition in PJM: Resource Retirements, Replacements & Risks," February 24, 2023, 2, https://www.pjm.com/-/media/library/reports-notices/special-reports/2023/energy-transition-in-pjm-resource-retirements-replacements-and-risks.ashx.

6. See, e.g., Claire Wayner et al., "Going the Distance on Interconnection Queue Reform: FERC's Rulemaking Takes Us Only Part of the Way to Effective and Efficient Interconnection," RMI, August 2023, https://rmi.org/going-the-distance-on-interconnection-queue-reform/; Robi Nilson, Ben Hoen, and Joseph Rand, "Survey of Utility-Scale Wind and Solar Developers Report," Lawrence Berkeley National Laboratory, January 2024, https://emp.lbl.gov/publications/survey-utility-scale-wind-and-solar (finding that, on a national basis, interconnection delays were the second biggest cause of canceled projects and the biggest driver of delays.

7. See, e.g., Nilson et al., "Survey of Utility-Scale Wind and Solar Developers Report."

8. As FERC notes, "backlogs in the generator interconnection process, in turn, can create reliability issues as needed new generating facilities are unable to come online in an efficient and timely manner." FERC, Order No. 2023 at P 3. See also Monitoring Analytics, "2023 State of

the PJM Market Report," 2024, 1, https://www.monitoringanalytics.com/reports/PJM_State_of_the_Market/2023/2023-som-pjm-sec1.pdf. ("The markets face a challenge from potentially high levels of expected thermal generator retirements, with no clear source of replacement capacity or the fuel required for that capacity.")

9. See Rand et al., "Queued Up: 2024 Edition."
10. Ibid., 3.
11. FERC, Order No. 2023.
12. See, e.g., Jesse D. Jenkins et al., "Mission Net-Zero America: The Nation-Building Path to a Prosperous, Net-Zero Emissions Economy," *Joule* 5, no. 11 (2021), https://doi.org/10.1016/j.joule.2021.10.016.
13. FERC, Order No. 2023.
14. For detailed background about PJM's efforts to fix its queue, see PJM Interconnection LLC, 181 FERC ¶ 61,162 (2022), footnote 15, https://pjm.com/directory/etariff/FercOrders/6581/20221129-er22-2110-000%20and%20-001.pdf.
15. PJM Interconnection LLC, 181 FERC ¶ 61,162 (2022) at P 57.
16. Monitoring Analytics, "2023 State of the Market Report," 74.
17. Ibid., 74.
18. Ibid., 75.
19. Ibid., 75.
20. PJM, "New Interconnection Process Reaches Next Milestone," press release, December 21, 2023, https://insidelines.pjm.com/new-interconnection-process-reaches-next-milestone/.
21. See PJM, "Energy Transition in PJM."
22. Ibid., 17.
23. Monitoring Analytics, "2023 State of the Market Report," 1.
24. PJM, "Energy Transition in PJM," 13.
25. See PJM, "Update on Reliability Risk Modeling," May 30, 2023, https://www.pjm.com/-/media/committees-groups/cifp-ra/2023/20230530/20230530-item-03---reliability-risk-modeling.ashx.

26. Mark Specht's primer "ELCC Explained: The Critical Renewable Energy Concept You've Never Heard Of," is an excellent resource for understanding capacity accreditation. Union of Concerned Scientists, 2020, https://blog.ucsusa.org/mark-specht/elcc-explained-the-critical-renewable-energy-concept-youve-never-heard-of/.

27. See PJM's report detailing extensive outages of fossil resources during December 2022 Winter Storm Elliott weather event: https://pjm.com/-/media/library/reports-notices/special-reports/2023/20230717-winter-storm-elliott-event-analysis-and-recommendation-report.ashx.

28. See PJM, "Energy Transition in PJM," 8.

29. Ibid., 5.

30. Monitoring Analytics, "2023 State of the Market Report," 1.

31. See PJM, "Energy Transition in PJM," 7.

32. For a detailed description of the statute, including reference emissions rates, see https://epa.illinois.gov/topics/ceja/electric-generating-units.html.

33. See PJM, "Energy Transition in PJM," 8.

34. Ibid., 6, figure 2.

35. PJM's commercial probability model suggests that less than 10% of the projects starting the interconnection process are expected to actually reach commercial operation and suggests that "after adjusting the new renewable capacity by Effective Load Carrying Capability (ELCC) derations, this commercial probability analysis estimates net 13.2 GW-nameplate / 6.7 GW-capacity to the system by 2030." See PJM, "Energy Transition in PJM,"12.

36. The PJM Energy Transition Report's High New Entry Scenario included "107 GW-nameplate/30.6 GW-capacity after ELCC derations. Net natural gas entry was approximately 5 GW, and renewables was 48.5 GW-nameplate/10.4 GW-capacity."

37. PJM, "New Interconnection Process Reaches Next Milestone."

38. See Letter from Ohio Manufacturers Association, December 21, 2023, https://www.pjm.com/-/media/about-pjm/who-we-are/public-disclosures/20231221-oh-manufacturers-assoc-letter-re-competitive-electricity-markets-during-rapid-system-technological-transformation.ashx; and James F. Wilson, "Maintaining the PJM Region's Robust Reserve Margins," National Resources Defense Council and Sierra Club, May 2023, (https://www.sierraclub.org/sites/www.sierraclub.org/files/2023-05/Wilson%20R4%20Report%20Critique%20Revised.pdf.

39. A small subset of projects in the study window received Wholesale Market Participation Agreements in lieu of an Interconnection Services Agreement, but are effectively the same for the purposes of our study.

40. "Uprates" are when an already-existing facility requests that PJM formally increase the maximum sustained output for the facility. Uprates are usually occasioned by improvements in power plant efficiency, changes in fuel type, or operational experience that justifies a higher output level.

41. PJM," Services Request Status," https://www.pjm.com/planning/service-requests/services-request-status.

42. Several developers self-identified as having more projects that appear in the queue. Because these were likely data entry errors or a misunderstanding of the question, we manually adjusted several of the numbers to bring them into line with what appears in the queue.

43. See Sarah Johnston, Yifei Liu, and Chenyu Yang, "An Empirical Analysis of the Interconnection Queue," National Bureau of Economic Research working paper, December 2023, https://doi.org/10.3386/w31946 (finding that they were able to identify developers for 39% of overall entrants into the PJM interconnection queue increasing to 52% and 81% of projects that had advanced further through the interconnection process).

44. The full survey instrument is available for download on the Center on Global Energy Policy website.

45. While PJM's Energy Transition Report focused on the reliability implications of reserve margins below 10%, low reserve margins typically lead to steeply increasing consumer costs, which could have major implications for energy affordability, even if grid reliability isn't compromised. See PJM, "Energy Transition in PJM," 15.

46. Ohio law requires that developers of most energy projects qualify for advantageous tax treatment if they receive the support of local government and employ a certain percentage of workers domiciled in Ohio. Section 5727.75, "Exemption on Tangible Personal Property and Real Property of Certain Qualified Energy Projects." For a summary of the implications of Ohio's siting rules, see https://www.bricker.com/Documents/Resources/QEP%20_project_white_paper.pdf.

47. For example, the Solar Energy Industries Association suggests that a typical large (250 MW) project takes approximately two years to construct after completion of the interconnection study process, construction of network upgrades, siting, permitting, and other necessary

steps. SEIA, "Development Timeline for Utility-Scale Solar Power Plant," https://www.seia.org/research-resources/development-timeline-utility-scale-solar-power-plant.

48. FERC recently approved a variety of changes to PJM's interconnection rules, including requiring developers to include deposits with their interconnection requests and to demonstrate that the project met certain project maturity requirements, e.g., demonstrating site control. These deposits are designed to ensure that developers are willing to post financial security behind their development efforts and reduce the incidence of speculative or low-probability projects.

49. Emma Penrod, "Why the Energy Transition Broke the US Interconnection System," Utility Drive, August 22, 2022, https://www.utilitydive.com/news/energy-transition-interconnection-reform-ferc-qcells/628822/.

50. In an analysis of the PJM queue, Johnston et al. suggest that the low concentration of projects among developers counters assertions that speculative interconnection requests are burdening queue processing. They find that in "cases where a developer had more than one generator in an entry cohort, either all or none of the generators were completed 71% of the time," and that "these data are generally consistent with developers being willing to build all generators that are individually profitable." Johnston et al., "An Empirical Analysis of the Interconnection Queue."

51. For a summary of solar tariff and import issues, see Lilly Yejin Lee and Noah Kaufman, "Q&A: Solar Tariffs and the US Energy Transition," Energy Explained, Center on Global Energy Policy, November 13, 2023, https://www.energypolicy.columbia.edu/qa-solar-tariffs-and-the-us-energy-transition/.

52. See, e.g., Comments of FERC Commissioner Allison Clements at the Raab Associates' New England Electricity Restructuring Roundtable on Dec. 8, *available at*: https://www.rtoinsider.com/65517-clements-raab-roundtable/.

53. See, e.g., Nilson et al., "Survey of Utility-Scale Wind and Solar Developers Report."

54. See Lewis (Zhaoyu) Wu, Abraham Silverman, Harrison Fell, and James Glynn, "A Quantitative Analysis of the Impact of Key Variables on Power Transmission Infrastructure Project Development in the US," Center on Global Energy Policy, Columbia University, April 5, 2024, https://www.energypolicy.columbia.edu/publications/a-quantitative-analysis-of-variables-affecting-power-transmission-infrastructure-projects-in-the-us/ (showing that transmission expansion in PJM has lagged behind several other regions).

55. See PJM's Long-Term Regional Transmission Planning initiative, https://www.pjm.com/

committees-and-groups/workshops/ltrtp.

56. See Federal Energy Regulatory Commission, “Building for the Future Through Electric Regional Transmission Planning and Cost Allocation and Generator Interconnection,” 179 FERC ¶ 61,028 (2022).

57. Silverman, et al., “FERC’s Interconnection Reform: Why It Matters for the Clean Energy Transition,” Energy Explained, Center on Global Energy Policy, August 7, 2023, https://www.energypolicy.columbia.edu/fercs-interconnection-reform-why-it-matters-for-the-clean-energy-transition/.

58. See, e.g., RMI, “Clean Repowering: How to Capitalize on Fossil Grid Connections to Unlock Clean Energy Growth,” January 2024, https://rmi.org/insight/clean-repowering.

59. See, e.g., Tyler Norris, “Beyond FERC Order 2023: Considerations on Deep Interconnection Reform,” Nicholas Institute for Energy, Environment & Stability, Duke University, August 2023, https://nicholasinstitute.duke.edu/publications/beyond-ferc-order-2023-considerations-deep-interconnection-reform.

60. See, e.g., RMI, “Clean Repowering.”

61. See, e.g., WATT Coalition, “Grid Enhancing Technologies in Generator Interconnection,” https://watt-transmission.org/grid-enhancing-technologies-in-generator-interconnection/; and Russell Mendell, Mathias Einberger, and Katie Siegner, “FERC Could Slash Inflation and Double Renewables with These Grid Upgrades,” RMI, July 7, 2022, https://rmi.org/ferc-could-slash-inflation-and-double-renewables-grid-upgrades/.

62. “Under the “connect and manage” model, the grid operator narrows the scope of the interconnection study process to look at the grid enhancements necessary to allow the generator to physically interconnect to the grid. Questions around deliverability of the power are deferred to subsequent studies. This reduces the complexity of the interconnection process, resulting in faster studies and increased ability to process interconnection requests. In exchange, interconnecting generators accept higher congestion and curtailment risk until deliverability studies and necessary upgrades are completed.” See Silverman et al., “What’s Next in Interconnection Reform? Lessons from International Experience,” Energy Explained, Center on Global Energy Policy, August 15, 2023, https://www.energypolicy.columbia.edu/whats-next-in-interconnection-reform-lessons-from-international-experience/; see also Tyler Norris, “Beyond FERC Order 2023.”

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