5 Capacity Market

In PJM, the capacity market exists to make the energy market work. Energy powers lights and computers and air conditioners. Capacity does not power anything. The capacity market needs to define the total MWh of energy that are needed to reliably serve load. The capacity market needs to provide the missing money. A primary reason to have a capacity market is that the energy market does not provide adequate net revenues to provide incentives for entry and for maintaining existing units. The obligation of load serving entities (LSEs) to own capacity equal to the peak demand plus a reserve margin was a longstanding feature of the PJM Operating Agreement before the creation of the PJM markets. The initial impetus to a capacity market in PJM, a request by the Pennsylvania PUC, was to support retail competition by ensuring that small new entrant competitive LSEs would have access to capacity at a competitive price in the PJM capacity market without having to build capacity or purchase capacity bilaterally from incumbent generation owners at monopoly prices. The PJM Capacity Market was created by FERC in order to prevent the exercise of market power that resulted from a bilateral market in which the ownership of capacity was concentrated. That logic continues to apply today. The first PJM Capacity Market, the daily capacity market, created in 1999, was replaced in 2007 by the current design based on the recognition that the energy market resulted in a shortfall in net revenues compared to that necessary to attract and retain adequate resources for the reliable operation of the energy market, the missing money. The exogenous reliability requirement to have a level of capacity in excess of the level that would result from the operation of an energy market alone reduces the level and volatility of energy market prices and reduces the duration of high energy market prices. This reduces net revenue to generation owners which reduces the incentive to invest. In order for the PJM markets to be self sustaining, the net revenues from PJM energy, ancillary services and capacity markets must be adequate for those resources. That adequacy requires a capacity market. The capacity market plays the essential role of equilibrating the revenues necessary to incent competitive entry and exit of the resources needed for reliability, with the revenues from the energy and ancillary services markets.

A number of PJM's recent changes to the capacity market design are antithetical to the purpose of the capacity market and serve to undermine that purpose.

The only goal of the detailed design of the capacity market is to ensure that the opportunity for that revenue equilibration exists through a competitive process. PJM's most recent filing to modify the definition of the capacity market demand curve (VRR curve) explicitly fails to recognize that equilibration logic and undercuts that revenue equilibration mechanism by failing to include a full net revenue offset in the definition of the maximum price on the demand curve.

The Capacity Performance (CP) design was a radical change to the capacity market paradigm. The CP design is a failed experiment. The fundamental mistake of the CP design was to attempt to recreate energy market incentives in the capacity market. The CP model was an explicit attempt to bring energy market shortage pricing into the capacity market design. The CP model was designed on the unfounded assumption that shortage prices in the energy market were not high enough and needed to be increased via the capacity market. The initial CP design replaced the definition of a competitive offer, net avoidable costs or the marginal cost of capacity, with a definition equal to the scarcity price, Net CONE. PJM's initial CP design permitted the exercise of market power based on the mistaken idea that the markets needed scarcity pricing all the time and the mistaken idea that Net CONE should be the price in every auction.[1]

PJM's introduction of its significantly modified ELCC method in the 2025/2026 BRA was another radical change to the capacity market design. While it is a good idea to evaluate unit specific performance and a good idea to recognize that risk occurs in the winter as well as the summer and that risks may be correlated, ELCC was implemented before it could be fully tested and unintended consequences evaluated. The results of the 2025/2026 BRA and subsequent BRAs illustrate the extreme sensitivity of the market outcomes to

1 176 FERC ¶ 61,137 (September 2, 2021), ***order on reh'g***, 178 FERC ¶ 61,121 (2022); ***appeal denied***, Vistra Corp. v FERC, Case Nos 21-1214 et al (D.C. Cir August 15, 2023).

a range of assumptions and decisions about market design details that were not adequately tested or reviewed with stakeholders.[2]

The challenge is to create a straightforward capacity market design that meets the simple objectives of a capacity market and that does not become a vehicle for energy market incentives or rent seeking or attempts to limit the ways in which specific types of generation participate in PJM markets. Energy market incentives should remain in the energy market.

The PJM market design is based on the must offer and must buy obligations of capacity resources. All capacity resources are required to offer into the capacity auctions. The categorical exemption for intermittent resources, capacity storage resources, and hybrid resources from the RPM must offer requirement was eliminated for all resources except demand resources in February 2025.[3] All LSEs must buy capacity equal to their peak load plus a reserve margin through the market.

Each organization serving PJM load must meet its capacity obligations through the PJM Capacity Market, where load serving entities (LSEs) must pay the locational capacity price for their zone. LSEs can also construct generation and offer it into the capacity market, enter into bilateral contracts, develop demand resources and offer them into the capacity market, or construct transmission upgrades and offer them into the capacity market.

PJM's current proposal to address the problems resulting from data center load continue on PJM's path of proposing changes to the capacity market design that are antithetical to the purpose of the capacity market and serve to undermine that purpose.[4] PJM's proposals would reverse 26 years of LSEs relying on the capacity market to cover their reliability obligations by requiring LSEs to enter into bilaterals and to hedge their positions based on PJM's view of an appropriate hedge. PJM's proposals abandon single clearing price logic. PJM's proposals abandon market power mitigation and fail to recognize and address the structural market power endemic to the capacity market.

There are significant market design issues in the PJM Capacity Market that currently prevent the market from achieving competitive results.

One of the most important issues currently facing the PJM Capacity Market is the addition of large amounts of data center load, both actual and forecast. The MMU concludes that the failure to recognize and address the role of large data center loads is a direct cause of higher prices and will continue to result in even higher prices unless the related issues are addressed. PJM should not simply permit the interconnection of large data center loads if it cannot do so reliably, with adequate generation capacity to meet those loads. Data centers should be required to directly contract for their own new generation rather than imposing their costs on other customers.

The Market Monitoring Unit (MMU) analyzed market design, market structure, participant conduct and market performance in the PJM Capacity Market, including supply, demand, concentration ratios, pivotal suppliers, volumes, prices, outage rates and reliability.[5] The conclusions for 2025 and the first six months of 2026 are a result of the MMU's evaluation of the 2025/2026, 2026/2027, and 2027/2028 Base Residual Auctions.[6] [7] [8] [9] [10] [11] [12] [13] [14] [15] [16] [17]

2 The MMU prepared a series of reports on the 2025/2026, 2026/2027 and 2027/2028 BRA results which can be found on the Monitoring Analytics website here: <https://www.monitoringanalytics.com/reports/Reports/2024.shtml>; <https://www.monitoringanalytics.com/reports/Reports/2025.shtml>; and <https://www.monitoringanalytics.com/reports/Reports/2026.shtml>.

3 FERC approved extending the RPM must offer requirement to intermittent resources, capacity storage resources, and hybrid resources but not to demand resources on February 20, 2025. 190 FERC ¶ 61,117.

4 See *Reliability Backstop Procurement to Address Resource Adequacy Concerns Stemming from Large Loads*, PJM Interconnection L.L.C., Docket No. ER26-3380-000 (July 31, 2026).

5 The values stated in this report for the RTO and LDAs refer to the aggregate level including all nested LDAs unless otherwise specified. For example, RTO values include the entire PJM market and all LDAs. Rest of RTO values are RTO values net of nested LDA values.

6 See "Analysis of the 2025/2026 RPM Base Residual Auction - Part A," (September 20, 2024) <https://www.monitoringanalytics.com/reports/Reports/2024/IMM_Analysis_of_the_20252026_RPM_Base_Residual_Auction_Part_A_20240920.pdf>.

7 See "Analysis of the 2025/2026 RPM Base Residual Auction - Part B," (October 15, 2024) <https://www.monitoringanalytics.com/reports/Reports/2024/IMM_Analysis_of_the_20252026_RPM_Base_Residual_Auction_Part_B_20241015.pdf>.

8 See "Analysis of the 2025/2026 RPM Base Residual Auction - Part C," (October 15, 2024) <https://www.monitoringanalytics.com/reports/Reports/2024/IMM_Analysis_of_the_20252026_RPM_Base_Residual_Auction_Part_C_20241106.pdf>.

9 See "Analysis of the 2025/2026 RPM Base Residual Auction - Part D," (December 6, 2024) <https://www.monitoringanalytics.com/reports/Reports/2024/IMM_Analysis_of_the_20252026_RPM_Base_Residual_Auction_Part_D_20241206.pdf>.

10 See "Analysis of the 2025/2026 RPM Base Residual Auction - Part E," (January 31, 2025). <https://www.monitoringanalytics.com/reports/Reports/2025/IMM_Analysis_of_the_20252026_RPM_Base_Residual_Auction_Part_E_20250131.pdf>.

11 See "Analysis of the 2025/2026 RPM Base Residual Auction - Part F," (February 4, 2025) <https://www.monitoringanalytics.com/reports/Reports/2025/IMM_Analysis_of_the_20252026_RPM_Base_Residual_Auction_Part_F_20250204.pdf>.

12 See "Analysis of the 2025/2026 RPM Base Residual Auction - Part G Revised," (June 3, 2025) <https://www.monitoringanalytics.com/reports/Reports/2025/IMM_Analysis_of_the_20252026_RPM_Base_Residual_Auction_Part_G_20250603_Revised.pdf>.

13 See "Analysis of the 2025/2026 RPM Base Residual Auction - Part H," (July 31, 2025) <https://www.monitoringanalytics.com/reports/Reports/2025/IMM_Analysis_of_the_20252026_RPM_Base_Residual_Auction_Part_H_20250731.pdf>.

14 See "Analysis of the 2026/2027 RPM Base Residual Auction - Part A," (October 1, 2025) <https://www.monitoringanalytics.com/reports/Reports/2025/IMM_Analysis_of_the_20262027_RPM_Base_Residual_Auction_Part_A_20251001.pdf>.

15 See "Analysis of the 2026/2027 RPM Base Residual Auction - Part B," (March 3, 2026) <https://www.monitoringanalytics.com/reports/Reports/2026/IMM_Analysis_of_the_20262027_RPM_Base_Residual_Auction_Part_B_20260303.pdf>.

16 See "Analysis of the 2027/2028 RPM Base Residual Auction – Part A," (January 5, 2026) <https://www.monitoringanalytics.com/reports/Reports/2026/IMM_Analysis_of_the_20272028_RPM_Base_Residual_Auction_Part_A_20260105.pdf>.

17 See "Analysis of the 2027/2028 RPM Base Residual Auction – Part B," (July 9, 2026) <https://www.monitoringanalytics.com/reports/Reports/2026/IMM_Analysis_of_the_20272028_RPM_Base_Residual_Auction_Part_B_20260709.pdf>.

Table 5-1 The capacity market results were not competitive

Market Element	Evaluation	Market Design
Market Structure: Aggregate Market	Not Competitive	
Market Structure: Local Market	Not Competitive	
Participant Behavior	Not Competitive	
Market Performance	**Not Competitive**	**Mixed**

- The aggregate market structure was evaluated as not competitive. For almost all auctions held from 2007 to the present, the PJM capacity market failed the three pivotal supplier test (TPS), which is conducted at the time of the auction.[18] Structural market power is endemic to the capacity market.
- The local market structure was evaluated as not competitive. For almost every auction held, all LDAs have failed the TPS test, which is conducted at the time of the auction.[19]
- Participant behavior was evaluated as not competitive in the 2026/2027 and the 2027/2028 BRA. Effective with the 2026/2027 Delivery Year, the market seller offer cap definition was modified to include unit specific standalone Capacity Performance Quantifiable Risk (CPQR) and segmented unit specific offer caps.[20] The offers in the 2026/2027 BRA included those based on standalone CPQR offer caps. The offers in the 2027/2028 BRA did not include those based on standalone CPQR offer caps. Market power mitigation measures were applied when the capacity market seller failed the market power test for the auction, the submitted sell offer exceeded the defined offer cap, and the submitted sell offer, absent mitigation, would increase the market clearing price.
- Market performance was evaluated as not competitive based on the 2026/2027 and 2027/2028 Base Residual Auctions as a result of the flaws in the Effective Load Carrying Capability (ELCC) design including the failure to correctly define the reliability contribution of thermal resources in the winter, and the failure to recognize and address the role of large data center loads is a direct cause of higher prices and will continue to result in even higher prices unless the related issues are addressed.
- Market design was evaluated as mixed because while there are many positive features of the capacity market design and some of the MMU's recommendations were implemented in the 2026/2027 BRA, there are several features of the RPM design which still threaten competitive outcomes. These include the lack of a queue for the addition of large new data center loads, details of PJM's ELCC implementation, the definition of market seller offer caps, the failure to apply the RPM must offer requirement to demand resources, the inclusion of performance assessment interval (PAI) penalties, the use of Gross CONE as the maximum price on the VRR curve, the definition of DR which permits inferior products to substitute for capacity, the replacement capacity issue, the definition of unit offer parameters, and the inclusion of imports which are not substitutes for internal capacity resources.[21]

Overview

RPM Capacity Market

Market Design

The Reliability Pricing Model (RPM) Capacity Market is a three year forward looking, annual, locational market, with a must offer requirement for Existing Generation Capacity Resources and a must buy requirement for load, with performance incentives, that includes clear market power mitigation rules and that permits the direct participation of demand side resources.[22] PJM introduced the Capacity Performance design for the 2017/2018 BRA. PJM introduced a new ELCC method for defining capacity MW offered in the 2025/2026 BRA.[23]

18 In the 2008/2009 RPM Third Incremental Auction, 18 participants in the RTO market passed the TPS test. In the 2018/2019 RPM Second Incremental Auction, 35 participants in the RTO market passed the test. In the 2023/2024 RPM Third Incremental Auction, 36 participants in the RTO passed the TPS test.

19 In the 2012/2013 RPM Base Residual Auction, six participants included in the incremental supply of EMAAC passed the TPS test. In the 2014/2015 RPM Base Residual Auction, seven participants in the incremental supply in MAAC passed the TPS test. In the 2021/2022 RPM First Incremental Auction, two participants in the incremental supply in EMAAC passed the TPS test. In the 2021/2022 RPM Second Incremental Auction, two participants in the incremental supply in EMAAC passed the TPS test. In the 2023/2024 RPM Third Incremental Auction, eight participants in MAAC passed the TPS test.

20 190 FERC ¶ 61,117 (2025).

21 While PJM filed for and FERC accepted the inclusion of RMR resources Brandon Shores and Wagner plants in the 2026/2027 through 2028/2029 BRAs, that does not require that RMR resources be included in capacity market auction clearing in future auctions for these or other RMR resources. See Letter Order, FERC Docket No. ER25-682-001 (April 29, 2025). See also 193 FERC ¶ 61,234 (2025).

22 The terms *PJM Region*, *RTO Region* and *RTO* are synonymous in this report and include all capacity within the PJM footprint.

23 See 186 FERC ¶ 61,080 (2024), *reh'g order*, 189 FERC ¶ 61,043 (2024).

Under RPM, capacity obligations are annual.[24] By design, Base Residual Auctions (BRA) are held for delivery years that are three years in the future despite recent auction delays. First, Second and Third Incremental Auctions (IA) are held for each delivery year.[25] First, Second, and Third Incremental Auctions are conducted 20, 10, and three months prior to the delivery year although some incremental auctions have not been held as a result of delays in holding BRAs.[26] A Conditional Incremental Auction may be held if there is a need to procure additional capacity resulting from a delay in a planned large transmission upgrade that was modeled in the BRA for the relevant delivery year.[27] A Reliability Backstop Auction may be conducted if tariff defined criteria are met to resolve reliability criteria violations caused by lack of sufficient capacity procured through RPM auctions.[28] If the installed reserve margin resulting from the total UCAP committed through self supply or BRAs for three consecutive years is more than one percentage point lower than the approved PJM installed reserve margin, PJM will make a filing with FERC to conduct a Reliability Backstop Auction. If the total UCAP committed for all base load generation resources in BRAs for three consecutive years is less than the forecasted minimum hourly load, PJM will make a filing with FERC to conduct a Reliability Backstop Auction. PJM has proposed significant changes to the tariff to create a new set of rules for a Reliability Backstop Auction.[29]

The 2026/2027 RPM Third Incremental Auction was conducted in the first six months of 2026.

Market Structure

- **RPM Installed Capacity.** In the first six months of 2026, RPM installed capacity decreased 347.0 MW or 0.2 percent, from 184,220.8 MW on January 1, to 183,873.8 MW on June 30. Installed capacity includes net capacity imports and exports and can vary on a daily basis.

- **Reserves.** Total reserves on June 1, 2026, were 20,843.9 MW, which is 279.2 MW (UCAP) short of the required reserve level of 21,123.1 MW (UCAP). On June 1, 2026, the target installed reserve margin was 18.6 percent, and the actual reserve margin was only 18.4 percent.

- **RPM Installed Capacity by Fuel Type.** Of the total installed capacity on June 30, 2026, 48.0 percent was gas; 20.0 percent was coal; 17.6 percent was nuclear; 4.5 percent was hydroelectric; 2.3 percent was oil; 1.9 percent was wind; 0.3 percent was solid waste; and 5.4 percent was solar.

- **Market Concentration.** In the 2026/2027 RPM Third Incremental Auction, all participants in the total PJM market as well as the LDA RPM markets failed the three pivotal supplier (TPS) test.[30] Offer caps were applied to all sell offers for resources which were subject to mitigation when the capacity market seller did not pass the test, the submitted sell offer exceeded the defined offer cap, and the submitted sell offer, absent mitigation, increased the market clearing price.[31] [32] [33]

- **Imports and Exports.** Of the 1,144.8 MW of imports offered in the 2027/2028 RPM Base Residual Auction, 1,005.9 MW cleared. Of the cleared imports, 695.6 MW (69.2 percent) were from MISO.

- **Demand Resources.** Committed DR was 4,805.8 MW for June 1, 2026, as a result of cleared capacity for demand resources in RPM auctions for the 2026/2027 Delivery Year (5,710.3 MW) less replacement capacity (904.5 MW).

Market Conduct

- 2026/2027 RPM Third Incremental Auction. Of the 985 generation resources that submitted Capacity Performance offers, unit specific offer caps were calculated for four generation resources (0.4 percent).

24 Effective for the 2020/2021 and subsequent delivery years, the RPM market design incorporated seasonal capacity resources. Summer period and winter period capacity must be matched either through commercial aggregation or through the optimization in equal MW amounts in the LDA or the lowest common parent LDA.
25 See 126 FERC ¶ 61,275 at P 86 (2009).
26 See Letter Order, FERC Docket No. ER10-366-000 (January 22, 2010).
27 See 126 FERC ¶ 61,275 at P 88 (2009). There have been no Conditional Incremental Auctions.
28 See OATT Attachment DD § 16.
29 See *Reliability Backstop Procurement to Address Resource Adequacy Concerns Stemming from Large Loads*, PJM Interconnection L.L.C., Docket No. ER26-3380-000 (July 31, 2026).
30 There are 27 Locational Deliverability Areas (LDAs) identified to recognize locational constraints as defined in "Reliability Assurance Agreement Among Load Serving Entities in the PJM Region," Schedule 10.1. PJM determines, in advance of each BRA, whether the defined LDAs will be modeled in the given delivery year using the rules defined in OATT Attachment DD § 5.10(a)(ii).
31 See OATT Attachment DD § 6.5.
32 Prior to November 1, 2009, existing DR and EE resources were subject to market power mitigation in RPM Auctions. See 129 FERC ¶ 61,081 at P 30 (2009).
33 Effective January 31, 2011, the RPM rules related to market power mitigation were changed, including revising the definition for Planned Generation Capacity Resource and creating a new definition for Existing Generation Capacity Resource for purposes of the must offer requirement and market power mitigation, and treating a proposed increase in the capability of a generation capacity resource the same in terms of mitigation as a Planned Generation Capacity Resource. See 134 FERC ¶ 61,065 (2011).

Market Performance

- The 2026/2027 RPM Third Incremental Auction was conducted in the first six months of 2026. The weighted average capacity price for the 2026/2027 Delivery Year is $324.88 per MW-day, including all RPM auctions for the 2026/2027 Delivery Year. The weighted average capacity price for the 2027/2028 Delivery Year is $333.44 per MW-day, including all RPM auctions for the 2027/2028 Delivery Year.
- For the 2025/2026 Delivery Year, RPM annual charges to load are $14.9 billion.
- In the 2027/2028 RPM Base Residual Auction, the market performance was determined to be not competitive.

Part V Reliability Service (RMR)

- Of the nine companies (28 units) that have provided service following deactivation requests, two companies (seven units) filed to be paid under the deactivation avoidable cost rate (DACR), the formula rate. The other seven companies (21 units) filed to be paid under the cost of service recovery rate.

Generator Performance

- Forced Outage Rates. The average PJM EFORd in the first six months of 2026 was 8.4 percent, an increase from 6.2 percent in the first six months of 2025.[34]
- **Generator Performance Factors.** The PJM aggregate equivalent availability factor in the first six months of 2026 was 79.9 percent, a decrease from 81.6 percent in the first six months of 2025.

34 The generator performance analysis includes all PJM capacity resources for which there are data in the PJM generator availability data systems (GADS) database. Data was downloaded from the PJM GADS database on July 22, 2026. EFORd data presented in state of the market reports may be revised based on data submitted after the publication of the reports as generation owners may submit corrections at any time with permission from PJM GADS administrators.

Recommendations[35]

Definition of Capacity

- The MMU recommends elimination of the key remaining components of the CP model because they interfere with competitive outcomes in the capacity market and create unnecessary complexity and risk. (Priority: High. First reported 2022. Status: Not adopted.)
- The MMU recommends the enforcement of a consistent definition of capacity resources. The MMU recommends that the tariff requirement to be a physical resource be enforced and enhanced. The requirement to be a physical resource should apply at the time of auctions and should also constitute a commitment to be physical in the relevant delivery year. The requirement to be a physical resource should be applied to all resource types, including planned generation, demand resources, and imports.[36] [37] (Priority: High. First reported 2013. Status: Not adopted.)
- The MMU recommends that DR providers be required to have a signed contract with specific customers for specific facilities for specific levels of DR at least six months prior to any capacity auction in which the DR is offered. (Priority: High. First reported 2016. Status: Not adopted.)
- The MMU recommends that Energy Efficiency Resources (EE) not be included in the capacity market construct because PJM's load forecasts have accounted for EE since the 2016 load forecast for the 2019/2020 Delivery Year. EE is not a capacity resource as defined in the tariff, and there is no reason to continue to pay large subsidies to EE providers.[38] (Priority: Medium. First reported 2016. Status: Adopted 2024.)[39]
- The MMU recommends that PJM require all market participants to meet their deliverability requirements under the same rules. PJM should end the practice of giving away winter CIRs to intermittent resources that

35 The MMU has identified serious market design issues with RPM and the MMU has made specific recommendations to address those issues. These recommendations have been made in public reports. See Table 5-2.
36 See also Comments of the Independent Market Monitor for PJM, Docket No. ER14-503-000 (December 20, 2013).
37 See "Analysis of Replacement Capacity for RPM Commitments: June 1, 2007 to June 1, 2019," <http://www.monitoringanalytics.com/reports/Reports/2019/IMM_Analysis_of_Replacement_Capacity_for_RPM_Commitments_June_1_2007_to_June_1_2019_20190913.pdf> (September 13, 2019).
38 "PJM Manual 19: Load Forecasting and Analysis," § 3.2 Development of the Forecast, Rev. 39 (June 30, 2026).
39 See 189 FERC ¶ 61,095 (2024).

appear to exist because other resources paid for the supporting network upgrades. (Priority: High. First reported 2017. Status: Not adopted.)[40]

- The MMU recommends that the must offer rule in the capacity market apply to all capacity resources. There is no reason to exempt intermittent and capacity storage resources, including hydro, and demand resources from the must offer requirement. The same rules should apply to all capacity resources in order to ensure open access to the transmission system and prevent the exercise of market power through withholding. (Priority: High. First reported 2021. Status: Partially adopted.)
- The MMU recommends that PJM require all market sellers of proposed generation capacity resources, including thermal and intermittent, to submit a binding notice of intent to offer at least six months prior to the base residual auction. This is consistent with the overall MMU recommendation that all capacity resources have a must offer obligation in the capacity market auctions. (Priority: High. First reported 2023. Status: Partially adopted.)
- The MMU recommends that PJM's application of the ELCC approach be replaced with an ELCC approach that is based on the actual hourly availability of all individual generators for accreditation and for payment. The MMU recommends short term modifications to PJM's approach to include hourly data that would permit unit specific ELCC ratings, to weight summer and winter risk in a more balanced manner, to eliminate PAI risks, and to pay for actual hourly performance rather than based on inflexible class capacity accreditation ratings derived from a small number of nonrepresentative hours of poor performance from PV1 and WSE. (Priority: High. First reported 2023. Status: Not adopted.)

Market Design and Parameters

- The MMU recommends that PJM establish a load queue for large new data center loads to ensure that such loads are not added until there is adequate generation capacity to serve them. The MMU recommends that an expedited queue option that would permit both the load and the generation to be added without delays be available to large data centers if they bring their own new generation with locational and temporal characteristics reasonably matched to their load profile. (Priority: High. First reported Q2, 2025. Status: Not adopted.)
- The MMU recommends that all forecast data center load be excluded from capacity market auctions if it is not on line on June 1, 2026. Only organic load and existing data center load as of June 1, 2026, would be included in the capacity market auctions. PJM would operate a reliability auction for forecast data center load that has not signed or committed to sign a bilateral contract for capacity.[41] (Priority: High. New recommendation. Status: Not adopted.)
- The MMU recommends that PJM reevaluate the shape of the VRR curve. The shape of the VRR curve directly results in load paying substantially more for capacity than load would pay with a vertical demand curve. More specifically, the MMU recommended that the VRR curve be rotated halfway towards the vertical demand curve at the reliability requirement in the 2022 Quadrennial Review. (Priority: High. First reported 2021. Status: Partially adopted.)
- The MMU recommends that the maximum price on the VRR curve be defined as 1.5 times Net CONE, capped at Gross CONE. (Priority: Medium. First reported 2019. Status: Not adopted.)
- The MMU recommends that the reference resource be a CT rather than a CC. The MMU recommends that the ELCC value used to convert the Gross CONE in ICAP terms for a CT to the Gross CONE in UCAP terms be the ELCC based on winter ratings. (Priority: High. First reported 2024. Status: Adopted 2025.)
- The MMU recommends that the test for determining modeled Locational Deliverability Areas (LDAs) in RPM be redefined. A detailed reliability analysis of all at risk units should be included in the redefined model including transmission constraints inside LDAs. The market design should clear and pay units that are needed for reliability per PJM's transmission

40 This recommendation was first made in the 2020/2021 BRA report in 2017. See the "Analysis of the 2020/2021 RPM Base Residual Auction," <http://www.monitoringanalytics.com/reports/Reports/2017/IMM_Analysis_of_the_20202021_RPM_BRA_20171117.pdf> (November 11, 2017).

41 The details of the MMU's proposed design are included in two executive summaries: See "IMM Reliability Backstop Auction Design Proposal," (June 30, 2026) <https://www.monitoringanalytics.com/reports/Presentations/2026/IMM%20Backstop%20auction%20design%20proposal%20-%20V6%202026.06.19.pdf>. See also "IMM Curtailable Load Proposal," (June 30, 2026) <https://www.monitoringanalytics.com/reports/Presentations/2026/IMM%20Connect%20and%20Manage%20proposal%20-%20V2%202026.06.19.pdf>.

reliability analysis in order to forestall RMRs. (Priority: Medium. First reported 2013. Status: Not adopted.)

- The MMU recommends that PJM clear the capacity market based on nodal capacity resource locations and the characteristics of the transmission system inside and outside LDAs consistent with the actual electrical facts of the grid. Absent a fully nodal capacity market clearing process, the MMU recommends that PJM use a non-nested model with all LDAs modeled including VRR curves for all LDAs. Each LDA requirement should be met with the capacity resources located within the LDA and exchanges from neighboring LDAs up to the transmission limit. LDAs should be allowed to price separate if that is the result of the LDA supply curves and the transmission constraints between LDAs. (Priority: Medium. First reported 2017. Status: Not adopted.)
- The MMU recommends that the net revenue offset calculation used by PJM to calculate the net Cost of New Entry (CONE) and net ACR be based on a forward looking calculation of expected energy and ancillary services net revenues using historical net revenues that are scaled based on forward prices for energy and fuel. (Priority: High. First reported 2014. Status: Not adopted.)[42]
- The MMU recommends that PJM reduce the number of incremental auctions to a single incremental auction held three months prior to the start of the delivery year and reevaluate the triggers for holding conditional incremental auctions. (Priority: Medium. First reported 2013. Status: Not adopted.)
- The MMU recommends that PJM not sell back any capacity in any IA procured in a BRA. If PJM continues to sell back capacity, the MMU recommends that PJM offer to sell back capacity in incremental auctions only at the BRA clearing price for the relevant delivery year. (Priority: Medium. First reported 2017. Status: Not adopted.)
- The MMU recommends that PJM not buy any capacity in any IA if PJM has already procured excess reserves. (Priority: Medium. First reported 2023. Status: Not adopted.)

42 This recommendation was first made during the Quadrennial Review in 2014, including the PJM Capacity Senior Task Force (CSTF), the MRC and the MC. <https://www.pjm.com/committees-and-groups/closed-groups/cstf>.

- The MMU recommends changing the RPM solution method to explicitly incorporate the cost of uplift (make whole) payments in the objective function. (Priority: Medium. First reported 2014. Status: Not adopted.)
- The MMU recommends that the Fixed Resource Requirement (FRR) rules, including obligations and performance requirements, be revised and updated to ensure that the rules reflect current market realities and that FRR entities do not unfairly take advantage of those customers paying for capacity in the PJM Capacity Market. (Priority: Medium. First reported 2019. Status: Not adopted.)
- The MMU recommends that the value of CTRs be defined by the total MW cleared in the capacity market, the internal MW cleared and the imported MW cleared, and not redefined later prior to the delivery year. (Priority: Medium. First reported 2021. Status: Not adopted.)
- The MMU recommends that the market clearing results be used in settlements rather than the reallocation process currently used, or that the process of modifying the obligations to pay for capacity be reviewed. (Priority: Medium. First reported 2021. Status: Not adopted.)[43]
- The MMU recommends that PJM improve the clarity and transparency of its CETL calculations. The MMU also recommends that CETL for capacity imports into PJM be based on the ability to import capacity only where PJM capacity exists and where that capacity has a must offer requirement in the PJM Capacity Market. (Priority: Medium. First reported 2021. Status: Partially adopted 2022.)

Offer Caps, Offer Floors, and Must Offer

- The MMU recommends using the lower of the cost or price-based energy market offer to calculate energy costs in the calculation of the historical net revenues which are an offset to gross ACR in the calculation of unit specific capacity resource offer caps based on net ACR. (Priority: Medium. First reported 2021. Status: Not adopted.)
- The MMU recommends that modifications to existing resources, including relatively small proposed increases in the capability of a Generation

43 This recommendation was first made in the 2023/2024 BRA report in 2022. See "Analysis of the 2023/2024 RPM Base Residual Auction Revised," <http://www.monitoringanalytics.com/reports/Reports/2022/IMM_Analysis_of_the_20232024_RPM_Base_Residual_Auction_20221028.pdf> (October 28, 2022).

Capacity Resource be treated as an existing resource and subject to the corresponding market power mitigation rules and no longer be treated as planned and exempt from offer capping. (Priority: Medium. First reported 2012. Status: Not adopted.)[44]

- The MMU recommends that the RPM market power mitigation rules be modified to apply offer caps in all cases when the three pivotal supplier test is failed and the sell offer is greater than the offer cap. This will ensure that market power does not result in an increase in uplift (make whole) payments for seasonal products. (Priority: Medium. First reported 2017. Status: Not adopted.)
- The MMU recommends that any combined seasonal resources be required to be in the same LDA and at the same location, in order for the energy market and capacity market to remain synchronized and reliability metrics correctly calculated. (Priority: Medium. First reported 2021. Status: Not adopted.)
- The MMU recommends that the definition of avoidable costs in the tariff be corrected to be consistent with the economic definition. Avoidable costs are costs that are neither short run marginal costs, like fuel or consumables, nor fixed costs like depreciation and rate of return. Avoidable costs are the marginal costs of capacity and therefore the competitive offer level for capacity resources and therefore the market seller offer cap. Avoidable costs are the marginal costs of capacity for both new resources and existing resources. (Priority: Medium. First reported 2017. Status: Not adopted.)[45]
- The MMU recommends that major maintenance costs be included in the definition of avoidable costs and removed from energy offers because such costs are avoidable costs and not short run marginal costs. (Priority: High. First reported 2019. Status: Not adopted.)
- The MMU recommends that capacity market sellers be required to explicitly request and support the use of minimum MW quantities (inflexible sell offer segments) and that the requests only be permitted for defined physical reasons. (Priority: Medium. First reported 2018. Status: Not adopted.)
- The MMU recommends that, as part of the MOPR unit specific standard of review, all projects be required to use the same basic modeling assumptions. That is the only way to ensure that projects compete on the basis of actual costs rather than on the basis of modeling assumptions.[46] (Priority: High. First reported 2013. Status: Not adopted.)
- The only function the current MOPR is serving now is to create unnecessary administrative work in the application and compliance screening and to create barriers to entry for generation resources. Absent a meaningful change to MOPR, the MMU recommends eliminating the MOPR. (Priority: High. First reported 2025. Status: Not adopted.)

Performance Incentive Requirements of RPM

- The MMU recommends that any unit not capable of supplying energy equal to its day-ahead must offer requirement (ICAP) be required to reflect an appropriate outage and associated performance penalty. (Priority: Medium. First reported 2009. Status: Not adopted.)
- The MMU recommends that retroactive replacement transactions associated with a failure to perform during a PAI not be allowed and that, more generally, retroactive replacement capacity transactions not be permitted. (Priority: Medium. First reported 2016. Status: Not adopted.)
- The MMU recommends that there be an explicit requirement that capacity resource offers in the day-ahead energy market be competitive, where competitive is defined to be the short run marginal cost of the units, including flexible operating parameters. (Priority: Low. First reported 2013. Status: Not adopted.)

44 This recommendation was first made in the 2014/2015 BRA report in 2012. See "Analysis of the 2014/2015 RPM Base Residual Auction," <http://www.monitoringanalytics.com/reports/Reports/2012/Analysis_of_2014_2015_RPM_Base_Residual_Auction_20120409.pdf> (April 9, 2012).

45 This recommendation was first made in the 2023/2024 BRA report in 2022. See "Analysis of the 2023/2024 RPM Base Residual Auction Revised," <http://www.monitoringanalytics.com/reports/Reports/2022/IMM_Analysis_of_the_20232024_RPM_Base_Residual_Auction_20221028.pdf> (October 28, 2022).

46 See 143 FERC ¶ 61,090 (2013) ("We encourage PJM and its stakeholders to consider, for example, whether the unit-specific review process would be more effective if PJM requires the use of common modeling assumptions for establishing unit-specific offer floors while, at the same time, allowing sellers to provide support for objective, individual cost advantages. Moreover, we encourage PJM and its stakeholders to consider these modifications to the unit-specific review process together with possible enhancements to the calculation of Net CONE."); see also, Comments of the Independent Market Monitor for PJM, Docket No. ER13-535-001 (March 25, 2013); Complaint of the Independent Market Monitor for PJM v. Unnamed Participant, Docket No. EL12-63-000 (May 1, 2012); Motion for Clarification of the Independent Market Monitor for PJM, Docket No. ER11-2875-000, et al. (February 17, 2012); Protest of the Independent Market Monitor for PJM, Docket No. ER11-2875-002 (June 2, 2011); Comments of the Independent Market Monitor for PJM, Docket Nos. EL11-20 and ER11-2875 (March 4, 2011).

- The MMU recommends that Capacity Performance resources be required to perform without excuses. Resources that do not perform should not be paid regardless of the reason for nonperformance. (Priority: High. First reported 2019. Status: Not adopted.)
- The MMU recommends that PJM require actual seasonal tests as part of the Summer/Winter Capability Testing rules, that the number of tests be limited, and that the ambient conditions under which the tests are performed be defined to reflect seasonal extreme conditions. (Priority: Medium. First reported 2022. Status: Partially adopted.)
- The MMU recommends that PJM select the time and day that a unit undergoes Net Capability Verification Testing, not the unit owner, and that this information not be communicated in advance to the unit owner. (Priority: Medium. First reported 2022. Status: Not adopted.)

Capacity Imports and Exports

- The MMU recommends that all capacity imports be required to be deliverable to PJM load in an identified LDA, zonal or subzonal, or defined combinations of specific zones, e.g. MAAC, prior to the relevant delivery year to ensure that they are full substitutes for internal, physical capacity resources. Pseudo ties alone are not adequate to ensure deliverability to PJM load. (Priority: High. First reported 2016. Status: Not adopted.)
- The MMU recommends that all costs incurred as a result of a pseudo tied unit be borne by the unit itself and included as appropriate in unit offers in the capacity market. (Priority: High. First reported 2016. Status: Not adopted.)
- The MMU recommends that the PJM Tariff be modified to explicitly state that in order to qualify, a Capacity Market Seller requesting a must offer exception based on a financially and physically firm commitment to an external sale of its capacity must provide a confirmed firm transmission reservation, covering the entire path from source to sink, for the full requested ICAP MW of the external sale that covers the entire delivery year, by the tariff defined deadline. The MMU recommends that this language apply to all external sales of Generation Capacity Resources, including those where an external balancing authority does not require this level of transmission service in order to consider a PJM resource as a network resource. (Priority: High. First reported 2025. Status: Not adopted.)

Deactivations/Retirements

- The MMU recommends that the notification requirement for deactivations be extended from the current one quarter prior (See Table 5-31) to 12 months prior to an auction in which the unit will not be offered due to deactivation; and no less than 12 months prior to the date of deactivation (Priority: Low. First reported 2012. Status: Partially adopted.)
- The MMU recommends that the same reliability standard be used in capacity auctions as is used by PJM transmission planning. One result of the current design is that a unit may fail to clear in a BRA, decide to retire as a result, but then be found to be needed for reliability by PJM planning and paid under Part V of the OATT (RMR) to remain in service while transmission upgrades are made. (Priority: High. First reported 2023. Status: Not adopted.)
- The MMU recommends elimination of both the cost of service recovery rate option and the deactivation avoidable cost rate option for providing Part V reliability service (RMR), and their replacement with clear language that provides for the recovery of 100 percent of the actual incremental costs required to operate to provide the service plus a defined incentive. (Priority: High. First reported 2017. Status: Not adopted.)
- The MMU recommends that units recover all and only the incremental costs, including incremental investment costs without a cap, required to provide Part V reliability service (RMR service) that the unit owner would not have incurred if the unit owner had deactivated its unit as it proposed, plus a defined incentive payment. Customers should bear no responsibility for paying previously incurred (sunk) costs, including a return on or of prior investments. (Priority: High. First reported 2010. Status: Not adopted.)

- The MMU recommends that if units that are paid under Part V of the OATT (RMR) are included in the calculation of CETO and/or reliability in the relevant LDA, the capacity of the RMR resources should also be included in capacity market supply at zero cost, but without all the obligations of a capacity resource, in order to ensure that the capacity market price signal reflects the appropriate supply and demand conditions. (Priority: High. First reported 2023. Status: Partially adopted.)
- The MMU recommends that units that are paid under Part V of the OATT (RMR) not be included in the calculation of CETO or reliability in the relevant LDA, in order to ensure that the capacity market price signal reflects the appropriate supply and demand conditions, until a decision is made to build transmission as a replacement, and then should be included. (Priority: High. First reported 2023. Status: Not adopted.)
- The MMU recommends that all CIRs be returned to the pool of available interconnection capability on the retirement date of generation resources in order to facilitate timely and competitive entry into the PJM markets, open access to the transmission system and maintain the priority order defined by the queue process. (Priority: High. First reported 2023. Status: Not adopted.)

Conclusion

The analysis of the PJM Capacity Market begins with market design and market structure, which provide the framework for the actual behavior or conduct of market participants. The analysis examines participant behavior within that market design and market structure. Regardless of the ownership structure of a market, the market design can result in noncompetitive outcomes or in competitive outcomes. In a good market design and a competitive market structure, market participants are constrained to behave competitively. In a market with endemic structural market power like the PJM Capacity Market, effective market power mitigation rules are required in order to constrain market participants to behave competitively. The analysis examines market performance, measured by price and the relationship between price and marginal cost, that results from the interaction of market structure and participant behavior. The analysis also examines the impact of market design choices on market performance.

The MMU concludes that the results of the 2027/2028 RPM Base Residual Auction were significantly affected by flawed market design elements including the inclusion of large new data center loads in the load forecast, the lack of a queue for the addition of large new data center loads, by the performance assessment interval (PAI) penalties that are part of the CP design, by PJM's ELCC approach, by the definition of market seller offer caps, by the failure to extend the RPM must offer requirement to demand resources, and by the product definition and lack of market power mitigation for demand resources. The BRA prices do not reflect supply and demand fundamentals but reflect, in significant part, PJM decisions about the definition of supply and demand. PJM filed changes that were approved by FERC to adopt two of the MMU's recommendations, the inclusion of specific RMR resources as supply in RPM auctions for the 2026/2027 through the 2028/2029 Delivery Year and the elimination of the categorical exemption to the RPM must offer requirement effective with the 2026/2027 Delivery Year, although PJM failed to include elimination of the categorical exemption for demand resources.[47] [48]

The capacity market is, by design, always tight in the sense that total supply is generally only slightly larger than demand. While the market may be long at times, that is not the equilibrium state. Market power is and will remain endemic to the structure of the PJM Capacity Market. Nonetheless, a competitive outcome can be assured by appropriate market power mitigation rules within an effective market design. 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.

The basic conclusion of Part A of the MMU's analysis of the 2027/2028 BRA is that data center load growth is the primary reason for recent and expected capacity market conditions, including total forecast load growth, the tight supply and demand balance, and high prices. But for data center growth, both actual and forecast, the PJM Capacity Market would not have seen the

47 See Letter Order, FERC Docket No. ER25-682-001 (April 29, 2025). See also 193 FERC ¶ 61,234 (2025).
48 190 FERC ¶ 61,117 (2025).

same tight supply demand conditions, the same high prices observed in the 2025/2026 BRA, the 2026/2027 BRA and the 2027/2028 BRA or the currently expected tight supply conditions and high prices for subsequent capacity auctions. The combined total increase in capacity market revenues resulting from data center load, both actual and forecast, for the 2025/2026 BRA, the 2026/2027 BRA and the 2027/2028 BRA was $23,100,955,341.[49] [50] [51] This total will continue to grow until the issues associated with the additions of large data center loads are addressed.

It is misleading to assert that the capacity market results are simply just a reflection of supply and demand. The current conditions are not the result of organic load growth. The current conditions in the capacity market are almost entirely the result of large load additions from data centers, both actual historical and forecast. The growth in data center load and the expected future growth in data center load are unique and unprecedented and uncertain and require a different approach than simply asserting that it is just supply and demand.

It is equally misleading to assert that the PJM Capacity Market does not work as a result of the impact of existing and forecast large data center load additions. Despite all the issues with PJM's changes to the capacity market design, the PJM Capacity Market would have provided for reliability at prices consistent with organic load growth and the cost of new capacity were it not for the paradigm shift represented by the almost inexhaustible demand for power from data centers.

Data center load growth is the core reliability issue facing PJM markets at present. There is still time to address the issue but failure to do so effectively will result in very high costs for other PJM customers and could also result in a switch from competitive markets to cost of service regulation or other distortions of the market design. Customers are already bearing billions of dollars in higher costs as a direct result of existing and forecast data center load as the Market Monitor demonstrated in the Analysis of the 2025/2026 RPM Base Residual Auction – Part G, the Analysis of the 2026/2027 RPM Base Residual Auction – Part A, and the Analysis of the 2027/2028 RPM Base Residual Auction – Part A.[52] [53] With the completion of the 2028/2029 BRA, the inclusion of data center load in the capacity market auctions has resulted in an irreversible total increase in costs of $29.4 billion.[54]

PJM should not continue to interconnect large new data center load if that load cannot be served reliably. The goal should be to serve all load that can be served reliably. The MMU recommends that PJM establish a load queue for large new data center loads to ensure that such loads are not added until there is adequate generation capacity to serve them. The MMU recommends that an expedited queue option that would permit both the load and the generation to be added without delays be available to large data centers if they bring their own new generation with locational and temporal characteristics reasonably matched to their load profile.

For the first time since the introduction of the RPM capacity market design, the 2026/2027 BRA used a VRR curve with both a defined maximum price and a defined minimum price. The maximum and minimum prices were based on the Agreement between Governor Shapiro of Pennsylvania and PJM that was incorporated in a PJM filing with FERC.[55] That VRR curve with the defined maximum and minimum price is referred to in this report as the actual (or restricted) VRR curve. The VRR curve that would have been used absent the Agreement is referred in this report as the unrestricted VRR curve.

The Agreement resulted in a reduction of 2026/2027 BRA revenues of $3,169,915,210, or 16.4 percent, compared to the revenues that would have resulted from the unrestricted VRR curve, holding everything else constant.

49 *See*, "Analysis of the 2025/2026 RPM Base Residual Auction - Part G Revised," <https://www.monitoringanalytics.com/reports/Reports/2025/IMM_Analysis_of_the_2025 2026_RPM_Base_Residual_Auction_Part_G_20250603_Revised.pdf> (June 3, 2025).

50 See "Analysis of the 2026/2027 RPM Base Residual Auction - Part A," ("Part A") <https://www.monitoringanalytics.com/reports/Reports/2025/IMM_Analysis_of_the_20262027_RPM_Base_Residual_Auction_Part_A_20251001.pdf> (October 1, 2025).

51 See "Analysis of the 2027/2028 RPM Base Residual Auction - Part A," ("Part A") <https://www.monitoringanalytics.com/reports/Reports/2026/IMM_Analysis_of_the_20272028_RPM_Base_Residual_Auction_Part_A_20260105.pdf> (January 5, 2026).

52 Post Technical Conference Comments of the Independent Market Monitor for PJM (July 7, 2025) *Resource Adequacy Meeting the Challenge of Resource Adequacy in Regional Transmission Organization and Independent System Operator Regions*, Docket No. AD25-7.

53 See "Analysis of the 2026/2027 RPM Base Residual Auction - Part A," (October 1, 2025) <https://www.monitoringanalytics.com/reports/Reports/2025/IMM_Analysis_of_the_20262027_RPM_Base_Residual_Auction_Part_A_20251001.pdf>.

54 See "Market Monitor Report," (July 28, 2025) <https://www.monitoringanalytics.com/reports/presentations/2026/IMM_MC_Market_Monitor_Report_20260728.pdf>.

55 On December 30, 2024, in Docket No. EL25-46-000, Governor Josh Shapiro and the Commonwealth of Pennsylvania filed a complaint against PJM asserting that the maximum price for PJM's capacity auctions is unjust and unreasonable. The Governor and PJM reached an Agreement. On February 20, 2025, in Docket No. ER25-1357-000, pursuant to FPA section 205, PJM submitted proposed revisions to its Tariff to establish a specific maximum price and minimum price for all RPM auctions for the 2026/2027 and 2027/2028 Delivery Years, consistent with the Agreement.

If the 2026/2027 BRA had been run with an unrestricted VRR curve, total revenues would have been $19,294,286,100, an increase of $3,169,915,210, or 19.7 percent, compared to the actual auction revenues of $16,124,370,889. The Agreement resulted in a reduction of 2027/2028 BRA revenues of $9,913,272,621, or 37.7 percent, compared to the revenues that would have resulted from the unrestricted VRR curve, holding everything else constant. If the 2027/2028 BRA had been run with an unrestricted VRR curve, total revenues would have been $26,324,850,846, an increase of $9,913,272,621, or 60.4 percent, compared to the actual auction revenues of $16,411,578,225. The Agreement resulted in a reduction of combined 2026/2027 and 2027/2028 BRA revenues of $13,083,187,831, or 28.7 percent, compared to the revenues that would have resulted from the unrestricted VRR curve, holding everything else constant.

The demand for capacity includes expected peak load plus a reserve margin, and points on the demand curve, called the Variable Resource Requirement (VRR) curve, exceed peak load plus the reserve margin. The maximum price on the VRR curve has a significant impact on market prices particularly when the market is tight. The shape of the VRR curve results in the purchase of excess capacity and higher payments by customers. The VRR curves used in the 2025/2026 BRA included a maximum price equal to Gross CONE for most LDAs that resulted in a significant increase in customer payments for load as a result of paying a price above the competitive level. Demand for capacity is almost entirely inelastic because the market rules require loads to purchase their share of the system capacity requirement. The VRR demand curve is everywhere inelastic. The result is that any supplier that owns more capacity than the typically small difference between total supply and the defined demand is individually pivotal and therefore has structural market power.

For the 2027/2028 RPM Base Residual Auction, total reserves were 16,977.4 MW, which is 6,516.6 MW (UCAP) short of the required reserve level of 23,494.0 MW (UCAP). The level of committed demand resources in the 2027/2028 BRA was 7,298.6 MW, meaning the PJM markets will rely on demand resources as part of the required reserve margin, rather than as excess above the required reserve margin. This is not consistent with the defined obligations of DR compared to other capacity resources. DR capacity resources do not have a must offer obligation in the energy market. DR capacity resources do not have a must offer obligation in the capacity market. The definition of performance for DR is not to provide a defined incremental level of MW when called but is only to be at a defined level of demand. DR capacity resources have significantly under performed during recent cold weather and hot weather events. DR capacity resources do not have a defined market seller offer cap. PJM markets for the first time in the 2025/2026, 2026/2027, and 2027/2028 Delivery Years will rely on demand response resources as part of the required reserve margin, rather than as excess above the required reserve margin. PJM markets for the first time in the 2025/2026, 2026/2027, and 2027/2028 Delivery Years will experience the implications of the definition of demand resources as a purely emergency capacity resource, when demand resources are a significant share of required reserves. Nonetheless, as another significant flaw in the market design, PJM does not include DR in its definition of primary or secondary reserves in the energy market. DR, for all these reasons, is an inferior resource in the capacity market. PJM does not have clear rules defining when the operators must call on DR.

There are currently two important gaps in the market power rules for the PJM Capacity Market related to demand resources. The RPM must offer requirement is not applied to demand resources. There are no market power mitigation rules that apply to demand resources.

For the 2027/2028 BRA, all participants to which the three pivotal supplier (TPS) test was applied (in the RTO RPM market) failed the three pivotal supplier test. The result was that offer caps were applied to all sell offers for Existing Generation Capacity Resources when the capacity market seller did not pass the test, the submitted sell offer exceeded the tariff defined offer cap, and the submitted sell offer, absent mitigation, would have resulted in a higher market clearing price.[56] [57]

56 Prior to November 1, 2009, existing DR and EE were subject to market power mitigation in RPM Auctions. See 129 FERC ¶ 61,081 (2009) at P 30.

57 Effective January 31, 2011, the RPM rules related to market power mitigation were changed, including revising the definition for Planned Generation Capacity Resource and creating a new definition for Existing Generation Capacity Resource for purposes of the must-offer requirement and market power mitigation, and treating a proposed increase in the capability of a Generation Capacity Resource the same in terms of mitigation as a Planned Generation Capacity Resource. See 134 FERC ¶ 61,065 (2011).

The correct definition of a competitive offer in the capacity market is the marginal cost of capacity, net ACR, where gross ACR includes an explicit accounting for the costs of mitigating risk, including the risk associated with mitigating rational capacity market nonperformance penalties, and the relevant costs of acquiring fuel, including natural gas, and net ACR includes all energy and ancillary services net revenues as an offset against every element of gross ACR.

The MMU recommends elimination of the key remaining components of the CP model because they interfere with competitive outcomes in the capacity market and create unnecessary complexity and risk. The use of Net CONE as the basis for the PAI penalty rate is unsupported by economic logic. The use of Net CONE to establish penalties is a form of arbitrary administrative pricing that creates arbitrarily high risk for generators, creates complexity in the calculation of CPQR and increases CPQR above rational levels, and ultimately raises the price of capacity above the competitive level. Given PJM's recent decision to rely on conservative operations during tight market conditions as evidenced during Polar Vortex 2025 in January 2025, the probability of a PAI is extremely small. In addition, PJM tightened the definition of a PAI and capped the total annual penalty at 1.5 times the resource's capacity market BRA clearing price. There is no effective performance incentive remaining in the capacity market. In the absence of the EFORd design and with the absence of actual or expected regular PAI events, there is no capacity market consequence for failing to perform.

Rather than penalizing capacity resources at extremely high levels for nonperformance only during PAI events, capacity resources should be paid the daily price of capacity only to the extent that they are available to produce energy or provide reserves, as required by PJM on a daily/hourly basis, based on their cleared capacity (ICAP). This is a positive performance incentive based on the market price of capacity rather than a penalty based on an arbitrary assumption. This would mean that capacity resources are paid to provide energy and reserves based on their full ICAP and are not paid a bonus for doing so. The reduced payments for capacity would directly reduce customers' bills for capacity. This would also end the pretense that there will be penalty payments to fund bonus payments. This would also end the need for complex CPQR calculations based on the penalty rate and assumptions about the number and timing of PAI events. CP has not worked as the theory suggested. PAI events are high impact, low probability events. The failure of the PAI incentives to prevent a very high level of outages during Winter Storm Elliott illustrates the weakness of incentives based on this type of event. In addition, the actual performance standards were unacceptably weakened in the CP model. The standard of performance in the CP model is (B) * (ELCC accredited UCAP factor for a unit), where B is the balancing ratio and the ELCC accredited UCAP factor is the derating factor. For example, if B were 80 percent, the actual required performance for a unit with an 80 percent ELCC accredited UCAP factor would be only 64 percent of ICAP (.80 * .80). For units with low ELCC accredited UCAP factors, the required performance is even lower. The obligation to perform should equal the full ICAP value of a unit, consistent with the associated must offer obligation in the energy market for capacity resources.

The MMU is required to identify market issues and to report them to the Commission and to market participants. The Commission decides on any action related to the MMU's findings.

The MMU has identified serious market design issues with RPM and the MMU has made specific recommendations to address those issues.[58] In 2025 and the first six months of 2026, the MMU prepared a number of RPM related reports and testimony, shown in Table 5-2.

The PJM markets have worked to provide incentives to entry and to retain capacity. A majority of capacity investments in PJM were financed by market sources. Of the 62,666.3 MW of additional capacity that cleared in RPM auctions for the 2007/2008 through 2025/2026 Delivery Years, 46,876.7 MW (74.8 percent) were based on market funding. Of the 3,294.6 MW of additional capacity that cleared in RPM auctions for the 2026/2027 through the 2027/2028 Delivery Years, 2,725.1 MW (82.7 percent) were based on market funding. Those investments were made based on the assumption that markets would be allowed to work and that inefficient units would exit.

58 For the complete list of RPM reports, see the ***2025 Annual State of the Market Report for PJM***, Volume 2, Section 5: Capacity Market.

It is essential that any approach to the PJM markets incorporate a consistent view of how the preferred market design is expected to provide competitive results in a sustainable market design over the long run. A sustainable market design means a market design that results in appropriate incentives to competitive market participants to retire units and to invest in new units over time such that reliability is ensured as a result of the functioning of the market.

In order to attract and retain adequate resources for the reliable operation of the energy market, revenues from PJM energy, ancillary services and capacity markets must be adequate for those resources. That adequacy requires a capacity market. The capacity market plays the essential role of equilibrating the revenues necessary to incent competitive entry and exit of the resources needed for reliability, with the revenues from the energy market that are directly affected by nonmarket sources.

Table 5-2 RPM related MMU reports: 2025 through June 2026

Date	Name
January 5, 2026	Analysis of the 2027/2028 RPM Base Residual Auction – Part A (PDF) https://www.monitoringanalytics.com/reports/Reports/2026/IMM_Analysis_of_the_20272028_RPM_Base_Residual_Auction_Part_A_20260105.pdf
January 9, 2026	IMM Comments re Economic Load Response Regulation Only Participants Docket No. ER26-846 (PDF) https://www.monitoringanalytics.com/filings/2026/IMM_Answer_to_Economic_Load_Response_Regulation_Only_Participants_Docket_No_ER26-846_20260109.pdf
January 12, 2026	IMM Answer to PJM re Warrior Run Waiver Request Docket No. ER26-880 (PDF) https://www.monitoringanalytics.com/filings/2026/IMM_Answer_to_PJM_Docket_No_ER26-880_20260112.pdf
January 12, 2026	RMR Matrix Issues: Scope Areas 4, 5 and 6 (PDF) https://www.monitoringanalytics.com/reports/Presentations/2026/IMM_DESTF_RMR_Matrix_Issues_Scope_Areas_4_5_6_20260112.pdf
January 20, 2026	IMM Answer to PJM re Quadrennial Review VRR Curve Docket No. ER26-455 (PDF) https://www.monitoringanalytics.com/filings/2026/IMM_Answer_to_PJM_Answer_Docket_No_ER26-455_20260120.pdf
January 20, 2026	DR Nonperformance Penalties (PDF) https://www.monitoringanalytics.com/reports/Presentations/2026/IMM_MIC_DR_Nonperformance_Penalties_20260120.pdf
January 28, 2026	Supply Uncertainty (PDF) https://www.monitoringanalytics.com/reports/Presentations/2026/IMM_RCSTF_Supply_Uncertainty_20260128.pdf
February 4, 2026	DR Nonperformance Penalty and Performance Adjustment Factor Example (PDF) https://www.monitoringanalytics.com/reports/Presentations/2026/IMM_MIC_Nonperformance_Penalty_and_Performance_Adjustment_Factor_Examples_20260204.pdf
February 5, 2026	IMM Answer to CEG re Co-located Load Docket No. EL25-49, et al (PDF) https://www.monitoringanalytics.com/filings/2026/IMM_Answer_to_CEG_RFC_Docket_No_EL25-49_et_al_20260205.pdf
February 17, 2026	IMM Backstop Auction Design Proposal (PDF) https://www.monitoringanalytics.com/reports/Presentations/2026/IMM_Reliability_Backstop_WS_Backstop_Auction_Design_Proposal_20260217.pdf
February 25, 2026	Reliability Backstop Auction Design Proposal –V2 (PDF) https://www.monitoringanalytics.com/reports/Presentations/2026/IMM_Reliability_Backstop_WS_%20Backstop_Auction_Design_Proposal-V2_20260224.pdf
March 3, 2026	Analysis of the 2026/2027 RPM Base Residual Auction – Part B (PDF) https://www.monitoringanalytics.com/reports/Reports/2026/IMM_Analysis_of_the_20262027_RPM_Base_Residual_Auction_Part_B_20260303.pdf
March 11, 2026	DR Penalties Matrix Additions (PDF) https://www.monitoringanalytics.com/reports/Presentations/2026/IMM_MIC_DR_penalties_matrix_additions_20260311.pdf
March 20, 2026	IMM Comments re PJM Price Collar Extension Docket No. ER26-1556 (PDF) https://www.monitoringanalytics.com/filings/2026/IMM_Comments_Docket_No_ER26-1556_20260320.pdf
March 25, 2026	IMM Reply Brief re Co-Location Order Paper Hearing Docket No. EL25-49, et al (PDF) https://www.monitoringanalytics.com/filings/2026/IMM_Reply_Brief_Docket_No_EL25-49_et_al_20250325.pdf
April 6, 2026	IMM Answer to Answer re PJM Price Collar Extension Docket No. ER26-1556 (PDF) https://www.monitoringanalytics.com/filings/2026/IMM_Answer_Docket_No_ER26-1556_20260406.pdf
April 22, 2026	IMM Comments on Proposed DR Penalties (PDF) https://www.monitoringanalytics.com/reports/Presentations/2026/IMM_MRC_Comments_on_Proposed_DR_Penalties_20260422.pdf
April 27, 2026	IMM Reliability Backstop Auction Design Proposal (PDF) https://www.monitoringanalytics.com/reports/Presentations/2026/IMM_Backstop_Auction_Design_Proposal_20260427.pdf
May 8, 2026	IMM Reliability Backstop Auction Design Proposal – V4 (PDF) https://www.monitoringanalytics.com/reports/Presentations/2026/IMM_Reliability_Backstop_WS_%20Backstop_Auction_Design_Proposal-V4_20260508.pdf
May 11, 2026	IMM Answer re Crane CIR Waiver Request Docket No. ER26-2028 (PDF) https://www.monitoringanalytics.com/filings/2026/IMM_Answer_to_Answer_Docket_No_ER26-2028_20260511.pdf
May 11, 2026	IMM Answer re Zimmer Bess CIR Waiver Request Docket No. ER26-2321 (PDF) https://www.monitoringanalytics.com/filings/2026/IMM_Answer_to_Protest_Docket_No-_ER26-2321_20260511.pdf
May 22, 2026	IMM Answer to PJM Answer re CP Penalties Complaints Docket Nos. EL26-59 and EL26-60 (PDF) https://www.monitoringanalytics.com/filings/2026/IMM_Answer_to_PJM_Answer_Docket_No_EL26-59_EL26-60_20260522.pdf
June 2, 2026	IMM Answer Supporting P3 Comments re Regulation Market Redesign Phase 2 Docket No. ER26-2446 (PDF)https://www.monitoringanalytics.com/filings/2026/IMM_Answer_Supporting_P3_Comments_Docket_No_ER26-2446_20260602.pdf
June 10, 2026	IMM Connect and Manage Design Proposal (PDF)https://www.monitoringanalytics.com/reports/Presentations/2026/IMM_CIFP_Connect_and_Manage_Proposal-V1_20260610.pdf
June 10, 2026	IMM Backstop Auction Design Proposal (PDF) https://www.monitoringanalytics.com/reports/Presentations/2026/IMM_CIFP_Backstop_Auction_Design_Proposal-V5_20260610.pdf
June 16, 2026	IMM Answer re Voltus/Mission:data complaint Docket No. EL26-4 (PDF) https://www.monitoringanalytics.com/filings/2026/IMM_Comments_Docket_No_ER26-2738_et_al_20260626.pdf
June 29, 2026	Generation Capacity Resources in PJM Region Subject to RPM Must Offer Obligation for 2027/2028 and 2028/2029 Delivery Years (PDF) https://www.monitoringanalytics.com/reports/Market_Messages/Messages/IMM_Notice_re_RPM_Must_Offer_Obligations_20260629.pdf
June 30, 2026	IMM Curtailable Load Proposal (PDF) https://www.monitoringanalytics.com/reports/Presentations/2026/IMM%20Connect%20and%20Manage%20proposal%20-%20V2%202026.06.19.pdf
June 30, 2026	IMM Reliability Backstop Auction Design Proposal (PDF) https://www.monitoringanalytics.com/reports/Presentations/2026/IMM%20Backstop%20auction%20design%20proposal%20-%20V6%202026.06.19.pdf
July 9, 2026	Analysis of the 2027/2028 RPM Base Residual Auction – Part B (PDF) https://www.monitoringanalytics.com/reports/Reports/2026/IMM_Analysis_of_the_20272028_RPM_Base_Residual_Auction_Part_B_20260709.pdf
July 10, 2026	Data Submission Window Opening for the 2029/2030 RPM Base Residual Auction (PDF) https://www.monitoringanalytics.com/reports/Market_Messages/RPM_Material/IMM_Data_Submission_Window_Opening_2029-2030_Base_Residual_Auction_20260710.pdf

Market Design

With the earlier introduction of the Capacity Performance model and the recent introduction of the ELCC model, combined with a tightening of the capacity supply and demand balance in ICAP terms, it is clear that PJM's choices about the details of market design have a potentially dominant impact on capacity market outcomes in PJM. The ongoing decision to allow the addition of a significant number of large new data center loads that cannot be served reliably due to inadequate capacity is the most recent and most significant example.

RPM prices are locational by LDA and may vary depending on transmission constraints into LDAs and local supply and demand conditions.[59] The capacity market is not fully locational. The capacity market locational differences exist only between and among LDAs. The capacity market design assumes that there are no transmission or operational constraints within LDAs and treats all capacity resources within an LDA as perfect substitutes even when they are not. The lack of a fully locational design is a market design flaw that has resulted in the designation of units as RMRs based on internal constraints that were not recognized in the market clearing process. Existing generation that qualifies as a capacity resource must be offered into RPM auctions, except for categorically exempt demand resources, and except for resources in a fixed resource requirement (FRR) plan. All load is required to pay for capacity. Participation by LSEs is mandatory, except for those entities that elect the FRR option. There is an administratively determined demand curve that defines scarcity pricing levels and that, with the supply curve derived from capacity offers, determines market prices in each BRA. There are explicit market power mitigation rules that define structural market power, that define offer caps based on the marginal cost of capacity, and that have flexible criteria for competitive offers by new entrants. Demand resources may be offered directly into RPM auctions but do not have a requirement to be identifiable physical resources, do not have a must offer obligation, do not have a corresponding must offer obligation in the energy market for cleared resources, do not have market seller offer caps, and receive the clearing price.

59 Transmission constraints are local capacity import capability limitations (low capacity emergency transfer limit (CETL) margin over capacity emergency transfer objective (CETO)) caused by transmission facility limitations, voltage limitations or stability limitations.

The results of the 2027/2028 RPM Base Residual Auction were significantly affected by flawed market design elements including the lack of a queue for the addition of large new data center loads, by the performance assessment interval (PAI) penalties that are part of the CP design, by PJM's ELCC approach, by the definition of market seller offer caps, by the failure to extend the RPM must offer requirement to demand resources, and by the product definition and lack of market power mitigation for demand resources. The BRA prices do not reflect supply and demand fundamentals but reflect, in significant part, PJM decisions about the definition of supply and demand. PJM filed changes that were approved by FERC and included in the 2026/2027 BRA and the 2027/2028 BRA to adopt two of the MMU's recommendations, the inclusion of specific RMR resources as supply in RPM auctions for the 2026/2027 through the 2028/2029 Delivery Year and the elimination of the categorical exemption to the RPM must offer requirement, although PJM failed to include elimination of the categorical exemption for demand resources.

The fundamental mistake of the CP design was to attempt to recreate energy market incentives in the capacity market. The CP model was an explicit attempt to bring energy market shortage pricing into the capacity market design. The CP model was designed on the unsupported assumption that shortage prices in the energy market were not high enough and needed to be increased via the capacity market. The CP design focused on a small number of critical hours (performance assessment hours or PAH, translated into five minute intervals as PAI) and imposed large penalties on generators that failed to produce energy only during those hours. The use of capacity market penalties rather than energy market incentives created a new risk. While there are differences of opinion about how to value the risk, this CP risk is not risk that is fundamental to the operation of a wholesale power market. This is risk created by the CP design in order to provide an incentive to produce energy during high demand hours that is even higher than the energy market incentive, amplified by an operating reserve demand curves (ORDC). The risk created by CP is not limited to risk for individual generators, but extends to the viability of the market. If penalties create bankruptcies that threaten the viability of required energy output from the affected units, there is a risk to the market.

The CP PAI incentives are not effective market incentives. PAI incentives are administrative and nonmarket incentives that are not compatible with an effective market design. The energy market clearing, in contrast, is transparent and efficient and timely. While there are issues with the details of energy market pricing that must be addressed, including shortage pricing, the energy market does not include or create the significant and long lasting uncertainty created by the PAI rules as exhibited most dramatically by the results of Winter Storm Elliott. The PAI design creates an administrative process that adds unacceptable uncertainty to the process and that can never approach the effectiveness of the energy market in providing price signals and timely settlement. In addition, the imposition of PAI penalties on intermittent resources when those resources cannot perform is illogical.

The MMU recommends that PJM's application of the ELCC approach be replaced with an ELCC approach that is based on the actual hourly availability of all individual generators for accreditation and for payment. The MMU recommends short term modifications to PJM's approach to include hourly data that would permit unit specific ELCC ratings, to weight summer and winter risk in a more balanced manner, to eliminate PAI risks, and to pay for actual hourly performance rather than based on inflexible class capacity accreditation ratings derived from a small number of nonrepresentative hours of poor performance from PV1 and WSE. In the short run capacity accreditation should eliminate the performance during PV1 and WSE and should recognize the winter capability of thermal resources rather than limiting such resources to summer ratings. Most 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. That unnecessarily limits supply and changes the ELCC values for all other resources and changes the system accredited unforced capacity and therefore AUCAP, the maximum level of load that can be served by the existing resources and therefore the reliability requirement. The CIRs of such resources are currently limited by the summer ratings but those rules can and should be changed given the use of the ELCC approach. There is no reason that excess winter CIRs cannot be assigned to these resources immediately.

The initial VRR curve, introduced in 2007, had a maximum price equal to 1.5 times the Net Cost of New Entry (Net CONE), determined annually based on the fixed cost of new generating capacity, or Gross Cost of New Entry (Gross CONE), net of the three year average energy and ancillary service revenues. That VRR curve was structured to yield auction clearing prices equal to the 1.5 times Net CONE when the amount of capacity cleared was less than 99 percent of the target reserve margin, and below 1.5 times Net CONE when the amount of capacity cleared was greater than 99 percent of the target reserve margin. The use of Net CONE was based on the logic of the capacity market, to ensure that the cost of entry was covered between the energy and capacity markets. Net CONE was the missing money that needed to be recoverable in the capacity market. Net CONE was the equilibrating factor between the capacity market and energy market. The use of Gross CONE is inconsistent with that basic capacity market logic. Gross CONE was introduced as the maximum price based on concerns that Net CONE would be too low. The maximum point on the VRR curve for the 2025/2026 BRA was the higher of Gross CONE or 1.5 times Net CONE and Gross CONE was used. For the first time since the introduction of the RPM capacity market design, the 2026/2027 BRA used a VRR curve with both a defined maximum price and a defined minimum price.[60] However, if the logic of the markets implies a low Net CONE, that is the right answer. There is nothing inherently wrong with a low Net CONE that requires abandoning the basic capacity market logic. The use of Gross CONE rather than 1.5 times Net CONE was an intervention designed to increase capacity market prices despite the fact that the basic economic logic did not support that increase. If there is an issue with the calculation of Net CONE, it should be addressed directly rather than by ignoring its central role in the design of the capacity market. As Gross CONE numbers are reasonably well defined, much more focus on the correct calculation of the net revenues used in the forward auctions is required in order to ensure that market participants have confidence in the Net CONE values used in the auctions.

PJM ended the long standing categorical exemption of intermittent resources, capacity storage resources, and hybrid resources from the RPM must offer

60 On April 21, 2025, FERC issued an order accepting PJM's proposal to establish a temporary capacity market price cap and floor for the 2026/2027 and 2027/2028 Delivery Years. 191 FERC ¶ 61,066 (April 21, 2025). On April 28, 2026, FERC issued an order accepting PJM's proposal to establish a temporary capacity market price cap and floor for the 2028/2029 and 2029/2030 Delivery Years. 195 FERC ¶ 61,076 (April 28, 2026).

requirement. Consistent with the MMU's recommendations, that exemption was eliminated for all but demand resources. There is no reason to continue to exempt demand resources 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, and therefore that the energy market works, based on the inclusion of all demand and all supply, to ensure competitive entry, to ensure open access to the transmission system, and to prevent the exercise of market power via withholding of capacity supply.

For these reasons, existing resources are required to return CIRs to the market within one year after retirement. The MMU recommends that resources return CIRs to the market on the day of retirement.[61] Waiving the rules for retaining CIRs to favor one resource over other suppliers in the interconnection queue that are seeking CIRs would be unduly discriminatory and cause harm to the public interest in the efficient procurement of capacity resources.

Consistent with the must offer obligation, performance penalties should not be applied to solar and wind resources when they are not capable of performing based on ambient conditions. For example, solar resources should be subject to performance penalties if they fail to perform when the sun is shining but should not be subject to performance penalties in the middle of the night. That would be the result under the incentive approach recommended by the MMU. If PAI is retained, this would be a rational application of the PAI penalties that recognizes the physical capabilities of resources and is therefore not discriminatory.

Demand resources (DR) have always been treated more favorably than generation capacity resources. Demand resources do not have an RPM must offer requirement. Demand resources, unlike all other capacity resources, are not subject to market seller offer caps to protect against the exercise of market power in the capacity market. When demand resources are pivotal, as they were for the 2026/2027 BRA, they have structural market power and can and do exercise market power. That conclusion does not depend on whether withholding directly benefits those resources through a portfolio effect. The result of the failure to offer can be a significant increase in the market price of capacity above the competitive level when that supply is pivotal. 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 requirement. The MMU recommends that demand resources have defined and enforced market seller offer caps in the capacity market, like all other capacity resources.

PJM filed tariff changes that transfer risk caused by the volatile ELCC ratings from generation owners to the load. ELCC ratings may increase or decrease significantly between the time a generator clears in the RPM Base Residual Auction and the final ELCC rating just prior to the start of the delivery year. Under the new tariff rules, generators will be excused from paying the Capacity Resource Deficiency Charge for a deficiency caused by a decrease in the final ELCC rating. Under the prior rules, a Capacity Market Seller was required to cover its short position by acquiring additional capacity or pay a deficiency penalty equal to 20 percent of the base residual auction clearing price for each MW of shortage. The tariff change was filed by PJM on April 18, 2025, and approved by FERC on June 17, 2025.[62] [63] The MMU opposed the change because the new rule does not mitigate the risk as asserted by PJM but simply transfers the ELCC rating volatility risk to the load.[64] The change is inconsistent with basic market logic under which investors bear the risk associated with the ownership of generation.

61 See Answer and Motion for Leave to Answer of the Independent Market Monitor for PJM, Docket No. ER25-2162-000 (May 28, 2025); Answer and Motion for Leave to Answer of the Independent Market Monitor for PJM, Docket No. ER25-2190-000 (May 28, 2025); and Answer and Motion for Leave to Answer of the Independent Market Monitor for PJM, Docket No. ER25-2197-000 (May 28, 2025).

62 *Proposal to Mitigate Impacts From Updates to ELCC Accreditation between the Base Residual Auction and the Final ELCC Accreditation Values*, PJM Interconnection L.L.C., Docket ER25-2002 (April 18, 2025).

63 191 FERC ¶ 61,203 (June 17, 2025).

64 See *Comments of the Independent Market Monitor for PJM* (May 9, 2025), *Answer and Motion for Leave to Answer of the Independent Market Monitor for PJM* (June 9, 2025), *Answer and Motion for Leave to Answer of the Independent Market Monitor for PJM* (June 16, 2025), Docket ER25-2002-000).

Installed Capacity

On January 1, 2026, RPM installed capacity was 184,220.8 MW (Table 5-3).[65] Over the next six months, new generation, unit deactivations, facility reratings, plus import and export shifts resulted in RPM installed capacity of 183,873.8 MW on June 30, 2026, a decrease of 347.0 MW or 0.2 percent from the January 1 level.[66 67] The 347.0 MW decrease was the net result of new or reactivated generation (2,049.0 MW) and net capacity modifications (2,173.7 MW), and an increase in imports (7.1 MW), offset by an increase in exports (521.2), derates (426.4 MW), and deactivations or changes in capacity resource status (3,629.2 MW).

At the beginning of the new delivery year on June 1, 2026, RPM installed capacity was 184,662.4 MW, an increase of 2,714.5 MW or 1.5 percent from the May 31, 2026, level of 181,947.9 MW. This change occurred as a result of deactivations, derates, capacity modifications, and import/export contracts beginning and/or ending at the start of the new delivery year.

Table 5-3 Installed capacity (By fuel source): January 1, May 31, June 1, and June 30, 2026[68 69]

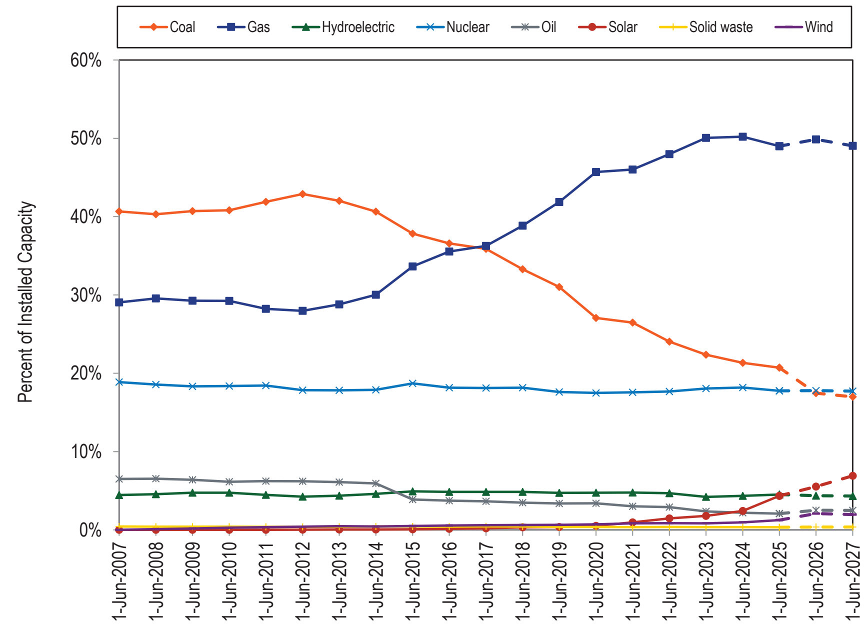
	01-Jan-26		31-May-26		01-Jun-26		30-Jun-26	
	MW	Percent	MW	Percent	MW	Percent	MW	Percent
Battery	24.0	0.0%	35.7	0.0%	186.4	0.1%	186.4	0.1%
Coal	37,544.6	20.4%	37,394.8	20.6%	36,715.9	19.9%	36,715.9	20.0%
Gas	88,888.4	48.3%	88,447.9	48.6%	89,008.4	48.2%	88,203.4	48.0%
Hybird	10.2	0.0%	10.2	0.0%	10.0	0.0%	10.0	0.0%
Hydroelectric	8,215.2	4.5%	8,166.3	4.5%	8,205.6	4.4%	8,205.6	4.5%
Nuclear	32,176.2	17.5%	32,163.4	17.7%	32,321.0	17.5%	32,321.0	17.6%
Oil	4,066.5	2.2%	4,245.7	2.3%	4,245.7	2.3%	4,245.7	2.3%
Solar	8,315.7	4.5%	8,630.8	4.7%	9,849.1	5.3%	9,853.8	5.4%
Solid waste	609.4	0.3%	587.4	0.3%	587.4	0.3%	587.4	0.3%
Wind	4,370.6	2.4%	2,265.7	1.2%	3,532.9	1.9%	3,544.6	1.9%
Total	184,220.8	100.0%	181,947.9	100.0%	184,662.4	100.0%	183,873.8	100.0%

65 Percent values shown in Table 5-3 are based on unrounded, underlying data and may differ from calculations based on the rounded values in the tables.
66 Unless otherwise specified, the capacity described in this section is the summer installed capacity rating of all PJM generation capacity resources, as entered into the Capacity Exchange system, regardless of whether the capacity cleared in the RPM auctions.
67 Wind resources accounted for 3,544.6 MW, and solar resources accounted for 9,853.8 MW of installed capacity in PJM on June 30, 2026. Prior to the 2023/2024 Delivery Year, PJM administratively reduced the capabilities of all wind generators to 14.7 percent for wind farms in mountainous terrain and 17.6 percent for wind farms in open terrain, and solar generators to 42.0 percent for ground mounted fixed panel, 60.0 percent for ground mounted tracking panel, and 38.0 percent for other than ground mounted solar arrays, of nameplate capacity when determining the installed capacity because wind and solar resources cannot be assumed to be available on peak and cannot respond to dispatch requests. As data became available, unforced capability of wind and solar resources was to be calculated using actual data. There are additional wind and solar resources not reflected in total capacity because they are energy only resources and do not participate in the PJM Capacity Market. See "PJM Manual 21B: PJM Rules and Procedures for Determination of Generating Capability," § 4 Calculations of ELCC Class Rating, ELCC Resource Performance Adjustment, Accredited UCAP, and Accredited UCAP Factor, Rev. 05 (Jan. 22, 2026). The derating approach has been replaced with ELCC starting in the 2023/2024 Delivery Year.

68 The data for hybrid solar/battery resources are included in the solar data for confidentiality reasons.
69 Installed capacity is based on imports, exports, and PJM's capacity modification ("capmod") database that tracks new and reactivated generation, unit uprates and derates, and deactivations/changes to capacity resource status. Demand Resources are not tracked in this way and are not included here. For analysis of Demand Resources in the capacity market, see the Demand Resources discussion later in this section.

Figure 5-1 shows the share of installed capacity by fuel source for the first day of each delivery year, from June 1, 2007, to June 1, 2026, as well as the expected installed capacity for the 2026/2027 and 2027/2028 Delivery Years. On June 1, 2007, coal comprised 40.7 percent of the installed capacity, reached a maximum of 42.9 percent in 2012, decreased to 20.71 percent on June 1, 2025, and is projected to decrease to 17.0 percent on June 1, 2027. The share of gas increased from 29.1 percent on June 1, 2007, reached a maximum of 50.2 percent in 2024, decreased to 49.0 percent on June 1, 2025, and is projected to increase to 49.1 on June 1, 2027.

Figure 5-1 Percent of installed capacity (By fuel source): June 1, 2007 through June 1, 2027[70] [71]



70 Prior to the 2025/2026 Delivery Year, ICAP for thermal resources were converted to UCAP using EFORd values. Beginning with the 2025/2026 Delivery Year, ICAP for thermal resources are converted to UCAP using the marginal ELCC values.

71 Prior to June 1, 2025, PJM set ICAP equal to UCAP for solar and wind units. Starting June 1, 2025, PJM began setting ICAP equal to CIRs for solar and wind units.

Table 5-4 shows the RPM installed capacity on January 1, 2026, through June 30, 2026, for the top five generation capacity resource owners, excluding FRR committed MW.

Table 5-4 Installed capacity by parent company: January 1, May 31, June 1, and June 30, 2026

	01-Jan-26			31-May-26			01-Jun-26			30-Jun-26		
Parent Company	ICAP (MW)	Percent of Total ICAP	Rank	ICAP (MW)	Percent of Total ICAP	Rank	ICAP (MW)	Percent of Total ICAP	Rank	ICAP (MW)	Percent of Total ICAP	Rank
Dominion Resources, Inc.	21,947.0	12.8%	1	21,959.4	13.0%	2	19,280.5	11.2%	2	19,280.5	11.3%	2
Constellation Energy Generation, LLC	20,279.1	11.9%	2	24,265.6	14.4%	1	24,381.3	14.2%	1	23,621.3	13.8%	1
Vistra Energy Corp.	13,929.1	8.2%	3	13,928.4	8.3%	3	14,331.4	8.3%	3	14,333.2	8.4%	4
Talen Energy Corporation	12,673.1	7.4%	4	12,665.7	7.5%	4	12,716.5	7.4%	4	16,882.3	9.9%	3
LS Power Equity Partners, L.P.	10,667.9	6.2%	5	4,409.6	2.6%	8	4,467.3	2.6%	8	4,467.3	2.6%	7
ArcLight Capital Partners, LLC	7,167.5	4.2%	7	8,033.1	4.8%	6	8,033.1	4.7%	6	9,070.1	5.3%	5
NRG Energy, Inc.	1,949.0	1.1%	21	8,335.6	4.9%	5	8,895.7	5.2%	5	8,895.7	5.2%	6

The sources of funding for generation owners can be categorized as one of two types: market and nonmarket. Market funding is from private investors bearing the investment risk without guarantees or support from any public sources, subsidies or guaranteed payment by ratepayers. Providers of market funding rely entirely on market revenues. Nonmarket funding is from guaranteed revenues, including cost of service rates for a regulated utility and subsidies. Table 5-5 shows the RPM installed capacity on January 1, 2026, to June 30, 2026, by funding type.

Table 5-5 Installed capacity by funding type: January 1, May 31, June 1, and June 30, 2026

	01-Jan-26		31-May-26		01-Jun-26		30-Jun-26	
Funding Type	ICAP (MW)	Percent of Total ICAP	ICAP (MW)	Percent of Total ICAP	ICAP (MW)	Percent of Total ICAP	ICAP (MW)	Percent of Total ICAP
Market	133,468.8	72.5%	130,458.4	71.7%	135,255.6	73.2%	134,475.0	73.1%
Nonmarket	50,730.0	27.5%	51,489.5	28.3%	49,406.8	26.8%	49,398.8	26.9%
Total	184,198.8	100.0%	181,947.9	100.0%	184,662.4	100.0%	183,873.8	100.0%

Fuel Diversity

Figure 5-2 shows the fuel diversity index (FDI_c) for RPM installed capacity.[72] The FDI_c is defined as $1-\sum_{i=1}^{N} s_i^2$, where s_i is the percent share of fuel type i. The minimum possible value for the FDI_c is zero, corresponding to all capacity from a single fuel type. The maximum possible value for the FDI_c is achieved when each fuel type has an equal share of capacity. For a capacity mix of eight fuel types, the maximum achievable index is 0.875. The fuel type categories used in the calculation of the FDI_c are in Table 5-3. FDI_c calculations prior to June 1, 2023 included eight fuel types. Batteries were added to the resource mix on June 1, 2023, and hybrid solar resources were added on January 1, 2024. The maximum achievable index with nine fuel types is 0.889. The maximum achievable index with ten fuel types is 0.900. The FDI_c is stable and does not exhibit any long-term trends. The only significant deviation occurred with the expansion of the PJM footprint. On April 1, 2002, PJM expanded with the addition of Allegheny Power System, which added about 12,000 MW of generation.[73] The

72 The MMU developed the FDI to provide an objective metric of fuel diversity. The FDI metric is similar to the HHI used to measure market concentration. The FDI is calculated separately for energy output and for installed capacity. The FDI_c includes derated capacity values for intermittent capacity subject to derating.

73 On April 1, 2002, the PJM Region expanded with the addition of Allegheny Power System under a set of agreements known as "PJM-West." See page 4 in the *2002 Annual State of the Market Report for PJM* for additional details.

reduction in the FDI_c resulted from an increase in coal capacity resources. A similar but more significant reduction occurred in 2004 with the expansion into the COMED, AEP, and DAY Control Zones.[74] The FDI_c on June 30, 2026, increased 1.8 percent in comparison with the FDI_c on June 30, 2025. Figure 5-2 also includes the expected FDI_c through June 30, 2027. The expected FDI_c is indicated in Figure 5-2 by the dotted orange line.

The FDI_c is used to measure the impact on fuel diversity of potential retirements in 2026 through 2030. A total of 10,963 MW of capacity are at risk of retirement, consisting of 8,330 MW currently planning to retire and 2,633 MW expected to be uneconomic.[75] The dotted green line in Figure 5-2 shows the FDI_c assuming that the capacity from the expected 2026 retirements were replaced by gas fired capacity.[76] The counterfactual FDI_c on June 30, 2027, under these assumptions is 0.9 percent lower than the expected FDI_c on June 30, 2027. The dotted blue line in Figure 5-2 shows the FDI_c assuming that the capacity from the expected retirements through 2030 were replaced by wind and solar capacity.[77] The counterfactual FDI_c on March 31, 2027, in this scenario, is 1.9 percent higher.

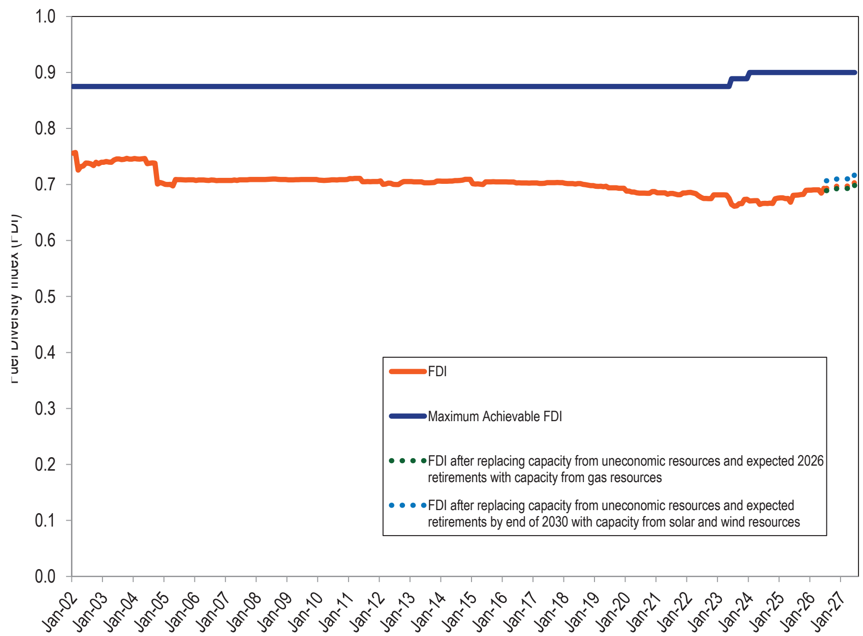
74 See the *2019 Annual State of the Market Report for PJM*, Appendix A, "PJM Geography" for an explanation of the expansion of the PJM footprint. The integration of the COMED Control Area occurred in May 2004 and the integration of the AEP and DAY Control Zones occurred in October 2004.

75 See the *2025 Annual State of the Market Report for PJM*, Volume 2, Section 7: Net Revenue.

76 It is assumed that all of the replacement capacity is from gas units. In previous reports, solar and wind capacity have also been used for replacement capacity with the amounts based on the expected increase in the PJM RPS obligation for the upcoming year. But the PJM RPS obligation will decrease in 2027 in comparison to 2026 due to the termination of the Ohio RPS in 2027.

77 The split between solar (79.4 percent) and wind (20.6 percent) is based on queue data. In previous reports, the replacement capacity included gas units in addition to solar and wind with the amount of solar and gas replacement capacity being based on the expected increase in the PJM RPS obligation in 2030 in comparison to current year. But the RPS increase for 2030 exceeds the expected retirements and only solar and wind are used for replacement capacity in this scenario.

Figure 5-2 Fuel Diversity Index for installed capacity: January 1, 2002 through June 30, 2027



RPM Capacity Market

The RPM Capacity Market, implemented June 1, 2007, is a three year forward looking, annual, locational market, with a must offer requirement for existing generation capacity resources, except for demand response resources, and except for resources owned by entities that elect the fixed resource requirement (FRR) option, and mandatory participation by load, with performance incentives, that includes clear market power mitigation rules and that permits the direct participation of demand side resources.

The standard schedule is that annual base residual auctions are held in May for delivery years that are three years in the future. Effective January 31, 2010, First, Second, and Third Incremental Auctions are conducted 20, 10, and three months prior to the delivery year.[78] In the first six months of 2026, the 2026/2027 RPM Third Incremental Auction was conducted. The auction schedule has diverged significantly from the standard schedule in recent years.

Market Structure

Supply

Table 5-6 shows generation capacity changes since the implementation of the Reliability Pricing Model through the 2025/2026 Delivery Year. The 18,288.5 MW increase was the result of new generation capacity resources (48,485.1 MW), reactivated generation capacity resources (1,691.2 MW), uprates (12,490.0 MW), integration of external zones (21,967.5 MW), a net decrease in capacity exports (1,516.0 MW), offset by a net decrease in capacity imports (1,500.2 MW), deactivations (59,698.1 MW) and derates (6,663.0 MW).

Table 5-7 shows the calculated RPM reserve margin and reserve in excess of, or short of, the target installed reserve margin (IRM) for June 1, 2023, through June 1, 2027, and accounts for cleared capacity, replacement capacity, and deficiency MW for all auctions held and the most recent peak load forecast for each delivery year. The completion of the replacement process using cleared buy bids from RPM incremental auctions includes two transactions. The first step is for the entity to submit and clear a buy bid in an RPM incremental auction. The next step is for the entity to complete a separate replacement transaction using the cleared buy bid capacity. Prior to the 2025/2026 Delivery Year, replacement capacity transactions can be completed only after the EFORds for the delivery year are finalized, on November 30 in the year prior to the delivery year, but before the start of the delivery day. Effective with the 2025/2026 Delivery Year, replacement capacity transactions can be completed only after the accredited UCAP factors for the delivery year are finalized, but before the start of the delivery day. Early replacement transactions can be approved for defined physical replacements.

78 See Letter Order, Docket No. ER10-366-000 (January 22, 2010).

Changes in Generation Capacity[79]

As shown in Table 5-6, for the period from the introduction of the RPM capacity market design in the 2007/2008 Delivery Year through the 2025/2026 Delivery Year, internal installed capacity decreased by 3,694.8 MW after accounting for new capacity resources, reactivations, and uprates (62,666.3 MW) and capacity deactivations and derates (66,361.1 MW).[80]

For the 2026/2027 Delivery Year, new generation capacity is defined as capacity that cleared an RPM auction for the first time for the specified delivery year. Based on expected completion rates of cleared new generation capacity (2,781.0 MW) and pending deactivations (760.9 MW), PJM capacity is expected to increase by 2,020.1 MW through the 2026/2027 Delivery Year.

79 For more details on future changes in generation capacity, see "2020 PJM Generation Capacity and Funding Sources 2007/2008 through 2021/2022 Delivery Years," <http://www.monitoringanalytics.com/reports/Reports/2020/IMM_2020_PJM_Generation_Capacity_and_Funding_Sources_20072008_through_20212022_DY_20200915.pdf> (September 15, 2020).

80 These results are for internal capacity only and do not include, for example, imports or exports or the impact of integrations of new areas.

Table 5-6 Generation capacity changes: 2007/2008 through 2025/2026[81]

	ICAP (MW)								
	New	Reactivations	Uprates	Integration	Net Change in Capacity Imports	Net Change in Capacity Exports	Deactivations	Derates	Net Change
2007/2008	45.0	0.0	691.5	0.0	70.0	15.3	380.0	417.0	(5.8)
2008/2009	815.4	238.3	987.0	0.0	473.0	(9.9)	609.5	421.0	1,493.1
2009/2010	406.5	0.0	789.0	0.0	229.0	(1,402.2)	108.4	464.3	2,254.0
2010/2011	153.4	13.0	339.6	0.0	137.0	367.7	840.6	223.5	(788.8)
2011/2012	3,096.4	354.5	507.9	16,889.5	(1,183.3)	(1,690.3)	2,542.0	176.2	18,637.1
2012/2013	1,784.6	34.0	528.1	47.0	342.4	84.0	5,536.0	317.8	(3,201.7)
2013/2014	198.4	58.0	372.8	2,746.0	934.3	28.9	2,786.9	288.3	1,205.4
2014/2015	2,276.8	20.7	530.2	0.0	2,335.7	177.3	4,915.6	360.3	(289.8)
2015/2016	4,291.8	90.0	449.0	0.0	511.4	(117.8)	8,338.2	215.8	(3,094.0)
2016/2017	3,679.3	532.0	419.2	0.0	575.6	722.9	659.4	206.7	3,617.1
2017/2018	4,127.3	5.0	562.1	0.0	(1,025.1)	(695.1)	2,657.4	148.5	1,558.5
2018/2019	8,127.5	4.0	330.9	2,120.0	(3,217.0)	212.7	6,730.0	89.2	333.5
2019/2020	4,612.0	13.3	494.9	165.0	(1,196.6)	401.3	3,296.0	116.8	274.5
2020/2021	403.1	11.6	575.4	0.0	(37.9)	(111.6)	3,572.0	206.4	(2,714.6)
2021/2022	3,309.3	6.0	412.2	0.0	38.5	1,066.1	2,197.6	125.5	376.8
2022/2023	4,743.2	0.0	417.0	0.0	(469.3)	(868.0)	7,460.5	302.0	(2,203.6)
2023/2024	2,696.8	0.0	420.5	0.0	(47.9)	1,067.8	5,149.2	1,441.1	(4,588.7)
2024/2025	1,724.3	0.0	919.5	0.0	17.1	212.0	1,068.0	737.7	643.2
2025/2026	1,994.0	310.8	2,743.2	0.0	12.9	(977.1)	850.8	404.9	4,782.3
Total	48,485.1	1,691.2	12,490.0	21,967.5	(1,500.2)	(1,516.0)	59,698.1	6,663.0	18,288.5

81 The capacity changes in this report are calculated based on June 1 through May 31.

As shown in Table 5-7, total reserves on June 1, 2026, were 20,843.9 MW, which is 279.2 MW (UCAP) short of the required reserve level of 21,123.1 MW (UCAP). In the 2027/2028 BRA, total reserves were 16,977.4 MW, which is 6,516.6 MW (UCAP) short of the required reserve level of 23,494.0 MW (UCAP). The level of committed demand resources was 7,298.6 in the 2027/2028 BRA, meaning the PJM markets will rely on demand resources as part of the required reserve margin, rather than as excess above the required reserve margin.

The fact that more than one quarter (31.1 percent of total reserves in the 2027/2028 BRA) of the PJM reserves depend on demand resources that are not subject to the RPM must offer requirement, a core part of the capacity market design, means that reliability is significantly less certain than the stated reserve margins indicate.

Table 5-7 RPM reserve margin: June 1, 2023, to June 1, 2027[82] [83] [84]

	01-Jun-23	01-Jun-24	01-Jun-25	01-Jun-26	01-Jun-27
Forecast peak load ICAP (MW)	149,382.2	151,631.1	154,534.1	156,760.6	164,579.0
FRR peak load ICAP (MW)	29,554.6	30,431.0	11,720.3	11,668.7	12,201.9
PRD ICAP (MW)	235.0	305.0	224.0	115.0	115.0
Installed reserve margin (IRM)	14.9%	17.7%	17.8%	18.6%	20.0%
Pool wide average EFORd	4.87%	5.10%			
Pool wide accredited UCAP factor			79.63%	78.34%	77.17%
Forecast pool requirement (FPR)	1.093	1.117	0.938	0.929	0.926
RPM committed less deficiency UCAP (MW) (generation and DR)	136,401.8	138,318.6	133,524.1	134,418.8	134,478.1
RPM committed less deficiency ICAP (MW) (generation and DR)	143,384.6	145,751.9	167,680.6	171,583.9	174,262.1
RPM peak load ICAP (MW)	119,592.6	120,895.1	142,589.7	144,976.9	152,262.1
Reserve margin ICAP (MW)	23,792.0	24,856.9	25,090.9	26,607.0	22,000.0
Reserve margin (%)	19.9%	20.6%	17.6%	18.4%	14.4%
Reserve margin in excess of IRM ICAP (MW)	5,972.7	3,458.4	(290.1)	(358.7)	(8,452.4)
Reserve margin in excess of IRM (%)	5.0%	2.9%	(0.2%)	(0.2%)	(5.6%)
RPM peak load UCAP (MW)	113,768.4	114,729.4	113,544.2	113,574.9	117,500.7
RPM reliability requirement UCAP (MW)	130,714.7	135,039.8	133,749.2	134,698.0	140,994.7
Reserve margin UCAP (MW)	22,633.4	23,589.2	19,979.9	20,843.9	16,977.4
Reserve cleared in excess of IRM UCAP (MW)	5,687.1	3,278.8	(225.1)	(279.2)	(6,516.6)
Projected replacement capacity UCAP (MW)	0.0	0.0	0.0	0.0	0.0
Projected reserve margin	19.9%	20.6%	17.6%	18.4%	14.4%
Reserve margin UCAP (MW)	22,633.4	23,589.2	19,979.9	20,843.9	16,977.4
Reserve cleared in excess of IRM UCAP (MW)	5,687.1	3,278.8	(225.1)	(279.2)	(6,516.6)
Projected replacement capacity UCAP (MW)	0.0	0.0	0.0	0.0	0.0
Projected reserve margin	19.9%	20.6%	17.6%	18.4%	14.4%

82 The calculated reserve margins in this table do not include EE on the supply side or the EE addback on the demand side. The EE excluded from the supply side for this calculation includes annual EE and summer EE. This is how PJM calculates the reserve margin. Effective with the 2026/2027 Deliver Year, EE resources no longer participate in the PJM capacity market. See 189 FERC ¶ 61,095 (November 5, 2024).

83 These reserve margin calculations do not consider Fixed Resource Requirement (FRR) load.

84 The RPM committed less deficiency MW values (rows H and J) and resultant reserve margin calculations for June 1, 2025, were revised from the ***2026 Quarterly State of the Market Report for PJM: January through March***.

Sources of Funding[85]

Developers use a variety of sources to fund their projects, including Power Purchase Agreements (PPA), cost of service rates, and private funds (from internal sources or private lenders and investors). PPAs can be used for a variety of purposes and the use of a PPA does not imply a specific source of funding.

New and reactivated generation capacity from the 2007/2008 Delivery Year through the 2025/2026 Delivery Year (Table 5-8) totaled 50,176.3 MW (80.1 percent of all additions), with 37,899.1 MW from market funding and 12,277.2 MW from nonmarket funding. Uprates to existing generation capacity from the 2007/2008 Delivery Year through the 2025/2026 Delivery Year totaled 12,490.0 MW (19.9 percent of all additions), with 8,977.6 MW from market funding and 3,512.4 MW from nonmarket funding. In summary, of the 62,666.3 MW of additional capacity from new, reactivated, and uprated generation that cleared in RPM auctions for the 2007/2008 through 2025/2026 Delivery Years, 46,876.7 MW (74.8 percent) were based on market funding.

Table 5-8 Sources of funding: 2007/2008 through 2025/2026 Delivery Years

	ICAP MW					
2007/2008 DY through 2025/2026 DY	New and Reactivated	Percent of Grand Total	Uprate	Percent of Grand Total	Total	Percent of Grand Total
Market	37,899.1	60.5%	8,977.6	14.3%	46,876.7	74.8%
Nonmarket	12,277.2	19.6%	3,512.4	5.6%	15,789.6	25.2%
Total	50,176.3	80.1%	12,490.0	19.9%	62,666.3	100.0%

Of the 3,294.6 MW of the additional generation capacity (new resources, reactivated resources, and uprates) that cleared in RPM auctions for the 2026/2027 through the 2027/2028 Delivery Years (Table 5-9), 658.4 MW are not yet in service, with 603.0 MW of those having market funding. Applying the historical completion rates, 65.2 percent of all the projects in development are expected to go into service, 393.3 MW of the 603.0 MW in development market funded projects, and 36.1 MW of the 55.4 MW in development non market funded projects.[86]

Of the 2,636.2 MW of the additional generation capacity that cleared in RPM auctions for the 2026/2027 through the 2027/2028 Delivery Years and are already in service, 2,122.1 MW (80.5 percent) are based on market funding and 514.1 MW (19.5 percent) are based on nonmarket funding.

In summary, 2,725.1 MW (82.7 percent) of the additional generation capacity (603.0 MW not yet in service and 2,122.1 MW in service) that cleared in RPM auctions for the 2026/2027 through the 2027/2028 Delivery Years are based on market funding. Capacity additions based on nonmarket funding are 569.5 MW (17.3 percent) of generation that cleared the RPM auctions for the 2026/2027 and 2027/2028 Delivery Years.

Table 5-9 Sources of funding: 2026/2027 through 2027/2028 Delivery Years

	ICAP MW							
2026/2027 DY through 2027/2028 DY	Not Yet in Service	Percent	Percent of Grand Total	In Service	Percent	Percent of Grand Total	Total	Percent of Grand Total
Market	603.0	91.6%	18.3%	2,122.1	80.5%	64.4%	2,725.1	82.7%
Nonmarket	55.4	8.4%	1.7%	514.1	19.5%	15.6%	569.5	17.3%
Total	658.4	100.0%	20.0%	2,636.2	100.0%	80.0%	3,294.6	100.0%

Demand

The MMU analyzed market sectors in the PJM Capacity Market to determine how they met their load obligations. The PJM Capacity Market was divided into the following sectors:

- **PJM EDC.** EDCs with a franchise service territory within the PJM footprint. This sector includes traditional utilities, electric cooperatives, municipalities and power agencies.
- **PJM EDC Generating Affiliate.** Affiliate companies of PJM EDCs that own generating resources.

85 For more details on sources of funding for generation capacity, see "2020 PJM Generation Capacity and Funding Sources 2007/2008 through 2021/2022 Delivery Years," <http://www.monitoringanalytics.com/reports/Reports/2020/IMM_2020_PJM_Generation_Capacity_and_Funding_Sources_20072008_through_20212022_DY_20200915.pdf> (September 15, 2020).

86 See the *2025 Annual State of the Market Report for PJM*, Volume 2, Section 12: Generation and Transmission Planning.

- **PJM EDC Marketing Affiliate.** Affiliate companies of PJM EDCs that sell power and have load obligations in PJM, but do not own generating resources.
- **Non-PJM EDC.** EDCs with franchise service territories outside the PJM footprint.
- **Non-PJM EDC Generating Affiliate.** Affiliate companies of non-PJM EDCs that own generating resources.
- **Non-PJM EDC Marketing Affiliate.** Affiliate companies of non-PJM EDCs that sell power and have load obligations in PJM, but do not own generating resources.
- **Non-EDC Generating Affiliate.** Affiliate companies of non-EDCs that own generating resources.
- **Non-EDC Marketing Affiliate.** Affiliate companies of non-EDCs that sell power and have load obligations in PJM, but do not own generating resources.

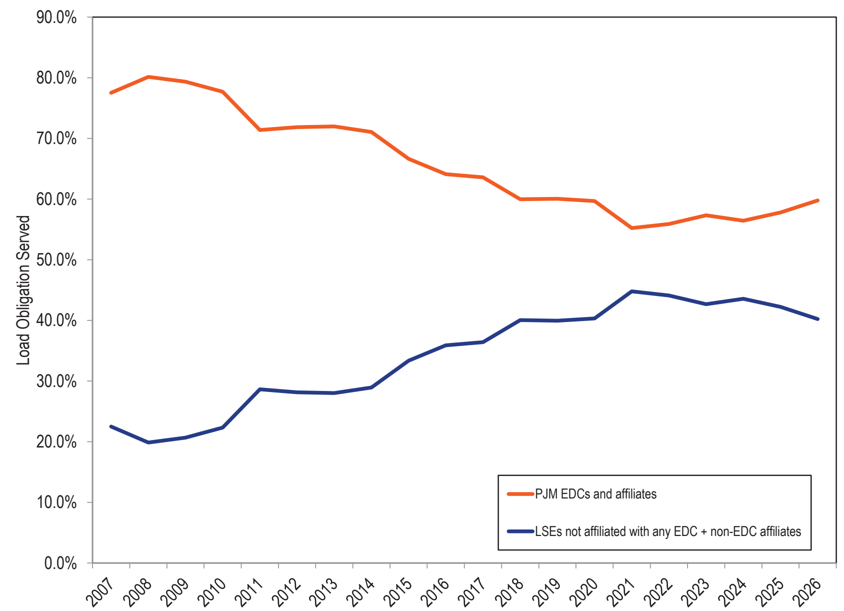
On June 1, 2026, PJM EDCs and their affiliates maintained a majority market share of load obligations under RPM, together totaling 59.8 percent (Table 5-10), up from 57.8 percent on June 1, 2025. The combined market share of LSEs not affiliated with any EDC and of non-PJM EDC affiliates was 40.2 percent, down from 42.2 percent on June 1, 2025. The share of capacity market load obligation fulfilled by PJM EDCs and their affiliates, and LSEs not affiliated with any EDC and non-PJM EDC affiliates from June 1, 2007, to June 1, 2026, is shown in Figure 5-3. PJM EDCs' and their affiliates' share of load obligation has decreased from 77.5 percent on June 1, 2007, to 59.8 percent on June 1, 2026. The share of load obligation held by LSEs not affiliated with any EDC and non-PJM EDC affiliates increased from 22.5 percent on June 1, 2007, to 40.2 percent on June 1, 2026.[87]

87 Prior to the 2012/2013 Delivery Year, obligation was defined as cleared and make whole MW in the Base Residual Auction and the Second Incremental Auction plus ILR forecast obligations. Effective with the 2012/2013 Delivery Year, obligation is defined as the sum of the unforced capacity obligations satisfied through all RPM auctions for the delivery year.

Table 5-10 Capacity market load obligation served: June 1, 2025 and June 1, 2026

	01-Jun-25		01-Jun-26		Change	
	Obligation (MW)	Percent of total obligation	Obligation (MW)	Percent of total obligation	Obligation (MW)	Percent of total obligation
PJM EDCs and Affiliates	86,471.6	57.8%	103,953.4	59.8%	17,481.8	2.0%
LSEs not affiliated with any EDC + non EDC Affiliates	63,166.5	42.2%	69,952.0	40.2%	6,785.5	(2.0%)
Total	149,638.1	100.0%	173,905.4	100.0%	24,267.3	0.0%

Figure 5-3 Capacity market load obligation served: June 1, 2007 through June 1, 2026



Capacity Transfer Rights (CTRs)

Capacity Transfer Rights (CTRs) are used to return capacity market congestion revenues to load. Load pays congestion. Capacity market congestion revenues are the difference between the total dollars paid by load for capacity and the total dollars received by capacity market sellers. The MW of CTRs available for allocation to LSEs in an LDA are equal to the Unforced Capacity imported into the LDA, less any MW of CETL paid for directly by market participants in the form of Qualifying Transmission Upgrades (QTUs) cleared in an RPM Auction, and Incremental Capacity Transfer Rights (ICTRs). There are two types of ICTRs, those allocated to a New Service Customer obligated to fund a transmission facility or upgrade and those associated with Incremental Rights-Eligible Required Transmission Enhancements.

The total required capacity in an LDA is provided by a mix of internal capacity and imported capacity. The imported capacity equals the total required capacity minus the internal capacity. The value of CTRs is based on the fact that load in an LDA pays the clearing price for all cleared capacity but that generators who provide imported capacity are paid a lower price based on the LDA in which they are located. The value of CTRs equals the imported MW times the price difference. This excess is paid by load and is returned to load using CTRs. CTRs are intended to permit customers to receive the benefit of importing cheaper capacity using transmission capability.

But PJM does not use the actual MW cleared in the BRA and three incremental auctions, the actual internal MW and the actual imported MW, when defining what customers pay and when defining the value of CTRs. Under the current rules, PJM defines the total MW needed for reliability in an LDA when clearing the BRA based on forecast demand at the time of the BRA. But PJM actually charges customers for the total MW needed for reliability based on forecast demand three years later, prior to the actual delivery year, and applies a zonal allocation. PJM also defines the internal capacity as the internal capacity after the final incremental auction conducted three years after the BRA, when auctions follow the traditional schedule. The difference between the updated MW needed for reliability and the updated internal capacity is the updated imported MW, adjusted for the final zonal allocation. In cases where the updated imported MW are smaller than the imported MW from the actual auction clearing, the total value of CTRs is lower that it would be if the actual auction clearing MW were used.

The actual load charges are allocated to each zone based on the ratio of the zonal forecast peak load to the RTO forecast peak load used for the third incremental auction conducted three months prior to the delivery year.

The CTR issue implies a broader issue with capacity market clearing and settlements. The capacity market is cleared based on a three year ahead forecast of load and offers of capacity. Payments to capacity resources in the delivery year are based on the capacity market clearing prices and quantities. But payments by customers in the delivery year are not based on market clearing prices and quantities. Payments by customers in each zone are based on the ratio of zonal forecast peak load to the RTO forecast peak load used for the Third Incremental Auction, run three months prior to the delivery year when auctions follow the traditional schedule.[88] The allocation sometimes creates significant differences between the capacity cleared to meet the reliability requirement and the capacity obligation allocated to the customers in a zone. For example, ComEd Zone, which is identical to ComEd LDA, cleared 27,932.1 MW including 5,574.0 MW of imports in the 2021/2022 RPM BRA. The ComEd Zone's capacity obligation, immediately after the clearing of the Base Residual Auction was 24,983.0 MW. The final ComEd Zone's capacity obligation for the 2021/2022 Delivery Year after the Third Incremental Auction was 22,721.2 MW.

As with CTRs, the underlying reasons for not using the market clearing results are not clear. Although not stated explicitly, the goal appears to be to reflect the fact that actual loads change between the auction and the delivery year. But the simple reallocation of capacity obligations based on changes in the load forecast does not reflect the BRA market results. The MMU recommends that the market clearing results be used in settlements rather than the reallocation process currently used or that the process of modifying the obligations to pay for capacity be reviewed.

For LDAs in which the RPM auctions for a delivery year resulted in a positive average weighted Locational Price Adder, an LSE with CTRs corresponding to the LDA is entitled to a payment or charge equal to the Locational Price Adder

88 See "PJM Manual 18: PJM Capacity Market," § 7.2.3 Final Zonal Unforced Capacity Obligations, Rev. 62 (Dec. 17, 2025).

multiplied by the MW of the LSEs' CTRs. The definition of the MW does not reflect auction clearing MW.

In the 2025/2026 RPM Third Incremental Auction, BGE had 5,024.2 MW of CTRs with a total value of $360.6 million and DOM had 1,752.6 MW of CTRs with a total value of $112.8 million. BGE had 65.7 MW of customer funded ICTRs with a total value of $4.7 million. BGE had 306.0 MW of ICTRs due to Incremental Rights Eligible Required Transmission Enhancements with a value of $22.0 million.

The 2026/2027 RPM Base Residual Auction cleared at $329.17 per MW-day with no price separation and therefore the value of CTRs is $0.

The 2027/2028 RPM Base Residual Auction cleared at $333.44 per MW-day with no price separation and therefore the value of CTRs is $0.

Demand Curve

A central feature of PJM's Reliability Pricing Model (RPM) design is that the demand curve, or Variable Resource Requirement (VRR) curve, has a downward sloping segment. In the RPM market design, the supply of three year forward capacity is cleared against this VRR curve. A VRR curve is defined for each Locational Deliverability Area (LDA). This shape replaced the vertical demand curve at the reliability requirement. The downward sloping segment begins at the MW level that is approximately 1.0 percent less than the reliability requirement.[89] Figure 5-4 shows the shape of the VRR curve for the 2026/2027 RPM Base Residual Auction.

The initial VRR curve, introduced in 2007, had a maximum price equal to 1.5 times the Net Cost of New Entry (Net CONE), determined annually based on fixed cost of new generating capacity, which is the Gross Cost of New Entry (Gross CONE), net of the three year average historical energy and ancillary service revenues. That VRR curve was structured to yield auction clearing prices equal to 1.5 times Net CONE when the amount of capacity cleared was less than 99 percent of the target reserve margin and below 1.5 times Net CONE when the amount of capacity cleared was greater than 99 percent of the target reserve margin.

Effective for the 2018/2019 through 2021/2022 Delivery Years, a revised VRR curve was implemented after PJM conducted a triennial review.[90] [91] PJM defines the reliability requirement as the capacity needed to satisfy the one event in ten years loss of load expectation (LOLE) for the RTO and capacity needed to satisfy the one event in 25 years loss of load expectation for the each LDA. PJM increased the maximum price on the VRR curve to be the greater of Gross CONE or 1.5 times Net CONE for all unforced capacity MW between 0 and 99.8 percent of the reliability requirement. The first downward sloping segment was from 99.8 percent and 102.5 percent of the reliability requirement. The second downward sloping segment was from 102.5 percent and 107.6 percent of the reliability requirement.

Effective for the 2022/2023 through 2025/2026 Delivery Years, another revised VRR curve was implemented after PJM conducted a quadrennial review.[92] The maximum price on the VRR curve was the greater of Gross CONE or 1.5 times Net CONE for all unforced capacity MW between 0 and 98.9 percent of the reliability requirement. The first downward sloping segment was from 98.9 percent and 101.6 percent of the reliability requirement. The second downward sloping segment was from 101.6 percent and 106.8 percent of the reliability requirement (Figure 5-4).

Effective for the 2026/2027 through 2029/2030 Delivery Years, another revised VRR curve was implemented after PJM conducted a quadrennial review.[93] PJM increased the maximum price on the VRR curve to the greater of Gross CONE or 1.75 times Net CONE for all unforced capacity MW between 0 and 99.0 percent of the reliability requirement. The first downward sloping segment is from 99.0 percent and 101.5 percent of the reliability requirement. The second downward sloping segment is from 101.5 percent and 104.5 percent of the reliability requirement.

89 The formula for the MW level where the VRR curve begins the downward slope is given by *(Reliability Requirement) x [1 – 1.2% / (Installed Reserve Margin)]*.

90 "Third Triennial Review of PJM's Variable Resource Requirement Curve," The Brattle Group, (May 15, 2014), <https://www.brattle.com/wp-content/uploads/2017/10/7510_third_triennial_review_of_pjms_variable_resource_requirement_curve-4.pdf>.

91 153 FERC ¶ 61,035 (October 15, 2015).

92 167 FERC ¶ 61,029 (April 15, 2019).

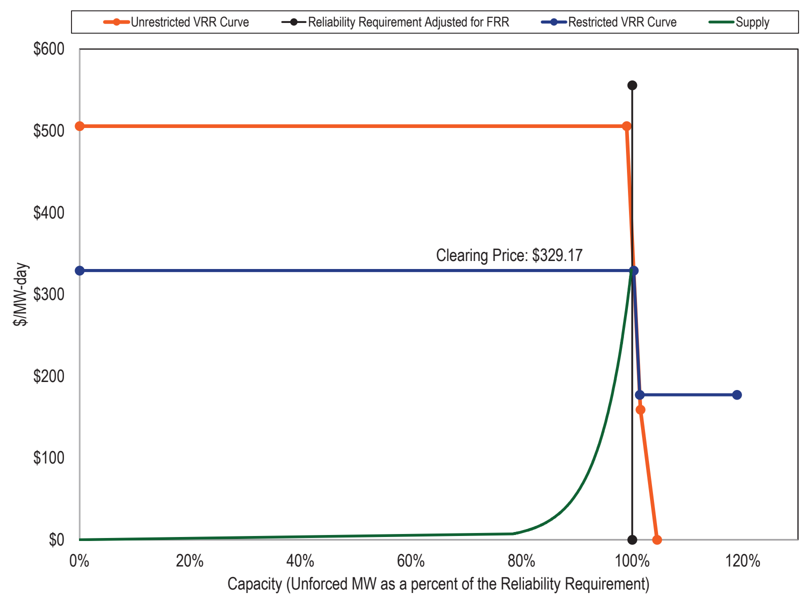
93 182 FERC ¶ 61,073 (Feb. 14, 2023).

The VRR curve was then changed significantly based on PJM's filing to establish the maximum price point on the VRR curve equal to "approximately" $325/MW-day in UCAP with a new MW point that is inconsistent with the tariff definition, a new minimum price point on the VRR curve of "approximately" $175/MW-day in UCAP for an unlimited number of MW that is inconsistent with the tariff, and a VRR curve shape not consistent with the tariff definition, for all Reliability Pricing Model ("RPM") Auctions, including Base Residual Auctions and Incremental Auctions, for the 2026/2027 and 2027/2028 Delivery Years.[94] The price cap and price floor was extended to apply to RPM auctions for the 2028/2029 and 2029/2030 Delivery Years.[95] The VRR curve has always had a maximum price. The VRR curve has always had a minimum price equal to zero. The proposal would set the maximum price level at somewhat higher than 1.5 times Net CONE. The MMU position is that the maximum price should be equal to the lesser of 1.5 times Net CONE or Gross CONE.[96] The MMU opposed the imposition of a completely unsupported floor price that is inconsistent with the longstanding VRR curve design.

The initial VRR curve, introduced in 2007, had a maximum price equal to 1.5 times the Net Cost of New Entry (Net CONE). The use of Net CONE was based on the logic of the capacity market, to ensure that between the energy and capacity markets the cost of entry was covered. Net CONE was the missing money from the energy and ancillary services markets that needed to be recoverable in the capacity market. The inclusion of the net energy and ancillary services markets revenue in the calculation of Net CONE was the equilibrating factor between the capacity market and energy market. The use of Gross CONE is inconsistent with that basic capacity market logic as is the use of 1.75 times Net CONE which is frequently greater than Gross CONE. Gross CONE was introduced as the maximum price based on PJM's unsupported assertions that Net CONE would somehow be too low. The maximum point on the VRR curve for the 2025/2026 BRA was the higher of Gross CONE or 1.5 times Net CONE, and Gross CONE was actually used. However, if the logic of the markets implies a low Net CONE, that is the right answer. There is nothing inherently wrong with a low Net CONE that requires abandoning the basic capacity market logic. Gross CONE was an intervention designed to increase capacity market prices based on a judgment about what prices should be despite the fact that the basic economic logic did not support that increase. If there is an issue with the calculation of Net CONE, it should be addressed directly rather than by ignoring its central role in the design of the capacity market. As Gross CONE numbers are reasonably well defined, much more focus on getting the net revenues used in the forward auctions is required in order to ensure that market participants have confidence in the Net CONE values used in the auctions.

Figure 5-4 shows the RTO VRR curve and RTO reliability requirement for the 2027/2028 RPM BRA.

Figure 5-4 Shape of the VRR curve relative to the reliability requirement: 2027/2028 Delivery Year



94 PJM Filing. Proposal for Revised Price Cap and Price Floor for the 2026/2027 and 2027/2028 Delivery Years, and Request for a Waiver of the 60-Days' Notice Requirement to Allow for a March 31, 2025 Effective Date, Docket No. ER25-1357 (Feb. 20, 2025). The modified maximum price and the addition of a price floor were based on the Agreement between Governor Josh Shapiro of the Commonwealth of Pennsylvania and PJM.

95 195 FERC ¶ 61,076 (April 28, 2026).

96 See Answer and Motion for Leave to Answer of the Independent Market Monitor for PJM, (April 16, 2025), <https://www.monitoringanalytics.com/filings/2025/IMM_Answer_to_Answer_Docket_No_ER25-1357_20250416.pdf>.

Market Concentration

Auction Market Structure

As shown in Table 5-11, in the 2026/2027 RPM Third Incremental Auction, all participants in the total PJM market as well as the LDA RPM markets failed the three pivotal supplier (TPS) test.[97] Offer caps were applied to all sell offers for resources which were subject to mitigation when the capacity market seller did not pass the test, the submitted sell offer exceeded the defined offer cap, and the submitted sell offer, absent mitigation, increased the market clearing price.[98] [99] [100]

In applying the market structure test, the relevant supply for the RTO market includes all supply offered at less than or equal to 150 percent of the RTO cost-based clearing price. The relevant supply for the constrained LDA markets includes the incremental supply inside the constrained LDAs which was offered at a price higher than the unconstrained clearing price for the parent LDA market and less than or equal to 150 percent of the cost-based clearing price for the constrained LDA. The relevant demand consists of the MW needed inside the LDA to relieve the constraint.

Table 5-11 presents the results of the TPS test. A generation owner or owners are pivotal if the capacity of the owners' generation facilities is needed to meet the demand for capacity. The results of the TPS are measured by the residual supply index (RSI_x). The RSI_x is a general measure that can be used with any number of pivotal suppliers. The subscript denotes the number of pivotal suppliers included in the test. If the RSI_x is less than or equal to 1.0, the supply owned by the specific generation owner, or owners, is needed to meet market demand and the generation owners are pivotal suppliers with a significant ability to influence market prices. If the RSI_x is greater than 1.0, the supply of the specific generation owner or owners is not needed to meet market demand and those generation owners have a reduced ability to unilaterally influence market price.

97 The market definition used for the TPS test includes all offers with costs less than or equal to 1.50 times the clearing price. See ***MMU Technical Reference for PJM Markets,*** at "Three Pivotal Supplier Test" for additional discussion.
98 See OATT Attachment DD § 6.5.
99 Prior to November 1, 2009, existing DR and EE resources were subject to market power mitigation in RPM Auctions. See 129 FERC ¶ 61,081 at P 30 (2009).
100 Effective January 31, 2011, the RPM rules related to market power mitigation were changed, including revising the definition for planned generation capacity resource and creating a new definition for existing generation capacity resource for purposes of the must offer requirement and market power mitigation, and treating a proposed increase in the capability of a generation capacity resource the same in terms of mitigation as a planned generation capacity resource. See 134 FERC ¶ 61,065 (2011).

Table 5-11 RSI results: 2023/2024 through 2027/2028 RPM Auctions[101]

RPM Markets	RSI1, 1.05	RSI3	Total Participants	Failed RSI3 Participants
2023/2024 Base Residual Auction				
RTO	0.78	0.68	134	134
MAAC	0.78	0.40	11	11
DPL South	0.00	0.00	1	1
BGE	0.00	0.00	1	1
2023/2024 Third Incremental Auction				
RTO	0.77	0.76	51	15
MAAC	0.41	0.76	17	9
EMAAC	0.45	0.18	10	10
BGE	0.00	0.00	1	1
2024/2025 Base Residual Auction				
RTO	0.77	0.64	133	133
MAAC	0.59	0.11	9	9
EMAAC	0.48	0.00	2	2
DPL South	0.00	0.00	1	1
BGE	0.00	0.00	1	1
DEOK	0.00	0.00	1	1
2024/2025 Third Incremental Auction				
RTO	0.88	0.59	64	64
MAAC	0.60	0.17	10	10
EMAAC	0.00	0.00	1	1
BGE	0.00	0.00	1	1
2025/2026 Base Residual Auction				
RTO	0.82	0.62	128	128
BGE	0.00	0.00	0	0
Dominion	0.00	0.00	0	0
2025/2026 Third Incremental Auction				
RTO	0.60	0.31	75	75
BGE	0.00	0.00	0	0
2026/2027 Base Residual Auction				
RTO	0.82	0.64	153	153
2026/2027 Third Incremental Auction				
RTO	0.82	0.67	120	120
2027/2028 Base Residual Auction				
RTO	0.82	0.63	155	155

101 The RSI shown is the lowest RSI in the market.

Locational Deliverability Areas (LDAs)

Under the PJM Tariff, PJM determines, in advance of each BRA, whether defined Locational Deliverability Areas (LDAs) will be modeled in the auction. Effective with the 2012/2013 Delivery Year, an LDA is modeled as a potentially constrained LDA for a delivery year if the Capacity Emergency Transfer Limit (CETL) is less than 1.15 times the Capacity Emergency Transfer Objective (CETO), such LDA had a locational price adder in one or more of the three immediately preceding BRAs, or such LDA is determined by PJM in a preliminary analysis to be likely to have a locational price adder based on historic offer price levels. The rules also provide that starting with the 2012/2013 Delivery Year, EMAAC, SWMAAC, and MAAC LDAs are modeled as potentially constrained LDAs regardless of the results of the above three tests.[102] In addition, PJM may establish a constrained LDA even if it does not qualify under the above tests if PJM finds that "such is required to achieve an acceptable level of reliability."[103] A reliability requirement and a Variable Resource Requirement (VRR) curve are established for each modeled LDA. Effective for the 2014/2015 through 2016/2017 Delivery Years, a Minimum Annual and a Minimum Extended Summer Resource Requirement were established for each modeled LDA. Effective for the 2017/2018 Delivery Year, Sub-Annual and Limited Resource Constraints, replacing the Minimum Annual and a Minimum Extended Summer Resource Requirements, were established for each modeled LDA.[104] [105] Effective for the 2018/2019 and the 2019/2020 Delivery Years, a Base Capacity Demand Resource Constraint and a Base Capacity Resource Constraint, replacing the Sub-Annual and Limited Resource Constraints, were established for each modeled LDA.

Imports and Exports

Units external to the metered boundaries of PJM can qualify as PJM capacity resources if they meet the requirements to be capacity resources. Generators on the PJM system that do not have a commitment to serve PJM loads in the given delivery year as a result of RPM auctions, FRR capacity plans, locational

102 Prior to the 2012/2013 Delivery Year, an LDA with a CETL less than 1.05 times CETO was modeled as a constrained LDA in RPM. No additional criteria were used in determining modeled LDAs.
103 OATT Attachment DD § 5.10 (a) (ii).
104 146 FERC ¶ 61,052 (2014).
105 Locational Deliverability Areas are shown in maps in the *2021 Annual State of the Market Report for PJM*, Volume 2, Section 5: "Capacity Market" at "Locational Deliverability Areas (LDAs)".

UCAP transactions, and/or are not designated as a replacement resource, are eligible to export their capacity from PJM.[106]

The market rules in other balancing authorities should also not create inappropriate barriers to the import or export of capacity. The PJM market rules should ensure that the definition of capacity is enforced including physical deliverability, recallability and the obligation to make competitive offers into the PJM Day-Ahead Energy Market equal to ICAP MW. Physical deliverability can only be assured by requiring that all imports are deliverable to PJM load to ensure that they are full substitutes for internal capacity resources. Selling capacity into the PJM Capacity Market but making energy offers daily of $999 per MWh would not fulfill the requirements of a capacity resource to make a competitive offer, but would constitute economic withholding. This is one of the reasons that the rules governing the obligation to make a competitive offer in the day-ahead energy market should be clarified for both internal and external resources. The PJM market rules should also not create inappropriate barriers to either the import or export of capacity.

The calculation of CETL should only include capacity imports into PJM where the capacity has an explicit must offer requirement in the PJM Capacity Market. These could include pseudo tied units or resources with a grandfathered obligation. The external capacity that does not have a must offer requirement in the PJM capacity market is not obligated to serve PJM load under all conditions and therefore should not be assumed to be a source of capacity. This capacity should not be included in PJM's power flow calculations used to deriver CETL values between PJM's LDAs. PJM has modified its CETL calculations to exclude such capacity.

The establishment of a pseudo tie is one requirement for an external resource to be eligible to participate in the PJM Capacity Market. Pseudo tied external resources, regardless of their location, are treated as only meeting the reliability requirements of the rest of RTO and not the reliability requirements of any specific locational deliverability area (LDA). All imports offered in the auction from areas external to PJM are modeled as supply in the rest of RTO and not in any specific zonal or subzonal LDA. The fact that pseudo tied external resources cannot be identified as equivalent to resources internal to specific LDAs illustrates a fundamental issue with capacity imports. Capacity imports are not equivalent to, nor substitutes for, internal resources. All internal resources are internal to a specific LDA.[107]

Effective May 9, 2017, significantly improved pseudo tie requirements for external generation capacity resources were implemented.[108] The rule changes include: defining coordination with other Balancing Authorities when conducting pseudo tie studies; establishing an electrical distance requirement; establishing a market to market flowgate test to establish limits on the number of coordinated flowgates PJM must add in order to accommodate a new pseudo tie; a model consistency requirement; the requirement for the capacity market seller to provide written acknowledgement from the external Balancing Authority Areas that such pseudo tie does not require tagging and that firm allocations associated with any coordinated flowgates applicable to the external Generation Capacity Resource under any agreed congestion management process then in effect between PJM and such Balancing Authority Area will be allocated to PJM; the requirement for the capacity market seller to obtain long-term firm point to point transmission service for transmission outside PJM with rollover rights and to obtain network external designated transmission service for transmission within PJM; establishing an operationally deliverable standard; and modifying the nonperformance penalty definition for external generation capacity resources to assess performance at subregional transmission organization granularity.

Generation external to the PJM region is eligible to be offered into an RPM auction if it meets specific requirements.[109] [110] [111] Firm transmission service must be acquired from all external transmission providers between the unit and border of PJM and generation deliverability into PJM must be demonstrated prior to the start of the delivery year. In order to demonstrate generation deliverability into PJM, external generators must obtain firm point

106 OATT Attachment DD § 5.6.6(b).

107 External resources are not assigned to any of the five global LDAs or 22 zonal and subzonal LDAs. PJM's current practice is to model external resources in the rest of RTO. The practice is not currently documented by PJM. It was previously documented in "PJM Manual 18: PJM Capacity Market," § 2.3.4 Capacity Import Limits, Rev. 39 (Dec. 21, 2017).

108 161 FERC ¶ 61,197 (2017).

109 See "Reliability Assurance Agreement Among Load Serving Entities in the PJM Region," Schedule 9 & 10.

110 "PJM Manual 18: PJM Capacity Market," § 4.2.2 Existing Generation Capacity Resources – External, Rev. 62 (Dec. 17, 2025).

111 "PJM Manual 18: PJM Capacity Market," § 4.6.4 Importing an External Generation Resource, Rev. 62 (Dec. 17, 2025).

to point transmission service on the PJM OASIS from the PJM border into the PJM transmission system or by obtaining network external designated transmission service. In the event that transmission upgrades are required to establish deliverability, those upgrades must be completed by the start of the delivery year. The following are also required: the external generating unit must be in the resource portfolio of a PJM member; 12 months of NERC/GADs unit performance data must be provided to establish an EFORd; the net capability of each unit must be verified through winter and summer testing; and a letter of non-recallability must be provided to assure PJM that the energy and capacity from the unit is not recallable to any other balancing authority.

All external generation resources that have an RPM commitment or FRR capacity plan commitment or that are designated as replacement capacity must be offered in the PJM day-ahead energy market.[112]

Planned External Generation Capacity Resources are eligible to be offered into an RPM Auction if they meet specific requirements.[113] [114] Planned External Generation Capacity Resources are proposed Generation Capacity Resources, or a proposed increase in the capability of an Existing Generation Capacity Resource, that is located outside the PJM region; participates in the generation interconnection process of a balancing authority external to PJM; is scheduled to be physically and electrically interconnected to the transmission facilities of such balancing authority on or before the first day of the delivery year for which the resource is to be committed to satisfy the reliability requirements of the PJM region; and is in full commercial operation prior to the first day of the delivery year.[115] An External Generation Capacity Resource becomes an Existing Generation Capacity Resource as of the earlier of the date that interconnection service commences or the resource has cleared an RPM Auction for a prior delivery year.[116]

112 OATT Schedule 1 § 1.10.1A.
113 See "Reliability Assurance Agreement among Load Serving Entities in the PJM Region," Section 1.69A.
114 "PJM Manual 18: PJM Capacity Market," § 4.2.4 Planned Generation Capacity Resources – External, Rev. 62 (Dec. 17, 2025).
115 Prior to January 31, 2011, capacity modifications to existing generation capacity resources were not considered planned generation capacity resources. See 134 FERC ¶ 61,065 (2011).
116 Effective January 31, 2011, the RPM rules related to market power mitigation were changed, including revising the definition for Planned Generation Capacity Resource for purposes of the must-offer requirement and market power mitigation. See 134 FERC ¶ 61,065 (2011).

As shown in Table 5-12, of the 1,144.8 MW of imports offered in the 2027/2028 RPM Base Residual Auction, 1,005.9 MW cleared. Of the cleared imports, 695.6 MW (69.2 percent) were from MISO.

Table 5-12 RPM imports: 2007/2008 through 2027/2028 RPM Base Residual Auctions

	UCAP (MW)					
	MISO		Non-MISO		Total Imports	
Base Residual Auction	Offered	Cleared	Offered	Cleared	Offered	Cleared
2007/2008	1,073.0	1,072.9	547.9	547.9	1,620.9	1,620.8
2008/2009	1,149.4	1,109.0	517.6	516.8	1,667.0	1,625.8
2009/2010	1,189.2	1,151.0	518.8	518.1	1,708.0	1,669.1
2010/2011	1,194.2	1,186.6	539.8	539.5	1,734.0	1,726.1
2011/2012	1,862.7	1,198.6	3,560.0	3,557.5	5,422.7	4,756.1
2012/2013	1,415.9	1,298.8	1,036.7	1,036.7	2,452.6	2,335.5
2013/2014	1,895.1	1,895.1	1,358.9	1,358.9	3,254.0	3,254.0
2014/2015	1,067.7	1,067.7	1,948.8	1,948.8	3,016.5	3,016.5
2015/2016	1,538.7	1,538.7	2,396.6	2,396.6	3,935.3	3,935.3
2016/2017	4,723.1	4,723.1	2,770.6	2,759.6	7,493.7	7,482.7
2017/2018	2,624.3	2,624.3	2,320.4	1,901.2	4,944.7	4,525.5
2018/2019	2,879.1	2,509.1	2,256.7	2,178.8	5,135.8	4,687.9
2019/2020	2,067.3	1,828.6	2,276.1	2,047.3	4,343.4	3,875.9
2020/2021	2,511.8	1,671.2	2,450.0	2,326.0	4,961.8	3,997.2
2021/2022	2,308.4	1,909.9	2,162.0	2,141.9	4,470.4	4,051.8
2022/2023	954.9	954.9	603.1	603.1	1,558.0	1,558.0
2023/2024	967.9	836.5	560.1	560.1	1,528.0	1,396.6
2024/2025	949.9	820.4	577.2	577.2	1,527.1	1,397.6
2025/2026	700.5	700.5	568.0	568.0	1,268.5	1,268.5
2026/2027	697.4	697.4	584.3	584.3	1,281.7	1,281.7
2027/2028	695.6	695.6	449.2	310.3	1,144.8	1,005.9

One of the reasons that a Generation Capacity Resource may qualify for an exception to the RPM must offer requirement is by demonstration that it has a financially and physically firm commitment to an external sale of its capacity.[117] Exporting a Generation Capacity Resource requires a financially and physically firm commitment to load located outside the PJM Region. The PJM Tariff states "In order to establish that a resource has a financially and physically firm commitment to an external sale of its capacity, the Capacity

117 OATT Attachment DD § 6.6(g).

Market Seller must demonstrate that it has entered into a unit-specific bilateral transaction for service to load located outside the PJM Region, by a demonstration that such resource is identified on a unit-specific basis as a network resource under the transmission tariff for the control area applicable to such external load, or by an equivalent demonstration of a financially and physically firm commitment to an external sale. The Capacity Market Seller additionally shall identify the megawatt amount, export zone, and time period (in days) of the export."[118]

The MMU recommends that the PJM Tariff be modified to explicitly state that in order to qualify, a Capacity Market Seller requesting a must offer exception based on a financially and physically firm commitment to an external sale of its capacity must provide a confirmed firm transmission reservation, covering the entire path from source to sink, for the full requested ICAP MW of the external sale that covers the entire delivery year, by the tariff defined deadline. The MMU recommends that this language apply to all external sales of Generation Capacity Resources, including those where an external balancing authority does not require this level of transmission service in order to consider a PJM resource as a network resource.

Demand Resources

The level of DR products that buy out of their positions after the BRA means that the treatment of DR has a negative impact on generation investment incentives and that the rules governing the requirement to be a physical resource should be more clearly stated and enforced.[119] If DR displaces new generation resources in BRAs, but then buys out of the position prior to the delivery year, this means potentially replacing new entry generation resources at the high end of the supply curve with other existing but uncleared capacity resources available in Incremental Auctions at reduced offer prices. This suppresses the price of capacity in the BRA compared to the competitive result because it permits the shifting of demand from the BRA to the Incremental Auctions, which is inconsistent with the must offer, must buy rules, and the requirement to be an actual, physical resource, governing the BRA. PJM's sell back of capacity in Incremental Auctions exacerbates the incentive for DR to buy out of its BRA positions in IAs.

Effective with the 2020/2021 Delivery Year, DR includes annual and summer products. Annual Demand Resources are required to be available on any day during the Delivery Year for an unlimited number of interruptions between the hours of 10:00 a.m. and 10:00 p.m. EPT for the months of June through October and the following May and between the hours of 6:00 a.m. and 9:00 p.m. EPT for the months of November through April unless there is a PJM approved maintenance outage during the October through April period.

Summer-Period Demand Resources are required to be available on any day from June through October and the following May of the delivery year for an unlimited number of interruptions between the hours of 10:00 a.m. to 10:00 p.m. EPT.

118 Ibid.
119 See "Analysis of Replacement Capacity for RPM Commitments: June 1, 2007 to June 1, 2019," <http://www.monitoringanalytics.com/reports/Reports/2019/IMM_Analysis_of_Replacement_Capacity_for_RPM_Commitments_June_1_2007_to_June_1_2019_20190913.pdf> (September 13, 2019).

As shown in Table 5-13, and Table 5-14, committed DR was 4,805.8 MW for June 1, 2026, as a result of cleared capacity for demand resources in RPM auctions for the 2026/2027 Delivery Year (5,710.3 MW) less replacement capacity (904.5 MW).

Table 5-13 RPM load management statistics by LDA: June 1, 2023 to June 1, 2027[120] [121] [122] [123]

		UCAP (MW)																
		RTO	MAAC	EMAAC	SWMAAC	DPL South	PSEG	PSEG North	Pepco	ATSI	ATSI Cleveland	ComEd	BGE	PPL	DAY	DEOK	Dominion	JCPL
	DR cleared	8,174.1	2,411.4	975.9	343.6	52.2	272.7	126.1	175.2	916.2	189.4	1,253.2	168.4	583.4	209.3	175.4		
	EE cleared	5,896.4	2,438.6	1,341.4	569.5	59.3	443.4	210.4	298.6	451.8	46.3	961.2	270.9	306.1	102.4	164.3		
	DR net replacements	(466.2)	(229.5)	(3.8)	(4.9)	22.8	3.4	2.6	(25.0)	47.2	(63.4)	160.7	20.1	(123.3)	(24.0)	25.0		
	EE net replacements	(5.3)	(2.2)	(1.0)	7.6	9.0	11.6	13.7	7.6	(15.3)	(0.5)	(20.9)	0.0	(6.2)	(7.9)	0.7		
01-Jun-23	RPM load management	13,599.0	4,618.3	2,312.5	915.8	143.3	731.1	352.8	456.4	1,399.9	171.8	2,354.2	459.4	760.0	279.8	365.4		
	DR cleared	8,064.7	2,497.6	1,004.0	358.5	46.0	285.7	98.2	160.4	682.6	141.6	1,554.0	198.1	603.4	192.9	221.9		
	EE cleared	7,716.0	3,543.5	2,064.9	787.4	99.9	802.9	392.0	398.9	587.6	54.9	1,063.4	388.5	391.4	128.3	188.1		
	DR net replacements	(364.8)	(197.4)	9.1	43.0	35.2	(7.3)	(14.9)	19.3	50.9	(58.3)	(56.0)	23.7	(138.9)	(6.2)	(5.4)		
	EE net replacements	(48.0)	(43.6)	(15.4)	21.3	14.1	(6.5)	(0.1)	9.1	(30.6)	0.0	1.2	12.2	(38.4)	(5.6)	(3.7)		
01-Jun-24	RPM load management	15,367.9	5,800.1	3,062.6	1,210.2	195.2	1,074.8	475.2	587.7	1,290.5	138.2	2,562.6	622.5	817.5	309.4	400.9		
	DR cleared	6,265.9	1,860.8	784.9	304.0	65.0	228.9	65.8	135.7	712.7	97.3	1,090.5	168.3	424.9	141.0	159.6	673.5	
	EE cleared	1,493.2	674.7	433.5	154.7	24.0	184.0	100.0	80.0	69.1	6.6	337.6	74.7	45.7	18.5	24.9	154.2	
	DR net replacements	(483.0)	(140.4)	(60.2)	(11.6)	(30.3)	(10.4)	(14.3)	(15.1)	(39.8)	(4.8)	(29.0)	3.5	(10.2)	(0.2)	(39.9)	(151.0)	
	EE net replacements	(11.6)	32.8	25.7	(2.6)	(1.3)	7.5	3.3	(2.6)	(6.8)	(0.1)	1.0	0.0	10.0	(0.2)	(1.6)	(11.6)	
01-Jun-25	RPM load management	7,264.5	2,427.9	1,183.9	444.5	57.4	410.0	154.8	198.0	735.2	99.0	1,400.1	246.5	470.4	159.1	143.0	665.1	
	DR cleared	5,710.3	1,611.1	620.0	381.5	33.9	179.1	45.6	229.3	597.8	94.4	970.7	152.2	327.5	152.0	116.3	555.1	59.2
	DR net replacements	(904.5)	(240.0)	(69.4)	(34.5)	(12.2)	(13.9)	(9.2)	(3.6)	(150.1)	(21.4)	(34.8)	(30.9)	(64.9)	(38.4)	6.3	(61.1)	(12.8)
01-Jun-26	RPM load management	4,805.8	1,371.1	550.6	347.0	21.7	165.2	36.4	225.7	447.7	73.0	935.9	121.3	262.6	113.6	122.6	494.0	46.4
	DR cleared	7,298.6	1,981.6	799.8	455.5	42.6	234.3	49.1	285.9	672.3	101.7	1,515.9	169.6	421.8	172.1	200.6	768.3	89.3
	DR net replacements	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
01-Jun-27	RPM load management	7,298.6	1,981.6	799.8	455.5	42.6	234.3	49.1	285.9	672.3	101.7	1,515.9	169.6	421.8	172.1	200.6	768.3	89.3

120 See OATT Attachment DD § 8.4. The reported DR cleared MW may reflect reductions in the level of committed MW due to relief from Capacity Resource Deficiency Charges.
121 Pursuant to OA § 15.1.6(c), PJM Settlement shall attempt to close out and liquidate forward capacity commitments for PJM Members that are declared in collateral default. The reported replacement transactions may include transactions associated with PJM members that were declared in collateral default.
122 EE resources are fully reflected in PJM load forecasts starting with the 2016 load forecast for the 2019/2020 delivery year, and EE resources are not defined to be capacity resources in any way as a result. EE resources do not clear in the capacity auctions.
123 See OATT Attachment DD § 5.14E. The reported DR cleared MW for the 2016/2017, 2017/2018, and 2018/2019 Delivery Years reflect reductions in the level of committed MW due to the Demand Response Legacy Direct Load Control Transition Provision.

Table 5-14 RPM commitments, replacements, and registrations for demand resources: June 1, 2007 to June 1, 2027[124 125 126]

	UCAP (MW)						Registered DR		
	RPM Cleared	Adjustments to Cleared	Net Replacements	RPM Commitments	RPM Commitment Shortage	RPM Commitments Less Commitment Shortage	ICAP (MW)	UCAP Conversion Factor	UCAP (MW)
01-Jun-07	127.6	0.0	0.0	127.6	0.0	127.6	0.0	1.033	0.0
01-Jun-08	559.4	0.0	(40.0)	519.4	(58.4)	461.0	488.0	1.034	504.7
01-Jun-09	892.9	0.0	(474.7)	418.2	(14.3)	403.9	570.3	1.033	589.2
01-Jun-10	962.9	0.0	(516.3)	446.6	(7.7)	438.9	572.8	1.035	592.6
01-Jun-11	1,826.6	0.0	(1,052.4)	774.2	0.0	774.2	1,117.9	1.035	1,156.5
01-Jun-12	8,752.6	(11.7)	(2,253.6)	6,487.3	(34.9)	6,452.4	7,443.7	1.037	7,718.4
01-Jun-13	10,779.6	0.0	(3,314.4)	7,465.2	(30.5)	7,434.7	8,240.1	1.042	8,586.8
01-Jun-14	14,943.0	0.0	(6,731.8)	8,211.2	(219.4)	7,991.8	8,923.4	1.042	9,301.2
01-Jun-15	15,774.8	(321.1)	(4,829.7)	10,624.0	(61.8)	10,562.2	10,946.0	1.038	11,360.0
01-Jun-16	13,284.7	(19.4)	(4,800.7)	8,464.6	(455.4)	8,009.2	8,961.2	1.042	9,333.4
01-Jun-17	11,870.7	0.0	(3,870.8)	7,999.9	(30.3)	7,969.6	8,681.4	1.039	9,016.3
01-Jun-18	11,435.4	0.0	(3,182.4)	8,253.0	(1.0)	8,252.0	8,512.0	1.091	9,282.4
01-Jun-19	10,703.1	0.0	(2,138.8)	8,564.3	(0.4)	8,563.9	9,229.9	1.090	10,056.0
01-Jun-20	9,445.7	0.0	(2,399.5)	7,046.2	(0.1)	7,046.1	7,867.6	1.088	8,561.5
01-Jun-21	11,427.7	0.0	(4,111.0)	7,316.7	0.0	7,316.7	7,754.2	1.087	8,429.6
01-Jun-22	8,866.2	0.0	(570.0)	8,296.2	(52.1)	8,244.1	8,518.5	1.091	9,290.2
01-Jun-23	8,174.1	0.0	(466.2)	7,707.9	(161.5)	7,546.4	7,383.0	1.093	8,069.6
01-Jun-24	8,064.7	0.0	(364.8)	7,699.9	(507.4)	7,192.5	6,758.7	1.117	7,549.5
01-Jun-25	6,265.9	0.0	(483.0)	5,782.9	(209.4)	5,573.5	7,748.7	0.770	5,966.5
01-Jun-26	5,710.3	0.0	(904.5)	4,805.8	(31.9)	4,773.9	7,228.3	0.720	5,204.4
01-Jun-27	7,298.6	0.0	0.0	7,298.6	0.0	7,298.6	0.0	0.920	0.0

ELCC: The Capacity Value of Resources

Given that many PJM states have aggressive renewable energy targets, a core goal of a competitive market design should be to ensure that the resources required to provide reliability receive appropriate competitive market incentives for entry and for ongoing investment and for exit when uneconomic. A significant level of renewable resources, operating with zero or near zero marginal costs, will result in very low energy prices at times of high intermittent output. Since renewable resources are intermittent, the contribution of renewables to meeting reliability targets must be analyzed carefully to ensure that the capacity value of renewables is calculated correctly.

The units of measurement for the PJM capacity market auctions are unforced capacity (UCAP). PJM uses conversion factors to convert installed capacity MW (ICAP) into UCAP MW and this process is known as capacity accreditation. Prior to the 2023/2024 Delivery Year, EFORd values for thermal generators were used to convert ICAP to UCAP. Conversion factors for wind and solar generators were based on energy output during summer peak hours. Conversion factors for storage resources were equal to the maximum capability during 10 continuous hours of operation. The conversion factor for Demand Resources was equal to the forecast

124 See OATT Attachment DD § 8.4. The reported DR adjustments to cleared MW include reductions in the level of committed MW due to relief from Capacity Resource Deficiency Charges.
125 See OATT Attachment DD § 5.14C. The reported DR adjustments to cleared MW for the 2015/2016 and 2016/2017 Delivery Years include reductions in the level of committed MW due to the Demand Response Operational Resource Flexibility Transition Provision.
126 See OATT Attachment DD § 5.14E. The reported DR adjustments to cleared MW for the 2016/2017, 2017/2018, and 2018/2019 Delivery Years include reductions in the level of committed MW due to the Demand Response Legacy Direct Load Control Transition Provision.

pool requirement (FPR). On July 30, 2021, FERC approved new PJM rules for defining/derating the capacity value of intermittent and storage resources, based on PJM's interpretation of the effective load carrying capability (ELCC) method.[127] PJM's average ELCC accreditations for intermittent and storage resources relied on the average capability by resource class for the 2023/2024 and 2024/2025 Delivery Years. Revisions, filed in October 2023, changed the capacity accreditation calculation to a marginal ELCC approach, applicable to all resource types. Beginning with the 2025/2026 Delivery Year, capacity accreditations are based on the revised marginal ELCC approach. The PJM marginal ELCC approach was accepted by FERC in January 2024.[128]

PJM's approach to ELCC is based on the correct high level insight that there is a need to calculate the availability of different resource types, but the actual implementation does not do that correctly and results in a set of illogical outcomes. For example, PJM assigned penalties to solar resources during Winter Storm Elliott in December 2022 when solar resources did not generate power after dark. PJM's ELCC calculations rely on a significant overweighting of generator performance during the Polar Vortex in 2014 and Winter Storm Elliott in 2022 that results in artificially suppressed ELCC values for thermal resources and other resource types. A PJM sensitivity analysis shows that not including generator performance during the 2014 Polar Vortex and Winter Storm Elliott lowers the winter portion of loss of load hours from 78.2 percent to 20.3 percent, a decrease of 74.1 percent, and increases the average accredited UCAP factor by 14.1 percent from 0.7858 to 0.8978.[129]

Under the PJM ELCC approach a solar resource is assigned a derating factor, and the derated MW are asserted to be equivalent to a perfect resource accredited at that MW level. PJM assigned penalties to solar resources during Elliott when they did not generate power after dark. This is clearly not correct and illustrates one of the flaws in the ELCC logic. The solar resource is available for sunny hours and not for unsunny hours. A solar resource is not expected to generate at night and should not face penalties for failing to do what it obviously cannot. ELCC does not convert intermittent resources, or any resource, into a perfect resource, or even the equivalent of a perfect resource. This illogical implication of PJM's ELCC means that there is a significant flaw in the ELCC approach. The penalties were assessed because the ELCC method determined that 1 MW of solar nameplate capacity was equivalent to 0.54 MW of perfect capacity, meaning capacity that is always available at the derated level, even in the middle of the night.[130]

The MMU opposes PJM's ELCC rules because they are an administrative determination by PJM based on a black box model of the capacity value of resources, they rely on significant counterfactual behavioral assumptions for storage and demand response resources, are not unit specific, are not hourly, are not locational, introduce significant volatility to the capacity accreditations, do not recognize the winter capability of thermal resources, overweight unit performance during Winter Storm Elliott, do not recognize actual performance in the delivery year and are an ex ante approach that must assume a capacity resource fleet for determining the ELCC marginal class ratings.[131] PJM does not check the actual cleared capacity in capacity market auctions to verify if the cleared capacity is expected to provide the target reliability.

The ELCC approach is not an appropriate way to define the MW capacity value for intermittent and storage resources, or for thermal resources, in a market. ELCC was developed as, and remains, a utility planning tool rather than a market design tool. ELCC was attractive as a possible analytical basis for the derating of intermittent and storage resources to a MW level consistent with their actual availability. The impetus made sense but the actual application of the ELCC planning tool cannot work in markets that include intermittent or thermal resources. The underlying logic makes sense but PJM's implementation does not.

As a result of all these issues, the MMU has concluded that ELCC is not a viable method for determining the reliability contributions of capacity resources. The

127 See 176 FERC ¶ 61,056.
128 186 FERC ¶61,080 (January 30, 2024).
129 ELCC Accreditation Methodology: Update on Sensitivity Analyses, Item 2 in the meeting materials for the ELCC Senior Task Force (May 22, 2025) <https://www.pjm.com/-/media/DotCom/committees-groups/task-forces/elccstf/2025/20250522/20250522-item-02---elcc-accreditation-methodology-update-on-sensitivity-analyses---pjm-presentation.pdf>.
130 PJM Interconnection L.L.C, "ELCC Class Ratings for 2024-2025 BRA," (December 28, 2021) <https://www.pjm.com/planning/resource-adequacy-planning/effective-load-carrying-capability>.
131 See Protest of the Independent Market Monitor for PJM, Docket ER24-99-000, et al. (November 9, 2023); Comments on Response to Deficiency Notice, Answer and Motion for Leave to Answer of the Independent Market Monitor for PJM, Docket No. ER24-99-000 (December 21, 2023); Answer and Motion for Leave to Answer of the Independent Market Monitor for PJM, Docket No. ER24-99-000 (January 12, 2024); Answer and Motion for Leave to Answer of the Independent Market Monitor for PJM, Docket No. ER24-99-000 (January 24, 2024).

MMU has proposed a replacement for the PJM ELCC approach that is based on the actual hourly availability of all individual generators.[132] [133] [134]

The ELCC ratings produced by the marginal approach in general, and by PJM's specific marginal approach specifically, are inherently volatile. PJM has calculated the marginal ELCC class ratings for the 2025/2026 delivery year on five separate occasions. Table 5-15 shows the results of each calculation. Each calculation is dependent upon the load forecast model, the combination of actual historical performance and changes in experienced weather, and the assumed forward looking resource mix. The PJM 2024 load forecast model was used to produce the February 2024, March 2024 and January 2025 ELCC ratings. The ELCC ratings posted on December 31, 2024, used an interim 2025 load forecast model. In early January, PJM removed the posted ELCC ratings from December 31, 2024, and posted recalculated ratings using the 2024 load forecast model. The modified ELCC ratings were posted on January 23, 2025. The January 23, 2025, ratings are the final ELCC ratings for 2025/2026 Delivery Year.[135] The ELCC rating changes have significant impacts on the amount of cleared capacity. Table 5-16 shows the difference between capacity that cleared the 2025/2026 Base Residual Auction and the updated capacity MW value based on the final ELCC ratings for 2025/2026 posted on January 23, 2025. In total, the capacity values decreased by 928.5 MW (UCAP) or 0.7 percent. Capacity market sellers are obligated to obtain additional capacity prior to the delivery year if they are short as a result of a reduction in ELCC rating between the BRA and the final ELCC rating from PJM's ELCC rating changes. Had PJM used the ELCC ratings posted on December 31, 2024, the capacity values would have decreased by 3,793.3 MW or 2.8 percent.

Table 5-15 Marginal ELCC ratings for the 2025/2026 Delivery Year

	2025/2026 Delivery Year				
ELCC Class	December 2023	February 2024	March 2024	December 2024	January 2025
Onshore Wind	21%	35%	35%	42%	38%
Offshore Wind	39%	60%	60%	71%	62%
Solar Fixed	15%	9%	9%	8%	10%
Solar Tracking	25%	14%	14%	11%	14%
Landfill Intermittent	56%	55%	54%	51%	51%
Hydro Intermittent	41%	36%	37%	37%	37%
4-hr Storage	76%	59%	59%	44%	55%
6-hr Storage	85%	67%	67%	53%	65%
8-hr Storage	89%	69%	68%	58%	68%
10-hr Storage	92%	78%	78%	67%	77%
Demand Response	95%	77%	76%	68%	77%
Nuclear	96%	96%	95%	95%	95%
Coal	86%	85%	84%	83%	83%
Gas Combined Cycle	87%	80%	79%	77%	78%
Gas Combustion Turbine	74%	62%	62%	59%	63%
Gas Combustion Turbine Dual Fuel	90%	78%	79%	78%	79%
Diesel Utility	91%	90%	92%	92%	92%
Steam	78%	70%	75%	73%	74%

132 For additional details on the MMU proposal see "Executive Summary of the IMM Capacity Market Design Proposal: Sustainable Capacity Market (SCM)", Independent Market Monitor for PJM (August 16, 2023) <http://www.monitoringanalytics.com/reports/Presentations/2023/IMM_RASTF-CIFP_SCM_Executive_Summary_20230816.pdf>.

133 Any generation from a resource in excess of its CIR value is equivalent to generation from an energy only resource and should not be included in the calculation of the capacity value of the resource or in the calculation of the derated ELCC class ratings that define the capacity value of the resource. Updated rules beginning with the 2025/2026 Delivery Year require that ELCC accreditations exclude energy in excess of a generator's CIR. See 183 FERC ¶ 61,009 (April 7, 2023).

134 New rules beginning with the 2025/2026 Delivery Year correctly limit the delivered energy to the CIR level in the ELCC calculations. The new rules also include a complex transition process that allocates available headroom to intermittent resources with understated CIRs. The new rules apply to Delivery Year 2025/2026 BRA and subsequent delivery years. *See* 183 FERC ¶ 61,009 (April 7, 2023).

135 See Item 5 in Markets and Reliability Committee Meeting Materials, ***Installed Reserve Margin (IRM), Forecast Pool Requirement (FPR), and Effective Load Carrying Capability (ELCC) for 2025/2026 3IA*** at 2, PJM Interconnection L.L.C. (January 23, 2025) <https://www.pjm.com/committees-and-groups/committees/mrc>.

Table 5-16 Impact of ratings changes on cleared capacity[136]

	MW (UCAP)	Reduction in capacity value compared to Base Residual Auction	Percent change in capacity value compared to Base Residual Auction
2025/2026 Base Residual Auction Cleared Capacity	135,684.0		
Updated Cleared Capacity based on Jan 23, 2025 ELCC Ratings	134,755.5	(928.5)	(0.7%)
Updated Cleared Capacity based on Dec 31, 2024 ELCC Ratings	131,890.7	(3,793.3)	(2.8%)

The ELCC volatility also affects the reliability requirement calculation. Table 5-17 shows the reliability requirement calculation for the 2025/2026 RPM Base Residual Auction and the update for the Third Incremental Auction for 2025/2026. The pool wide accredited UCAP factor for the Third IA is based on the January 23, 2025, ELCC ratings which use the PJM 2024 load forecast model. These updated ELCC ratings reduced the pool wide accredited UCAP factor from 0.7969 to 0.7963. The reliability requirement and the FRR obligation both increase, resulting in an increase of 395.7 MW (UCAP) to the reliability requirement adjusted for FRR. PJM needs to procure an additional 395.7 MW (UCAP) of capacity in the Third Incremental Auction.

136 PJM stated that the 2024 load forecast model was used because it is the "most recently finalized PJM load forecast." The January 23, 2025, ELCC Ratings are based on the PJM 2024 load forecast model. The December 31, 2024, ELCC Ratings are based on an interim PJM 2025 load forecast model.

Table 5-17 PJM Reliability Requirement[137] [138] [139]

	2025/2026 Base Residual Auction	2025/2026 Third Incremental Auction	Change
ICAP	191,693.0	188,920.0	(2,773.0)
Solved Load	160,624.0	158,357.0	(2,267.0)
Installed Reserve Margin	17.800%	17.800%	0.0%
Accredited UCAP	152,765.0	150,438.0	(2,327.0)
Pool Wide Accredited UCAP Factor	0.797	0.796	(0.001)
Forecast Pool Requirement	0.939	0.938	(0.001)
Preliminary Forecast Peak Load	153,883.0	154,534.1	651.0
Reliability Requirement	144,450.0	144,953.0	503.0
Fixed Resource Requirement (FRR)	10,886.4	10,993.7	107.3
Reliability Requirement Adjusted for FRR	133,563.6	133,959.3	395.7

PJM filed tariff changes that transfer risk caused by the volatile ELCC ratings from generation owners to the load. ELCC ratings may increase or decrease significantly between the time a generator clears in the RPM Base Residual Auction and the final ELCC rating just prior to the start of the delivery year. Under the new tariff rules, generators will be excused from paying the Capacity Resource Deficiency Charge for a deficiency caused by a decrease in the final ELCC rating. Under the prior rules, a Capacity Market Seller was required to cover its short position by acquiring additional capacity or pay a deficiency penalty equal to 20 percent of the base residual auction clearing price for each MW of shortage. The tariff change was filed by PJM on April 18, 2025, and approved by FERC on June 17, 2025.[140] [141] The MMU opposed the change because the new rule does not mitigate the risk as asserted by PJM but simply transfers the ELCC rating volatility risk to the load.[142] The change is inconsistent with basic market logic under which investors bear the

137 *2025/2026 RPM 3rd Incremental Auction Planning Parameters*, PJM Interconnection L.L.C. (January 31, 2025) <https://www.pjm.com/markets-and-operations/rpm>.

138 *Installed Reserve Margin (IRM), Forecast Pool Requirement (FPR), and Effective Load Carrying Capability (ELCC) for BRA* at 15, Item 5, PJM Markets & Reliability Committee meeting, PJM Interconnection L.L.C. (March 20, 2024). <https://www.pjm.com/committees-and-groups/committees/mrc>.

139 *Installed Reserve Margin (IRM), Forecast Pool Requirement (FPR), and Effective Load Carrying Capability (ELCC) for 3IA* at 7, Item 3, PJM Members Committee meeting, PJM Interconnection L.L.C. (January 23, 2025). <https://www.pjm.com/committees-and-groups/committees/mc>.

140 *Proposal to Mitigate Impacts From Updates to ELCC Accreditation between the Base Residual Auction and the Final ELCC Accreditation Values*, PJM Interconnection L.L.C., Docket ER25-2002 (April 18, 2025).

141 191 FERC ¶ 61,203 (June 17, 2025).

142 See *Comments of the Independent Market Monitor for PJM* (May 9, 2025), *Answer and Motion for Leave to Answer of the Independent Market Monitor for PJM* (June 9, 2025), *Answer and Motion for Leave to Answer of the Independent Market Monitor for PJM* (June 16, 2025), Docket ER25-2002-000).

risk associated with the ownership of generation. The new rules are effective beginning with the 2026/2027 Delivery Year.

PJM has calculated and posted marginal ELCC ratings on 11 occasions for the 2025/2026 through 2028/2029 Delivery Years. Figure 5-5 shows the ELCC class ratings for intermittent resources. The horizontal axis shows the delivery year to which the ratings apply and the month the ratings were posted. The ratings change each time they are recalculated. The original rating for onshore wind for the 2025/2026 Delivery Year was 21 percent and the final rating for 2025/2026 Delivery Year was 38 percent, an 80.9 percent increase. The onshore wind rating for the 2027/2028 Delivery Year is 41 percent, a 95.2 percent increase over the initial 2025/2026 rating. Solar has decreased. Solar with tracking technology has decreased from the initial 2025/2026 rating of 25 percent to 8 percent for the 2027/2028 Delivery Year, a 68.0 percent decrease. Solar with fixed panels has decreased 53.3 percent over the same period.

Figure 5-5 Marginal ELCC Class Ratings for Intermittent Resources

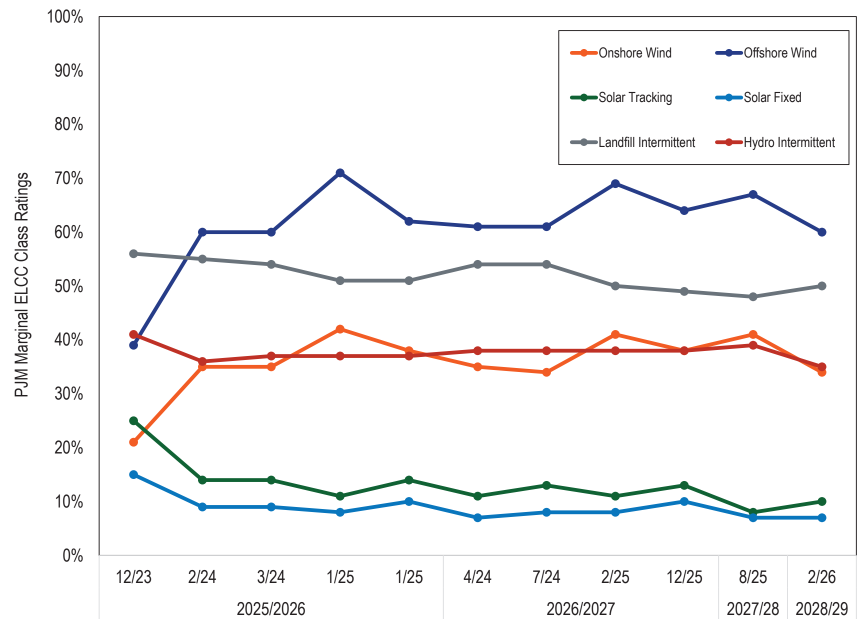
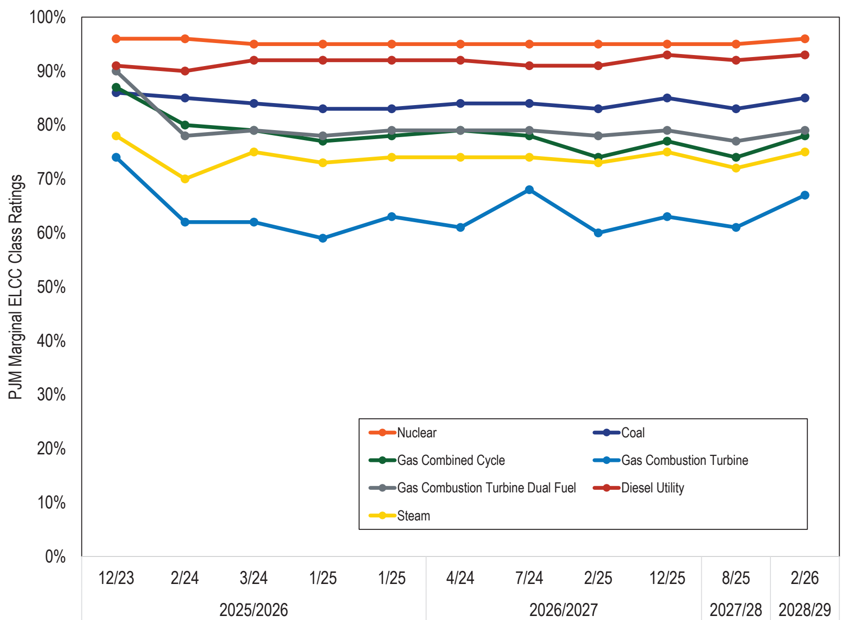


Figure 5-6 shows the ELCC rating for thermal resources. Combined cycle resource and combustion turbine ratings have decreased from their initial 2025/2026 ratings. The original rating for combined cycle resources for the 2025/2026 Delivery Year was 87 percent and the final rating for 2025/2026 Delivery Year was 78 percent, a 10.3 percent decrease. The combined cycle rating for the 2027/2028 Delivery Year is 74 percent, a 14.9 percent decrease over the initial 2025/2026 rating. Combustion turbine ratings have also decreased. Ratings for combustion turbines with dual fuel capability have decreased from the initial 2025/2026 rating of 90 percent to 77 percent for the 2027/2028 Delivery Year, a 14.4 percent decrease. Ratings for combustion turbines without dual fuel capability have decreased 17.6 percent over the same period. The change in UCAP for combined cycle and combustion turbine resources from the initial 2025/2026 ELCC ratings to the latest 2027/2028 ratings is a decrease of 11.5 GW. The corresponding change in ICAP is a decrease of 1.2 GW.

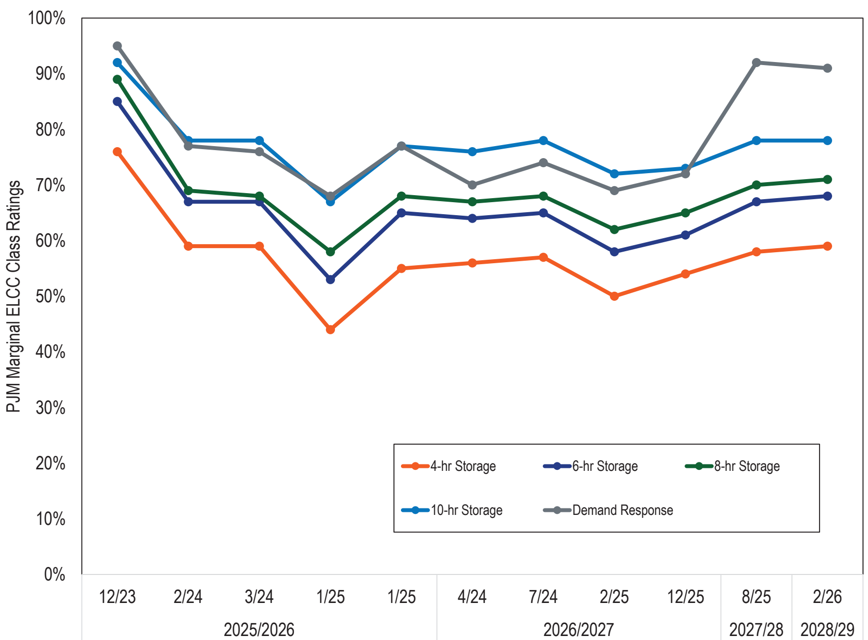
PJM could partially offset this loss of capacity in the short run by recognizing the winter capability of thermal resources rather than limiting such resources to summer ratings. Most of the risk recognized in the ELCC model is winter risk but the ELCC accreditation values for thermal resources are capped at the summer ratings. That unnecessarily limits supply and changes the ELCC values for all other resources and changes the system accredited unforced capacity and therefore AUCAP, the maximum level of load that can be served by the existing resources and therefore the reliability requirement. The CIRs of such resources are currently limited by the summer ratings but those rules can and should be changed given the use of the ELCC approach. There is no reason that excess winter CIRs cannot be assigned to these resources immediately.

Figure 5-6 Marginal ELCC Class Ratings for Thermal Resources



Marginal ELCC ratings for storage and demand response resources have also exhibited volatility. Figure 5-7 shows that the storage resource ratings have decreased. On average across all durations, storage ELCC ratings have decreased 20.4 percent from the initial 2025/2026 Delivery Year ratings to the 2027/2028 Delivery Year ratings. The initial rating for demand response for the 2025/2026 Delivery Year was 95 percent and final rating for the 2025/2026 Delivery Year was 77 percent, an 18.9 percent decrease. Due to recent rule change, the demand response rating for the 2027/2028 Delivery Year is 92 percent.[143]

Figure 5-7 Marginal ELCC Class Ratings for Storage and Demand Resources



143 191 FERC ¶61,103 (May 5, 2025).

Market Conduct

Offer Caps

Market power mitigation measures were applied to capacity resources such that the sell offer was set equal to the defined offer cap when the capacity market seller failed the market structure test for the auction, the submitted sell offer exceeded the defined offer cap, and the submitted sell offer, absent mitigation, would have increased the market clearing price.[144] [145] [146] For Capacity Performance Resources, for RPM auctions prior to September 2, 2021, offer caps were defined in the PJM Tariff as the applicable zonal Net Cost of New Entry (CONE) times (B) where B is the average of the Balancing Ratios (B) during the Performance Assessment Hours in the three consecutive calendar years that precede the base residual auction for such delivery year, unless net avoidable costs exceed this level, or opportunity costs based on the potential sale of capacity in an external market exceed this level. The Commission issued an order eliminating the prior offer cap and establishing a competitive market seller offer cap set at Net ACR, effective September 2, 2021.[147] The Commission rejected an attempt by PJM to undermine the Market Seller Offer Cap rules by order issued February 6, 2024.[148] The Commission approved changes to the Market Seller Offer Cap that allow Capacity Market Sellers to offer the higher of the net ACR and the Capacity Performance Quantifiable Risk (CPQR)[149] and to submit resource specific segmented offer caps.[150] Both changes to the Market Seller Offer Cap give Capacity Market Sellers the ability to offer in excess of the competitive offer and exercise market power as a result.

For RPM Third Incremental Auctions prior to September 2, 2021, capacity market sellers may elect an offer cap equal to the greater of the Net CONE for the relevant LDA and delivery year or 1.1 times the BRA clearing price for the relevant LDA and delivery year. For RPM Third Incremental Auctions after September 2, 2021, capacity market sellers may elect an offer cap of 1.1 times the BRA clearing price for the relevant LDA and delivery year.

Avoidable costs are costs that are neither short run marginal costs, like fuel or consumables, nor fixed costs like depreciation and rate of return. Avoidable costs are the costs that a generation owner incurs as a result of operating a generating unit for one year, in particular the delivery year.[151] As a result, the tariff defines avoidable costs as the costs that a generation owner would not incur if the generating unit did not offer for one year. Although the term mothball is used in the tariff to modify the term ACR, the term mothball is not defined in the tariff. Mothball is an informal term better understood as a metaphor for the cost to operate for one year. Avoidable costs are the costs to operate the unit for one year, regardless of whether the unit plans to retire. Although the tariff includes different mothball and retirement values, the distinction is based on a misunderstanding of the meaning of avoidable costs and should be eliminated. PJM never explained exactly how it calculated mothball and retirement avoidable cost levels. The MMU recommends that major maintenance costs be included in the definition of avoidable costs and removed from energy offers because such costs are avoidable costs and not short run marginal costs.[152] The tariff states that avoidable costs may also include annual capital recovery associated with investments required to maintain a unit as a Generation Capacity Resource, termed Avoidable Project Investment Recovery (APIR), despite the fact that these are not actually avoidable costs, particularly after the first year.

Avoidable cost based offer caps are defined to be net of revenues from all other PJM markets and unit-specific bilateral contracts, including RECs, and expected bonus performance payments/nonperformance charges.[153] Capacity resource owners could provide ACR data by providing their own unit-specific data or, for auctions for delivery years prior to 2020/2021 and auctions held

144 See OATT Attachment DD § 6.5.
145 Prior to November 1, 2009, existing DR and EE resources were subject to market power mitigation in RPM Auctions. See 129 FERC ¶ 61,081 at P 30 (2009).
146 Effective January 31, 2011, the RPM rules related to market power mitigation were changed, including revising the definition for Planned Generation Capacity Resource and creating a new definition for Existing Generation Capacity Resource for purposes of the must offer requirement and market power mitigation, and treating a proposed increase in the capability of a Generation Capacity Resource the same in terms of mitigation as a Planned Generation Capacity Resource. See 134 FERC ¶ 61,065 (2011).
147 176 FERC ¶ 61,137 (2021), *order denying reh'g*, 178 FERC ¶ 61,121 (2022), *appeal denied*, EPSA, et al. v. FERC, Case No. 21-1214, et al. (DC Cir. October 10, 2023), *cert. denied*.
148 186 FERC ¶ 61,097, *reh'g denied*, 187 FERC ¶ 62,016 (2024).
149 190 FERC ¶ 61,117 (February 20, 2025).
150 Id. at 123.
151 OATT Attachment DD § 6.8(b).
152 *PJM Interconnection L.L.C., Docket Nos. ER19-210-000 and EL19-8-000, Responses to Deficiency Letter re: Major Maintenance and Operating Costs Recovery* (February 14, 2019).
153 For details on the competitive offer of a capacity performance resource, see "Analysis of the 2023/2024 RPM Base Residual Auction," <https://www.monitoringanalytics.com/reports/Reports/2022/IMM_Analysis_of_the_20232024_RPM_Base_Residual_Auction_20221028.pdf> (October 28, 2022).

after September 2, 2021, by selecting the default ACR values. The specific components of avoidable costs are defined in the PJM tariff.[154]

Effective for the 2018/2019 and subsequent delivery years, the ACR definition includes two additional components, Avoidable Fuel Availability Expenses (AFAE) and Capacity Performance Quantifiable Risk (CPQR).[155] AFAE is available for Capacity Performance Resources. AFAE is defined to include expenses related to fuel availability and delivery. CPQR is available for Capacity Performance Resources and, for the 2018/2019 and 2019/2020 Delivery Years, Base Capacity Resources. CPQR is defined to be the quantifiable and reasonably supported cost of mitigating the risks of nonperformance associated with submission of an offer.

The opportunity cost option allows capacity market sellers to offer based on a documented price available in a market external to PJM, subject to export limits. If the relevant RPM market clears above the opportunity cost, the generation capacity resource is sold in the RPM market. If the opportunity cost is greater than the clearing price and the generation capacity resource does not clear in the RPM market, it is available to sell in the external market.

Effective with the 2026/2027 Delivery Year, the market seller offer cap definition was modified to include unit specific standalone Capacity Performance Quantifiable Risk (CPQR) and segmented unit specific offer caps.[156] For standalone CPQR, the offer cap is defined as the unit specific CPQR with no net revenue offset applied. For segmented unit specific offer caps, the capacity market seller can request that the first segment of the segmented unit specific offer cap be based on either unit specific standalone CPQR or net unit specific ACR. The remaining segments from the second segment up to the tenth segment are defined to be based on standalone CPQR.[157]

Allowing offers based on gross CPQR when net revenues are greater than total gross ACR, including CPQR, permits offers greater than the competitive level by allowing resources with a competitive offer of $0 per MW-day to make positive offers equal to one component of ACR, the gross CPQR component, ignoring net revenues entirely. The rule also permits offers greater than the competitive level by allowing resources with a competitive offer greater than $0 per MW-day but less than gross CPQR to make offers equal to one standalone component of ACR, the gross CPQR component, also ignoring net revenues entirely.

The decision to allow segmented offer caps means allowing the exercise of market power. This is the case first because the segmented offer caps require that all avoidable costs be spread over a first MW segment that is smaller than the full resource, thus inflating the MSOC, and allow offer caps for all segments after the first segment based on gross CPQR with no net revenue offsets. If avoidable costs can be assigned to the first, self defined MW offer segment, and the later MW segments are not defined in the rules, MSOCs are meaningless. Assigning gross CPQRs and no net revenues to one or more undefined MW tail blocks would permit offers that exceed the correctly calculated MSOC by multiples and would permit the exercise of market power. The rule does not use any net revenue offset for the CPQR segments. The competitive level is defined as total gross avoidable costs, net of net revenues, divided by the total MW in the offer.

On October 17, 2024, the Commission issued a final rule, Order No. 904, eliminating separate payments for reactive in all jurisdictional markets, including PJM.[158] As a result, effective with the 2026/2027 Delivery Year, reactive revenues are not included in the net revenue offset for RPM purposes including the VRR curve, market seller offer caps, and MOPR floors.[159]

Competitive Offers

The competitive offer of a capacity resource is based, regardless of tariff requirements, on a market seller's expectations of the resource's net going forward costs (net ACR) which are the net of the resource's gross ACR and the resource's forward looking net revenues. The gross ACR includes the cost to mitigate the resource's risk of incurring performance assessment penalties (CPQR).

154 OATT Attachment DD § 6.8(a).
155 151 FERC ¶ 61,208 (2015).
156 190 FERC ¶ 61,117 (2025).
157 OATT Attachment DD § 6.4(e)

158 *Compensation for Reactive Power within the Standard Power Factor Range*, Order No. 904, 189 FERC ¶ 61,034 (2024) ("Order No. 904").
159 See Letter Order, FERC Docket No. ER25-682-001 (April 29, 2025).

The competitive offer is based on a forward looking energy and ancillary services (E&AS) net revenue offset rather than the backward looking E&AS net revenue offset currently in the tariff. Forward prices for energy prices and fuel prices are a better guide to market expectations than historical energy and fuel prices but both sources of information should be incorporated. This is particularly important in years, like 2022, when there is a significant change from the historical level of energy market prices. The forward curves reflect this change, but the historical prices do not. However, the PJM method for calculating forward looking net revenues is significantly flawed and overestimates net revenues.

PJM had a forward looking net revenue calculation in the tariff that applied to RPM Auctions for the 2022/2023 Delivery Year.[160] FERC subsequently reversed its approval of that method as part of rejecting PJM's ORDC filing.[161] PJM's method for calculating forward looking E&AS net revenues was flawed for several reasons. PJM's method included an adjustment based on the prices of long term FTRs for the planning period closest in time to the delivery year which requires an adjustment for monthly average day-ahead congestion price differentials and an adjustment for loss component differentials of historical LMPs. Use of the adjustment based on the prices of long term FTRs adds unnecessary complexity, fails to make the result more accurate, makes the results less transparent, and in some cases make the results less accurate. PJM's use of long term FTRs in the forward energy market price calculation does not use the FTR auction for the desired delivery year as a result of the timing of capacity auctions and FTR auctions when PJM is on its defined three year capacity market auction schedule. It would be simpler, more accurate and more transparent to use forward LMPs calculated using real-time monthly on and off peak forward prices for the delivery year at the PJM Western Hub, adjusted to the zone and hour using the historical zonal, nodal and hourly real-time price differentials for each of the last three years. The MMU and PJM have been implementing this method for years in the calculation of the opportunity costs associated with environmental limits on the operation of generating units.[162]

More fundamentally, PJM's forward looking net revenue calculation tends to overestimate forward net revenues. The PJM method is based on a theoretical, unit by unit perfect dispatch based on unit parameters and forward fuel costs and LMPs. The PJM method fails to account for the realities of committing and dispatching units. Nonetheless, it remains correct that generation owners look forward and not backwards when calculating net revenues. The goal is an approach that retains the reality of historical commitment and dispatch while recognizing that future conditions will be different. A better approach would calculate unit forward looking expected energy and ancillary services net revenues using historical revenues that are scaled based on a comparison of forward prices for energy and fuel to the historical prices for energy and fuel.

The competitive offer of a capacity resource is based on a market seller's expectations of market variables during the delivery year, the impact of these variables on the resource's risk, and the cost to mitigate that risk. These market variables are: the number of performance assessment intervals (PAI) in a delivery year where the resource is located; the level of performance required to meet its capacity obligation during those performance assessment intervals, measured as the average Balancing Ratio (B); and the level of the bonus performance payment rate (CPBR) compared to the nonperformance charge rate (PPR). The total capacity revenues earned by a resource are the sum of revenues earned in the forward capacity auctions and additional bonus revenues earned (or penalties paid) during the delivery year, which are a function of unit performance during PAI (A). The level of the bonus performance payment rate depends on the level of underperforming MW net of the underperforming MW excused by PJM during performance assessment intervals for reasons defined in the PJM OATT.[163]

The September 2, 2021, Commission order addressed the definition of the market seller offer cap by eliminating the Net CONE times B offer cap

160 171 FERC ¶ 61,153 (May 21, 2020) and 173 FERC ¶ 61,134 (November 12, 2020).
161 Forward energy and ancillary services (E&AS) revenue offsets were applicable from November 12, 2020, as approved in the FERC Order on compliance in Docket Nos. EL19-58-002 and EL19-58-003 until December 22, 2021, when the Commission issued an Order on Voluntary Remand in Docket Nos. EL19-58-006 and ER19-1486-003 reversing its prior determination that PJM should use a forward looking energy E&AS revenue offset and directing PJM to submit a compliance filing restoring the tariff provisions defining the historical E&AS revenue offset.
162 *See* "PJM Manual 15: Cost Development Guidelines," § 12.7 IMM Opportunity Cost Calculator, Rev. 47 (Oct. 1, 2025).
163 OATT Attachment DD § 10A (d).

and establishing a competitive market seller offer cap of net ACR.[164] The Commission rejected a more recent attempt by PJM to undermine the Market Seller Offer Cap rules by order issued February 6, 2024.[165]

In February 2025, PJM filed, and FERC approved, changes to the Market Seller Offer Cap that allow Capacity Market Sellers to offer the higher of the net ACR and the Capacity Performance Quantifiable Risk (CPQR).[166] The changes also allow Capacity Market Sellers to submit resource specific segmented offer caps.[167] Both changes to the Market Seller Offer Cap give Capacity Market Sellers the ability to offer in excess of the competitive offer.

Allowing offers based on gross CPQR when net revenues are greater than total gross ACR, including CPQR, permits offers greater than the competitive level by allowing resources with a competitive offer of $0 per MW-day to make positive offers equal to one component of ACR, the gross CPQR component, ignoring net revenues entirely. The rule also permits offers greater than the competitive level by allowing resources with a competitive offer greater than $0 per MW-day but less than gross CPQR to make offers equal to one standalone component of ACR, the gross CPQR component, also ignoring net revenues entirely.

The decision to allow segmented offer caps means allowing the exercise of market power. This is the case first because the segmented offer caps require that all avoidable costs be spread over a first MW segment that is smaller than the full resource, thus inflating the MSOC, and allow offer caps for all segments after the first segment based on gross CPQR with no net revenue offsets. If avoidable costs can be assigned to the first, self defined MW offer segment, and the later MW segments are not defined in the rules, MSOCs are meaningless. Assigning gross CPQRs and no net revenues to one or more undefined MW tail blocks would permit offers that exceed the correctly calculated MSOC by multiples and would permit the exercise of market power. The rule does not use any net revenue offset for the CPQR segments. The competitive level is defined as total gross avoidable costs, net of net revenues, divided by the total MW in the offer.

164 176 FERC ¶ 61,137 (2021), *order denying reh'g*, 178 FERC ¶ 61,121 (2022), *appeal denied*, EPSA, et al. v. FERC, Case No. 21-1214, et al. (DC Cir. October 10, 2023).
165 186 FERC ¶ 61,097, *reh'g denied*, 187 FERC ¶ 62,016 (2024).
166 190 FERC ¶ 61,117 (February 20, 2025).
167 Id. at 123.

2026/2027 RPM Third Incremental Auction

As shown in Table 5-18, 985 generation resources submitted Capacity Performance offers in the 2026/2027 RPM Third Incremental Auction. Unit specific offer caps were calculated for four generation resources (0.4 percent). Of the 985 generation resources, 816 generation resources elected the offer cap option of 1.1 times the BRA clearing price (82.8 percent), four generation resource had unit specific ACR based offer caps (0.4 percent), 13 Planned Generation Capacity Resources had uncapped offers (1.3 percent), and the remaining 152 generation resources were price takers (15.4 percent). Market power mitigation was applied to zero Capacity Performance sell offers.

Table 5-18 ACR statistics: RPM auctions held through the first six months, 2026

	2026/2027 Third Incremental Auction	
Offer Cap/Mitigation Type	Number of Generation Resources	Percent of Generation Resources Offered
Default ACR	0	0.0%
Unit specific ACR (APIR)	4	0.4%
Unit specific ACR (APIR and CPQR)	0	0.0%
Unit specific ACR (non-APIR)	0	0.0%
Unit specific ACR (non-APIR and CPQR)	0	0.0%
Unit specific standalone CPQR	NA	NA
Unit specific segmented offer caps	NA	NA
Opportunity cost input	0	0.0%
Default ACR and opportunity cost	0	0.0%
Offer cap of 1.1 times BRA clearing price elected	816	82.8%
Uncapped planned uprate and default ACR	0	0.0%
Uncapped planned uprate and opportunity cost	0	0.0%
Uncapped planned uprate and price taker	0	0.0%
Uncapped planned uprate and 1.1 times BRA clearing price elected	0	0.0%
Uncapped planned generation resources	13	1.3%
Existing generation resources as price takers	152	15.4%
Total Generation Capacity Resources offered	985	100.0%

MOPR

By order issued December 19, 2019, the RPM Minimum Offer Price Rule (MOPR) was modified.[168] The rules applying to natural gas fired capacity resources without state subsidies were retained. The changes included expanding the MOPR to new or existing state subsidized capacity resources; establishing a competitive exemption for new and existing resources other than natural gas fired resources while also allowing a resource specific exception process for those that do not qualify for the competitive exemption; defining limited categorical exemptions for renewable resources participating in renewable portfolio standards (RPS) programs, self supply, DR, EE, and capacity storage; defining the region subject to MOPR for capacity resources with state subsidy as the entire RTO; and defining the default offer price floor for capacity resources with state subsidies as 100 percent of the applicable Net CONE or net ACR values.

On September 29, 2021, PJM's FPA section 205 filing in Docket No. ER21-2582-000 revising the Minimum Offer Price Rule (MOPR) was made effective by operation of law.[169] The revised MOPR in OATT Attachment DD § 5.14(h-2) became effective for RPM auctions for the 2023/2024 and subsequent delivery years. Under the revised MOPR, a generation resource would be subject to an offer floor if the capacity is deemed to meet the definition of Conditioned State Support or if the capacity market seller plans to use the resource to exercise Buyer-Side Market Power as the term is defined in the tariff through either self certification or a fact specific review initiated by the MMU or PJM. Whether a state program or policy qualifies for Conditioned State Support would be the result of a Commission determination.

The PJM markets would be better off, more competitive, and more efficient with no MOPR than with PJM's approach. PJM's proposal effectively eliminated the MOPR while creating a confusing and inefficient administrative process that effectively makes it both unnecessary and impossible to prove buyer side market power as PJM has defined it.[170]

168 169 FERC ¶ 61,239 (2019), *order denying reh'g*, 171 FERC ¶ 61,035 (2020), *aff'd* PJM Power Providers Group, et al. v. FERC, Case No. 21-3068 (3rd Cir. December 1, 2023), *cert denied*.

169 *PJM Interconnection, L.L.C*, Notice of Filing Taking Effect by Operation of Law, Docket No. ER21-2582 (September 29, 2021).

170 See Protest of the Independent Market Monitor for PJM, Docket No. ER21-2582-000 (August 20, 2021); Answer and Motion for Leave to Answer of the Independent Market Monitor for PJM, Docket No. ER21-2582-000 (September 22, 2021).

The current form of the MOPR has no meaningful impact. The only function the current MOPR is serving now is to create unnecessary administrative work in the application and compliance screening and to create barriers to entry for generation resources. Generation resources that miss a certification deadline to check a box that they are not receiving state conditioned support and will not exercise market power are then required to offer at uncompetitive Net CONE levels or are not allowed to offer because the applicable MOPR floor exceeds the offer cap or no default MOPR floor for the technology is defined. Absent a meaningful change to MOPR, the MMU recommends eliminating the MOPR.

MOPR Statistics

Under the applicable MOPR rules, market power mitigation measures were applied to MOPR Screened Generation Resources such that the sell offer is set equal to the MOPR Floor Offer Price when the submitted sell offer is less than the MOPR Floor Offer Price and an exemption or exception was not granted, or the sell offer is set equal to the agreed upon minimum level of sell offer when the sell offer is less than the agreed upon minimum level of sell offer based on a Unit-Specific Exception or Resource-Specific Exception.

As shown in Table 5-19, there were no unit specific exception requests for MOPR under OATT Attachment DD § 5.14(h-2) for the 2025/2026 RPM Third Incremental Auction. Of the 14.7 MW offered in the 2026/2027 RPM Third Incremental Auction that were subject to MOPR, 14.6 MW cleared and 0.1 MW did not clear.

Table 5-19 MOPR statistics: RPM auctions held through the first six months, 2026

	MOPR Type	Calculation Type	Number of Requests	ICAP (MW) Requested	ICAP (MW) MMU Agreed	ICAP (MW) Offered	UCAP (MW) Offered	UCAP (MW) Cleared
2026/2027 Third Incremental Auction	OATT Attachment DD § 5.14(h-2)	Unit Specific Exception	0	0.0	0.0	0.0	0.0	0.0
	OATT Attachment DD § 5.14(h-2)	Default	NA	NA	NA	63.8	14.7	14.6
	Total		0	0.0	0.0	63.8	14.7	14.6

Replacement Capacity[171]

When a capacity resource is not available for a delivery year, the owner of the capacity resource may purchase replacement capacity. Replacement capacity is the vehicle used to offset any reduction in capacity from a resource which is not available for a delivery year. But the replacement capacity mechanism may also be used to manipulate the market.

Table 5-20 shows the committed and replacement capacity for all capacity resources for June 1 of each year from 2007 through 2027.

Sellers of demand resources in RPM auctions disproportionately replace those commitments on a consistent basis compared to sellers of other resource types. External generation and internal generation not in service had high rates of replacement in some years and those are also of concern.

The dynamic that can result is that the speculative DR suppresses prices in the BRA and displaces physical generation assets. Those generation assets then have an incentive to offer at a low price, including offers at zero and below cost, in IAs in order to ensure some capacity market revenue for long lived physical resources which the owners expect to maintain for multiple years. The result is lower IA prices which permit the buyback of the speculative DR at prices below the BRA prices which encourages the greater use of speculative DR.

PJM's sale of capacity in IAs at very low prices, given that PJM announces the MW quantity and the sell offer price in advance of the auctions, further reduces IA prices and increases the incentive of DR sellers to speculate in the BRAs. The MMU recommends that if PJM sells capacity in incremental auctions, PJM should offer the capacity for sale at the BRA clearing price in order to avoid suppressing the IA price below the competitive level. If the PJM sell offer price is not the BRA clearing price, PJM should not reveal its proposed sell offer price or the MW quantity to be sold prior to the auction.

It has been asserted that selling at a high price in the BRA and buying back at a low price in the IA is just a market transaction and therefore does not constitute a problem. But permitting DR to be an option in the BRA rather than requiring DR to be a commitment to provide a physical asset gives DR an unfair advantage and creates a self fulfilling dynamic that incents more of the same behavior. Only DR is permitted to be an option in the BRA. Generation resources must have met physical milestones in order to offer in the BRA. It is not reasonable to permit DR capacity resources to have a different product definition than generation capacity resources. Even if DR is treated as an annual product, this unique treatment as an option makes DR an inferior resource and not a complete substitute for generation resources. The current approach to DR is also inconsistent with the history of the definition of capacity in PJM, which has always been that capacity is physical and unit specific. The current approach to DR effectively makes DR a virtual participant in the PJM Capacity Market. That option should be eliminated.

171 For more details on replacement capacity, see "Analysis of Replacement Capacity for RPM Commitments: June 1, 2007 to June 1, 2019," <http://www.monitoringanalytics.com/reports/Reports/2019/IMM_Analysis_of_Replacement_Capacity_for_RPM_Commitments_June_1_2007_to_June_1_2019_20190913.pdf> (September 13, 2019).

The definition of demand side resources in PJM capacity markets is flawed in a variety of ways. The current demand side definition should be replaced with a definition that includes demand on the demand side of the market. There are ways to ensure and enhance the vibrancy of demand side without negatively affecting markets for generation.

Table 5-20 RPM commitments and replacements for all Capacity Resources: June 1, 2007 to June 1, 2027[172]

	UCAP (MW)					
	RPM Cleared	Adjustments to Cleared	Net Replacements	RPM Commitments	RPM Commitment Shortage	RPM Commitments Less Commitment Shortage
01-Jun-07	129,409.2	0.0	0.0	129,409.2	(8.1)	129,401.1
01-Jun-08	130,629.8	0.0	(766.5)	129,863.3	(246.3)	129,617.0
01-Jun-09	134,030.2	0.0	(2,068.2)	131,962.0	(14.7)	131,947.3
01-Jun-10	134,036.2	0.0	(4,179.0)	129,857.2	(8.8)	129,848.4
01-Jun-11	134,182.6	0.0	(6,717.6)	127,465.0	(79.3)	127,385.7
01-Jun-12	141,295.6	(11.7)	(9,400.6)	131,883.3	(157.2)	131,726.1
01-Jun-13	159,844.5	0.0	(12,235.3)	147,609.2	(65.4)	147,543.8
01-Jun-14	161,214.4	(9.4)	(13,615.9)	147,589.1	(1,208.9)	146,380.2
01-Jun-15	173,845.5	(326.1)	(11,849.4)	161,670.0	(1,822.0)	159,848.0
01-Jun-16	179,773.6	(24.6)	(16,157.5)	163,591.5	(924.4)	162,667.1
01-Jun-17	180,590.5	0.0	(13,982.7)	166,607.8	(625.3)	165,982.5
01-Jun-18	175,996.0	0.0	(12,057.8)	163,938.2	(150.5)	163,787.7
01-Jun-19	177,064.2	0.0	(12,300.3)	164,763.9	(9.3)	164,754.6
01-Jun-20	174,023.8	(335.3)	(10,582.7)	163,105.8	(5.7)	163,100.1
01-Jun-21	174,713.0	0.0	(12,963.3)	161,749.7	(316.9)	161,432.8
01-Jun-22	150,465.2	0.0	(5,576.9)	144,888.3	(1,212.7)	143,675.6
01-Jun-23	150,143.9	0.0	(5,517.6)	144,626.3	(2,363.5)	142,262.8
01-Jun-24	154,362.5	0.0	(4,046.2)	150,316.3	(4,377.2)	145,939.1
01-Jun-25	137,733.6	0.0	(1,812.6)	135,921.0	(954.8)	134,966.2
01-Jun-26	137,803.1	0.0	(3,283.5)	134,519.6	(100.8)	134,418.8
01-Jun-27	134,478.1	0.0	0.0	134,478.1	0.0	134,478.1

Market Performance

Figure 5-8 shows cleared MW weighted average capacity market prices on a delivery year basis including base and incremental auctions for each delivery year, and the weighted average clearing prices by LDA in each Base Residual Auction for the entire history of the PJM capacity markets.

172 The RPM Commitment Shortage MW for June 1, 2025, were revised from the ***2026 Quarterly State of the Market Report for PJM: January through March***.

Table 5-21 shows RPM clearing prices for the 2021/2022 through 2027/2028 Delivery Years for all RPM auctions held through the first six months of 2026, and Table 5-22 shows the RPM cleared MW for the 2021/2022 through 2027/2028 Delivery Years for all RPM auctions held through the first six months of 2026.

Figure 5-9 shows the RPM cleared MW weighted average prices for each LDA from the 2022/2023 Delivery Year to the current delivery year, and all results for auctions for future delivery years that have been held through the first six months of 2026. A summary of these weighted average prices is given in Table 5-23.

Table 5-24 shows RPM revenue by delivery year for all RPM auctions held through the first six months of 2026 based on the unforced MW cleared and the resource clearing prices. For the 2025/2026 Delivery Year, RPM revenue is $14.9 billion. For the 2026/2027 Delivery Year, RPM revenue is $16.3 billion.

Table 5-25 shows RPM revenue by calendar year for all RPM auctions held through the first six months of 2026. In 2025, RPM revenue is $9.8 billion. In 2026, RPM revenue is $15.8 billion.

Table 5-26 shows the RPM annual charges to load. For the 2025/2026 Delivery Year, annual charges to load are $14.8 billion. For the 2026/2027 Delivery Year, annual charges to load are $16.2 billion.

Table 5-21 Capacity market clearing prices: 2021/2022 through 2027/2028 RPM Auctions

		RPM Clearing Price ($ per MW-day)														
	Product Type	RTO	MAAC	APS	PPL	EMAAC	SWMAAC	DPL South	PSEG	PSEG North	PEPCO	ATSI	COMED	BGE	DUKE	DOM
2021/2022 BRA	Capacity Performance	$140.00	$140.00	$140.00	$140.00	$165.73	$140.00	$165.73	$204.29	$204.29	$140.00	$171.33	$195.55	$200.30	$140.00	$140.00
2021/2022 First Incremental Auction	Capacity Performance	$23.00	$23.00	$23.00	$23.00	$25.00	$23.00	$25.00	$45.00	$219.00	$23.00	$23.00	$23.00	$60.00	$23.00	$23.00
2021/2022 Second Incremental Auction	Capacity Performance	$10.26	$10.26	$10.26	$10.26	$15.37	$10.26	$15.37	$125.00	$125.00	$10.26	$10.26	$10.26	$70.00	$10.26	$10.26
2021/2022 Third Incremental Auction	Capacity Performance	$20.55	$20.55	$20.55	$20.55	$26.36	$20.55	$26.36	$31.00	$31.00	$20.55	$20.55	$20.55	$39.00	$20.55	$20.55
2022/2023 BRA	Capacity Performance	$50.00	$95.79	$50.00	$95.79	$97.86	$95.79	$97.86	$97.86	$97.86	$95.79	$50.00	$68.96	$126.50	$71.69	$50.00
2022/2023 Third Incremental Auction	Capacity Performance	$19.00	$35.00	$19.00	$35.00	$35.00	$96.15	$35.00	$35.00	$35.00	$35.00	$19.00	$19.00	$35.00	$19.00	$19.00
2023/2024 BRA	Capacity Performance	$34.13	$49.49	$34.13	$49.49	$49.49	$49.49	$69.95	$49.49	$49.49	$49.49	$34.13	$34.13	$69.95	$34.13	$34.13
2023/2024 Third Incremental Auction	Capacity Performance	$37.53	$49.49	$37.53	$49.49	$146.03	$49.49	$146.03	$146.03	$146.03	$49.49	$37.53	$37.53	$79.03	$37.53	$37.53
2024/2025 BRA	Capacity Performance	$28.92	$49.49	$28.92	$49.49	$53.60	$49.49	$426.17	$53.60	$53.60	$49.49	$28.92	$28.92	$73.00	$96.24	$28.92
2024/2025 Third Incremental Auction	Capacity Performance	$58.00	$80.00	$58.00	$80.00	$175.81	$80.00	$175.81	$175.81	$175.81	$80.00	$58.00	$58.00	$155.29	$58.00	$58.00
2025/2026 BRA	Capacity Performance	$269.92	$269.92	$269.92	$269.92	$269.92	$269.92	$269.92	$269.92	$269.92	$269.92	$269.92	$269.92	$466.35	$269.92	$444.26
2025/2026 Third Incremental Auction	Capacity Performance	$323.90	$323.90	$323.90	$323.90	$323.90	$323.90	$323.90	$323.90	$323.90	$323.90	$323.90	$323.90	$559.64	$323.90	$323.90
2026/2027 BRA	Capacity Performance	$329.17	$329.17	$329.17	$329.17	$329.17	$329.17	$329.17	$329.17	$329.17	$329.17	$329.17	$329.17	$329.17	$329.17	$329.17
2026/2027 Third Incremental Auction	Capacity Performance	$164.70	$164.70	$164.70	$164.70	$164.70	$164.70	$164.70	$164.70	$164.70	$164.70	$164.70	$164.70	$164.70	$164.70	$164.70
2027/2028 BRA	Capacity Performance	$333.44	$333.44	$333.44	$333.44	$333.44	$333.44	$333.44	$333.44	$333.44	$333.44	$333.44	$333.44	$333.44	$333.44	$333.44

Table 5-22 Capacity market cleared MW: 2021/2022 through 2027/2028 RPM Auctions[173]

		UCAP (MW)														
Delivery Year	Auction	RTO	MAAC	APS	PPL	EMAAC	DPL South	PSEG	PSEG North	PEPCO	ATSI	COMED	BGE	DUKE	DOM	TOTAL
2021/2022	BASE	26,552.8	12,565.1	10,136.1	15,368.6	22,286.8	1,673.8	2,237.7	3,134.1	6,013.2	8,010.5	22,358.1	4,200.7	2,746.1	26,343.7	163,627.3
2021/2022	FIRST	118.7	200.4	45.9	27.2	119.0	15.3	18.3	79.1	207.9	739.3	360.4	48.7	87.6	75.4	2,143.2
2021/2022	SECOND	1,082.0	335.8	30.3	55.4	129.9	39.3	97.0	98.1	75.7	1,216.8	205.9	115.5	65.3	160.5	3,707.5
2021/2022	THIRD	1,243.7	168.7	231.6	127.8	911.0	18.3	227.7	244.8	67.2	942.7	221.7	275.9	159.2	394.7	5,235.0
2022/2023	BASE	29,596.0	12,804.7	10,147.4	14,118.7	23,651.2	1,312.9	1,914.3	2,531.1	3,621.8	10,550.7	19,223.7	4,750.9	2,117.7	8,136.3	144,477.3
2022/2023	THIRD	703.3	338.9	84.2	105.7	572.2	9.4	244.3	402.0	27.4	358.0	2,292.3	409.7	44.8	395.7	5,987.9
2023/2024	BASE	28,642.1	10,098.5	8,145.5	14,352.7	22,912.6	1,412.8	2,497.1	3,344.9	3,521.8	9,535.9	25,368.9	5,001.0	1,966.4	8,266.7	145,066.9
2023/2024	THIRD	255.9	1,786.4	395.0	79.3	671.0	24.2	32.4	43.8	15.3	355.8	1,050.0	240.0	68.4	59.8	5,077.0
2024/2025	BASE	28,760.7	10,854.4	8,874.0	14,178.1	23,135.1	1,448.6	2,665.3	3,494.3	3,429.7	9,720.6	25,156.1	5,056.5	2,062.1	8,646.1	147,481.5
2024/2025	THIRD	365.3	744.8	815.6	665.2	963.0	33.2	48.7	60.2	78.7	245.6	2,370.0	222.5	90.2	177.9	6,881.0
2025/2026	BRA	24,573.1	9,490.1	8,481.3	12,368.8	19,043.0	958.7	1,894.3	2,520.1	2,274.4	7,778.5	21,814.2	2,800.6	1,636.7	20,050.2	135,684.0
2025/2026	THIRD	731.3	22.2	90.8	31.9	564.8	26.1	9.0	34.7	79.4	177.2	91.5	8.3	19.8	162.7	2,049.6
2026/2027	BRA	24,888.5	9,213.7	8,476.5	11,939.7	18,861.0	998.0	1,725.3	2,361.6	2,170.2	7,433.9	20,273.0	4,319.1	1,560.1	19,984.8	134,205.3
2026/2027	THIRD	743.4	197.4	149.4	332.3	247.8	31.9	62.4	75.0	98.6	298.3	544.6	89.9	84.9	641.9	3,597.8
2027/2028	BRA	24,711.5	9,147.3	8,542.9	12,146.5	18,754.7	959.6	1,777.6	2,379.7	2,222.2	7,603.6	19,567.1	4,334.2	2,416.6	19,914.6	134,478.1

173 The MW values in this table refer to rest of LDA or RTO values, which are net of nested LDA values.

Table 5-23 Weighted average clearing prices by zone: 2024/2025 through 2027/2028

	Weighted Average Clearing Price ($ per MW-day)			
LDA	2024/2025	2025/2026	2026/2027	2027/2028
RTO				
AEP	$29.80	$270.57	$324.96	$333.44
APS	$29.80	$270.57	$324.96	$333.44
ATSI	$29.80	$271.18	$321.98	$333.44
Cleveland	$28.92	$270.90	$325.95	$333.44
COMED	$31.42	$270.15	$324.87	$333.44
DAY	$29.13	$295.05	$322.41	$333.44
DUKE	$94.57	$270.57	$320.68	$333.44
DUQ	$29.80	$270.57	$324.96	$333.44
DOM	$29.80	$443.29	$324.05	$333.44
EKPC	$29.80	$270.57	$324.96	$333.44
MAAC				
EMAAC				
ACEC	$58.47	$271.47	$327.72	$333.44
DPL	$58.47	$271.47	$327.72	$333.44
DPL South	$420.55	$271.35	$324.08	$333.44
JCPLC	$58.47	$271.47	$322.79	$333.44
PECO	$58.47	$271.47	$327.72	$333.44
PSEG	$55.54	$270.17	$323.43	$333.44
PSEG North	$55.48	$270.65	$324.11	$333.44
REC	$58.47	$271.47	$327.72	$333.44
SWMAAC				
BGE	$77.88	$466.64	$324.89	$333.44
PEPCO	$50.12	$271.74	$322.02	$333.44
WMAAC				
MEC	$51.07	$270.01	$326.00	$333.44
PE	$51.07	$270.01	$326.00	$333.44
PPL	$51.18	$270.12	$323.88	$333.44

Table 5-24 RPM revenue by delivery year: 2007/2008 through 2027/2028[174]

Delivery Year	Weighted Average RPM Price ($ per MW-day)	Weighted Average Cleared UCAP (MW)	Days	RPM Revenue
2007/2008	$89.78	129,409.2	366	$4,252,287,381
2008/2009	$127.67	130,629.8	365	$6,087,147,586
2009/2010	$153.37	134,030.2	365	$7,503,218,157
2010/2011	$172.71	134,036.2	365	$8,449,652,496
2011/2012	$108.63	134,182.6	366	$5,335,087,023
2012/2013	$75.08	141,283.9	365	$3,871,714,635
2013/2014	$116.55	159,844.5	365	$6,799,778,047
2014/2015	$126.40	161,205.0	365	$7,437,267,646
2015/2016	$160.01	173,519.4	366	$10,161,726,902
2016/2017	$121.84	179,749.0	365	$7,993,888,695
2017/2018	$141.19	180,590.5	365	$9,306,676,719
2018/2019	$172.09	175,996.0	365	$11,054,943,851
2019/2020	$109.82	177,064.2	366	$7,116,815,360
2020/2021	$111.07	173,688.5	365	$7,041,524,517
2021/2022	$147.33	174,713.0	365	$9,395,567,946
2022/2023	$72.33	150,465.2	365	$3,972,428,671
2023/2024	$42.01	150,143.9	366	$2,308,670,914
2024/2025	$45.57	154,362.5	365	$2,567,491,013
2025/2026	$296.98	137,733.6	365	$14,930,072,430
2026/2027	$324.88	137,803.1	365	$16,340,680,278
2027/2028	$333.44	134,478.1	366	$16,411,578,225

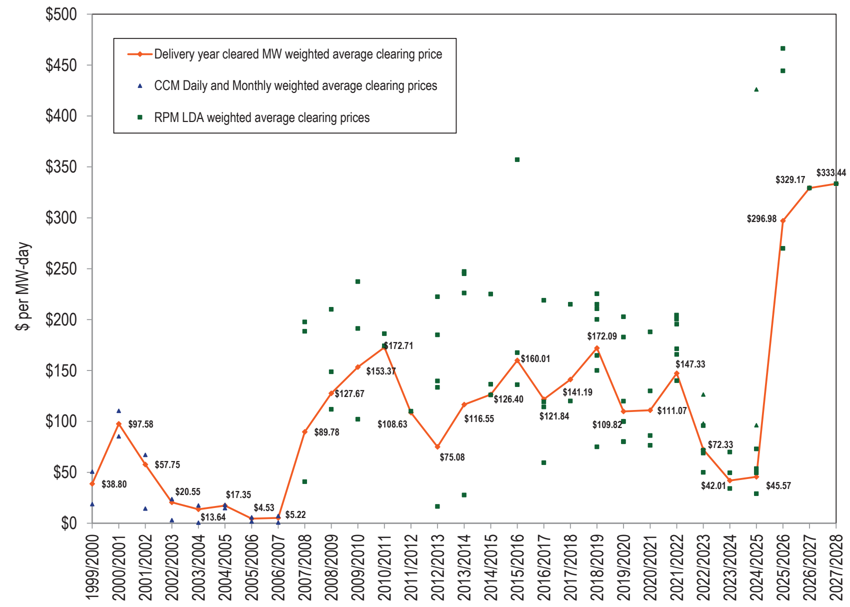
174 The results for the ATSI Integration Auctions are not included in this table.

Table 5-25 RPM revenue by calendar year: 2007 through 2028[175]

Year	Weighted Average RPM Price ($ per MW-day)	Weighted Average Cleared UCAP (MW)	Effective Days	RPM Revenue
2007	$89.78	75,665.5	214	$2,486,310,108
2008	$111.93	130,332.1	366	$5,334,880,241
2009	$142.74	132,623.5	365	$6,917,391,702
2010	$164.71	134,033.7	365	$8,058,113,907
2011	$135.14	133,907.1	365	$6,615,032,130
2012	$89.01	138,561.1	366	$4,485,656,150
2013	$99.39	152,166.0	365	$5,588,442,225
2014	$122.32	160,642.2	365	$7,173,539,072
2015	$146.10	168,147.0	365	$9,018,343,604
2016	$137.69	177,449.8	366	$8,906,998,628
2017	$133.19	180,242.4	365	$8,763,578,112
2018	$159.31	177,896.7	365	$10,331,688,133
2019	$135.58	176,338.6	365	$8,734,613,179
2020	$110.55	175,368.7	366	$7,084,072,778
2021	$132.33	174,289.2	365	$8,421,703,404
2022	$103.36	160,496.5	365	$6,215,973,960
2023	$54.56	150,036.3	365	$2,993,266,921
2024	$44.09	152,857.8	366	$2,464,115,790
2025	$192.97	144,613.0	365	$9,815,689,432
2026	$313.34	137,774.3	365	$15,757,113,743
2027	$329.90	135,638.2	365	$16,355,957,867
2028	$333.44	55,848.8	152	$6,815,737,405

175 The results for the ATSI Integration Auctions are not included in this table.

Figure 5-8 History of capacity prices: 1999/2000 through 2027/2028[176]



176 The 1999/2000 through 2006/2007 capacity prices are CCM combined market, weighted average prices. The 2007/2008 through 2027/2028 capacity prices are RPM weighted average prices. The CCM data points plotted are cleared MW weighted average prices for the daily and monthly markets by delivery year. The RPM data points plotted are RPM LDA clearing prices. For the 2014/2015 and subsequent delivery years, only the prices for Annual Resources or Capacity Performance Resources are plotted.

Figure 5-9 Map of RPM capacity prices: 2024/2025 through 2027/2028

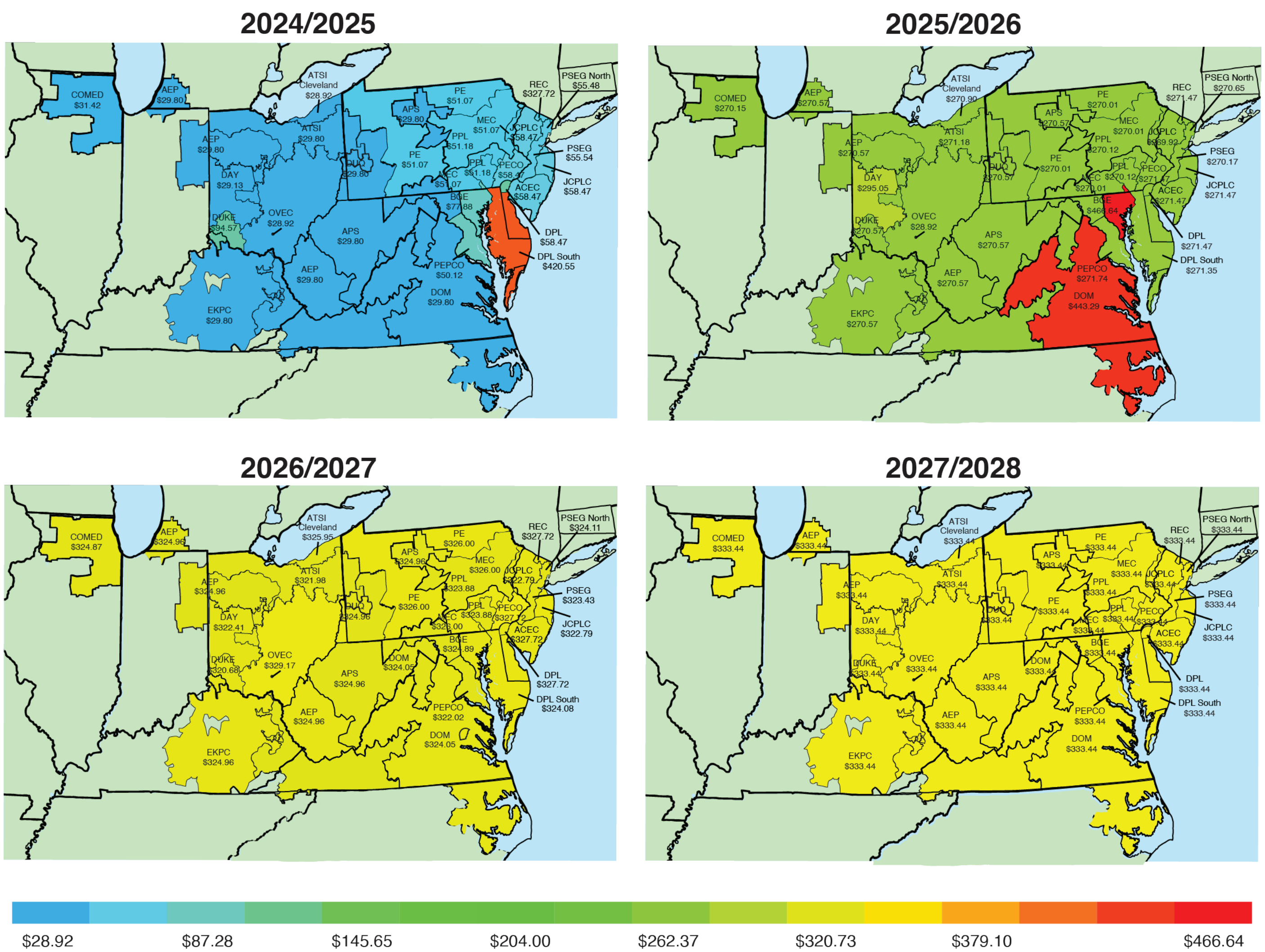


Table 5-26 RPM cost to load: 2021/2022 through 2027/2028 RPM Auctions[177 178]

	Net Load Price ($ per MW-day)	UCAP Obligation (MW)	Annual Charges
2021/2022			
Rest of RTO	$142.16	82,768.3	$4,294,838,410
Rest of EMAAC	$164.73	23,719.9	$1,426,178,211
ATSI	$160.21	13,995.4	$818,411,597
BGE	$163.50	7,491.2	$447,049,048
COMED	$198.43	22,721.2	$1,645,630,168
PSEG	$188.46	10,987.4	$755,803,998
Total		161,683.4	$9,387,911,433
2022/2023			
Rest of RTO	$50.05	50,750.7	$927,101,691
EMAAC	$97.93	35,388.1	$1,264,867,389
WMAAC	$96.61	15,072.2	$531,498,382
BGE	$108.22	7,457.7	$294,575,131
COMED	$66.23	24,064.5	$581,774,443
DEOK	$59.75	5,090.6	$111,011,442
PEPCO	$96.15	6,870.5	$241,111,291
Total		144,694.3	$3,951,939,768
2023/2024			
Rest of RTO	$34.18	78,896.5	$986,982,057
EMAAC	$50.96	30,972.7	$577,657,195
WMAAC	$49.58	22,401.9	$406,535,572
Rest of EMAAC	$57.19	4,375.0	$91,582,753
BGE	$59.38	7,496.6	$162,936,916
Total		144,142.8	$2,225,694,492
2024/2025			
Rest of RTO	$29.50	77,398.7	$833,520,097
EMAAC	$56.56	32,270.3	$666,184,144
WMAAC	$50.22	22,872.2	$419,263,035
Rest of EMAAC	$175.22	4,590.0	$293,561,344
BGE	$61.53	7,726.0	$173,527,700
DEOK	$57.93	5,254.4	$111,105,639
Total		150,111.7	$2,497,161,960
2025/2026			
Rest of RTO	$270.43	108,328.9	$10,692,932,080
BGE	$306.84	6,005.7	$672,628,585
DOM	$432.48	21,570.5	$3,405,010,751
Total		135,905.1	$14,770,571,416
2026/2027			
Rest of RTO	$329.08	134,490.7	$16,154,098,654
Total		134,490.7	$16,154,098,654
2027/2028			
Rest of RTO	$333.69	134,478.1	$16,379,008,974
Total		134,478.1	$16,379,008,974

177 The RPM annual charges are calculated using the rounded, net load prices as posted in the PJM RPM auction results.
178 There is no separate obligation for DPL South as the DPL South LDA is completely contained within the DPL Zone. There is no separate obligation for PSEG North as the PSEG North LDA is completely contained within the PSEG Zone. There is no separate obligation for ATSI Cleveland as the ATSI Cleveland LDA is completely contained within the ATSI Zone.

FRR

The states have authority over their generation resources and can choose to remain in PJM capacity markets or to create FRR entities. The existing FRR approach remains an option for utilities with regulated revenues based on cost of service rates, including both privately and publicly owned (including public power entities and electric cooperatives) utilities. Such regulated utilities have had and continue to have the ability to opt out of the capacity market and provide their own capacity. The existing FRR rules were created in 2007 primarily for the specific circumstances of AEP as part of the original RPM capacity market design settlement. The MMU recommends that the FRR rules be revised and updated to ensure that the rules reflect current market realities and that FRR entities do not unfairly take advantage of those customers paying for capacity in the PJM Capacity Market.

The MMU has prepared reports with analysis of the potential impacts on states pursuing the FRR option. In separate reports for Illinois, Maryland, New Jersey, Ohio, Virginia, and the District of Columbia, the cost impacts of the state choosing the FRR option are computed under different FRR capacity price assumptions and different assumptions regarding the composition of the FRR service area.[179 180 181 182 183 184] The reports showed that the FRR approach is likely to lead to significant increases in payments by customers if it were to replace participation in the PJM markets. The impact on the remaining PJM capacity market footprint is also computed for each scenario. In all but a few scenarios the MMU finds that the FRR leads to higher costs for load included in the FRR service area. In all scenarios the MMU finds that prices in what remains of the PJM Capacity Market would be significantly lower.

179 See Monitoring Analytics, LLC, "Potential Impacts of the Creation of a ComEd FRR," <http://www.monitoringanalytics.com/reports/Reports/2019/IMM_Potential_Impacts_of_the_Creation_of_a_ComEd_FRR_20191218.pdf> (December 18, 2020).
180 See Monitoring Analytics, LLC, "Potential Impacts of the Creation of Maryland FRRs," <http://www.monitoringanalytics.com/reports/Reports/2020/IMM_Potential_Impacts_of_the_Creation_of_Maryland_FRRs_20200416.pdf> (April 16, 2020).
181 See Monitoring Analytics, LLC, "Potential Impacts of the Creation of New Jersey FRRs," <http://www.monitoringanalytics.com/reports/Reports/2020/IMM_Potential_Impacts_of_the_Creation_of_New_Jersey_FRRS_20200513.pdf> (May 13, 2020).
182 *In the Matter of the Investigation of Resource Adequacy Alternatives*, New Jersey Board of Public Utilities, Docket No. EO20030203. Monitoring Analytics, LLC Comments, <http://www.monitoringanalytics.com/filings/2020/IMM_Comments_Docket_No_EO20030203_20200520.pdf> (May 20, 2020). Monitoring Analytics, LLC, Reply Comments <http://www.monitoringanalytics.com/filings/2020/IMM_Reply_Comments_Docket_No_EO20030203_20200624.pdf>. (June 24, 2020). Monitoring Analytics, Answer to Exelon and PSEG, <http://www.monitoringanalytics.com/filings/2020/IMM_Answer_to_Exelon_PSEG_Docket_No_EO20030203_20200715.pdf> (July 15, 2020).
183 See Monitoring Analytics, LLC, "Potential Impacts of the Creation of Ohio FRRs," <http://www.monitoringanalytics.com/reports/Reports/2020/IMM_Potential_Impacts_of_the_Creation_of%20Ohio_FRRs_20200717.pdf> (July 17, 2020).
184 See Monitoring Analytics, LLC, "Potential Impacts of the Creation of Virginia FRRs," <https://www.monitoringanalytics.com/reports/Reports/2021/IMM_VA_FRR_Report_20210518.pdf> (May 18, 2021).

Both FERC and the states have significant and overlapping authority affecting wholesale power markets. While the FERC MOPR approach was designed to ensure that subsidies did not affect the wholesale power markets, the states have ultimate authority over the generation choices made in the states. The FRR explorations by multiple states illustrated a possible path forward. Under that path, the FERC regulated markets would be unaffected by subsidies but many states would withdraw from the FERC regulated markets and create higher cost nonmarket solutions rather than be limited by MOPR. That would not be an efficient outcome and would not serve the interests of customers or generators.

With the elimination of the prior MOPR rules, the capacity market design must accommodate the choices made by states to subsidize renewable resources in a way that maximizes the role of competition to ensure that customers pay the lowest amount possible, consistent with state goals and the costs of providing the desired resources. Such an approach can take several forms, but none require the dismantling of the PJM capacity market design. The PJM capacity market design can adapt to a wide range of state supported resources and state programs. As a simple starting point, states can continue to support selected resources using a range of payment structures and those resources could participate in the capacity auctions. As a broader and more comprehensive option, PJM could create a central PJM RECs market to facilitate the competitive sale and purchase of RECs.

Dominion Energy Virginia elected the FRR option for the 2022/2023 through 2024/2025 delivery years but returned to the capacity market for the 2025/2026 BRA.

CRF Issue[185]

As a result of the significant changes to the federal tax code in December 2017, the capital recovery factor (CRF) tables in PJM OATT Attachment DD § 6.8(a) and Schedule 6A were not correct from 2018 through June 6, 2021.[186] These tables should have been updated in 2018. Correct CRFs ensure that offer caps and offer floors in the capacity market are correct. On May 4, 2021, PJM filed updates to the OATT under FPA Section 205.[187] In the filing, PJM proposed new CRFs based on the new tax law and new financial assumptions. The new financial assumptions are identical to the assumptions used in the PJM quadrennial review for the calculation of the cost of new entry (CONE) for the PJM reference resource. The MMU, in comments to the Commission, asked that the following formula be included in the tariff as an efficient alternative to use of tables which require updates whenever tax laws or financial assumptions change:[188] [189]

$$\mathrm{CRF} = \frac{r(1+r)^N\left[1-\frac{sB}{\sqrt{1+r}}-s(1-B)\sqrt{1+r}\sum_{j=1}^{L}\frac{m_j}{(1+r)^j}\right]}{(1-s)\sqrt{1+r}\,[(1+r)^N-1]}$$

The MMU also proposed that PJM discontinue the practice of using an average state tax rate in the CRF calculation. The CRF formula allows for the quick and efficient calculation of a unit's CRF using the state tax rate that is applicable to a specific unit.

185 See related filing on CRF issue in black start: Comments of the Independent Market Monitor for PJM, Docket No. ER21-1635 (April 28, 2021).
186 The federal tax code was changed in the Tax Cuts and Jobs Act or TCJA, Pub. L. No. 115-97, 131 Stat. 2096, Stat. 2105 (2017).
187 "Revisions to Capital Recovery Factor for Avoidable Project Investment Cost Determinations and Request for Waiver of Sixty-Day Notice Requirement," PJM Interconnection L.L.C., Docket No. ER21-1844-000 (May 4, 2021).
188 See "Comments of the Independent Market Monitor for PJM," Docket No. ER21-1844-000 (May 25, 2021).
189 The formula was first introduced in a related Section 205 filing regarding CRFs for black start service. See "Comments of the Independent Market Monitor for PJM" (April 28, 2021) and "Answer and Motion to Answer of the Independent Market Monitor for PJM" (May 19, 2021) in Docket No. ER21-1635-000.

FERC accepted PJM's filing but also required that the MMU's CRF formula be included in the tariff.[190] FERC rejected the MMU's unit specific state tax recommendation. Going forward, PJM will post the CRFs on their website. Table 5-28 shows the CRFs that are currently posted. The values in Table 5-28 were calculated using the formula above and the financial assumptions in Table 5-29. Bonus depreciation assumptions vary by delivery year with 100 percent bonus depreciation assumed in the 2022/2023 Delivery Year. Under the TCJA, the bonus depreciation in each subsequent delivery year is reduced by 20 percent.

Table 5-27 Variable descriptions for the CRF formula

Formula Symbol	Description
r	After tax weighted average cost of capital (ATWACC)
s	Effective tax rate
B	Bonus depreciation percent
N	Cost Recovery Period (years)
L	Lesser of N or 16 (years)
mj	Modified Accelerated Cost Recovery System (MACRS) depreciation factor for year j = 1, ..., 16

On July 4, 2025, with the enactment of the One Big Beautiful Bill Act ("OBBBA"), the bonus depreciation rules changed again. Section 70301 of OBBBA (I.R.C. § 168(k)) allows 100 percent bonus depreciation for "qualified production property ("QPP") acquired and placed in service on or after January 20, 2025.[191] QPP means nonresidential real property used in manufacturing, production, or refining of tangible personal property in the United States.[192] QPP includes power production facilities. To be eligible, construction must begin after January 19, 2025, and before January 1, 2029, and the property must be placed in service before January 1, 2031.[193] Table 5-28 shows the CRF values produced by the CRF formula using the parameter assumptions in Table 5-29. The effect of the change in bonus depreciation rules from the OBBBA is reflected in the CRF for 2027/2028 Third IA. The CRF value for the five year recovery period decreases from 0.314 to 0.249, a 20.7 percent decrease.

190 176 FERC ¶61,003 (2021).
191 OBBBA § 70301(c)(1).
192 OBBBA § 70307(a)(2).
193 *Id.*

Table 5-28 Levelized CRF values: 2023/2024 through 2028/2029 Delivery Years

Age of Unit (Years)	Cost Recovery Period	2023/2024	2024/2025	2025/2026	2026/2027	2027/2028 BRA	2027/2028 3rd IA	2028/2029
		Bonus Depreciation Percent						
		80%	60%	40%	20%	0%	100%	100%
1 to 5	30	0.091	0.094	0.096	0.105	0.107	0.093	0.099
6 to 10	25	0.096	0.098	0.101	0.110	0.113	0.098	0.103
11 to 15	20	0.104	0.107	0.110	0.118	0.121	0.105	0.110
16 to 20	15	0.119	0.122	0.126	0.134	0.138	0.120	0.124
21 to 25	10	0.152	0.158	0.164	0.174	0.180	0.151	0.155
25 Plus	5	0.258	0.271	0.283	0.301	0.314	0.249	0.253
Mandatory CapEx	4	0.312	0.328	0.345	0.367	0.383	0.300	0.303
40 Plus Alternative	1	1.100	1.100	1.100	1.100	1.100	1.100	1.100

Table 5-29 Financial parameter and tax rate assumptions for CRF calculations

	Parameter Values			
Parameter	Prior to 2026/2027	2026/2027	2027/2028	2028/2029
Equity Funding Percent	45.000%	45.000%	45.000%	45.000%
Debt Funding Percent	55.000%	55.000%	55.000%	55.000%
Equity Rate	13.000%	14.100%	14.100%	16.000%
Debt Interest Rate	6.000%	6.300%	6.300%	5.800%
Federal Income Tax Rate	21.000%	21.000%	21.000%	21.000%
State Income Tax Rate	9.300%	9.933%	9.933%	8.500%
Effective Income Tax Rate	28.347%	28.847%	28.847%	27.715%
After Tax Weighted Average Cost of Capital	8.215%	8.810%	8.810%	9.506%

The 2021 update to the CRF values was calculated using the weighted average cost of capital (WACC) model. The original CRF values, prior to 2021, were calculated using a flow to equity (FTE) model. The WACC model assumes a constant debt to equity ratio during the capital recovery period and therefore assumes that debt holders are paid more quickly than is required. The FTE model recognizes that the debt is repaid according to a predetermined payment schedule with all revenue in excess of taxes and debt payments going to the equity investor. The FTE model accurately reflects the cash flows that occur during capital recovery. Table 5-30 compares CRFs calculated under the two approaches using the assumptions in Table 5-29. The difference between the WACC CRF and FTE CRF is dependent upon the capital recovery term and the level of bonus depreciation. The WACC CRF exceeds the FTE CRF by 16.4

percent under 100 percent bonus depreciation with a 30 year cost recovery term. The FTE model is the correct approach because it accurately captures the cash flows during capital recovery over the defined financial life of the asset.

Table 5-30 Comparison of FTE and WACC CRFs

	WACC CRF						FTE CRF					
Capital Recovery	Bonus Percent						Bonus Percent					
Term (years)	100%	80%	60%	40%	20%	0%	100%	80%	60%	40%	20%	0%
4	0.296	0.312	0.328	0.345	0.361	0.377	0.289	0.307	0.324	0.342	0.360	0.377
5	0.246	0.258	0.271	0.283	0.296	0.308	0.238	0.252	0.266	0.280	0.294	0.308
10	0.147	0.152	0.158	0.164	0.169	0.175	0.138	0.145	0.153	0.160	0.168	0.175
15	0.116	0.119	0.122	0.126	0.129	0.132	0.105	0.111	0.116	0.122	0.127	0.133
20	0.101	0.104	0.107	0.110	0.113	0.115	0.090	0.095	0.100	0.105	0.110	0.115
25	0.093	0.096	0.098	0.101	0.104	0.106	0.081	0.086	0.091	0.096	0.100	0.105
30	0.088	0.091	0.094	0.096	0.099	0.101	0.076	0.081	0.085	0.090	0.095	0.099
	Absolute Change (WACC CRF less FTE CRF)						Relative Change					
Capital Recovery	Bonus Percent						Bonus Percent					
Term (years)	100%	80%	60%	40%	20%	0%	100%	80%	60%	40%	20%	0%
4	0.007	0.005	0.004	0.003	0.001	-0.000	2.3%	1.8%	1.2%	0.8%	0.3%	(0.1%)
5	0.007	0.006	0.004	0.003	0.001	-0.000	3.1%	2.3%	1.6%	1.0%	0.4%	(0.1%)
10	0.009	0.007	0.005	0.003	0.002	-0.000	6.5%	4.9%	3.4%	2.1%	0.9%	(0.2%)
15	0.010	0.008	0.006	0.004	0.002	-0.000	9.5%	7.2%	5.0%	3.1%	1.3%	(0.3%)
20	0.011	0.009	0.007	0.005	0.003	0.000	12.2%	9.3%	6.7%	4.4%	2.3%	0.4%
25	0.012	0.010	0.007	0.005	0.003	0.001	14.4%	11.2%	8.2%	5.6%	3.2%	1.1%
30	0.012	0.010	0.008	0.006	0.004	0.002	16.4%	12.8%	9.6%	6.7%	4.1%	1.7%

Timing of Unit Retirements

Generation owners that want to deactivate a unit, either to mothball or permanently retire, must provide notice to PJM and the MMU prior to the proposed deactivation date. Prior to September 2022, generation owners were required to provide deactivation notices at least 90 days before the proposed deactivation date. Beginning in September 2022, PJM and the MMU began reviewing deactivation requests quarterly, and the desired deactivation date is now based on the quarter the request was submitted (Table 5-31). The result is no change to the effective period between the notice and the retirement if notice is provided on the last day of the submittal period, and an increase to six months notice, if notice is given on the first day of the submittal period. The MMU recommends that participants be required to provide a notice of deactivation 12 months prior to an auction in which the unit will not be offered due to the deactivation; and no less than 12 months prior to the date of deactivation.

Table 5-31 Earliest deactivation dates allowed based on quarterly submission

Date Request Submitted	Earliest Deactivation Date Permitted
January 1 to March 31	July 1
April 1 to June 30	October 1
July 1 to September 30	January 1 (following calendar year)
October 1 to December 31	April 1 (following calendar year)

Generation owners seeking a capacity market must offer exemption for a delivery year must submit their deactivation request no later than the December 1 preceding the Base Residual Auction or 120 days before the start of an Incremental Auction for that delivery year.[194] If no reliability issues are found during PJM's analysis of the retirement's impact on the transmission system, and the MMU finds no market power issues associated with the proposed deactivation, the unit may deactivate at any time thereafter.[195]

Table 5-32 shows the timing of actual deactivation dates and the initially requested deactivation date, for all deactivation requests submitted from January 2018 through June 2026. Of the 236 deactivation requests submitted from January 2018 through June 2026, totaling 50,432.4 MW, 38 units (16.1 percent) totaling 6,662.1 MW (13.2 percent) deactivated an average of 167 days earlier than their initially requested date; 38 units (16.1 percent) totaling 7,216.9 (14.3 percent) deactivated an average of 145 days later than the originally requested deactivation date; and 90 units (38.1 percent) totaling 11,241.1 (22.3 percent) deactivated on their initially requested date. Forty two (17.8 percent) of the unit deactivations totaling 17,323.3 (34.3 percent) were cancelled an average of 234 days (approximately 33 weeks) before their scheduled deactivation date, and 28 (11.9 percent) of the unit deactivations totaling 7,989.0 (15.8 percent) have not yet reached their target retirement date. Table 5-33 shows this information broken out by fuel types. Table 5-33 shows the timing of actual deactivation dates and the initially requested deactivation date, for all deactivation requests submitted from January 2018 through June 2026, by fuel type.

Due to the significant increase in the capacity price for the 2025/2026 Delivery Year in the BRA run in June 2024, several units that were scheduled to deactivate rescinded their deactivation requests. In 2024, four units that were slated to deactivate (483 MW from Middle River Power, LLC rescinding Elgin CT 1-4) announced they were rescinding their deactivations. In 2025, 18 other units that were slated to deactivate (216 MW from Gen On Energy Management, LLC rescinding Morgantown CT 3-6; 54.9 MW from Constellation Energy Co. rescinding Perryman 6 unit 1; 15 MW from Tenaska Power Services, Co. rescinding Kenilworth; 272.1 MW from NRG Business Marketing LLC rescinding Fisk CT 31- 34 and Waukegan CT 31 & 32; 223.0 MW from Heritage Power, LLC rescinding Sayreville CT 1-4; 31.0 MW from Forked River Power, LLC rescinding Forked River 2), accounting for 812.0 MW, announced they were rescinding their deactivation requests. In the first six months of 2026, four units that scheduled to deactivate (450.0 MW from Dairyland Power rescinded Elwood CT 5-7; 16.0 MW from NRG, Inc. rescinding Indian River CT 10), accounting for 466.0 MW, announced they were rescinding their deactivation requests. In total, 1,761.0 MW have stayed in the capacity market for the 2026/2027 through 2028/2029 Delivery Years by rescinding their deactivation requests as a result of the significant increase in capacity market prices starting in the 2025/2026 Delivery Year.

Table 5-32 Timing of actual unit deactivations compared to requested deactivation date: Requests submitted January 2018 through June 2026[196]

Status	Number of Units	Percent	Average Days Deviation from Originally Requested Date
Early	37	15.7%	(167)
Late	38	16.1%	145
On time	89	37.7%	0
Cancelled	42	17.8%	(234)
Pending	30	12.7%	-
Total	236	100.0%	-

194 OATT Attachment DD § 6.6(g).
195 OATT Part V §113.
196 Negative values indicate the average number of days the action is taken prior to the requested date.

Table 5-33 Timing of actual unit deactivations compared to requested deactivation date by fuel type: Requests submitted January 2018 through June 2026

Fuel Type	Status	Number of Units	Percent	Average Days Deviation from Originally Requested Date
Biomass	Early	2	40.0%	(4)
	Late	1	20.0%	14
	On time	2	40.0%	-
	Cancelled	0	0.0%	-
	Pending	0	0.0%	-
Total		5	100.0%	-
Coal	Early	15	28.3%	(169)
	Late	10	18.9%	170
	On time	16	30.2%	0
	Cancelled	4	7.5%	(371)
	Pending	8	15.1%	-
Total		53	100.0%	-
Diesel	Early	0	0.0%	-
	Late	0	0.0%	-
	On time	7	100.0%	0
	Cancelled	0	0.0%	-
	Pending	0	0.0%	-
Total		7	100.0%	-
Methane	Early	6	21.4%	(127)
	Late	7	25.0%	71
	On time	11	39.3%	0
	Cancelled	2	7.1%	(190)
	Pending	2	7.1%	-
Total		28	100.0%	-
Natural Gas	Early	7	12.1%	(209)
	Late	12	20.7%	164
	On time	20	34.5%	0
	Cancelled	11	19.0%	(68)
	Pending	8	13.8%	-
Total		58	100.0%	-
Nuclear	Early	0	0.0%	-
	Late	0	0.0%	-
	On time	0	0.0%	-
	Cancelled	10	100.0%	(312)
	Pending	0	0.0%	-
Total		10	100.0%	-
Oil	Early	3	5.6%	(218)
	Late	7	13.0%	188
	On time	24	44.4%	0
	Cancelled	14	25.9%	(296)
	Pending	6	11.1%	-
Total		54	100.0%	-
Solar	Early	0	0.0%	-
	Late	0	0.0%	-
	On time	1	1.9%	0
	Cancelled	0	0.0%	-
	Pending	0	0.0%	-
Total		1	1.9%	-
Solid Waste	Early	0	0.0%	-
	Late	0	0.0%	-
	On time	1	100.0%	0
	Cancelled	0	0.0%	-
	Pending	0	0.0%	-
Total		1	100.0%	-
Storage	Early	4	21.1%	(194)
	Late	1	5.3%	-
	On time	7	36.8%	0
	Cancelled	1	5.3%	-
	Pending	6	31.6%	-
Total		19	100.0%	-

Part V Reliability Service (RMR)

PJM must make out of market payments to units that want to retire (deactivate) but that PJM requires to remain in service, for limited operation, for a defined period because the unit is needed for reliability.[197] This provision has been known as Reliability Must Run (RMR) service but RMR is not defined in the PJM tariff, and the PJM market design has important distinguishing features relative to other regions where arrangements referred to as RMR are used. Here the term Part V reliability service is used. The need to retain uneconomic units in service reflects a flawed market design and/or planning process problems. The current capacity market design fails to include transmission constraints inside LDAs with the result that units needed for reliability do not clear in capacity auctions and that prices are suppressed and an RMR is then required. The current approach does not adequately look forward and attempt to address foreseeable unit retirements, whether for economic or regulatory reasons. The result is the wrong price signal for either investing in the existing resource or investing in new resources to provide locational reliability. The answer is not to artificially increase prices during the RMR while the transmission alternative is under construction but to provide an actionable price signal in advance of retirement as a signal to new generation to enter and compete with the transmission solution. It is essential that the deactivation provisions of the tariff be evaluated and modified, both to provide rules that better anticipate deactivations in the markets and rules that reasonably compensate Part V reliability service if it is still needed. Recent changes to the rules fail to address these issues.[198] It is also essential that queue processes that effectively prevent competition from new generation to replace the old generation be modified.

To improve coordination of deactivations and PJM transmission system planning, the MMU recommends that the same reliability standard be used in capacity auctions as is used by PJM transmission planning which means recognizing transmission constraints inside LDAs when they create reliability issues. One result of the current design is that a unit may fail to clear in a BRA, decide to retire as a result, but then be found to be needed for reliability by PJM planning and paid under Part V of the OATT (RMR) to remain in service while transmission upgrades are made. This result indicates a significant market design flaw.

The MMU recommends that PJM treat the inclusion of RMR resources in the capacity market consistently. PJM currently includes RMR units in the reliability analysis for RPM auctions but does not include the RMR units in the supply curves. This approach is internally inconsistent. It would be internally consistent to leave the RMR units out of the CETO/CETL analysis. It would also be internally consistent to include the RMR units in the supply of capacity and in the CETO/CETL analysis. Including RMR resources in the capacity supply curve does not mean forcing unit owners to offer or to take on PAI risk, for example. It simply means that PJM would recognize the fact that PJM treats RMR resources as a source of reliability. The goal is to ensure that the underlying supply and demand fundamentals are included in the capacity market prices. These two options have very different implications for capacity market prices. There are times early in the process when a price signal for the entry of generation is appropriate, e.g. when the goal is to allow generation to compete to replace the transmission option, in whole or in part, and there is enough time to permit such new entry. There are times later in the process when a price signal for the entry of generation is not needed or appropriate, e.g. when PJM has committed to the construction of new transmission that will eliminate the price signal when complete or when there is not enough time to permit such new entry. The relevant rules can and should be changed.[199]

The planning process should, to the extent possible, evaluate the impact of the loss of units at risk and determine in advance whether transmission upgrades are required.[200] It is essential that PJM look forward and attempt to plan

197 OATT Part V §114.

198 See Deactivation Enhancements Senior Task Force (DESTF), which can be accessed at: <https://www.pjm.com/committees-and-groups/task-forces/destf>.

199 While PJM filed for and FERC accepted the inclusion of RMR resources Brandon Shores and Wagner plants in the 2026/2027 through and 2028/2029 BRAs, that does not require that RMR resources be included in capacity market auction clearing in future auctions for these or other RMR resources. See Letter Order, FERC Docket No. ER25-682-001 (April 29, 2025). See also 193 FERC ¶ 61,234 (2025).

200 *See, e.g.*, 140 FERC ¶ 61,237 at P 36 (2012) ("The evaluation of alternatives to an SSR designation is an important step that deserves the full consideration of MISO and its stakeholders to ensure that SSR Agreements are used only as a 'limited, last-resort measure.'"); 118 FERC ¶ 61,243 at P 41 (2007) ("the market participants that pay for the agreements pay out-of-market prices for the service provided under the RMR agreements, which broadly hinders market development and performance.[footnote omitted] As a result of these factors, we have concluded that RMR agreements should be used as a last resort."); 110 FERC ¶ 61,315 at P 40 (2005) ("The Commission has stated on several occasions that it shares the concerns . . . that RMR agreements not proliferate as an alternative pricing option for generators, and that they are used strictly as a last resort so that units needed for reliability receive reasonable compensation.").

for foreseeable unit retirements, whether for economic or regulatory reasons. While not all retirements are completely foreseeable, improvement is needed in the process for ensuring that planning is looking at the probability of retirements, especially of resources that are critical to locational reliability in order to minimize the duration of any RMR requirement.

The actual implementation of Part V of the tariff has resulted in overpayment of the RMR resources. It is essential that the compensation provisions of Part V of the tariff be modified to ensure payment of all but only the actual costs incurred by the generation owner to provide the service, plus an incentive. Generators operating in competitive markets should be required, as an obligation of receiving interconnection service and having the ability to participate in competitive markets, to provide service under Part V on an incremental cost plus incentive basis when they are needed for reliability.

When notified of an intended deactivation, the MMU performs a market power study to ensure that the deactivation is economic, not an exercise of market power through withholding, and consistent with competition.[201] If the MMU determines that expected revenues exceed avoidable costs and therefore that the deactivation is not economic, the MMU will inform the unit owner that there is a market power issue. The MMU has no authority to prevent the retirement. The MMU can pursue the matter at FERC. Part V status by itself creates market power for the retiring resource. The owners of Part V resources have threatened to shut down the resources and put the grid at risk if they do not receive their requested level of Part V payments. Such exercises of market power have been effective in increasing payments to Part V units during the settlement proceedings that have resolved all Part V filings, generally on a black box basis.

PJM performs a system study to determine whether the system can accommodate the deactivation on the desired date, and if not, when it could.[202] If PJM determines that it needs a unit for a period beyond the intended deactivation date, PJM will request a unit to remain in service for a defined period.[203] The PJM market rules do not require an owner to remain in service. Owners must provide notice of a proposed deactivation at least twelve months prior to the desired deactivation date, although the advance notice can be too short to permit new generation to enter (See Table 5-31).[204] [205] The owner of a generation capacity resource must provide notice of a proposed deactivation in order to avoid a requirement to offer in RPM auctions.[206] In order to avoid submitting an offer for a unit in the next three-year forward RPM base residual auction based on retirement, an owner must submit a preliminary RPM must offer exception request no later than September 1 preceding the BRA and a final RPM must offer exception request demonstrating "a documented plan in place to retire the resource," including a notice of deactivation filed with PJM no later than December 1 preceding the BRA.[207]

Under the current rules, a unit remaining in service at PJM's request can recover its costs of continuing to operate under either the deactivation avoidable cost rate (DACR), which is a formula rate, or the cost of service recovery rate. The deactivation avoidable cost rate is designed to permit the recovery of the costs of the unit's "continued operation," termed "avoidable costs," plus an incentive adder.[208] Avoidable costs are defined to mean "incremental expenses directly required for the operation of a generating unit."[209] The incentives escalate for each year of service (first year, 10 percent; second year, 20 percent; third year, 35 percent; fourth year, 50 percent).[210] The rules provide terms for the repayment of project investment by owners of units that choose to keep units in service after the defined period ends.[211] The amount of project investment recovered cannot exceed the actual amount of the PI.[212] The cost of service rate is designed to permit the recovery of the unit's "cost of service rate to recover the entire cost of operating the generating unit" if the generation owner files a separate rate schedule at FERC.[213]

201 OATT § 113.2; OATT Attachment M § IV.1.
202 OATT § 113.2.
203 *Id.*
204 See Letter Order, FERC Docket No. ER25-1501-000 (April 15, 2025).
205 OATT § 113.1.
206 OATT Attachment DD § 6.6(g).
207 *Id.*
208 OATT § 114 (Deactivation Avoidable Credit = ((Deactivation Avoidable Cost Rate + Applicable Multiplier) * MW capability of the unit * Number of days in the month) + (APIR * First Year Multiplier) – Actual Net Revenues).
209 OATT § 115.
210 *Id.*
211 OATT § 118.
212 OATT §§ 115.
213 OATT § 119.

The DACR is unnecessarily prescriptive about the nature of the incremental costs needed to provide service, and includes unsupported escalation to extremely high incentive rates.

Table 5-34 shows units that have provided Part V reliability service to PJM, including the Indian River 4 unit, which began providing RMR service on June 1, 2022, and ended on February 24, 2025, and Brandon Shores 1 and 2 and Wagner 3 and 4 which began providing RMR service on June 1, 2025.[214] Only two of nine owners have used the deactivation avoidable cost rate approach. The other seven owners used the cost of service recovery rate. For units using the cost of service recovery rate option, revenues have averaged about 3.4 times the corresponding market price of capacity while for units using the deactivation avoidable cost rate, revenues have averaged about 1.6 times the corresponding market price of capacity.[215]

Table 5-34 Part V reliability service summary

Unit Names	Owner	Fuel Type	ICAP (MW)	Cost Recovery Method	Docket Numbers	Start of Term	End of Term
Brandon Shores 1	Talen Energy Corporation	Coal	635.0	Cost of Service Recovery Rate	ER24-1790	01-Jun-25	31-May-29
Brandon Shores 2	Talen Energy Corporation	Coal	638.0	Cost of Service Recovery Rate	ER24-1790	01-Jun-25	31-May-29
Wagner 3	Talen Energy Corporation	Coal	305.0	Cost of Service Recovery Rate	ER24-1787	01-Jun-25	31-May-29
Wagner 4	Talen Energy Corporation	Oil	397.0	Cost of Service Recovery Rate	ER24-1787	01-Jun-25	31-May-29
Indian River 4	NRG Power Marketing LLC	Coal	410.0	Cost of Service Recovery Rate	ER22-1539	01-Jun-22	24-Feb-25
B.L. England 2	RC Cape May Holdings, LLC	Coal	150.0	Cost of Service Recovery Rate	ER17-1083	01-May-17	01-May-19
Yorktown 1	Dominion Virginia Power	Coal	159.0	Deactivation Avoidable Cost Rate	ER17-750	06-Jan-17	13-Mar-18
Yorktown 2	Dominion Virginia Power	Coal	164.0	Deactivation Avoidable Cost Rate	ER17-750	06-Jan-17	13-Mar-18
B.L. England 3	RC Cape May Holdings, LLC	Oil	148.0	Cost of Service Recovery Rate	ER17-1083	01-May-17	24-Jan-18
Ashtabula	FirstEnergy Service Company	Coal	210.0	Deactivation Avoidable Cost Rate	ER12-2710	01-Sep-12	11-Apr-15
Eastlake 1	FirstEnergy Service Company	Coal	109.0	Deactivation Avoidable Cost Rate	ER12-2710	01-Sep-12	15-Sep-14
Eastlake 2	FirstEnergy Service Company	Coal	109.0	Deactivation Avoidable Cost Rate	ER12-2710	01-Sep-12	15-Sep-14
Eastlake 3	FirstEnergy Service Company	Coal	109.0	Deactivation Avoidable Cost Rate	ER12-2710	01-Sep-12	15-Sep-14
Lakeshore	FirstEnergy Service Company	Coal	190.0	Deactivation Avoidable Cost Rate	ER12-2710	01-Sep-12	15-Sep-14
Elrama 4	GenOn Power Midwest, LP	Coal	171.0	Cost of Service Recovery Rate	ER12-1901	01-Jun-12	01-Oct-12
Niles 1	GenOn Power Midwest, LP	Coal	109.0	Cost of Service Recovery Rate	ER12-1901	01-Jun-12	01-Oct-12
Cromby 2 and Diesel	Exelon Generation Company, LLC	Natural gas/oil, Diesel	203.7	Cost of Service Recovery Rate	ER10-1418	01-Jun-11	01-Jan-12
Eddystone 2	Exelon Generation Company, LLC	Coal	309.0	Cost of Service Recovery Rate	ER10-1418	01-Jun-11	01-Jun-12
Brunot Island CT2A, CT2B, CT3 and CC4	Orion Power MidWest, L.P.	Natural gas	244.0	Cost of Service Recovery Rate	ER06-993	16-May-06	05-Jul-07
Hudson 1	PSEG Energy Resources & Trade LLC and PSEG Fossil LLC	Natural gas	355.0	Cost of Service Recovery Rate	ER05-644, ER11-2688	25-Feb-05	08-Dec-11
Sewaren 1-4	PSEG Energy Resources & Trade LLC and PSEG Fossil LLC	Natural gas	453.0	Cost of Service Recovery Rate	ER05-644	25-Feb-05	01-Sep-08

214 See PJM, "Informational Filing Regarding Formal Notice of Termination of Reliability Must-Run Service," Docket Nos. ER22-2539-000 and ER23-2688-000 (December 23, 2024); See 191 FERC ¶ 61,098 (2025); Offer of Settlement, Docket No. ER24-1787, -1790 (January 1, 2025), Exhibit 2. On June 4, 2026, in Docket No. ER26-30, Talen filed to extend the terms of and compensation for Part V service provided by Brandon Shores and Wagner from May 31, 2029, to May 31, 2031, which is now pending.

215 The final rates for Brandon Shores and Wagner have not been established.

Table 5-35 Part V reliability service cost summary[216 217 218]

		Initial Filing		Actual		Weighted Average RPM
Unit Names	Owner	Total Cost	Cost per MW-day	Total Cost	Cost per MW-day	Clearing Price ($ per MW-day)
Brandon Shores 1	Talen Energy Corporation	$327,039,342	$307.66	$203,330,544	$877.28	$318.45
Brandon Shores 2	Talen Energy Corporation	$328,584,409	$307.66	$204,291,161	$877.28	$318.45
Wagner 3	Talen Energy Corporation	$64,791,528	$126.90	$54,413,731	$488.78	$318.45
Wagner 4	Talen Energy Corporation	$84,335,202	$126.90	$70,827,053	$488.78	$318.45
Indian River 4	NRG Power Marketing LLC	$357,065,662	$871.76	$198,617,019	$484.92	$54.04
B.L. England 2	RC Cape May Holdings, LLC	$35,953,561	$328.34	$51,779,892	$472.88	$154.51
Yorktown 1	Dominion Virginia Power	$9,739,434	$142.12	$8,427,011	$122.97	$134.64
Yorktown 2	Dominion Virginia Power	$10,045,705	$142.12	$9,529,149	$134.81	$134.64
B.L. England 3	RC Cape May Holdings, LLC	$28,710,481	$723.84	$10,058,665	$253.60	$138.95
Ashtabula	FirstEnergy Service Company	$35,236,541	$176.25	$25,177,042	$125.94	$107.91
Eastlake 1	FirstEnergy Service Company	$20,842,416	$257.01	$18,484,399	$227.93	$102.73
Eastlake 2	FirstEnergy Service Company	$20,182,025	$248.87	$17,683,994	$218.06	$102.73
Eastlake 3	FirstEnergy Service Company	$20,192,938	$249.00	$17,391,797	$214.46	$102.73
Lakeshore	FirstEnergy Service Company	$33,993,468	$240.47	$20,532,969	$145.25	$102.73
Elrama 4	GenOn Power Midwest, LP	$15,435,472	$739.88	$7,576,435	$363.17	$75.08
Niles 1	GenOn Power Midwest, LP	$9,510,580	$715.19	$4,829,423	$363.17	$75.08
Cromby 2 and Diesel	Exelon Generation Company, LLC	$20,213,406	$463.70	$17,776,658	$407.80	$108.63
Eddystone 2	Exelon Generation Company, LLC	$165,993,135	$1,467.74	$85,364,570	$754.81	$108.63
Brunot Island CT2A, CT2B, CT3 and CC4	Orion Power MidWest, L.P.	$60,933,986	$601.76	$23,507,795	$232.15	$89.78
Hudson 1	PSEG Energy Resources & Trade LLC and PSEG Fossil LLC	$28,934,341	$32.90	$62,364,359	$70.92	$132.72
Sewaren 1-4	PSEG Energy Resources & Trade LLC and PSEG Fossil LLC	$47,633,115	$81.89	$79,580,435	$136.82	$97.39

In each of the cost of service recovery rate filings for Part V reliability service, the scope of recovery permitted under the cost of service approach defined in Section 119 has been a significant issue. Owners have sought to recover fixed costs, incurred prior to the noticed deactivation date, in addition to the cost of operating the generating unit. Owners have cited the cost of service reference to mean that the unit is entitled to file to recover sunk costs that it was unable to recover in the competitive markets, in addition to recovery of costs of actually providing the Part V reliability service.

The cost of service recovery rate approach has been interpreted by the companies using that approach to allow the company to develop the type of rate case filing used by regulated utilities, using a test year with adjustments, to establish a rate base including investment in the existing plant and new investment necessary to remain in service and to earn a return on that rate base and receive depreciation of that rate base, plus guarantee recovery of estimated operation and maintenance expenses without verification of actual expenses. Despite the asserted reliance on traditional cost of service ratemaking principles, in practice generators seek approval of high rates that have weak or non existent support in law and fact relative to what has been traditionally required to justify

216 Actual cost data includes RMR charges through May 31, 2026.
217 The actual cost data for Indian River 4 include a refund of the difference between the filed rate that was collected pending resolution and the RMR settlement amount.
218 The data reported for Brandon Shores and Wagner are the Settlement gross costs. See 191 FERC ¶ 61,098 (2025); Offer of Settlement, Docket No. ER24-1787, -1790 (January 1, 2025), Exhibit 2.

of cost of service rates. 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.[219] In some cases, the filing included costs that already had been written off, or impaired, on the company's public books.[220] [221] In another case, the filing ignored evidence of actual book value based on market purchase of the asset.[222] The cost of service recovery rates substantially exceed the actual costs of operating to provide the reliability required by PJM. The costs are generally not subject to review, audit and verification. The Commission has approved black box settlement rates (i.e., no explicit basis for the rate is stated) that included arbitrarily inflated asset values and costs, despite protests.[223]

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 which have generally been set through settlements.

This reliability service should be provided to PJM customers at reasonable rates, which reflect the relatively low risk nature of providing such service to owners, the reliability need for such service and the opportunity for owners to be guaranteed recovery of 100 percent of the actual incremental costs required to operate to provide the service plus an incentive.

The MMU recommends elimination of both the cost of service recovery rate in OATT Section 119 and the deactivation avoidable cost rate in Part V, and their replacement with clear language that provides for the recovery of 100 percent of the actual incremental costs required to operate to provide the service plus an incentive.

219 See, e.g., FERC Dockets Nos. ER10-1418-000, ER12-1901-000 and ER17-1083-000.
220 See GenOn Filing, Docket No. ER12-1901-000 (May 31, 2012) at Exh. No. GPM-1 at 9:16–21.
221 See NRG Filing, Docket No. ER22- 1539-000 (April 1, 2022).
222 See Brandon Shores, H.A. Wagner, Docket No. ER24-1787-000, et al. (April 18, 2024); Comments of the Independent Market Monitor for PJM in Opposition to Settlement, Docket No. ER24-1787-000, et al. (February 18, 2025).
223 See 190 FERC ¶ 61,026 (2025), *reh'g denied*, 191 FERC ¶ 61,170 (2025), *appeal pending* (D.C. Cir. Case No. 25-1260); 191 FERC ¶ 61,098 (2025), *reh'g denied*, 191 FERC ¶ 62,189 (2025).

The MMU recommends that units recover all and only the incremental costs, including incremental investment costs without a cap, required to provide Part V reliability service (RMR service) that the unit owner would not have incurred if the unit owner had deactivated its unit as it proposed, plus a defined incentive payment. Customers should bear no responsibility for paying previously incurred (sunk) costs, including a return on or of prior investments.

The Indian River RMR was effective from June 1, 2022, through February 24, 2025. After the RMR ended, Indian River submitted additional bills until the final invoice for October 2025. Additional costs beyond February 2025 were incurred for the removal of remaining coal inventory and chemicals. The MMU was unable to review all costs charged to the project because NRG refused to provide supporting documentation after several requests from the MMU. NRG only provided invoices over $10,000 starting January 2024. NRG did not provide supporting documentation for costs prior to January 2024 and for costs under $10,000. As a result, the MMU was unable to determine if all costs charged to the project were reasonable. On February 20, 2026, the MMU filed a Petition with FERC to require NRG to produce the requested cost documentation.[224]

Department of Energy (DOE) 202(c) Orders

Eddystone

On May 30, 2025, the Department of Energy (DOE) issued an order under Section 202(c) of the Federal Power Act stating that the operational availability and economic dispatch of Eddystone units 3 and 4 is necessary to meet an emergency and serve the public interest.[225] The order requires that Constellation Energy, LLC and PJM take measures to ensure that Eddystone units 3 and 4 are available to operate from May 30, 2025, initially through 5:03 PM EDT on August 28, 2025.[226] The term of operation was extended,

224 See *Petition of Monitoring Analytics, LLC, LLC for Order Directing Production of Information*, Docket No. EL26-54-00 (February 20, 2026).
225 16 U.S.C. § 824a(c).
226 Department of Energy, Order No. 202-25-4 (May 30, 2025) <https://www.energy.gov/ceser/federal-power-act-section-202c-pjm-interconnection> .

including to August 22, 2026, in subsequent orders.[227] [228] Eddystone Units 3 and 4 were previously scheduled to retire on May 31, 2025.

PJM and Constellation notified the Commission by letter dated June 26, 2025, that they had agreed to a rate for service under Section 202(c) based on a modified version of the Deactivation Avoidable Cost Credit method included in Section 114 of the OATT. The modified approach ensure rates based on the actual fuel costs for operating the units and a reasonable approximation of actual avoidable costs rather than the arbitrary regulated cost of service model in recent RMR cases.

Table 5-36 shows the cost information for units subject to DOE orders under Section 202(c) of the Federal Power Act requiring resources to operate beyond their requested deactivation dates.

Wagner

On July 28, 2025, the Department of Energy (DOE) issued an order under Section 202(c) of the Federal Power Act stating that the operational availability and economic dispatch of H.A. Wagner Unit 4 is necessary to meet an emergency and serve the public interest.[229] The order required that PJM take measures in coordination with Talen Energy, the owner, to ensure that H.A. Wagner Unit 4 remain available to operate from July 28, 2025, initially through October 26, 2025.[230] The term of operation was extended to January 1, 2026, in a subsequent order.[231] On May 21, 2026, the DOE issued another order under Section 202(c) of the Federal Power Act for H.A. Wagner Unit 4 in effect from May 22, 2026, until August 19, 2026.[232]

227 Department of Energy, Order No. 202-25-8 (August 28, 2025), <https://www.energy.gov/sites/default/files/2025-08/202c%20Order%20No.%20202-25-8.pdf>; Department of Energy, Order No. 202-25-10 (November 26, 2025), <https://www.energy.gov/sites/default/files/2025-11/Order%20No.%20202-25-10.pdf>; Department of Energy, Order No. 202-26-17 (February 23, 2026), <https://www.energy.gov/documents/eddystone-202c-order-no-202-26-17>; Department of Energy, Order No. 202-26-24 (May 21, 2026), <https://www.energy.gov/documents/doe-emergency-order-202-26-24>.

228 On June 9, 2025, the PJM Board of Managers initiated a Critical Issue Fast Path (CIFP) stakeholder process to address the allocation of costs associated with the payments to Constellation for continuing to operate Eddystone units 3 and 4. On August 15, 2025, FERC issued an order accepting PJM's cost allocation methodology related to the retention of Eddystone units 3 and 4. 192 FERC ¶ 61,159 (2025).

229 Department of Energy, Order No. 202-25-6 (July 28, 2025), <https://www.energy.gov/sites/default/files/2025-07/PJM%27s%20202%28c%29%20Order%20No.%20202-25-6.pdf>.

230 *Id.*

231 Department of Energy, Order No. 202-25-6A (October 24, 2025), <https://www.energy.gov/sites/default/files/2025-10/202c%20Order%20No.%20202-25-6A_0.pdf>

232 Department of Energy, Order No. 202-26-25 (May 21, 2026), <https://www.energy.gov/documents/doe-emergency-order-no-202-26-25>.

Other 202(c) Orders

Operation in Excess of Operational Limits, Permit Restrictions, and Other Causes

On January 25 and January 29, 2026, in response to an application filed by PJM, the DOE issued an emergency order and a subsequent order pursuant to section 202(c) allowing PJM to run all electric generating units located within the PJM Region up to their maximum generation output levels, notwithstanding air quality or other permit limitations or fuel shortages, from January 25 to February 2, 2026.[233]

Backup Generation Resources at Data Centers and Other Large Load Customers

On January 26 and January 29, 2026, in response to an application filed by PJM, the DOE issued an emergency order and a subsequent order pursuant to section 202(c) authorizing PJM to direct backup generation resources at data centers and other large load customers to operate as a last resort before declaring an Energy Emergency Alert (EEA) 3 or during an EEA 3 effective January 26 to February 2, 2026.[234]

On May 18, 2026, in response to an application filed by PJM, the DOE issued an emergency order authorizing PJM to deploy backup generation resources at data centers and other major facilities.[235]

On June 30, July 3, 2026, and July 14, 2026, in response to applications filed by PJM, DOE issued an emergency order and subsequent orders pursuant to section 202(c) authorizing PJM to direct backup generation resources at data centers and other large load customers to operate as a last resort before declaring an Energy Emergency Alert (EEA) 3 or during an EEA 3 effective June 30 to July 21, 2026.[236]

233 Department of Energy, Order No. 202-26-02, <https://www.energy.gov/documents/order-no-202-26-2-pjm>; Department of Energy, Order No. 202-26-02A, <https://www.energy.gov/documents/doe-order-no-202-26-02a-pjm>.

234 Department of Energy, Order No. 202-26-06, <https://www.energy.gov/documents/doe-order-no-202-26-06-pjm> Department of Energy, Order No. 202-26-06A, <https://www.energy.gov/documents/order-no-202-26-06-pjm-backup-generators>;

235 Department of Energy, Order No. 202-26-23, <https://www.energy.gov/documents/doe-emergency-order-no-202-26-23pdf>.

236 Department of Energy, Order No. 202-26-33, <https://www.energy.gov/documents/doe-order-no-202-26-33>; Department of Energy, Order No. 202-26-33A, <https://www.energy.gov/documents/doe-order-no-202-26-33a>. Department of Energy, Order No. 202-26-35, <https://www.energy.gov/documents/doe-order-no-202-26-35>.

Dispatch of Specified Units as Needed to Maintain Reliability

On June 30 and July 2, 2026, in response to an application filed by PJM, DOE issued an emergency order and a subsequent order pursuant to section 202(c) directing PJM to dispatch specified units and to order their operation as needed to maintain reliability effective June 30 to July 6, 2026.[237]

On July 14, 2026, in response to an application filed by PJM, DOE issued an emergency order pursuant to section 202(c) directing PJM to dispatch specified units and to order their operation as needed to maintain reliability effective July 14 to July 21, 2026.[238]

202(c) Cost Information

Table 5-36 DOE 202(c) cost summary[239]

Unit Names	Owner	Fuel Type	ICAP (MW)	Start of Term	End of Term	Total Cost	Cost per MW-day
Eddystone 3	Constellation Energy Generation, LLC	Oil	380.0	01-Jun-25	22-Aug-26	$6,525,722	$47.05
Eddystone 4	Constellation Energy Generation, LLC	Oil	380.0	01-Jun-25	22-Aug-26	$6,525,722	$47.05

Generator Performance

Generator performance results from the interaction between the physical characteristics of the units and the level of expenditures made to maintain the capability of the units, which in turn is a function of incentives from energy, ancillary services and capacity markets. Generator performance indices include those based on total hours in a period (generator performance factors) and those based on hours when units are needed to operate by the system operator (generator forced outage rates).

237 Department of Energy, Order No. 202-26-32, <https://www.energy.gov/documents/doe-order-no-202-26-32>; Department of Energy, Order No. Order No. 202-26-32A, <https://www.energy.gov/documents/doe-order-no-202-26-32a>.
238 Department of Energy, Order No. 202-26-35, <https://www.energy.gov/documents/doe-order-no-202-26-35>.
239 PJM Manual 33 states that cost information "related to DOE 202(c) orders requiring resources to run beyond their requested deactivation dates" may be publicly posted. As the DOE 202(c) orders for Wagner Unit 4 differ from the type of DOE 202(c) order described in Manual 33, the cost information for Wagner Unit 4 is not included in this table. See "PJM Manual 33: Administrative Services for the PJM Interconnection Operating Agreement," § 6 Market Data Postings, Rev. 21 (Apr. 22, 2026).

Capacity Factor

Capacity factor measures the actual output of a power plant over a period of time compared to the potential output of the unit had it been running at full nameplate capacity for every hour during that period. Table 5-37 shows the capacity factors by unit type for the first six months of 2025 and 2026. In the first six months of 2026, nuclear units had a capacity factor of 95.2 percent, compared to a capacity factor of 94.6 percent in the first six months of 2025; combined cycle units had a capacity factor of 62.1 percent in the first six months of 2026, compared to a capacity factor of 61.6 percent in the first six months of 2025; coal units had a capacity factor of 42.3 percent in the first six months of 2026, compared to a capacity factor of 43.1 percent in the first six months of 2025.

Table 5-37 Capacity factor (By unit type (GWh)): January through June, 2025 and 2026[240 241 242]

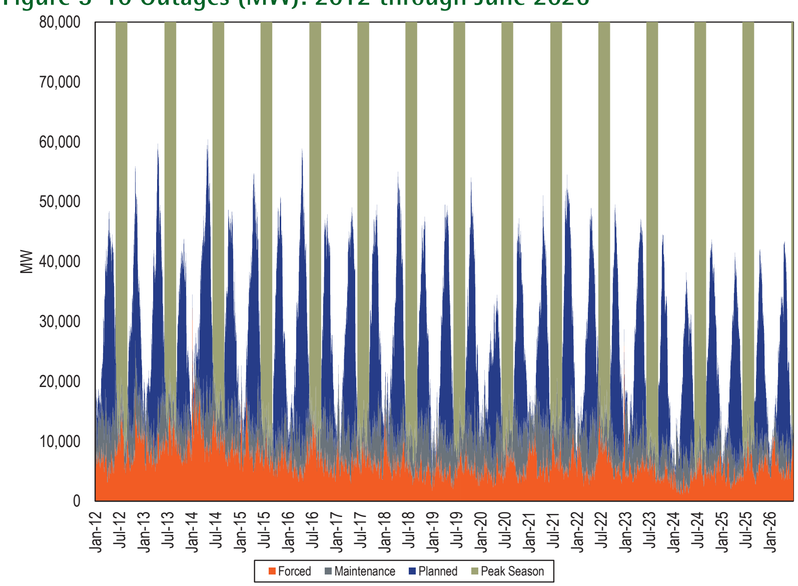
	2025 (Jan-Jun)		2026 (Jan-Jun)		
Unit Type	Generation (GWh)	Capacity Factor	Generation (GWh)	Capacity Factor	Change in Capacity Factor
Battery	32.5	2.0%	80.5	4.0%	2.0%
Combined Cycle	154,609.2	61.6%	158,068.8	62.1%	0.4%
Single Fuel	134,639.4	67.0%	137,103.0	65.6%	(1.4%)
Dual Fuel	19,969.8	40.0%	20,965.8	45.7%	5.8%
Combustion Turbine	10,378.1	8.4%	11,952.4	9.7%	1.3%
Single Fuel	6,367.7	7.4%	7,351.9	8.6%	1.2%
Dual Fuel	4,010.4	10.5%	4,600.6	12.0%	1.6%
Diesel	195.7	12.4%	173.8	11.5%	(0.9%)
Single Fuel	172.3	12.1%	148.5	10.9%	(1.2%)
Dual Fuel	23.4	15.6%	25.3	16.9%	1.3%
Diesel (Landfill gas)	378.0	43.3%	379.8	46.2%	2.9%
Fuel Cell	107.9	93.9%	106.4	92.6%	(1.3%)
Nuclear	133,994.6	94.6%	134,859.1	95.2%	0.6%
Pumped Storage Hydro	3,960.0	16.8%	4,066.0	17.3%	0.5%
Run of River Hydro	4,899.1	54.9%	4,013.7	45.0%	(9.9%)
Solar	12,254.8	22.5%	15,019.6	22.8%	0.3%
Steam	78,828.8	39.1%	79,052.4	39.4%	0.3%
Biomass	2,456.0	64.6%	2,498.7	66.2%	1.6%
Coal	70,250.3	43.1%	68,549.9	42.3%	(0.9%)
Single Fuel	70,250.3	43.9%	68,549.9	43.0%	(0.9%)
Dual Fuel	0.0	0.0%	0.0	0.0%	0.0%
Natural Gas	5,558.1	43.1%	7,165.1	44.4%	1.4%
Single Fuel	247.2	51.1%	107.1	50.9%	(0.2%)
Dual Fuel	5,310.9	24.5%	7,058.0	28.4%	3.9%
Oil	564.4	4.3%	838.7	6.6%	2.3%
Wind	18,939.8	16.1%	19,341.3	22.0%	5.9%
Total	418,578.4	48.5%	427,114.0	48.6%	0.1%

Generator Performance Factors

Generator outages fall into three categories: planned, maintenance, and forced. The scheduling of planned and maintenance outages must be approved by PJM. The approval may be withdrawn in order to maintain system reliability.[243] The PJM Market Rules do not specify any consequences if the planned outage continues after PJM withdraws approval. If PJM withdraws approval for a maintenance outage during the outage and the unit cannot operate, the outage is defined to be a forced outage.[244] Outages that are approved by PJM may be extended. An extension to a planned outage that enters the peak period is treated as a forced outage. A maintenance outage that is extended to more than nine days during the peak period is treated as a forced outage.

The MW on outage vary during the year. For example, the MW on planned outage are generally highest in the spring and fall, as shown in Figure 5-10, as a result of restrictions on planned outages during the winter and summer. The Peak Period Maintenance Season, shown in Figure 5-10 as the peak season, runs from the weeks containing the twenty-fourth through thirty-sixth Wednesdays of the year. Planned outages cannot start in nor extend into this period. In 2026, the period runs from Monday, June 15 through Friday, September 11. The effect of the seasonal variation in outages can be seen in the monthly generator performance metrics in Figure 5-13.

Figure 5-10 Outages (MW): 2012 through June 2026



240 The capacity factors in this table are based on nameplate capacity values, and are calculated based on when the units come on line.
241 The subcategories of steam units are consolidated consistent with confidentiality rules. Coal is comprised of coal and waste coal. Natural gas is comprised of natural gas and propane. Oil is comprised of both heavy and light oil. Biomass is comprised of biomass, landfill gas, and municipal solid waste.
242 Hours in which batteries have net negative generation do not count toward their runtime.
243 "PJM Manual 10: Pre-Scheduling Operations," § 2.3.2 Maintenance Outage Rules, Rev. 65 (July 23, 2025).
244 OATT, Attachment K (Appendix) § 1.9.3 (b).

Table 5-38 shows the total MWh by outage type. In the first six months of 2026, forced outage MWh were 38.1 percent higher, planned outage MWh were 2.9 percent lower, and maintenance outage MWh were 5.9 percent lower than in the first six months of 2025.

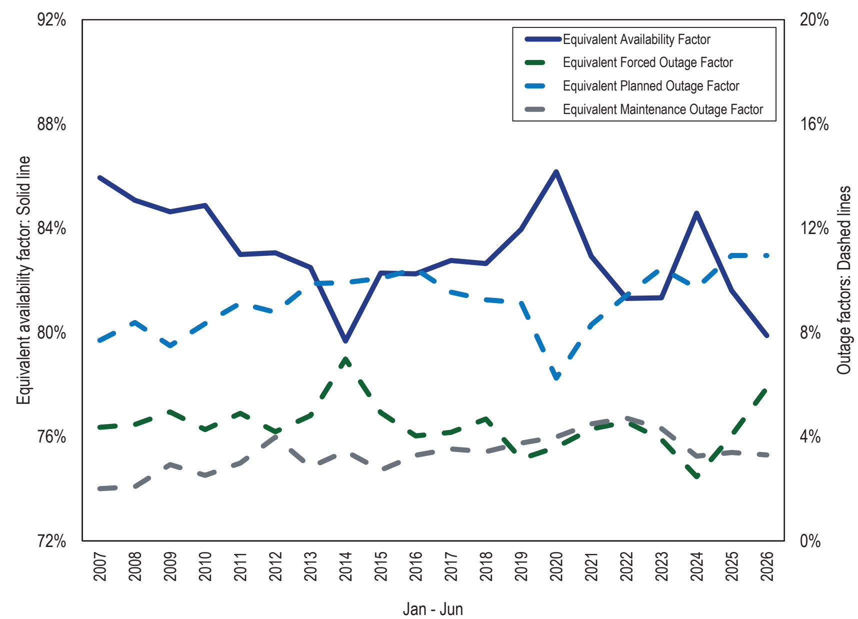
Table 5-38 Outages (MWh): January through June, 2012 through 2026

Jan-Jun	Forced MWh	Planned MWh	Maintenance MWh
2012	1,292,060	2,665,013	1,199,959
2013	1,587,665	3,032,253	896,719
2014	2,249,995	2,984,012	990,748
2015	1,584,622	2,877,497	825,914
2016	1,168,978	3,102,343	912,005
2017	1,182,860	2,592,417	985,338
2018	1,295,062	2,752,757	934,979
2019	907,884	2,515,435	1,016,714
2020	911,469	1,702,312	1,129,011
2021	1,242,658	2,135,115	1,208,302
2022	1,138,626	2,376,361	1,196,745
2023	998,303	2,382,515	1,042,008
2024	599,783	1,969,323	796,319
2025	810,465	2,109,949	674,158
2026	1,118,964	2,170,726	634,198
Change in 2026 from 2025	38.1%	2.9%	(5.9%)

Performance factors include the equivalent availability factor (EAF), the equivalent maintenance outage factor (EMOF), the equivalent planned outage factor (EPOF) and the equivalent forced outage factor (EFOF). These four factors add to 100 percent for any generating unit. The EAF is the proportion of hours in a year when a unit is available to generate at full capacity while the three outage factors include all the hours when a unit is unavailable. The EMOF is the proportion of hours in a year when a unit is unavailable because of maintenance outages and maintenance deratings. The EPOF is the proportion of hours in a year when a unit is unavailable because of planned outages and planned deratings. The EFOF is the proportion of hours in a year when a unit is unavailable because of forced outages and forced deratings.

The PJM aggregate EAF, EFOF, EPOF, and EMOF are shown in Figure 5-11. Metrics by unit type are shown in Table 5-39.

Figure 5-11 Equivalent outage and availability factors: January through June, 2007 through 2026



The PJM aggregate equivalent availability factor in the first six months of 2026 was 79.9 percent, a decrease from 81.6 percent in the first six months of 2025.

Table 5-39 EFOF, EPOF, EMOF and EAF by unit type: January through June, 2007 through 2026

	Coal				Combined Cycle				Combustion Turbine				Diesel				Hydroelectric				Nuclear				Other				Total			
Jan-Jun	EFOF	EPOF	EMOF	EAF	EFOF	EPOF	EMOF	EAF	EFOF	EPOF	EMOF	EAF	EFOF	EPOF	EMOF	EAF	EFOF	EPOF	EMOF	EAF	EFOF	EPOF	EMOF	EAF	EFOF	EPOF	EMOF	EAF	EFOF	EPOF	EMOF	EAF
2007	6%	10%	3%	81%	1%	7%	2%	89%	5%	3%	3%	88%	9%	1%	2%	88%	2%	6%	2%	90%	1%	5%	0%	94%	6%	11%	2%	80%	4%	8%	2%	86%
2008	8%	10%	3%	80%	2%	7%	2%	90%	3%	6%	2%	88%	9%	2%	1%	87%	1%	7%	2%	89%	1%	7%	1%	92%	4%	13%	3%	81%	4%	8%	2%	85%
2009	8%	9%	3%	80%	4%	6%	3%	87%	1%	4%	3%	92%	7%	0%	2%	91%	2%	10%	3%	84%	4%	6%	1%	90%	4%	11%	6%	79%	5%	7%	3%	85%
2010	8%	11%	4%	78%	3%	9%	1%	87%	2%	3%	2%	94%	4%	1%	1%	94%	1%	10%	2%	87%	1%	6%	1%	92%	3%	11%	3%	83%	4%	8%	3%	85%
2011	9%	12%	4%	75%	3%	8%	2%	87%	1%	3%	2%	93%	2%	0%	3%	95%	1%	14%	2%	84%	2%	7%	2%	89%	4%	12%	3%	82%	5%	9%	3%	83%
2012	7%	11%	8%	74%	2%	8%	2%	88%	2%	3%	2%	93%	4%	0%	2%	94%	4%	4%	2%	91%	1%	8%	1%	90%	5%	12%	3%	80%	4%	9%	4%	83%
2013	8%	14%	5%	74%	1%	10%	3%	86%	5%	4%	1%	90%	4%	0%	2%	94%	0%	8%	2%	90%	1%	7%	0%	92%	7%	13%	4%	76%	5%	10%	3%	82%
2014	11%	12%	6%	72%	3%	12%	2%	83%	9%	5%	2%	84%	15%	1%	2%	82%	2%	11%	4%	83%	2%	7%	1%	90%	8%	15%	6%	71%	7%	10%	3%	80%
2015	9%	11%	4%	76%	2%	12%	2%	84%	3%	5%	2%	90%	10%	1%	3%	87%	2%	10%	2%	86%	1%	6%	1%	92%	7%	22%	5%	67%	5%	10%	3%	82%
2016	8%	11%	5%	75%	3%	12%	2%	83%	2%	6%	2%	89%	6%	0%	4%	90%	2%	8%	4%	86%	1%	6%	1%	92%	3%	24%	4%	69%	4%	10%	3%	82%
2017	10%	13%	7%	70%	3%	13%	1%	83%	1%	5%	2%	91%	6%	0%	2%	92%	2%	7%	3%	88%	0%	6%	1%	93%	3%	11%	5%	81%	4%	10%	4%	83%
2018	11%	13%	6%	70%	2%	11%	1%	87%	2%	5%	2%	91%	6%	1%	3%	90%	2%	6%	3%	89%	0%	6%	0%	93%	4%	12%	8%	76%	5%	9%	3%	83%
2019	7%	10%	7%	75%	2%	11%	2%	86%	1%	8%	1%	89%	7%	1%	3%	89%	1%	5%	4%	90%	0%	6%	1%	92%	3%	15%	7%	75%	3%	9%	4%	84%
2020	4%	8%	10%	78%	5%	7%	1%	86%	2%	4%	2%	92%	6%	0%	3%	91%	5%	2%	3%	90%	2%	5%	1%	92%	4%	9%	4%	83%	4%	6%	4%	86%
2021	8%	10%	10%	72%	2%	11%	2%	85%	2%	7%	3%	89%	7%	1%	4%	88%	10%	4%	3%	83%	1%	6%	1%	92%	9%	8%	6%	76%	4%	8%	4%	83%
2022	10%	12%	11%	67%	3%	14%	2%	81%	2%	7%	2%	89%	9%	1%	5%	85%	3%	7%	3%	87%	1%	6%	1%	92%	5%	9%	7%	79%	5%	9%	5%	81%
2023	8%	16%	8%	68%	4%	14%	2%	80%	2%	7%	2%	88%	13%	0%	4%	83%	2%	14%	6%	78%	0%	5%	2%	93%	5%	10%	8%	76%	4%	10%	4%	81%
2024	4%	12%	7%	77%	3%	13%	2%	82%	2%	6%	2%	90%	8%	0%	2%	89%	3%	17%	3%	77%	1%	7%	2%	91%	4%	11%	3%	82%	2%	10%	3%	85%
2025	8%	15%	7%	71%	4%	15%	2%	80%	4%	7%	2%	87%	13%	2%	2%	83%	2%	13%	5%	81%	1%	7%	2%	91%	7%	14%	4%	75%	4%	11%	3%	82%
2026	12%	18%	5%	65%	4%	14%	2%	80%	6%	7%	2%	85%	15%	4%	5%	77%	2%	9%	4%	86%	1%	5%	3%	92%	13%	16%	5%	65%	6%	11%	3%	80%

Generator Outage Rates

The most fundamental forced outage rate metric is the equivalent demand forced outage rate (EFORd). EFORd is a measure of the probability that a generating unit will fail, either partially or totally, to perform when it is needed to operate. EFORd measures the forced outage rate during periods of demand, and does not include planned or maintenance outages. A period of demand is a period during which a generator is running or needed to run. EFORd calculations use historical performance data, including equivalent forced outage hours, service hours, average forced outage duration, average run time, average time between unit starts, available hours and period hours.[245] The EFORd metric includes all forced outages, regardless of the reason for those outages.

The average PJM EFORd in the first six months of 2026 was 8.4 percent, an increase from 6.2 percent in the first six months of 2025. Figure 5-12 shows the average EFORd since 1999 for all units in PJM.[246]

245 Equivalent forced outage hours are the sum of all forced outage hours in which a generating unit is fully inoperable and all partial forced outage hours in which a generating unit is partially inoperable, prorated to full hours.
246 The universe of units in PJM changed as the PJM footprint expanded and as units retired from and entered PJM markets. See the *2019 State of the Market Report for PJM*, Appendix A: "PJM Overview" for details.

Figure 5-12 Equivalent demand forced outage rates (EFORd): 1999 through June, 2026

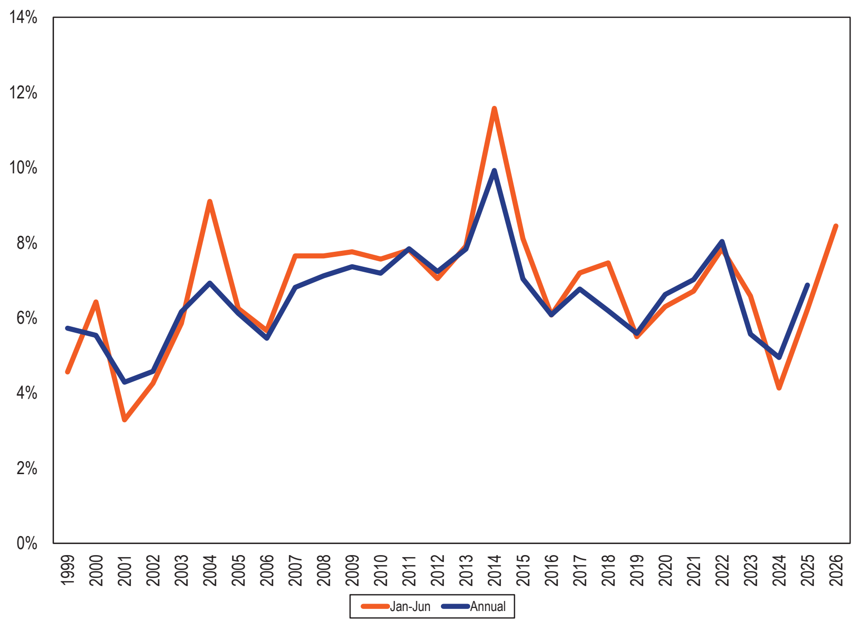


Table 5-40 shows the class average EFORd by unit type.

Table 5-40 EFORd by unit type: January through June, 2007 through 2026

	Jan-Jun																			
	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026
Coal	7.5%	9.1%	9.6%	9.7%	11.4%	10.7%	10.5%	14.0%	10.9%	10.6%	12.9%	14.3%	10.7%	7.8%	10.8%	14.5%	14.2%	6.1%	11.2%	17.1%
Combined Cycle	3.4%	3.7%	5.8%	3.6%	3.6%	2.8%	1.6%	5.1%	2.7%	3.8%	3.4%	2.8%	2.4%	7.0%	3.1%	4.7%	4.7%	3.5%	5.7%	5.0%
Combustion Turbine	19.9%	15.6%	9.5%	15.1%	9.0%	7.8%	14.1%	22.8%	13.9%	7.2%	6.4%	7.8%	6.6%	5.9%	5.1%	5.8%	6.1%	6.3%	8.2%	10.7%
Diesel	10.9%	10.2%	8.7%	5.9%	6.2%	5.3%	4.5%	16.2%	10.7%	7.8%	6.5%	6.3%	7.8%	8.4%	8.3%	12.9%	16.0%	11.4%	15.6%	17.6%
Hydroelectric	2.1%	2.2%	2.5%	1.0%	1.4%	5.2%	0.8%	3.2%	2.6%	3.1%	2.9%	3.3%	1.2%	5.7%	11.6%	4.9%	3.2%	3.3%	2.2%	2.8%
Nuclear	1.3%	1.1%	4.0%	1.5%	2.3%	1.3%	1.3%	2.2%	1.2%	1.1%	0.4%	0.6%	0.6%	2.0%	0.9%	0.9%	0.4%	0.8%	0.7%	0.5%
Other	11.6%	10.7%	10.2%	7.2%	10.2%	8.6%	12.9%	16.7%	13.9%	6.9%	14.2%	11.3%	7.5%	12.5%	17.9%	18.2%	9.3%	6.5%	10.0%	19.2%
Total	7.6%	7.6%	7.8%	7.6%	7.8%	7.0%	7.9%	11.6%	8.1%	6.1%	7.2%	7.5%	5.5%	6.3%	6.7%	7.8%	6.6%	4.1%	6.2%	8.4%

EFORd vs EAF

EFORd is not an adequate measure of unit availability because EFORd measures only forced outages and does not account for planned or maintenance outages. Forced outage rates can be managed under the existing outage rules. The EAF (Equivalent Availability Factor), which reflects all forced, planned, and maintenance outages, is a more accurate measure of the capacity actually available to meet load.

Table 5-41 shows the differences between EFORd and EAF by unit type.

Table 5-41 EFORd and EAF by unit type: January through June, 2012 through 2026

	Unit Types															
	Coal		Combined Cycle		Combustion Turbine		Diesel		Hydroelectric		Nuclear		Other		All	
Jan-Jun	EFORd	1-EAF	EFORd	1-EAF	EFORd	1-EAF	EFORd	1-EAF	EFORd	1-EAF	EFORd	1-EAF	EFORd	1-EAF	EFORd	1-EAF
2012	10.7%	26.0%	2.8%	12.1%	7.8%	6.6%	5.3%	6.0%	5.2%	9.4%	1.3%	10.0%	8.6%	19.6%	7.0%	16.9%
2013	10.5%	26.2%	1.6%	14.3%	14.1%	9.7%	4.5%	6.5%	0.8%	10.2%	1.3%	8.2%	12.9%	24.3%	7.9%	17.5%
2014	14.0%	28.0%	5.1%	17.0%	22.8%	15.8%	16.2%	18.4%	3.2%	16.8%	2.2%	9.5%	16.7%	29.0%	11.6%	20.3%
2015	10.9%	23.6%	2.7%	16.2%	13.9%	10.5%	10.7%	12.9%	2.6%	14.0%	1.2%	8.3%	13.9%	33.0%	8.1%	17.7%
2016	10.6%	24.8%	3.8%	16.9%	7.2%	10.5%	7.8%	9.8%	3.1%	13.9%	1.1%	8.4%	6.9%	31.2%	6.1%	17.8%
2017	12.9%	29.7%	3.4%	16.5%	6.4%	8.8%	6.5%	8.0%	2.9%	12.1%	0.4%	7.3%	14.2%	18.6%	7.2%	17.2%
2018	14.3%	30.0%	2.8%	13.3%	7.8%	9.4%	6.3%	10.1%	3.3%	11.3%	0.6%	7.2%	11.3%	23.8%	7.5%	17.4%
2019	10.7%	25.0%	2.4%	14.3%	6.6%	10.6%	7.8%	11.4%	1.2%	9.7%	0.6%	7.8%	7.5%	25.0%	5.5%	16.0%
2020	7.8%	21.9%	7.0%	14.3%	5.9%	8.1%	8.4%	9.2%	5.7%	9.6%	2.0%	7.6%	12.5%	17.1%	6.3%	13.8%
2021	10.8%	27.9%	3.1%	15.4%	5.1%	11.1%	8.3%	12.3%	11.6%	17.2%	0.9%	7.8%	17.9%	23.8%	6.7%	17.1%
2022	14.5%	32.8%	4.7%	19.2%	5.8%	11.4%	12.9%	15.1%	4.9%	13.2%	0.9%	7.9%	18.2%	21.1%	7.8%	18.7%
2023	14.2%	31.9%	4.7%	19.7%	6.1%	11.5%	16.0%	17.2%	3.2%	22.4%	0.4%	7.3%	9.3%	23.6%	6.6%	18.7%
2024	6.1%	22.5%	3.5%	17.6%	6.3%	10.2%	11.4%	10.9%	3.3%	23.0%	0.8%	9.2%	6.5%	17.9%	4.1%	15.4%
2025	11.2%	29.4%	5.7%	20.3%	8.2%	12.8%	15.6%	16.7%	2.2%	19.4%	0.7%	9.2%	10.0%	25.0%	6.2%	18.4%
2026	17.1%	35.5%	5.0%	19.6%	10.7%	15.0%	17.6%	23.4%	2.8%	14.2%	0.5%	8.3%	19.2%	34.6%	8.4%	20.1%
Average	11.8%	27.7%	3.9%	16.4%	9.0%	10.8%	10.4%	12.5%	3.7%	14.4%	1.0%	8.3%	12.4%	24.5%	7.1%	17.5%

Outage Analysis

The MMU analyzed the causes of outages for the PJM system. The metric used was lost generation, which is the product of the duration of the outage and the size of the outage reduction. Lost generation can be converted into lost system equivalent availability.[247] On a system wide basis, the resultant lost equivalent availability from forced outages is equal to the equivalent forced outage factor (EFOF), the resultant lost equivalent availability from maintenance outages is equal to the equivalent maintenance outage factor (EMOF), and the resultant lost equivalent availability from planned outages is equal to the equivalent planned outage factor (EPOF).

The PJM EFOF was 5.9 percent in the first six months of 2026. Table 5-42 shows the causes of EFOF by unit type. Forced outages for boiler tube leaks, 12.7 percent of the system EFOF, were the largest single contributor to average system EFOF across all unit types.

247 For any unit, lost generation can be converted to lost equivalent availability by dividing lost generation by the product of the generating units' capacity and period hours. This can also be done on a system basis.

Table 5-42 Contribution to PJM EFOF by unit type by cause: January through June, 2026

	Coal	Combined Cycle	Combustion Turbine	Diesel	Hydroelectric	Nuclear	Other	System
Boiler Tube Leaks	19.3%	4.8%	0.0%	0.0%	0.0%	0.0%	14.2%	12.7%
Wet Scrubbers	21.5%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	11.3%
Boiler Air and Gas Systems	7.7%	0.0%	0.0%	0.0%	0.0%	0.0%	40.5%	9.5%
Miscellaneous (Gas Turbine)	0.0%	25.1%	21.1%	0.0%	0.0%	0.0%	0.0%	6.4%
Personnel or Procedure Errors	9.6%	1.0%	2.0%	2.4%	0.0%	0.0%	0.0%	5.5%
Electrical	2.0%	6.8%	3.3%	1.4%	3.8%	61.0%	1.1%	4.3%
Economic	0.0%	0.5%	18.6%	10.3%	19.5%	4.4%	0.3%	3.6%
High Pressure Turbine	5.8%	0.0%	0.0%	0.0%	0.0%	0.0%	0.2%	3.1%
Boiler Piping System	1.9%	12.0%	0.0%	0.0%	0.0%	0.0%	0.2%	2.6%
Circulating Water Systems	3.6%	2.3%	0.0%	0.0%	0.0%	1.5%	0.8%	2.3%
Auxiliary Systems	1.2%	5.6%	5.8%	0.2%	0.2%	0.0%	0.2%	2.2%
Stack Emission	2.6%	0.3%	0.1%	0.0%	0.0%	0.0%	4.8%	2.1%
Exciter	0.5%	1.4%	6.2%	0.1%	0.2%	0.0%	4.7%	2.1%
Miscellaneous (Generator)	0.1%	2.3%	1.5%	22.4%	4.0%	0.0%	8.5%	2.0%
Miscellaneous (Jet Engine)	0.0%	0.0%	12.6%	0.0%	0.0%	0.0%	0.0%	1.9%
Low Pressure Turbine	2.1%	0.0%	0.0%	0.0%	0.0%	0.0%	6.1%	1.9%
Fuel, Ignition and Combustion Systems	0.0%	5.3%	7.3%	0.0%	0.0%	0.0%	0.0%	1.8%
Turbine	0.0%	2.4%	6.7%	0.0%	9.0%	0.0%	0.0%	1.5%
Valves	2.6%	0.8%	0.0%	0.0%	0.0%	0.2%	0.0%	1.5%
All Other Causes	19.5%	29.3%	14.9%	63.3%	63.4%	33.0%	18.4%	21.5%
Total	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%

The PJM EMOF was 3.3 percent in the first six months of 2026. Table 5-43 shows the causes of EMOF by unit type. Maintenance outages for boiler tube leaks, 9.5 percent of the system EMOF, were the largest single contributor to average system EMOF across all unit types, although miscellaneous gas turbine issues were the largest contributors to EMOF for combustion turbines.

Table 5-43 Contribution to EMOF by unit type by cause: January through June, 2026

	Coal	Combined Cycle	Combustion Turbine	Diesel	Hydroelectric	Nuclear	Other	System
Boiler Tube Leaks	14.9%	19.2%	0.0%	0.0%	0.0%	0.0%	17.4%	9.5%
Core/Fuel	0.0%	0.0%	0.0%	0.0%	0.0%	40.0%	0.0%	8.9%
Miscellaneous (Reactor)	0.0%	0.0%	0.0%	0.0%	0.0%	37.0%	0.0%	8.2%
Miscellaneous (Balance of Plant)	13.0%	3.2%	2.2%	0.1%	0.2%	0.0%	12.0%	6.8%
Miscellaneous (Gas Turbine)	0.0%	12.2%	42.4%	0.0%	0.0%	0.0%	0.0%	6.1%
Valves	13.3%	1.5%	0.0%	0.0%	0.0%	0.0%	0.3%	5.5%
Reactor Coolant System	0.0%	0.0%	0.0%	0.0%	0.0%	20.5%	0.0%	4.5%
Boiler Air and Gas Systems	10.1%	0.0%	0.0%	0.0%	0.0%	0.0%	4.9%	4.5%
Turbine	0.0%	10.0%	4.3%	0.0%	40.9%	0.0%	0.0%	4.2%
Electrical	0.4%	5.2%	9.4%	21.9%	27.1%	0.0%	0.1%	3.7%
Feedwater System	5.0%	4.2%	0.0%	0.0%	0.0%	0.4%	5.9%	3.1%
Slag and Ash Removal	4.9%	0.0%	0.0%	0.0%	0.0%	0.0%	9.0%	2.7%
Boiler Tube Fireside Slagging or Fouling	5.8%	0.0%	0.0%	0.0%	0.0%	0.0%	3.9%	2.7%
Boiler Overhaul and Inspections	3.2%	0.0%	0.0%	0.0%	0.0%	0.0%	11.1%	2.2%
Fuel, Ignition and Combustion Systems	0.0%	10.7%	8.9%	0.0%	0.0%	0.0%	0.0%	2.1%
Cooling System	5.2%	0.0%	0.1%	0.1%	0.0%	0.0%	0.0%	2.1%
Miscellaneous (Boiler)	3.5%	0.1%	0.0%	0.0%	0.0%	0.0%	1.9%	1.6%
Inlet Air System and Compressors	0.0%	2.7%	9.9%	0.0%	0.0%	0.0%	0.0%	1.4%
NOx Reduction Systems	3.2%	0.0%	0.6%	0.0%	0.0%	0.0%	0.3%	1.4%
All Other Causes	17.4%	31.1%	22.2%	78.0%	31.8%	2.0%	33.1%	18.6%
Total	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%

PJM EPOF was 11.0 percent in the first six months of 2026. Table 5-44 shows the causes of EPOF by unit type. Planned outages for miscellaneous balance of plant, 25.6 percent of the system EPOF, were the largest single contributor to average system EPOF across all unit types, although miscellaneous gas turbine issues were the largest contributors to EPOF for combustion turbines.

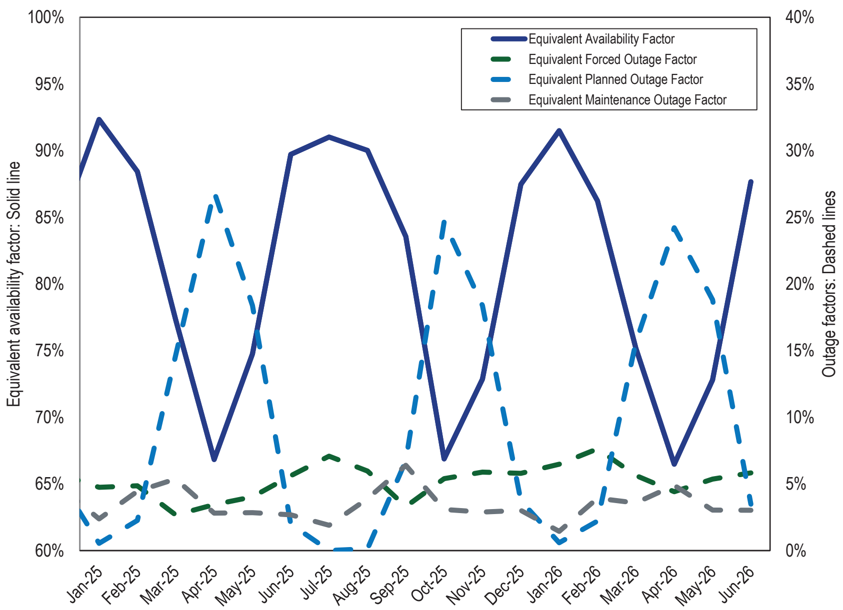
Table 5-44 Contribution to EPOF by unit type and cause: January through June, 2026

	Coal	Combined Cycle	Combustion Turbine	Diesel	Hydroelectric	Nuclear	Other	System
Miscellaneous (Balance of Plant)	19.4%	41.2%	11.1%	0.0%	0.8%	0.0%	77.9%	25.6%
Miscellaneous (Gas Turbine)	0.0%	40.5%	64.1%	0.0%	0.0%	0.0%	0.0%	17.2%
Core/Fuel	0.0%	0.0%	0.0%	0.0%	0.0%	98.4%	0.0%	11.8%
Boiler Overhaul and Inspections	26.1%	1.8%	0.0%	0.0%	0.0%	0.0%	10.4%	11.4%
Miscellaneous (Steam Turbine)	21.1%	8.9%	0.0%	0.0%	0.0%	0.0%	4.6%	10.8%
Miscellaneous (Inspection)	0.0%	0.0%	0.0%	0.0%	89.3%	0.0%	0.0%	4.3%
Generator	8.9%	0.0%	1.8%	7.0%	7.2%	0.0%	0.0%	4.0%
Wet Scrubbers	10.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	3.9%
Feedwater System	5.8%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	2.2%
Miscellaneous (Pollution Control Equipment)	4.6%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	1.8%
Stack Emission	3.2%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	1.2%
Fuel, Ignition and Combustion Systems	0.0%	0.1%	10.8%	0.0%	0.0%	0.0%	0.0%	1.2%
Miscellaneous (Generator)	0.0%	3.7%	0.0%	0.5%	0.0%	0.0%	0.0%	1.0%
Turbine	0.0%	2.1%	0.0%	0.0%	2.0%	0.0%	0.0%	0.6%
Power Station Switchyard	0.0%	0.0%	3.5%	0.1%	0.0%	0.0%	0.0%	0.4%
Boiler Piping System	0.8%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.3%
Exhaust Systems	0.0%	0.0%	2.9%	0.0%	0.0%	0.0%	0.0%	0.3%
Inlet Air System and Compressors	0.0%	0.3%	1.6%	0.0%	0.0%	0.0%	0.0%	0.3%
Miscellaneous (Jet Engine)	0.0%	0.0%	2.0%	0.0%	0.0%	0.0%	0.0%	0.2%
All Other Causes	0.0%	1.2%	2.2%	92.4%	0.7%	1.6%	7.1%	1.5%
Total	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%

Performance by Month

Monthly values for EAF, EFOF, EMOF and EPOF are shown in Figure 5-13.

Figure 5-13 Monthly generator performance factors: 2025 through June 2026



Generator Testing Issues

PJM Manual 21: Rules and Procedures for Determination of Generating Capability describes how generators are to be tested. PJM's testing requirements are not well designed, permit excessive generator discretion, and do not require adequate winter testing. As a result of the introduction of ELCC, winter capability is much more significant in defining the value of capacity that can be sold in the capacity market, especially for thermal resources. That fact makes it even more essential that PJM require winter testing and include the results of that testing in the calculation of ELCC values.

Net Capability Verification Testing data, meant to demonstrate that a unit has the ICAP claimed, are submitted for the summer and winter testing periods.[248] These periods run from the start of June until September and the start of December until March. If a unit is on a planned or maintenance outage for the entire testing period, it is expected to perform an out of period test once the outage ends. Out of period tests can be performed from the start of September until December for summer tests and from the start of March until June for winter tests. Hydroelectric generators only perform summer tests.[249] Wind and solar resources do not perform verification tests to prove capability.[250]

While data must be submitted for the winter testing period, PJM permits the use of summer test data adjusted for ambient winter conditions in lieu of actual winter test data. The MMU recommends that PJM require actual seasonal tests as part of the Summer/Winter Capability Testing rules and that the ambient conditions under which the tests are performed be defined.

Results, including failed test results, must be submitted to PJM via eGADS. Failing to submit data before the deadline can result in a Data Submission Charge of $500 per day late.[251]

Failure to demonstrate the claimed net capability results in a forced outage or derating effective from the beginning of the testing period and lasting until either a reduced claimed ICAP is in effect, the beginning of the next testing period, or, except for failures due to environmental constraints or a lack of resources, a successful out of period test.

Failed test results must be accompanied by a derating or outage in eGADS and in eDART. Failure to report failed tests and failure to derate the unit can result in a Generation Resource Rating Test Failure Charge, equal to the Daily Deficiency Rate multiplied by: the daily ICAP shortfall multiplied by one minus the effective EFORd for unlimited resources; the UCAP for the daily ICAP shortfall, for limited duration resources and combination resources.[252] Five resources were assessed for generation resource rating test failure charges

248 PJM. "PJM Manual 18: PJM Capacity Market," § 8.5 Summer/Winter Capability Testing, Rev. 62 (December 17, 2025).
249 PJM. "PJM Manual 18: PJM Capacity Market," § 8.5 Summer/Winter Capability Testing, Rev. 62 (December 17, 2025).
250 PJM. "PJM Manual 18: PJM Capacity Market," Appendix B: Calculating Capacity Values for Wind and Solar Capacity Resources, Rev. 62 (December 17, 2025).
251 "Reliability Assurance Agreement Among Load Serving Entities in the PJM Region," Schedule 12, Section A.
252 PJM. "PJM Manual 18: PJM Capacity Market," § 9.1.5 Generation Resource Rating Test Failure Charge, Rev. 62 (December 17, 2025).

in 2024. There were 207 resources assessed for generation resource rating test failure charges in 2025. There were 157 resources assessed for generation resource rating test failure charges in the first six months of 2026.

The Daily Deficiency Rate in dollars per MW-day is equal to the weighted average capacity resource clearing price from the RPM auction that resulted in the resource's commitment plus the greater of 20 percent of that clearing price or 20 dollars per MW-day.[253]

While generation owners are required to report failed tests and to derate their unit in eGADS, owners can perform an unlimited number of tests before submitting a successful result. The MMU recommends that PJM limit the number of tests that can be made before submitting final results and that the data be collected by PJM's Power Meter instead of being submitted in eGADS. The MMU recommends that PJM select the time and day for testing a unit, not the unit owner, and that this testing not be communicated in advance. Instead, a unit would be tested by how well it follows its dispatch signal. Under the current testing rules, generation owners have the opportunity to perform tests during more favorable conditions to achieve better performance.

Generator output is also assessed during Performance Assessment Intervals (PAIs), which occur when PJM declares an emergency action as listed in Manual 18, Section 8.4A. If a unit fails to perform as expected, generators may incur a Non-Performance Charge, which is equal to the performance shortfall multiplied by the Non-Performance Charge Rate.[254] In 2022, PAIs occurred on June 13, June 14, June 15, December 23, and December 24. For the December 23 and 24 PAIs, PJM total nonperformance charges were approximately $1.796 billion, reduced to $1.226 billion in a settlement agreement.[255] There were no such charges assessed in 2023, 2024, 2025, or the first six months of 2026.

For each day of a delivery year, generators are required to meet their daily unforced capacity commitments. Generation owners have the option to buy replacement capacity that satisfies the same locational requirements.[256] [257] Failure to meet this commitment can result in a Daily Capacity Resource Deficiency Charge.[258] [259] This charge is equal to the Daily Deficiency Rate multiplied by the difference between a resource's daily commitments and daily position. Thirty resources were assessed for deficiency charges in 2021, 65 resources were assessed for deficiency charges in 2022, 176 resources were assessed for deficiency charges in 2023, 432 resources were assessed for deficiency charges in 2024, 577 resources were assessed for deficiency charges in 2025, and 358 resources were assessed for deficiency charges in the first six months of 2026. The increase in the number of resources subject to deficiency charges is a result of the implementation of class average ELCC in the 2023/2024 Delivery Year and marginal ELCC starting in the 2025/2026 Delivery Year.

Changing Outage Types

Capacity resource owners have an incentive to modify the categorization of their outages in order to maximize capacity revenue and minimize penalties. Generation owners have had the ability to change the designation of the outage type after the initial submission to the eGADS database since 2014. Table 5-45 shows all the changes in outage status from 2014 through June 2026. Generation owners' incentives to categorize outages in specific ways changed with two recent significant changes in the capacity market design. The two changes were the full implementation of the Capacity Performance design in the 2020/2021 Delivery Year and the implementation of ELCC to replace EFORd to determine unforced capacity in the 2025/2026 Delivery Year.[260] [261]

The full implementation of the Capacity Performance design in the 2020/2021 Delivery Year increased the incentive for units on outage to categorize outages

253 OATT, Attachment DD (Reliability Pricing Model) § 7.
254 OATT, Attachment DD (Reliability Pricing Model) § 10A.
255 See Settlement Agreement, Docket No. ER23-2975-000 (September 29, 2023), which can be accessed at: <https://pjm.com/-/media/documents/ferc/filings/2023/20230929-er23-2975-000.ashx>.
256 "PJM Manual 21: Rules and Procedures for Determination of Generating Capability," § 1.3.6 Impacts of Test Results, Rev. 19 (June 27, 2024).
257 OATT, Attachment DD (Reliability Pricing Model) § 7 (a).
258 PJM. "PJM Manual 18: PJM Capacity Market," § 8.2 RPM Commitment Compliance, Rev. 62 (December 17, 2025).
259 OATT, Attachment DD (Reliability Pricing Model) § 8.
260 CP transition auctions were held for the 2016/2017 and 2017/2018 Delivery Years. Both Base and CP products existed for the 2018/2019 and 2019/2020 Delivery Years. The 2020/2021 Delivery Year was the first delivery year in which all capacity was Capacity Performance.
261 ELCC rates were used starting with the 2025/2026 Delivery Year. See BRA Class Ratings <https://www.pjm.com/planning/resource-adequacy-planning/effective-load-carrying-capability>.

as planned outages because units on planned outages are exempt from paying Non-Performance Charges during Performance Assessment Intervals. From 2014 through 2020, of all the changes in outage status, 3.9 percent of outages and 32.9 percent of outage MW were changed to planned outage status. From 2021 through the first six months of 2026, of all the changes in outage status, 19.6 percent of outages and 61.6 percent of outage MW were changed to planned outage status.

The implementation of ELCC in the 2025/2026 Delivery Year meant that if a unit was on outage, the unit was indifferent between being on forced, planned, or maintenance outage for the purposes of determining the unit's unforced capacity. When EFORd was the metric, there was a disincentive to be on forced outage because only forced outages affect EFORd. From 2014 through 2024, of all the changes in outage status, 10.0 percent of outages and 17.7 percent of outage MW were changed from forced outage status. From 2025 through the first six months of 2026, of all the changes in outage status, 13.4 percent of outages and 2.7 percent of outage MW were changed from forced outage status.

Table 5-45 Changed outages by unit type: 2014 through June 2026[262] [263] [264]

		Forced to Maintenance or Planned		Maintenance to Planned or Forced		Planned to Maintenance or Forced		Maintenance or Forced to Planned	
Unit Type	Year	No. Outages	MWh	No. Outages	MWh	No. Outages	MWh	No. Outages	MWh
Coal	2014	3	183,698	1	2,794	1	6,794	0	0
	2015	11	176,739	41	692,950	5	5,621	0	0
	2016	9	79,852	71	1,355,363	2	8,171	3	809,759
	2017	5	154,446	41	553,575	13	14,608	1	211,688
	2018	5	86,024	43	566,736	5	15,458	1	33,310
	2019	1	22,952	94	557,361	4	85,146	0	0
	2020	5	79,162	39	212,285	9	144,677	0	0
	2021	0	0	1	8,310	0	0	0	0
	2022	0	0	6	2,018,520	0	0	5	2,012,296
	2023	1	13,211	1	744,576	2	456,160	1	744,576
	2024	1	18,908	0	0	0	0	0	0
	2025	0	0	0	0	1	34,968	0	0
	2026 (Jan-Jun)	0	0	0	0	1	81,302	0	0
	Total	41	814,992	338	6,712,469	43	852,905	11	3,811,630
Combined Cycle	2014	7	5,711	2	87,161	3	77,027	6	88,526
	2015	2	43,414	11	45,348	5	37,570	1	3,068
	2016	13	240,506	29	251,830	20	137,030	5	284,199
	2017	17	96,805	40	617,749	6	36,614	8	305,925
	2018	7	66,065	18	58,148	12	32,392	3	12,915
	2019	14	22,610	21	344,996	10	230,173	11	245,271
	2020	14	93,001	33	737,663	22	480,618	15	797,848
	2021	14	636,121	17	1,169,417	2	14,810	26	1,782,678
	2022	9	185,326	4	793,030	10	37,104	7	550,032
	2023	4	123,264	5	267,475	7	331,057	2	111,229
	2024	7	395,783	7	1,064,214	0	0	9	1,453,698
	2025	2	3,751	13	460,194	3	611,697	6	58,395
	2026 (Jan-Jun)	4	27,198	20	131,668	9	20,627	3	117,822
	Total	114	1,939,555	220	6,028,893	109	2,046,719	102	5,811,605
Combustion Turbine	2014	4	15,186	8	30,993	0	0	5	40,893
	2015	3	17,872	10	11,854	12	141,679	2	10,370
	2016	7	135,979	75	452,987	17	36,715	21	468,584
	2017	2	43,095	22	25,517	8	22,143	2	43,175
	2018	5	64,317	32	25,755	2	6,092	3	63,700
	2019	3	30,748	29	22,457	10	67,742	3	27,609
	2020	4	10,147	38	44,895	30	16,143	0	0
	2021	3	133	6	46,241	5	44,407	1	21,147
	2022	1	985	4	17,597	11	41,887	0	0
	2023	4	53,922	7	292,895	0	0	7	76,480
	2024	8	19,494	10	287,119	1	255	2	20,667
	2025	0	0	6	275,332	2	520,190	1	17,552
	2026 (Jan-Jun)	0	0	8	137,909	1	36,439	5	102,968
	Total	44	391,877	255	1,671,551	99	933,692	52	893,144
Diesel	2014	0	0	30	3,559	0	0	0	0
	2015	4	12	162	3,141	19	51,146	0	0
	2016	7	2,276	188	4,114	11	389	2	410
	2017	0	0	222	7,653	224	8,162	0	0
	2018	2	59	292	5,004	63	1,992	0	0
	2019	2	32	224	7,365	48	6,195	0	0
	2020	13	3,578	121	5,921	70	1,575	0	0
	2021	30	1,356	2	195	0	0	0	0
	2022	3	1,537	2	3,866	59	1,609	0	0
	2023	2	24	0	0	0	0	0	0
	2024	0	0	4	140	0	0	0	0
	2025	0	0	0	0	0	0	0	0
	2026 (Jan-Jun)	0	0	0	0	0	0	0	0
	Total	63	8,875	1,247	40,959	494	71,068	2	410
Hydroelectric	2014	38	817,089	123	1,626,516	2	284	34	816,953
	2015	6	18,336	250	981,999	0	0	3	23,984
	2016	16	148,285	373	1,558,527	0	0	2	33,611
	2017	2	52,080	121	597,753	13	212,758	0	0
	2018	5	82,438	82	1,709,513	2	38,275	4	1,299,056
	2019	0	0	42	152,449	0	0	0	0
	2020	0	0	62	281,999	1	4,046	0	0
	2021	1	261	33	263,525	0	0	0	0
	2022	0	0	1	4,887	0	0	0	0
	2023	0	0	9	196,512	0	0	0	0
	2024	0	0	0	0	0	0	0	0
	2025	0	0	0	0	0	0	0	0
	2026 (Jan-Jun)	0	0	0	0	0	0	0	0
	Total	68	1,118,489	1,096	7,373,680	18	255,363	43	2,173,604
Nuclear	2014	5	192,712	0	0	1	278,160	3	188,554
	2015	9	178,056	14	79,149	0	0	4	57,197
	2016	5	84,435	18	88,462	0	0	0	0
	2017	0	0	4	35,260	1	0	0	0
	2018	0	0	14	19,517	1	16	1	823
	2019	0	0	11	703	2	3,225	2	168
	2020	3	5,782	18	313,678	9	32,198	4	9,144
	2021	0	0	3	1,134,618	0	0	1	1,134,553
	2022	12	15,541	2	960	2	300,314	3	58
	2023	7	87,630	2	3	6	83,620	0	0
	2024	2	168,615	1	553,435	0	0	3	722,050
	2025	0	0	0	0	0	0	0	0
	2026 (Jan-Jun)	1	1,660	1	7,170	0	0	1	1,660
	Total	44	734,432	88	2,232,955	22	697,533	22	2,114,208
Other	2014	9	130,402	5	22,515	0	0	3	19,487
	2015	7	30,064	12	179,670	3	5,368	1	9,833
	2016	4	24,869	24	232,507	16	81,464	2	5,874
	2017	6	319,884	20	84,853	13	55,109	1	28,636
	2018	27	424,540	14	115,939	3	7,831	4	399,203
	2019	18	152,809	41	1,282,610	9	5,887	4	1,216,374
	2020	14	26,821	31	125,046	5	22,760	2	4,678
	2021	6	9,403	2	601,218	1	2,392	2	601,218
	2022	1	397	3	1,702	1	1,485	0	0
	2023	4	251,874	0	0	2	93,080	0	0
	2024	1	272	0	0	0	0	1	272
	2025	2	5	0	0	1	212,495	0	0
	2026 (Jan-Jun)	2	39,169	0	0	5	58,162	1	39,168
	Total	101	1,410,508	152	2,646,059	59	546,032	21	2,324,742
All Units	2014	66	1,344,797	169	1,773,537	7	362,265	51	1,154,413
	2015	42	464,493	500	1,994,111	44	241,383	11	104,451
	2016	61	716,202	778	3,943,790	66	263,769	35	1,602,436
	2017	32	666,310	470	1,922,360	278	349,395	12	589,424
	2018	51	723,443	495	2,500,613	88	102,056	16	1,809,007
	2019	38	229,150	462	2,367,942	83	398,368	20	1,489,422
	2020	53	218,491	342	1,721,487	146	702,016	21	811,671
	2021	54	647,273	64	3,223,524	8	61,609	30	3,539,596
	2022	26	203,786	22	2,840,562	83	382,399	15	2,562,386
	2023	22	529,925	24	1,501,460	17	963,917	10	932,285
	2024	19	603,072	22	1,904,907	1	255	15	2,196,688
	2025	4	3,756	19	735,525	7	1,379,350	7	75,947
	2026 (Jan-Jun)	7	68,028	29	276,748	16	196,530	10	261,618
	Total	475	6,418,728	3,396	26,706,566	844	5,403,311	253	17,129,343

Cont'd

262 Year describes the year in which the outage started and not the year in which the outage designation was changed.
263 Table has been significantly updated using a more accurate unit mapping to account for ownership changes over time.
264 The first three column groupings, Forced to Maintenance or Planned, Maintenance to Planned or Forced, and Planned to Maintenance or Forced are the universe of outages that have been changed since first entered in the GADS database.