10. Ancillary Service Markets

FERC defined six ancillary services in Order No. 888: scheduling, system control and dispatch; reactive supply and voltage control from generation service; regulation and frequency response service; energy imbalance service; operating reserve - spinning reserve service; and operating reserve - supplemental reserve service.[1] PJM provides scheduling, system control and dispatch as part of the PJM administrative function. PJM provides reactive on what is asserted to be a cost of service basis. PJM provides regulation, energy imbalance, synchronized reserve, and supplemental reserve services through market mechanisms.[2] The PJM ancillary service markets are regulation, synchronized reserve, primary reserve, and 30-minute reserve. Although not defined by FERC as an ancillary service, black start service plays a comparable role. Black start service is provided on the basis of formula rates and cost of service rates.

The MMU analyzed measures of market structure, conduct and performance for the PJM Synchronized Reserve Market for the first three months of 2026.

Table 10-1 The synchronized reserve market results were not competitive

Market Element	Evaluation	Market Design
Market Structure: Regional Markets	Not Competitive	
Participant Behavior	Competitive	
Market Performance	**Not Competitive**	**Flawed**

- The synchronized reserve market structure was evaluated as not competitive due to supplier concentration. The RTO Reserve Zone was unconcentrated in the day-ahead market and unconcentrated in the real-time market. The MAD Reserve Subzone was highly concentrated in the day-ahead market and highly concentrated in the real-time market.
- Participant behavior was evaluated as competitive because the market rules require all available reserves to offer at cost-based offers.
- Market performance was evaluated as not competitive because the interaction of participant behavior with the market design does not result in competitive prices as a result of PJM's changes to the operating reserve demand curve (ORDC). In an attempt to counter poor unit specific synchronized reserve performance, PJM unilaterally and inappropriately extended the first step of the ORDC for synchronized reserve, known as the synchronized reserve reliability requirement, in May 2023, raising prices for synchronized reserves, nonsynchronized reserves and energy.
- Market design was evaluated as flawed based on PJM's modifications to the ORDC. PJM previously adopted reforms, including several based on MMU recommendations, removing both physical and economic withholding from the market.
- Significant communications technology issues when calling resources during synchronized reserve events have resulted in slow response from resources. On December 17, 2024, PJM implemented an electronic deployment of reserves via an augmented dispatch signal, but PJM does not require that resources be able to receive this signal.

The MMU analyzed measures of market structure, conduct and performance for the PJM Nonsynchronized Reserve Market for the first three months of 2026.

Table 10-2 The nonsynchronized reserve market results were not competitive

Market Element	Evaluation	Market Design
Market Structure: Regional Markets	Not Competitive	
Participant Behavior	Competitive	
Market Performance	**Not Competitive**	**Flawed**

- The nonsynchronized reserve market structure was evaluated as not competitive due to supplier concentration for primary reserve. The RTO Reserve Zone was moderately concentrated in the day-ahead market and moderately concentrated in the real-time market. The MAD Reserve Subzone was highly concentrated in the day-ahead market and highly concentrated in the real-time market.
- Participant behavior was evaluated as competitive because all available reserves are included by the PJM markets software, so withholding is not possible.

1 See 75 FERC ¶ 61,080 (1996). PJM renamed spinning reserve as synchronized reserve based on PJM's inclusion of demand side resources in the product.
2 Energy imbalance service refers to the real-time energy market.

- Market performance was evaluated as not competitive because the interaction of participant behavior with the market design does not result in competitive prices as a result of PJM's changes to the operating reserve demand curve (ORDC). In an attempt to counter poor unit specific synchronized reserve performance, PJM unilaterally and inappropriately extended the first step of the ORDC for synchronized reserve, known as the synchronized reserve reliability requirement, in May 2023. Because the first step of the ORDC for primary reserve, known as the primary reserve reliability requirement, is based on the synchronized reserve reliability requirement, the primary reserve reliability requirement was consequently also extended, raising prices for synchronized reserves, nonsynchronized reserves, and energy.
- Market design was evaluated as flawed based on PJM's modifications to the first step of the ORDC.

The MMU analyzed measures of market structure, conduct and performance for the PJM Secondary Reserve Market for the first three months of 2026.

Table 10-3 The secondary reserve market results were competitive

Market Element	Evaluation	Market Design
Market Structure	Competitive	
Participant Behavior	Competitive	
Market Performance	Competitive	Effective

- The secondary reserve market structure was evaluated as competitive due to the lack of supplier concentration for 30-minute reserve. The RTO Reserve Zone was unconcentrated in the day-ahead market and unconcentrated in the real-time market.
- Participant behavior was evaluated as competitive because all available reserves are included by the PJM software, so withholding is not possible.
- Market performance was evaluated as competitive because the combination of a competitive market structure and competitive participation resulted in competitive market outcomes.
- The market design was evaluated as effective because the market rules ensure competitive market offers and require repayment of offline cleared secondary reserves that are not available when called on to provide energy in 30 minutes.

The MMU analyzed measures of market structure, conduct and performance for the PJM Regulation Market for the first three months of 2026.

Table 10-4 The regulation market results were not competitive

Market Element	Evaluation	Market Design
Market Structure	Not Competitive	
Participant Behavior	Competitive	
Market Performance	Not Competitive	Flawed

- The regulation market structure was evaluated as not competitive because the PJM Regulation Market failed the three pivotal supplier (TPS) test in 84.5 percent of half hour market intervals in the first three months of 2026.
- Participant behavior in the PJM Regulation Market was evaluated as competitive in the first three months of 2026 because market power mitigation requires competitive offers when the three pivotal supplier test is failed, although the inclusion of a positive margin is not consistent with competitive offers.
- Market performance was evaluated as not competitive, because all units are not paid the same price on an equivalent MW basis.
- Market design was evaluated as flawed. The post-October 1, 2025 market results include an improved approach to opportunity cost but include an incorrect definition of opportunity cost that has significant effects on prices. The definition of performance is also incorrect. The post-October 1, 2025 design is a significant improvement over the pre-October 1, 2025 design although there are significant issues in the new design.

Overview

Primary Reserve

Primary reserves consist of both synchronized and nonsynchronized reserves that can provide energy within 10 minutes and sustain that output for at least 30 minutes during a contingency event. PJM made several changes to the primary reserve market, effective October 1, 2022. These included a must offer requirement and correction of misspecified cost-based offers. By removing opportunities for physical and economic withholding, the changes resulted in clearing increased quantities of available synchronized reserves at competitive prices. Starting in May 2023, to compensate for poor unit specific resource performance, PJM unilaterally increased the synchronized reserve reliability requirement, which in turn increased the primary reserve reliability requirement. That increase was not justified when implemented as current data demonstrates and the increase should be removed.

Market Structure

- **Supply.** Primary reserve is provided by both synchronized reserve (generation or demand response currently synchronized to the grid and available within 10 minutes) and nonsynchronized reserve (generation currently offline but available to start and provide energy within 10 minutes).
- **Demand.** The primary reserve reliability requirement is equal to 150 percent of the synchronized reserve reliability requirement. The primary reserve requirement is equal to the primary reserve reliability requirement, with a shortage penalty price of $850 per MWh, plus the extended reserve requirement (190 MW), with a shortage penalty price of $300 per MWh. The synchronized reserve requirement is equal to the synchronized reserve reliability requirement plus the extended reserve requirement, with a default level of 190 MW. The synchronized reserve reliability requirement is normally equal to the most severe single contingency (MSSC). Starting in May 2023, PJM increased the size of the synchronized reserve reliability requirement in the RTO Reserve Zone by 30 percentage points to 130 percent of the most severe single contingency (MSSC), in effect increasing the primary reserve reliability requirement to 195 percent of the MSSC. In the first three months of 2026, the real-time average primary reserve requirement was 3,377.5 MW in the RTO Reserve Zone and 2,701.5 MW in the Mid-Atlantic Dominion Reserve Subzone. In the first three months of 2026, the day-ahead average primary reserve requirement was 3,380.6 MW in the RTO Reserve Zone and 2,695.2 MW in the Mid-Atlantic Dominion Reserve Subzone.
- **Market Concentration.** The Mid-Atlantic Dominion (MAD) Reserve Subzone Market for primary reserve was characterized by structural market power in the first three months of 2026. The average HHI for real-time primary reserve in the RTO Reserve Zone was 1149, which is classified as moderately concentrated. The real-time RTO primary reserve market was highly concentrated in 1.3 percent of intervals.[3] The average HHI for day-ahead primary reserve in the RTO Zone was 1126, which is classified as moderately concentrated. The day-ahead RTO primary reserve market was highly concentrated in 1.8 percent of hours. The average HHI for real-time primary reserve in the MAD Reserve Subzone was 2554, which is classified as highly concentrated. The real-time MAD primary reserve market was highly concentrated in 80.6 percent of intervals. The average HHI for day-ahead primary reserve in the MAD Reserve Subzone was 2198, which is classified as highly concentrated. The day-ahead time MAD primary reserve market was highly concentrated in 65.6 percent of hours.

Synchronized Reserve Market

Synchronized reserves include all capacity synchronized to the grid and available to provide power within 10 minutes. This includes online resources loaded below their full output, storage or condensing resources synchronized to the grid but consuming energy, and 10-minute demand response capability. As of October 1, 2022, all generation capacity resources must offer their entire synchronized reserve capability to the PJM market at all times. PJM jointly optimizes energy, synchronized reserve, primary reserve, and 30-minute reserve needs in both the day-ahead and real-time markets. Synchronized reserve prices are based on opportunity costs calculated by PJM in the market optimization and the anticipated cost of a performance penalty. All real-time cleared synchronized reserves are obligated to perform when PJM initiates a synchronized reserve event.

3 FERC defines a highly concentrated market as having an HHI greater than 1800.

Market Structure

- **Supply.** In the first three months of 2026, the real-time average supply of available synchronized reserve was 5,453.7 MW in the RTO Reserve Zone, of which 2,384.9 MW on average was located in the Mid-Atlantic Dominion Reserve Subzone. In the first three months of 2026, the day-ahead average supply of available synchronized reserve was 6,693.7 MW in the RTO Reserve Zone, of which 3,077.3 MW on average was located in the Mid-Atlantic Dominion Reserve Subzone.
- **Demand.** The synchronized reserve requirement is equal to the synchronized reserve reliability requirement, with a shortage penalty price of $850 per MWh, plus the extended reserve requirement, with a shortage penalty price of $300 per MWh and a default value of 190 MW. The synchronized reserve reliability requirement is normally equal to the most severe single contingency (MSSC). Since May 19, 2023, PJM has inappropriately set the synchronized reserve reliability requirement to 130 percent of the MSSC for the RTO Reserve Zone. The real-time average synchronized reserve requirement in the first three months of 2026 was 2,315.0 MW in the RTO Reserve Zone and 1,864.4 MW in the Mid-Atlantic Dominion Reserve Subzone. The day-ahead average synchronized reserve requirement in the first three months of 2026 was 2,317.1 MW in the RTO Reserve Zone and 1,860.2 MW in the Mid-Atlantic Dominion Reserve Subzone.
    - **Market Concentration.** The Mid-Atlantic Dominion (MAD) Reserve Subzone Market for synchronized reserve was characterized by structural market power in the first three months of 2026. The average HHI for real-time synchronized reserve in the RTO Reserve Zone was 901, which is classified as unconcentrated. The real-time RTO synchronized reserve market was highly concentrated in 0.1 percent of intervals. The average HHI for day-ahead synchronized reserve in the RTO Zone was 922, which is classified as unconcentrated. The day-ahead RTO synchronized reserve market was highly concentrated in 0.6 percent of hours. The average HHI for real-time synchronized reserve in the MAD Reserve Subzone was 1989, which is classified as highly concentrated. The real-time MAD synchronized reserve market was highly concentrated in 55.6 percent of intervals. The average HHI for day-ahead synchronized reserve in the MAD Reserve Subzone was 1800, which is classified as highly concentrated. The day-ahead MAD synchronized reserve market was highly concentrated in 42.6 percent of hours.

Market Conduct

- **Offers.** There is a must offer requirement for synchronized reserve. All nonemergency generation capacity resources are required to offer their entire synchronized reserve capability. PJM calculates the available synchronized reserve for all conventional resources based on the energy offer ramp rate, energy dispatch point, and the lesser of the synchronized reserve maximum or economic maximum output. Hydro resources, Energy Storage Resource model participants, and demand response resources submit their available synchronized reserve MW. Wind, solar, and nuclear resources are by default considered incapable of providing synchronized reserve, but may offer with an exception approved by PJM. Synchronized reserve offers are capped at cost plus the expected value of performance penalties. PJM calculates opportunity costs based on LMP.

  In December 2024, PJM updated the economic basepoint signal to include deployed reserve MW during synchronized reserve events, improving performance. The yearly average performance in 2024 for events that were 10 minutes or longer was 58.2 percent, while for 2025 it was 78.3 percent and for 2026 it was 72.3 percent. However, significant communications technology and modelling issues when calling resources during spinning events continue to result in slow response from a significant share of resources.

Market Performance

- **Price.** In the first three months of 2026, for the Mid-Atlantic Dominion Reserve Subzone, the weighted average real-time price for synchronized reserve was $6.23 per MWh and the weighted average day-ahead price was $8.11 per MWh. In the first three months of 2026, for the RTO Reserve Zone, the weighted average real-time price for synchronized reserve was

$6.38 per MWh and the weighted average day-ahead price was $7.50 per MWh.

Nonsynchronized Reserve

Nonsynchronized reserve is comprised of nonemergency energy resources not currently synchronized to the grid that can provide energy within 10 minutes. Nonsynchronized reserve is available to meet the portions of the primary reserve requirement and the 30-minute reserve requirement not already satisfied by reserve cleared for the synchronized reserve requirement.

Market Structure

- **Supply.** In the first three months of 2026, the real-time average supply of eligible and available nonsynchronized reserve was 1,173.8 MW in the RTO Reserve Zone, of which 783.2 MW on average was available in the Mid-Atlantic Dominion Reserve Subzone. In the first three months of 2026, the real-time average supply of eligible and available nonsynchronized reserve was 1,193.2 MW in the RTO Reserve Zone, of which 739.5 MW on average was available in the Mid-Atlantic Dominion Reserve Subzone.
- **Demand.** Demand for nonsynchronized reserve is the primary reserve requirement less the amount of synchronized reserves cleared by PJM.[4] Although nonsynchronized reserve can be used to meet the 30-minute reserve requirement, any 30-minute reserve beyond the primary reserve requirement is usually provided by secondary reserve due to secondary reserve having lower cost and greater availability.

Market Conduct

- **Offers.** Generation owners do not submit supply offers for nonsynchronized reserve from non-hydroelectric units. Nonemergency generation resources that are available to provide energy and can start in 10 minutes or less are defined to be available for nonsynchronized reserves. For non-hydroelectric units, PJM calculates the MW available from a unit based on the unit's energy offer. Hydroelectric units set their own offered reserve amount. For all units, the offer price of nonsynchronized reserve is $0 per MWh.[5] Hybrid units and Energy Storage Resource model participants are not eligible to provide nonsynchronized reserves.

Market Performance

- **Price.** The nonsynchronized reserve price is determined by the marginal primary reserve resource. In the first three months of 2026, the nonsynchronized reserve weighted average real-time price for all intervals in the RTO Reserve Zone was $2.34 per MWh and the weighted average day-ahead price was $1.96 per MWh. In the first three months of 2026, the nonsynchronized reserve weighted average real-time price for all intervals in the MAD Reserve Subzone was $2.94 per MWh and the weighted average day-ahead price was $1.48 per MWh.

30-Minute Reserve Market

The supply of 30-minute reserves consists of resources, online or offline, which can respond within 30 minutes. This includes primary reserves and secondary reserves. By default, there is no reserve subzone for 30-minute reserves.

Market Structure

- **Supply.** The supply of 30-minute reserve is provided by both primary reserve (synchronized and nonsynchronized resources that can provide energy within 10 minutes) and secondary reserve (synchronized and nonsynchronized resources that can provide energy within 30 minutes but that take more than 10 minutes). In the first three months of 2026, the real-time average supply of available 30-minute reserve was 26,301.7 MW in the RTO Zone.
- **Demand.** The 30-minute reserve requirement is equal to the 30-minute reserve reliability requirement, with a shortage penalty price of $850 per MWh, plus the extended reserve requirement (190 MW), with a shortage penalty price of $300 per MWh. The 30-minute reserve reliability requirement is equal to the maximum of: the primary reserve reliability requirement; the largest active gas contingency; and 3,000 MW. Since PJM

4 See PJM. "PJM Manual 11: Energy & Ancillary Services Market Operations," § 4.1 Overview of the PJM Reserve Markets, Rev. 136 (Oct. 1, 2025).

5 See PJM. "PJM Manual 11: Energy & Ancillary Services Market Operations," § 4.2.3 Reserve Market Resource Offer Structure, Rev. 136 (Oct. 1, 2025).

increased the synchronized reserve reliability requirement, the 30-minute reserve reliability requirement is frequently equal to the primary reserve reliability requirement. In the first three months of 2026, the average 30-minute reserve requirement was 3,453.2 MW in the real-time market and 3,452.3 MW in the day-ahead market.

- **Market Concentration.** The RTO Reserve Zone Market for 30-minute reserves was characterized by low concentration in the first three months of 2026. In the first three months of 2026, the average HHI for real-time 30-minute reserves was 748, which is classified as unconcentrated. The real-time RTO 30-minute reserve market was highly concentrated in 0.1 percent of intervals. In the first three months of 2026, the average HHI for day-ahead 30-minute reserves was 841, which is classified as unconcentrated. The day-ahead RTO 30-minute reserve market was highly concentrated in 0.0 percent of hours.

Secondary Reserve

Secondary reserves are reserves that take more than 10 minutes to convert to energy, but less than 30 minutes. This includes the unloaded capacity of online generation that can be achieved according to the resource ramp rates in 10 to 30 minutes, and offline resources with a start time of less than 30 minutes. Secondary reserves can only be used to satisfy the 30-minute reserve requirement.

Market Structure

- **Supply.** In the first three months of 2026, in the RTO Reserve Zone, the real-time average supply of available secondary reserve was 20,180.6 MW and the day-ahead average supply of available secondary reserve was 12,307.3 MW. As with the 30-minute reserve service, there is no defined reserve subzone for secondary reserves.
- **Demand.** Demand for secondary reserve is the 30-minute reserve requirement less the amount of primary reserves cleared by PJM.[6]

6 See PJM. "PJM Manual 11: Energy & Ancillary Services Market Operations," § 4.1 Overview of the PJM Reserve Markets, Rev. 136 (Oct. 1, 2025).

Market Conduct

- **Offers.** Energy Storage Resource model participants, hydroelectric resources, hybrid resources, and demand-side response resources submit their available secondary reserve MW. For all other resource types, PJM calculates the MW available from a resource based on the resource's energy offer. For all resources, the offer price of secondary reserve is $0 per MWh.[7] In both the day-ahead and real-time secondary reserves markets, PJM uses lost opportunity costs as the offers and not offers submitted by market participants. For online secondary reserves, PJM calculates an opportunity cost based on LMP.

Market Performance

- **Price.** The secondary reserve price is determined by the marginal 30-minute reserve resource. In the first three months of 2026, the secondary reserve real-time price for all intervals was $0.00 per MWh. In the first three months of 2026, the secondary reserve day-ahead price for all hours was $0.00 per MWh.

Regulation Market

The PJM Regulation Market is a real-time market. The regulation market design changed significantly on October 1, 2025. PJM jointly optimizes regulation with synchronized reserve and energy to provide all three products at least cost. The PJM regulation market design includes three clearing price components: capability; performance; and opportunity cost.

PJM plans to implement additional changes to the regulation market in a second phase, to be implemented on October 1, 2026. This phase 2 will include separate regulation up and regulation down markets. The Phase 1 changes eliminated many of the significant issues identified by the MMU under the pre-October 1, 2025, design. However, the Phase 1 changes introduced new issues that are significantly affecting market prices.

This report analyzes the results of the regulation market in the first three months of 2026.

7 See PJM. "PJM Manual 11: Energy & Ancillary Services Market Operations," § 4.2.3 Reserve Market Resource Offer Structure, Rev. 136 (Oct. 1, 2025).

Market Structure

- **Supply.** In the first three months of 2026, the average half hour offered supply of regulation for nonramp hours was 958.8 actual MW (835.4 effective MW), 1,117.2 actual MW (967.8 effective MW) for shoulder hours, and 1,200.8 actual MW (1,048.1 effective MW) for ramp hours.
- **Demand.** The half hour regulation demand is 550 MW for nonramp hours, 650 MW for shoulder hours, and 750 MW for ramp hours.
- **Supply and Demand.** The nonramp regulation requirement of 550.0 effective MW was provided by 623.1 hourly average actual MW in the first three months of 2026. The shoulder regulation requirement of 650.0 effective MW was provided by 740.2 hourly average actual MW in the first three months of 2026. The ramp regulation requirement of 750.0 effective MW was provided by 848.9 hourly average actual MW in the first three months of 2026.

  The ratio of the average half hour offered supply of regulation to average half hour regulation demand (actual cleared MW) for nonramp hours was 1.54 in the first three months of 2026. The ratio of the average half hour offered supply of regulation to average half hour regulation demand (actual cleared MW) for shoulder hours was 1.15 in the first three months of 2026. The ratio of the average half hour offered supply of regulation to average half hour regulation demand (actual cleared MW) for ramp hours was 1.41 in the first three months of 2026.
- **Market Concentration.** In the first three months of 2026, the three pivotal supplier test was failed in 84.5 percent of half hours. In the first three months of 2026, the effective MW weighted average HHI was 1268, which is moderately concentrated.

Market Conduct

- **Offers.** Daily regulation offer prices are submitted for each unit by the unit owner. Owners are required to submit a cost-based offer and may submit a price-based offer. Offers include both a capability offer and a performance offer. In the first three months of 2026, there were 217 resources providing regulation.

Market Performance

- **Price and Cost.** The weighted average clearing price for regulation was $148.22 per MW of regulation in first three months of 2026. The weighted average cost of regulation in the first three months of 2026 was $151.56 per MW of regulation.

Black Start Service

Black start service is required for the reliable restoration of the grid following a blackout. Black start service is the ability of a generating unit to start without an outside electrical supply, or is the demonstrated ability of a generating unit to automatically remain operating at reduced levels when disconnected from the grid (automatic load rejection or ALR).[8]

In the first three months of 2026, total black start charges were $11.4 million, a decrease of $4.8 million (29.4 percent) from the first three months of 2025. In the first three months of 2026, total revenue requirement charges were $11.2 million, a decrease of $4.7 million (29.6 percent) from the first three months of 2025. In the first three months of 2026, total black start uplift charges were $0.2 million, a decrease of $0.04 million (14.9 percent) from 2025. Black start revenue requirements consist of fixed black start service costs, variable black start service costs, training costs, fuel storage costs, and an incentive payment. Black start uplift charges are paid to units scheduled in the day-ahead energy market or committed in real time to provide black start service under the ALR option or for black start testing. Black start zonal charges in the first three months of 2026 ranged from $0 in the OVEC and REC Zones to $2.2 million in the AEP Zone.

CRF values are a key determinant of total payments to black start units. The CRF values in PJM tariff tables should have been changed for both black start and the capacity market when the tax laws changed effective January 1, 2018. As a result of the failure to reduce the CRF values, black start units have been and continue to be significantly overcompensated since the changes to the tax code. In March 2023, FERC issued an order establishing hearing and settlement judge procedures.[9] By order issued September 23, 2025, the

8 OATT Schedule 1 § 1.3BB. There are no ALR units currently providing black start service.
9 See 182 FERC ¶ 61,194.

Commission approved a settlement over the MMU's objection that continued to allow overcompensation.[10] On July 4, 2025, enactment of the One Big Beautiful Bill Act (OBBBA) changed the rules for bonus depreciation again, allowing 100 percent bonus depreciation for assets constructed between January 20, 2025 and December 31, 2028, and placed in service before January 1, 2031.[11] The CRF values for affected units should incorporate 100 percent bonus depreciation. It is essential that PJM not repeat its earlier mistake when it ignored the tax law changes in 2017.

Reactive

Reactive service, reactive supply and voltage control are provided by generation and other sources of reactive power (measured in MVAr). Reactive power helps maintain appropriate voltage levels on the transmission system and is essential to the flow of real power (measured in MW). The same equipment provides both MVAr and MW. Generation resources are required to meet defined reactive capability requirements as a condition to receive interconnection service in PJM.[12] RTOs and their customers are not required to separately compensate generation resources for such reactive capability.[13]

In the first three months of 2026, PJM customers paid $85.6 million for reactive capability based on archaic, nonmarket and unsupported assertions about cost allocation and a regulatory review process of filings by individual units that results in unsupported black box settlements. The current rules have permitted over recovery of reactive costs through reactive capability charges. All costs of generators should be incorporated in the market.

The nonmarket approach to reactive capability payments will be eliminated effective June 1, 2026, based on FERC's Order No. 904 and the order approving PJM's compliance filing.[14]

10 See 193 FERC ¶ 61,059
11 OBBA § 70301(b)(3).
12 OATT Attachment O.
13 See 182 FERC ¶ 61,033 at P 52 (2023); see also Standardization of Generator Interconnection Agreements & Procedures, Order No. 2003, 104 FERC ¶ 61,103 at P 546 (2003), order on reh'g, Order No. 2003-A, 106 FERC ¶ 61,220 at P 28, order on reh'g, Order No. 2003-B, 109 FERC ¶ 61,287 (2004), order on reh'g, Order No. 2003-C, 111 FERC ¶ 61,401 (2005), aff'd sub nom. National Association of Regulatory Utility Commissioners v. FERC, 475 F.3d 1277 (D.C. Cir. 2007); California ISO, 160 FERC ¶ 61,035 at P 19 (2017); 119 FERC ¶ 61,199 at P 28 (2007), order on reh'g, 121 FERC ¶ 61,196 (2007); see also 178 FERC ¶ 61,088, at PP 29–31 (2022); 179 FERC ¶ 61,103, at PP 20-21 (2022).
14 See *Compensation for Reactive Power within the Standard Power Factor Range*, Order No. 904, 189 FERC ¶ 61,034 (2024); PJM compliance filing, Docket No. ER24-1073 (January 28, 2025); 192 FERC ¶ 61,113 (2025).

Reactive service charges based on opportunity costs are appropriately paid to units that operate in real time outside of their normal range at the direction of PJM for the purpose of providing real-time reactive power.

In the first three months of 2026, total reactive charges were $85.7 million, a decrease of $6.5 million (7.1 percent) from first three months of 2025. In the first three months of 2026, total reactive capability charges were $85.6 million, a decrease of $6.1 million (6.7 percent) from the first three months of 2025. In the first three months of 2026, total reactive service charges were $0.1 million, a decrease of $0.4 million (77.1 percent) from the first three months of 2025.

Total zonal reactive service charges ranged from $0 in the REC and OVEC Zones, to $13.8 million in the AEP Zone in the first three months of 2026.

Primary Frequency Response

On February 15, 2018, the Commission issued Order No. 842, which modified the pro forma large and small generator interconnection agreements and procedures to require all newly interconnecting non-nuclear generating facilities, both synchronous and nonsynchronous, to include equipment for primary frequency response capability as a condition to receive interconnection service.[15] [16]

Primary frequency response begins within a few seconds and extends up to a minute. The purpose of primary frequency response is to arrest and stabilize the system until other measures (secondary and tertiary frequency response) become active. This includes a governor or equivalent controls capable of operating with a maximum five percent droop and a ±0.036 Hz deadband.[17] In addition to resource capability, resource owners must comply by setting control systems to autonomously adjust real power output in a direction to correct for frequency deviations.

15 Nuclear Regulatory Commission (NRC) regulated facilities are exempt from this provision. Behind the meter generation that is sized to load is also exempt.
16 Frequency bias settings and frequency response obligations are shared in NERC's Resources Subcommittee <https://www.nerc.com/comm/OC/Pages/Resources-Subcommittee.aspx> and PJM's Operating Committee <https://www.pjm.com/committees-and-groups/committees/oc.aspx>.
17 OATT Attachment O § 4.7.2 (Primary Frequency Response).

The response of generators within PJM to NERC identified frequency events occurs two to three times per month. A frequency event is declared whenever the system frequency stays outside ±0.040 Hz deadband for at least one minute, and the minimum/maximum frequency reaches ±0.053 Hz.[18] Exclusions to PJM monitoring include nuclear plants, offline units, units with no available headroom, units assigned to regulation, and units with a current outage ticket in eDART. From June 2024 through May 2025, the NERC BAL-003-2 requirement for balancing authorities (PJM is a balancing authority) used a threshold value (L_{10}) equal to ±258.3 MW/0.1 Hz.[19] Effective June 2025 through May 2026, the threshold value (L_{10}) is equal to ±227.6 MW/0.1 Hz.[20]

The MMU has identified several issues with PJM's enforcement and evaluation of generation PFR performance.

Market Procurement of Real-Time Ancillary Services

PJM uses market mechanisms to varying degrees in the procurement of ancillary services including synchronized reserves, primary reserves, 30-minute reserves, and regulation. Ideally, all ancillary services would be procured taking full account of the interactions with the energy market. When a resource is used for an ancillary service instead of providing energy in real time, the cost of removing the resource, either fully or partially, from the energy market should be included in the offer for the ancillary service. The degree to which PJM markets account for these interactions depends on the timing of the product clearing, software limitations, and the accuracy of resource parameters and offers.

All reserve products are jointly cleared with energy in every real-time market solution. The synchronized reserve market clearing is more integrated with the energy market clearing than the other ancillary services because dispatched energy and synchronized reserve are outputs of the same optimization problem for each market interval. Given the joint clearing of energy and flexible synchronized reserves, the synchronized reserve market clearing price should always cover the opportunity cost of providing flexible synchronized reserves. Inflexible synchronized reserves, provided by resources that require hourly commitments due to run-time or staffing constraints, are not cleared with energy in the real-time market solution.[21] Instead, inflexible synchronized reserves are cleared hourly by the Ancillary Service Optimizer (ASO) or the day-ahead energy market.[22] The ASO considers energy market price forecasts, availability of resources for flexible synchronized reserves, and regulation requirements to estimate the costs and benefits of using a resource for inflexible synchronized reserves. The ASO selected inflexible reserves are a fixed input to RT SCED, which clears the balance of the requirement with flexible synchronized reserves.

Nonsynchronized reserves and offline secondary reserves are cleared with every real-time energy market solution. The energy commitment decisions to keep the resources offline have already been made when the RT SCED clears the five-minute reserves markets. Therefore, offline reserves have no lost opportunity cost. They will not be called on for energy during the market interval for which they are assigned as offline resources.

Prices for the regulation and reserve markets are set by the pricing calculator (LPC), which uses the RT SCED solution as an input. The LPC includes fast start pricing logic and system marginal price caps, so the final prices can be inconsistent with the marginal cost of the resources that clear regulation and reserves.

Recommendations

Reserve Markets

- The MMU recommends that to minimize lag and improve performance, PJM use an electronic synchronized reserve event notification process for all resources and that all resources be required to have the ability to receive and automatically respond to the notifications. (Priority: Medium. First reported 2023. Status: Partially adopted 2024.)

18 See PJM. "PJM Manual 12: Balancing Operations," § 3.6.2 Event Selection, Rev. 56 (Oct. 1, 2025).
19 See NERC. "2024 Frequency Bias Settings," June 11, 2024. <https://www.nerc.com/comm/OC/Documents/OY_2024_Frequency_Bias_Annual_Calculations_correction_06112024.pdf>.
20 See NERC. "2025 Frequency Bias Settings," Sep. 9, 2025. <https://www.nerc.com/globalassets/who-we-are/standing-committees/rstc/rs/oy_2025_frequency_bias_annual_calculations.pdf>.
21 See PJM. "PJM Manual 11: Energy & Ancillary Services Market Operations," § 4.4.3 Reserve Market Clearing, Rev. 136 (Oct. 1, 2025).
22 Starting October 1, 2025, the ASO now schedules regulation in half-hour blocks. However, as before the change, the ASO still schedules reserves in one-hour blocks.

- The MMU recommends that PJM replace the Mid-Atlantic Dominion Reserve Subzone with a reserve zone structure consistent with the actual deliverability of reserves based on current transmission constraints. (Priority: High. First reported 2019. Status: Partially adopted 2022.)
- The MMU recommends that the components of the cost-based offers for providing regulation and synchronous condensing be defined in Schedule 2 of the Operating Agreement. (Priority: Low. First reported 2019. Status: Not adopted.)
- The MMU recommends that, for calculating the penalty for a synchronized reserve resource failing to meet its scheduled obligation during a spinning event, the unit repay all credits back to the last time that the unit successfully responded to an event 10 minutes or longer. (Priority: Medium. First reported 2018. Status: Not adopted.)
- The MMU recommends that, for calculating the penalty for a synchronized reserve resource failing to meet its scheduled obligation during a spinning event, the synchronized reserve shortfall penalty should include LOC payments as well as SRMCP and MW of shortfall. (Priority: Medium. First reported 2018. Status: Not adopted.)
- The MMU recommends that aggregation not be permitted to offset unit specific penalties for failure to respond to a synchronized reserve event. (Priority: Medium. First reported 2018. Status: Not adopted.)
- The MMU recommends that PJM immediately remove the increase to the synchronized reserve reliability requirement that PJM added based on a misunderstanding of reserve performance during synchronized reserve events. (Priority: High. First reported 2024. Status: Not adopted.)
- The MMU recommends that reserve resources operating below economic minimum should not be treated as being backed down by that amount to provide reserve. (Priority: Medium. First reported 2025. Status: Not adopted.)

Regulation Market

- The MMU recommends that the two signal regulation market design be replaced with a one signal regulation market design. (Priority: Medium. First reported 2023. Status: Adopted 2025.)[23]
- The MMU recommends that the ability to make dual offers (to make offers as both a RegA and a RegD resource in the same market hour) be removed from the regulation market. (Priority: High. First reported 2019. Status: Adopted 2025.)[24]
- The MMU recommends that the regulation market be modified to incorporate a consistent application of the marginal benefit factor (MBF) throughout the optimization, assignment and settlement process. The MBF should be defined as the Marginal Rate of Technical Substitution (MRTS) between RegA and RegD. (Priority: High. First reported 2012. Status: Adopted 2025.)[25]
- The MMU recommends that the calculation of the performance score (based on precision, delay and correlation metrics) be replaced. (Priority: Medium. First reported 2023. Status: Partially adopted.).
- The MMU recommends that the performance score be revised to eliminate the effect of the size of the regulation assignment and to directly calculate the performance score based on the actual performance and the requested performance. (Priority: High. First reported 2025. Status: Not adopted.).
- The MMU recommends that the regulation market optimization be reviewed to address the logic that allows the partial clearing of inframarginal resources. (Priority: Medium. First reported 2025. Status: Not adopted.).
- The MMU recommends that if a unit sets its economic maximum at a value greater than its regulation maximum, the lost opportunity cost (LOC) of the unit should be calculated assuming the economic maximum of the unit is equal to the regulation maximum of the unit. The MMU

23 PJM filed proposed changes to the regulation market with the FERC on April 16, 2024, (Regulation Market Design Filing," Docket No. ER24-1772-000). The Commission Order on June 17, 2024 accepted the PJM Proposal as filed. PJM will implement the changes to the regulation market in two phases. Phase 1, was implemented on October 1, 2025, resulting in a single signal, bidirectional market with one clearing price that eliminates the need for an MBF. Phase 1 eliminated RegA and RegD dual offers. Phase 1 reduced the regulation commitment period from a 60-minute commitment to a 30-minute commitment. In Phase 1 the lost opportunity cost calculation used in the regulation market is based on the resource's dispatched energy offer schedule, not the lower of its price or cost offer schedule.

24 See *id.*

25 See 162 FERC ¶ 61,295 (2018), *reh'g denied*, 170 FERC ¶ 61,259 (2020).

recommends that, in cases where offered ramp is greater than actual ramp, the actual ramp be used to calculate the LOC of the unit. The MMU recommends that these fixes to the LOC logic be implemented prior to implementing Phase 2 of the regulation market design. (Priority: High. New Recommendation. Status: Not adopted.).

- The MMU recommends that the regulation market commitment period be reduced from a 60-minute commitment to a 30-minute commitment. (Priority: Medium. First reported 2023. Status: Adopted 2025.).[26]
- The MMU recommends that the lost opportunity cost in all of the ancillary services markets be calculated using the schedule on which the unit was scheduled to run in the energy market. (Priority: High. First reported 2010. Status: Adopted 2025.[27] FERC rejected.)[28]
- The MMU recommends that the lost opportunity cost calculation used in the regulation market be based on the resource's dispatched energy offer schedule, not the lower of its price or cost offer schedule. (Priority: Medium. First reported 2010. Status: Adopted 2025. FERC accepted.)[29]
- The MMU recommends that the $12.00 margin adder be eliminated from the definition of the cost based regulation offer because it is a markup and not a cost. (Priority: Medium. First reported 2021. Status: Not adopted.)
- The MMU recommends that the ramp rate limited desired MW output be used in the regulation uplift calculation, to reflect the physical limits of the unit's ability to ramp and to eliminate overpayment for opportunity costs when the payment uses an unachievable MW. (Priority: Medium. First reported 2022. Status: Adopted 2025.)[30]
- The MMU recommends enhanced documentation of the implementation of the regulation market design. (Priority: Medium. First reported 2010. Status: Not adopted. FERC rejected.)[31]

26 See *id.*
27 This recommendation was adopted by PJM for the energy market and the regulation market. Lost opportunity costs in the energy market and the regulation market are calculated using the schedule on which the unit is scheduled to run.
28 See 162 FERC ¶ 61,295 (2018), *reh'g denied*, 170 FERC ¶ 61,259 (2020).
29 See *id.*
30 In Phase 1 the ramp rate limited desired MW output is used in the regulation uplift calculation. The MMU does not agree with how this change has been implemented.
31 See *id.*

- The MMU recommends that PJM be required to save data elements necessary for verifying the performance of the regulation market. (Priority: Medium. First reported 2010. Status: Not adopted.)
- The MMU recommends that all data necessary to perform the regulation market three pivotal supplier test be saved by PJM so that the test can be replicated. (Priority: Medium. First reported 2016. Status: Not adopted.)
- The MMU recommends that the total regulation (TReg) signal sent on a fleet wide basis be eliminated and replaced with individual regulation signals for each unit. (Priority: Low. First reported 2019. Status: Not adopted.)
- The MMU recommends that, to prevent gaming, there be a penalty enforced in the regulation market as a reduction in performance score and/or a forfeiture of revenues when resource owners elect to deassign assigned regulation resources within the hour. (Priority: Medium. First reported 2016. Status: Not adopted. FERC rejected.)[32]

Frequency Response, Reactive, and Black Start

- The MMU recommends that all resources, new and existing, have a requirement to include and maintain equipment for primary frequency response capability as a condition of interconnection service. The PJM markets already compensate resources for frequency response capability and any marginal costs. (Priority: Medium. First reported 2018. Status: Partially adopted.)
- The MMU recommends that all data necessary to perform the generator primary frequency response evaluation be saved by PJM so that the test can be replicated. (Priority: Medium. First reported 2023. Status: Not adopted.)
- The MMU recommends that PJM maintain a full list of all units subject to the Primary Frequency Response generator requirements. (Priority: Medium. First reported Q1, 2025. Status: Not adopted.)
- The MMU recommends that PJM develop the metric(s) necessary to objectively evaluate each unit's performance during primary frequency

32 See *id.*

response events. (Priority: Medium. First reported Q2, 2025. Status: Not adopted.)

- The MMU recommends that PJM create the necessary tariff/manual language to properly enforce compliance with the NERC mandated Primary Frequency Response generator requirements. (Priority: Medium. First reported Q1, 2025. Status: Not adopted.)
- The MMU recommends that separate cost of service payments for reactive capability be eliminated and the cost of reactive capability be recovered in PJM markets. (Priority: Medium. First reported 2016. Status: Adopted 2024.)[33]
- The MMU recommends that new CRF rates for black start units, incorporating current tax code changes, be implemented immediately. The new CRF rates should apply to all black start units. Black start units should be required to commit to providing black start service for the life of the unit. CRF rates effective January 20, 2025, should reflect 100 percent bonus depreciation.[34] (Priority: High. First reported 2020. Status: Not adopted.)
- The MMU recommends that black start planning and coordination be on a regional basis recognizing cross zonal cranking paths and not on a narrowly or purely zonal basis and that the costs of black start service be shared on an equal per MWh basis across the region. (Priority: Medium. First reported 2023. Status: Not adopted.)
- The MMU recommends that the black start rate under the Base Formula Rate should be based on the actual cost of providing the black start service, plus an incentive, rather than the unsupported use of Net CONE, escalated each year. (Priority: Medium. First reported 2025. Status: Not adopted.)
- The MMU recommends that the fuel assurance rules be modified to recognize actual fuel assured resources within and across zones. (Priority: High. First reported Q2, 2025. Status: Not adopted.)
- The MMU recommends that the Reliability Backstop for black start service be eliminated. There is no reason that PJM cannot acquire black start resources if the TOs can acquire black start resources. (Priority: High. First reported Q2, 2025. Status: Not adopted.)

Conclusion

The October 1, 2022, changes to the reserve markets included a synchronized reserve must offer requirement applicable to all generation capacity resources. This resulted in an increase in available supply. Combined with the removal of the $7.50 per MWh margin and the invalid variable operations and maintenance cost, supply and demand logic predicts lower prices, which occurred in 2022, except during Winter Storm Elliott. This is evidence of market efficiency. With the elimination of tier 1 reserves, the total reserve market clearing price credits, while based on lower prices, are paid to a larger MW quantity. Prices have been higher since PJM increased the demand for reserves in May 2023.

The new reserve market design has been called into question by PJM based on a slow response during synchronized reserve events. In all cases, other than once during Winter Storm Elliott and once during the July 2025 hot weather event, the ACE recovered within the required time frame. No reliability problems have occurred. While the total response met the needs of the system, PJM responded to the poor performance of individual units by unilaterally and inappropriately increasing reserve requirements. This increase shifts the burden of poor resource performance from the resources themselves to customers, clearing more reserves instead of directly dealing with the causes of poor performance. These increases in reserve requirements were the primary cause of higher reserve prices in 2023, 2024, 2025, and the first three months of 2026, including 35 intervals of shortage pricing in May 2023 and several intervals of shortage pricing during spin events in 2024, 2025, and the first three months of 2026, even while reserve markets cleared over 1,000 MW more than what was normally cleared in the months and years prior.

The data on synchronized reserve event recovery do not support the conclusion that there was or is a need to increase the demand for reserves. The focus

33 On October 17, 2024, the Commission issued a final rule, Order No. 904, eliminating separate payments for reactive in all jurisdictional markets, including PJM. On January 28, 2025, PJM submitted a compliance filing to implement Order No. 904 ("Compliance Filing") that proposed a transition mechanism lasting through May 31, 2026. See Docket No. ER25-1073. This recommendation will be implemented effective June 1, 2026.

34 OBBA § 70301(b)(3).

should be on correcting issues related to the responses of individual units rather than increasing demand.

Significant communications technology and modelling issues when calling resources during spinning events result in slow response. While PJM now calculates reserve offer MW for the majority of resource types, a resource's cleared reserve MW are based on a resource's energy output at the end of a scheduling interval. If a unit is still moving when an event is called, such as near the beginning of a scheduling interval, it may or may not be able to achieve its scheduled output. Likewise, a unit that is decreasing output to create more headroom might not be able to immediately increase output when an event is called.

Although PJM now augments a resource's economic basepoint with its dispatched reserve MW during a spin event, PJM does not require resources to be able to receive this signal. Many resources are still dispatched using phone calls, either from markets operation centers waiting for the PJM ALL-CALL or from MOCs themselves manually calling plant personnel.

Even if a unit is on AGC and receiving the augmented basepoint, depending on where that unit finds itself on its ramp rate curve, it might have to spend time coming off AGC or decreasing output in order to start ramping using power augmentation. Having a synchronized reserve maximum that is less than the unit's economic maximum can address this case, but it is the unit's responsibility to request the exception.

The immediate solution is to improve the deployment of reserves in synchronized reserve events by requiring the capability to use an electronic signal for all synchronized reserves and by requiring the actual use of the signal. The archaic telephone communications technology has been a source of slow response times, such as markets operation centers waiting for the PJM ALL-CALL or manually calling unit personnel to deploy reserves. Phone calls are not an effective or efficient method for deploying resources for immediate response. The MMU recommends that to minimize lag and improve performance, PJM use an electronic synchronized reserve event notification process for all resources and that all resources be required to have the ability to receive and automatically respond to the notifications. On December 17, 2024, PJM partially adopted this recommendation by implementing an electronic deployment of reserves via an augmented dispatch signal, but PJM does not require that resources be able to receive this signal nor that the receiving units be able to follow the signal for deploying reserves. Further improvements in communications technology and requirements are necessary and PJM should pursue them immediately.

Along with changes to the communications and deployment process, PJM and the MMU have worked with generators and DSR to identify circumstances where reserves were not accurately measured based on the energy and reserve offer parameters. More broadly, the MMU's proposal is to buy the correct amount of reserves. No increase in demand is required. There has been no change in the need/demand for reserves. PJM ignored the supply side. The issue is that resources have not provided the reserves that were offered and paid for. With improved communications technology, instead of buying more MW of poorly performing reserves, PJM will be able to accurately recognize the actual supply of reserves and to more efficiently deploy them in synchronized reserve events. PJM should immediately remove the increase to the synchronized reserve reliability requirement in place from May 2023 through March 2026.

PJM will implement significant changes to the regulation market in two phases.[35] Phase 1, implemented on October 1, 2025, is a single product, single signal market with one clearing price. Phase 2, to be implemented on October 1, 2026, will include separate regulation up and regulation down markets. The Phase 1 changes eliminated many of the significant issues identified by the MMU that have resulted from a two product, two signal market design including the incorrect and inconsistent use and application of the MBF/MRTS. The actual implementation of the new design is flawed, but the design is significantly improved. Significant new issues were created by Phase 1 that significantly affect price and should be fixed as soon as possible.

The benefits of markets can be realized under the current approach to ancillary service markets. Even in the presence of structurally noncompetitive markets,

35 See 187 FERC ¶ 61,173.

there can be transparent, market clearing prices based on competitive offers that account explicitly and accurately for opportunity cost. This is consistent with the market design goal of ensuring competitive outcomes that provide appropriate incentives without reliance on the exercise of market power and with explicit mechanisms to prevent the exercise of market power. However, there are significant issues with the PJM ancillary services markets.

The MMU concludes that the synchronized reserve market results were not competitive. The MMU concludes that the nonsynchronized reserve market results were not competitive. The MMU concludes that the secondary reserve market results were competitive. The MMU concludes that the regulation market results were not competitive, and that the pre-October 1, 2025, market design is significantly flawed.

PJM Reserve Markets

Reserves resources are scheduled and paid for the availability to respond to a loss of supply on the system by increasing their energy output within defined time limits. When a resource clears in a reserve market, it is assigned scheduled reserve MW by that reserve market. Most reserve MW are cleared by the reserve markets, but PJM has the ability to schedule resources outside of the markets when needed.

PJM clears reserves to satisfy defined reserve service requirements. There are three reserve services: the synchronized reserve service (SR), the primary reserve service (PR), and the 30-minute reserve service (TMR). Each reserve service is defined by its response time requirement and by whether the service can be provided by offline resources (Table 10-5). Only the synchronized reserve service requires that all providers be online and synchronized to the grid. The other two services, primary reserve and 30-minute reserve, can be provided by both online and offline resources.

Table 10-5 Reserve services and their definitions

Service	Response Requirement (minutes)	Provided by Online Resources	Provided by Offline Resources
Synchronized Reserve	10 or less	Yes	No
Primary Reserve	10 or less	Yes	Yes
30-Minute Reserve	30 or less	Yes	Yes

Each reserve service requires a specified number of MW to be available in order to cover a potential loss of supply event, known as that service's reserve requirement. The size of a service's requirement depends on the contingencies that the service is designed to address (determining the service's reliability requirement), plus the option to add a requirement to account for potential demand increases due to temporary conditions like emergencies and weather alerts (determining the extended requirement). A service's total requirement is equal to the sum of its reliability requirement, which is unique to each service, plus the extended reserve requirement, which is the same for all services and has a base value of 190 MW.[36] [37] The default extended reserve requirement of 190 MW was designed to phase in the price impacts of shortage pricing in real time.

The reserve services are nested, such that the satisfaction of the synchronized reserve requirement counts towards the satisfaction of the primary reserve requirement, which counts towards the satisfaction of the 30-minute reserve requirement. The principal contingency for which reserves are cleared is the loss, in a single event, of the largest generator or group of generators, known as the "most severe single contingency," or the MSSC. Therefore, the reliability requirement of each service, in whole or in part, depends upon the size of the MSSC. Table 10-6 shows the default definitions of the reliability requirements and the full requirements. For calculating the 30-minute reserve requirement, PJM uses a pre-defined set of additional contingencies to simulate the effects of gas infrastructure failures on gas generators.[38] The use of these special

36 See PJM. "PJM Manual 11: Energy & Ancillary Services Market Operations," § 4.3 Reserve Requirement Determination, Rev. 136 (Oct. 1, 2025).
37 PJM has proposed creating individual extended requirements for each reserve service. This proposal was approved by the Reserve Certainty Senior Task Force on June 6, 2024, but was rejected by the Markets & Reliability Committee on July 24, 2024.
38 See PJM. "PJM Manual 13: Emergency Operations," § 3.9 Assessing Gas Infrastructure Contingency Impacts on the Electric System, Rev. 97 (Nov. 20, 2025).

contingencies is communicated to generators via PJM Emergency Procedures under "Gas Pipeline Emergencies".[39]

PJM selectively calls upon reserve services to respond to events. For example, to engage synchronized reserves, PJM initiates a synchronized reserve event, also called a spinning event.[40] In the first three months of 2026, PJM did not call on nonsynchronized reserves to collectively respond to a reserve event. PJM calls on some nonsynchronized resources to individually respond during synchronized reserve events.

The deployment of 10-minute reserves can also be in response to dispatches from the New York Independent System Operator (NYISO), which serves as the dispatcher for shared reserve activation.[41] [42] Members of the PJM Mid-Atlantic Control Zone have agreed to activate a portion of 10-minute reserve in coordination with members of the Northeast Power Coordinating Council when directed in order to relieve stress on the interconnected grid.

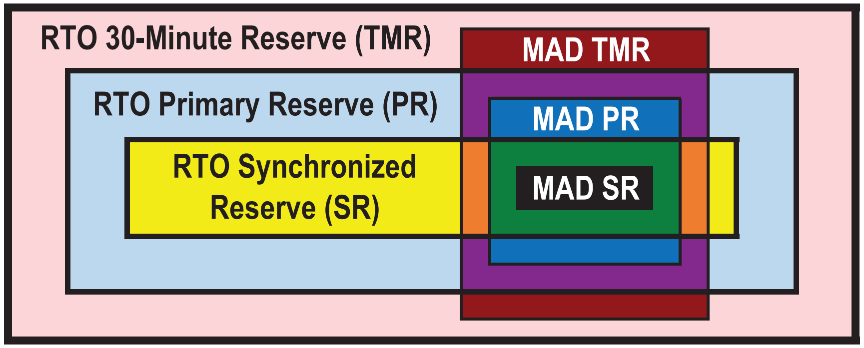
During an event, reserves respond either by increasing their energy output to the grid or by decreasing their energy consumption from the grid. The delivery of this energy is constrained by transmission limits, such that there are also limited locational requirements for each of the reserve services, except for the 30-minute reserve service.[43] PJM uses these constraints to define a reserve subzone with its own smaller requirements for synchronized reserve and primary reserve. Reserves in the subzone count towards the satisfaction of the requirements for the entire RTO Reserve Zone.[44] For example, satisfaction of the synchronized reserve requirement in the Mid-Atlantic Dominion (MAD) Reserve Subzone also counts towards the primary reserve requirement in the MAD Subzone and the synchronized reserve requirement in the RTO Zone, which in turn counts towards the satisfaction of the primary reserve requirement in the RTO Zone. There is only one active reserve subzone at a time. Figure 10-1 shows how reserve requirements for the MAD Reserve Subzone are nested inside the RTO Reserve Zone when the MAD Subzone is the active subzone.

39 PJM. Emergency Procedures – Message Definitions. (2025) <https://emergencyprocedures.pjm.com/ep/pages/messagedefinitions.jsf> Mar. 3, 2025.
40 See PJM. "PJM Manual 12: Balancing Operations," § 4.1.2 Loading Reserves, Rev. 56 (Oct. 1, 2025).
41 See PJM. "PJM Manual 12: Balancing Operations," § 4.2 Shared Reserves, Rev. 56 (Oct. 1, 2025).
42 See NPCC. "NPCC Regional Reliability Directory #5: Reserve," Attachment B - Simultaneous Activation of Ten-Minute Reserve (SAR) Contingencies, Rev. 5 (Apr. 20, 2020).
43 See PJM. "PJM Manual 11: Energy & Ancillary Services Market Operations," § 4.3.1 Locational Aspect of Reserves, Rev. 136 (Oct. 1, 2025).
44 See PJM. "PJM Manual 11: Energy & Ancillary Services Market Operations," § 4.4.1 Product and Locational Substitution, Rev. 136 (Oct. 1, 2025).

Table 10-6 Service requirement definitions[45]

Service	Service Reliability Requirement	Service Extended Requirement
Synchronized Reserve (SR)	Most Severe Single Contingency	SR Reliability Requirement + Extended Reserve Requirement
Primary Reserve (PR)	1.5 × SR Reliability Requirement	PR Reliability Requirement + Extended Reserve Requirement
30-Minute Reserve (TMR)	Max(Largest Active Gas Contingency, PR Reliability Requirement, 3,000 MW)	TMR Reliability Requirement + Extended Reserve Requirement

Figure 10-1 Service nesting in the RTO Reserve Zone and the Mid-Atlantic Dominion (MAD) Reserve Subzone



In May 2023, PJM made two unilateral changes in succession to the reserve requirements to compensate for the asserted lack of performance during spin events. Table 10-21 shows the average performance for events 10 or more minutes long. The average response to the two events of 10 minutes or more that occurred in the first four months of 2023, both in January, was 56.9 percent, compared to 50.3 percent in the last three months of 2022. On May 12, 2023, PJM inappropriately increased the extended reserve requirement by 1,588 MW and on May 15, 2023, PJM reversed the increase. On

45 From mid-May 2023 through December 2025, PJM has set the synchronized reserve reliability requirement to be 130 percent of the MSSC. See "Synchronized Reserve Requirement for Reliability – Update," (March 6, 2025). <https://www.pjm.com/-/media/DotCom/committees-groups/committees/oc/2025/20250306/20250306-item-08b---synchronized-reserve-adder.pdf>.

May 19, 2023, PJM inappropriately increased the synchronized reserve reliability requirement by 30 percentage points to 130 percent of the MSSC. The reliability requirement was 130 percent of the MSSC in 2025. Figure 10-18 compares the changes in demand. PJM will decrease or increase the adder based on the average performance across non-overlapping sets of three 10-minute events.[46]

The reserve requirements effective for a scheduling interval can change from interval to interval depending on the contingencies and needs of the grid. When maintenance work at a power station risks tripping multiple generators whose total output is larger than the MSSC, PJM can increase the requirement for synchronized reserve to include that total output. PJM can increase the reserve requirement due to emergencies and weather alerts. In May 2023, PJM unilaterally modified *PJM Manual 11: Energy & Ancillary Services Market Operations* to allow PJM to temporarily increase the requirements to compensate for poor resource performance in order to continue compliance with ReliabilityFirst's regional criteria.[47] [48] Table 10-7 shows the instances identified by the MMU when PJM temporarily increased the reserve requirements in the first three months of 2026.

Table 10-7 Temporary adjustments to 30-minute, primary, and synchronized reserve requirements: January through March, 2026[49]

From	To	Number of Hours	Amount of Adjustment
19-May-2023	08-Jan-2026	23,208	30 percent increase to synchronized reserve reliability requirement
09-Jan-2026	Ongoing	1,968+	20 percent increase to synchronized reserve reliability requirement
09-Mar-2026	30-Mar-2026	511	30-Minute Reserve (28 MW), Primary Reserve (28 MW), Synchronized Reserve (19 MW)

PJM must comply with the reserve requirements imposed by NERC, but PJM uses requirements that are more restrictive than NERC requirements. NERC Performance Standard BAL-002-3, which describes NERC's Disturbance Control Standard (DCS), defines a requirement for contingency reserve, which PJM implements as primary reserve.[50] [51] NERC BAL-002-3 does not define requirements specifically for synchronized reserve or for 30-minute reserve. NERC requires that contingency reserves respond within 15 minutes, while PJM requires that primary reserves respond within 10 minutes. NERC requires that PJM have contingency reserves greater than or equal to the MSSC, while PJM has historically targeted procuring primary reserve equal to at least 150 percent of the MSSC and procuring synchronized reserve equal to at least 100 percent of the MSSC. With PJM's increase to the synchronized reserve reliability requirement (Table10-7), from May 19, 2023, until January 9, 2026, PJM targeted procuring primary reserve in excess of 195 percent of the MSSC and procuring synchronized reserve in excess of 130 percent of the MSSC. From January 9, 2026, through March 31, 2026, and continuing, PJM targeted procuring primary reserve in excess of 180 percent of the MSSC and procuring synchronized reserve in excess of 120 percent of the MSSC.

A NERC DCS event is defined as the loss of supply, in a single event, of 80 percent or more of the MSSC. The event begins as soon as the Reporting ACE (a version of the area control error) starts to drop and ends when the Reporting ACE returns to the lesser of zero and its value at the start of the event. Although PJM uses synchronized reserve events to recover from DCS events, synchronized reserve events are generally longer than their corresponding DCS events (Figure 10-20).

46 See "Synchronized Reserve Requirement for Reliability – Update," PJM presentation to the Operating Committee. (March 6, 2025) <https://www.pjm.com/-/media/DotCom/committees-groups/committees/oc/2025/20250306/20250306-item-08b---synchronized-reserve-adder.pdf>.
47 RFC_Criteria_BAL-002-02. "Operating Reserves," August 29, 2012. <https://rfirst.org/ProgramAreas/Standards/Criteria/Regional%20Criteria%20Library/RFC_Criteria_BAL-002-02.pdf>.
48 See *id*, which describes the document as a "ReliabilityFirst Board of Directors approved good utility practice document which are not reliability standards" and notes that "ReliabilityFirst Regional Criteria are not NERC reliability standards, regional reliability standards, or regional variances, and therefore are not enforceable under authority delegated by NERC pursuant to delegation agreements and do not require NERC approval."
49 PJM does not make public the exact increases in reserves nor the exact times increases are used. This table shows the differences between the average reserve values during times that have been identified for possible increases in reserves with the average values before and after those times. The ranges given can include several overlapping timespans of possible increases.
50 NERC BAL-002-3. "Disturbance Control Standard – Contingency Reserve for Recovery from a Balancing Contingency Event," April 1, 2019. <https://www.nerc.com/pa/Stand/Reliability%20Standards/BAL-002-3.pdf>.
51 See PJM. "PJM Manual 10: Pre-Scheduling Operations," § 3.1.1 Day-ahead and Real-Time Reserves, Rev. 46 (Jul. 23, 2025).

There are three kinds of resources that can provide reserves: online generators that can increase their energy output, offline generators that can start and provide their energy output, and demand response resources that can decrease their energy use. From these resources, there are three reserve products: synchronized reserves (SR), nonsynchronized reserves (NSR), and secondary reserves (SecR).[52] A reserve product is defined by its response-time requirement and by the types of resources that can provide it (Table 10-8).

Table 10-8 Reserve products and definitions

Reserve Product	Response Requirement (minutes)	Provided by Online Generators	Provided by Offline Generators	Provided by Demand-Side Response
Synchronized Reserve	10 or less	Yes	No	Yes
Nonsynchronized Reserve	10 or less	No	Yes	No
Secondary Reserve	10 exclusive to 30 exclusive	Yes	Yes	Yes

A reserve product can only be used to satisfy a reserve service's scheduling requirement if it also satisfies that service's response-time requirement and synchronization requirement, which are listed in Table 10-5. Table 10-9 shows which reserve products can be used to satisfy which reserve services.

Table 10-9 Reserve products and the services they can provide

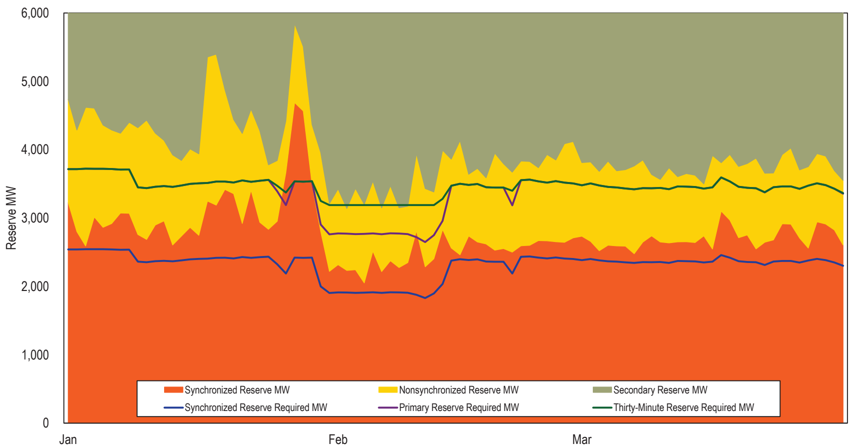
Reserve Product	Can Provide Synchronized Reserve	Can Provide Primary Reserve	Can Provide 30-Minute Reserve
Synchronized Reserve	Yes	Yes	Yes
Nonsynchronized Reserve	No	Yes	Yes
Secondary Reserve	No	No	Yes

Figure 10-2 shows how reserve products were cleared in real time to meet the reserve service requirements in the first three months of 2026. In the figure, each line represents the extended requirement of a reserve service, which is the service's reliability requirement plus the generic extended requirement. The colored areas represent how the cleared MW of the three reserve products combine to satisfy the reserve requirements. As can be seen in the figure, the cleared reserve products providing the services do not exactly equal the service requirements. In the first three months of 2026, the total amounts of cleared synchronized reserve and 30-minute reserve were frequently greater than their requirements. This can result from cleared resources providing more reserves than needed to satisfy the remainder of a requirement and can result from PJM clearing reserve products to help satisfy the requirements of the next broader reserve service. For example, in January, PJM cleared synchronized reserves in excess of the synchronized reserve requirement in order to, along with the cleared nonsynchronized reserve, more economically satisfy the primary reserve requirement.

Although not seen in Figure 10-2, PJM does not always clear enough reserves to satisfy a reserve requirement. When a service's requirement is not met, the result is shortage pricing.

52 OATT, Attachment K - Appendix § 1.7.19 (Ramping).

Figure 10-2 Daily average real-time reserve products cleared and daily average real-time reserve service requirements used by RT SCED: January through March, 2026



PJM uses market mechanisms to clear resources. In general, products that meet shorter response time requirements and that can be used to satisfy multiple reserve requirements have higher prices. The objective is to minimize total cost when purchasing reserves and energy.

Implementation of PJM Reserve Markets

While the primary reserve requirement and 30-minute reserve requirement can be satisfied using multiple products, the products are purchased separately. There are separate markets for synchronized reserves, nonsynchronized reserves, and secondary reserves.[53] MW that are selected as reserve are said to have cleared the market. Effective October 1, 2022, each product's reserve market has a day-ahead component and a real-time component. The obligations of a reserve resource depend on its real-time assignment, which in turn depends on how the resource clears the day-ahead and real-time markets. A resource that cleared one market is not guaranteed to have cleared the other market, and a resource that cleared both markets need not clear the same amount in real time as it did day ahead. Although multiple reserve products can be used to satisfy the same reserve service requirements, the reserve products are not necessarily paid the same market clearing prices. Each market for a reserve product has a single market clearing price that is applied to all reserve MW cleared in that market, regardless of the service that required the clearing of those MW.

In general, the reserve MW available from a resource are calculated by PJM based on the parameters in the resource's energy offer and reserve parameters. Some resource types, such as hydroelectric resources, Energy Storage Resource model participants, and demand response resources, can specify reserve offer amounts.[54] Generation capacity resources are required to participate in the reserve markets. However, nuclear, solar, and wind resources are excluded by default and must request inclusion in the reserve markets. PJM can automatically deselect a resource from participating in the reserve market for performance reasons.[55] [56] PJM can temporarily deselect a resource from providing reserves for, among other reasons, failing to reliably follow PJM's dispatch signal. A resource that is deselected for failing to follow PJM's dispatch signal is in violation of its must-offer requirement.[57]

A generation resource can request a maximum MW value for its reserve offer (synchronized, secondary, or both individually) that is lower than its economic maximum if that generator's reserve offer is subject to a physical limitation that cannot be modeled by a segmented hourly ramp rate.[58] Such a request must include documentation and data demonstrating the limitation. Both PJM and the MMU review the request. PJM must respond within 30 days after data supporting the request is submitted, telling the generation owner whether the request was accepted or denied, and if denied, for what reason.

53 See PJM. "PJM Manual 11: Energy & Ancillary Services Market Operations," § 4.4.1 Product and Locational Substitution, Rev. 136 (Oct. 1, 2025).

54 See PJM. "PJM Manual 11: Energy & Ancillary Services Market Operations," § 4.2.3 Reserve Market Resource Offer Structure, Rev. 136 (Oct. 1, 2025).

55 See PJM. "PJM Manual 11: Energy & Ancillary Services Market Operations," § 4.2.1 Reserve Market Eligibility, Rev. 136 (Oct. 1, 2025).

56 See PJM. "PJM Manual 11: Energy & Ancillary Services Market Operations," § 4.4.3.1 Deselection of Reserve Resources in Real-Time, Rev. 136 (Oct. 1, 2025).

57 See PJM. "PJM Manual 11: Energy & Ancillary Services Market Operations," § 4.4.3.1 Deselection of Reserve Resources in Real-Time, Rev. 136 (Oct. 1, 2025).

58 See PJM. "PJM Manual 11: Energy & Ancillary Services Market Operations," § 4.2.2.1 Communication for Reserve Capability Limitation, Rev. 136 (Oct. 1, 2025).

The clearing of resources to meet PJM's operational requirements includes multiple steps to commit resources, dispatch resources, and calculate clearing prices.[59] [60] Each program in the commitment and dispatching process estimates future needs. The day-ahead market solution software schedules resources in one-hour blocks.[61] The real-time software schedules resources in five-minute intervals.

Due to their start and notification times, some resources can only be cleared in the earlier steps of PJM's commitment and dispatching process. Depending on their physical run-time requirements, resources are described as either flexible or inflexible. Inflexible resources are those that must run for at least one hour and are only committed in real-time by the hour-ahead real-time software or by a PJM operator, and can include demand response resources, offline CTs and hydro resources that can operate in condensing mode, and resources whose economic minimum output equals their economic maximum output. Flexible resources are those that can be cleared for reserves by RT SCED later in the process. Such resources are already online for energy, require no notification time, and can be automatically dispatched.

In general, resources do not have to clear the same amounts in the real-time and day-ahead markets, and a resource that cleared one of the markets is not guaranteed to have cleared the other. However, if an inflexible condenser or an inflexible economic load response resource has a day-ahead assignment, that assignment is also applied to the operating day.[62]

Not all resources that provide reserves necessarily clear the reserve market. When needed, PJM is able to manually schedule a resource for reserves if that resource would not have otherwise run.[63] Similarly, not all inflexible reserve resources cleared by the ASO and IT SCED are necessarily used for reserves. When needed, PJM can manually switch inflexible resources from providing reserves to providing energy.

Figure 10-4 compares the daily average requirements of the day-ahead clearing engine, the ASO, and RT SCED. Figure 10-4 shows that the reserve requirements used by the ASO and RT SCED do not differ significantly. Until May 12, 2023, the daily average 30-minute reserve requirement was almost always 3,190 MW in the day-ahead software, the ASO, and RT SCED (Figure 10-4).

Figure 10-3 compares the daily average cleared MW of the day-ahead clearing engine, the ASO, and RT SCED. In addition to the increase in cleared secondary reserve resulting from PJM correcting its software error, Figure 10-3 shows that the day-ahead market also tended to clear the most nonsynchronized reserve. For satisfying the primary reserve requirement, the ASO uses more synchronized reserves, clearing less nonsynchronized reserves than RT SCED due to differences in the available MW that result from differences in the applied unit schedules. This difference is also seen in Figure 10-25.

59 For more on the market solution software, see the *2019 Annual State of the Market Report for PJM*, Appendix E - Ancillary Service Markets.
60 For more on the market solution software, see the *2019 Annual State of the Market Report for PJM*, Appendix E - Ancillary Service Markets.
61 See PJM. "PJM Manual 11: Energy & Ancillary Services Market Operations," § 4.4.2 Day-ahead Reserve Market Clearing, Rev. 136 (Oct. 1, 2025).
62 See PJM. "PJM Manual 11: Energy & Ancillary Services Market Operations," § 4.4.3 Real-time Reserve Market Clearing, Rev. 136 (Oct. 1, 2025).
63 See PJM. "PJM Manual 11: Energy & Ancillary Services Market Operations," § 4.4.3 Real-time Reserve Market Clearing, Rev. 136 (Oct. 1, 2025).

Figure 10-3 Daily average MW cleared by the day-ahead engine, the ASO, and RT SCED: January through March, 2026

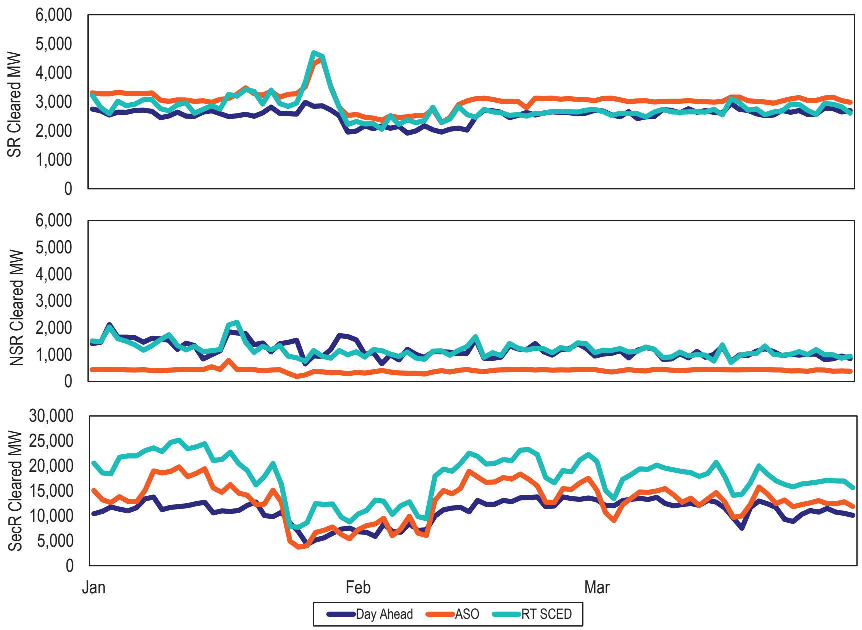


Figure 10-4 Daily average requirements used in the day-ahead engine, the ASO, and RT SCED: January through March, 2026

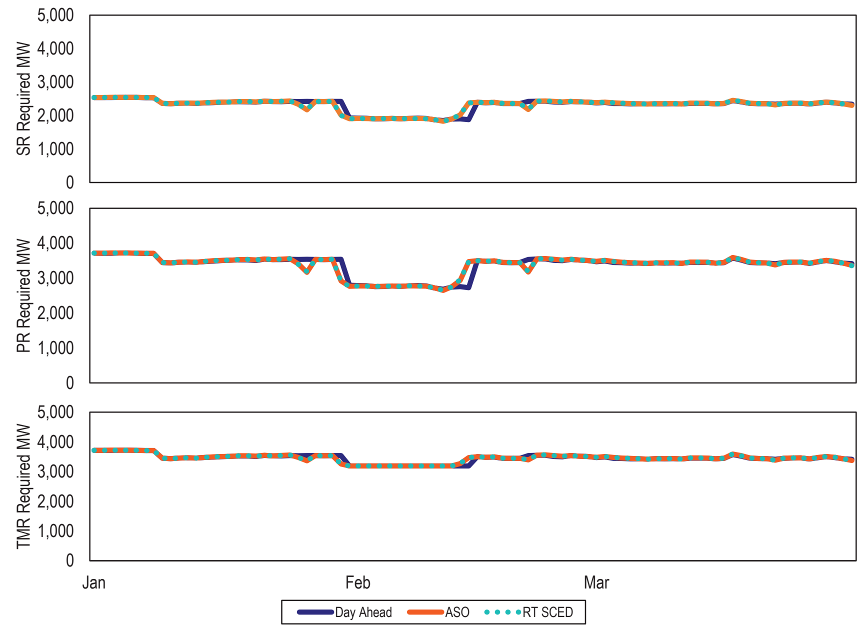
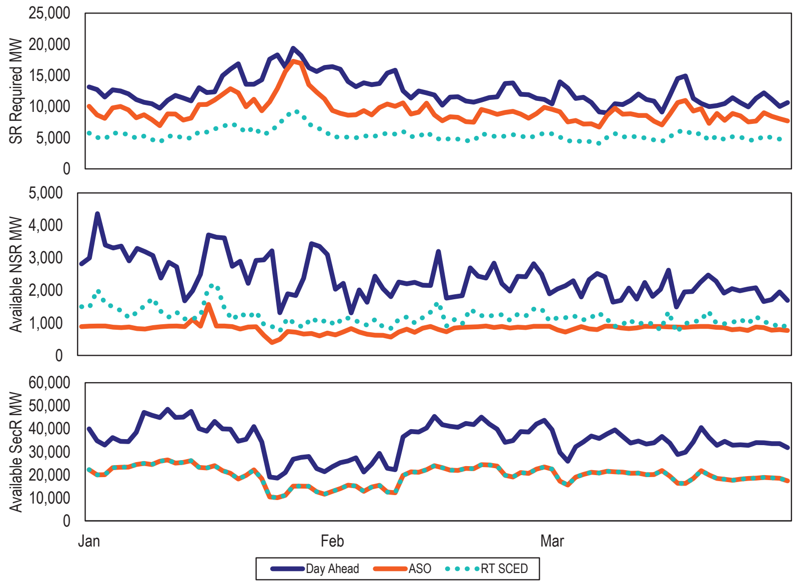


Figure 10-5 Daily average available MW used in the day-ahead engine, the ASO, and RT SCED: January through March, 2026

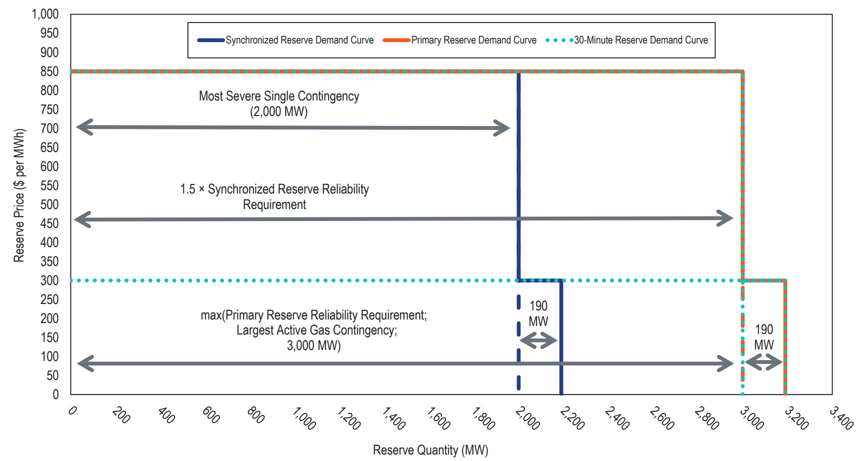


There is a defined MW demand only for synchronized reserves, primary reserves, and 30-minute reserves. The demand for nonsynchronized reserves and for secondary reserves is derived from those defined MW demand levels and cleared supply. PJM's administratively defined demand curve for reserves is called the Operating Reserve Demand Curve (ORDC) and has two steps. The first step of each reserve product's ORDC is set at that product's reliability requirement and is priced at $850 per MWh. The second step is the extended reserve requirement and is priced at $300 per MWh. Figure 10-6 shows example ORDCs for the three reserve products using an example MSSC of 1,000 MW with no increases in the extended reserve requirement.

In 2014, PJM added an optional second step to the ORDC, which could be increased from its default value of 0 MW to account for increased uncertainty identified by PJM. In 2017, PJM proposed a minimum value of 190 MW for the then optional second step, bringing it to its current form.[64] [65]

Figure 10-6 shows an example of the three operating reserve demand curves for each reserve product for an example MSSC at 1,000 MW with no increases in the extended reserve requirement. The adjusted ORDCs resulting from PJM's increase to the synchronized reserve reliability requirement are shown in Figure 10-19.

Figure 10-6 An example of the reserve product real-time operating reserve demand curves, including the permanent second steps



During periods of shortage pricing, the reserve market clearing prices can be higher than the limits shown in Figure 10-6. Offer prices for synchronized reserve are cost based and are capped at the expected value of the synchronized reserve penalty. The product substitution cost is a function of LMPs, the marginal cost of energy for the resources providing reserves, and the minimized cost of substituted MW providing energy. At the margin, the

64 See the transmittal letter to Revisions to OA Schedule 1 and OATT Att K-Appx RE Operating Reserve Demand Curve, Docket No. ER17-1590-000 (May 12, 2017) at 8.

65 For background data, see "Shortage Pricing ORDC - Order 825," PJM presentation to the Market Implementation Committee. (October 26, 2016) <https://www.pjm.com/-/media/committees-groups/committees/mic/20161026-special/20161026-item-03-shortage-ordc.ashx>.

price is the sum of the offer price and the product substitution cost of the marginal unit(s).[66]

Like the markets, credits and charges for reserves have day-ahead and real-time components. Day-ahead credits depend only on a resource's day-ahead assignment and the day-ahead market clearing price. There are no lost opportunity cost (LOC) credits in the day-ahead market, nor are there any shortfall charges applied to day-ahead assignments when evaluating resource performance. These concepts apply only to the real-time reserve markets.

The real-time component, known as the balancing credit, is added to day-ahead credits based on the difference between the real-time and day-ahead assignments. This balancing credit for a resource is the sum of a resource's balancing MCP credit and LOC credit, less any shortfall charge for failing to provide the service. If a resource clears less MW in real-time than in the day-ahead market, and if it is found to be at fault for this reduction, then the balancing MCP credit is negative and so the resource buys back this difference at real-time prices. If the resource clears more in real time, then it is positive. If a resource's real-time assignment is the same as its day-ahead assignment, then the balancing MCP credit is $0 and the resource's total MCP credit uses only the day-ahead MCP.

For the synchronized reserve product and the secondary reserve product, the MW for which a resource receives real-time credit can be capped at a value less than the cleared real-time amount. Without capping, a reserve resource producing energy above its directed amount would be paid for reserve MW that it did not actually make available.

Reserve Subzones

Reserve subzones address transmission limits that may prevent the lowest cost reserves from being deliverable throughout the RTO. A reserve subzone has its own reserve requirements, which can only be satisfied by resources within the subzone. The RTO Reserve Zone has only one active subzone at any time. In practice, PJM has maintained only one subzone, the Mid-Atlantic Dominion Reserve Subzone (MAD), and in every market solution, the most limiting constraining path sets the transfer limit between the RTO and in MAD. The price in MAD may exceed the price in the rest of the RTO when the constraints are binding.

While PJM generally triggers synchronized reserve events for the entire RTO, PJM has the option to only deploy reserves in the defined subzone. For example, on January 18, 2026, PJM triggered a synchronized reserve event only for MAD.

The choice of MAD was a result of historical congestion patterns. Transmission limits at times required maintaining out of merit reserves in the MAD area. On most days, the MAD Subzone is no longer binding. As of October 1, 2022, PJM has a process to revise the definition of the subzone. The subzone definition may change as often as daily based on system conditions, and new subzones can be defined as needed.[67] To date, PJM has used only the MAD Reserve Subzone as the chosen subzone.

Figure 10-7 is a map of constraints and major generation sources, showing how the constraints separating the RTO Reserve Zone and MAD Reserve Subzone are defined by the underlying grid topology. The most frequently binding constraints in the first three months of 2026 were Brighton-Conastone, Bedington-Black Oak, and Black Oak-Hatfield.

Figure 10-8 shows the reserve service requirements and cleared reserve product in the MAD Reserve Subzone in the first three months of 2026. As there is no 30-minute reserve requirement for the MAD Reserve Subzone, secondary reserve is excluded. The increase in reserve requirements in effect since mid-May 2023 does not apply to the MAD Reserve Subzone, only to the RTO Reserve Zone.

66 See PJM. "PJM Manual 11: Energy & Ancillary Services Market Operations," § 4.2.9 Synchronized Reserve Market Clearing Price (SRMCP) Calculation, Rev. 121 (July 7, 2022). This version of the manual has a clearer definition than later versions.

67 See PJM. "PJM Manual 11: Energy & Ancillary Services Market Operations," § 4.3.2 Creation of New Reserve Subzones, Rev. 136 (Oct. 1, 2025).

Figure 10-7 PJM RTO Zone and MAD Subzone map of constraints and generation sources

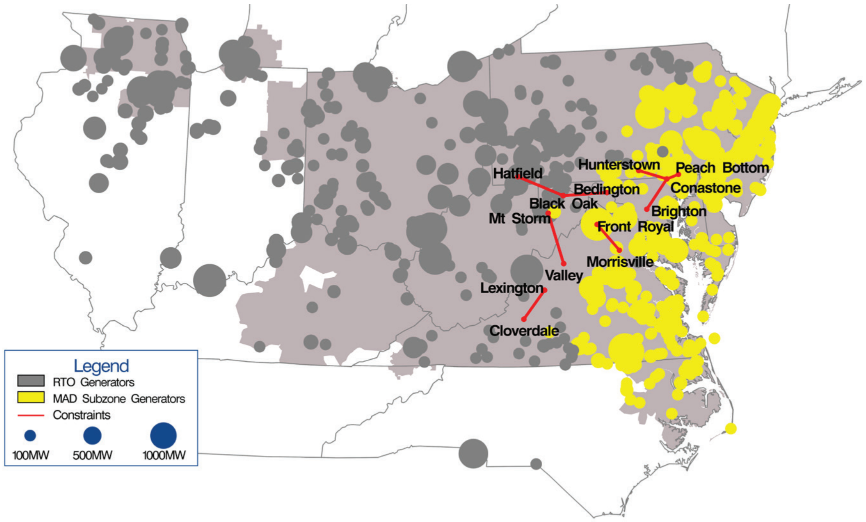
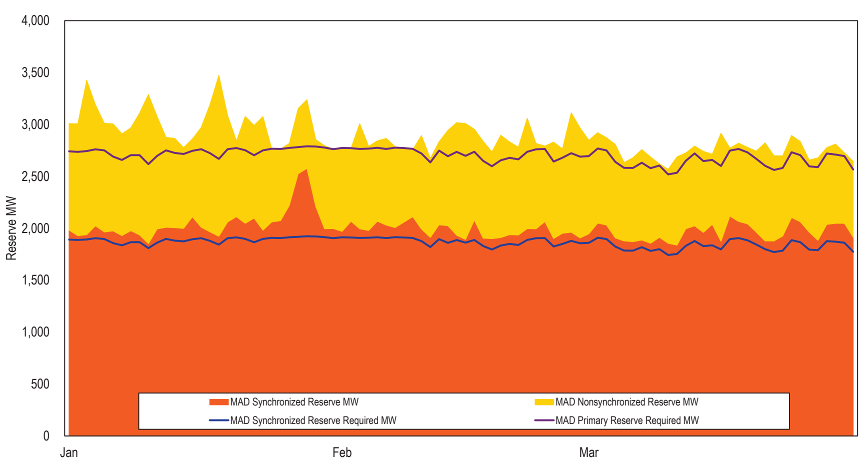


Figure 10-8 Daily average real-time MAD reserve products and daily average real-time MAD reserve service requirements: January through March, 2026



Primary Reserve

NERC Performance Standard BAL-002-3, Disturbance Control Standard – Contingency Reserve for Recovery from a Balancing Contingency Event, requires PJM to carry sufficient contingency reserve to recover from a sudden balancing contingency (usually a loss of generation). The Contingency Event Recovery Period is the time required to return the Reporting ACE to the lesser of zero and its pre-event level. The Contingency Reserve Restoration period is the time required to restore contingency (primary) reserve to a level greater than or equal to the largest single contingency after the end of the Contingency Event Recovery Period. NERC standards set the Contingency Event Recovery Period as 15 minutes and the Contingency Reserve Restoration Period as 90 minutes.[68] The NERC requirement is 100 percent compliance and status must be reported quarterly. PJM implements this contingency reserve recovery period requirement using primary reserve.[69] PJM maintains 10-minute reserve (primary reserve) which is more conservative than the NERC requirement. PJM's primary reserve is made up of resources, both synchronized and nonsynchronized, that can provide energy within 10 minutes. PJM does not have a Contingency Reserve Restoration Period standard.

Market Structure

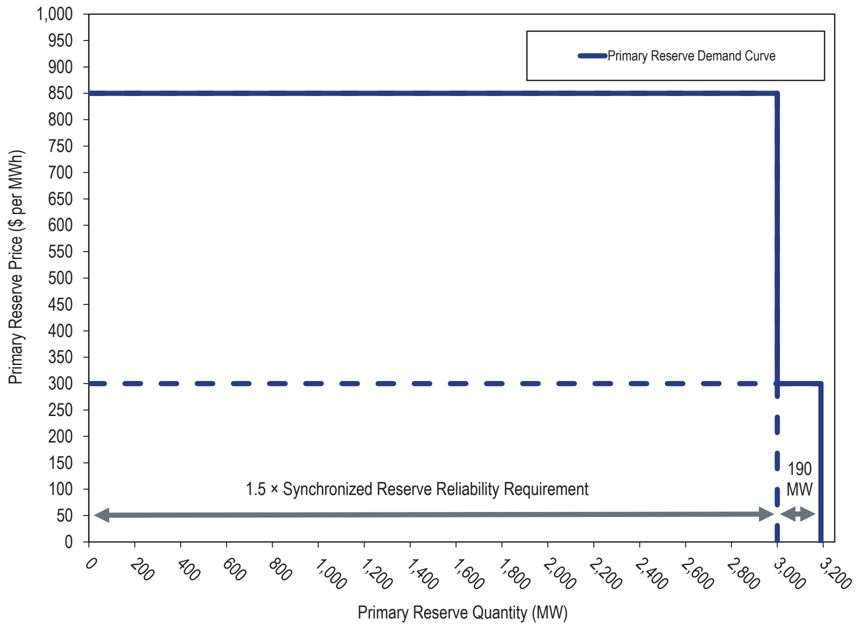
Demand

Demand for primary reserves is based on the primary reserve requirement. The primary reserve requirement is equal to the sum of the primary reserve reliability requirement, unique to the primary reserve service, plus the extended reserve requirement, which is the same for all services. The primary reserve reliability requirement is equal to 150 percent of the synchronized reserve reliability requirement. Figure 10-9 shows an example operating reserve demand curve for primary reserve for an example synchronized reserve reliability requirement of 2,000 MW plus the default 190 MW extension.

68 See PJM. "PJM Manual 12: Balancing Operations," Rev. 56 (Oct. 1, 2025) Attachment D, "the Disturbance Recovery Period is 15 minutes after the start of a Reportable Disturbance. Subsequently, PJM must fully restore the Synchronized Reserve within 90 minutes." While this cited attachment only references restoring synchronized reserves, PJM Manuals 10 & 13 make it clear that primary reserves serve as PJM's contingency reserves, although PJM generally uses synchronized reserves to recover from contingency events.

69 See PJM. "PJM Manual 10: Pre-Scheduling Operations," § 3.1 Reserve Definitions, Rev. 46 (Jul. 23, 2025).

Figure 10-9 An example of a primary reserve real-time operating reserve demand curve, including the permanent second step



In the first three months of 2026, the average primary reserve requirement for the RTO Zone was 3,377.5 MW in the real-time market and 3,380.6 MW in the day-ahead market. The average primary reserve requirement in the MAD Subzone was 2,701.5 MW in the real-time market and 2,695.2 MW in the day-ahead market.

In an attempt to offset poor unit specific synchronized reserve performance, PJM unilaterally and inappropriately made changes to the reserve requirements in May 2023. On May 12, 2023, PJM inappropriately increased the extended reserve requirement by 1,588 MW and on May 15, 2023, PJM reversed the increase. On May 19, 2023, PJM inappropriately increased the synchronized reserve reliability requirement by 30 percentage points to 130 percent of the MSSC. In effect, this increased the primary reserve reliability requirement by 45 percentage points to 195 percent of the MSSC. PJM has announced criteria to decrease or increase the adder based on average performance across non-overlapping sets of three 10-minute events.[70]

Supply

In the first three months of 2026, the demand for primary reserve was satisfied by synchronized reserves and nonsynchronized reserves. The primary reserve requirement is met from the least expensive combination of synchronized and nonsynchronized reserves that satisfies the requirements of the primary reserve service and the synchronized reserve service. Table 10-10 shows the real-time average available MW from synchronized and nonsynchronized resources in the first three months of 2026.

Table 10-10 Average available MW for clearing: January through March, 2026

Location	Synchronized Reserve MW	Nonsynchronized Reserve MW
RTO	5,453.7	1,173.8
MAD	2,384.9	783.2

Table 10-11 provides the average dispatched reserves, by reserve product, used by the RT SCED market solution to satisfy the primary reserve requirement in the MAD Subzone from January 2025 through March 2026. Table 10-12 shows the average dispatched reserves, by reserve product, used by the RT SCED market solution to satisfy the primary reserve requirement in the RTO Zone from January 2025 through March 2026.

70 See "Synchronized Reserve Requirement for Reliability – Update," PJM presentation to the Operating Committee. (March 6, 2025) <https://www.pjm.com/-/media/DotCom/committees-groups/committees/oc/2025/20250306/20250306-item-08b---synchronized-reserve-adder.pdf>.

Table 10-11 Average monthly reserves used to satisfy the primary reserve requirement, MAD Subzone: January 2025 through March 2026

Year	Month	Synchronized Reserve MW	Nonsynchronized Reserve MW	Total Primary Reserve MW
2025	Jan	1,984.6	924.8	2,909.4
2025	Feb	1,970.7	839.5	2,810.2
2025	Mar	1,966.3	666.9	2,633.2
2025	Apr	1,783.1	598.5	2,381.6
2025	May	1,832.7	618.7	2,451.4
2025	Jun	2,040.1	613.2	2,653.3
2025	Jul	2,038.1	621.3	2,659.4
2025	Aug	2,072.8	738.4	2,811.2
2025	Sep	2,089.3	770.6	2,859.9
2025	Oct	1,929.8	690.6	2,620.4
2025	Nov	1,972.0	714.1	2,686.1
2025	Dec	2,008.6	863.0	2,871.7
2025	Average	1,970.2	755.9	2,726.1
2026	Jan	2,047.6	960.4	3,008.1
2026	Feb	1,982.7	879.2	2,862.0
2026	Mar	1,962.9	790.2	2,753.2
2026	Average	1,998.3	876.6	2,874.9

Table 10-12 Average monthly reserves used to satisfy the primary reserve requirement, RTO Zone: January 2025 through March 2026

Year	Month	Synchronized Reserve MW	Nonsynchronized Reserve MW	Total Primary Reserve MW
2025	Jan	2,581.5	1,130.2	3,711.8
2025	Feb	2,111.2	1,012.8	3,124.0
2025	Mar	2,801.9	881.5	3,683.4
2025	Apr	2,182.8	776.3	2,959.1
2025	May	2,894.5	863.9	3,758.3
2025	Jun	3,222.9	734.0	3,956.8
2025	Jul	3,580.8	746.6	4,327.4
2025	Aug	4,068.4	1,096.1	5,164.6
2025	Sep	3,814.6	980.6	4,795.2
2025	Oct	2,952.2	789.0	3,741.2
2025	Nov	3,130.1	971.4	4,101.6
2025	Dec	3,066.4	1,298.3	4,364.7
2025	Average	3,041.0	940.3	3,981.3
2026	Jan	3,081.1	1,322.1	4,403.2
2026	Feb	2,502.5	1,146.8	3,649.3
2026	Mar	2,705.6	1,048.6	3,754.1
2026	Average	2,771.8	1,173.4	3,945.2

Market Concentration

In the first three months of 2026, the RTO primary reserve market was moderately concentrated in day ahead and moderately concentrated in real time. In the first three months of 2026, the MAD primary reserve market was highly concentrated in day ahead and highly concentrated in real time. Table 10-13 shows the average of the HHI values of each interval for primary reserves in the first three months of 2026.

Table 10-13 Average primary reserve HHI: January through March, 2026

Location	Market	Average HHI	Percent of Intervals Max Market Share Above 20%	Description
RTO	RT	1149	72.0%	Moderately Concentrated
RTO	DA	1126	64.8%	Moderately Concentrated
MAD	RT	2554	99.0%	Highly Concentrated
MAD	DA	2198	97.5%	Highly Concentrated

Market Performance

Figure 10-10 shows daily weighted average synchronized and nonsynchronized market clearing prices in the first three months of 2026. The synchronized reserve market clearing prices for the RTO Reserve Zone and the MAD Reserve Subzone diverged in 62 intervals, 0.2 percent of the total 25,908 five-minute intervals in the first three months of 2026.[71] The nonsynchronized reserve market clearing prices for the RTO Reserve Zone and the MAD Reserve Subzone diverged in 59 intervals, 0.2 percent of the total 25,908 five-minute intervals in the first three months of 2026.

Prices of synchronized reserve and nonsynchronized reserve spiked in late January and early February during a cold weather event that included Winter Storm Fern. Shortage pricing was used for RTO primary reserve on January 24 and 31; February 2, 6, 9, 13, and 16; and March 1, 12, 13, and 22. Shortage pricing was used for MAD primary reserve on January 24; February 9; and March 1, 12, and 13. Shortage pricing was used for RTO synchronized reserve on January 23 and 30; February 1, 4, 6, and 7; and March 1, 13, and 14. Shortage pricing was used for MAD synchronized reserve on January 23 and on March 12 and 13. For the cold weather event, conservative operations were declared from January 24 through February 2.

Table 10-14 shows the number of intervals with shortage pricing in which the amount cleared by RT SCED was greater than the reserve requirement absent the increase to the synchronized reserve reliability requirement. In the first three months of 2026, in the majority of intervals with shortage pricing, RT SCED cleared enough reserve MW to satisfy the original RTO reserve service requirements. These intervals were not short in the sense of failing to clear a sufficient amount of reserves; these intervals were short because of PJM's unilateral increase to the synchronized reserve reliability requirement. The unilateral increase does not affect the MAD Reserve Subzone.

Figure 10-10 Daily average market clearing prices for synchronized reserve and nonsynchronized reserve: January through March, 2026

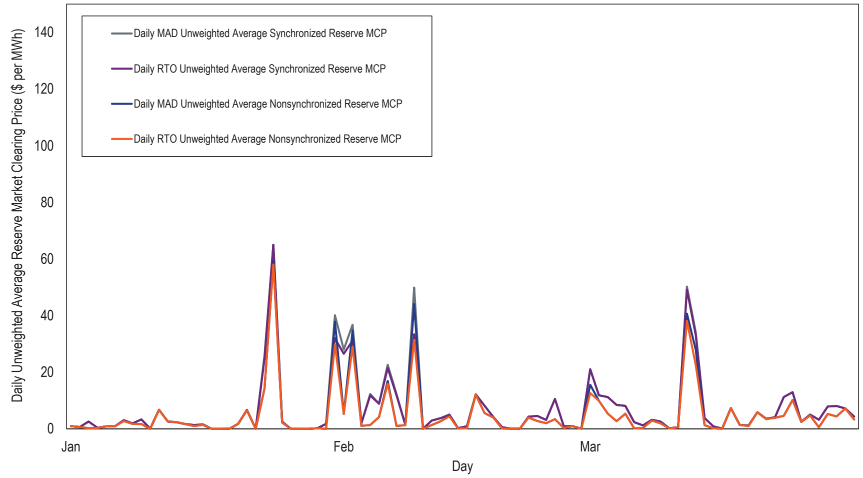


Table 10-14 Number of shortage pricing intervals which satisfied the unmodified reserve service requirement: January through March, 2026

	Reserve Service		
	SR	PR	TMR
Intervals with Shortage Pricing	22	76	0
Intervals where RT SCED Satisfied Original Requirement	22	58	0
Percentage of Intervals where RT SCED Satisfied Original Requirement	100.0%	76.3%	NA
Intervals where RT SCED Did Not Satisfy Original Requirement	0	18	0

71 Billing data can be modified by PJM Settlements at any time to reflect changes in the evaluation of energy uplift. The billing data reflected in this report were current on April 6, 2026.

Synchronized Reserve

All eligible generation capacity resources capable of providing synchronized reserves have a must offer requirement, and all cleared synchronized reserves have an obligation to perform and receive payment based on the synchronized reserve market clearing price. PJM Manual 11 states, "Any generator that is a PJM generation capacity resource that has a Reliability Pricing Model (RPM) or Fixed Resource Requirement (FRR) Resource commitment that is eligible to provide Reserves must offer their 10-minute and 30-minute reserve capability, unless the unit is unavailable due to an approved planned outage, maintenance outage or forced outage."[72]

Since October 1, 2022, the reserve market design for synchronized reserve includes both day-ahead and real-time markets. Prior to that date, synchronized reserve was only a real-time product.

PJM uses synchronized reserve when PJM calls synchronized reserve events, also called spin events or spinning events.

Market Structure

For most resources, synchronized reserves consist of any online capacity not being used for energy that can be achieved within 10 minutes from the current dispatch point according to the resource's ramp rate. The PJM market solves an economic dispatch to determine which, if any, of these resources should be backed down to provide reserves. Some nondispatchable resources can provide synchronized reserves, including storage resources, hydro resources with storage, synchronous condensers, and demand response resources. For both the RTO and the reserve subzone, the day-ahead market clears hourly synchronized reserve assignments and the real-time market clears five-minute synchronized reserve assignments.

Demand

Demand for the synchronized reserve product comes from the reserve requirement for the synchronized reserve service. The synchronized reserve requirement is equal to the synchronized reserve reliability requirement plus the extended reserve requirement. The synchronized reserve reliability requirement is normally equal to the most severe single contingency (MSSC). Figure 10-6 shows an example operating reserve demand curve for synchronized reserve.

In the first four months of 2023, the synchronized reserve reliability requirement was equal to the most severe single contingency (MSSC). PJM unilaterally increased the extended reserve requirement by 1,588 MW from May 12, 2023, through May 15, 2023. Then, on May 19, 2023, PJM unilaterally increased the synchronized reserve reliability requirement to 130 percent of the MSSC, which increased the effective primary reserve reliability requirement from 150 percent of the MSSC to 195 percent of the MSSC. From May 19, 2023, through January 8, 2026, the demand portion was equal to 130 percent of the MSSC. From January 9, 2026, through March 2026, the demand portion has been equal to 120 percent of the MSSC. This increase does not apply to the MAD requirement and does not apply to the RTO requirement when the RTO MSSC is inside of the MAD Reserve Subzone. Figure 10-18 compares the old and new RTO ORDCs with an example MSSC of 1,000 MW.

Figure 10-2 shows a plot of the RTO daily average real-time requirement for synchronized reserve and the RTO daily average cleared synchronized reserve MW. Figure 10-11 shows the real-time and day-ahead daily average synchronized reserve requirements for the RTO Reserve Zone and the MAD Reserve Subzone. In the first three months of 2026, the average real-time synchronized requirement in the RTO Reserve Zone was 2,315.0 MW and the average day-ahead requirement was 2,317.1 MW. In the MAD Reserve Subzone, the average real-time synchronized requirement was 1,864.4 MW and the average day-ahead requirement was 1,860.2 MW. In February 2026, the RTO and MAD requirements were frequently equal because the MSSC in the MAD Reserve Subzone during those intervals was also the MSSC of the whole RTO Reserve Zone. PJM's SR adder does not apply to MSSCs inside of the MAD Reserve Subzone.

72 See PJM. "PJM Manual 11: Energy & Ancillary Services Market Operations," § 4.2.2 Reserve Resource Offer Requirements, Rev. 136 (Oct. 1, 2025).

Figure 10-11 Daily average required MW: January through March, 2026

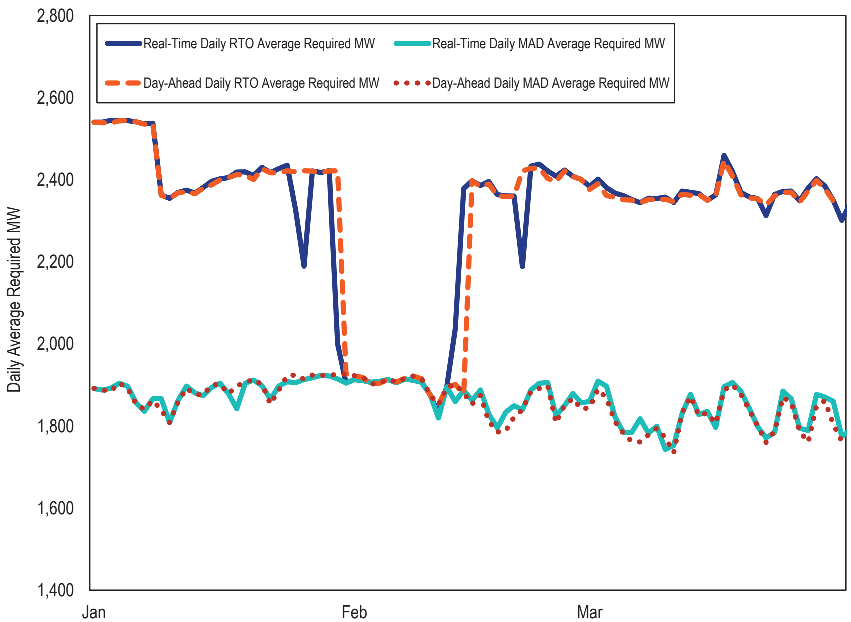


Figure 10-17 compares the total amount of cleared synchronized reserve with the subset of cleared synchronized reserve that is provided by DSR. Prior to October 1, 2022, DSR resources were limited by PJM to being no more than 33 percent of the total cleared synchronized reserves in each interval, but that limitation was removed on October 1, 2022, as part of the Reserve Price Formation changes to the reserve markets.

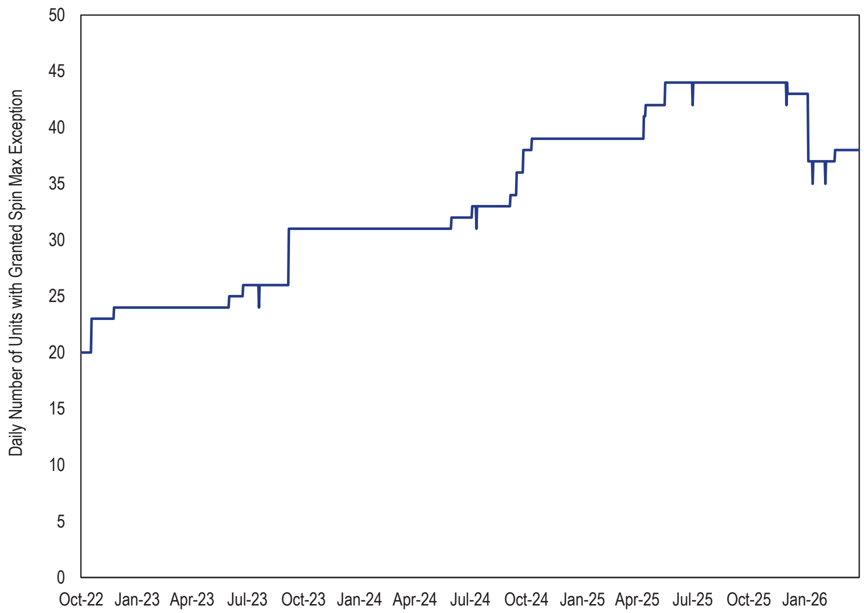
Supply

The supply of synchronized reserves consists of all unloaded capacity from eligible online generators that can convert to energy in 10 minutes and offers from eligible economic load response that can curtail in 10 minutes.[73] Any of this capacity that is not offered as dispatchable in the energy market does not have a lost opportunity cost in the security constrained economic dispatch (SCED). This includes synchronous condensers, storage resources, and demand response. Synchronous condensers and demand response are also considered inflexible in the reserve market and require an hourly commitment, which is made by the Ancillary Services Optimizer (ASO) in real time.[74] This means that these resources enter the SCED reserves supply curve with a marginal cost of zero because PJM is effectively committing them as must run, block loaded reserves.

In general, a resource's reserve MW are the lesser of a resource's 10-minute ramp, and the difference between its energy output and its economic maximum output. A generation resource can request a maximum MW value for its synchronized reserve offer that is lower than its economic maximum if that generator's reserve offer is subject to a physical limitation that cannot be modeled by a segmented hourly ramp rate.[75] For example, units that must hold their output steady while activating duct burners. Figure 10-12 shows how the number of units that can use a lower synchronized reserve maximum MW has increased. If generators in need of the exception request it, PJM should see improved reserve performance due to a more accurate calculation of the available reserve MW.

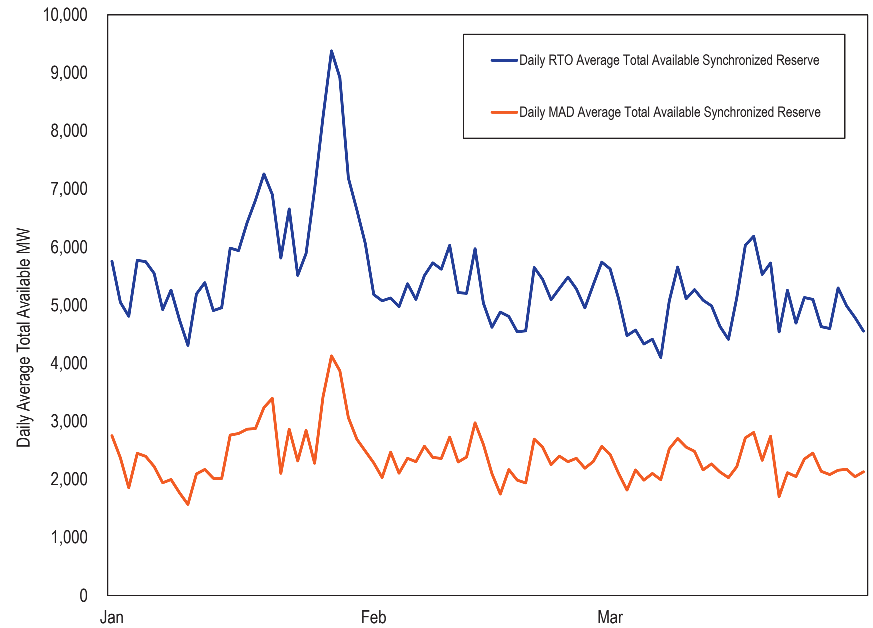
73 See PJM. "PJM Manual 11: Energy & Ancillary Services Market Operations," § 4.2.1 Reserve Market Eligibility, Rev. 136 (Oct. 1, 2025).
74 Starting October 1, 2025, the ASO now schedules regulation in half-hour blocks. However, as before the change, the ASO still schedules reserves in one-hour blocks.
75 See PJM. "PJM Manual 11: Energy & Ancillary Services Market Operations," § 4.2.2.1 Communication for Reserve Capability Limitation, Rev. 136 (Oct. 1, 2025).

Figure 10-12 Number of units per day allowed to use a spin max less than eco max:[76] October 2022 through March 2026



In the first three months of 2026, the average supply of offered and eligible synchronized reserve was 5,453.7 MW in the RTO Reserve Zone, of which 2,384.9 MW was located in the MAD Reserve Subzone. Figure 10-13 shows the daily average available synchronized reserve MW in the first three months of 2026. The daily average total available synchronized reserve MW increased in late January due to PJM committing more resources to be online during a cold weather event which included Winter Storm Fern.

Figure 10-13 Daily Average Available Synchronized Reserve: January through March, 2026



Market Concentration

Table 10-15 provides the average HHI and the percent of intervals during which the maximum market share was above 20 percent for the day-ahead and real-time synchronized reserve markets for the first three months of 2026. In the first three months of 2026, the MAD synchronized reserve market was highly concentrated in the day-ahead market and highly concentrated in the real-time market. In the first three months of 2026, the RTO synchronized reserve market was unconcentrated in the day-ahead market and unconcentrated in the real-time market.

76 That a unit is able to use a spin maximum less than its economic maximum does not mean that it is required to do so. The count of units that used the exception on a given day can be less than what is shown.

Table 10-15 Day-ahead and real-time synchronized reserve average HHI: January through March, 2026

Location	Market	Average HHI	Percent of Intervals Max Market Share Above 20%	Description
RTO	RT	901	23.8%	Unconcentrated
RTO	DA	922	24.4%	Unconcentrated
MAD	RT	1989	92.3%	Highly Concentrated
MAD	DA	1800	90.9%	Highly Concentrated

In the first three months of 2026, the Ancillary Service Optimizer, which schedules economic inflexible resources while considering all resources against forecasted LMPs, failed the three pivotal supplier test in 2,210 ASO intervals, 60.2 percent of the 3,671 ASO intervals to which the test applied.[77]

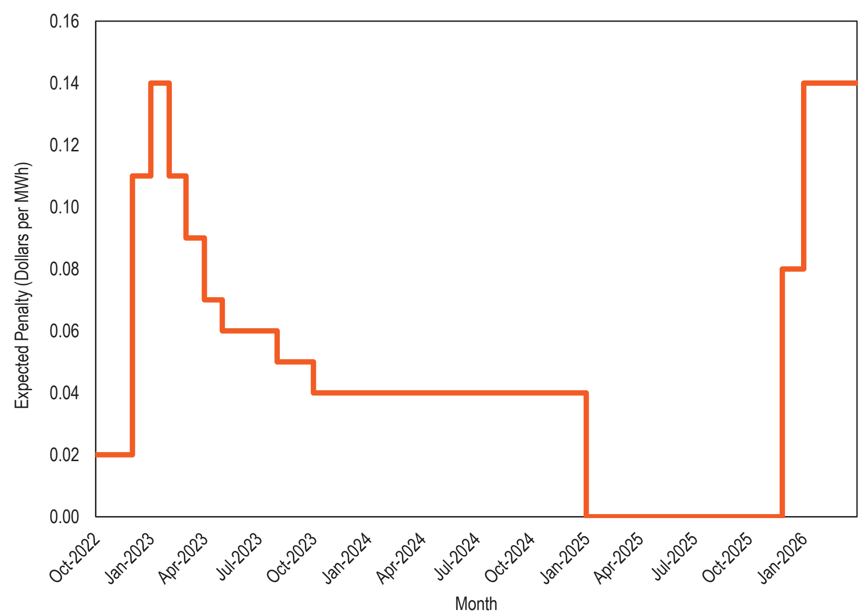
Market Behavior

The synchronized reserve offer price must be cost based and is capped at the expected value of the synchronized reserve penalty, which equals the average penalty multiplied by the average rate of nonperformance multiplied by the probability that an event will occur.[78] These expected values are shown in Figure 10-14. For resources that do not provide an offer price, the offer price is treated as $0 per MWh. In the first three months of 2026, the weighted average offer price for generators that set their offer MW was $0.00 per MWh. In the first three months of 2026, the weighted average offer price for DSR resources that set their offer MW was $0.04 per MWh.

The synchronized reserve offer cap was updated monthly from October 2022 through December 2023, after which it is updated annually. On November 26, 2025, the offer cap was increased from $0.00 to $0.08 to correct for an error.[79] For 2026, the offer cap is $0.14 per MWh.

77 On October 1, 2025, the ASO switched from producing one-hour solutions to producing 30-minute solutions. Although the ASO's intervals are now 30 minutes long, the ASO still schedules reserves in one-hour blocks, each of which now span two 30-minute intervals.
78 See PJM. "PJM Manual 15: Cost Development Guidelines," § 4.7 Synchronized Reserve, Rev. 47 (Oct. 1, 2025).
79 See PJM. "Synchronized Reserve Offer Cap", 2025 Annual Calculation (Dec. 12, 2025). <https://www.pjm.com/-/media/DotCom/markets-ops/ancillary/synchronized-reserve-offer-cap-2025.xlsx>

Figure 10-14 Expected values of the synchronized reserve penalty: October 2022 through March 2026[80]



Market Performance

In the first three months of 2026, the real-time RTO weighted average synchronized reserve market clearing price (SRMCP) was $6.38 per MWh and the day-ahead RTO weighted average SRMCP was $7.50 per MWh. The real-time MAD weighted average SRMCP was $6.23 per MWh and the day-ahead MAD weighted average SRMCP was $8.11 per MWh. In the first three months of 2026, there were 25,908 five-minute intervals in the real-time market and there were 2,159 hours in the day-ahead market. The real-time RTO SRMCP was $0 per MWh in 12,135 intervals (46.8 percent of all intervals). The real-time MAD SRMCP was $0 per MWh in 12,134 intervals (46.8 percent of all intervals). The day-ahead RTO SRMCP was $0 per MWh in 484 hours (22.4

80 PJM. "Synchronized Reserve Offer Cap". December 12, 2025. <https://www.pjm.com/-/media/markets-ops/ancillary/synchronized-reserve-offer-cap-penalty.ashx>.

percent of all hours). The day-ahead MAD SRMCP was $0 per MWh in 218 hours (10.1 percent of all hours).

Figure 10-15 shows the daily unweighted average prices for synchronized reserve in the real-time and day-ahead markets. Higher day-ahead prices in late January and early February occurred during a cold weather event that included Winter Storm Fern, for which conservative operations were declared, a cold weather alert was issued, and maintenance outages were recalled. Shortage pricing for the RTO and MAD was used on January 23 and March 12. Shortage pricing for the RTO was used on January 30; February 1, 4, 6, and 7; and March 1, 13, and 14.

Figure 10-15 Day-ahead and real-time synchronized reserve average market clearing prices: January through March, 2026

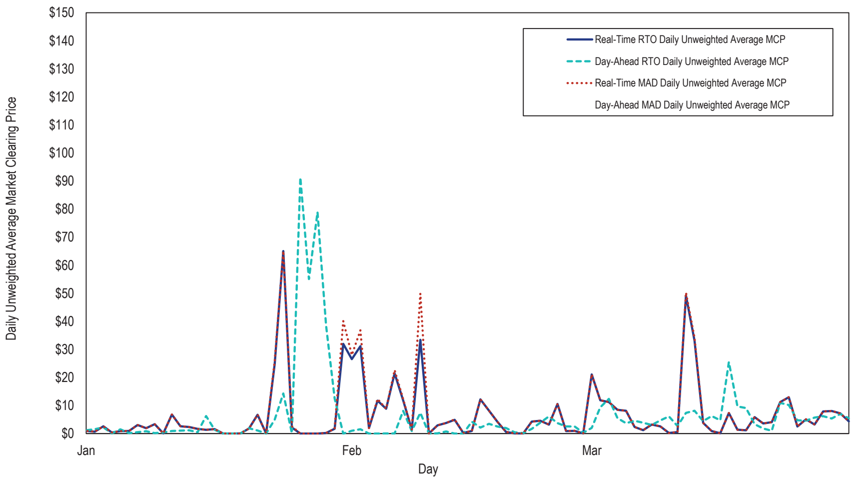


Table 10-16 and Table 10-17 compare the dispatch run and pricing run weighted average prices for the day-ahead and real-time markets. Fast start pricing increases LMP in the pricing run relative to the dispatch run, which increases reserve prices. Fast start pricing also reduces the amount of reserves available in the pricing run compared to the dispatch run, by pretending that fast start units can be dispatched for energy below their economic minimum output limit but not counting MW below the eco min as reserves. For the real-time values, these are the LPC prices weighted using the RT SCED MW. For the day-ahead values, these are the DA prices weighted using the DA dispatch MW. PJM dispatchers can update assignments after RT SCED has run, so these weights differ from the weighted average value reported elsewhere in this section.[81] In the first three months of 2026, the real-time RTO weighted average price from the pricing run was 25.5 percent higher than the real-time RTO weighted average price from the dispatch run. In the first three months of 2026, the day-ahead RTO weighted average price from the pricing run was 1.8 percent higher than the day-ahead RTO weighted average price from the dispatch run. In the first three months of 2026, the real-time MAD weighted average price from the pricing run was 22.2 percent higher than the real-time MAD weighted average price from the dispatch run. In the first three months of 2026, the day-ahead MAD weighted average price from the pricing run was 6.8 percent higher than the day-ahead MAD weighted average price from the dispatch run.

81 See PJM. "PJM Manual 01: Control Center and Data Exchange Requirements," § 1.7 Dispatch Management Tool (DMT), Rev. 50 (May 21, 2025).

Table 10-16 Day-ahead and real-time fast start pricing in the RTO synchronized reserve market: January 2025 through March 2026

		Day-Ahead				Real-Time			
Year	Month	Dispatch-Run MCP	Pricing-Run MCP	Difference	Percent Difference	Dispatch-Run MCP	Pricing-Run MCP	Difference	Percent Difference
2025	Jan	$4.43	$4.79	$0.36	8.0%	$2.02	$2.62	$0.61	30.1%
2025	Feb	$2.56	$2.56	($0.00)	(0.1%)	$1.96	$2.88	$0.92	46.9%
2025	Mar	$7.73	$7.23	($0.50)	(6.5%)	$4.89	$7.28	$2.39	48.9%
2025	Apr	$8.65	$8.48	($0.17)	(2.0%)	$2.64	$4.91	$2.28	86.4%
2025	May	$5.77	$5.45	($0.32)	(5.6%)	$2.15	$3.14	$0.99	45.7%
2025	Jun	$7.96	$7.51	($0.44)	(5.6%)	$9.48	$10.77	$1.29	13.6%
2025	Jul	$10.69	$9.98	($0.70)	(6.6%)	$2.87	$4.67	$1.80	62.8%
2025	Aug	$3.78	$3.22	($0.55)	(14.6%)	$1.24	$2.03	$0.79	63.9%
2025	Sep	$5.66	$4.69	($0.97)	(17.1%)	$2.77	$3.42	$0.65	23.3%
2025	Oct	$6.50	$6.44	($0.06)	(0.9%)	$2.53	$3.59	$1.07	42.1%
2025	Nov	$5.37	$4.00	($1.37)	(25.5%)	$1.02	$1.62	$0.60	58.3%
2025	Dec	$3.16	$2.59	($0.58)	(18.2%)	$1.90	$2.61	$0.71	37.2%
2025	All	$6.08	$5.62	($0.46)	(7.5%)	$2.96	$4.10	$1.14	38.6%
2026	Jan	$10.61	$11.51	$0.90	8.5%	$3.29	$4.67	$1.37	41.7%
2026	Feb	$2.98	$2.15	($0.83)	(27.8%)	$5.66	$6.98	$1.32	23.3%
2026	Mar	$6.76	$6.89	$0.13	1.9%	$6.42	$7.55	$1.13	17.7%
2026	All	$7.05	$7.18	$0.13	1.8%	$5.01	$6.29	$1.28	25.5%

Table 10-17 Day-ahead and real-time fast start pricing in the MAD synchronized reserve market: January 2025 through March 2026

		Day-Ahead				Real-Time			
Year	Month	Dispatch-Run MCP	Pricing-Run MCP	Difference	Percent Difference	Dispatch-Run MCP	Pricing-Run MCP	Difference	Percent Difference
2025	Jan	$5.11	$5.53	$0.42	8.2%	$2.15	$2.68	$0.54	25.1%
2025	Feb	$4.02	$4.02	($0.00)	(0.1%)	$1.67	$2.40	$0.73	43.6%
2025	Mar	$8.08	$7.58	($0.49)	(6.1%)	$4.47	$6.65	$2.18	48.9%
2025	Apr	$9.09	$8.92	($0.17)	(1.8%)	$2.41	$4.11	$1.71	70.9%
2025	May	$5.94	$5.60	($0.34)	(5.7%)	$1.92	$2.81	$0.88	45.9%
2025	Jun	$8.17	$7.74	($0.44)	(5.3%)	$7.76	$8.52	$0.77	9.9%
2025	Jul	$10.69	$9.97	($0.72)	(6.7%)	$2.74	$4.37	$1.63	59.7%
2025	Aug	$3.98	$3.46	($0.52)	(13.0%)	$1.16	$1.91	$0.75	64.5%
2025	Sep	$5.42	$4.51	($0.90)	(16.7%)	$2.61	$3.16	$0.55	21.1%
2025	Oct	$6.70	$6.69	($0.02)	(0.3%)	$2.35	$3.18	$0.83	35.4%
2025	Nov	$6.16	$6.36	$0.20	3.2%	$1.81	$2.33	$0.52	28.8%
2025	Dec	$6.32	$6.49	$0.17	2.7%	$5.49	$6.61	$1.11	20.2%
2025	All	$6.57	$6.32	($0.24)	(3.7%)	$3.01	$4.01	$1.00	33.4%
2026	Jan	$13.16	$14.46	$1.30	9.9%	$3.52	$4.99	$1.47	41.7%
2026	Feb	$3.40	$3.65	$0.25	7.3%	$5.69	$7.04	$1.35	23.8%
2026	Mar	$7.46	$7.60	$0.14	1.8%	$6.52	$7.09	$0.58	8.8%
2026	All	$8.24	$8.80	$0.56	6.8%	$5.13	$6.27	$1.14	22.2%

Figure 10-16 shows the dispatch-run synchronized reserve RTO market clearing prices of the day-ahead software (DA), the hour-ahead software (ASO), and the real-time software (RT SCED). The pricing-run market clearing prices, calculated by the LPC, are in Figure 10-15. As seen in Figure 10-16, there can be significant differences in the dispatch-run clearing prices. The ASO schedules units by forecasting least-cost outcomes for the operating hour, and any inflexible resources cleared by the ASO are automatically cleared by RT SCED. Because it is possible for real time to differ from the ASO's forecasts, it is possible for an inflexible resource to be scheduled during real-time conditions in which, had it not been inflexible and already cleared by the ASO, RT SCED would not have scheduled it. For example, it is possible for an inflexible resource to be scheduled in real time even when its bid price is higher than the clearing prices used by RT SCED and the LPC. This did not occur in 2025, or in 2026, but in 2024, there were 47,229 RT SCED five-minute intervals in which there was at least one inflexible unit scheduled by the ASO whose bid price was greater than the RT SCED market clearing price. In 2024, there were 229 inflexible resources cleared by the ASO for which the market clearing price of the RT SCED five-minute interval was less than the resource's bid price. The opposite can also happen, in which an inflexible resource is not cleared by the ASO while its offer parameters, had it not been inflexible, would have led to it having been cleared by RT SCED.

Figure 10-16 Dispatch run synchronized reserve market clearing prices from the day-ahead software, the ASO, and RT SCED: January through March, 2026

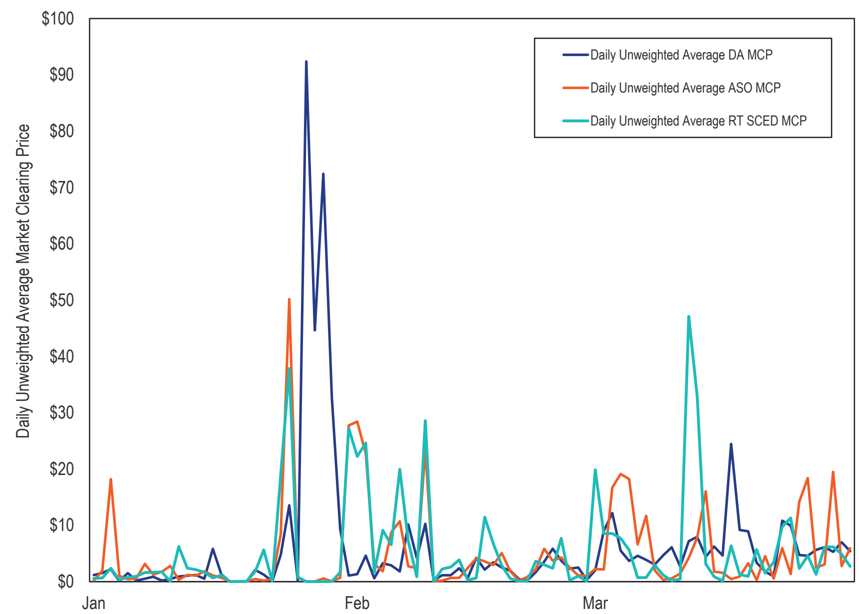


Table 10-18 shows total synchronized reserve payments by month for January 2025 through March 2026. Balancing credits for all but one month are negative, because, on average, resources buy back their day-ahead positions at higher real-time prices. LOC credits are paid to cover negative balancing credits if PJM converted a resource's day-ahead reserve position to energy in the real-time market. LOC credits are also paid to inflexible reserves when prices do not cover their opportunity costs. Shortfall charges are incurred by resources that do not provide their cleared reserve positions in real time. In Table10-18, the only months with synchronized reserve events that lasted for 10 or more minutes were February 2025, July 2025, September 2025 through November 2025, and March 2026, so there are no shortfall charges possible outside of those months. Total credits in June 2025 were larger due to price spikes during a hot weather event in which shortage pricing was used for synchronized reserve in the RTO Reserve Zone and the MAD Reserve Subzone. Total credits in July 2025 were larger due to price spikes during a second set hot weather event in which PJM declared hot weather alerts, emergency maximum generation alerts, and a maintenance outage recall. Shortage pricing was not used for synchronized reserve during the July hot weather event. Total credits in January 2026 were larger due to price spikes during a cold weather event covering Winter Storm Fern, in which PJM declared cold weather alerts, conservative operations, and a maintenance outage recall.

Table 10-18 Total synchronized reserve payments and charges by month: January 2025 through March 2026

Year	Month	Total Day-Ahead Credits	Total Balancing MCP Credits	Total LOC Credits	Total Shortfall Charges	Total Credits
2025	Jan	$9,766,427	($93,903)	$1,086,575	$0	$10,759,099
2025	Feb	$5,437,781	($126,526)	$779,549	$118,146	$5,972,657
2025	Mar	$15,181,061	($1,464,818)	$2,047,513	$0	$15,763,757
2025	Apr	$13,256,012	($345,197)	$1,268,522	$0	$14,179,338
2025	May	$10,685,430	($13,743)	$786,811	$0	$11,458,498
2025	Jun	$15,012,782	($4,327,200)	$4,657,382	$0	$15,342,965
2025	Jul	$22,507,389	($310,371)	$2,566,238	$76,684	$24,686,572
2025	Aug	$7,390,714	$20,554	$1,016,144	$0	$8,427,413
2025	Sep	$10,131,551	($840,026)	$1,576,176	$159,581	$10,708,120
2025	Oct	$11,138,947	($485,436)	$1,526,784	$114,170	$12,066,126
2025	Nov	$9,137,073	($11,535)	$1,375,185	$4,336	$10,496,388
2025	Dec	$9,324,827	($435,351)	$1,998,439	$0	$10,887,915
2025	All	$138,969,996	($8,433,550)	$20,685,319	$472,917	$150,748,848
2026	Jan	$23,153,558	($231,344)	$2,986,156	$0	$25,908,371
2026	Feb	$4,348,346	($1,100,363)	$3,640,493	$0	$6,888,476
2026	Mar	$13,523,239	($1,974,988)	$3,056,498	$299,649	$14,305,100
2026	All	$41,025,143	($3,306,695)	$9,683,147	$299,649	$47,101,946

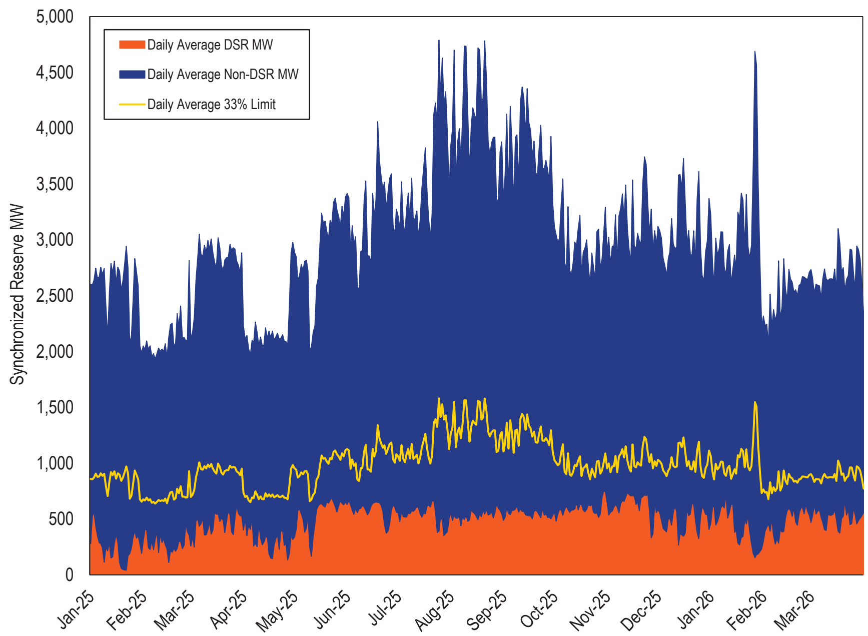
Table 10-19 provides the day-ahead and real-time synchronized reserve by resource type and fuel type for the first three months of 2026. For synchronized reserve, the MW for which a resource is credited at the market clearing price is capped at the lesser of its real-time assignment and the difference between its real-time output and the lesser of its economic maximum and its real-time reserve maximum. During spin events, this capped value is equal to the cleared MW. As it is this capped value for which a resource is credited, Table 10-19 only shows the capped value, excluding the additional cleared MW.

Table 10-19 Day-ahead and real-time synchronized reserve by resource type and fuel type: January through March, 2026

Resource / Fuel Type	Day-Ahead MWh	Real-Time Capped MWh	Day-Ahead Credits	Balancing MCP Credits	LOC Credits	Shortfall Charges	Total Credits
Combined Cycle	2,432,519	1,941,018	$18,144,761	($6,138,620)	$4,335,816	$84,893	$16,257,064
CT - Natural Gas	337,358	727,891	$7,884,450	$1,523,908	$1,346,466	$815	$10,754,009
Steam - Coal	931,381	1,198,616	$2,560,869	$1,888,327	$1,781,490	$34,869	$6,195,817
DSR	701,933	1,012,352	$3,647,887	$1,456,883	$1,140,515	$67,639	$6,177,646
Hydro - Pumped Storage	469,815	466,704	$3,907,443	($1,137,866)	$200,618	$89,698	$2,880,497
Hydro - Run of River	283,258	142,044	$2,238,995	($480,470)	$4,534	$12,984	$1,750,076
CT - Oil	107,220	128,529	$1,328,947	($296,069)	$345,516	$0	$1,378,395
Steam - Natural Gas	108,493	141,589	$729,964	$190,846	$264,469	$2,533	$1,182,746
Steam - Other	13,139	4,390	$90,952	($40,551)	$162,808	$83	$213,125
RICE - Natural Gas	11,037	6,657	$205,227	($26,502)	$21,311	$0	$200,036
RICE - Other	54,267	26,695	$214,052	($212,477)	$32,722	$6,135	$28,163
Other	20,312	17,581	$71,596	($34,102)	$46,882	$0	$84,375

The October 1, 2022, changes, removed the prior cap that limited DSR to 33 percent of the cleared synchronized reserves. In the first three months of 2026, real-time DSR was more than 33 percent of the cleared real-time synchronized reserves in 255 five-minute intervals, 1.0 percent of the total 25,908 five-minute intervals. In the first three months of 2026, day-ahead DSR was more than 33 percent of the cleared day-ahead synchronized reserves in one hours. During these 255 five-minute intervals, on average, DSR made up 38.0 percent of the synchronized reserve MW. Figure 10-17 shows the portion of synchronized reserve provided by DSR. Since September 2023, there has been an increase in the use of DSR, but not enough to frequently exceed the former limit.

Figure 10-17 Daily average synchronized reserve from DSR and non-DSR: January 2025 through March 2026



Synchronized Reserve Performance

Resources providing synchronized reserves are paid for being available to respond to a synchronized reserve event and not for the actual response. Synchronized reserve resources are paid for their output in the energy market when they respond to an event.

Actual synchronized reserve event response is determined by final output minus initial output where final output is the largest output between 9 and 11 minutes after the start of the event, and initial output is the lowest output between one minute before the event and one minute after the event.[82]

Cleared synchronized reserve resources are obligated to sustain their final output for the shorter of the length of the event or 30 minutes. The owner of a cleared resource is penalized if it fails to perform during any synchronized reserve event lasting 10 minutes or longer, although the resource owner can use overperformance from another resource to offset those losses. As synchronized reserve resources are allowed 10 minutes to ramp up to their cleared output, performance penalties are not assessed for events lasting less than 10 minutes.

Table 10-20 shows synchronized reserve event response compliance for events that lasted 10 minutes or longer, using only the response from cleared synchronized reserves. In 2024, five events were 10 minutes or longer. Of those five reserve events, only one was associated with a DCS event. In the first three months of 2026, one event lasted for at least 10 minutes. That one 10 minute event was due to a unit trip and was associated with a DCS event. In the first three months of 2026, PJM triggered zero events explicitly due to low ACE. For all other DCS events, any associated reserve event lasted less than 10 minutes. PJM has the option, but not the obligation, to trigger a reserve event in response to a DCS event. In some circumstances, PJM system operators will opt to recover the system via regulation and the normal dispatching process.

Actual synchronized reserve response is the total increase in MW from all synchronized reserve resources from the moment the spinning event is called to 10 minutes after. The overall response to spinning events was adequate or more than adequate to meet NERC requirements, in which the Reporting ACE must return to the lesser of zero and the value of the Reporting ACE before the disturbance that caused the event.[83] PJM, in practice, not only corrects the Reporting ACE disturbance that led to the event but over corrects. In the one event lasting 10 or more minutes in the first three months of 2026, the Reporting ACE recovered not just to the NERC required level of zero but overshot by approximately 1,000 MW.

82 See PJM. "PJM Manual 11: Energy & Ancillary Services Market Operations," § 4.2.10 Settlements, Rev. 136 (Oct. 1, 2025).

83 See PJM. "PJM Manual 12: Balancing Operations," Rev. 56 (Oct. 1, 2025) Attachment D.

Table 10-20 Response compliance for synchronized reserve events 10 minutes or longer by primary fuel and resource type, excluding over response: January 2025 through March 2026[84]

Spin Event	Duration (Minutes)	Primary Resource/Fuel Type	Total Synchronized Reserve Deployed (MW)	Total Capped Synchronized Reserve Resource Response (MW)	Total Synchronized Reserve Resource Shortfall (MW)	Synchronized Reserve Response Percent	Total Synchronized Reserve Response,including Over-Response (MW)	Synchronized Reserve Response Percent, including Over-Response
5-Feb-2025	10.0	Combined Cycle	548	411	137	75%	627	115%
		CT - Natural Gas	559	513	46	92%	563	101%
		Steam - Coal	199	106	93	53%	119	60%
		Steam - Natural Gas	120	42	78	35%	46	38%
		Other	412	180	232	44%	267	65%
		Total	1,837	1,252	585	68%	1,623	88%
1-Jul-2025	10.6	Combined Cycle	780	661	119	85%	991	127%
		CT - Natural Gas	963	760	203	79%	848	88%
		DSR	544	406	138	75%	525	96%
		Steam - Coal	345	282	63	82%	332	96%
		Other	287	229	57	80%	237	83%
		Total	2,918	2,337	580	80%	2,933	101%
22-Jul-2025	10.5	Combined Cycle	1,071	909	162	85%	1,197	112%
		CT - Natural Gas	585	510	75	87%	652	112%
		DSR	548	439	110	80%	600	109%
		Steam - Coal	806	611	195	76%	708	88%
		Other	236	141	95	60%	147	62%
		Total	3,246	2,610	636	80%	3,304	102%
25-Sep-2025	10.7	Combined Cycle	813	608	205	75%	775	95%
		CT - Natural Gas	971	829	142	85%	949	98%
		DSR	589	491	98	83%	625	106%
		Hydro - Pumped Storage	376	262	114	70%	563	150%
		Steam - Coal	168	126	42	75%	127	75%
		Steam - Natural Gas, Other	95	52	44	54%	52	55%
		Other	220	198	22	90%	206	94%
		Total	3,232	2,566	666	79%	3,297	102%
17-Oct-2025	11.1	Combined Cycle	413	331	81	80%	488	118%
		CT - Natural Gas	228	228	-0	100%	299	131%
		DSR	644	595	49	92%	750	116%
		Steam - Coal, Natural Gas	433	292	141	68%	377	87%
		Other	618	446	173	72%	483	78%
		Total	2,336	1,893	444	81%	2,397	103%
28-Oct-2025	14.7	Combined Cycle	658	501	157	76%	693	105%
		CT - Natural Gas	222	58	164	26%	124	56%
		DSR	574	447	126	78%	551	96%
		Steam - Coal	320	250	70	78%	337	105%
		Steam - Natural Gas	181	100	81	55%	108	60%
		Other	61	32	29	53%	35	58%
		Total	2,015	1,389	627	69%	1,847	92%
11-Nov-2025	10.3	Combined Cycle	706	495	211	70%	697	99%
		CT - Natural Gas	304	270	34	89%	355	117%
		DSR	673	610	63	91%	783	116%
		RICE - Natural Gas	43	40	2	95%	44	103%
		Steam - Coal	303	266	37	88%	301	99%
		Steam - Natural Gas	176	119	57	67%	143	81%
		Other	474	454	20	96%	506	107%
		Total	2,679	2,254	425	84%	2,829	106%
1-Mar-2026	11.15	Combined Cycle	538	363	175	67%	578	107%
		CT - Natural Gas	437	435	3	99%	508	116%
		DSR	643	499	144	78%	592	92%
		Hydro	470	195	276	41%	241	51%
		Steam - Coal	391	316	74	81%	380	97%
		Other	59	25	34	42%	30	51%
		Total	2,537	1,832	705	72%	2,328	92%

84 Results for identified technologies shown only if they are consistent with PJM confidentiality rules.

In the first three months of 2026, compliance with calls to respond to the single synchronized reserve event was significantly less than 100 percent. Table 10-21 shows the average amount of cleared synchronized reserve MW that responded to events 10 minutes or longer from 2017 through 2025. PJM experienced one event longer than 10 minutes in the first three months of 2026. In December 2024, PJM updated the economic basepoint signal to include deployed reserve MW during synchronized reserve events. This allowed resources to stay on AGC while responding to synchronized reserve events and led to improved average performance in 2025 and the first three months of 2026.

Table 10-21 Average synchronized reserve response from scheduled resources for events longer than 10 minutes, excluding over response: January 2017 through March 2026

Year	Number of Events of Any Length	Number of Events Longer than 10 Minutes	Average Percent of Scheduled Synchronized Reserve MW that Responded to Events Longer than 10 Minutes	Percent of Events that were Longer than 10 Minutes
2017	16	6	87.6%	37.5%
2018	18	8	74.2%	44.4%
2019	13	3	86.8%	23.1%
2020	17	5	59.5%	29.4%
2021	18	5	83.1%	27.8%
2022 (Jan - Sep)	14	3	71.2%	21.4%
2022 (Oct - Dec)	9	7	50.3%	77.8%
2023	12	3	55.6%	25.0%
2024	19	5	58.2%	26.3%
2025	28	7	78.3%	25.0%
2026	8	1	72.3%	12.5%

In Table 10-21, from January 2017 through September 2022, cleared synchronized reserve was provided by tier 2 synchronized reserves, which were cleared when the estimated response from tier 1 resources was insufficient to cover the requirement. Since October 1, 2022, the requirement is fully met by cleared resources that offer the new synchronized reserve product. In the new reserve market, most resources capable of providing reserves were required to offer their full capability as calculated by PJM, whereas previously resources had set their own offer MW. Additionally, while units still set their prices in the new market, the maximum allowed offer price was reduced. Under these new market rules, there was a much larger pool of resources offering synchronized reserves, but the resources clearing the reserve market changed. In the months immediately following the change, PJM was clearing less DSR and fewer natural gas CTs and more combined cycles and steam coal units, a portion of which had not cleared in the months leading up to the change. This, in part, lead to the drop in synchronized reserve performance seen in Table 10-21.

In 2024 and, to a lesser degree, in 2025 and the first three months of 2026, when PJM and the MMU inquired about poorly performing resources, responses pointed towards shortcomings in how resources were deployed. Although resources are required to fully respond within 10 minutes, resources do not necessarily have a full 10 minutes to respond. PJM schedules reserve MW with the expectation that resources will start responding as soon as an event begins, but this expectation fails to consider communication delays that result from how a resource's market operation center (MOC) notifies the resource of events. When a MOC receives PJM's ALL-CALL, it can take several minutes for the MOC to acknowledge the call and to contact the appropriate resources, which then can take minutes more to start responding.

The MMU recommends that, to minimize such lag, PJM use an electronic synchronized reserve event notification process for all resources and that all resources be required to have the ability to receive and to have the ability to automatically respond to the notifications. PJM currently has an optional inter-control room connection protocol (ICCP) signal that some control rooms use, but PJM does not track who is actually using it. This or another form of electronic signal should be required for all resources. On July 24, 2024, stakeholders approved a joint PJM/MMU proposal to implement an electronic communications and reserve deployment process. On December 17, 2024, PJM implemented changes to augment the SCED dispatch signal to include reserve response during reserve events. However, this new process is not required for all synchronized reserve resources and does not replace the ALL-CALL. The new process mainly benefits units that automatically respond to the dispatch signal, such as by following AGC. Between December 17, 2024, and the end of

March 2026, there were eight events lasting 10 or more minutes with which to sufficiently test the augmented dispatch signal. For the event on February 5, 2025, PJM took explicit action to make the event last long enough for testing. As shown in Table10-21, following the signaling improvements, PJM saw an increase in average performance from 58.2 percent in 2024 to 78.3 percent in 2025.

The penalty structure when a resource fails to respond fully to a spinning event has two components. The first component is, for each interval during the day on which the event occurred, the forfeiture of awarded SRMCP credits in the amount of the lesser of the resource's capped synchronized reserve assignment during that interval and the resource's maximum shortfall MW during that day. The second component is a required return of SRMCP credits paid in the Immediate Past Interval (IPI), equal to the sum of, for each scheduled interval within the IPI, the SRMCP multiplied by the lesser of a resource's capped MW assignment during the penalized interval and the resource's penalty obligation for the day of the event. The IPI is defined as the average time, in number of days, since the start of the previous event over the previous two years or, if less, the number of days since the resource last failed to fully respond. For example, the maximum IPI for 2026 is 18 days and was calculated using the events from November 1, 2023, through October 31, 2025.[85]

There are several problems with this penalty structure.[86] First, resource owners are permitted to aggregate the response of multiple cleared reserve resources within the same portfolio, allowing owners to reduce the penalty obligation of a resource's underresponse by offsetting it with another scheduled resource's overresponse.[87] Second, the maximum IPI is calculated using events of any length, even though a resource is automatically considered compliant for events less than 10 minutes in length, artificially and significantly shortening the applied IPI. Third, the historical component of the penalty only applies to a resource's SRMCP credits, but not to LOC credits, even though a large portion of credits is awarded for LOC. For the one event that lasted for 10 or more minutes in the first three months of 2026, for each resource interval in which the resource's penalty obligation MW was greater than or equal to the resource's capped MW during the penalized interval, the total historical penalty was $81,812 and the total LOC credit was $12,389.

The penalty structure for synchronized reserve nonperformance does not provide appropriate or reasonable performance incentives. Under the current penalty structure and due to the low frequency of sufficiently long events, it is possible for a resource to not respond to any spin events and yet still receive net revenues for providing synchronized reserve. The MMU continues to recommend that the penalty's repayment include the LOC credits in addition to the SRMCP credits. The MMU also recommends that a unit that fails to respond to a synchronized reserve event 10 minutes or longer repay all credits back to the last time that the unit successfully responded to an event 10 minutes or longer. A resource should not be paid for reserves that it does not provide.

The MMU also continues to recommend that aggregation not be permitted to offset resource specific penalties for failure to respond to a synchronized reserve event. Including aggregate responses from all cleared resources weakens the incentive to perform and creates an incentive to withhold reserves from other resources. Synchronized reserve commitment is resource specific, so the obligation to respond should also be resource specific.

Each row of Table 10-22 shows the possible total historical penalty if the historical penalty had been defined differently based on each of the MMU's recommendations in the first three months of 2026 for the one event lasting 10 or more minutes in length. It compares the status quo amount, the amount if the IPI were defined using only events of 10 or more minutes, the amount if LOC credits were penalized in an amount proportionate to the shortfall, and the amount if aggregate response were not allowed to offset shortfalls. As can be seen in the table, the values are similar for the status quo, for penalizing LOC credits, and for disallowing aggregate response. The larger effect of only using 10-minute events to calculate the IPI is due to using a 56-day IPI

85 See "2024 Third Quarter Synchronized Reserve Performance," PJM presentation to the Operations Committee. (December 5, 2024) <https://www.pjm.com/-/media/DotCom/committees-groups/committees/oc/2024/20241205/20241205-item-12---synchronous-reserve-update.pdf>.
86 See "IMM Proposal: Reserve Deployment and Compensation," IMM presentation to the Reserve Certainty Senior Task Force. (March 13, 2024) <https://pjm.com/-/media/committees-groups/task-forces/rcstf/2024/20240313/20240313-item-02---imm-proposal---deployment-and-compensation.ashx>.
87 See PJM. "PJM Manual 28: Operating Agreement Accounting," § 6.3 Charges for Synchronized Reserve, Rev. 102 (Oct. 1, 2025).

compared to PJM's current 18-day IPI. Table10-22 shows that redefining only a single component of the reserve penalty structure will not necessarily yield a large increase in penalties. All shortcomings of the current reserve penalty structure should be addressed.

Table 10-22 Comparison of historical/retroactive penalties using possible different definitions: January through March, 2026

Description	Total Retroactive Penalty
Status Quo	$330,003
Using only 10-minute events for IPI	$2,744,414
Including LOC credits in retroactive penalty	$389,305
Disallowing aggregate response	$352,767
All three changes	$3,390,648

Resources should not be paid for reserves that they do not provide. The MMU recommends reclaiming credits back to the last known fully compliant performance, while providing the opportunity to demonstrate performance between events. Resources do not control when PJM calls 10-minute events, nor do they control whether they are scheduled during the few 10-minute events that PJM calls. While actual performance is the key to not being penalized, those factors contribute to defining penalties for many resources. The solution is not to arbitrarily limit the penalized period, as PJM does with its IPI, but to instead provide opportunities, between events, for resources to demonstrate that they are capable of providing reserves.

PJM's 2023 Response to Poor Unit Specific Performance

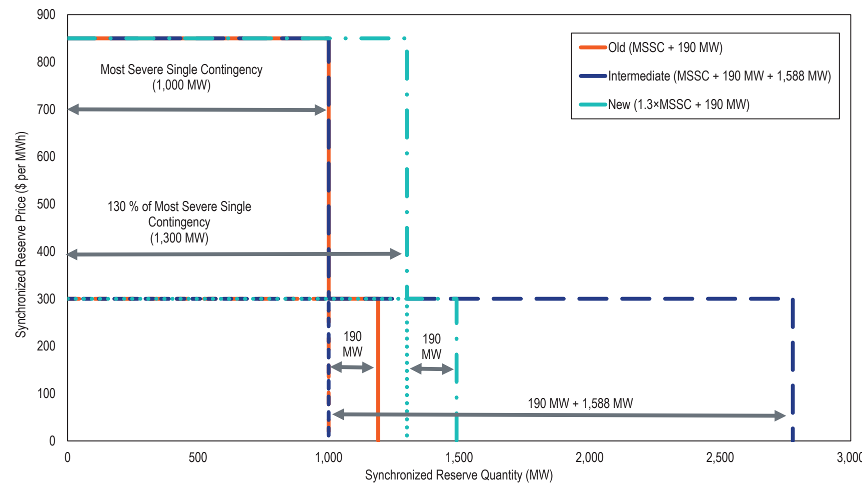
On October 1, 2022, PJM implemented substantial changes to the reserves markets, called Reserve Price Formation, meant to improve reserve reliability and improve accuracy when calculating reserve supply. Winter Storm Elliot occurred in December 2022. In the nine synchronized reserve events from October 2022 through April 2022, the average reserve performance was 53.7 percent. Excluding the events of Winter Storm Elliot, it was 49.4 percent.

In May 2023, in response to poor unit specific reserve performance since the market changes made on October 1, 2022, PJM made two unilateral decisions without approval from stakeholders or FERC. On May 12, 2023, PJM inappropriately increased the extended reserve requirement by 1,588 MW and on May 15, 2023, PJM reversed the increase. On May 19, 2023, PJM inappropriately increased the synchronized reserve reliability requirement by 30 percentage points to 130 percent of the most severe single contingency (MSSC). On January 9, 2026, PJM adjusted the synchronized reserve reliability requirement to be 120 percent of the MSSC.

This increase only applies to MSSCs located outside of the reserve subzone. If the RTO's MSSC is located inside the MAD Reserve Subzone (meaning that the MAD MSSC is also the RTO MSSC), then the adder is not used and the RTO and MAD reliability requirements are equal. Because the MAD Reserve Subzone's MSSC is always located within the subzone, the increase does not affect the MAD reserve requirements.

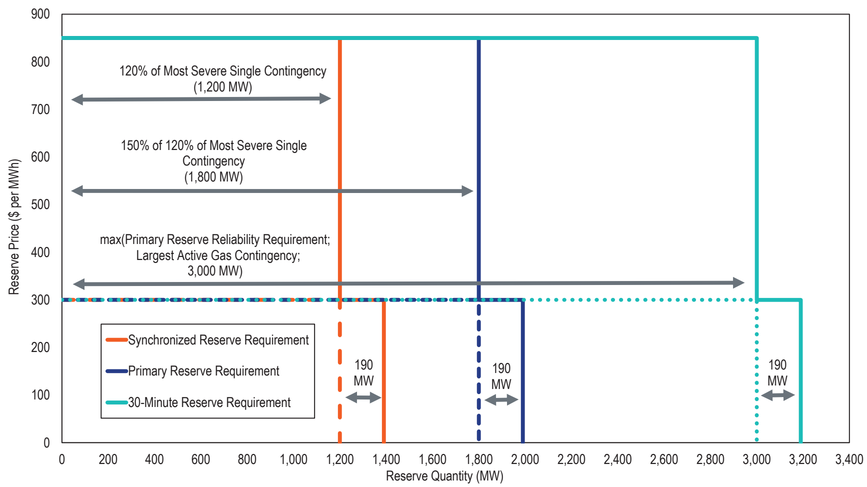
Figure 10-18 compares, for an example MSSC of 1,000 MW, the initial synchronized reserve ORDC from before these changes, the intermediate ORDC with the extension to the second step, and the new ORDC with the 30 percent increase in the first step.

Figure 10-18 An example comparison of the old, intermediate, and new real-time synchronized reserve ORDCs



Because the definitions of the reserve reliability requirements are nested, PJM's increase to the synchronized reserve reliability requirement also increased the primary reserve reliability requirement, which in turn could increase the 30-minute reserve reliability requirement. Figure 10-19 shows the new ORDCs of the three reserve services using an example MSSC of 1,000 MW and the default 190 MW for the extended requirements. Figure 10-6 shows the original ORDCs for the same example MSSC. As seen in Figure 10-2, although not shown in Figure 10-19, as a result of the increase, the 30-minute reserve requirement is now usually equal to the primary reserve requirement.

Figure 10-19 An example of the reserve services' new real-time operating reserve demand curves using the 20-percent increase, including the permanent second steps



PJM did not have the authority to increase the extended reserve requirements without a hot or cold weather alert or an emergency condition. The most common cause of doubled synchronized reserve requirements in the first four months of 2023 and in prior years was the possibility of large units tripping or being disconnected while undergoing maintenance work, which is a clear increase in the size of the most severe single contingency.

The doubling of the requirement for May 12 to May 16, 2023, lead to 31 intervals of shortage pricing for synchronized reserve and primary reserve in the RTO, even though, based on the actual contingencies, both services cleared well in excess of what was actually needed. In addition, because there was no spin event on either May 12 or May 15, it is unknown whether the response that could have been gained by this increase in demand justified these higher prices.

After making these changes, PJM later modified Manual 11 to allow "temporarily" increasing contingency reserve requirements "as necessary to account for resource performance."[88] Neither temporary nor resource performance criteria are specified or defined in the manual. PJM announced criteria for reducing the increase to the synchronized reserve reliability requirement in the PJM Operating Committee on March 6, 2025.[89]

PJM already clears additional 10-minute reserve in the form of nonsynchronized reserve. PJM had and continues to have the option to use all 10-minute reserve that it clears for recovering within 10 minutes, but instead chooses to increase the amount of all 10-minute reserve that PJM clears, even though it only uses a subset.[90] Despite PJM's unexplained reluctance to call a nonsynchronized reserve event, PJM does use NSR resources to respond to synchronized reserve events. That PJM occasionally uses certain nonsynchronized resources to respond to synchronized reserve events while wishing to avoid the general use of NSR suggests a mismatch between NSR's definition, its actual characteristics, and PJM's definition of its operational needs.

PJM gave several reasons to support the changes to the reserve ORDCs, including that resource response to spin events has been poor and that the average length of spin events greater than 10 minutes has increased. In addition, PJM was concerned that it might be less able to avoid Disturbance Control Standard (DCS) violations, in which PJM would exceed the NERC-

88 See PJM. "PJM Manual 11: Energy & Ancillary Services Market Operations," § 6.3 Charges for Synchronized Reserve, Rev. 136 (Oct. 1, 2025). "In order to meet Reliability First (RF) Regional Criteria, PJM may schedule additional Contingency Reserves on a temporary basis in order to meet the Largest Single Contingency, as necessary to account for resource performance. PJM shall post details regarding additional scheduling of reserves in Markets Gateway."

89 See "Synchronized Reserve Requirement for Reliability – Update," PJM presentation to the Operating Committee. (March 6, 2025) <https://www.pjm.com/-/media/DotCom/committees-groups/committees/oc/2025/20250306/20250306-item-08b---synchronized-reserve-adder.pdf> .

90 See PJM. "PJM Manual 12: Balancing Operations," § 4.1.2 Loading Reserves, Rev. 56 (Oct. 1, 2025).

imposed 15-minute limit for recovering Reporting ACE from changes due to Reportable Disturbances.[91] The MMU agrees about the underlying facts, with caveats, but does not agree with PJM's assertions about the reasons for poor performance, or with the assumption about DCS events or that any of these reasons support PJM's actions.

The MMU agrees that the average length of reserve events has increased, but notes that recent DCS event lengths have remained well below NERC's 15-minute requirement, except in two cases. The first case was on December 26, 2022, during Winter Storm Elliott, when PJM recovered from a DCS event in 15 minutes and 52 seconds. The second case was on July 27, 2025, during a summer hot weather event, when PJM recovered from a DCS event in 15 minutes and 41 seconds. Regardless, the data do not support the assertion that PJM is at risk of violating NERC standards during nonemergency conditions and the data do not support the assertion that there has been a change in PJM's DCS event response times. In general, PJM's recovery times are clearly and significantly shorter than NERC's 15-minute requirement and PJM's self-imposed 10-minute requirement. In many cases, PJM recovers Reporting ACE within five minutes. Figure 10-20 compares the lengths of recent DCS events with the lengths of their corresponding spin events. PJM triggers a spin event for most, but not all, DCS events. As can be seen, many spin events are minutes longer than the DCS event for which they were triggered. In the cases where a spin event continues for more than 10 minutes, this can mean that resource performance becomes subject to evaluation for spin events whose purpose had already been achieved minutes ago (that is, the recovery of the Reporting ACE and the end of the DCS event). While there are reasons for PJM dispatchers to continue a spin event even after ACE recovers, Figure 10-20 shows that the lengths of spin events do not suggest that PJM has become closer to having a DCS violation. Instead, it shows that the length of DCS events from immediately before and immediately after the implementation of Reserve Price Formation on October 1, 2022, are similar. It also demonstrates the effect of the improvement to reserve deployment since December 2024, in that all DCS events since the improvement were less than five minutes (one third of NERC's 15-minute requirement and half of PJM's 10-minute target).

91 See PJM. "PJM Manual 12: Balancing Operations," Rev. 56 (Oct. 1, 2025) Attachment D.

Figure 10-20 Comparison of DCS event lengths with corresponding spin event lengths: January 2021 through March 2026[92]

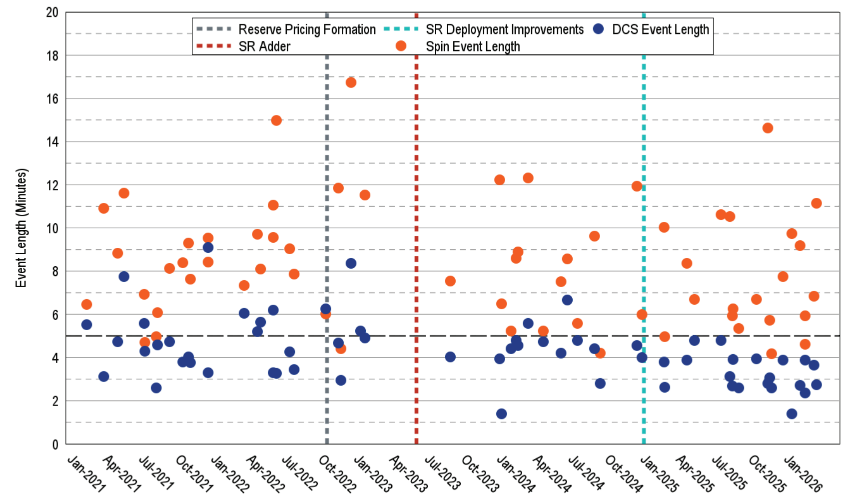


Table 10-23 lists the DCS events and corresponding spin events shown in Figure 10-21.

92 This chart previously showed the SR deployment improvement starting on December 17, 2023, instead of the correct date, December 17, 2024.

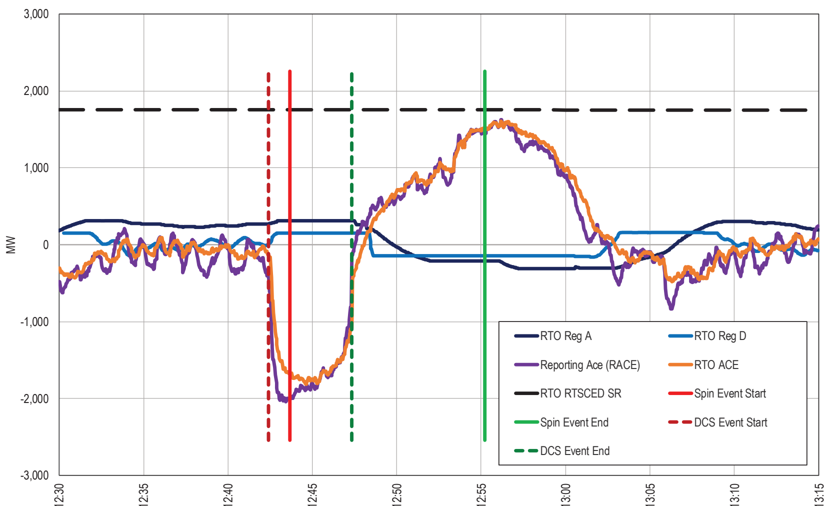
Table 10-23 Comparison of DCS event lengths with corresponding spin event lengths: January 2021 through March 2026[93]

DCS Start	DCS End	DCS Length	Spin Start	Spin End	Spin Length
03-Mar-2022 1218 (EPT)	03-Mar-2022 1224 (EPT)	00:06:03	03-Mar-2022 1220 (EPT)	03-Mar-2022 1227 (EPT)	00:07:21
06-Apr-2022 1144 (EPT)	06-Apr-2022 1149 (EPT)	00:05:12	06-Apr-2022 1145 (EPT)	06-Apr-2022 1155 (EPT)	00:09:43
14-Apr-2022 0928 (EPT)	14-Apr-2022 0934 (EPT)	00:05:40	14-Apr-2022 0930 (EPT)	14-Apr-2022 0938 (EPT)	00:08:07
16-May-2022 1531 (EPT)	16-May-2022 1537 (EPT)	00:06:12	16-May-2022 1532 (EPT)	16-May-2022 1543 (EPT)	00:11:05
16-May-2022 1553 (EPT)	16-May-2022 1556 (EPT)	00:03:18	16-May-2022 1553 (EPT)	16-May-2022 1603 (EPT)	00:09:34
23-May-2022 1717 (EPT)	23-May-2022 1720 (EPT)	00:03:17	23-May-2022 1717 (EPT)	23-May-2022 1732 (EPT)	00:15:00
27-Jun-2022 1700 (EPT)	27-Jun-2022 1704 (EPT)	00:04:16	27-Jun-2022 1701 (EPT)	27-Jun-2022 1710 (EPT)	00:09:03
07-Jul-2022 1720 (EPT)	07-Jul-2022 1724 (EPT)	00:03:27	07-Jul-2022 1721 (EPT)	07-Jul-2022 1729 (EPT)	00:07:52
26-Sep-2022 0335 (EPT)	26-Sep-2022 0342 (EPT)	00:06:16	26-Sep-2022 0339 (EPT)	26-Sep-2022 0345 (EPT)	00:06:02
29-Oct-2022 0210 (EPT)	29-Oct-2022 0215 (EPT)	00:04:42	29-Oct-2022 0212 (EPT)	29-Oct-2022 0224 (EPT)	00:11:52
04-Nov-2022 1501 (EPT)	04-Nov-2022 1504 (EPT)	00:02:58	04-Nov-2022 1503 (EPT)	04-Nov-2022 1507 (EPT)	00:04:25
29-Nov-2022 1629 (EPT)	29-Nov-2022 1638 (EPT)	00:08:23	29-Nov-2022 1630 (EPT)	29-Nov-2022 1647 (EPT)	00:16:45
24-Dec-2022 0223 (EPT)	24-Dec-2022 0228 (EPT)	00:05:15	24-Dec-2022 0223 (EPT)	24-Dec-2022 0254 (EPT)	00:30:35
05-Jan-2023 1242 (EPT)	05-Jan-2023 1247 (EPT)	00:04:56	05-Jan-2023 1243 (EPT)	05-Jan-2023 1255 (EPT)	00:11:33
10-Aug-2023 0039 (EPT)	10-Aug-2023 0043 (EPT)	00:04:02	10-Aug-2023 0041 (EPT)	10-Aug-2023 0049 (EPT)	00:07:33
14-Dec-2023 1939 (EPT)	14-Dec-2023 1943 (EPT)	00:03:58	15-Dec-2023 0041 (EPT)	15-Dec-2023 0053 (EPT)	00:12:15
19-Dec-2023 0449 (EPT)	19-Dec-2023 0450 (EPT)	00:01:25	19-Dec-2023 1451 (EPT)	19-Dec-2023 1458 (EPT)	00:06:30
13-Jan-2024 0157 (EPT)	13-Jan-2024 0201 (EPT)	00:04:26	13-Jan-2024 0159 (EPT)	13-Jan-2024 0204 (EPT)	00:05:15
25-Jan-2024 1237 (EPT)	25-Jan-2024 1241 (EPT)	00:04:48	25-Jan-2024 1239 (EPT)	25-Jan-2024 1247 (EPT)	00:08:37
29-Jan-2024 1202 (EPT)	29-Jan-2024 1206 (EPT)	00:04:35	29-Jan-2024 1203 (EPT)	29-Jan-2024 1212 (EPT)	00:08:54
24-Feb-2024 1546 (EPT)	24-Feb-2024 1551 (EPT)	00:05:36	24-Feb-2024 1548 (EPT)	24-Feb-2024 1600 (EPT)	00:12:19
04-Apr-2024 1047 (EPT)	04-Apr-2024 1052 (EPT)	00:04:45	04-Apr-2024 1050 (EPT)	04-Apr-2024 1055 (EPT)	00:05:15
03-Jun-2024 1852 (EPT)	03-Jun-2024 1858 (EPT)	00:06:41	03-Jun-2024 1853 (EPT)	03-Jun-2024 1902 (EPT)	00:08:35
29-Jun-2024 2101 (EPT)	29-Jun-2024 2106 (EPT)	00:04:48	29-Jun-2024 2103 (EPT)	29-Jun-2024 2109 (EPT)	00:05:36
12-Aug-2024 1709 (EPT)	12-Aug-2024 1713 (EPT)	00:04:25	12-Aug-2024 1710 (EPT)	12-Aug-2024 1720 (EPT)	00:09:39
26-Aug-2024 1352 (EPT)	26-Aug-2024 1355 (EPT)	00:02:48	26-Aug-2024 1353 (EPT)	26-Aug-2024 1357 (EPT)	00:04:13
27-Nov-2024 1934 (EPT)	27-Nov-2024 1939 (EPT)	00:04:35	27-Nov-2024 1934 (EPT)	27-Nov-2024 1946 (EPT)	00:11:57
11-Dec-2024 0819 (EPT)	11-Dec-2024 0823 (EPT)	00:04:00	11-Dec-2024 0821 (EPT)	11-Dec-2024 0827 (EPT)	00:06:00
05-Feb-2025 1003 (EPT)	05-Feb-2025 1007 (EPT)	00:03:49	05-Feb-2025 1005 (EPT)	05-Feb-2025 1015 (EPT)	00:10:02
06-Feb-2025 1355 (EPT)	06-Feb-2025 1358 (EPT)	00:02:39	06-Feb-2025 1356 (EPT)	06-Feb-2025 1401 (EPT)	00:04:59
05-Apr-2025 0420 (EPT)	05-Apr-2025 0424 (EPT)	00:03:54	05-Apr-2025 0421 (EPT)	05-Apr-2025 0429 (EPT)	00:08:22
24-Apr-2025 0048 (EPT)	24-Apr-2025 0052 (EPT)	00:04:49	24-Apr-2025 0050 (EPT)	24-Apr-2025 0057 (EPT)	00:06:43
19-May-2025 1145 (EPT)	19-May-2025 1149 (EPT)	00:04:14	19-May-2025 1146 (EPT)	19-May-2025 1153 (EPT)	00:07:31
01-Jul-2025 1016 (EPT)	01-Jul-2025 1021 (EPT)	00:04:49	01-Jul-2025 1018 (EPT)	01-Jul-2025 1029 (EPT)	00:10:39
22-Jul-2025 1510 (EPT)	22-Jul-2025 1513 (EPT)	00:03:08	22-Jul-2025 1511 (EPT)	22-Jul-2025 1522 (EPT)	00:10:32
30-Jul-2025 1330 (EPT)	30-Jul-2025 1333 (EPT)	00:02:41	30-Jul-2025 1331 (EPT)	30-Jul-2025 1337 (EPT)	00:05:58
31-Jul-2025 0132 (EPT)	31-Jul-2025 0136 (EPT)	00:03:56	31-Jul-2025 0133 (EPT)	31-Jul-2025 0139 (EPT)	00:06:17
15-Aug-2025 1531 (EPT)	15-Aug-2025 1534 (EPT)	00:02:37	15-Aug-2025 1533 (EPT)	15-Aug-2025 1538 (EPT)	00:05:23
29-Sep-2025 2128 (EPT)	29-Sep-2025 2132 (EPT)	00:03:58	29-Sep-2025 2130 (EPT)	29-Sep-2025 2136 (EPT)	00:06:45
09-Jan-2026 2131 (EPT)	09-Jan-2026 2133 (EPT)	00:01:55	09-Jan-2026 2132 (EPT)	09-Jan-2026 2138 (EPT)	00:05:18
18-Jan-2026 0320 (EPT)	18-Jan-2026 0322 (EPT)	00:02:43	18-Jan-2026 0321 (EPT)	18-Jan-2026 0330 (EPT)	00:09:11
30-Jan-2026 1246 (EPT)	30-Jan-2026 1250 (EPT)	00:03:54	30-Jan-2026 1247 (EPT)	30-Jan-2026 1252 (EPT)	00:04:37
31-Jan-2026 0522 (EPT)	31-Jan-2026 0524 (EPT)	00:02:23	31-Jan-2026 0523 (EPT)	31-Jan-2026 0529 (EPT)	00:05:57
23-Feb-2026 0205 (EPT)	23-Feb-2026 0209 (EPT)	00:03:40	23-Feb-2026 0206 (EPT)	23-Feb-2026 0213 (EPT)	00:06:52
01-Mar-2026 1928 (EPT)	01-Mar-2026 1930 (EPT)	00:02:45	01-Mar-2026 1929 (EPT)	01-Mar-2026 1940 (EPT)	00:11:09

93 This chart previously showed the SR deployment improvement starting on December 17, 2023, instead of the correct date, December 17, 2024.

As an example of the differences between the lengths of spin events and the lengths of DCS events, Figure 10-21 shows PJM ACE during a DCS event and its corresponding spin event on January 5, 2023. The DCS event lasted 4 minutes and 56 seconds, while the spin event lasted 11 minutes and 33 seconds, more than twice as long. The DCS event ended when Reporting ACE (RACE) recovered to its level at the time of the loss of supply, while the spin event ended based on PJM discretion.

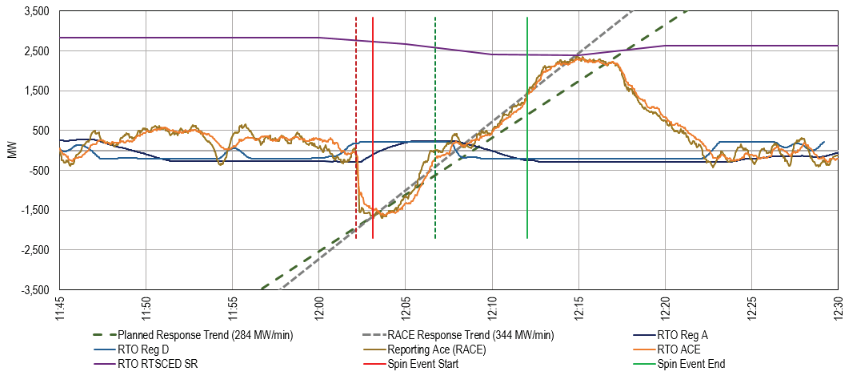
Figure 10-21 DCS Event vs. Spin Event: January 5, 2023



If the basis of the original definition of the synchronized reserve reliability requirement was an amount of MW needed to recover within 10 minutes, then an increase in the amount of cleared reserves can shorten the length of synchronized reserve events to be less than 10 minutes. In the remainder of 2023 after the increase in the reliability requirement in May 2023, there were eight spin events, of which seven were less than 10 minutes. Similarly, of the 19 spin events in 2024, 13 were less than 10 minutes. Of the 28 spin events in 2025, 21 were less than 10 minutes. Of the eight events in the first three months of 2026, PJM triggered only one event of 10 or more minutes. Because these shorter events lasted less than 10 minutes, only a small portion of the events since the increase qualify for performance assessment under the PJM Market Rules. PJM has stated that they monitor performance for events less than 10 minutes. If the PJM analysis fails to consider the lags that the ALL-CALL system introduces, different for each contacted resource, then it will continue to show underperformance.

In most of the spin events for the RTO Reserve Zone that have occurred since the reserve requirement increase in May 2023 through the first three months of 2026, including the events less than 10 minutes, ACE response is consistent with the rate of recovery that would be expected if reserves had performed adequately. Figure 10-22 shows one such event on January 29, 2024. However, some resources are responding to PJM's event notifications when they did not clear the reserve market, so they do not have reserve assignments during those events and so do not count towards reserve performance. PJM has defined the problem as one not of poor overall system response nor of poor ACE recovery, but one of poor performance from the assigned reserves. At the Operating Committee on March 6, 2025, PJM announced that they would decrease the adder to the synchronized reserve reliability requirement if average event performance were greater than 75 percent for qualifying events. Under these announced criteria, qualifying events would be any 10-minute event and any shorter event in which event performance was at least 75 percent. Even with these criteria, the fact that performance remains unsatisfactory for multiple events in the months with the increased requirements is evidence that the increase is not the correct solution to the asserted problem.

Figure 10-22 ACE response during a synchronized reserve event: January 29, 2024 from 12:03 to 12:12 EPT



The MMU disagrees with PJM that increasing the reserve requirement is the correct solution for accounting for poor reserve performance.[94] The MMU's position is that these problems with the supply of reserves should not be solved by changing the demand for reserves. The situation is a problem on the supply side, and it should be dealt with and solved on the supply side. The repeated lack of response means that resource personnel are insufficiently trained or that resource data inputs, such as ramp rates, the times needed for condensers to start, and economic maximums, are incorrect. It is the responsibility of market participants to correct their offer parameters and operating parameters. It is their obligation to submit correct data.

The data on synchronized reserve event recovery do not support the conclusion that there is an immediate need to change how reserves clear. If PJM insists on an immediate change, the focus should be on correcting the supply of reserves rather than increasing demand.

PJM's logic is that because reserves are responding at an average rate of about 50 percent during spin events, the solution is to buy twice as many MW of reserves. The result is that PJM is overpaying for reserve MW. PJM is paying for 1.0 MW but receiving 0.5 MW. PJM's solution is to pay for 2.0 MW in order to receive 1.0 MW.

Instead of increasing the demand requirement, the MMU proposes to purchase reserve MW from resources only in the amounts for which they can actually perform. If an underperforming resource's behavior shows that they can only reliably provide five MW of reserve, then PJM should only be purchasing five MW of reserve from them. PJM should not be paying MCP credits for MW that are not reliably provided, especially when it only recovers a portion of that money later via penalties and charges.

The MMU proposal is to pay for 0.5 MW from the underperforming unit. The MMU proposal is to pay for actual unit specific MW. The MMU proposal is to pay for 0.5 MW from each of two underperforming units. The result is to pay for 1.0 MW and to receive 1.0 MW of reserves. The MMU proposal is to buy the correct amount of reserves. No increase in demand is required.

The solution is not to buy more MW of poorly performing reserves. The solution is to accurately recognize the actual supply of reserves. The solution is to buy the correct amount of reserves, accounting for the actual performance of supply.

A focus on the supply side issues should be implemented immediately: ensure correct and timely signals; provide education on requirements; buy required reliable MW, based on actual performance; pay only for reliable MW based on actual performance; and do not pay for MW not provided. Detailed, unit by unit analysis of the reasons for poor performance is needed. Potential unit specific issues include: ensuring the ability to receive and respond to signals; discontinuities in offer curves; the accuracy of ramp rates; ambient derates; fuel availability; demand side resource response; failure to follow dispatch; incorrect eco max or spin max; and incorrect parameters.

One result of PJM's changes to the reserve requirements is that the total cost of the synchronized reserve market has increased. For May 2023 through December 2023, total credits paid for synchronized reserve were $66.7 million in eight months or $8.3 million per month, compared to $6.4 million in four

94 See "Market Monitor Report," MMU presentation to the Members Committee Webinar. (May 22, 2023) <https://pjm.com/-/media/committees-groups/committees/mc/2023/20230522-webinar/item-04---imm-report.ashx>.

months or $1.6 million per month for January 2023 through April 2023. In 2024, the total credits paid for synchronized reserve were $74.1 million or $6.2 million per month. In 2025, the total credits paid for synchronized reserve were $150.8 million or $12.6 million per month. In the first three months of 2026, the total credits paid for synchronized reserve were $47.1 million or $15.7 million per month. Table 10-18 shows the total payments and charges for synchronized reserve by month. In the first three months of 2026, day-ahead credits to day-ahead synchronized reserve (which, as seen in Table 10-18, is by far the largest contributor to total synchronized reserve credits) cleared in excess of the original day-ahead synchronized reserve requirement had the adder not been in place totaled $14.0 million. In 2025, such credits totaled $47.5 million. The cost of underperformance by reserve suppliers is paid by PJM customers, while it should be incurred by the suppliers who fail to meet their responsibilities. If reserve suppliers cannot provide the energy that they offer and clear during synchronized reserve events, they should not be paid from the last time they successfully responded to a spin event. These suppliers are not accurately representing their true capability to the PJM market and/or have failed to establish processes to ensure that they follow PJM's instructions.

On March 6, 2025, PJM presented to the PJM Operating Committee its criteria for decreasing (or increasing) the adder to the synchronized reserve reliability requirement by reviewing the average performance of non-overlapping sets of three qualifying events.[95] [96] A qualifying event is an event lasting at least 10 minutes or an event whose performance was at least 75 percent of the total reserve assignment. This performance is based on a resource's scheduled MW, not the MW amount that PJM uses its tools to deploy. Table 10-24 shows the average performance required for each level of adjustment, with the adder not to exceed 30 percent of the most severe single contingency. In the first three months of 2026, there have been one event lasting 10 or more minutes out of eight events total. If synchronized reserve performs well in terms of its goal of restoring the system within 10 minutes, one would expect that the synchronized reserve event would last less than 10 minutes. As reserve performance improves following the improvement to synchronized reserve deployment in December 2024, it is possible for the larger reserve amounts cleared due to the adder to result in shorter synchronized reserve events, as more reserves are being deployed to cover supply losses less than or equal to the MSSC. If a synchronized reserve event lasts less than 10 minutes, one would expect that the reserve resources would not increase output by their full 10 minute ramp. Although PJM has included a way for shorter events to be considered for decreasing the adder, the 75 percent cutoff is arbitrary. That a shorter event does not achieve 75 percent performance in less than, for example, five minutes, is not necessarily indicative of a problem, because the only defining performance requirement for the synchronized reserve product is that it should achieve full performance by the tenth minute. Only events lasting 10 or more minutes can be true measures of under performance.

As shown by Table 10-20, poor performance is not an across the board problem, yet PJM's current criteria and approach treat it as if it were. Reserve supply issues are resource specific and should be addressed at the resource level, such as by requiring support for an electronic deployment signal. Increasing the requirement does not change resource behavior. Engaging with poorly performing resources, as the MMU and PJM have been doing, does change behavior. Reserve testing would allow PJM to identify underperforming resources that would benefit from unit specific engagement. Such identification would be proactive instead of reactive, improving event performance.

Table 10-24 PJM criteria for adjusting the adder in the synchronized reserve reliability requirement

Average Performance	Adder Adjustment
Below 70%	Increase by 10 percentage points
Above 75%	Decrease by 10 percentage points
Above 85%	Decrease by 20 percentage points
Above 95%	Decrease by 30 percentage points

95 See "Synchronized Reserve Requirement for Reliability – Update," PJM presentation to the Operating Committee. (March 6, 2025) <https://www.pjm.com/-/media/DotCom/committees-groups/committees/oc/2025/20250306/20250306-item-08b---synchronized-reserve-adder.pdf>.

96 See "Synchronized Reserve Requirement for Reliability – Update," PJM presentation to the Operating Committee. (May 8, 2025) <https://www.pjm.com/-/media/DotCom/committees-groups/committees/oc/2025/20250508/20250508-item-20---synchronized-reserve-for-reliability-update.pdf>.

History of Synchronized Reserve Events

Synchronized reserve is designed to provide relief for disturbances, which NERC calls "balancing contingency events".[97] [98] Reportable balancing contingency events, from which PJM must recover within 15 minutes, are defined as the loss, within 60 seconds, of no more than the most severe single contingency (MSSC) and no less than lesser of 900 MW and 80 percent of the MSSC. In the absence of a disturbance, PJM operators have used synchronized reserve as a source of energy to provide relief from low ACE. Of the 28 events that occurred in 2025, four events were explicitly due to low ACE, of which all four events were less than 10 minutes. Of the eight events in the first three months of 2026, zero events were explicitly due to low ACE.

The risk of using synchronized reserves for energy or any other nondisturbance reason is that it reduces the amount of synchronized reserve available for a disturbance. Disturbances are unpredictable. Synchronized reserve has a requirement to sustain its output for 30 minutes at the most. When reserve output is still needed after 30 minutes, that output should come from secondary reserves, not synchronized reserves.

From January 2022 through March 2026, PJM experienced 90 synchronized reserve events, approximately 1.4 events per month, with an average duration of 10.9 minutes. Table10-25 shows these events with their region and their duration rounded to the nearest tenth of a minute.

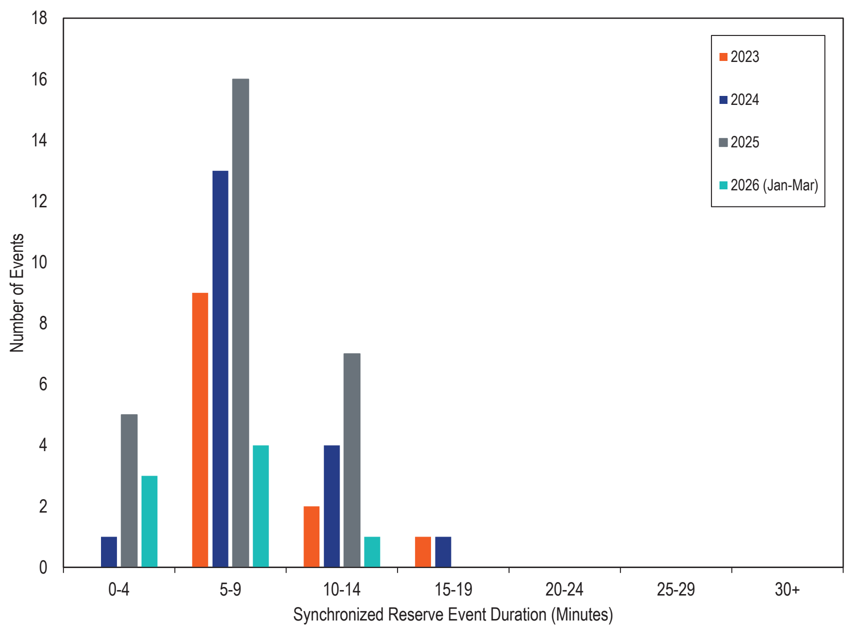
97 *2012 Annual State of the Market Report for PJM*, Appendix E – PJM's DCS Performance.
98 See PJM. "PJM Manual 12: Balancing Operations," § 4.1.2 Loading Reserves, Rev. 56 (Oct. 1, 2025).

Table 10-25 Synchronized reserve events: January 2022 through March 2026

Effective Time	Region	Duration (Minutes)	Effective Time	Region	Duration (Minutes)	Effective Time	Region	Duration (Minutes)
03-Jan-2022 1227 (EPT)	RTO	8.9	13-Jan-2024 0159 (EPT)	RTO	5.3	21-Jan-2025 0520 (EPT)	RTO	4.7
03-Mar-2022 1220 (EPT)	RTO	7.4	25-Jan-2024 1239 (EPT)	RTO	8.6	05-Feb-2025 1505 (EPT)	RTO	10.0
06-Apr-2022 1145 (EPT)	RTO	9.7	29-Jan-2024 1203 (EPT)	RTO	8.9	06-Feb-2025 1856 (EPT)	RTO	5.0
13-Apr-2022 1725 (EPT)	RTO	28.5	24-Feb-2024 1548 (EPT)	MAD	12.3	11-Feb-2025 1404 (EPT)	RTO	5.3
14-Apr-2022 0931 (EPT)	RTO	8.1	04-Apr-2024 1050 (EPT)	RTO	5.3	05-Apr-2025 0421 (EPT)	RTO	8.4
16-May-2022 1532 (EPT)	RTO	11.1	13-Apr-2024 0036 (EPT)	RTO	7.1	24-Apr-2025 0050 (EPT)	MAD	7.1
16-May-2022 1553 (EPT)	RTO	9.6	03-Jun-2024 1853 (EPT)	RTO	8.6	19-May-2025 1146 (EPT)	RTO	7.5
23-May-2022 1717 (EPT)	RTO	15.0	29-Jun-2024 2103 (EPT)	RTO	5.6	22-Jun-2025 1937 (EPT)	RTO	7.8
26-May-2022 1409 (EPT)	RTO	6.3	08-Jul-2024 1757 (EPT)	RTO	14.5	01-Jul-2025 1018 (EPT)	RTO	10.6
22-Jun-2022 1506 (EPT)	RTO	7.2	18-Jul-2024 1524 (EPT)	RTO	7.0	22-Jul-2025 1511 (EPT)	RTO	11.5
27-Jun-2022 1701 (EPT)	RTO	9.1	21-Jul-2024 1753 (EPT)	RTO	10.2	30-Jul-2025 1331 (EPT)	RTO	6.0
07-Jul-2022 1721 (EPT)	RTO	7.9	12-Aug-2024 1710 (EPT)	RTO	9.7	31-Jul-2025 0133 (EPT)	RTO	6.3
26-Sep-2022 0339 (EPT)	RTO	6.0	18-Aug-2024 1604 (EPT)	RTO	15.9	06-Aug-2025 1849 (EPT)	MAD	7.9
29-Sep-2022 1025 (EPT)	RTO	6.2	26-Aug-2024 1353 (EPT)	RTO	4.2	14-Aug-2025 1740 (EPT)	RTO	4.3
29-Oct-2022 1412 (EPT)	RTO	11.9	22-Oct-2024 1002 (EPT)	RTO	6.2	15-Aug-2025 1533 (EPT)	RTO	5.4
04-Nov-2022 1503 (EPT)	RTO	4.4	10-Nov-2024 0020 (EPT)	RTO	10.8	04-Sep-2025 1956 (EPT)	RTO	9.0
14-Nov-2022 22:01 (EPT)	RTO	6.7	27-Nov-2024 1936 (EPT)	RTO	10.0	25-Sep-2025 1912 (EPT)	RTO	10.7
29-Nov-2022 1630 (EPT)	RTO	16.8	29-Nov-2024 1103 (EPT)	RTO	7.4	25-Sep-2025 1935 (EPT)	RTO	7.7
23-Dec-2022 1014 (EPT)	RTO	11.1	11-Dec-2024 0821 (EPT)	RTO	6.0	29-Sep-2025 2130 (EPT)	RTO	6.8
23-Dec-2022 1617 (EPT)	RTO	111.5				15-Oct-2025 1652 (EPT)	RTO	5.4
24-Dec-2022 0501 (EPT)	RTO	25.7				17-Oct-2025 1013 (EPT)	RTO	11.1
24-Dec-2022 0223 (EPT)	RTO	30.6				28-Oct-2025 1905 (EPT)	RTO	14.7
24-Dec-2022 0423 (EPT)	RTO	87.5				02-Nov-2025 1446 (EPT)	RTO	5.7
						06-Nov-2025 2240 (EPT)	RTO	4.2
05-Jan-2023 1243 (EPT)	RTO	11.6				11-Nov-2025 1004 (EPT)	RTO	10.3
10-Jan-2023 0706 (EPT)	RTO	17.5				05-Dec-2025 1930 (EPT)	RTO	4.4
26-Jan-2023 1452 (EPT)	MAD	6.9				06-Dec-2025 0505 (EPT)	RTO	7.8
02-Feb-2023 0606 (EPT)	RTO	8.0				28-Dec-2025 1707 (EPT)	RTO	9.8
28-May-2023 2009 (EPT)	RTO	7.4						
11-Jun-2023 1611 (EPT)	MAD	8.7				09-Jan-2026 2132 (EPT)	RTO	5.3
23-Jun-2023 1905 (EPT)	RTO	7.0				18-Jan-2026 0321 (EPT)	MAD	9.2
08-Aug-2023 0041 (EPT)	RTO	7.6				30-Jan-2026 1247 (EPT)	RTO	4.6
07-Nov-2023 1619 (EPT)	RTO	5.4				31-Jan-2026 0523 (EPT)	RTO	6.0
10-Nov-2023 0621 (EPT)	RTO	8.1				03-Feb-2026 1149 (EPT)	RTO	4.4
15-Dec-2023 0041 (EPT)	RTO	12.3				23-Feb-2026 0206 (EPT)	RTO	6.9
19-Dec-2023 0951 (EPT)	RTO	6.5				01-Mar-2026 1929 (EPT)	RTO	11.2
						05-Mar-2026 0224 (EPT)	RTO	4.0

Figure 10-23 shows spin event durations over the past 4 years. Events can last longer than 30 minutes. Beyond 30 minutes, reserves no longer have an obligation to perform. It is not clear what resources are instructed or expected to do after the 30-minute performance obligation. This ambiguity applies to three synchronized reserve events during Winter Storm Elliott in December 2022, which all lasted longer than 30 minutes.

Figure 10-23 Synchronized reserve events duration distribution curve: January 2023 through March 2026



Nonsynchronized Reserve

Nonsynchronized reserve (NSR), also called quick start reserve, consists of MW available within 10 minutes but not synchronized to the grid. Startup time for nonsynchronized reserve resources is not subject to testing and is based on the parameters in the energy offers submitted by resource owners. There is no defined requirement for nonsynchronized reserve; it is available to economically meet the primary reserve requirement. Generation resources that have designated their entire output as emergency are not eligible to provide nonsynchronized reserves. Generation resources that are not available to provide energy are not eligible to provide nonsynchronized reserves.

The nonsynchronized reserve market has a day-ahead and a real-time component. There are no lost opportunity costs for nonsynchronized reserve. Offline units cannot be dispatched to provide energy, because PJM has not called them to come online, so they do not have a lost opportunity to provide energy. As a result, the supply curve for nonsynchronized reserve has a price of zero and there are no uplift credits paid when LMP is higher than the incremental cost of nonsynchronized reserve units.

PJM defines the demand curve for nonsynchronized reserve, and PJM defines the supply curve based on nonemergency generation resources that are available to provide energy and can start in 10 minutes or less. Since nonsynchronized reserve is considered a lower quality product than synchronized reserve, its clearing price is less than or equal to the synchronized reserve market clearing price. In most market intervals, under usual circumstances, the nonsynchronized reserve market clearing price (NSRMCP) is $0 per MWh. However, due to PJM's increase of the synchronized reserve reliability requirement, there has been an increase in the number of intervals with nonzero NSRMCPs. For example, in 2024, over 60 percent of intervals had a non-zero NSRMCP. Table 10-26 shows the number of intervals with non-zero NSRMCPs in the first three months of 2026.

PJM uses nonsynchronized reserve when PJM calls nonsynchronized reserve events and when PJM calls specific nonsynchronized reserve resources to respond to synchronized reserve events. There were no nonsynchronized reserve events in the first three months of 2026.

Market Structure

Demand

There is no explicit demand for nonsynchronized reserve beyond a more general demand for primary reserve, which can be satisfied by the synchronized and nonsynchronized reserve products, and for 30-minute reserve, which can be satisfied by all three reserve products. Beyond the synchronized reserve requirement, the balance of primary reserve can be made up by the economic combination of synchronized and nonsynchronized reserve. While it can be used to satisfy the 30-minute reserve requirement, as seen in Figure 10-2, nonsynchronized reserve is mainly used for satisfying the primary reserve requirement.

In the RTO Reserve Zone, in the first three months of 2026, the average amount of real-time cleared nonsynchronized reserve was 1,171.6 MW and the average day-ahead cleared nonsynchronized reserve was 1,181.5 MW. In the MAD Reserve Subzone, in the first three months of 2026, the average real-time cleared nonsynchronized reserve was 781.2 MW and the average day-ahead cleared nonsynchronized reserve was 728.8 MW.

Supply

The market solution considers the available supply of nonsynchronized reserve to be all generation resources currently not synchronized to the grid but available and capable of providing energy within 10 minutes. Generators that have made themselves unavailable or that have defined themselves to be emergency only are not considered. Resources that generally qualify as nonsynchronized reserve include run of river hydro, pumped hydro, and combustion turbines and RICE generators that can start in 10 minutes or less.

The available reserve MW for nonsynchronized reserve units is the lesser of the economic maximum or the ramp rate times 10 minutes minus the startup and notification time. Hydroelectric resources must separately specify their availability and offer MW.

In the first three months of 2026, an average of 1,171.6 MW of nonsynchronized reserve was cleared per five-minute interval out of an average eligible and available 1,193.2 MW as part of the primary reserve requirement in the RTO Reserve Zone. Figure 10-24 shows daily average total nonsynchronized reserve MW available in the first three months of 2026. Available nonsynchronized reserve decreased on January 25 and January 26 during a cold weather event which included Winter Storm Fern, for which PJM increased online generation.

Figure 10-24 Daily Average Available Nonsynchronized Reserve: January through March, 2026

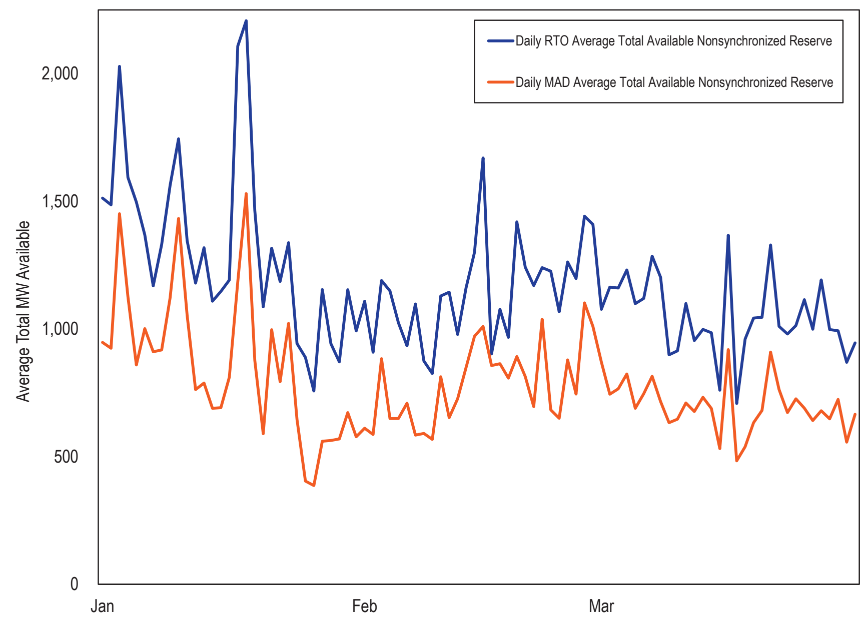
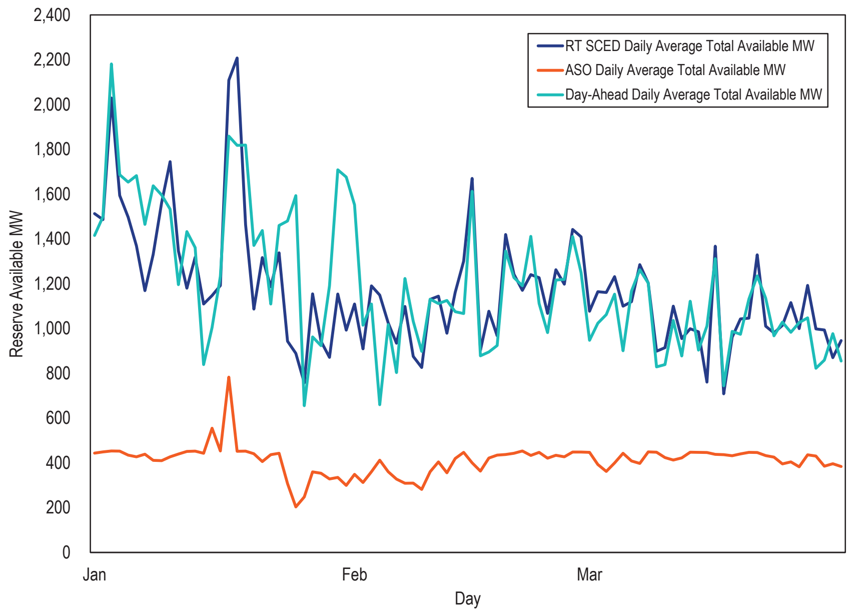


Figure 10-25 shows the daily average total available NSR MW in the ASO, RT SCED, and day-ahead solutions. The available MW in the ASO are consistently lower due to differences in the available MW from flexible units based on the goal of the ASO. For example, a unit could be projected to be online by the ASO but actually be offline in real time.

Figure 10-25 Daily average total available MW in the day-ahead, ASO, and RT SCED solutions: January through March, 2026



Market Behavior

The offer price for nonsynchronized reserve for all resources is cost based, which is $0 per MWh for all nonsynchronized resources.

Market Performance

The settled price of nonsynchronized reserve is calculated in real time every five minutes for the RTO Reserve Zone and the MAD Reserve Subzone. Figure 10-26 shows the daily average nonsynchronized reserve market clearing price (NSRMCP) and average credited MW for the RTO Reserve Zone. In the first three months of 2026, the real-time weighted average NSRMCP for all intervals in the RTO Reserve Zone was $2.34 per MWh and the real-time average nonsynchronized reserve cleared was 1,171.6 MW. The day-ahead weighted average NSRMCP for all intervals in the RTO Reserve Zone was $1.96 per MWh and the day-ahead average nonsynchronized reserve cleared MW was 1,181.5 MW. The real-time weighted average NSRMCP for all intervals in the MAD Reserve Subzone was $2.94 per MWh and the real-time average nonsynchronized reserve cleared was 781.2 MW. The day-ahead weighted average NSRMCP for all intervals in the MAD Reserve Subzone was $1.48 per MWh and the day-ahead average nonsynchronized reserve cleared MW was 728.8 MW.

In the first three months of 2026, shortage pricing was used in the RTO Reserve Zone for primary reserve on January 24 and 31; February 2, 6, 9, 13, and 16; and March 1, 12, 13, and 22. In the first three months of 2026, shortage pricing was used in the MAD Reserve Subzone for primary reserve on January 24; February 9; and March 1, 12, and 13. The shortage pricing on March 1, 2026, overlapped with synchronized reserve events. Conservative operations due to cold weather were in place from January 24 through February 2, 2026. Cold weather alerts were issued for January 19, 20, 23, and 24 through 31 and for February 1, 2, 7, 8, and 9. During most of these short intervals, there was not a true shortage, as PJM still cleared above the average reserve requirements used before PJM's mid-May 2023 increase.

Figure 10-26 Daily weighted average RTO Zone nonsynchronized reserve market clearing price, average MW purchased, and average percent of PR that is NSR: January 2025 through March 2026

Table 10-26 shows the number of five-minute intervals with an NSRMCP above $0 per MWh. The NSRMCP is equal to the cost of the marginal primary reserve resource.[99] While the offer price of NSR resources is cost based and therefore $0 per MWh, if the marginal resource of primary reserve in an interval is an SR resource with a nonzero cost, then the NSRMCP in that interval will also be nonzero. While the real-time market clears resources in five-minute intervals, the day-ahead market clears by hour, equivalent to blocks of 12 five-minute intervals. Table10-26 compares the two markets

99 See PJM. "PJM Manual 11: Energy & Ancillary Services Market Operations," § 4.4.5.2 Determination of Non-Synchronized Reserve Clearing Prices, Rev. 136 (Oct. 1, 2025).

using five-minute intervals. There were 25,908 five-minute intervals in the first three months of 2026.

Table 10-26 Number of five minute intervals with NSRMCP above $0 per MWh: January through March, 2026

Location	Market	Number of Intervals Where NSRMCP Above $0 per MWh	Percent of Intervals Where NSRMCP Above $0 per MWh
RTO	RT	6,910	26.7%
RTO	DA	11,556	44.6%
MAD	RT	6,911	26.7%
MAD	DA	12,636	48.8%

Figure 10-27 shows the number of intervals per day for which a nonzero NSRMCP equaled the SRMCP. Since the increase to the reserve requirement on May 12, 2023, the average number of such intervals per day has increased, with the maximum number and given number of such intervals per day both trending upwards. In the first three months of 2026, the number of such intervals differed for the RTO Reserve Zone and the MAD Reserve Subzone from January 4 through January 5. Table10-27 shows the intervals for which a nonzero NSRMCP did not equal the SRMCP. Generally, when the marginal primary resource is a synchronized resource, then the NSRMCP equals the SRMCP. However, when shortage pricing is used, the two can differ, due to the NSRMCP being capped at $1,275 per MWh (1.5 times the $850 penalty factor) while the SRMCP is capped at $1,700 (twice the $850 penalty factor). Higher prices are seen in Figure 10-27 and Table10-27 on December 14 and December 15 during a cold weather event for which PJM issued cold weather alerts.

Figure 10-27 Number of intervals per day for which a nonzero NSRMCP equaled the SRMCP: January 2025 through March 2026

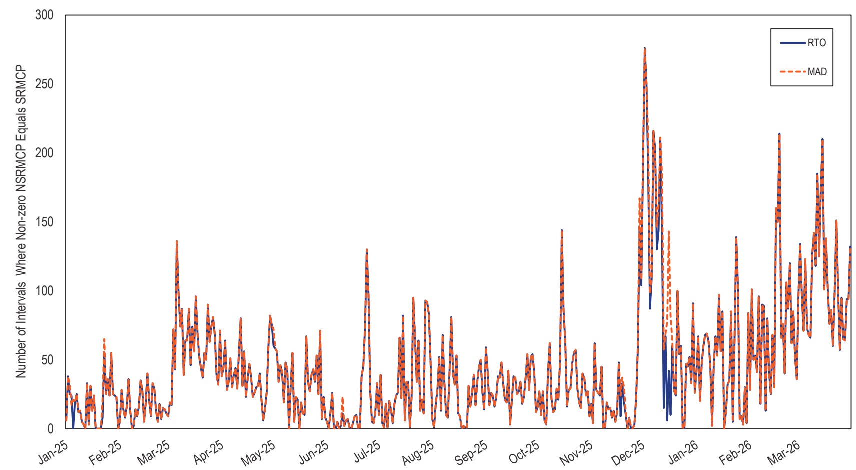


Table 10-27 Intervals with a nonzero NSRMCP in which the NSRMCP did not equal the SRMCP: January through March, 2026

	RTO		MAD	
Interval	NSRMCP	SRMCP	NSRMCP	SRMCP
24-Jan-2026 0535 (EPT)	$850.00	$1,150.00	$850.00	$1,150.00
24-Jan-2026 0540 (EPT)	$850.00	$1,700.00	$1,150.00	$1,700.00
25-Jan-2026 0140 (EPT)	$0.00	$0.00	$74.04	$115.02
09-Feb-2026 0720 (EPT)	$850.00	$1,030.34	$1,275.00	$1,700.00
09-Feb-2026 0725 (EPT)	$850.00	$850.00	$1,275.00	$1,700.00
09-Feb-2026 0730 (EPT)	$850.00	$850.00	$1,275.00	$1,700.00
01-Mar-2026 1930 (EPT)	$850.00	$1,700.00	$1,275.00	$1,700.00
01-Mar-2026 1935 (EPT)	$850.00	$1,700.00	$1,275.00	$1,700.00
12-Mar-2026 1855 (EPT)	$850.00	$1,700.00	$850.00	$1,700.00
12-Mar-2026 1900 (EPT)	$850.00	$1,700.00	$850.00	$1,700.00
12-Mar-2026 1905 (EPT)	$850.00	$1,150.00	$1,150.00	$1,450.00
12-Mar-2026 1910 (EPT)	$850.00	$1,700.00	$1,275.00	$1,700.00
13-Mar-2026 0710 (EPT)	$850.00	$1,150.00	$1,150.00	$1,450.00
13-Mar-2026 0715 (EPT)	$850.00	$1,700.00	$1,275.00	$1,700.00
13-Mar-2026 0720 (EPT)	$850.00	$1,700.00	$1,275.00	$1,700.00
13-Mar-2026 0725 (EPT)	$850.00	$1,700.00	$1,275.00	$1,700.00

Table 10-28 shows the effect of fast start pricing on the nonsynchronized reserve market's monthly weighted average market clearing price for January 2025 through March 2026. Fast start pricing increases LMP in the pricing run relative to the dispatch run, which increases reserve prices. Fast start pricing also reduces the amount of reserves available in the pricing run compared to the dispatch run, by pretending that fast start units can be dispatched for energy below their economic minimum output limit but not counting MW below the economic minimum output limit as reserves. For the real-time market, these are the LPC prices weighted by the RT SCED MW. For the day-ahead values, these are the DA prices weighted by the DA dispatch MW. The weighted average market clearing price for each month tends to be higher in the pricing run than in the dispatch run. In the first three months of 2026, the real-time RTO weighted average price of the pricing run was 23.6 percent higher than that of the dispatch run. In the first three months of 2026, the day-ahead RTO weighted average price of the pricing run was 1.4 percent lower than that of the dispatch run. In the first three months of 2026, the real-time MAD weighted average price of the pricing run was 21.4 percent higher than that of the dispatch run. In the first three months of 2026, the day-ahead MAD weighted average price of the pricing run was 2.8 percent higher than that of the dispatch run.

Table 10-28 Comparison of fast start and dispatch RTO pricing: January 2025 through March 2026

		Day-Ahead				Real-Time			
Year	Month	Dispatch-Run MCP	Pricing-Run MCP	Difference	Percent Difference	Dispatch-Run MCP	Pricing-Run MCP	Difference	Percent Difference
2025	Jan	$1.23	$1.30	$0.07	6.1%	$0.70	$0.92	$0.22	31.7%
2025	Feb	$0.59	$0.59	($0.00)	(0.7%)	$0.51	$0.79	$0.28	54.2%
2025	Mar	$3.27	$3.00	($0.26)	(8.1%)	$2.20	$3.41	$1.21	55.1%
2025	Apr	$3.56	$3.41	($0.15)	(4.2%)	$0.93	$1.85	$0.92	99.5%
2025	May	$1.89	$1.77	($0.12)	(6.4%)	$1.11	$1.55	$0.44	39.8%
2025	Jun	$3.74	$3.47	($0.27)	(7.1%)	$3.31	$4.10	$0.79	23.8%
2025	Jul	$6.12	$5.56	($0.56)	(9.2%)	$1.81	$2.66	$0.85	47.2%
2025	Aug	$1.89	$1.59	($0.30)	(15.8%)	$0.78	$1.10	$0.33	42.3%
2025	Sep	$2.52	$1.92	($0.60)	(23.7%)	$1.36	$1.70	$0.34	25.1%
2025	Oct	$3.65	$3.66	$0.02	0.5%	$1.67	$2.33	$0.66	39.5%
2025	Nov	$1.84	$1.35	($0.49)	(26.6%)	$0.58	$0.86	$0.28	48.4%
2025	Dec	$1.15	$0.91	($0.25)	(21.4%)	$0.84	$1.17	$0.33	39.2%
2025	All	$2.41	$2.18	($0.23)	(9.6%)	$1.23	$1.75	$0.52	42.0%
2026	Jan	$2.15	$2.18	$0.03	1.6%	$1.56	$2.09	$0.53	34.4%
2026	Feb	$0.73	$0.53	($0.20)	(27.4%)	$1.56	$1.92	$0.36	23.0%
2026	Mar	$2.67	$2.73	$0.06	2.2%	$2.55	$2.95	$0.40	15.7%
2026	All	$1.88	$1.86	($0.03)	(1.4%)	$1.86	$2.30	$0.44	23.6%

Table 10-29 Comparison of fast start and dispatch MAD pricing: January 2025 through March 2026

		Day-Ahead				Real-Time			
Year	Month	Dispatch-Run MCP	Pricing-Run MCP	Difference	Percent Difference	Dispatch-Run MCP	Pricing-Run MCP	Difference	Percent Difference
2025	Jan	$1.09	$1.14	$0.05	4.9%	$1.01	$1.25	$0.23	22.9%
2025	Feb	$1.24	$1.23	($0.01)	(1.1%)	$0.60	$0.94	$0.34	56.1%
2025	Mar	$4.53	$4.21	($0.33)	(7.2%)	$2.71	$4.14	$1.43	52.9%
2025	Apr	$6.57	$6.38	($0.19)	(3.0%)	$1.30	$2.37	$1.07	81.8%
2025	May	$4.13	$3.87	($0.26)	(6.4%)	$1.42	$2.04	$0.61	43.1%
2025	Jun	$7.22	$6.76	($0.46)	(6.4%)	$4.28	$4.91	$0.62	14.5%
2025	Jul	$10.23	$9.40	($0.83)	(8.1%)	$1.88	$2.80	$0.92	49.2%
2025	Aug	$3.34	$2.82	($0.52)	(15.5%)	$0.82	$1.25	$0.44	53.3%
2025	Sep	$2.74	$2.22	($0.52)	(19.0%)	$1.60	$1.96	$0.36	22.5%
2025	Oct	$4.30	$4.27	($0.03)	(0.7%)	$1.95	$2.66	$0.71	36.4%
2025	Nov	$3.23	$3.32	$0.09	2.7%	$1.14	$1.54	$0.40	34.7%
2025	Dec	$3.20	$3.25	$0.04	1.4%	$2.76	$3.33	$0.57	20.7%
2025	All	$3.66	$3.47	($0.20)	(5.3%)	$1.73	$2.33	$0.60	35.0%
2026	Jan	$0.95	$0.98	$0.03	3.3%	$2.22	$2.98	$0.76	34.0%
2026	Feb	$0.93	$0.98	$0.04	4.7%	$2.17	$2.61	$0.45	20.6%
2026	Mar	$2.78	$2.83	$0.05	1.9%	$3.06	$3.38	$0.32	10.5%
2026	All	$1.44	$1.48	$0.04	2.8%	$2.46	$2.99	$0.53	21.4%

In the first three months of 2026, in the RTO Reserve Zone, the real-time weighted average price of nonsynchronized reserve was $2.34 per MWh and the real-time weighted average sum of the MCP credits and LOC credits for nonsynchronized reserve was $0.89 per MWh. In the first three months of 2026, in the MAD Reserve Subzone, the real-time weighted average price of nonsynchronized reserve was $2.94 per MWh and the real-time weighted average sum of the MCP credits and LOC credits for nonsynchronized reserve was $0.28 per MWh.

Table 10-30 shows the total nonsynchronized reserve payments by month from January 2025 through March 2026. In January and February 2026, shortage pricing for primary reserve in the RTO was used for 34 intervals during a cold weather event. Figure 10-26 shows the resulting spike in prices. Due to units buying back portions of their day-ahead schedule at these high real-time prices, the sum of the real-time and balancing MCP credits seen in Table 10-30 for January 2026 is significantly negative.

Table 10-30 Total nonsynchronized reserve payments and charges by month: January 2025 through March 2026

Year	Month	Day-Ahead Credits	Real-Time and Balancing MCP Credits	LOC Credits	Shortfall Charges	Total Credits
2025	Jan	$1,310,758	($807,014)	$185,652	NA	$689,396
2025	Feb	$698,931	($300,892)	$96,940	NA	$494,978
2025	Mar	$2,079,574	($470,698)	$289,300	NA	$1,898,176
2025	Apr	$1,984,502	($247,956)	$91,497	NA	$1,828,043
2025	May	$1,340,915	($151,404)	$64,475	NA	$1,253,986
2025	Jun	$2,457,199	($2,282,555)	$102,702	NA	$277,346
2025	Jul	$3,413,482	($958,506)	$121,292	NA	$2,576,268
2025	Aug	$1,266,236	($425,994)	$67,415	NA	$907,657
2025	Sep	$1,261,458	($285,138)	$163,072	NA	$1,139,392
2025	Oct	$1,708,180	$132,342	$61,983	NA	$1,902,505
2025	Nov	$1,411,665	($216,606)	$84,484	NA	$1,279,542
2025	Dec	$1,658,885	($113,519)	$184,463	NA	$1,729,828
2025	All	$20,591,785	($6,127,942)	$1,513,273	NA	$15,977,117
2026	Jan	$2,369,695	($2,011,682)	$97,621	NA	$455,634
2026	Feb	$585,493	($640,427)	$104,604	NA	$49,670
2026	Mar	$2,041,630	($394,677)	$87,783	NA	$1,734,736
2026	All	$4,996,817	($3,046,786)	$290,009	NA	$2,240,040

Table 10-31 provides the day-ahead and real-time nonsynchronized reserve by primary resource type and fuel type for the first three months of 2026. Much of the negative balancing MCP credits applied to hydro resources occurred during Winter Storm Fern in January.

Table 10-31 Day-ahead and real-time nonsynchronized reserve by primary resource type and fuel type: January through March, 2026

Resource / Fuel Type	Day-Ahead MWh	Real-Time Scheduled MWh	Day-Ahead Credits	Balancing MCP Credits	LOC Credits	Total Credits
Oil	2,861,560	2,780,215	$14,245,479	($1,905,518)	$161,980	$12,501,941
Hydro	4,955,596	4,723,905	$4,685,853	($3,695,135)	$1,242,490	$2,233,207
RICE - Natural Gas	806,538	665,432	$1,434,452	($401,574)	$93,220	$1,126,099
Other	62,407	40,564	$226,002	($31,870)	$3,060	$197,193

30-Minute Reserve

The 30-minute reserve service is provided by resources that can respond in 30 minutes. The requirement for the 30-minute reserve service can be satisfied by the synchronized reserve product, the nonsynchronized reserve product, and the secondary reserve product. There is no NERC standard for 30-minute reserve.

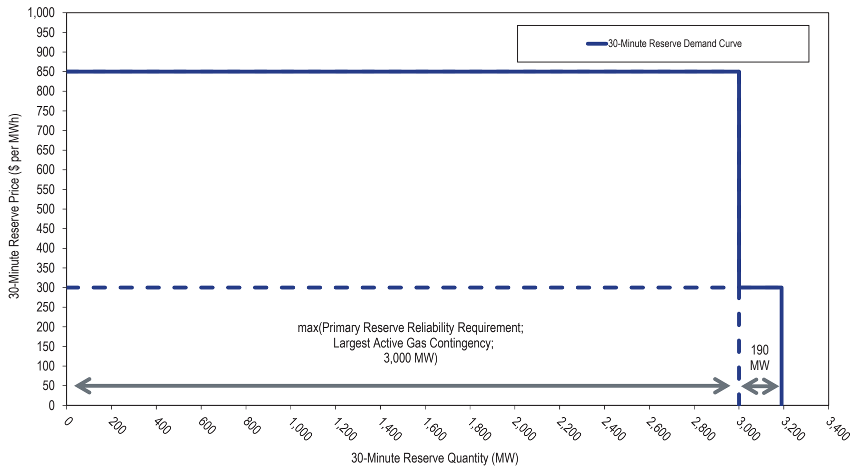
Market Structure

Demand

Demand for the 30-minute reserve service comes from the 30-minute reserve requirement. By default, the 30-minute reserve requirement is equal to the extended reserve requirement plus the 30-minute reserve reliability requirement. The 30-minute reserve reliability requirement is equal to the maximum of: the primary reserve reliability requirement; the largest active gas contingency; and 3,000 MW.[100] Unlike with synchronized reserve and primary reserve, PJM does not model a 30-minute reserve requirement for the defined reserve subzone.[101] However, PJM has the option to define a subzone natural gas contingency reserve requirement using 30-minute reserves. PJM did not exercise this option in the first three months of 2026.

Figure 10-28 shows an example ORDC for 30-minute reserve for when the primary reserve reliability requirement and the largest active gas contingency are both less than 3,000 MW, and when the extended reserve requirement is equal to its base value of 190 MW. Since the increase to the synchronized reserve reliability requirement in May 2023, the 30-minute reserve requirement has frequently equaled the primary reserve requirement.

Figure 10-28 An example of a 30-minute reserve real-time operating reserve demand curve, including the permanent second step



In the first three months of 2026, the real-time average 30-minute requirement was 3,453.2 MW and the day-ahead average 30-minute requirement was 3,452.3 MW (Figure 10-4).

100 See PJM. "PJM Manual 11: Energy & Ancillary Services Market Operations" § 4.3 Reserve Requirement Determination, Rev. 136 (Oct. 1, 2025).
101 See PJM. "PJM Manual 11: Energy & Ancillary Services Market Operations" § 4.3.1 Locational Aspect of Reserves, Rev. 136 (Oct. 1, 2025).

Supply

The supply of 30-minute reserves includes all reserves that can convert to energy in 30 minutes. All reserve products can participate in the 30-minute reserve service. In the first three months of 2026, the demand for 30-minute reserve was satisfied by primary reserves (made of synchronized reserves and nonsynchronized reserves) and secondary reserves. The 30-minute reserve requirement is met from the least expensive combination of synchronized, nonsynchronized, and secondary reserves that satisfies the requirements of the synchronized, primary, and 30-minute reserve services (Table10-9).

Market Concentration

Table 10-32 shows the average HHI of the 30-minute reserve market, including synchronized, nonsynchronized, and secondary reserves, and the percent of intervals for which the maximum market share is above 20 percent. In the first three months of 2026, the RTO Reserve Zone was unconcentrated in the day-ahead market and unconcentrated in the real-time market.

Table 10-32 PJM 30-minute reserve market HHI: January through March, 2026

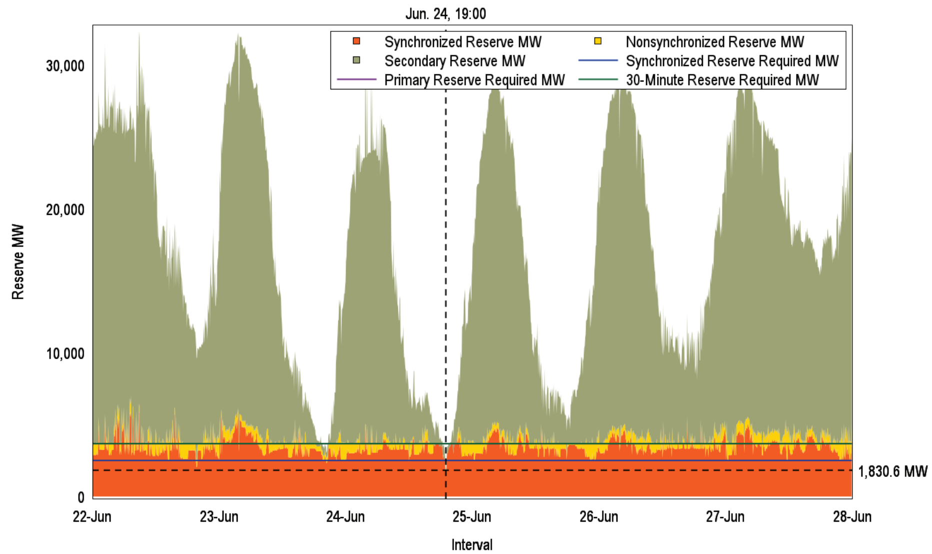
Location	Market	Average HHI	Percent of Intervals Max Market Share Above 20%	Description
RTO	RT	748	13.6%	Unconcentrated
RTO	DA	841	26.4%	Unconcentrated

Market Performance

Due to the large amount of available secondary reserve, most 30-minute reserve is procured at low cost, with the amount of cleared secondary reserve far exceeding what is strictly needed to satisfy the 30-minute reserve requirement (Figure 10-2). In the first three months of 2026, there were no intervals short of 30-minute reserve.

However, 30-minute reserves were short in 23 intervals from June 23, 2025, through June 24, 2025, during a hot weather event. Figure 10-29 shows the point during the hot weather event when cleared 30-minute reserves were at their lowest. For that interval, the amount of 30-minute reserve offered was 5,954.9 MW. This was larger than the 30-minute requirement of 3,677.6 MW.

Figure 10-29 30-minute reserve shortage during the June 2025 hot weather event: June 22 through June 27, 2025



Secondary Reserve

PJM defines secondary reserve as reserves (online or offline available for dispatch) that can be converted to energy in 10 to 30 minutes. There is no NERC standard for secondary reserve. The secondary reserve product can only be used to satisfy the 30-minute reserve requirement, and is cleared for five-minute intervals in the real-time market and hourly intervals in the day-ahead market. Failure to convert offline secondary reserves to energy at PJM's request results in a shortfall charge.

Unlike synchronized reserve and nonsynchronized reserve, there is no "event" process to deploy secondary reserve. Instead, PJM uses secondary reserve via the normal energy commitment and dispatch process.

Market Structure

Demand

There is no explicit demand for secondary reserve beyond a more general demand for 30-minute reserve, which can be satisfied by the synchronized, nonsynchronized, and secondary reserve products. Beyond the primary reserve requirement, the balance of 30-minute reserve can be made up by the economic combination of synchronized, nonsynchronized, and secondary reserve.

When the secondary reserve market clearing price is $0 per MWh, PJM's clearing engines clear all available secondary reserve MW. Because of the large amount of secondary reserve cleared, most 30-minute reserve is secondary reserve and most cleared secondary reserve is cleared well in excess of the 30-minute reserve requirement (Figure 10-2).

Supply

Secondary reserves are reserves that can convert to energy within 10 to 30 minutes. This includes the unloaded capacity of online generation that can be achieved according to the resource ramp rates in 10 to 30 minutes. It also includes offline resources that offer a time to start of less than 30 minutes but more than 10 minutes. Secondary reserves do not include pre-emergency or emergency demand response resources, even if they offer to start in less than 30 minutes. Secondary reserves do not include exports that can be recalled in less than 30 minutes.

As with the other reserve products, for most resources, PJM determines the MW available for secondary reserve based on energy offer parameters.[102] Energy Storage Resource model participants, hydroelectric resources, and demand response resources must specify their availability and MW separately. Online resources' secondary reserves are based on ramp rates and the lesser of the secondary reserve maximum or economic maximum parameters, as well as any cleared synchronized reserve.[103] The use of the secondary reserve maximum output limit requires prior approval by PJM.[104] Offline resources' secondary reserves are based on the time to start, which is the start-up time plus notification time, and any cleared nonsynchronized reserve.[105] Certain resource types, including nuclear, wind, and solar units, are by default excluded from providing secondary reserves.

Figure 10-30 shows the daily average total available secondary reserve in the first three months of 2026. In the first three months of 2026, the real-time average supply of secondary reserve was 20,180.6 MW and the day-ahead average supply was 12,307.3 MW. The available secondary reserve decreased in January and February during a cold weather event which included Winter Storm Fern (Figure 10-28) as PJM brought on more units for energy.

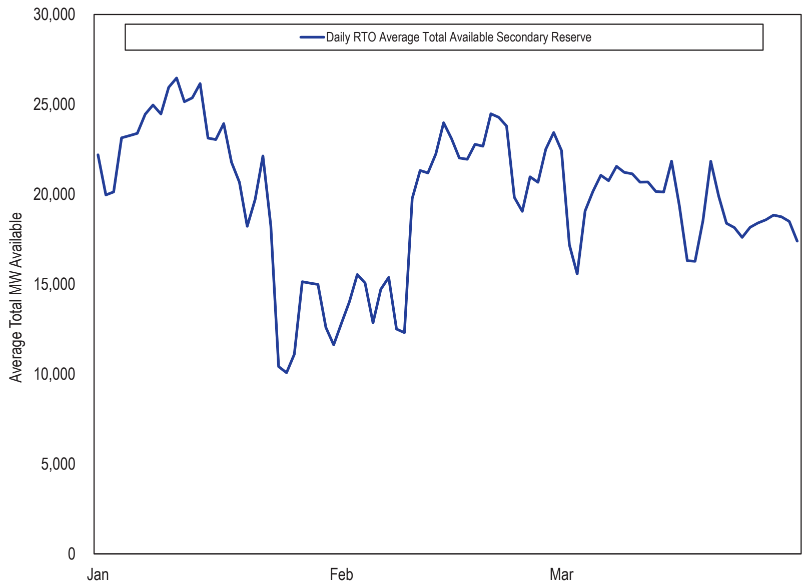
102 See PJM. "PJM Manual 11: Energy & Ancillary Services Market Operations" § 4.2.3 Reserve Market Resource Offer Structure, Rev. 136 (Oct. 1, 2025).

103 See PJM. "PJM Manual 11: Energy & Ancillary Services Market Operations" § 4.2.5.1 Reserve Market Capability for Online Generation Resources, Rev. 136 (Oct. 1, 2025).

104 See PJM. "PJM Manual 11: Energy & Ancillary Services Market Operations" § 4.2.2.1 Communication for Reserve Capability Limitation, Rev. 136 (Oct. 1, 2025).

105 See PJM. "PJM Manual 11: Energy & Ancillary Services Market Operations" § 4.2.5.2 Reserve Market Capability for Offline Generation Resources, Rev. 136 (Oct. 1, 2025).

Figure 10-30 Daily Average Available Secondary Reserve: January through March, 2026



Market Behavior

For all resources, the secondary reserve offer price is $0 per MWh.[106] For online resources, the energy market opportunity cost is calculated by PJM based on market prices.

Market Performance

Figure 10-31 shows the unweighted average market clearing prices for secondary reserves in the first three months of 2026. Due to the product's low cost and ample supply, the secondary reserve market clearing price (SecRMCP) is almost always $0 per MWh. In the first three months of 2026, the real-time SecRMCP was nonzero for zero five-minute intervals and the day-ahead SecRMCP was nonzero for zero hours.

Figure 10-31 Secondary reserve prices: January through March, 2026

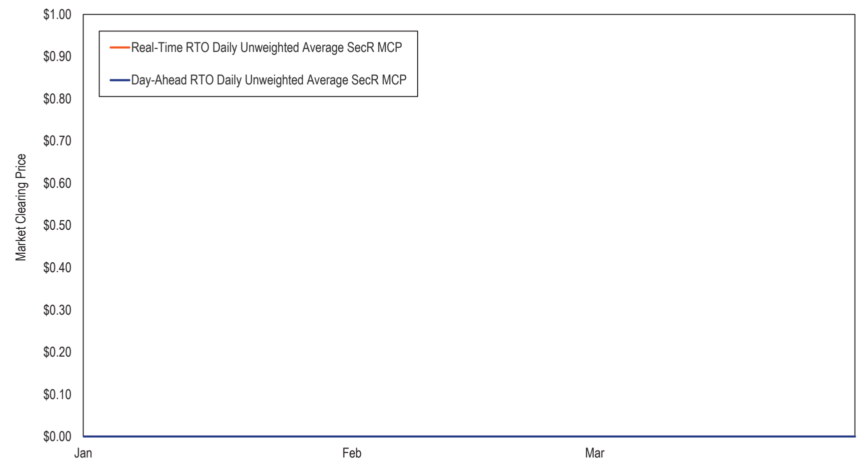


Table 10-33 compares the dispatch run and pricing run market clearing prices for the day-ahead and real-time secondary reserve markets. For both the dispatch run and the pricing run, the real-time values are the LPC prices for each run weighted by the RT SCED MW. For the day-ahead values, these are the day-ahead prices weighted by the day-ahead dispatch MW. In the first three months of 2026, the day-ahead SecRMCPs were $0 per MWh for all hours in both the pricing run and the dispatch run. In real time, the SecRMCPs for the pricing run and dispatch run were $0 per MWh for all intervals.

106 See PJM. "PJM Manual 11: Energy & Ancillary Services Market Operations" § 4.2.3 Reserve Market Resource Offer Structure, Rev. 136 (Oct. 1, 2025).

Table 10-33 Comparison of fast start and dispatch pricing components: January 2025 through March 2026

		Day-Ahead				Real-Time			
Year	Month	Dispatch-Run MCP	Pricing-Run MCP	Difference	Percent Difference	Dispatch-Run MCP	Pricing-Run MCP	Difference	Percent Difference
2025	Jan	$0.00	$0.00	$0.00	NA	$0.00	$0.00	$0.00	NA
2025	Feb	$0.00	$0.00	$0.00	NA	$0.00	$0.00	$0.00	NA
2025	Mar	$0.00	$0.00	$0.00	NA	$0.00	$0.00	$0.00	NA
2025	Apr	$0.00	$0.00	$0.00	NA	$0.00	$0.00	$0.00	NA
2025	May	$0.00	$0.00	$0.00	NA	$0.00	$0.00	$0.00	NA
2025	Jun	$0.00	$0.00	$0.00	NA	$0.05	$0.05	$0.00	0.0%
2025	Jul	$0.00	$0.00	$0.00	NA	$0.00	$0.00	$0.00	NA
2025	Aug	$0.00	$0.00	$0.00	NA	$0.00	$0.00	$0.00	NA
2025	Sep	$0.00	$0.00	$0.00	NA	$0.00	$0.00	$0.00	NA
2025	Oct	$0.00	$0.00	$0.00	NA	$0.00	$0.00	$0.00	NA
2025	Nov	$0.00	$0.00	$0.00	NA	$0.00	$0.00	$0.00	NA
2025	Dec	$0.00	$0.00	$0.00	NA	$0.00	$0.00	$0.00	NA
2025	All	$0.00	$0.00	$0.00	NA	$0.00	$0.00	$0.00	0.0%
2026	Jan	$0.00	$0.00	$0.00	NA	$0.00	$0.00	$0.00	NA
2026	Feb	$0.00	$0.00	$0.00	NA	$0.00	$0.00	$0.00	NA
2026	Mar	$0.00	$0.00	$0.00	NA	$0.00	$0.00	$0.00	NA
2026	All	$0.00	$0.00	$0.00	NA	$0.00	$0.00	$0.00	NA

Table 10-34 shows the day-ahead credits, balancing market credits, LOC credits, and effective shortfall charges for secondary reserves from January 2025 through March 2026.[107] In the first three months of 2026, the real-time weighted average secondary reserve market clearing price was $0.00 per MWh and the day-ahead weighted average secondary reserve market clearing price was $0.00 per MWh. In the first three months of 2026, the real-time weighted average credit per MWh, considering the total credits paid and the capped MWh, was $0.12 per MWh and the day-ahead weighted average credit was $0.00 per MWh. In June 2025, balancing credits were negative during a hot weather event that saw 30-minute reserve shortage, causing shortage pricing for secondary reserve.

107 Unlike synchronized reserve, for secondary reserve, shortfall is accounted for in the balancing MCP credits and is not a separate item. The effective shortfall charge is the real-time SecR MCP multiplied by the shortfall MW, a value used when calculating the balancing MCP credits.

Table 10-34 Monthly secondary reserve settlements: January 2025 through March 2026

Year	Month	Total Day-Ahead Credits	Total Balancing MCP Credits	Total LOC Credits	Total Effective Shortfall Charge	Total Credits
2025	Jan	$0	$0	$243,258	$0	$243,258
2025	Feb	$0	$0	$133,463	$0	$133,463
2025	Mar	$0	$0	$126,843	$0	$126,843
2025	Apr	$0	$0	$135,333	$0	$135,333
2025	May	$0	$0	$420,010	$0	$420,010
2025	Jun	$0	($986,243)	$1,825,703	$0	$839,460
2025	Jul	$0	$0	$1,274,869	$0	$1,274,869
2025	Aug	$0	$0	$1,150,153	$0	$1,150,153
2025	Sep	$0	$0	$850,339	$0	$850,339
2025	Oct	$0	$0	$927,503	$0	$927,503
2025	Nov	$0	$0	$682,979	$0	$682,979
2025	Dec	$0	$0	$1,540,616	$0	$1,540,616
2025	All	$0	($986,243)	$9,311,069	$0	$8,324,826
2026	Jan	$0	$0	$1,669,975	$0	$1,669,975
2026	Feb	$0	$0	$1,833,828	$0	$1,833,828
2026	Mar	$0	$0	$990,352	$0	$990,352
2026	All	$0	$0	$4,494,155	$0	$4,494,155

Table 10-35 provides secondary reserve credits by primary resource and fuel type for the first three months of 2026.

Table 10-35 Secondary reserve credits by primary resource and fuel type: January through March, 2026

Resource / Fuel Type	Day-Ahead MWh	Real-Time Capped MWh	Day-Ahead Credits	Balancing MCP Credits	LOC Credits	Total Credits
Combined Cycle	462	2,554,867	$0	$0	$1,531,645	$1,531,645
Steam - Coal	0	2,156,824	$0	$0	$1,315,799	$1,315,799
CT - Natural Gas	20,017,248	27,861,440	$0	$0	$1,105,652	$1,105,652
CT - Oil	3,246,984	4,169,982	$0	$0	$174,302	$174,302
RICE - Natural Gas	12,004	68,748	$0	$0	$139,141	$139,141
Steam - Natural Gas	0	264,152	$0	$0	$126,553	$126,553
Steam - Other	0	37,013	$0	$0	$96,050	$96,050
RICE - Oil	162,231	199,653	$0	$0	$5,012	$5,012
Hydro - Pumped Storage	36,950	779,514	$0	$0	$0	$0
Other	5,724	106,059	$0	$0	$0	$0

Among other reasons, a secondary reserve resource is paid an LOC credit when PJM determines that the resource was backed down in order to clear more secondary reserve. Because the supply of secondary reserves greatly exceeds the amount needed to meet the 30-minute reserve requirement, PJM does not actually back down resources to clear more secondary reserve. However, because of the method used by PJM to determine whether a resource was backed down, PJM at times pays resources for an incorrectly determined real-time opportunity cost. For example, PJM erroneously treated resources coming online to provide energy as having been backed down to provide secondary reserves. PJM does not back down resources below their economic minimum to provide secondary reserves, but in the first three months of 2026, for secondary reserve resources that did not clear day-ahead and were generating below their economic minimum points, PJM paid $1,122,586 in LOC credits.

Regulation Market

Regulation matches generation with short term changes in load by moving the output of selected resources up and down via an automatic control signal. Regulation is provided by generators with a short-term response capability (less than five minutes) or by demand response (DR). The PJM Regulation Market is operated as a single real-time market.

PJM filed proposed significant changes to the regulation market design with FERC on April 16, 2024.[108] The Commission Order of June 14, 2024, accepted the PJM proposal as filed. PJM will implement the changes to the regulation market in two phases.[109] Phase 1, implemented on October 1, 2025, is a single product, single signal market with one clearing price. Phase 2, to be implemented on October 1, 2026, will include separate regulation up and regulation down markets. The Phase 1 changes eliminated many of the significant issues identified by the MMU that resulted from the prior two product, two signal market design, including the incorrect and inconsistent use and application of the MBF/MRTS.[110]

108 PJM, "Regulation Market Design Filing," Docket No. ER24-1772-000.
109 See 187 FERC ¶ 61,173.
110 See Order No. 755, 137 FERC ¶ 61,064 at P 2 (2011).

This report analyzes the regulation market results from the first quarter of 2026 under the new Phase 1 regulation market design.

Market Design

The objective of PJM's regulation market design should be to minimize the cost to provide regulation. The new design, as actually implemented, does not meet that goal.

The regulation market design includes three clearing price components: capability ($/MW, based on the MW offered); performance ($/MW*mile, based on the total MW movement requested by the control signal, known as mileage); and lost opportunity cost ($/MW of lost revenue from the energy market as a result of providing regulation). The performance score translates actual MW into effective MW, and offers and clearing prices into $/effective MW.

Phase 1 of PJM's regulation market redesign was implemented on October 1, 2025. The new market design replaced two separate RegA/RegD signals/products with a single signal/product, eliminating the need for the benefit factor. The new market design includes the LOC in the market price, although there are issues with the LOC calculation. The new market design simplifies the performance score calculation.

Market solution software relevant to regulation consists of the Ancillary Services Optimizer (ASO) solving each half hour; the intermediate term security constrained economic dispatch market solution (IT SCED) solving every 15 minutes; and the real-time security constrained economic dispatch market solution (RT SCED) solving every five minutes. The ASO, incorporating the forecast LMP values in the LOC calculation, defines the cleared regulation MW. The regulation market clearing price is a function of the defined demand for regulation and the offer prices that incorporate LOC based on real-time LMP based on the most recently approved RT SCED case, approximately 10 minutes ahead of the target solution time. The regulation market clears based on the resultant offer prices over 30 minute periods.

The current design includes new definitions of regulation demand. The demand for regulation is defined by the categories of ramp hours, nonramp hours, and shoulder hours. In addition, the length of the regulation seasons and the regulation requirements for each category were modified (Table10-36). The regulation requirement for ramp hours was changed from 800 effective MW to 750 effective MW, for nonramp hours was changed from 525 effective MW to 550 effective MW, and for the new shoulder hours was set to 650 effective MW. The definition of the hours for each category of ramp hours changes by season. These changes together will increase the yearly regulation effective MW demand by 3.9 percent.

Table 10-36 Seasonal regulation requirement definitions.

Season	Dates	Nonramp Hours (550 MW)	Shoulder Hours (650 MW)	Ramp Hours (750 MW)
Winter	Nov 1 - Feb 28(29)	01:00 - 03:59 11:00 - 15:59	0:00 - 0:59 10:00 - 10:59	04:00 - 09:59 16:00 - 23:59
Spring	Mar 1 - Apr 30	02:00 - 04:59 10:00 - 17:59	1:00 - 1:59 9:00 - 9:59	05:00 - 08:59 18:00 - 00:59
Summer	May 1 - Sep 15	02:00 - 03:59	1:00 - 1:59	04:00 - 00:59
Fall	Sep 16 - Oct 31	01:00 - 04:59 10:00 - 16:59	0:00 - 0:59 9:00 - 9:59	05:00 - 08:59 17:00 - 23:59

Each cleared resource is allocated a portion of the signal based on the cleared regulation MW of the resource relative to the total cleared MW of regulation. This signal is called the Total Regulation Signal (TREG) for the resource. A resource that cleared 10 MW of capability (Assigned Regulation or AREG) will be provided a percent TREG signal asking for a positive or negative regulation movement between negative and positive 100 percent around its regulation set point.

Regulation performance scores (0.0 to 1.0) measure the response of a regulating resource to the assigned regulation signal every 10 seconds by measuring the precision, defined to be the difference between the regulation response and the regulation requested.[111] Performance scores are reported on a half hour basis for each resource.

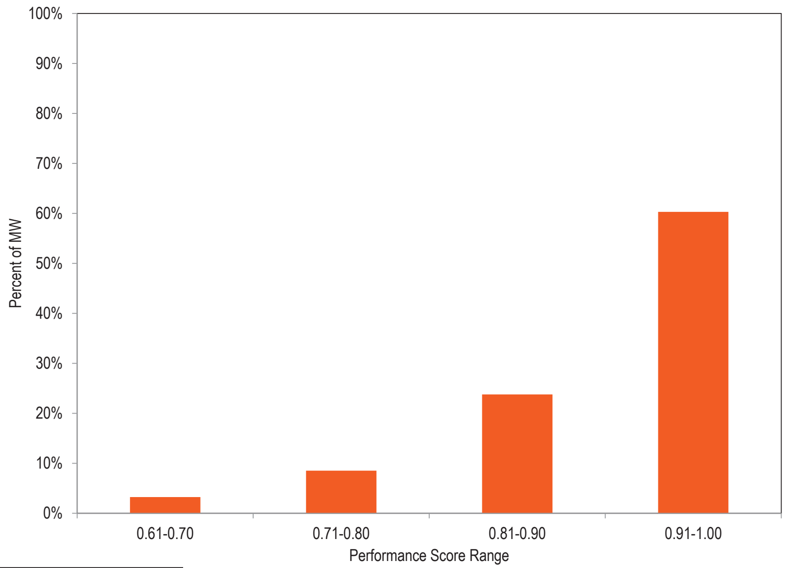
111 PJM "Manual 12: Balancing Operations," § 4.5.6 Performance Score Calculation, Rev. 54 (July Dec. 17, 2024).

Table 10-37 and Figure 10-32 show the average half hour performance score by resource type in the first three months of 2026.[112] Each category is based on the percentage of the full performance score distribution for each resource type.[113] In the first three months of 2026, 60.3 percent of all regulation resources had average performance scores within the 0.91-1.00 range.

Table 10-37 Half hour average performance score by unit type: January through March, 2026

	Performance Score Range			
Unit Type	61-70	71-80	81-90	91-100
Battery	1.2%	2.0%	5.7%	88.5%
CT	2.8%	9.1%	32.6%	51.6%
Diesel	0.9%	2.7%	18.8%	75.7%
DSR	2.3%	2.8%	4.3%	84.3%
Hydro	2.4%	7.2%	29.7%	58.2%
Steam	5.1%	14.1%	34.5%	40.9%

Figure 10-32 Half hour average performance score: January through March, 2026

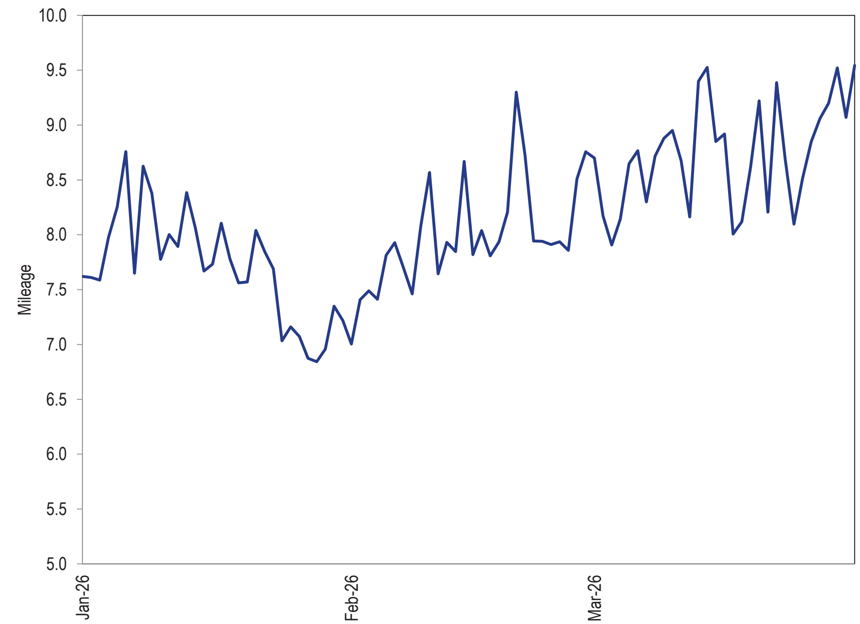


112 Except where explicitly referred to as effective MW or effective regulation MW, MW means actual MW unadjusted for performance score.
113 PJM "Manual 12: Balancing Operations," § 4.5.6 Performance Score Calculation, Rev. 54 (July Dec. 17, 2024).

The October 1, 2025, redesign eliminated the marginal benefit factor, and changed the definition of the mileage ratio. The mileage ratio is defined as the actual mileage divided by the 100 hour historical average mileage. The new design uses this mileage ratio to calculate the regulation mileage credits portion of settlements.

Figure 10-33 shows the daily average mileage ratio in the first three months of 2026.

Figure 10-33 Daily average mileage ratio: January through March, 2026



Market Design Issues

While the new market design corrected a number of issues with the old design, new issues have been identified in the new design.

The performance score is incorrect. All else being held equal, the current design inappropriately calculates a lower error for units with larger MW regulation assignments than units that perform exactly the same but with a smaller regulation assignment.

Under the new regulation market design, PJM determines the five minute interval performance score by evaluating a unit's performance every 10 seconds. This performance score is determined by calculating the error in a unit's output based on the average regulation signal MW during the entire half hour clearing interval.

The numerator is the difference between the actual regulation MW and the assigned regulation MW based on the regulation signal. The denominator is calculated as the average of the unit's assigned regulation and the average of the absolute value of the regulation signal calculated over the half hour clearing interval. This has the effect of scaling each 10 second performance score based on the clearing interval average of the overall regulation signal. The MMU disagrees with this calculation method because it scales the actual response based on the average signal over the clearing interval for no apparent reason. Identical behavior of the same unit can yield different results if the overall interval average signal is different. More importantly, the inclusion of the assigned regulation MW (AREG) in the denominator results means that identical responses from units with different levels of committed regulation MW will have different performance scores. Both results are illogical.

The MMU proposes to define regulation performance using only the ratio of the unit's response to the regulation signal.

The total performance score for the clearing interval is the average of each 10 second performance score. This means that any unit providing a steady 7.5 MW to a signal calling for 10 MW would logically receive a performance score of 0.75, regardless of the assigned regulation MW of the unit. Using PJM's equation in this case would result in different performance scores for units with the same 75 percent response, based solely on the magnitude of regulation assignment. Table10-38 illustrates the variation in performance scores that result from different assigned regulation MW amounts and average interval signals under the current calculation, compared to the MMU's proposal.

Table 10-38 Performance scores under different market conditions: Current versus MMU proposed calculation

				Performance Score	
Clearing Interval Average Absolute Signal MW	Assigned Regulation MW	Regulation Output MW	Signal MW	PJM	MMU
5.0	10.0	7.5	10.0	66.7%	75.0%
	50.0	7.5	10.0	90.9%	75.0%
	100.0	7.5	10.0	95.2%	75.0%
10.0	10.0	7.5	10.0	75.0%	75.0%
	50.0	7.5	10.0	91.7%	75.0%
	100.0	7.5	10.0	95.5%	75.0%
20.0	10.0	7.5	10.0	83.3%	75.0%
	50.0	7.5	10.0	92.9%	75.0%
	100.0	7.5	10.0	95.8%	75.0%

The MMU recommends that the performance score be revised to eliminate the effect of the size of the regulation assignment and to directly calculate the performance score based on the actual performance and the requested performance.

In October 2025, PJM identified that the clearing of less than 1.0 MW for resources was a contributing factor to extremely high prices in the regulation market, particularly during reserve shortages.

As an initial workaround, PJM told participants that they could set a minimum regulation MW level in their regulation offers. In addition, PJM implemented an after the fact (after market clearing) step that replaces any fractional MW regulation assignments with a 1.0 MW regulation assignment for any units that are eligible for LOC and have a regulation capability greater than 1.0 MW. While this override reduced the LOC contributions to regulation prices, the override did not eliminate all associated high prices and is an ad hoc fix that ignores the underlying issue.

The MMU does not agree that asking participants to make inflexible regulation offers is the correct way to address the fractional MW clearing results of the current market clearing engine design. Relying on participants to make their offers less flexible to correct for an optimization issue is not efficient or reasonable. The MMU does not agree that overriding the fractional

MW assignment with a 1.0 MW assignment is a correct way to address the fractional MW clearing results of the current market clearing engine design.

The MMU recommends that the regulation market optimization be reviewed to address the logic that allows the partial clearing of inframarginal resources.

Since the implementation of the inflexible offers and the 1.0 MW override, it became clear that the very high regulation prices are a result of interactions between offer parameters (differences between the regulation range and economic range of units and differences in offered ramp and actual ramp of units) and differences between ASO forecasted LMP and actual LMP used to set LOC for cleared regulation resources.

More fundamentally, the LOC calculation is incorrect. Regulation prices and total costs were expected to increase due to the inclusion of LOC in clearing prices rather than being paid as unit specific uplift. However, prices have been higher than appropriate in some hours as a result of differences between the regulation ranges and economic ranges of units and differences in offered ramp and actual ramp of units. Offer parameters define a regulation maximum MW (RegMax) and an economic maximum MW (EcoMax). The RegMax is the upper limit on the regulation offer and the EcoMax is the upper limit on the energy offer. RegMax should equal EcoMax. For some resources, the EcoMax is incorrectly offered as greater than the RegMax. The result is to artificially increase the LOC because the LOC is defined as the revenues that could have been earned in the energy market if the unit were not providing regulation. If RegMax and EcoMax are matched, the LOC is correctly defined by matching each MW of regulation offered with a MW of energy not sold. If the EcoMax is greater than the RegMax, the LOC is incorrectly defined by a higher MW level on the energy offer than the unit's regulation offer defines as the maximum MW for which it can provide regulation. The LOC calculation is based on the incorrect assumption that the unit gives up multiple MW of energy output for every MW of regulation. That can and does lead to extremely high LOC calculations that incorrectly inflate the clearing prices in the regulation market.

Differences between ASO forecasted LMPs and real time LMPs used to set LOC for cleared regulation resources can significantly amplify the RegMax/EcoMax issue and have resulted in the extremely high regulation prices observed at times since October 1, 2025.

Table 10-39 shows three different resources (Unit 1, Unit 2 and Unit 3) with identical costs curves (each MW of output increases marginal cost by $1), the same Reg Max, but different Eco Max. Unit 1 has Eco Max equal to Reg Max (20 MW). Unit 2 has Eco Max (30 MW) greater than Reg Max (20 MW). Unit 3 has Eco Max (40 MW) greater than Reg Max (20 MW). The clearing engine (ASO) has a forecasted LMP for all three units at $15. At $15, the economic desired MW equals the regulation set point at 15 MW for all three units, the total LOC is equal to $0.00 for all three units and each resource can clear for 5 MW of regulation at an offer of $0.00 per MW of regulation. If the real time LMP is equal to $15 (no change from the ASO forecast LMP), $/MW LOC stays at $0.00 per MW of regulation provided (first result for each unit in Table 10-39). If, however, the real time LMP is $200, the calculated $/MW LOC of Unit 1 is $182.50, the calculated $/MW LOC of Unit 2 is $532.50, and the calculated $/MW LOC of Unit 3 is $862.50.

Table 10-39 Regulation LOC Examples: Eco Max Greater than or Equal to Reg Max

Unit	Energy Price	Reg MW	Reg Set Point	Economic Desired MW	Reg Max	EcoMax	Marginal Cost at Reg Set Point	MC at Economic Desired	LOC $/MW	Total LOC
Unit 1	$15.00	5	15	15	20	20	$15.00	$15.00	$0.00	$0.00
Unit 1	$20.00	5	15	20	20	20	$15.00	$20.00	$2.50	$12.50
Unit 1	$25.00	5	15	20	20	20	$15.00	$20.00	$7.50	$37.50
Unit 1	$200.00	5	15	20	20	20	$15.00	$20.00	$182.50	$912.50
Unit 2	$15.00	5	15	15	20	30	$15.00	$15.00	$0.00	$0.00
Unit 2	$20.00	5	15	20	20	30	$15.00	$20.00	$2.50	$12.50
Unit 2	$25.00	5	15	25	20	30	$15.00	$25.00	$10.00	$50.00
Unit 2	$200.00	5	15	30	20	30	$15.00	$30.00	$532.50	$2,662.50
Unit 3	$15.00	5	15	15	20	40	$15.00	$15.00	$0.00	$0.00
Unit 3	$20.00	5	15	20	20	40	$15.00	$20.00	$2.50	$12.50
Unit 3	$25.00	5	15	25	20	40	$15.00	$25.00	$10.00	$50.00
Unit 3	$200.00	5	15	40	20	40	$15.00	$40.00	$862.50	$4,312.50

In evaluating the available supply for an interval, the clearing engine can clear less than the entire offer of a unit and can also clear less than 1.0 MW of a unit's offer. When the economic max of the unit is higher than the regulation max of the unit, clearing less than 1.0 of regulation can generate an extreme version of the problem shown in Table 10-39 above. Even after replacing the fractional MW with 1.0 MW, the market results when EcoMax is greater than regMax can be extreme.

The MMU recommends that if a unit sets its economic maximum at a value greater than its regulation maximum, the lost opportunity cost (LOC) of the unit should be calculated assuming the economic maximum of the unit is equal to the regulation maximum of the unit. The MMU recommends that, in cases where offered ramp is greater than actual ramp, the actual ramp be used to calculate the LOC of the unit. The MMU recommends that these fixes to the LOC logic be implemented prior to implementing Phase 2 of the regulation market design.

Market Redesign Phase 2

PJM is planning to introduce implement its Phase 2 regulation market design in October 2026, as approved by FERC. [114] In PJM's Phase 2 design, the regulation market will once again be split into two products with two separate prices: one product that only needs to respond when the regulation signal is above zero (RegUp), and one product that only needs to respond when the regulation signal is below zero (RegDown). In Phase 2, market resources will be able to clear as RegUp, RegDown or both in any given 30 minute market interval. PJM has not done any systematic testing of the proposal. PJM has not explained what problem this design change is intended to fix, analyzed what impact this design would have on reliability, or how this will affect the cost of regulation. The MMU continues to recommend a single product market with a single signal. Phase 1 with the issues corrected is preferable to Phase 2.

114 See Docket No. ER24-1772-000.

Market Structure

Supply

Table 10-40 shows average hourly offered MW (actual and effective), and average hourly cleared MW (actual and effective) for all hours in the first three months of 2026.[115] Actual MW are adjusted by the historic 100-hour moving average performance score to get effective MW. Offered MW are calculated based on the offers from units that are designated as available for the day. These are daily offers that can be modified on an hourly basis up to 65 minutes before the hour.[116] Eligible MW are calculated from the hourly offers from units with daily offers and units that are offered as unavailable for the day, but still offer MW into some hours. Units with daily offers are permitted to offer above or below their daily offer from hour to hour. As a result of these hourly MW adjustments, the average hourly Eligible MW can be higher than the Offered MW.

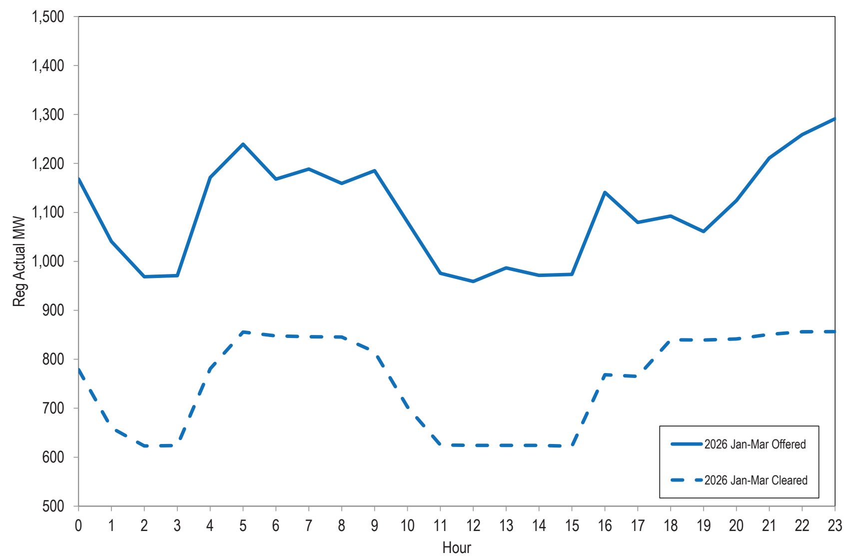
In the first three months of 2026, the average half hour offered supply of regulation for nonramp hours was 958.8 actual MW (835.4 effective MW). In the first three months of 2026, the average half hour offered supply of regulation for shoulder hours was 1,117.2 actual MW (967.8 effective MW). In the first three months of 2026, the average half hour offered supply of regulation for ramp hours was 1,200.8 actual MW (1,048.1 effective MW).

The ratio of the average half hour offered supply of regulation to average half hour regulation demand (actual cleared MW) for nonramp hours was 1.54 in the first three months of 2026. The ratio of the average half hour offered supply of regulation to average half hour regulation demand (actual cleared MW) for shoulder hours was 1.51 in the first three months of 2026. The ratio of the average half hour offered supply of regulation to average half hour regulation demand (actual cleared MW) for ramp hours was 1.41 in the first three months of 2026.

Table 10-40 Hourly average actual and effective MW offered and cleared: January through March, 2026

			By Resource Type	
		All Regulation	Generating Resources	Demand Resources
Actual Offered MW	Ramp	1,200.8	1,136.7	64.1
	Shoulder	1,117.2	1,060.1	57.1
	Nonramp	958.8	902.3	56.5
Effective Offered MW	Ramp	1,048.1	989.2	58.9
	Shoulder	967.8	915.1	52.7
	Nonramp	835.4	783.4	51.9
Actual Cleared MW	Ramp	848.9	785.1	63.9
	Shoulder	740.1	683.1	57.0
	Nonramp	623.3	567.3	56.0
Effective Cleared MW	Ramp	750.1	691.5	58.6
	Shoulder	650.1	597.5	52.6
	Nonramp	550.2	498.6	51.5

Figure 10-34 Average hourly Reg actual MW offered and cleared: January through March, 2026



115 Effective MW are actual MW multiplied by performance score.
116 See "PJM Manual 11: Energy & Ancillary Services Market Operations," § 3.2.2 Regulation Market Eligibility, Rev. 136 (October 1, 2025).

Battery Projects in the Queue

Significant flaws in the regulation market design led to an over procurement of RegD MW primarily in the form of storage capacity. The incorrect market signals contributed to the significant rise in storage projects entering PJM's interconnection queue from 2019 through 2025, despite clear evidence that the market design was flawed and despite operational evidence that the RegD market was saturated (Table 10-41).

Table 10-41 Active battery storage projects by submitted year: 2014 through March 2026

Year	Number of Storage Projects	Total Capacity (MW)
2014	1	10.0
2015	1	20.0
2016	0	0.0
2017	0	0.0
2018	6	432.0
2019	28	1,939.4
2020	28	2,309.0
2021	56	4,655.8
2022	0	0.0
2023	0	0.0
2024	0	0.0
2025	3	1,575.0
2026 (Jan-Mar)	0	0.0
Total	123	10,941.2

The supply of regulation can be affected by units that leave the PJM markets. If all units that are requesting retirement from PJM markets through the first three months of 2026 actually retire, the supply of regulation in PJM would be reduced by less than one percent.

Demand

The demand for regulation does not change with price. The regulation requirement is set by PJM to meet NERC control standards, based on reliability objectives, which means that a significant amount of judgment is exercised by PJM in determining the actual demand.

Table 10-42 shows the average half hour required regulation by month and the ratio of supply to demand for both actual and effective MW, for ramp, shoulder, and nonramp hours, for the first three months of 2026. The average half hour required regulation by month is an average of the ramp, shoulder, and nonramp hours in the month.

The nonramp regulation requirement of 550.0 effective MW was provided by 623.1 half hour average actual MW in the first three months of 2026. The shoulder regulation requirement of 650.0 effective MW was provided by 740.2 half hour average actual MW in the first three months of 2026. The ramp regulation requirement of 750.0 effective MW was provided by 848.9 half hour average actual MW in the first three months of 2026.

Table 10-42 Required regulation and ratio of supply to requirement: January through March, 2026

Hours	Month	Average Required Regulation (MW)	Average Required Regulation (Effective MW)	Ratio of Supply MW to MW Requirement	Ratio of Supply Effective MW to Effective MW Requirement
Nonramp	Jan	620.5	550.1	1.68	1.65
	Feb	623.8	550.1	1.57	1.55
	Mar	625.1	550.2	1.42	1.40
Shoulder	Jan	738.2	650.1	1.60	1.57
	Feb	744.3	650.2	1.50	1.49
	Mar	738.1	650.0	1.43	1.41
Ramp	Jan	847.0	750.1	1.49	1.46
	Feb	853.5	750.1	1.42	1.41
	Mar	846.2	750.1	1.31	1.30

Market Concentration

In the first three months of 2026, the effective MW weighted average HHI was 1268, which is moderately concentrated.

Table 10-43 includes a monthly summary of three pivotal supplier (TPS) results. In the first three months of 2026, the three pivotal supplier test was failed in 84.5 percent of half hours. The MMU concludes that the PJM Regulation Market in the first three months of 2026 was characterized by structural market power. The results presented here are calculated by PJM.

The MMU has been unable to verify these results, as some of the underlying data necessary to replicate these calculations are not saved. PJM submitted a request to the vendor more than five years ago to save all data necessary for verification.

Table 10-43 Regulation market monthly three pivotal supplier results: January through March, 2026

	Percent of Half Hours Pivotal
Month	2026
Jan	75.3%
Feb	82.3%
Mar	95.9%
Average	84.5%

Market Conduct

Offers

Resources seeking to regulate must qualify to follow a regulation signal by passing a test for that signal with at least a 75 percent performance score. The regulating resource must be able to supply at least 0.1 MW of regulation and not allow the sum of its regulating ramp rate and energy ramp rate to exceed its overall ramp rate.[117] When offering into the regulation market, regulating resources must submit a cost-based offer and may submit a price-based offer (capped at $100 per MW) by 1415 the day before the operating day. Regulation resources are also permitted to change and/or submit intraday offers.[118]

Offers in the PJM Regulation Market consist of a capability component for the MW of regulation capability provided and a performance component for the miles (ΔMW of regulation movement) provided. The capability component for cost-based offers is not to exceed the increased fuel costs resulting from operating the regulating unit at a lower output level than its economically optimal output level, plus a $12.00 per MW margin. The $12.00 margin embeds market power in the regulation offers, is not part of the cost of regulation, and should be eliminated. The performance component for cost-based offers is not to exceed the increased costs (increased short run marginal costs including increased fuel costs) resulting from moving the unit up and down to provide regulation. Batteries and flywheels have zero cost for lower efficiency from providing regulation instead of energy, as they are not net energy producers. There is an energy storage loss component for batteries and flywheels as a cost component of regulation performance offers to reflect the net energy consumed to provide regulation service.[119]

Up until 65 minutes before the operating hour, the regulating resource must provide: status (available, unavailable, or self scheduled); capability (movement up and down in MW); regulation maximum and regulation minimum (the highest and lowest levels of energy output while regulating in MW. Resources have the option to submit a minimum level of regulation they are willing to provide.[120]

Demand

All LSEs are required to procure regulation in proportion to their load share. LSEs can purchase regulation in the regulation market, purchase regulation from other providers bilaterally, or self schedule regulation to satisfy their obligation (Table 10-47).[121]

117 See "PJM Manual 11: Energy & Ancillary Services Market Operations," § 3.2.1 Regulation Market Eligibility, Rev. 136 (October 1. 2026).
118 Id. at 3.2.2, at p 62.
119 See "PJM Manual 15: Cost Development Guidelines," § 7.8 Regulation Cost, Rev. 47 (October 1, 2025).
120 See "PJM Manual 11: Energy & Ancillary Services Market Operations," § 3.2.1 Regulation Market Eligibility, Rev. 136 (October 1, 2025).
121 See "PJM Manual 28: Operating Agreement Accounting," § 4.1 Regulation Accounting Overview, Rev. 104 (March 1, 2026).

Market Performance

Results

The top 10 units that received the most regulation uplift in the first three months of 2026 are shown in Table 10-44.

Table 10-44 Top 10 recipients of regulation uplift credits: January through March, 2026

Rank	Parent Company	Unit Name	Fuel Type	Total Regulation Uplift Credit	Share of Total Regulation Uplift Credits
1	Constellation Energy Generation LLC	PE MUDDY RUN 1-8 H	HYDRO	$2,543,123	57.4%
2	Dominion Energy Inc	VP BATH COUNTY 1-6 H	HYDRO	$493,920	11.1%
3	Arclight Capital Holdings LLC	PEP KEYS ENERGY CENTER 1 CC	NATURAL GAS	$178,432	4.0%
4	Apollo Global Management Inc	AP LKLYN 1-4 H	HYDRO	$146,892	3.3%
5	Onward Energy LLC	PEP PANDA 2 F	NATURAL GAS	$64,217	1.4%
6	Vistra Energy Corp	ME ONTELAUNEE 1 F	NATURAL GAS	$62,562	1.4%
7	Strategic Value Partners LLC	ME BIRDSBORO 1 CC	NATURAL GAS	$50,136	1.1%
8	JERA CO INC	PE PHILLIPS ISL LINWOOD 1 CC	NATURAL GAS	$45,365	1.0%
9	Onward Energy LLC	PEP PANDA 1 F	NATURAL GAS	$41,086	0.9%
10	Quantum Energy Partners LLC	PL PATRIOT 1 F	NATURAL GAS	$39,608	0.9%
Total of Top 10				$3,665,340	82.7%
Total Regulation Uplift Credits				$4,434,221	100.0%

Table 10-45 shows the settled regulation MW and credits received for each unit type in the first three months of 2026.

Table 10-45 PJM regulation by source: January through March, 2026 [122]

Year (Jan-Mar)	Source	Number of Units	Settled Regulation (Effective MW)	Percent of Settled Regulation	Clearing Price Credits	Uplift Credits	Total Regulation Credits
2026	Battery	19	380,335	26.8%	$55,929,297	$0	$55,929,297
	Coal	15	10,662	0.8%	$2,414,020	$29,773	$2,443,793
	DR	24	117,909	8.3%	$16,929,862	$0	$16,929,862
	Hydro	25	276,405	19.5%	$43,999,405	$3,216,172	$47,215,577
	Natural Gas	134	635,180	44.7%	$93,421,233	$1,188,275	$94,609,508
Total		217	1,420,491.1	100.0%	$212,693,816	$4,434,221	$217,128,037

Quantity

Figure 10-35 compares average half hour regulation and self scheduled regulation during ramp, shoulder, and nonramp hours on an effective MW basis. Self scheduled regulation averaged 46.6 percent of all effective MW during ramp hours, 48.5 percent of all effective MW during shoulder hours, and 58.0 percent of all effective MW during nonramp hours in the first three months of 2026. Over all hours in the first three months of 2026, self scheduled regulation averaged 50.4 percent of all effective MW (See Table10-46). The average half hour regulation is the amount of regulation that actually cleared and is not the same as the regulation requirement because PJM clears the market within a two percent band around the requirement.

122 Biomass data have been added to the natural gas category based on confidentiality rules.

Figure 10-35 Nonramp, shoulder, and ramp regulation levels: January through March 2026

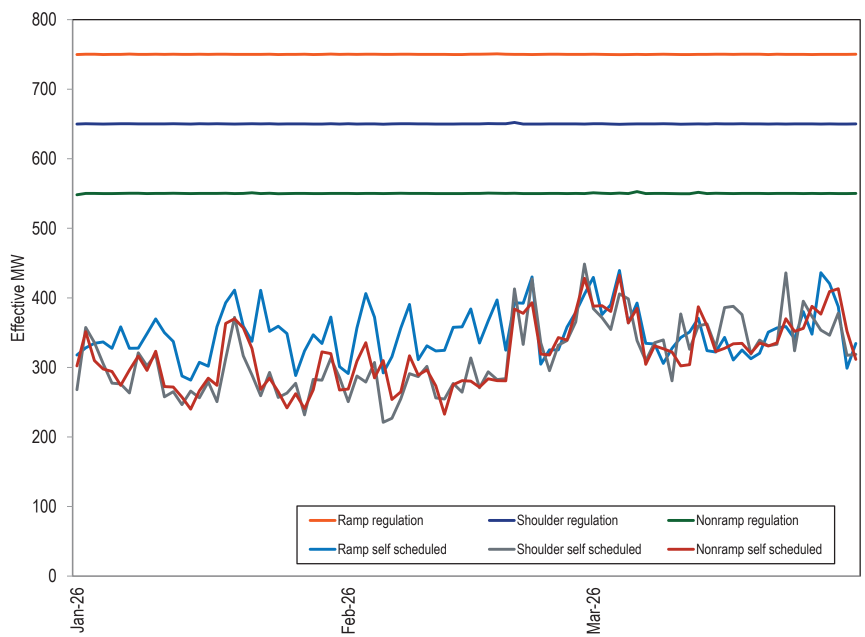


Table 10-46 Total Effective MW and Self Scheduled Effective MW during ramp, shoulder, and non ramp hours: January through March, 2026

Year (Jan-Mar)		Effective MW	Self Scheduled Effective MW	Percent Effective MW
	Ramp	67,510.4	31,476.1	46.6%
	Shoulder	58,510.7	28,363.7	48.5%
2026	Non Ramp	49,514.1	28,702.6	58.0%
Total		175,535.1	88,542.5	50.4%

For total spot market regulation and self scheduled regulation, Table 10-47 shows monthly data for the first three months of 2026, and Table 10-48 shows data for the first three months of 2012 through 2026. Table10-47 and Table10-48 are based on settled (purchased) MW.

Table 10-47 Regulation sources: spot market and self scheduled purchases: January 2026 through March 2026

Year	Month	Spot Market Regulation (Unadjusted MW)	Self Scheduled Regulation (Unadjusted MW)
	Jan	218,130.9	233,173.2
	Feb	184,870.5	219,287.4
2026	Mar	170,750.8	256,823.1
Total		573,752.1	709,283.8

Table 10-48 Regulation sources: spot market and self scheduled: January through March, 2012 through 2026

Year (Jan-Mar)	Spot Market Regulation (Unadjusted MW)	Self Scheduled Regulation (Unadjusted MW)
2012	1,510,190.1	485,672.8
2013	1,026,962.9	342,003.1
2014	724,996.3	404,832.1
2015	670,281.4	411,928.8
2016	583,928.2	546,238.8
2017	534,901.2	520,871.7
2018	678,027.7	395,994.0
2019	539,672.1	500,324.0
2020	515,297.0	557,703.5
2021	542,542.7	556,355.1
2022	687,265.9	369,137.6
2023	464,507.1	524,639.2
2024	376,548.7	622,545.4
2025	437,439.7	561,216.5
2026	573,752.1	709,283.8

In the first three months of 2026, DR provided an average of 63.9 MW of regulation per half hour during ramp hours, 57.0 MW of regulation per half hour during shoulder hours, and 56.0 MW of regulation per half hour during non ramp hours. In the first three months of 2026, generating units supplied an average of 785.1 MW of regulation per half hour during ramp hours, 683.1 MW of regulation per half hour during shoulder hours, and 567.3 MW of regulation per half hour during non ramp hours.

Price

Table 10-49 shows the regulation price and regulation cost per MW for the first three months of 2009 through 2026. The weighted average RMCP for the first three months of 2026 was $148.22 per effective MW. This is an increase of $101.58 per effective MW, or 217.8 percent, from the weighted average RMCP of $46.64 per effective MW in the first three months of 2025. This increase in the regulation clearing price was the result of the increase in the opportunity cost component of RMCP and the price increase associated with the new market design starting on October 1, 2025.

Table 10-49 Comparison of average price and cost for regulation: January through March, 2009 through 2026

Year (Jan-Mar)	Weighted Regulation Market Price	Weighted Regulation Market Cost	Regulation Price as Percent of Cost
2009	$22.25	$34.06	65.3%
2010	$17.97	$31.24	57.5%
2011	$11.52	$25.03	46.0%
2012	$12.62	$16.75	75.3%
2013	$33.91	$39.36	86.2%
2014	$92.97	$112.30	82.8%
2015	$47.91	$58.23	82.3%
2016	$15.55	$17.92	86.8%
2017	$13.89	$18.47	75.2%
2018	$40.33	$49.60	81.3%
2019	$14.05	$18.49	76.0%
2020	$10.99	$13.91	79.0%
2021	$17.18	$21.01	81.8%
2022	$45.24	$55.64	81.3%
2023	$17.83	$24.20	73.7%
2024	$28.00	$36.40	76.9%
2025	$46.64	$58.86	79.2%
2026	$148.22	$151.56	97.8%

The introduction of fast start pricing in the PJM energy market on September 1, 2021, had an effect on the regulation market LOC included in regulation offers and in the resulting clearing price for regulation. Table10-50 shows the effect of fast start pricing on the regulation market monthly capability component of price and the total regulation market clearing price from September 2021 through March 2026. In the first three months of 2026, fast start pricing increased the average regulation market clearing price by $81.72 (an increase of 122.9 percent), from $66.50 per effective MW to $148.22 per effective MW, compared to dispatch pricing. This resulted in an additional $116.0 million in regulation credits.

Table 10-50 Comparison of fast start and dispatch pricing: September 2021 through March 2026[123]

		Weighted Average Price ($/Perf. Adj. Actual MW)				
		Capability Clearing Price		Regulation Market Clearing Price		
Year	Month	Dispatch	Fast Start	Dispatch	Fast Start	Percent Fast Start Increase
2021	Sep	$27.22	$29.08	$28.55	$30.41	6.5%
	Oct	$35.64	$39.92	$37.12	$41.40	11.5%
	Nov	$50.56	$54.40	$52.43	$56.28	7.3%
	Dec	$25.62	$27.37	$27.05	$28.79	6.4%
2022	Jan	$68.25	$71.14	$69.68	$72.56	4.1%
	Feb	$31.14	$31.93	$32.76	$33.55	2.4%
	Mar	$23.91	$25.94	$25.70	$27.73	7.9%
	Apr	$45.07	$48.85	$47.49	$51.27	7.9%
	May	$38.09	$41.85	$39.84	$43.60	9.4%
	Jun	$47.26	$52.57	$49.17	$54.48	10.8%
	Jul	$47.40	$54.51	$48.92	$56.04	14.5%
	Aug	$57.43	$64.13	$59.17	$65.87	11.3%
	Sep	$46.17	$48.84	$48.07	$50.73	5.5%
	Oct	$33.38	$36.76	$35.33	$38.70	9.6%
	Nov	$21.29	$23.08	$22.42	$24.21	8.0%
	Dec	$115.65	$112.52	$116.94	$113.81	(2.7%)
Total		$48.66	$51.82	$50.37	$53.53	6.3%
2023	Jan	$16.61	$17.25	$17.58	$18.22	3.7%
	Feb	$15.12	$15.48	$16.29	$16.65	2.2%
	Mar	$17.11	$17.80	$17.89	$18.57	3.8%
	Apr	$21.51	$23.20	$22.60	$24.29	7.5%
	May	$22.75	$24.58	$24.31	$26.14	7.5%
	Jun	$19.77	$20.88	$21.27	$22.38	5.2%
	Jul	$21.45	$23.43	$22.56	$24.54	8.8%
	Aug	$20.10	$21.32	$21.17	$22.39	5.8%
	Sep	$22.34	$23.92	$23.49	$25.08	6.7%
	Oct	$28.11	$32.37	$29.25	$33.51	14.6%
	Nov	$18.48	$20.83	$18.95	$21.30	12.4%
	Dec	$16.78	$18.12	$17.81	$19.15	7.5%
Total		$20.01	$21.60	$21.10	$22.69	7.5%
2024	Jan	$35.33	$36.70	$36.91	$38.28	3.7%
	Feb	$17.72	$19.44	$18.70	$20.42	9.2%
	Mar	$20.05	$22.88	$21.21	$24.04	13.3%
	Apr	$20.36	$24.52	$20.75	$24.90	20.0%
	May	$32.60	$37.59	$33.66	$38.64	14.8%
	Jun	$27.57	$28.96	$28.29	$29.68	4.9%
	Jul	$37.03	$39.87	$38.51	$41.35	7.4%
	Aug	$29.85	$31.48	$30.56	$32.18	5.3%
	Sep	$25.66	$28.31	$27.36	$30.01	9.7%
	Oct	$33.33	$35.59	$34.27	$36.53	6.6%
	Nov	$25.68	$28.52	$26.60	$29.45	10.7%
	Dec	$31.90	$33.14	$33.45	$34.69	3.7%
Total		$28.29	$30.76	$29.39	$31.86	8.4%
2025	Jan	$57.21	$59.04	$60.17	$61.99	3.0%
	Feb	$34.73	$36.62	$36.51	$38.41	5.2%
	Mar	$31.37	$35.60	$33.70	$37.93	12.6%
	Apr	$26.33	$31.51	$26.84	$32.02	19.3%
	May	$26.44	$28.74	$27.61	$29.91	8.4%
	Jun	$56.45	$61.08	$57.81	$62.43	8.0%
	Jul	$37.82	$43.07	$39.31	$44.56	13.3%
	Aug	$26.10	$29.39	$27.48	$30.77	12.0%
	Sep	$36.70	$39.27	$38.49	$41.06	6.7%
	Oct	$50.79	$125.89	$52.82	$127.92	142.2%
	Nov	$33.23	$62.87	$33.69	$63.33	88.0%
	Dec	$37.65	$66.64	$38.26	$67.24	75.7%
Total		$40.44	$53.66	$41.46	$55.05	32.8%
2026	Jan	$85.24	$142.52	$86.35	$143.64	66.3%
	Feb	$75.01	$196.52	$75.46	$196.96	161.0%
	Mar	$37.26	$107.08	$37.39	$107.22	186.7%
Total		$65.93	$147.64	$66.50	$148.22	122.9%

123 The performance component of the regulation market clearing price is unaffected by fast start pricing.

Figure 10-36 shows the capability price, performance price, and the opportunity cost component for the PJM Regulation Market on an effective MW basis. The regulation clearing price is determined based on the marginal unit's total offer (RCP + RPP + PJM calculated LOC). Then the maximum performance offer price (RPP) of any of the cleared units is used to set the marginal performance clearing price for the purposes of settlements. The difference between the marginal total clearing price and the highest performance clearing price (RMPCP) is the marginal capability clearing price (RMCCP). The capability price presented here is equal to the clearing price, minus the maximum cleared performance offer price. This data is based on actual five minute interval operational data.

Figure 10-36 illustrates the components of the regulation market clearing price. Each section represents the contribution of the lost opportunity cost (green area), capability price (blue area), and performance price (orange area), to the total price. From this figure, it is clear that the lost opportunity cost is the largest component of the total clearing price. In the first three months of 2026, LOC accounted for 90.1 percent of the daily weighted average capability price, and 89.8 percent of the daily weighted average total clearing price.

Figure 10-36 Regulation market clearing price components (Dollars per effective MW): January through March, 2026

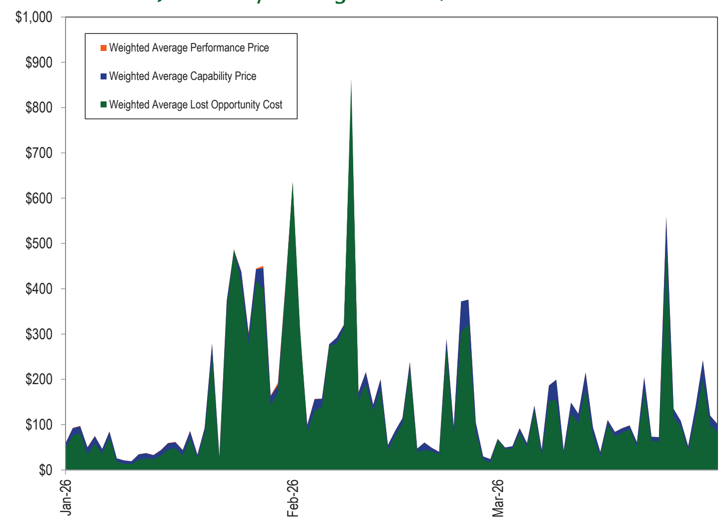


Table 10-51 shows the capability and performance components of the monthly average regulation prices. These components differ from the components of the marginal unit's offers in Figure 10-36 because the performance component of the settlement price for each hour is determined from the average of the highest performance offers in each five-minute interval, calculated independent of the marginal unit's offers in those intervals.

Table 10-51 Regulation market monthly component of price (Dollars per MW): January through March, 2026

Year	Month	Weighted Average Regulation Market Capability Clearing Price ($/Effective MW)	Weighted Average Regulation Market Performance Clearing Price ($/Effective MW)	Weighted Average Regulation Market Clearing Price ($/Effective MW)
2026	Jan	$142.52	$1.11	$143.64
	Feb	$196.52	$0.44	$196.96
	Mar	$107.08	$0.13	$107.22
Average		$147.64	$0.57	$148.22

Monthly and total scheduled regulation MW and regulation charges, as well as monthly average regulation price and regulation cost are shown in Table 10-52. Total scheduled regulation is based on settled effective MW. The total of all regulation charges in the first three months of 2026 was $217,491,353.

Table 10-52 Total regulation charges: January through March, 2026

Year	Month	Scheduled Regulation (Effective MW)	Total Regulation Charges ($)	Weighted Average Regulation Market Price ($/Effective MW)	Cost of Regulation ($/Effective MW)	Price as Percent of Cost
2026	Jan	501,730.2	$74,547,172	$143.64	$148.58	96.7%
	Feb	451,980.3	$90,476,677	$196.96	$200.18	98.4%
	Mar	481,303.7	$52,467,503	$107.22	$109.01	98.4%
Total		1,435,014.2	$217,491,353	$148.22	$151.56	97.8%

The capability, performance, and opportunity cost components of the cost of regulation are shown in Table10-53. Total scheduled regulation is based on settled effective MW. In the first three months of 2026, the average total cost of regulation was $151.56 per MW. In the first three months of 2026, the monthly average capability component cost of regulation was $147.43. In the first three months of 2026, the monthly average performance component cost of regulation was $0.78

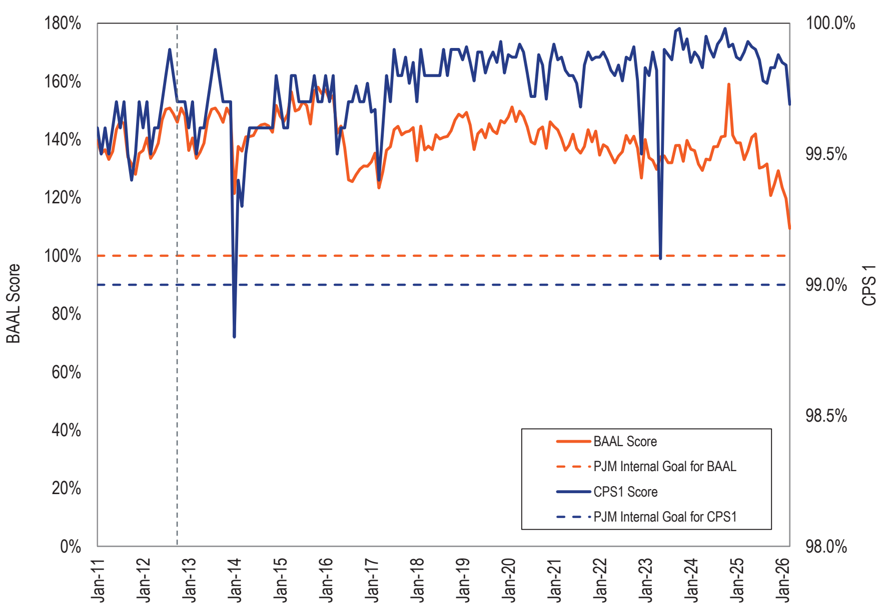
Table 10-53 Components of regulation cost: January through March, 2026

Year	Month	Scheduled Regulation (Effective MW)	Cost of Regulation Capability ($/Effective MW)	Cost of Regulation Performance ($/Effective MW)	Opportunity Cost ($/Effective MW)	Total Cost ($/Effective MW)
	Jan	501,730.2	$142.07	$1.57	$4.94	$148.58
	Feb	451,980.3	$196.36	$0.60	$3.22	$200.18
2026	Mar	481,303.7	$107.08	$0.14	$1.80	$109.01
Total		1,435,014.2	$147.43	$0.78	$3.34	$151.56

Performance Standards

PJM's performance as measured by CPS1 and BAAL standards is shown in Figure 10-37 for every month from January 2011 through March 2026 with the dashed vertical line marking the date (October 1, 2012) of the implementation of the Performance Based Regulation Market design.[124] The horizontal dashed lines represent PJM internal goals for CPS1 and BAAL performance.

Figure 10-37 Monthly CPS1 and BAAL performance: January 2011 through March 2026



124 See *2019 Annual State of the Market Report for PJM*, Appendix F: Ancillary Services.

Black Start Service

Black start service is required for the reliable restoration of the grid following a blackout. Black start service is the ability of a generating unit to start without an outside electrical supply, or the demonstrated ability of a generating unit to automatically remain operating at reduced levels when disconnected from the grid (automatic load rejection or ALR).[125]

PJM does not have a market to provide black start service, but compensates black start resource owners on the basis of cost of service rates defined in the tariff.[126] Currently, there are a small number of units in unique circumstances with bilateral agreements with their transmission operator (TO) to provide black start service that were entered into prior to joining PJM. These units are compensated directly by the TO. PJM has the ability to use a backstop black start service acquisition process under some circumstances that would result in shifting responsibility from PJM to the TOs.

PJM defines required black start capability zonally, while recognizing that the most effective way to provide black start service is a regional approach that recognizes cost effective ways to provide black start across transmission zonal boundaries.[127] PJM does not adequately use a regional or cross zonal approach to providing black start. Under the current rules PJM has substantial flexibility in procuring black start resources and is responsible for black start resource selection under most conditions.[128] But PJM's stated principles for system restoration are not fully incorporated in the rules in Schedule 6A. Costs should also be allocated on a regional basis to reflect the regional benefits of black start service.

The MMU recommends that black start planning and coordination be on a regional basis recognizing cross zonal cranking paths and not on a narrowly or purely zonal basis. The region as a whole benefits from black start service,

125 OATT Schedule 1 § 1.3BB.
126 See OATT Schedule 6A para. 18.
127 See Motion for Leave to Answer and Answer of PJM Interconnection, L.L.C to Comments, FERC Docket No. ER13-1911-000 (August 19, 2013) at 5 ("To be sure, restoration plans utilizing interconnecting Transmission Owners is not new and is currently included in all restoration plans today. Geographic or political boundaries play no role in the evaluation of the most reliable and efficient restoration strategies.").
128 See Docket No. ER13-1911-000.

regardless of the transmission zone in which it is located, and the costs of black start service should be shared equally across the region.

Fuel Assurance

Black start units must maintain enough fuel to allow for 16 hours of run time or for the minimum time required by the TO whichever is less. Generator operators must notify PJM and the TO when fuel levels fall below the required levels.[129] A black start unit must be able to start without an outside electrical supply or a unit with a high operating factor with demonstrated ability to automatically remain operating, at reduced levels, when disconnected to the grid.[130]

Fuel assured black start units have to meet the same requirements as black start units including maintaining enough onsite fuel and non-fuel consumables for three starts and 16 hours of full load operation, or operate on two or more interstate pipelines independently. Hybrid or intermittent resources must be able to provide 16 hours each day of full load with 90 percent confidence, although the 16 hours do not need to be continuous. Fuel assured black start units are required to provide annual certification that they met the minimum fuel and non-fuel consumables requirements. PJM may also request certification at any time. If a fuel assured black start unit's fuel or non-fuel consumables drop below their ability to run 16 hours at full load and three starts they must report to PJM within 24 hours. In any month a fuel assured black start unit fails to maintain the fuel and non-fuel consumables they will not receive black start revenues in that month unless it meets the exception rules.[131] Exceptions rules are for an approved outage and if levels go below 16 hours as the result of a PAI.[132] Black start units that are not fuel assured do not lose black start revenues if their fuel and or non-fuel consumables fall below a 16 hour run time and or cannot make three starts.

By order issued October 6, 2023, the FERC approved revisions to Schedule 6A defining fuel assurance for black start units, effective July 12, 2023.[133] The revisions were approved over the protest of the MMU, which identified significant flaws.[134] The planning criteria for fuel assured units and charges are applied on a zonal basis and not a regional basis, even though PJM is a regional transmission operator. The revisions to the tariff ignore the attributes of existing fuel assured units if they do not offer into the fuel assurance RFP. Intermittent resources are treated as if they are fuel assured. The X allocation factor for fuel assured hydro units is arbitrarily doubled from 0.01 to 0.02. The Z incentive factor for fuel assured units is arbitrarily doubled from 10 percent to 20 percent. For black start units in service prior to June 6, 2021, the rules apply CRF rates that ignore significant reductions in federal tax rates, including depreciation provisions, resulting in significant overpayments by PJM customers. The rules do not address environmental permits, which may limit the ability of units to provide black start service. The rules do not define the provision of black start service by DERs. The rules do not require testing units without notice to operators. The rules do not address the availability of natural gas and stored water levels. Reporting requirements for onsite fuel are not adequate. The reliability backstop improperly depends on TOs to secure black start service if PJM has two failed auctions.

The MMU recommends that the fuel assurance rules be modified to recognize actual fuel assured resources within and across zones.

Definition of Black Start Costs

In the November 8, 2024, MIC meeting PJM proposed to change the definition of Net CONE used in the Black Start Base Formula Rate (BFR) calculation.[135] The Base Formula Rate is a formula based cost of service rate and not a market based rate. The rationale was that Net CONE values based on a combined cycle reference resource defined for the capacity market could be negative at times. PJM did not retract its proposal even after PJM decided to use a combustion turbine as the reference resource rather than a combined cycle as the reference resource. That change eliminated PJM's identified issue with negative Net CONE values. The MMU presented historical information on payments under the BFR rate and argued that no change is needed to the Net

129 See "PJM Manual 36: Minimum Critical Black start Requirements," § A.1.2 (June 15, 2025).
130 *See* OATT Schedule 6A para. 2.
131 *See* OATT Schedule 6A para. 14.
132 See "PJM Manual 12: Balancing Operations," §4.5.10 Performance Standards Non-Performance §4.5.14, Rev. 56 (October 1, 2025).
133 See 85 FERC ¶ 91,000.
134 See Comments of the Independent Market Monitor for PJM, FERC Docket No. ER23-1874-000 (June 6, 2023) and Answer and Motion for Leave to Answer of the Independent Market Monitor for PJM, FERC Docket No. ER23-1874-000 (July 6, 2023).
135 See MIC, Problem Statement and Issues Charge, "Black Start Base Formula Rate," <https://www.pjm.com/-/media/DotCom/committees-groups/committees/mic/2024/20241108/20241108-item-03-1---black-start-base-formula-rate---problem-statement.pdf> and <https://www.pjm.com/-/media/DotCom/committees-groups/committees/mic/2024/20241108/20241108-item-03-2---black-start-base-formula-rate---issue-charge.pdf> (Nov. 8, 2024).

CONE calculation.[136] PJM filed its proposal with the Commission on April 30, 2025.[137] The MMU filed a protest, and, after a deficiency letter issued and PJM responded, filed additional comments.[138]

Ultimately PJM's argument was simply that the current tariff calculation would result in a short term decrease in black start payments under the Base Formula Rate which includes Net CONE, and PJM did not want the rate to decrease. PJM proposed to use average Net CONE for the entire RTO over the last five years as a fixed value subject to escalation. Both Gross CONE and the net revenue offset will be escalated using an inflation index. It is illogical to escalate net revenue because net revenue is a function of the dynamics of the energy market and the fuel markets. Given the current and expected high levels of Gross CONE compared to the five year average, PJM's proposal could actually reduce payments to these black start resources compared to the status quo. PJM did not address that possibility. PJM failed to explain why their proposal is a reasonable approach to compensating these resources for providing black start service. PJM provided no information about the actual costs of providing black start service. PJM provided no information about the actual mark up over costs currently paid to these black start resources. PJM's proposal does not approximate black start service costs and fails to even attempt to demonstrate any relationship to black start service costs. Under an approach that uses Net CONE, PJM does not justify using system wide Net CONE rather than locational Net CONE.

The MMU recommends that the black start rate under the Base Formula Rate should be based on the actual cost of providing the black start service, plus an incentive, rather than the unsupported use of Net CONE, escalated each year.

Black Start Backstop Acquisition Process

PJM Manual 14D defines a Black Start Reliability Backstop Process that is implemented in the event that PJM does not acquire enough black start resources through the RFP process. One option under this process is that one or more Transmission Owners can take responsibility for procuring the needed black start resources in their zones.

There can be up to four steps in the reliability backstop process. The first step is triggered by: a black start generation shortage or a failure to meet the fuel assurance criteria in a zone; and two failed RFPs; and no cross-zonal solutions available; and no RTEP transmission solutions available. In the second step, PJM, affected TOs, and affected state(s) will discuss the shortage, the costs, and the TO proposal. They will consider the impacts on the restoration plan and PJM will determine whether to issue a reliability backstop RFP. If a reliability backstop RFP is not issued, PJM will monitor the shortfall. If a reliability backstop RFP is issued then a third step will be taken. In the third step, an RFP will be issued by PJM to address the shortfall. The TO solution at this point will be made public excluding CEII information. The TO solution may be owned by the TO, generation owning affiliate or contracted for by the TO with a third party generation owner. The TO is obligated to provide a proposal. In the fourth step, PJM will evaluate the RFP responses and compare them to the TO solution(s). If the TO solution is the only option received then it will be implemented.[139]

The backstop process for black start service is flawed. PJM has units in zones which are fuel assured capable but are ignored if they do not bid into a fuel assured RFP. There is no reason to believe that TOs can procure black start more effectively than PJM. TOs should not own generation under cost of service regulation because it is inconsistent with competitive markets. PJM should continue its efforts until their goals are met. It is PJM's responsibility to manage black start capability.[140]

The MMU recommends that the reliability backstop for black start service be eliminated. There is no reason that PJM cannot acquire black start resources if the TOs can acquire black start resources.

136 See MIC, IMM Education, Black Start Costs and Net CONE <https://www.pjm.com/-/media/DotCom/committees-groups/committees/mic/2025/20250205/20250205-item-03-2---black-start-base-formula-rate---imm-solution.pdf> (February 5, 2025).
137 See PJM Filing, Docket No. ER25-2123-000.
138 See Comments of the Independent Market Monitor for PJM, FERC Docket No. ER25-2123-000 (May 21, 2025); Comments of the Independent Market Monitor for PJM, FERC Docket No. ER25-2123-000 (July 21, 2025).
139 See "PJM Manual 14D: Generator Operational Requirements," §10.3 Black Start Reliability Backstop Process, Rev. 69 (December 17, 2025).
140 See 144 FERC ¶ 61,191 (2013).

RFPs for Black Start Service

PJM requires a minimum of one fuel assured black start site in each zone or two non fuel assured black start sites connected to different pipelines per zone.[141] New or existing black start units that wish to be designated as fuel assured black start units must offer into the PJM fuel assured RFP.[142]

In order for a unit to be considered fuel assured, it must have one of five characteristics: onsite fuel; be capable of operating independently on two or more pipelines; be directly connected to a natural gas gathering system; hydro, non-hydro and intermittent resources must be capable of 16 hours of noncontinuous full load operation with 90 percent confidence. A zone also meets the fuel assurance requirement if the zone includes a minimum of two gas units connected to two separate natural gas pipelines.[143]

On April 7, 2021, PJM issued an incremental RFP for black start service in the BGE and PEPCO Zones. On November 1, 2021, PJM made awards for the April 7, 2021, incremental RFP. The in service date was May 2024. On August 1, 2022, PJM issued an incremental RFP for black start service in the PECO Zone. No awards were made.

On June 20, 2023, PJM issued an RTO wide request for proposals (RFP) in accordance with the five year black start selection process. The RFP was for black start service and fuel assured black start service. PJM awarded multiple existing black start units fuel assured black start service status in eight zones.

On April 29, 2024, PJM issued an incremental RFP for fuel assured black start service, because the 2023 RFP did not attract offers for fuel assured black start units in all zones. The April 29, 2024, RFP failed to result in acceptable offers in six zones.

Despite the fact that the April 29, 2024, auction process is not expected to be completed until the end of June 2026, PJM has started the reliability backstop process.

141 See "PJM Manual 36: System Restoration," §1.2 Minimum Critical Black Start Requirement, Rev. 35 (June. 15, 2025).
142 See "PJM Manual 14D: Generator Operational Requirements," §10.1 Black Start Selection Process, Rev. 69 (December 17, 2025).
143 See "PJM Manual 12: Balancing Operations," §4.5.7 Minimum Critical Black Start Unit and Fuel Assurance Black Start Unit Requirements, Rev. 55 (June. 18, 2025).

PJM has implemented the reliability backstop to secure fuel assured black start service in six zones. There are three zones where no units offered into the fuel assured RFP. In the six zones where a fuel assured reliability backstop process has started, PJM has units that meet the technical requirements to be fuel assured. The actual fuel assurance characteristics of these black start units were ignored because they did not offer into the fuel assured RFP.

The premature implementation of the reliability backstop process illustrates the inefficiency and excess cost to customers of ignoring the attributes of existing fuel assured units if they do not offer into the fuel assurance RFP. PJM has failed to consider whether existing black start resources meet the fuel assurance goals regardless of whether they applied for fuel assurance status.

Black Start Charges

Total black start charges are the sum of black start revenue requirement charges and black start uplift (operating reserve) charges.

Black start revenue requirements for black start units consist of fixed black start service costs, variable black start service costs, training costs, fuel storage costs, and an incentive factor applicable when CRF rates are not used. The tariff specifies how to calculate each component of the revenue requirement formula.[144]

Fixed black start service costs are calculated using one of three methods chosen by the black start provider from the options defined in the OATT Schedule 6A: base formula rate; capital cost recovery rate; or incremental black start NERC-CIP cost recovery. The base formula rate is Net CONE multiplied by the black start unit's capacity multiplied by the X factor. The X factor is 0.01 for hydro units and 0.02 for CT units. The capital recovery rate is the capital investment multiplied by the CRF rate. The incremental NERC-CIP cost, for existing black start resources that need to add additional capital to meet NERC-CIP requirements, is calculated using the capital cost recovery rate. Black start uplift charges are paid to units committed in real time to provide black start service or for black start testing.[145] Total black start charges

144 *See* OATT Schedule 6A para. 18.
145 There are no black start units currently using the ALR option.

are allocated monthly to PJM customers based on their zone and nonzone peak transmission use and point to point transmission reservations.[146]

No black start units have requested new or additional black start NERC – CIP Capital Costs.[147]

In the first three months of 2026, total black start charges were $11.4 million, a decrease of $4.8 million (29.4 percent) from 2025. In the first three months of 2026, total revenue requirement charges were $11.2 million, a decrease of $04.7 million (129.6 percent) from the first three months of 2025. In the first three months of 2026, total uplift charges were $0.21 million, a decrease of $0.04 million (14.9 percent) from 2025. Table10-54 shows total charges for January through March of each year from 2010 through 2026.[148]

Table 10-54 Black start revenue requirement charges: January through March, 2010 through 2026

Jan-Mar	Revenue Requirement Charges	Uplift Charges	Total
2010	$2,673,689	$0	$2,673,689
2011	$2,793,709	$0	$2,793,709
2012	$3,864,301	$0	$3,864,301
2013	$5,412,855	$22,210,646	$27,623,501
2014	$5,104,104	$7,561,533	$12,665,637
2015	$10,276,712	$4,699,965	$14,976,676
2016	$16,677,315	$57,082	$16,734,396
2017	$17,731,836	$63,384	$17,795,220
2018	$16,840,283	$23,309	$16,863,592
2019	$15,938,101	$36,188	$15,974,289
2020	$15,944,660	$40,587	$15,985,247
2021	$16,483,246	$86,695	$16,569,941
2022	$17,408,156	$125,306	$17,533,462
2023	$16,721,128	$143,876	$16,865,004
2024	$16,482,115	$185,047	$16,667,162
2025	$15,936,476	$252,214	$16,188,690
2026	$11,216,962	$214,735	$11,431,697

Black start zonal charges in the first three months of 2026 ranged from $0 in the OVEC and REC Zones to $2.2 million in the AEP Zone. For each zone, Table10-55 shows black start charges, zonal peak loads, and black start rates (calculated as charges per MW-day).[149] [150]

146 OATT Schedule 6A (paras. 25, 26 and 27 outline how charges are to be applied).
147 OATT Schedule 6A para. 21. "The Market Monitoring Unit shall include a Black Start Service summary in its annual State of the Market report which will set forth a descriptive summary of the new or additional Black Start NERC-CIP Capital costs requested by Black Start Units, and include a list of the types of capital costs requested and the overall cost of such capital improvements on an aggregate basis such that no data is attributable to an individual Black Start Unit."
148 Starting December 1, 2012, PJM defined a separate black start uplift category. ALR units accounted for the high uplift charges in 2013 – 2015. All ALR units had been replaced by April 2015.
149 See "PJM Manual 27: Open Access Transmission Tariff Accounting," § 7.3 Black Start Service Charges, Rev. 102 (Jan. 23, 2025).
150 For each zone and import export/wheels the black start rates ($/MW day) are calculated by taking total charges by zone and divided by peak load then divided by days in the period.

Table 10-55 Black start zonal charges: January through March, 2025 and 2026[151]

	Jan-Mar 2025					Jan-Mar 2026				
Zone	Revenue Requirement Charges	Uplift Charges	Total Charges	Peak Load (MW)	Black Start Rate ($/MW-day)	Revenue Requirement Charges	Uplift Charges	Total Charges	Peak Load (MW)	Black Start Rate ($/MW-day)
ACEC	$593,540	$0	$593,540	2,566	$2.57	$572,452	$0	$572,452	2,709	$2.35
AEP	$2,419,746	$1,595	$2,421,341	22,318	$1.21	$2,219,434	$0	$2,219,434	23,710	$1.04
APS	$1,384,337	$18,366	$1,402,703	8,938	$1.74	$697,878	$0	$697,878	9,792	$0.79
ATSI	$759,099	$9,162	$768,261	12,508	$0.68	$734,915	$9,154	$744,069	12,659	$0.65
BGE	$938,896	$8,803	$947,699	6,766	$1.56	$947,655	$0	$947,655	6,585	$1.60
COMED	$1,990,114	$35,796	$2,025,910	21,560	$1.04	$726,765	$0	$726,765	20,714	$0.39
DAY	$67,841	$48,313	$116,154	3,365	$0.38	$50,648	$21,945	$72,593	3,396	$0.24
DUKE	$97,989	$1,819	$99,807	5,171	$0.21	$101,810	$0	$101,810	5,190	$0.22
DUQ	$217,348	$1,272	$218,621	2,691	$0.90	$221,182	$0	$221,182	2,695	$0.91
DOM	$1,082,911	$91,595	$1,174,506	23,118	$0.56	$692,646	$169,966	$862,612	24,678	$0.39
DPL	$328,117	$0	$328,117	4,189	$0.87	$209,165	$0	$209,165	4,198	$0.55
EKPC	$85,764	$0	$85,764	3,748	$0.25	$89,415	$0	$89,415	3,757	$0.26
JCPLC	$148,880	$0	$148,880	6,184	$0.27	$117,860	$0	$117,860	6,273	$0.21
MEC	$106,215	$3,891	$110,106	3,067	$0.40	$88,617	$0	$88,617	3,000	$0.33
OVEC	$0	$0	$0	NA	NA	$0	$0	$0	NA	NA
PECO	$362,849	$976	$363,825	8,652	$0.47	$340,352	$425	$340,776	8,380	$0.45
PE	$976,682	$0	$976,682	2,953	$3.67	$246,470	$0	$246,470	2,909	$0.94
PEPCO	$1,744,125	$13,583	$1,757,708	6,162	$3.17	$1,836,737	$0	$1,836,737	6,016	$3.39
PPL	$1,069,522	$324	$1,069,846	7,460	$1.59	$395,286	$0	$395,286	8,057	$0.55
PSEG	$395,288	$0	$395,288	10,152	$0.43	$202,234	$0	$202,234	10,230	$0.22
REC	$0	$0	$0	NA	NA	$0	$0	$0	NA	NA
(Imp/Exp/Wheels)	$1,167,212	$16,720	$1,183,932	12,800	$1.03	$725,442	$13,245	$738,686	11,432	$0.72
Total	$15,936,476	$252,214	$16,188,690	174,365	$1.03	$11,216,962	$214,735	$11,431,697	176,378	$0.72

Table 10-56 provides a revenue requirement estimate by zone for the 2025/2026, 2026/2027, and 2027/2028 Delivery Years.[152] Revenue requirement values are rounded up to the nearest $50,000, reflecting the uncertainty about future black start revenue requirement costs. These values are illustrative only. The estimates are based on the best available data including current black start unit revenue requirements, expected black start unit termination and in service dates, changes in recovery rates, and owner provided cost estimates of incoming black start units at the time of publication and may change significantly. The estimates do not reflect the impact of FERC decisions that could affect compensation for black start.

151 Peak load for each zone is used to calculate the black start rate per MW day.
152 The System Restoration Strategy Task Force requested that the MMU provide estimated black start revenue requirements.

Table 10-56 Black start zonal revenue requirement estimate: 2025/2026 through 2027/2028 Delivery Years

Zone	2025 / 2026 Revenue Requirement	2026 / 2027 Revenue Requirement	2027 / 2028 Revenue Requirement
ACEC	$2,450,000	$2,500,000	$2,350,000
AEP	$9,200,000	$8,100,000	$8,250,000
APS	$2,750,000	$1,150,000	$1,200,000
ATSI	$3,250,000	$3,200,000	$3,200,000
BGE	$4,150,000	$4,150,000	$4,150,000
COMED	$3,000,000	$2,550,000	$2,650,000
DAY	$250,000	$250,000	$300,000
DUKE	$400,000	$500,000	$500,000
DUQ	$950,000	$400,000	$400,000
DOM	$3,050,000	$2,700,000	$2,800,000
DPL	$1,050,000	$1,050,000	$1,050,000
EKPC	$350,000	$400,000	$450,000
JCPLC	$600,000	$650,000	$700,000
MEC	$550,000	$600,000	$650,000
OVEC	$0	$0	$0
PECO	$1,450,000	$1,550,000	$1,600,000
PE	$1,000,000	$1,150,000	$1,200,000
PEPCO	$7,850,000	$7,900,000	$7,900,000
PPL	$1,550,000	$1,600,000	$1,650,000
PSEG	$850,000	$900,000	$950,000
REC	$0	$0	$0
Total	$44,700,000	$41,300,000	$41,950,000

CRF Issues

The capital recovery factor (CRF) defines the revenue requirement of black start units when new equipment is added to provide black start capability.[153] The CRF is a rate, which when multiplied by the investment, provides for a return on and of capital over a defined time period. CRFs are calculated using a formula (or a correctly defined standard financial model) that accounts for the weighted average cost of capital and its components, plus depreciation and taxes. The PJM CRF table was created in 2007 as part of the new RPM capacity market design.[154] That CRF table provided for the accelerated return of incremental investment in capacity resources based on concerns about the fact that some old coal units would be making substantial investments related to pollution control. The CRF values were later added to the black start rules.[155]

The CRF table for existing black start units includes the column header, term of black start commitment, which is misleading and incorrect. The column is simply the cost recovery period. Accelerated recovery reduces risk to black start units and should not be the basis for a shorter commitment. Full payment of all costs of black start investment on an accelerated basis should not be a reason for a shortened commitment period. Regardless of the recovery period, payment of the full costs of the black start investment should require commitment for the life of the unit.[156] In addition, there is no need for such short recovery periods for black start investment costs. Two periods, based on unit age, are more than adequate.

The values in the original CRF tariff tables, in Schedule 6A and Attachment DD § 6.8(a), were based on 2007 income tax rates and depreciation rules. The U.S. Internal Revenue Code changed significantly in December 2017 with updates to the corporate income tax rate and depreciation rules.[157] [158] The PJM CRF table did not change to reflect these changes.[159] [160] The PJM CRF tables in the tariff should have been updated immediately to reflect the change in the tax laws. As a result, CRF values have overcompensated black start units since the 2017 changes to the tax code. On April 7, 2021, PJM filed with FERC to update the CRF values for new black start service units.[161] PJM proposed to bifurcate the CRF calculation, applying an updated CRF calculation that incorporates the new federal tax law to new black start units while leaving the outdated and incorrect CRF in place for existing black start units. Rather than fix the inaccurate CRF values used for existing black start units, PJM's filing would have made the use of inaccurate values permanent. The MMU filed comments

153 *See* OATT Schedule 6A para. 18.
154 See OATT Attachment DD § 6.8(a).
155 See OATT Schedule 6A.
156 PJM's recent filing to revise Schedule 6A includes a required commitment to provide black start service for the life of the unit. See FERC Docket No. ER21-1635.
157 Tax Cuts and Jobs Act, Pub. L. No. 115-97, 131 Stat. 2096, Stat. 2105 (2017).
158 26 U.S. Code §11(b).
159 The corporate tax rate was lowered to 21 percent and bonus depreciation, which allows generator owners to depreciate 100 percent of the capital investment in the first year of operation, was introduced.
160 Bonus depreciation is 100 percent for capital investments placed in service after September 27, 2017, and before January 1, 2023. Bonus depreciation is 80 percent for capital investments placed in service after December 31, 2022, and before January 1, 2024, and the bonus depreciation level is reduced by 20 percent for each subsequent year through 2026. Capital investments placed in service after December 31, 2026, are not eligible for bonus depreciation. See 26 U.S. Code §168(k)(6)(A).
161 *See* Docket No. ER21-1635-000.

on April 28, 2021.[162] The MMU objected to the continued use of the outdated CRF for existing units. The MMU also introduced a CRF formula for calculating the CRF for new black start units and requested that the CRF formula be included in the tariff.[163] [164] On August 10, 2021, FERC issued an order ("August 10th Order") that accepted PJM's tariff revisions that apply to new black start units (selected for service after June 6, 2021) and directed PJM to include the CRF formula proposed by the MMU.[165] The August 10th Order also established a show cause proceeding in a new docket to "determine whether the existing rates for generating units providing Black Start Service (Black Start Units), which are based on a federal corporate income tax that pre-dates the Tax Cuts and Jobs Act of 2017 (TCJA), remains just and reasonable."[166] The MMU requested rehearing over the Commission's conclusion that the MMU had requested "retroactive changes to the rates previously paid to generators."[167] [168] The request for rehearing was denied.[169] PJM's compliance filing to address the August 10 Order was accepted by letter order, subject to edits proposed by the MMU, on December 16, 2021.[170]

PJM's response to the show cause directive in the August 10th Order continued to support the use of the outdated CRF despite the Commission's statement that the CRF values "appear to be unjust, unreasonable, unduly discriminatory or preferential, or otherwise unlawful."[171] [172] The MMU responded with analysis showing that PJM's proposal for maintaining the outdated CRF values would result in significant over recovery of black start capital investments.[173] In March 2023, FERC issued an order establishing hearing and settlement judge procedures.[174] Settlement talks continued and in January 2024 Commission Trial Staff moved to suspend the proceeding because a settlement had been reached in principle.[175] The MMU filed comments in opposition to the settlement, and the settlement was not certified to the Commission.[176] [177] The hearing process then resumed, but rather than hold a hearing, PJM, with the support of FERC Staff, submitted a second offer of settlement on behalf of itself and certain black start unit owners, AMP, ODEC and the PJM ICC. The settlement included exactly the same values as the first settlement, but also included affidavits. By order issued September 23, 2025, the Commission approved the second offer of settlement over the MMU's objection.[178] Forty-nine black start generators received payments based on the outdated CRF. All but eight of the 49 generators have completed their black start capital cost recovery terms.

The November 15, 2024, settlement reduced the capital recovery payments for 38 black start generators. Table10-57 shows the new CRF values from the settlement. The settlement CRF values became effective on January 1, 2024.

Table 10-57 Settlement CRF Values

Capital Recovery Period (years)	Original CRF Value	November 2024 Settlement CRF Value
5	0.363	0.310
10	0.198	0.177
15	0.146	0.135
20	0.125	0.118

There is no financial basis for the settlement CRF values and the settlement will result in significant over recovery for the owners of the black start generators. The settlement reduced the excess recovery payments from $89.7 million to $74.1 million. FERC never made a determination in the show cause proceeding (EL21-91) regarding the "just and reasonableness" of continuing to pay the existing resources at an outdated CRF based on an income tax rate that is no longer in effect. This question remains outstanding today and a similar over or under recovery issue will arise if there is a significant change in a state or federal income tax rate.

162 See Comments of the Independent Market Monitor for PJM, FERC Docket No. ER21-1635-000 (April 28, 2021).
163 See Answer and Motion for Leave to Answer of the independent Market Monitor for PJM, ER21-1635 (May 20, 2021).
164 See Comments of the Independent Market Monitor for PJM, FERC Docket No. ER21-1635 (July 2, 2021).
165 See 176 FERC ¶ 61,080 at 42 and 44 (2021).
166 176 FERC ¶ 61,080 at 2 (2021).
167 *Id.* at 50.
168 Request for Rehearing of the Independent Market Monitor for PJM, FERC Docket No. ER21-1635 (September 9, 2021).
169 See 177 FERC ¶ 62,017 (2021).
170 See 177 FERC ¶ 61,202 (2021).
171 *PJM Interconnection, L.L.C., Response to Commission's Show Cause Order*, Docket No. EL21-91 (October 12, 2021).
172 August 10th Order at 47.
173 Errata Filing of the Independent Market Monitor for PJM, Attachment B at 17, Docket No. EL21-91 (November 18, 2022).
174 See 182 FERC ¶ 61,194.
175 Motion of Commission Trial Staff to Suspend Procedural Schedule and Shorten Answer Period, Docket No. EL21-91-003 (January 10, 2024).
176 Comments of the Independent Market Monitor for PJM in Opposition to Offer of Settlement, Docket No. EL21-91-000, -003 (February 20, 2024).
177 186 FERC ¶ 63,019 (2024).
178 See 193 FERC ¶ 61,059.

On July 4, 2025, with the enactment of the One Big Beautiful Bill Act ("OBBBA"),[179] 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.[180] QPP means nonresidential real property used in manufacturing, production, or refining of tangible personal property in the United States.[181] 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.[182]

The CRF value, once it has been assigned to a generator, should not be updated unless there is a significant change in the state or federal income tax rate.[183] PJM currently updates the CRF for generators that have already begun receiving capital recovery payments anytime the debt rate changes. This is not correct. The debt rate reflects the market conditions during the year the investment is placed into service. A change in the debt rate in a subsequent year is not relevant to the capital cost recovery, and will lead to an over or under recovery. This is not how the MMU intended for the CRF formula to be utilized. This is another negative consequence of the show cause procedure (EL21-91) being passed to hearing and settlement without resolution. A process needs to be included in Schedule 6A that specifies how and when to update the CRF value for a generator that has already been assigned a CRF and begun capital cost recovery. The formula and parameter values currently in Schedule 6A are for determining the initial capital recovery payment. To correctly update a CRF for a generator that is already receiving capital recovery payments, the outstanding capital investment must be determined and a new CRF calculated based on the updated parameter values and the years remaining in the capital recovery period.

179 Also known as the 2025 Reconciliation Bill and Public Law 119-21.
180 OBBBA § 70301(c)(1).
181 OBBBA § 70307(a)(2).
182 *Id.*
183 Because PJM rounds CRF to 3 digits, a "significant change" is one that changes the CRF by ± 0.001.

Reactive Service and Capability

Under Schedule 2 to the OATT, suppliers of reactive power have been compensated separately for both reactive service and reactive capability.[184] [185] [186] [187]

On October 17, 2024, the Commission issued a final rule, Order No. 904, eliminating separate payments for reactive in all jurisdictional markets, including PJM.[188] On January 28, 2025, PJM submitted a compliance filing to implement Order No. 904 ("Compliance Filing").[189] The Compliance Filing proposed a transition mechanism lasting through May 31, 2026. On August 4, 2025, the Commission accepted PJM's termination of separate Schedule 2 payments after May 31, 2026, but rejected PJM's proposed transition mechanism and the MMU's proposed enhancements to that mechanism.[190] The current rules apply until payments under Schedule 2 terminate.

Reactive Costs

Customers in PJM paid total reactive capability charges of $85.6 million in the first three months of 2026. Under the current rules, effective through May 31, 2026, compensation for reactive capability is approved separately for each resource or resource group by FERC per Schedule 2 of the OATT.[191] Reactive capability credits are based on FERC approved filings for individual unit revenue requirements that are typically black box settlements.[192] Reactive service credits are paid to units that operate in real time outside of their normal range at the direction of PJM for the purpose of providing reactive

184 See Monitoring Analytics, LLC, *2024 Quarterly State of the Market Report for PJM: January through September* (November 14, 2024) at 652–656, for history and analysis of reactive power in PJM.
185 See Order No. 2003, 104 FERC ¶ 61,103 at P 544 (2003), *order on reh'g*, Order No. 2003-A, 106 FERC ¶ 61,220 at P 28, *order on reh'g*, Order No. 2003-B, 109 FERC ¶ 61,287 (2004), *order on reh'g*, Order No. 2003-C, 111 FERC ¶ 61,401 (2005), *aff'd sub nom. National Association of Regulatory Utility Commissioners v. FERC*, 475 F.3d 1277 (D.C. Cir. 2007); *CAISO*, 160 FERC ¶ 61,035 at P 19 (2017); *SPP*, 119 FERC ¶ 61,199 at P 28 (2007), *order on reh'g*, 121 FERC ¶ 61,196 (2007); *see also* 178 FERC ¶ 61,088, at PP 29–31 (2022); 179 FERC ¶ 61,103, at PP 20–21 (2022).
186 See OATT Attachment O.
187 See *MISO*, 182 FERC ¶ 61,033 at P 52 (January 27, 2023) (*MISO*); *see also Standardization of Generator Interconnection Agreements & Procedures*, Order No. 2003, 104 FERC ¶ 61,103 at P 546.
188 See *Compensation for Reactive Power within the Standard Power Factor Range*, Order No. 904, 189 FERC ¶ 61,034 ("Order No. 904").
189 See Docket No. ER25-1073.
190 See 192 FERC ¶ 61,113; see also, Comments of the Independent Market Monitor for PJM, Docket No. ER25-1073 (February 18, 2025).
191 See "PJM Manual 27: Open Access Transmission Tariff Accounting," § 3.2 Reactive Supply and Voltage Control Credits, Rev. 102 (Jan. 23, 2025); 192 FERC ¶ 61,113 (2025).
192 See OATT Schedule 2.

service. Compensation for reactive power service is based on real-time lost opportunity costs.[193]

Total reactive capability charges are the sum of FERC approved reactive supply revenue requirements. Zonal reactive supply revenue requirement charges are allocated monthly to PJM customers based on their zonal and to any nonzonal (outside of PJM) peak transmission use and daily average point to point transmission reservations.[194] [195]

In the first three months of 2026, total reactive charges were $85.7 million, a decrease of $6.5 million (7.1 percent) from the first three months of 2025. In the first three months of 2026, total reactive capability charges were $85.6 million, a decrease of $6.1 million (6.7 percent) from the first three months of 2025. In the first three months of 2026, total reactive service charges were $0.1 million, a decrease of $0.4 million (77.0 percent) from the first three months of 2025. Total zonal reactive service charges ranged from $0 in the REC and OVEC Zones, to $13.8 million in the AEP Zone in the first three months of 2025.

Table 10-58 shows reactive service charges for January through March of each year from 2010 through 2026.

Table 10-58 Reactive service charges and reactive capability charges: January through March, 2010 through 2025

Jan-Mar	Reactive Service Charges	Reactive Capability Charges	Total
2010	$1,462,979	$60,140,250	$61,603,229
2011	$7,901,985	$61,525,380	$69,427,366
2012	$22,774,605	$68,171,375	$90,945,980
2013	$55,579,356	$68,330,702	$123,910,058
2014	$7,589,161	$70,631,766	$78,220,927
2015	$6,330,318	$69,482,495	$75,812,813
2016	$250,496	$72,742,919	$72,993,415
2017	$5,872,960	$75,383,924	$81,256,884
2018	$6,054,364	$74,884,662	$80,939,026
2019	$124,821	$80,560,451	$80,685,272
2020	$45,745	$85,354,846	$85,400,591
2021	$705,618	$89,123,265	$89,828,883
2022	$231,202	$95,355,371	$95,586,572
2023	$0	$95,904,368	$95,904,368
2024	$892,690	$94,627,077	$95,519,767
2025	$522,553	$91,656,198	$92,178,751
2026	$119,852	$85,551,307	$85,671,159

Table 10-59 shows zonal reactive service charges, reactive capability charges and total charges for the first three months of 2025 and 2026. Reactive service charges show charges to each zone for reactive service. Reactive capability charges show charges to each zone for reactive capability.

193 See OA Schedule 1 § 3.2.3B.
194 OATT Schedule 2.
195 See "PJM Manual 27: Open Access Transmission Tariff Accounting," § 3.3 Reactive Supply and Voltage Control Charges, Rev. 102 (Jan. 23, 2025).

Table 10-59 Reactive service charges and reactive capability charges by zone: January through March, 2025 and 2026

	Jan-Mar 2025			Jan-Mar 2026		
Zone	Reactive Service Charges	Reactive Capability Charges	Total Charges	Reactive Service Charges	Reactive Capability Charges	Total Charges
ACEC	$0	$448,441	$448,441	$0	$359,085	$359,085
AEP	$0	$14,289,629	$14,289,629	$0	$13,796,417	$13,796,417
APS	$6,825	$4,971,593	$4,978,418	$0	$4,421,221	$4,421,221
ATSI	$0	$6,256,994	$6,256,994	$0	$5,882,823	$5,882,823
BGE	$0	$1,616,939	$1,616,939	$0	$855,315	$855,315
COMED	$0	$12,108,885	$12,108,885	$71,282	$11,351,515	$11,422,797
DAY	$0	$685,731	$685,731	$0	$668,927	$668,927
DUKE	$0	$1,948,686	$1,948,686	$0	$1,723,691	$1,723,691
DOM	$0	$11,326,226	$11,326,226	$0	$10,489,103	$10,489,103
DPL	$505,276	$2,369,747	$2,875,023	$45,133	$2,361,144	$2,406,278
DUQ	$0	$19,734	$19,734	$0	$19,914	$19,914
EKPC	$0	$530,918	$530,918	$0	$535,758	$535,758
JCPLC	$0	$1,332,739	$1,332,739	$0	$1,344,890	$1,344,890
MEC	$5,204	$1,420,616	$1,425,819	$0	$1,090,345	$1,090,345
OVEC	$0	$0	$0	$0	$0	$0
PECO	$0	$5,014,629	$5,014,629	$0	$5,001,619	$5,001,619
PE	$0	$3,060,796	$3,060,796	$0	$3,021,319	$3,021,319
PEPCO	$5,249	$2,006,980	$2,012,229	$0	$2,025,277	$2,025,277
PPL	$0	$8,718,893	$8,718,893	$3,436	$8,211,121	$8,214,558
PSEG	$0	$6,565,087	$6,565,087	$0	$6,616,234	$6,616,234
REC	$0	$0	$0	$0	$0	$0
(Imp/Exp/Wheels)	$0	$6,962,935	$6,962,935	$0	$5,775,589	$5,775,589
Total	$522,553	$91,656,198	$92,178,751	$119,852	$85,551,307	$85,671,159

Table 10-60 shows the units which received reactive service credits in the first three months of 2026.

Table 10-60 Reactive service credits by plant (Total dollars): January through March, 2026

	Jan-Mar 2026	
Zone	Plant	Reactive Service Credits
COMED	COM 11 FISK 32 CT	$71,282
DPL	DPL COMM CHESAPEAKE - NEW CHURCH 3 CT	$45,133
PPL	PL HAZELTON 2 CT	$1,194
PPL	PL HAZELTON 3 CT	$1,157
PPL	PL HAZELTON 4 CT	$1,085

Table 10-61 shows the settled reactive capability revenue requirements by technology effective on March 1, 2026, for active units.[196] These revenue requirements do not include revenue requirements that were filed but not yet final. The table demonstrates the wide disparity in payments for reactive capability that result from the current cost of service rate case model settlement process.

196 The total amount in the final row of Table10-24 is the amount that would be paid if the total rate effective on March 1, 2026, were effective for an entire year. The total rates effective on any given day depend on requests made by resource owners in filings to FERC and FERC approval of those rates.

Table 10-61 Total settled reactive revenue requirements by unit type and fuel type for active units[197]: March 1, 2026

Unit Type	Fuel Type	Total Revenue Requirement per Year	MW	Number of Resources	Revenue Requirement per MW-year	Minimum Revenue Requirement per MW-year	Maximum Revenue Requirement per MW-year
CC	Gas	$122,213,638.36	48,906.6	152	$371,800.95	$302.10	$22,500.00
CT	Gas	$44,998,557.53	27,734.0	245	$531,994.39	$103.64	$19,610.84
CT	Oil	$4,034,823.25	2,714.9	98	$143,701.18	$289.74	$4,052.58
Diesel	Oil	$839,703.17	145.3	31	$183,630.75	$395.37	$8,812.75
Diesel	Other - Gas	$1,117,240.13	102.6	12	$118,519.87	$3,984.09	$13,468.38
FC	Gas	$45,000.00	2.3	1	$19,565.22	$19,565.22	$19,565.22
Hydro	Water	$24,401,850.45	6,676.3	53	$254,134.36	$126.37	$23,996.44
Nuclear	Nuclear	$68,243,063.20	32,530.9	31	$75,841.24	$807.91	$7,140.45
Solar	Solar	$4,572,620.48	1,466.9	13	$77,386.09	$705.15	$15,007.81
Steam	Coal	$45,956,273.10	34,811.2	56	$128,165.58	$255.85	$9,804.78
Steam	Gas	$5,801,349.66	5,725.3	17	$19,869.70	$626.53	$3,737.86
Steam	Oil	$2,486,051.94	1,499.3	6	$10,944.78	$1,262.01	$3,211.11
Steam	Other - Solid	$340,000.00	34.0	2	$18,919.11	$8,311.11	$10,608.00
Steam	Wood	$330,830.32	153.0	3	$6,486.87	$2,162.29	$2,162.29
Wind	Wind	$17,987,594.17	4,877.4	38	$154,123.83	$1,860.80	$9,564.74
All		$343,368,595.75	167,380.0	758	$2,051.43	$103.64	$23,996.44

Frequency Control

There are four distinct types of frequency control, distinguished by response timeframe and operational nature: Inertial Response, Primary Frequency Response, Secondary Frequency Control (Regulation), and Tertiary Frequency Control (Primary Reserve).

- **Inertial Response.** Inertial response to frequency excursion is the natural resistance of rotating mass turbine generators to changes in their stored kinetic energy. This response is immediate and resists short term changes to ACE from the instant of the disturbance up to twenty seconds after the disturbance.
- **Primary Frequency Response.** Primary frequency response is a response to a disturbance based on a local detection of frequency and local operational control settings. Primary frequency response begins within a few seconds and extends up to a minute. The purpose of primary frequency response is to arrest and stabilize the system until other measures (secondary and tertiary frequency response) become active.
- **Secondary Frequency Control.** Secondary frequency control is called regulation. In PJM it begins to respond within 10 to 15 seconds and can continue up to an hour. Regulation is controlled by PJM which detects the grid frequency, calculates a counterbalancing signal, and transmits that signal to all regulating resources.
- **Tertiary Frequency Control.** Tertiary frequency control and imbalance control lasting 10 minutes to an hour is called primary reserve.

197 For aggregate requirements, in which a single payment is made for the combined output of multiple units, the aggregate requirement was distributed in proportion to unit size for calculating a resource's individual revenue requirement. For wind, solar, and hydro resources, that size is the ELCC. For all other resources, that size is the ICAP.

Primary Frequency Response

Primary Frequency Response ("PFR") is achieved through the use of automatic governors installed on generators. A governor can be either an electronic or mechanical device that increases or decreases a generator's output based on frequency changes in the system. Governors are set to respond to any frequency changes larger than a defined minimum, called a deadband, which is expressed in Hertz (Hz). Governors have a frequency change limit, called droop, which is expressed as a percentage of the frequency change from the optimal 60 Hz (e.g. 2 percent droop equals 0.02 * 60 Hz, or 1.2 Hz). Governor droop changes resource output in proportion to the deviation of frequency once frequency has exceeded the deadband limit. Primary frequency response alone does not restore frequency to the original scheduled value primarily because governor directed changes only occur when frequency is beyond the governor deadband.

On February 15, 2018, the Commission issued Order No. 842, which modified the pro forma large and small generator interconnection agreements and procedures to require all newly interconnecting non nuclear generating facilities, both synchronous and nonsynchronous, to include equipment for primary frequency response capability as a condition to receive interconnection service. Such equipment must include a governor or equivalent controls with the capability of operating at a maximum five percent droop and ±0.036 Hz deadband (or the equivalent or better).[198] PJM filed revisions in compliance with Order No. 842 that substantively incorporated the pro forma agreements into its market rules.[199]

PJM evaluates generators' primary frequency capabilities using two to three frequency events per month, with events being chosen based on the criteria that the frequency stays outside ±0.040 Hz deadband for at least one minute, and the minimum/maximum frequency reaches ±0.053 Hz. Nuclear units, offline units, units with no available headroom/footroom, units assigned regulation, and units with an active eDART ticket for governor outage are not evaluated. The performance of each unit is evaluated, with each event evaluated separately with a responsive/non-responsive pass/fail determination, and then averaged quarterly. A quarterly unit performance of 50 percent or greater is considered responsive.[200]

There are several current issues with PJM's enforcement and evaluation of generations PFR requirements. Despite the 2018 FERC order, PJM has not maintained an accurate, up to date list of all units subject to evaluation. This means that as new units have come online (since approximately 2020), they are not being tested at all during the monthly frequency events. In addition, PJM does not currently have an objective metric to determine what response constitutes a unit passing a test during these frequency events. Instead, the telemetric response of each unit is compared to the frequency conditions during an event, and a judgement is made as to whether or not the unit has adequately responded. Further, this underlying unit data and results of these primary frequency response events are not saved in PJM's databases, so the MMU is not currently able to verify the results of these tests. In the event of a unit's noncompliance, PJM does not have a defined penalty and remediation process.

The MMU recommends that PJM update and maintain a full list of generation resources required to provide PFR, save all of the results and underlying data associated with testing PFR capabilities, develop the metric(s) necessary to objectively evaluate each unit's PFR during events, and create the necessary tariff/manual language to properly enforce the NERC mandated requirements.

The MMU is working with PJM to update PJM's list of units that are subject to evaluation and to develop a set of metrics for monitoring compliance and measuring performance by units subject to Order No. 842.

The MMU recommends that the same capability be required of both new and existing resources. The MMU agrees with Order No. 842 that RTOs not be required to provide additional compensation specifically for frequency response. The current PJM market design provides the ability to cover all costs, including these. The current market design provides compensation, through heat rate adjusted energy offers, for any costs associated with providing

198 See 157 FERC ¶ 61,122 (2016).
199 See 164 FERC ¶ 61,224 (2018).
200 See PJM Manual 12: Balancing Operations, § 3.6.2. Rev. 56 (October 1, 2025).

frequency response. PJM rules appropriately require frequency response as a condition to receive interconnection service.[201]

On August 15, 2024, NERC proposed Project 2020-02, a modification to the PRC-029-1 reliability standard, called, “The frequency and voltage ride through requirement for inverter based generating resources (“IBRs”).” This proposed standard is intended to address the risk to reliability associated with the rapid adoption of IBRs, by requiring that Category 2 Generator Owner and Generator Operator (“Category 2 GO/GOP”) IBRs remain operational during and after defined frequency and voltage excursions.[202] [203] To achieve this, IBRs must continue to deliver predisturbance levels of active and reactive power, and would only be permitted to trip to avoid equipment damage. This proposal was adopted by the NERC board on October 8, 2024.[204] NERC is currently working with the regional entities to register IBRs, with an effective registration date of May 15, 2026.[205] PJM has identified and submitted to NERC a list of 50 units that meet the criteria for Category 2 GO/GOP IBRs.

201 See 164 FERC ¶ 61,224 at P 2 (2018).
202 “Category 2 GO/GOP,” is defined as Generator Owners and Generator Operators that, “...own or operate IBRs that: (i) either have or contribute to an aggregate nameplate capacity of greater than or equal to 20 MVA, and (ii) are connected through a system designed primarily for delivering such capacity to a common point of connection at a voltage greater than or equal to 60 kV.” See NERC, “North American Electric Reliability Corporation Inverter-Based Resources Work Plan Progress Update,” <https://www.nerc.com/FilingsOrders/us/NERC Filings to FERC DL/IBR Work Plan Filing_May Update_signed.pdf> (Accessed November 7, 2025)
203 See NERC, “PRC-029-1,” <https://www.nerc.com> (Accessed November 6, 2024).
204 See NERC, “Project 2020-02 Modifications to PRC-024 (Generator Ride-through),” <https://www.nerc.com/pa/Stand/Pages/Project_2020-02_Transmission-connected_Resources.aspx> (Accessed August 7, 2025).
205 See NERC, “North American Electric Reliability Corporation Inverter-Based Resources Work Plan Progress Update,” <https://www.nerc.com/FilingsOrders/us/NERC Filings to FERC DL/IBR Work Plan Filing_October 2025 Update_signed.pdf> (Accessed October 31, 2025).