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 nine months of 2024.

Table 10-1 The synchronized reserve market results were competitive

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

- The synchronized reserve market structure was evaluated as not competitive due to moderate levels of supplier concentration in the MAD Reserve Subzone.
- 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 competitive because the interaction of participant behavior with the market design results in competitive prices. In an attempt to counter poor synchronized reserve performance, PJM unilaterally and inappropriately extended the first step of the operating reserve demand curve (ORDC) for synchronized reserve, known as the synchronized reserve reliability requirement, in May 2023.
- Market design was evaluated as effective. PJM 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. PJM has planned reforms to improve reserve deployment speed.

The MMU analyzed measures of market structure, conduct and performance for the PJM Nonsynchronized Reserve Market for the first nine months of 2024.

Table 10-2 The nonsynchronized reserve market results were competitive

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

- The nonsynchronized reserve market structure was evaluated as not competitive due to moderate levels of supplier concentration for primary reserve in the MAD Reserve Subzone.
- Participant behavior was evaluated as competitive because all available reserves are included by the PJM markets software, so withholding is not possible.
- Market performance was evaluated as competitive because the interaction of participant behavior with the market design results in competitive prices.
- Market design was evaluated as effective.

1 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.

The MMU analyzed measures of market structure, conduct and performance for the PJM Secondary Reserve Market for first nine months of 2024.

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, because the supply of 30-minute reserves was not concentrated in the real-time market. The secondary reserve market was moderately concentrated in the day-ahead 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 nine months of 2024.

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 95.4 percent of the hours in the first nine months of 2024.
- Participant behavior in the PJM Regulation Market was evaluated as competitive in the first nine months of 2024 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 market design has failed to correctly incorporate a consistent implementation of the marginal benefit factor in optimization, pricing and settlement. The market results continue to include the incorrect definition of opportunity cost. The result is significantly flawed market signals to existing and prospective suppliers of regulation.

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 resource performance, PJM increased the synchronized reserve reliability requirement, which in turn increased the primary reserve reliability requirement.

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 nine months of 2024, the real-time average primary reserve requirement was 3,502.8 MW in the RTO Reserve Zone and 2,577.1 MW in the Mid-Atlantic Dominion Reserve Subzone.
- **Market Concentration.** Both the Mid-Atlantic Dominion (MAD) Reserve Subzone Market and the RTO Reserve Zone Market for primary reserve were characterized by structural market power in the first nine months of 2024. The average HHI for real-time primary reserve in the RTO Reserve Zone was 919, which is classified as unconcentrated. The average HHI for day-ahead primary reserve in the RTO Zone was 979, which is classified as unconcentrated. The average HHI for real-time primary reserve in the MAD Reserve Subzone was 1607, which is classified as moderately concentrated. The average HHI for day-ahead primary reserve in the MAD Reserve Subzone was 1572, which is classified as moderately concentrated.

Synchronized Reserve Market

Synchronized reserves include all capacity synchronized to the grid and available to satisfy PJM's power balance requirements 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 full 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 based on a loss of supply.

Market Structure

- **Supply.** In the first nine months of 2024, the real-time average supply of available synchronized reserve was 5,750.5 MW in the RTO Zone, of which 2,821.1 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 nine months of 2024 was 2,399.7 MW in the RTO Reserve Zone and 1,781.4 MW in the Mid-Atlantic Dominion Reserve Subzone. The day-ahead average synchronized reserve requirement in the first nine months of 2024 was 2,474.8 MW in the RTO Reserve Zone and 1,787.9 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 nine months of 2024. The average HHI for real-time synchronized reserve in the RTO Reserve Zone was 823, which is classified as unconcentrated. The average HHI for day-ahead synchronized reserve in the RTO Zone was 896, which is classified as unconcentrated. The average HHI for real-time synchronized reserve in the MAD Reserve Subzone was 1739, which is classified as moderately concentrated. The

average HHI for day-ahead synchronized reserve in the MAD Reserve Subzone was 1575, which is classified as moderately concentrated.

Market Conduct

- **Offers.** There is a must offer requirement for synchronized reserve. All nonemergency generation capacity resources are required to offer their full 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 resources, 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.

  Significant communications technology issues when calling resources during spinning events result in slow response.

Market Performance

- **Price.** In the first nine months of 2024, for the Mid-Atlantic Dominion Reserve Subzone, the weighted average real-time price for synchronized reserve was $3.41 per MWh and the weighted average day-ahead price was $3.06 per MWh. In the first nine months of 2024, for the RTO Reserve Zone, the weighted average real-time price for synchronized reserve was $3.28 per MWh and the weighted average day-ahead price was $2.86 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 nine months of 2024, the average supply of eligible and available nonsynchronized reserve was 893.9 MW in the RTO Reserve Zone, of which 623.4 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.[3] 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 reserves, as a result of 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.[4] Hybrid units and energy storage resources 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 nine months of 2024, the nonsynchronized reserve weighted average real-time price for all intervals in the RTO Reserve Zone was $1.68 per MWh and the weighted

3 See PJM. "PJM Manual 11: Energy & Ancillary Services Market Operations," § 4.1 Overview of the PJM Reserve Markets, Rev. 132 (Sept. 1, 2024).

4 See PJM. "PJM Manual 11: Energy & Ancillary Services Market Operations," § 4.2.3 Reserve Market Resource Offer Structure, Rev. 132 (Sept. 1, 2024).

average day-ahead price was $1.42 per MWh. In the first nine months of 2024, the nonsynchronized reserve weighted average real-time price for all intervals in the MAD Reserve Subzone was $1.93 per MWh and the weighted average day-ahead price was $1.51 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.

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).
- **Demand.** 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 increased the synchronized reserve reliability requirement, the 30-minute reserve reliability requirement is frequently equal to the primary reserve reliability requirement. In the first nine months of 2024, the average 30-minute reserve requirement was 3,550.5 MW in the real-time market and 3,670.7 MW in the day-ahead market.
- **Market Concentration.** The RTO Reserve Zone Market for 30-minute reserves was characterized by moderate structural market power in the first nine months of 2024. For the first nine months of 2024, the average HHI for real-time 30-minute reserves was 909, which is classified as unconcentrated. For the first nine months of 2024, the average HHI for day-ahead 30-minute reserves was 1032, which is classified as moderately concentrated.

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 nine months of 2024, the real-time average supply of available secondary reserve was 21,791.9 MW in the RTO Reserve Zone. 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.[5]

Market Conduct

- **Offers.** Energy storage resources, 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.[6] 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 nine months of 2024, the secondary reserve real-time price for all intervals was $0.00 per MWh.

5 See PJM. "PJM Manual 11: Energy & Ancillary Services Market Operations," § 4.1 Overview of the PJM Reserve Markets, Rev. 132 (Sept. 1, 2024).
6 See PJM. "PJM Manual 11: Energy & Ancillary Services Market Operations," § 4.2.3 Reserve Market Resource Offer Structure, Rev. 132 (Sept. 1, 2024).

Regulation Market

The PJM Regulation Market is a real-time market. Regulation is provided by generation resources and demand response resources that qualify to follow one of two regulation signals, RegA or RegD. 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. The RegA signal is designed for energy unlimited resources with physically constrained ramp rates. The RegD signal is designed for energy limited resources with fast ramp rates. In the regulation market RegD MW are converted to effective MW using a marginal rate of technical substitution (MRTS), called a marginal benefit factor (MBF). Correctly implemented, the MBF would be the marginal rate of technical substitution (MRTS) between RegA and RegD, holding the level of regulation service constant. The current market design is critically flawed as it has not properly implemented the MBF as an MRTS between RegA and RegD resource MW and the MBF has not been consistently applied in the optimization, clearing and settlement of the regulation market.

Market Structure

- **Supply.** In the first nine months of 2024, the average hourly offered supply of regulation for nonramp hours was 695.5 performance adjusted MW (708.3 effective MW). This was a decrease of 6.1 performance adjusted MW (a decrease of 3.1 effective MW) from the first nine months of 2023. In the first nine months of 2024, the average hourly offered supply of regulation for ramp hours was 994.4 performance adjusted MW (1,047.0 effective MW). This was a decrease of 16.0 performance adjusted MW (a decrease of 0.8 effective MW) from the first nine months of 2023, when the average hourly offered supply of regulation was 1,010.4 performance adjusted MW (1,046.2 effective MW).
- **Demand.** The hourly regulation demand is 525.0 effective MW for nonramp hours and 800.0 effective MW for ramp hours.
- **Supply and Demand.** The nonramp regulation requirement of 525.0 effective MW was provided by a combination of cleared RegA and RegD resources equal to 478.5 hourly average performance adjusted actual MW in the first nine months of 2024. This is a decrease of 1.7 performance adjusted actual MW from the first nine months of 2023, when the average hourly total regulation cleared performance adjusted actual MW for nonramp hours were 476.8 performance adjusted actual MW. The ramp regulation requirement of 800.0 effective MW was provided by a combination of cleared RegA and RegD resources equal to 697.5 hourly average performance adjusted actual MW in the first nine months of 2024. This is a decrease of 12.2 performance adjusted actual MW from the first nine months of 2023, where the average hourly regulation cleared MW for ramp hours were 709.7 performance adjusted actual MW.
- The ratio of the average hourly offered supply of regulation to average hourly regulation demand (performance adjusted cleared MW) for nonramp hours was 1.45 in the first nine months of 2024 (1.45 in the first nine months of 2023). The ratio of the average hourly offered supply of regulation to average hourly regulation demand (performance adjusted cleared MW) for ramp hours was 1.42 in the first nine months of 2024 (1.42 in the first nine months of 2023).
- **Market Concentration.** In the first nine months of 2024, the three pivotal supplier test was failed in 95.4 percent of hours. In the first nine months of 2024, the effective MW weighted average HHI of RegA resources was 2571 which is highly concentrated and the effective MW weighted average HHI of RegD resources was 1549 which is moderately concentrated. The effective MW weighted average HHI of all resources was 1327, 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. Owners must specify which signal type the unit will be following, RegA or RegD.[7] In the first nine months of 2024, there were

7 See the *2023 Annual State of the Market Report for PJM*, Vol. II, Appendix F "Ancillary Services Markets."

182 resources following the RegA signal and 54 resources following the RegD signal.

Market Performance

- **Price and Cost.** The weighted average clearing price for regulation was $31.30 per MW of regulation in the first nine months of 2024, an increase of $9.26 per MW, or 42.0 percent, from the weighted average clearing price of $22.04 per MW in the first nine months of 2023. The weighted average cost of regulation in the first nine months of 2024 was $39.72 per MW of regulation, an increase of 37.2 percent, from the weighted average cost of $28.96 per MW in the first nine months of 2023.
- **Prices.** RegD resources continue to be incorrectly compensated relative to RegA resources due to an inconsistent application of the marginal benefit factor in the optimization, assignment and settlement processes. If the regulation market were functioning efficiently and competitively, RegD and RegA resources would be paid the same price per effective MW.
- **Marginal Benefit Factor.** The marginal benefit factor (MBF) is intended to measure the operational substitutability of RegD resources for RegA resources. The marginal benefit factor is incorrectly defined and applied in the PJM market clearing. The current incorrect and inconsistent implementation of the MBF has resulted in the PJM Regulation Market over procuring RegD relative to RegA in most hours and in an inefficient market signal about the value of RegD in every hour.

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 nine months of 2024, total black start charges were $55.2 million, including $54.9 million in revenue requirement charges and $0.30 million in uplift charges. 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 nine months of 2024 ranged from $0 in the OVEC and REC Zones to $13.8 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 change 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] Hearing procedures have been terminated while the Commission's consideration of settlement options is pending.

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.[10] RTOs and their customers are not required to separately compensate generation resources for such reactive capability.[11] In the first nine months of 2024, PJM customers paid $285.2 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

8 OATT Schedule 1 § 1.3BB. There are no ALR units currently providing black start service.

9 182 FERC ¶ 61,194 (2023).

10 OATT Attachment O.

11 *See* 182 FERC ¶ 61,033 at P 52 (January 27, 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).

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 based on FERC's Order No. 904.[12]

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.

Total reactive charges decreased 1.88 percent from $291.7 million in the first nine months of 2023 to $286.2 million in the first nine months of 2024. Reactive capability charges decreased 2.06 percent from $291.2 million in 2023 to $285.2 million in 2024. Total zonal reactive service charges ranged from $0 in the REC and OVEC Zones, to $45.1 million in the AEP Zone in the first nine months of 2024.

Frequency Response

The PJM Tariff requires that all new generator interconnection customers, both synchronous and nonsynchronous, have hardware and/or software that provides primary frequency responsive real power control with the ability to sense changes in system frequency and autonomously adjust real power output to correct for frequency deviations.[13] 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 +/- 36 mHz deadband.[14] 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.

The response of generators within PJM to NERC identified frequency events remains under evaluation. A frequency event is declared whenever the system frequency goes outside of 60 Hz by +/- 40 mHz and stays there for 60 continuous seconds. The NERC BAL-003-2 requirement for balancing authorities (PJM is a balancing authority) uses a threshold value (L_{10}) equal to -259.3 MW/0.1 Hz and has selected 12 frequency events between December 1, 2020, and November 30, 2021, to evaluate.

As a balancing authority, PJM requires all generators to be capable of providing primary frequency response and to operate with primary frequency response controls enabled.[15] PJM does monitor primary frequency response during NERC identified frequency events for all resources 50 MW or greater. 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.

Market Procurement of Real-Time Ancillary Services

PJM uses market mechanisms to varying degrees in the procurement of ancillary services, including primary reserves, secondary 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 unit parameters and offers.

The synchronized reserve market clearing is more integrated with the energy market clearing than the other ancillary services. Synchronized reserves are jointly cleared with energy in every real-time market solution. 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.[16] Instead, inflexible synchronized reserves are cleared hourly by the Ancillary Service Optimizer (ASO) or the day-ahead energy market. The ASO

12 *Compensation for Reactive Power within the Standard Power Factor Range*, Order No. 904, 189 FERC ¶ 61,034 (2024).
13 Nuclear Regulatory Commission (NRC) regulated facilities are exempt from this provision. Behind the meter generation that is sized to load is also exempt.
14 OATT Attachment O § 4.7.2 (Primary Frequency Response).
15 *Id.*; see also "PJM Manual 12: Balancing Operations," § 3.6 Primary Frequency Response, Rev. 53 (July 24, 2024).
16 See PJM. "PJM Manual 11: Energy & Ancillary Services Market Operations," § 4.4.3 Reserve Market Clearing, Rev. 132 (Sept. 1, 2024).

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 respond to the notifications. (Priority: Medium. First reported 2023. Status: Not adopted.)
- 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 October 1, 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.)

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: Not adopted.)
- 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: Not adopted.)
- 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: Not adopted. FERC rejected.[17])
- The MMU recommends that the current calculation of the performance score (based on precision, delay and correlation metrics) be replaced with

17 162 FERC ¶ 61,295 (2018), *reh'g denied*, 170 FERC ¶ 61,259 (2020).

the current calculation of the precision score. (Priority: Medium. First reported 2023. 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: Not adopted.).
- The MMU recommends that the lost opportunity cost in 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: Not adopted.[18] FERC rejected.[19])
- 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: Not adopted. FERC rejected.[20])
- 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: Not adopted.)
- The MMU recommends enhanced documentation of the implementation of the regulation market design. (Priority: Medium. First reported 2010. Status: Not adopted. FERC rejected.[21])
- 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 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 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.[22])

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: Not adopted.)
- 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. (Priority: High. First reported 2020. Status: Not adopted.)
- The MMU recommends that black start planning and coordination be on a regional basis and not on a zonal basis and that the costs of black start

18 This recommendation was adopted by PJM for the energy market. Lost opportunity costs in the energy market are calculated using the schedule on which the unit was scheduled to run. In the regulation market, this recommendation has not been adopted, as the LOC continues to be calculated based on the lower of price or cost in the energy market offer.
19 162 FERC ¶ 61,295 (2018), *reh'g denied*, 170 FERC ¶ 61,259 (2020).
20 *Id.*
21 *Id.*
22 *Id.*

service be shared on an equal per MWh basis across the region. (Priority: Medium. First reported 2023. 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: Not adopted.)
- The MMU recommends that payments for reactive capability, if continued, be based on the 0.95 power factor included in the voltage schedule in Interconnection Service Agreements. (Priority: Medium. First reported 2018. Status: Not adopted.)
- The MMU recommends that, if payments for reactive are continued, fleet wide cost of service rates used to compensate resources for reactive capability be eliminated and replaced with compensation based on unit specific costs. (Priority: Low. First reported 2019.[23] Status: Partially adopted.)
- The MMU recommends that, if payments for reactive are continued, Schedule 2 to OATT be revised to state explicitly that only generators that provide reactive capability to the transmission system that PJM operates and has responsibility for are eligible for reactive capability compensation. (Priority: Medium. First reported 2020. 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. However, prices have been higher since PJM extended the ORDCs in May 2023.

23 The MMU has discussed this recommendation in state of the market reports since 2016 but Q3, 2019 was the first time it was reported as a formal MMU recommendation.

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 during Winter Storm Elliott, the ACE recovered within the required time frame and no reliability problems occurred. PJM responded to this poor performance 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 were the cause of higher reserve prices in 2023 and the first nine months of 2024, including 35 intervals of shortage pricing in May 2023 and several intervals of shortage pricing during spin events on January 29, 2024, June 3, 2024, and July 8, 2024, 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 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.

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. The current archaic communications technology has been a source of slow response times. 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 respond to the notifications. PJM plans to partially adopt this recommendation by implementing an electronic deployment of reserves in December 2024.

PJM stakeholders approved a joint PJM/MMU proposal to implement an electronic communications and reserve deployment process. Along with changes to the deployment process, PJM and the MMU have worked with generators 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 for/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 the improved communications, 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 remove the 30 percent increase to the synchronized reserve reliability requirement in place from May 2023 through the first nine months of 2024.

The design of the current PJM Regulation Market is significantly flawed.[24] The market design does not correctly incorporate the marginal rate of technical substitution (MRTS) in market clearing and settlement. The market design uses the marginal benefit factor (MBF) to incorrectly represent the MRTS and uses a mileage ratio instead of the MBF in settlement. The current market design allows regulation units that have the capability to provide both RegA and RegD MW to submit an offer for both signal types in the same market hour. However, the method of clearing the regulation market for an hour in which one or more units has a dual offer incorrectly accounts for the amount of RegD and the effective MW of the RegD that it clears. The result of the flaw is that the MBF in the clearing phase is incorrectly low compared to the MBF in the solution phase and the actual amount of effective MW procured is higher than the regulation requirement. This failure to correctly and consistently incorporate the MRTS into the regulation market design has resulted in both underpayment and overpayment of RegD resources and in the over procurement of RegD resources in all hours. Under the current design, slower response RegA resources (generating units) must provide additional regulation to offset the negative impact of RegD resources (largely batteries) that are charging in the middle of a regulation hour. The ability of some resources to submit offers for both RegA and RegD (dual offers) results in inefficient high prices. The market results continue to include the incorrect definition of opportunity cost. These issues are the basis for the MMU's conclusion that the regulation market design is flawed.

24 The current PJM regulation market design that incorporates two signals using two resource types was a result of FERC Order No. 755 and subsequent orders. Order No. 755, 137 FERC ¶ 61,064 at PP 197–200 (2011).

PJM filed proposed changes to the regulation market with the FERC on April 16, 2024.[25] The MMU filed a protest to the PJM filing on May 7, 2024, and answer to PJM's answer on June 7, 2024. 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, scheduled to be implemented on October 1, 2025, will result in a single signal, bidirectional market with one clearing price. Phase 2, to be implemented on October 1, 2026, will result in separate regulation up and regulation down markets.

The benefits of markets can be realized under the current approach to ancillary service markets. Even in the presence of structurally noncompetitive markets, 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. But there are significant issues with the PJM ancillary services markets.

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

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

25 PJM. "Regulation Market Design Filing," Docket No. ER24-1772-000 (April 16, 2024).)

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.[26] 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.

26 See PJM. "PJM Manual 11: Energy & Ancillary Services Market Operations," § 4.3 Reserve Requirement Determination, Rev. 132 (Sept 1, 2024).

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.[27] In the first nine months of 2024, PJM did not call on primary reserves or 30-minute reserves to collectively respond to a reserve event. PJM calls on some non-synchronized resources to individually respond during synchronized reserve events.

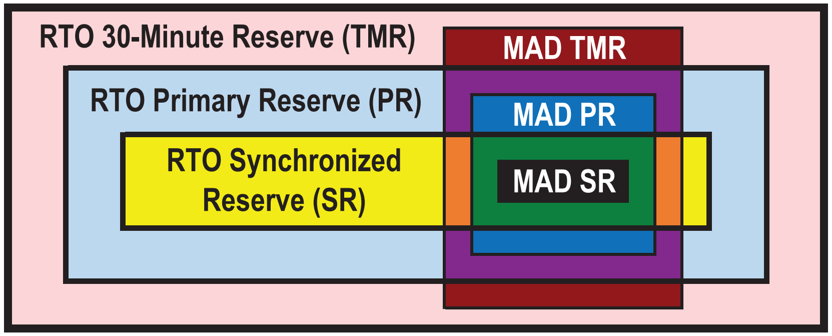
During an event, reserves respond either by increasing their energy output to the grid or by decreasing their energy consumption from the grid. The delivery of this energy is constrained by transmission limits, such that there are also limited locational requirements for each of the reserve services, except for the 30-minute reserve service.[28] 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.[29] 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.

Table 10-6 Service requirement definitions[30]

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

27 See PJM. "PJM Manual 12: Balancing Operations," § 4.1.2 Loading Reserves, Rev. 53 (July 24, 2024).
28 See PJM. "PJM Manual 11: Energy & Ancillary Services Market Operations," § 4.3.1 Locational Aspect of Reserves, Rev. 132 (Sept. 1, 2024).
29 See PJM. "PJM Manual 11: Energy & Ancillary Services Market Operations," § 4.4.1 Product and Locational Substitution, Rev. 132 (Sept 1, 2024).
30 From mid-May 2023 through the first three months of 2024, PJM has set the synchronized reserve reliability requirement to be 130 percent of the MSSC. This change, although implemented without specific criteria for ending the increase, is defined as temporary. See "Synchronized Reserve Requirement Reliability Update," (May 18, 2023). <https://www.pjm.com/-/media/markets-ops/ancillary/reserves-procedure-memo.ashx>.

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 May 19, 2023, PJM inappropriately increased the synchronized reserve reliability requirement by 30 percentage points to 130 percent of the MSSC. Figure 10-19 compares the changes in demand. PJM has not identified an end date or end criteria for this change.[31]

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 Reliability*First*'s regional criteria.[32] [33] Table 10-7 shows the instances identified by the MMU when PJM temporarily increased the reserve requirements during the first nine months of 2024.

Table 10-7 Temporary adjustments to 30-minute, primary, and synchronized reserve requirements: January through September, 2024[34]

From	To	Number of Hours	Amount of Adjustment
19-May-23	Ongoing	12,024+	30 percent increase to synchronized reserve reliability requirement
26-Jan-24	28-Jan-24	48	30-Minute Reserve (10 MW), Primary Reserve (10 MW), Synchronized Reserve (7 MW)
26-Feb-24	18-Mar-24	504	30-Minute Reserve (0 MW), Primary Reserve (0 MW), Synchronized Reserve (0 MW)
18-Apr-24	30-Apr-24	300	30-Minute Reserve (0 MW), Primary Reserve (10 MW), Synchronized Reserve (7 MW)
5-Jun-24	7-Jun-24	55	30-Minute Reserve (50 MW), Primary Reserve (50 MW), Synchronized Reserve (33 MW)

PJM must comply with the reserve requirements imposed by NERC and Reliability*First* 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, but not for synchronized reserve nor for 30-minute reserve.[35] NERC requires that contingency reserves respond within 15 minutes, while PJM requires that primary reserves respond within 10 minutes. Reliability*First* Regional Criteria RFC_Criteria_BAL-002-02 in effect requires that the amount of cleared synchronized reserve be at least 50 percent of the MSSC, while PJM requires cleared synchronized reserve to be at least 100 percent of the MSSC.[36] A NERC DCS event is defined as the

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

32 RFC_Criteria_BAL-002-02. "Operating Reserves," August 29, 2012. <https://rfirst.org/ProgramAreas/Standards/Criteria/Regional%20 Criteria%20Library/RFC_Criteria_BAL-002-02.pdf>.

33 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."

34 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 inside 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.

35 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>.

36 RFC_Criteria_BAL-002-02. "Operating Reserves," August 29, 2012. <https://rfirst.org/ProgramAreas/Standards/Criteria/Regional%20 Criteria%20Library/RFC_Criteria_BAL-002-02.pdf>.

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 can be longer than their corresponding DCS events (Table 10-23).

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).[37] 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.

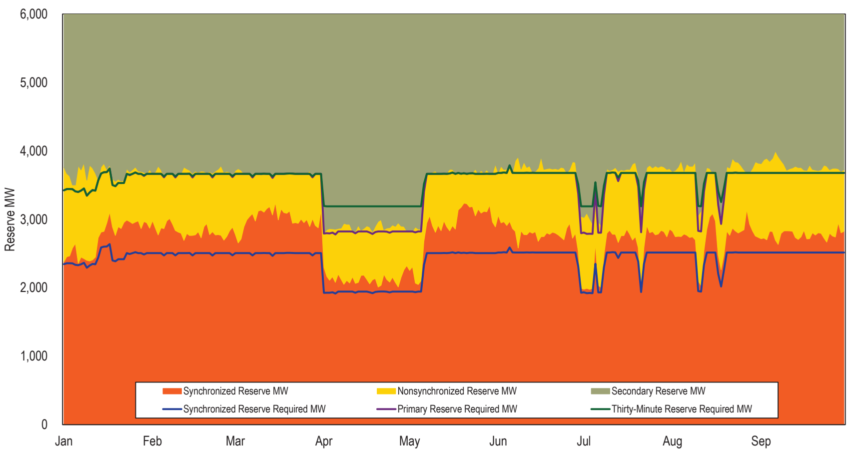
Table 10-9 Reserve products and the services they can provide

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 nine months of 2024. 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 sum 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 nine months of 2024, 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 result from PJM clearing reserve products to help satisfy the requirements of the next broader reserve service. For example, since mid-January, PJM has 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.

Figure 10-2 Daily average real-time reserve products cleared and daily average real-time reserve service requirements used by RT SCED: January through September, 2024



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

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.[38] 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 resources, and load response resources, can specify reserve offer amounts.[39] 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.[40] [41] 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.[42]

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.[43] 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.

The clearing of resources to meet PJM's operational requirements includes multiple steps to commit resources, dispatch resources, and calculate clearing prices.[44] [45] Each program in the commitment and dispatching process estimates future needs. The day-ahead market solution software schedules resources in one-hour blocks.[46] 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

38 See PJM. "PJM Manual 11: Energy & Ancillary Services Market Operations," § 4.4.1 Product and Locational Substitution, Rev. 132 (Sept. 1, 2024).
39 See PJM. "PJM Manual 11: Energy & Ancillary Services Market Operations," § 4.2.3 Reserve Market Resource Offer Structure, Rev. 132 (Sept. 1, 2024).
40 See PJM. "PJM Manual 11: Energy & Ancillary Services Market Operations," § 4.2.1 Reserve Market Eligibility, Rev. 132 (Sept. 1, 2024).
41 See PJM. "PJM Manual 11: Energy & Ancillary Services Market Operations," § 4.4.3.1 Deselection of Reserve Resources in Real-Time, Rev. 132 (Sept. 1, 2024).
42 See *id.*
43 See PJM. "PJM Manual 11: Energy & Ancillary Services Market Operations," § 4.2.2.1 Communication for Reserve Capability Limitation, Rev. 132 (Sept. 1, 2024).
44 For more on the market solution software, see the *2023 Annual State of the Market Report for PJM*, Appendix E - Ancillary Service Markets.
45 See PJM. "PJM Manual 11: Energy & Ancillary Services Market Operations," § 5.2 Scheduling Tools, Rev. 132 (Sept. 1, 2024).
46 See PJM. "PJM Manual 11: Energy & Ancillary Services Market Operations," § 4.4.2 Day-ahead Reserve Market Clearing, Rev. 132 (Sept. 1, 2024).

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.[47]

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.[48] 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.

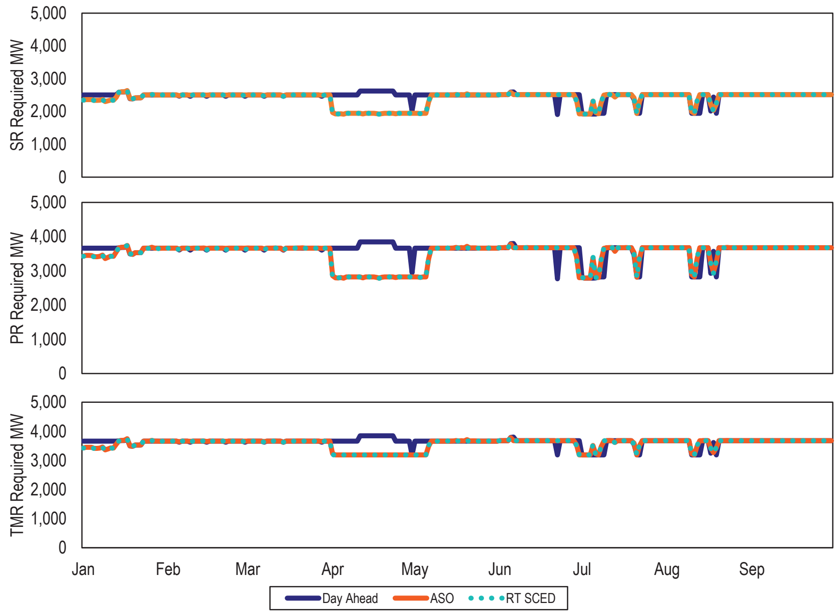
Figure 10-4 compares the daily average requirements of the day-ahead clearing engine, the ASO, and RT SCED. Figure 10-4 shows that the reserve requirements used by the ASO and RT SCED do not differ significantly. Until May 12, 2023, the daily average 30-minute reserve requirement was almost always 3,190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

Figure 10-3 MW cleared by the day-ahead engine, the ASO, and RT SCED: January through September, 2024

47 See PJM. "PJM Manual 11: Energy & Ancillary Services Market Operations," § 4.4.3 Real-time Reserve Market Clearing, Rev. 132 (Sept. 1, 2024).
48 See PJM. "PJM Manual 11: Energy & Ancillary Services Market Operations," § 4.4.3 Real-time Reserve Market Clearing, Rev. 132 (Sept. 1, 2024).

Figure 10-4 Requirements used in the day-ahead engine, the ASO, and RT SCED: January through September, 2024

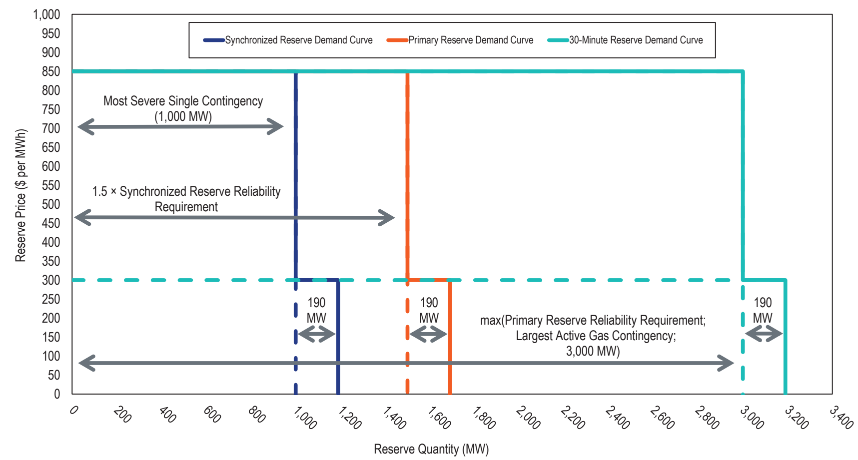


There is a defined MW demand only for synchronized reserves, primary reserves, and 30-minute reserves. The demand for nonsynchronized reserves and for secondary reserves is derived from those defined MW demand levels and cleared supply. PJM's administratively defined demand curve for reserves is called the Operating Reserve Demand Curve (ORDC) and has two steps. The first step of each service's ORDC is set at that service'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 10-5 shows example ORDCs for the three reserve services 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.[49] [50]

Figure 10-5 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 10-20.

Figure 10-5 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 10-5. 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

49 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.

50 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 plus the product substitution cost of the marginal unit(s).[51]

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. This capping accounts for a resource's real-time energy output and prevents crediting a resource for a reserve amount that it did not actually provide.

Reserve Subzones

Reserve subzones address transmission limits that may prevent the lowest cost reserves from being available 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 load reserves in the defined subzone. For example, on February 24, 2024, PJM initiated 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.[52] In 2023 and the first nine months of 2024, PJM did not change the subzone.

Figure 10-6 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 underlying grid topology. The most frequently binding constraints in the first nine months of 2024 were Bedington-Black Oak, Brighton-Conastone, and Front Royal-Warren County.

Figure 10-7 shows the reserve service requirements and cleared reserve product in the MAD Reserve Subzone in the first nine months of 2024. 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.

51 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).

52 See PJM. "PJM Manual 11: Energy & Ancillary Services Market Operations," § 4.3.2 Creation of New Reserve Subzones, Rev. 132 (Sept. 1, 2024).

Figure 10-6 PJM RTO Zone and MAD Subzone map of constraints and generation sources

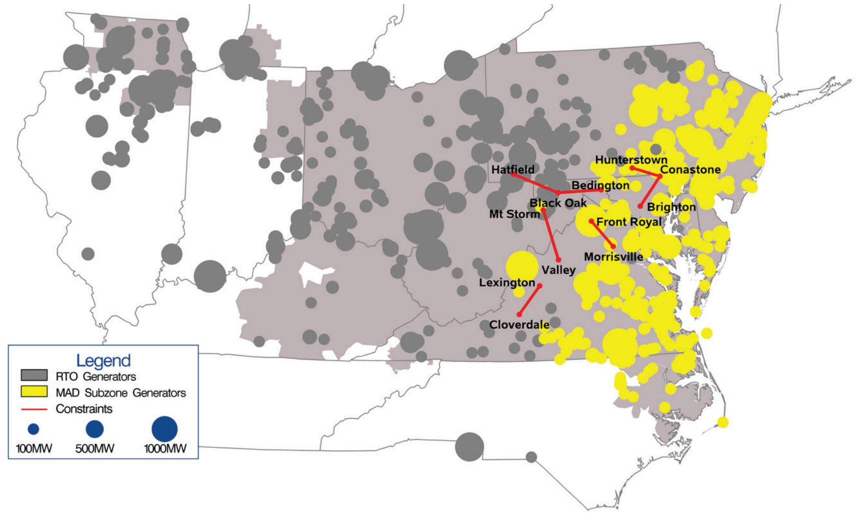
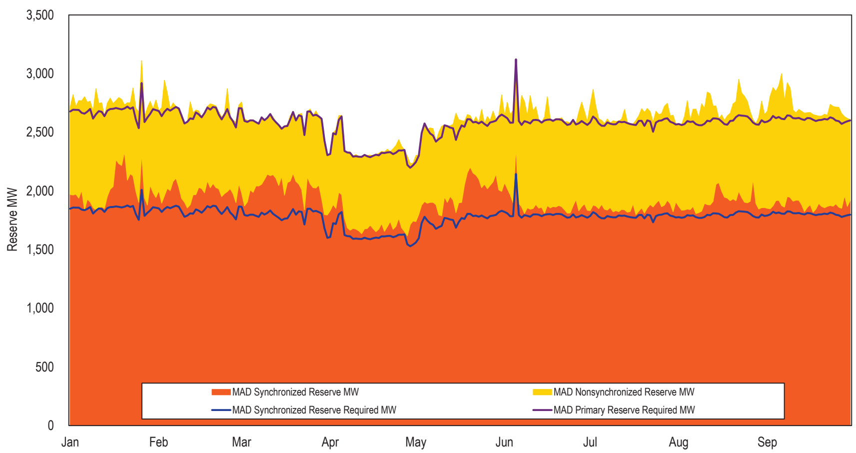


Figure 10-7 Daily average real-time MAD reserve products and daily average real-time MAD reserve service requirements: January through September, 2024



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) reserves 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.[53] The NERC requirement is 100 percent compliance and status must be reported quarterly. PJM implements this contingency reserve recovery period requirement using primary reserves.[54] PJM maintains 10-minute reserves (primary reserve) which is more conservative than the NERC requirement. PJM's primary reserves are 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

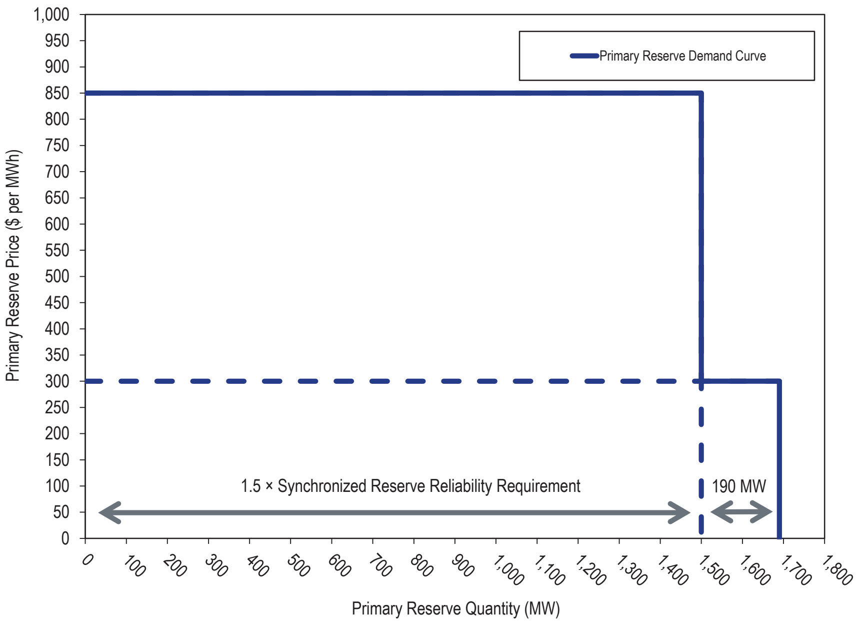
Demand

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 10-8 shows an example operating reserve demand curve for primary reserve for an example synchronized reserve reliability requirement of 1,000 MW plus the default 190–MW extension.

53 See PJM. "PJM Manual 12: Balancing Operations," Rev. 53 (Sept. 1, 2024) 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.

54 See PJM. "PJM Manual 10: Pre-Scheduling Operations," § 3.1 Reserve Definitions, Rev. 44 (Nov. 15, 2023).

Figure 10-8 An example of a primary reserve real-time operating reserve demand curve, including the permanent second step



In the first nine months of 2024, the average primary reserve requirement for the RTO Zone was 3,502.8 MW. The average primary reserve requirement in the MAD Subzone was 2,577.1 MW. The average synchronized reserve requirement in the RTO Zone was 2,399.7 MW. The average synchronized reserve requirement in the MAD Subzone was 1,781.4 MW.

In an attempt to offset poor 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.

Supply

In the first nine months of 2024, 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 nine months of 2024.

Table 10-10 Average available MW for clearing: January through September, 2024

Location	Synchronized Reserve MW	Nonsynchronized Reserve MW
RTO	5,750.5	893.9
MAD	2,821.1	623.4

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 2023 through September 2024. 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 2023 through September 2024.

Table 10-11 Average monthly reserves used to satisfy the primary reserve requirement, MAD Subzone: January 2023 through September 2024

Year	Month	Synchronized Reserve MW	Nonsynchronized Reserve MW	Total Primary Reserve MW
2023	Jan	1,932.9	791.9	2,724.8
2023	Feb	1,955.1	672.8	2,627.9
2023	Mar	1,695.5	678.2	2,373.7
2023	Apr	1,664.1	615.4	2,279.5
2023	May	1,940.1	685.2	2,625.3
2023	Jun	1,973.0	688.2	2,661.2
2023	Jul	1,958.5	714.1	2,672.6
2023	Aug	1,965.5	763.5	2,729.0
2023	Sep	1,925.4	731.5	2,656.9
2023	Oct	1,975.1	688.2	2,663.3
2023	Nov	1,756.3	719.4	2,475.7
2023	Dec	1,927.3	797.6	2,724.9
2023	Average	1,886.2	735.1	2,621.3
2024	Jan	2,007.8	754.0	2,761.8
2024	Feb	1,991.5	707.2	2,698.7
2024	Mar	2,024.3	578.1	2,602.3
2024	Apr	1,724.3	632.6	2,356.9
2024	May	1,968.1	606.3	2,574.4
2024	Jun	1,891.4	782.2	2,673.5
2024	Average	1,917.4	719.9	2,637.3

Table 10-12 Average monthly reserves used to satisfy the primary reserve requirement, RTO Zone: January 2023 through September 2024

Year	Month	Synchronized Reserve MW	Nonsynchronized Reserve MW	Total Primary Reserve MW
2023	Jan	1,934.6	861.0	2,795.6
2023	Feb	1,974.8	718.4	2,693.2
2023	Mar	1,722.1	812.4	2,534.5
2023	Apr	1,787.9	770.9	2,558.8
2023	May	2,425.4	803.9	3,229.3
2023	Jun	2,628.5	847.8	3,476.2
2023	Jul	2,710.1	845.8	3,556.0
2023	Aug	2,464.1	1,079.3	3,543.5
2023	Sep	2,531.2	1,203.6	3,734.8
2023	Oct	2,544.1	992.3	3,536.4
2023	Nov	2,232.2	1,114.5	3,346.7
2023	Dec	2,567.7	1,211.6	3,779.3
2023	Average	2,296.2	939.8	3,236.0
2024	Jan	2,732.1	950.0	3,682.1
2024	Feb	2,826.8	867.6	3,694.4
2024	Mar	3,006.7	662.7	3,669.4
2024	Apr	2,130.2	753.3	2,883.5
2024	May	2,874.4	674.4	3,548.8
2024	Jun	2,779.6	950.8	3,730.4
2024	Average	2,716.6	862.2	3,578.8

Market Concentration

In the first nine months of 2024, for the day-ahead market, the RTO and MAD primary reserve markets were moderately concentrated. In the first nine months of 2024, for the real-time market, the RTO primary reserve market was unconcentrated and the MAD primary reserve market was moderately concentrated. Table 10-13 shows the average of the HHI values of each interval for primary reserves in the first nine months of 2024.

Table 10-13 Average primary reserve HHI: January through September, 2024

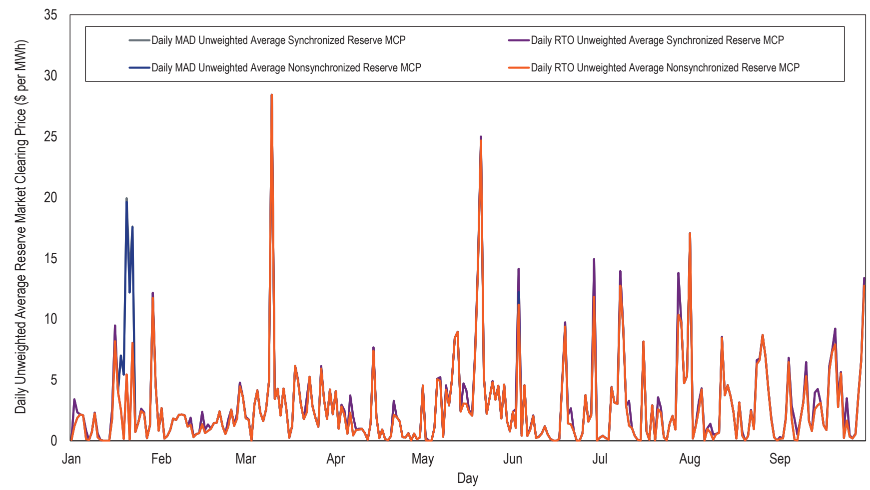
Location	Market	Average HHI	Percent of Intervals Max Market Share Above 20%	Description
RTO	RT	919	39.6%	Unconcentrated
RTO	DA	979	44.9%	Unconcentrated
MAD	RT	1607	83.8%	Moderately Concentrated
MAD	DA	1572	80.0%	Moderately Concentrated

Market Performance

Figure 10-9 shows daily weighted average synchronized and nonsynchronized market clearing prices in the first nine months of 2024. The synchronized reserve market clearing prices for the RTO Reserve Zone and the MAD Reserve Subzone diverged in 826 five-minute intervals, 1.0 percent of the total 78,900 intervals in the first nine months of 2024. The nonsynchronized reserve market clearing prices for the RTO Reserve Zone and the MAD Reserve Subzone diverged in 608 five-minute intervals, 0.8 percent of the total 78,900 intervals in the first nine months of 2024.

The prices of synchronized reserve and nonsynchronized reserve spiked on January 16 and January 17, 2024, during conservative operations for cold weather. Prices spiked on August 1, August 4, and August 26 during hot weather alerts. There was shortage pricing in the RTO Reserve Zone for primary reserve on January 20, January 22, January 29, March 10, March 18, April 14, May 21, June 3, July 8, July 28, and September 4. There was shortage pricing in the MAD Reserve Subzone for primary reserve on January 20, January 21, January 22, and June 3, 2024. There was shortage pricing in the RTO for synchronized reserve on June 3 and July 28. Shortage intervals for primary reserves on January 29, June 3, and July 8 occurred during spinning events. Of the 29 intervals short of primary reserve in the RTO Reserve Zone or the MAD Reserve Subzone, 25 were shortage intervals only as a result of the 30 percent increase to the synchronized reserve reliability requirement imposed by PJM in May 2023. There were four intervals of shortage pricing for primary reserve for which PJM would not have met the primary reserve requirement in RT SCED even without 30 percent increase to the demand for synchronized reserves.

Figure 10-9 Daily average market clearing prices for synchronized reserve and nonsynchronized reserve: January through September, 2024



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. 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 10-5 shows an example operating reserve demand curve for synchronized reserve.

In the first four months of 2023, the demand portion of the first step of the ORDC for synchronized reserve was equal to the MSSC. PJM unilaterally increased the extended reserve requirement by 1,588 MW from May 12, 2023, through May 15, 2023. PJM then unilaterally increased the synchronized reserve reliability requirement to 130 percent of the MSSC on May 19, 2023, which increased the effective primary reserve reliability requirement from 150 percent of the MSSC to 195 percent of the MSSC. Since May 19, the demand portion has been equal to 130 percent of the MSSC. PJM did not increase demand in the MAD Reserve Subzone, only in the RTO Reserve Zone. Figure 10-19 compares the old and new RTO ORDCs with an example MSSC of 1,000 MW.

Figure 10-2 shows a plot of the daily average real-time requirement for synchronized reserve. In the first nine months of 2024, the average real-time synchronized requirement in the RTO Reserve Zone was 2,399.7 MW and the average day-ahead requirement was 2,474.8 MW. In the MAD Reserve Subzone, the average real-time synchronized requirement was 1,781.4 MW and the average day-ahead requirement was 1,787.9 MW.

NERC allows contingency reserves to include "operating reserves – spinning" and "operating reserves – supplemental." Operating reserves – spinning are fully synchronized generation and interruptible load that can respond within 10 minutes. Operating reserves – supplemental are any resources that qualify as operating reserves – spinning plus nonsynchronized generation that can respond within 10 minutes. Reliability*First* (RF) follows NERC's definition for operating reserves, but RF recommends (but does not require or have the authority to require) for contingency reserves that PJM maintain operating reserves – spinning equal to at least half of the most severe single contingency, that PJM not assign interruptible load as operating reserves – spinning, and that no more than 25 percent of operating reserves – supplemental be interruptible load.[55] [56] Figure 10-16 compares cleared primary reserve with the DSR portion of cleared synchronized reserve. In effect, no more than 25 percent of PJM's contingency reserves can be DSR resources. Prior to October 1, 2022, DSR resources were limited by PJM to being no more than 33 percent

55 RFC_Criteria_BAL-002-02. "Operating Reserves," August 29, 2012. <https://www.rfirst.org/wp-content/uploads/2023/10/RFC_Criteria_BAL-002-02.pdf>.

56 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."

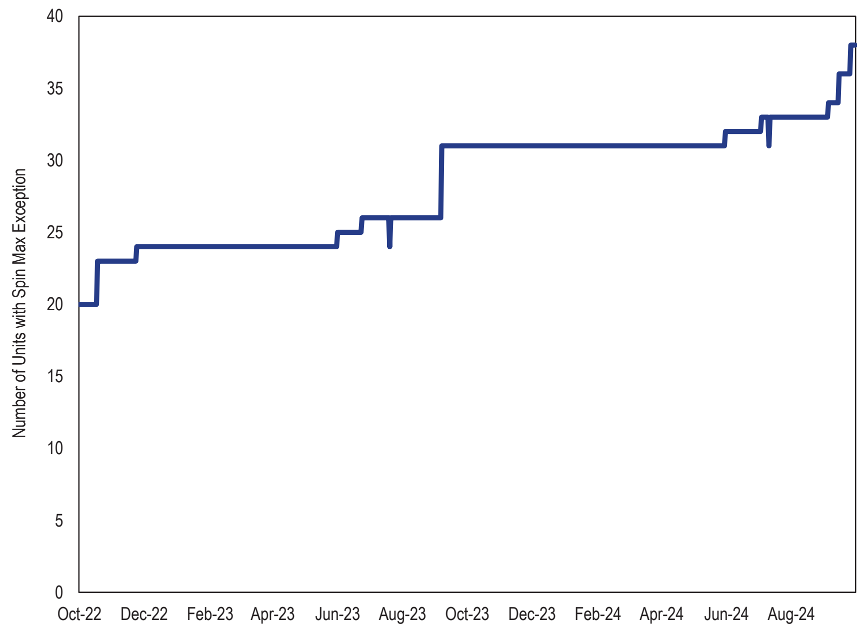
of cleared synchronized reserves, but that limitation was removed on October 1, 2022, as part of the changes to the reserve markets.

Supply

The supply of synchronized reserves consists of all unloaded capacity that can convert to energy in 10 minutes from online resources and all synchronized load that can curtail in 10 minutes. 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. 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.[57] Figure 10-10 shows how use of the exception for a lower synchronized reserve maximum MW has grown. If generators in need of the exception request it, PJM should see improved reserve performance due to better calculation of the available reserve MW.

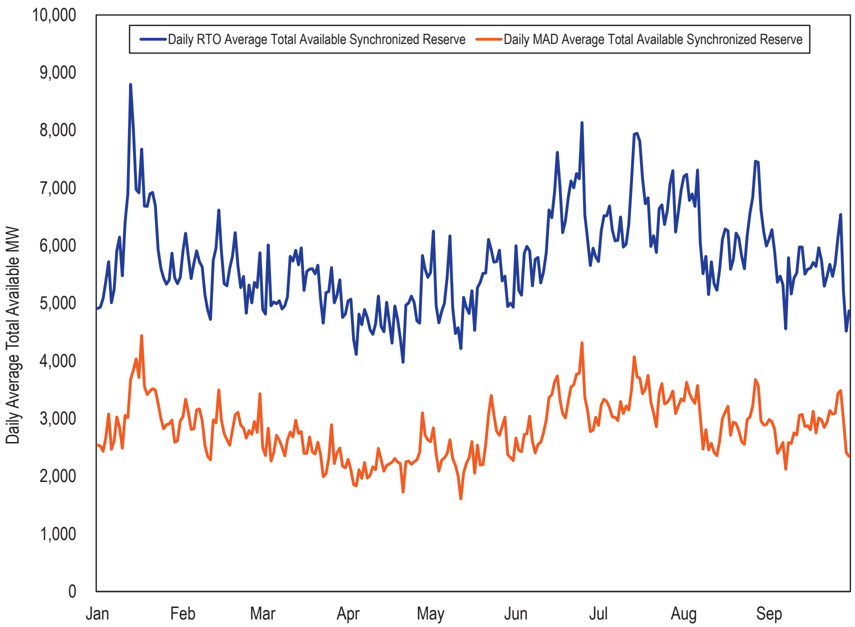
Figure 10-10 Number of units per day allowed to use a spin max less than eco max: October 2022 through September 2024



In the first nine months of 2024, the average supply of daily offered and eligible synchronized reserve was 5,750.5 MW in the RTO Reserve Zone, of which 2,821.1 MW was located in the MAD Reserve Subzone. Figure 10-11 shows the daily average available synchronized reserve MW.

57 See PJM. "PJM Manual 11: Energy & Ancillary Services Market Operations," § 4.2.2.1 Communication for Reserve Capability Limitation, Rev. 132 (Sept. 1, 2024).

Figure 10-11 Daily Average Available Synchronized Reserve: January through September, 2024



Market Concentration

Table 10-14 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 nine months of 2024. In the first nine months of 2024, the MAD real-time and day-ahead synchronized reserve markets were moderately concentrated. In the first nine months of 2024, the RTO real-time and day-ahead synchronized reserve markets were unconcentrated.

Table 10-14 Day-ahead and real-time synchronized reserve average HHI: January through September, 2024

Location	Market	Average HHI	Percent of Intervals Max Market Share Above 20%	Description
RTO	RT	823	19.9%	Unconcentrated
RTO	DA	896	40.5%	Unconcentrated
MAD	RT	1739	90.3%	Moderately Concentrated
MAD	DA	1575	86.4%	Moderately Concentrated

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.[58] These values are listed in Table 10-15. For resources that do not provide an offer price, the offer price is treated as $0 per MWh. In the first nine months of 2024, the weighted average offer price for generators that set their offer MW was $0.01 per MWh. In the first nine months of 2024, the weighted average offer price for DSR resources that set their offer MW was $0.02 per MWh.

58 See PJM. "PJM Manual 15: Cost Development Guidelines," § 4.7 Synchronized Reserve, Rev. 45 (Sept. 1, 2024).

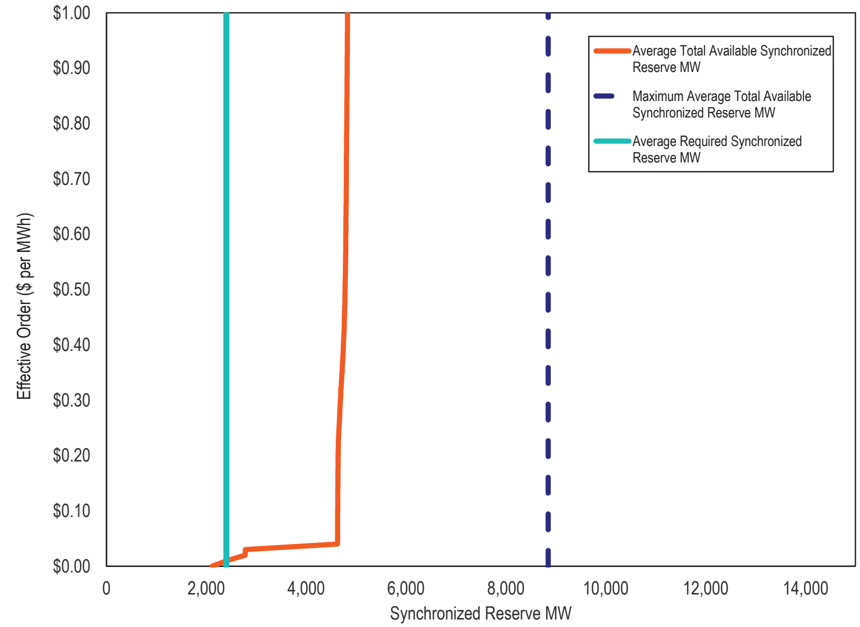
Table 10-15 Expected values of the synchronized reserve penalty: January 2023 through September 2024[59]

Year	Month	Value of Expected Penalty ($/MWh)
2023	Jan	$0.14
2023	Feb	$0.11
2023	Mar	$0.09
2023	Apr	$0.07
2023	May	$0.06
2023	Jun	$0.06
2023	Jul	$0.06
2023	Aug	$0.05
2023	Sep	$0.05
2023	Oct	$0.04
2023	Nov	$0.04
2023	Dec	$0.04
2024	Jan	$0.04
2024	Feb	$0.04
2024	Mar	$0.04
2024	Apr	$0.04
2024	May	$0.04
2024	Jun	$0.04
2024	Jul	$0.04
2024	Aug	$0.04
2024	Sep	$0.04

Figure 10-12 shows the average supply of synchronized reserve MW seen by the ASO based on the effective offers for the interval. A generator's effective offer is the sum of the generator's offer price, energy use cost, and the absolute value of the product substitution cost. A DSR resource's effective offer is equal to the offer price. Figure 10-12 also shows the average synchronized reserve requirement across all intervals used by the ASO and the maximum average supply of synchronized reserve MW using the highest effective offer.

59 PJM. *Synchronized Reserve Offer Cap Penalty.* June 27, 2023. <https://www.pjm.com/-/media/markets-ops/ancillary/synchronized-reserve-offer-cap-penalty.ashx>.

Figure 10-12 Average total available MW by effective offer: January through September, 2024



Market Performance

In the first nine months of 2024, the real-time RTO weighted average synchronized reserve market clearing price (SRMCP) was $3.28 per MWh and the day-ahead RTO weighted average SRMCP was $2.86 per MWh. The real-time MAD weighted average SRMCP was $3.41 per MWh and the day-ahead MAD weighted average SRMCP was $3.06 per MWh.

Figure 10-13 shows the daily unweighted average prices for synchronized reserve in the real-time and day-ahead markets. Higher prices on January 16 and January 17 were a result of conservative operations for cold weather during Winter Storm Gerri. Higher prices on March 10, April 14, and May 21 corresponded with shortage pricing for primary reserve in the RTO Reserve

Zone, though there were no intervals with shortage pricing for synchronized reserve during that time. Higher prices on June 3 were a result of shortage pricing for synchronized reserve and primary reserve used during a spinning event. Higher prices in July correspond with hot weather alerts, spin events, and shortage pricing on July 28. Higher prices in August correspond with hot weather alerts. Higher prices on September 4 are due to shortage pricing for synchronized reserve.

Figure 10-13 Day-ahead and real-time synchronized reserve average market clearing prices: January through September, 2024

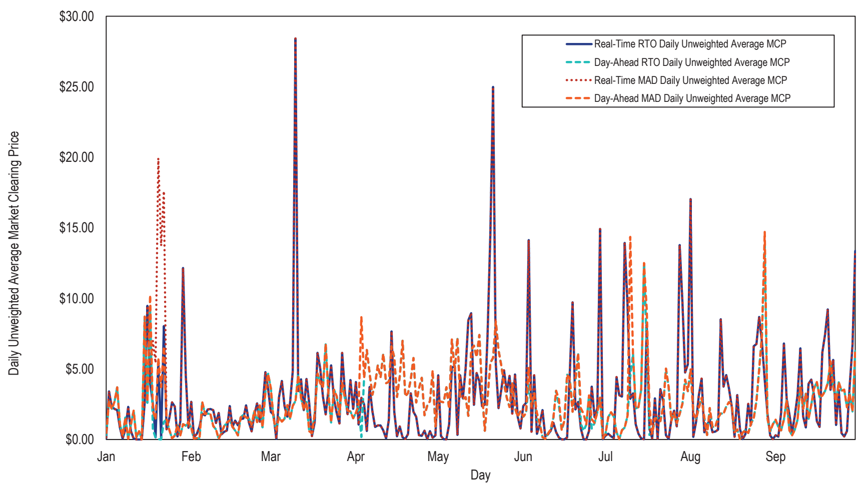


Table 10-16 and Table 10-17 compare the dispatch run and pricing run weighted average prices for the day-ahead and real-time markets. For the real-time values, these are the LPC prices weighted using the RT SCED MW. For the day-ahead values, these are the DA prices weighted using the DA dispatch MW. PJM dispatchers can update assignments after RT SCED has run, so these weights differ from the weighted average value reported elsewhere in this section.[60]

Table 10-16 Day-ahead and real-time fast start pricing in the RTO synchronized reserve market: January 2023 through September 2024

		Day-Ahead				Real-Time			
Year	Month	Dispatch-Run MCP	Pricing-Run MCP	Difference	Percent Difference	Dispatch-Run MCP	Pricing-Run MCP	Difference	Percent Difference
2023	Jan	$0.34	$0.35	$0.02	4.8%	$0.78	$0.96	$0.18	22.9%
2023	Feb	$0.33	$0.36	$0.03	9.4%	$0.10	$0.20	$0.10	107.3%
2023	Mar	$0.33	$0.35	$0.01	4.4%	$0.15	$0.26	$0.11	68.9%
2023	Apr	$1.60	$1.64	$0.04	2.5%	$0.64	$1.22	$0.58	90.8%
2023	May	$4.83	$4.82	($0.02)	(0.3%)	$4.51	$6.16	$1.65	36.6%
2023	Jun	$1.94	$1.96	$0.02	1.0%	$0.55	$0.99	$0.44	80.6%
2023	Jul	$4.71	$4.79	$0.08	1.7%	$1.00	$1.64	$0.64	64.4%
2023	Aug	$1.26	$1.32	$0.06	4.4%	$0.35	$0.54	$0.20	56.6%
2023	Sep	$1.26	$1.32	$0.05	4.3%	$0.50	$0.68	$0.18	36.1%
2023	Oct	$9.60	$9.65	$0.05	0.5%	$3.02	$4.70	$1.69	55.9%
2023	Nov	$5.59	$5.69	$0.09	1.7%	$1.21	$1.85	$0.64	52.8%
2023	Dec	$1.31	$1.34	$0.03	2.6%	$1.16	$1.65	$0.49	41.8%
2023	All	$3.07	$3.11	$0.04	1.4%	$1.24	$1.84	$0.61	49.1%
2024	Jan	$1.69	$1.72	$0.03	1.9%	$1.98	$2.53	$0.55	28.0%
2024	Feb	$1.49	$1.50	$0.00	0.3%	$1.29	$1.82	$0.53	40.9%
2024	Mar	$2.72	$2.74	$0.02	0.8%	$2.69	$3.88	$1.19	44.3%
2024	Apr	$4.14	$4.15	$0.01	0.2%	$0.99	$1.54	$0.55	55.1%
2024	May	$4.29	$4.28	($0.01)	(0.2%)	$3.28	$4.99	$1.72	52.4%
2024	Jun	$2.02	$2.13	$0.11	5.5%	$2.29	$2.56	$0.27	11.8%
2024	Jul	$2.63	$2.80	$0.17	6.3%	$3.00	$3.69	$0.69	23.0%
2024	Aug	$2.33	$2.44	$0.11	4.7%	$2.81	$3.44	$0.62	22.2%
2024	Sep	$2.72	$2.82	$0.11	3.9%	$2.77	$3.73	$0.96	34.8%
2024	All	$2.69	$2.75	$0.06	2.2%	$2.39	$3.20	$0.81	33.7%

60 See PJM. "PJM Manual 01: Control Center and Data Exchange Requirements," § 1.7 Dispatch Management Tool (DMT), Rev. 48 (Sep. 25, 2023).

Table 10-17 Day-ahead and real-time fast start pricing in the MAD synchronized reserve market: January 2023 through September 2024

		Day-Ahead				Real-Time			
Year	Month	Dispatch-Run MCP	Pricing-Run MCP	Difference	Percent Difference	Dispatch-Run MCP	Pricing-Run MCP	Difference	Percent Difference
2023	Jan	$0.34	$0.35	$0.01	2.8%	$1.22	$1.12	($0.09)	(7.5%)
2023	Feb	$1.09	$1.17	$0.09	8.0%	$0.63	$0.70	$0.08	12.5%
2023	Mar	$0.41	$0.43	$0.02	3.9%	$0.16	$0.25	$0.09	53.5%
2023	Apr	$1.69	$1.73	$0.04	2.4%	$0.56	$1.04	$0.48	85.2%
2023	May	$4.79	$4.78	($0.01)	(0.3%)	$4.73	$6.30	$1.58	33.3%
2023	Jun	$2.00	$2.03	$0.02	1.2%	$0.53	$0.93	$0.40	74.4%
2023	Jul	$4.31	$4.40	$0.08	1.9%	$0.90	$1.44	$0.54	60.4%
2023	Aug	$1.34	$1.40	$0.06	4.3%	$0.37	$0.56	$0.19	52.3%
2023	Sep	$1.30	$1.36	$0.06	4.2%	$0.51	$0.65	$0.14	26.9%
2023	Oct	$9.73	$9.77	$0.05	0.5%	$3.25	$4.80	$1.55	47.9%
2023	Nov	$5.43	$5.53	$0.09	1.7%	$1.29	$1.94	$0.65	50.3%
2023	Dec	$1.55	$1.58	$0.04	2.4%	$1.30	$1.78	$0.48	36.4%
2023	All	$3.36	$3.40	$0.05	1.4%	$1.41	$1.99	$0.58	40.8%
2024	Jan	$2.63	$2.68	$0.05	1.8%	$3.59	$4.22	$0.63	17.5%
2024	Feb	$1.64	$1.65	$0.00	0.3%	$1.37	$1.89	$0.53	38.4%
2024	Mar	$2.85	$2.87	$0.02	0.7%	$2.69	$3.81	$1.12	41.7%
2024	Apr	$4.37	$4.38	$0.01	0.3%	$0.93	$1.41	$0.48	51.3%
2024	May	$4.19	$4.18	($0.00)	(0.1%)	$3.19	$4.73	$1.54	48.4%
2024	Jun	$2.34	$2.41	$0.07	2.8%	$2.59	$2.83	$0.24	9.1%
2024	Jul	$3.10	$3.30	$0.20	6.5%	$2.81	$3.40	$0.59	21.0%
2024	Aug	$2.43	$2.56	$0.13	5.3%	$3.19	$3.82	$0.63	19.9%
2024	Sep	$2.89	$3.00	$0.11	3.8%	$2.91	$3.95	$1.04	35.8%
2024	All	$3.01	$3.07	$0.06	2.0%	$2.63	$3.41	$0.78	29.6%

Figure 10-14 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 10-13. As seen in Figure 10-14, there can be significant differences in the clearing prices. Because the ASO's clearing is used by RT SCED, it is possible for a lower MCP in the ASO to prevent an inflexible resource from being cleared in real time, even when its bid price is lower than MCP calculated by RT SCED and by the LPC.

Figure 10-14 Dispatch run synchronized reserve market clearing prices from the day-ahead software, the ASO, and RT SCED: January through September, 2024

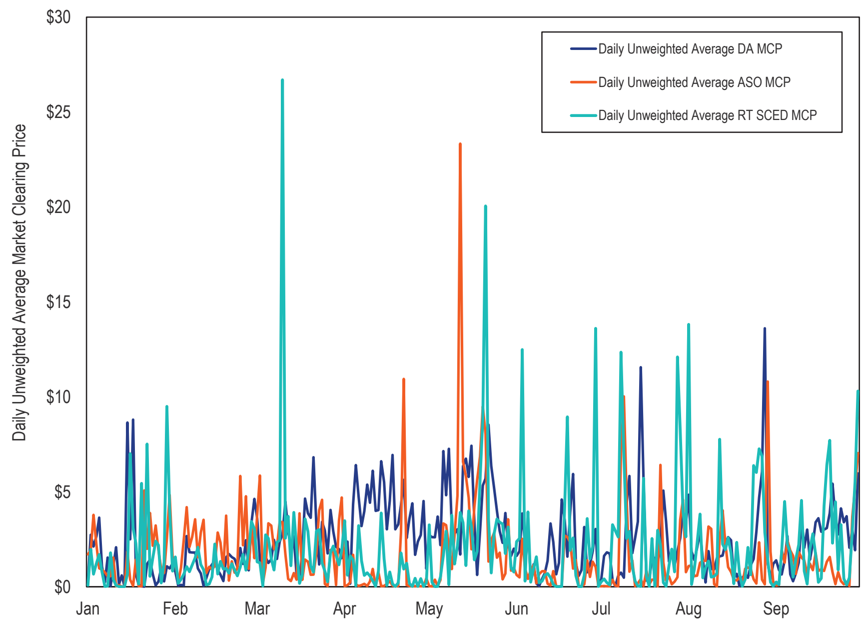


Table 10-18 shows total synchronized reserve payments by month for January 2023 through September 2024. Balancing credits for all but three months are negative, because, on average, resources buy back their day-ahead positions at higher real-time prices. LOC credits are paid to cover negative balancing 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 Table 10-18, the only months with synchronized reserve events that lasted for 10 or more minutes were January 2023, December 2023, February 2024, July 2024, and August 2024, so there are no shortfall charges possible outside of those months. Day-ahead credits were larger in May 2023 due to shortage pricing from PJM's unilateral change in the reserve requirements. Day-ahead credits were larger in July 2023 due to higher prices during hot weather alerts on July 28 and July 29. Day-ahead credits were larger in October 2023 and November 2023 due to higher, more volatile prices corresponding to tighter supply and a change in how condensers cleared. Day-ahead credits were larger in April and May 2024, corresponding with higher requirements in April and lower supply in May.

Table 10-18 Total payments and charges by month: January 2023 through September 2024

Year	Month	Total Day-Ahead Credits	Total Balancing MCP Credits	Total LOC Credits	Total Shortfall Charges	Total Credits
2023	Jan	$505,429	($114,061)	$977,167	$336,246	$1,032,289
2023	Feb	$735,351	$99,577	$493,619	$0	$1,328,546
2023	Mar	$439,364	($5,172)	$744,887	$0	$1,179,079
2023	Apr	$2,088,876	$55,121	$702,100	$0	$2,846,098
2023	May	$8,590,787	($1,102,233)	$1,522,021	$0	$9,010,575
2023	Jun	$4,061,466	($136,555)	$504,843	$0	$4,429,754
2023	Jul	$10,125,951	($209,684)	$843,603	$0	$10,759,870
2023	Aug	$2,822,099	($101,170)	$583,173	$0	$3,304,101
2023	Sep	$2,808,344	($352,447)	$762,318	$0	$3,218,215
2023	Oct	$21,150,975	($806,826)	$1,025,750	$0	$21,369,899
2023	Nov	$11,822,028	($959,271)	$635,270	$0	$11,498,027
2023	Dec	$2,843,149	($313,929)	$628,588	$80,447	$3,077,361
2024	Jan	$4,327,646	($426,107)	$1,144,741	$0	$5,046,280
2024	Feb	$2,894,089	($98)	$536,025	$19,515	$3,410,501
2024	Mar	$5,930,989	($297,375)	$1,079,741	$0	$6,713,356
2024	Apr	$9,018,149	($907,004)	$595,636	$0	$8,706,781
2024	May	$9,477,497	($169,439)	$1,260,078	$0	$10,568,136
2024	Jun	$4,594,840	($602,073)	$788,619	$0	$4,781,386
2024	Jul	$5,994,640	$88,604	$1,400,675	$508,031	$6,975,888
2024	Aug	$5,015,123	($203,403)	$998,564	$22,877	$5,787,407
2024	Sep	$5,792,899	($174,272)	$913,531	$0	$6,532,157

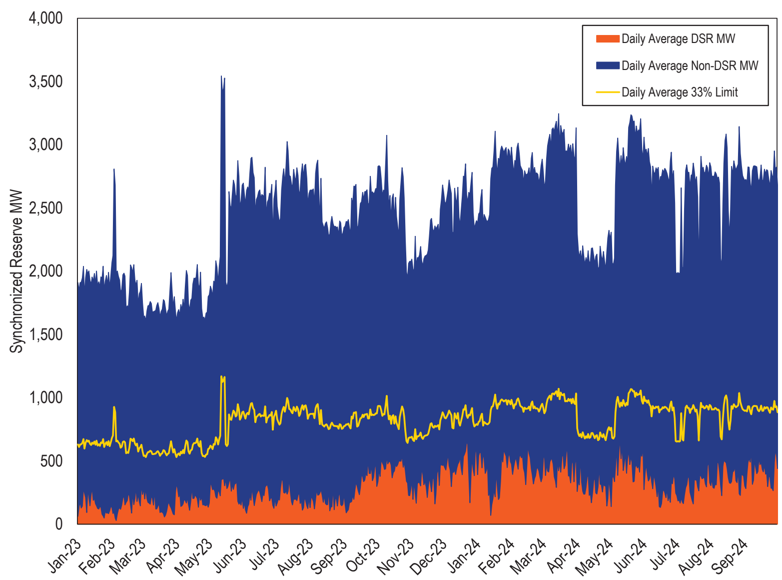
Table 10-19 provides the day-ahead and real-time synchronized reserve by resource type and fuel type for the first nine months of 2024. For synchronized reserve, the MW for which a resource is credited at the market clearing price is capped at the lesser of its real-time assignment and the difference 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 September, 2024

Resource / Fuel Type	Day-Ahead MWh	Real-Time Capped MWh	Day-Ahead Credits	Balancing MCP Credits	LOC Credits	Shortfall Charges	Total Credits
Combined Cycle	8,739,296	5,734,754	$22,332,469	($8,015,148)	$3,302,572	$166,319	$17,453,573
CT - Natural Gas	1,724,955	2,500,881	$11,149,728	$2,273,643	$2,075,677	$224,070	$15,274,978
DSR	997,595	2,518,608	$3,808,202	$3,633,048	$907,586	$6,529	$8,342,309
Steam - Coal	4,204,798	4,085,429	$6,553,196	$371,025	$1,295,505	$92,385	$8,127,341
CT - Oil	386,390	479,283	$2,202,386	$214,218	$269,085	$16	$2,685,674
Hydro - Pumped Storage	1,069,280	630,112	$3,426,738	($1,570,586)	$202,450	$17,025	$2,041,576
Steam - Natural Gas	409,074	593,619	$1,085,547	$506,526	$319,871	$21,150	$1,890,795
Hydro - Run of River	693,556	643,824	$1,308,373	$403,203	$47,090	$1,658	$1,757,007
RICE - Other	227,016	134,220	$600,016	($320,805)	$95,554	$11,477	$363,287
RICE - Natural Gas	31,737	11,775	$325,036	($145,861)	$39,536	$125	$218,587
Other	29,690	45,409	$122,475	$58,316	$31,501	$9,433	$202,858
Steam - Other	65,449	14,803	$131,707	($98,745)	$131,181	$236	$163,907

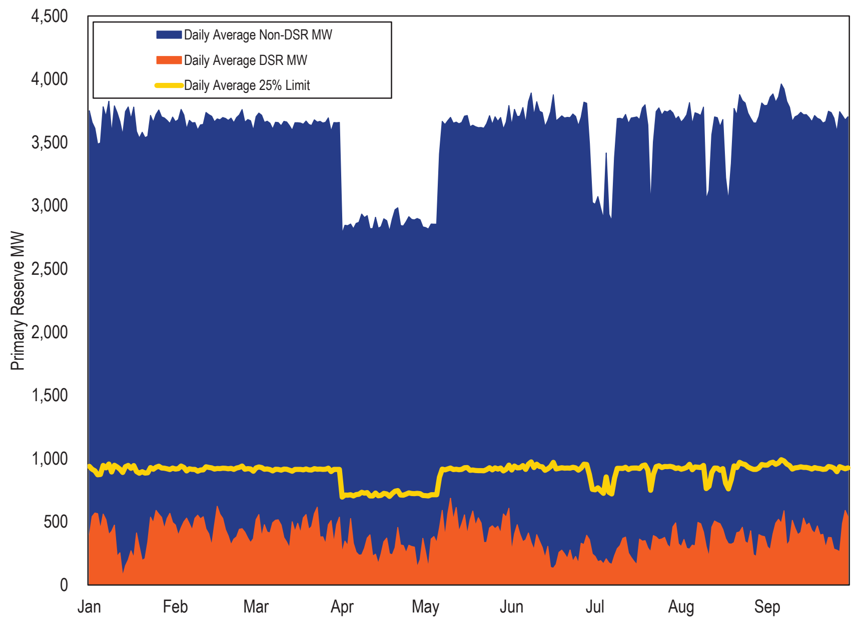
Before the October 1, 2022, changes, DSR was limited to 33 percent of the cleared synchronized reserves. This limitation was removed. In the first nine months of 2024, DSR was more than 33 percent of the cleared synchronized reserves in 141 of 78,900 five-minute intervals. In all of the 141 intervals, DSR exceeded 33 percent of the real-time MW, but not of the day-ahead MW. During these 141 intervals, on average, DSR made up 39.3 percent of the synchronized reserve MW. Figure 10-15 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 10-15 Daily average synchronized reserve from DSR and non-DSR: January 2023 through September 2024



Reliability*First*'s regional criteria recommend that DSR be no more than 25 percent of contingency reserve, which PJM implements as primary reserve.[61] Figure 10-16 shows the daily average DSR percentage of primary reserve, which PJM purchases as synchronized reserve. In the first nine months of 2024, the amount of cleared DSR exceeded 25 percent of the amount of cleared primary reserve in 74 intervals. During those intervals, the average percent of primary reserve that was DSR was 28.9 percent.

Figure 10-16 Comparison of daily average cleared primary reserve and daily average cleared DSR: January through September, 2024



61 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>.

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.[62] 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 response from cleared synchronized reserves. In 2023, three events were 10 minutes or longer. In the first nine months of 2024, four events were 10 minutes or longer. Of those four reserve events, three were due to unit losses and one was due to low ACE. Of those four reserve events, only one was associated with a DCS event. For all other DCS events, any associated reserve event lasted less than 10 minutes.

Actual synchronized reserve response is the total increase in MW from all 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.[63] PJM, in practice, not only corrects the Reporting ACE disturbance that led to the event but over corrects. In three of the four spinning events of 10 minutes or longer in the first nine months of 2024, the Reporting ACE recovered not just to the NERC required level of zero but overshot by over approximately 1,000 MW.

62 See PJM. "PJM Manual 11: Energy & Ancillary Services Market Operations," § 4.2.10 Settlements, Rev. 132 (Sept. 1, 2024).
63 See PJM. "PJM Manual 12: Balancing Operations," Rev. 53 (July 24, 2024) Attachment D.

Table 10-20 Response compliance for synchronized reserve events 10 minutes or longer: January 2023 through September 2024

Spin Event	Duration (Minutes)	Resource/Fuel Type	Total Synchronized Reserve Scheduled (MW)	Total Capped Synchronized Reserve Resource Response (MW)	Total Synchronized Reserve Resource Shortfall (MW)	Synchronized Reserve Response Percent
05-Jan-2023 1243 (EPT)	11.6	Combined Cycle	586	354	232	60%
		Steam - Coal	410	143	267	35%
		Steam - Other	85	59	26	69%
		Other	632	456	176	72%
		Total	1,714	1,012	702	59%
10-Jan-2023 0706 (EPT)	17.5	Combined Cycle	563	207	356	37%
		CT - Natural Gas, Oil	738	328	410	44%
		DSR	370	227	144	61%
		Steam - Coal	352	243	109	69%
		Steam - Other	64	19	45	29%
		Other	281	274	7	98%
		Total	2,368	1,297	1,071	55%
14-Dec-2023 1941 (EPT)	12.3	Combined Cycle	770	303	467	39%
		CT - Natural Gas	432	69	363	16%
		DSR	488	411	77	84%
		Steam - Coal	535	278	257	52%
		Steam - Other	37	22	15	60%
		Other	450	354	97	79%
		Total	2,712	1,436	1,276	53%
24-Feb-2024 1548 (EPT)	12.3	Combined Cycle	925	579	347	63%
		CT - Natural Gas	445	34	411	8%
		DSR	262	20	243	7%
		Steam	774	28	747	4%
		Other	544	67	477	12%
		Total	2,951	727	2,225	25%
08-Jul-2024 1757 (EPT)	14.5	Combined Cycle	701	237	463	34%
		CT - Natural Gas, Oil	1,535	696	838	45%
		Hydro	261	212	49	81%
		Steam - Coal	465	202	263	43%
		Steam - Other	133	29	104	22%
		Other	141	101	39	72%
		Total	3,234	1,479	1,755	46%
21-Jul-2024 1753 (EPT)	10.17	Combined Cycle	560	356	203	64%
		CT - Natural Gas	494	327	167	66%
		DSR	553	533	20	96%
		Hydro	168	130	38	77%
		Steam - Coal	530	415	116	78%
		Other	74	5	69	7%
		Total	2,379	1,766	613	74%
18-Aug-2024 1604 (EPT)	15.85	Combined Cycle	318	230	88	72%
		DSR	529	477	51	90%
		Hydro	366	155	211	42%
		Steam - Coal	525	417	107	80%
		Other	207	61	146	30%
		Total	1,945	1,342	603	69%

In the first nine months of 2024, 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 January 2017 through September 2024. PJM experienced four synchronized reserve event longer than 10 minutes in the first nine months of 2024, of which one applied only to the MAD Reserve Subzone.

Table 10-21 Average synchronized reserve response for events longer than 10 minutes: January 2017 through September 2024

Year	No. of Events Longer than 10 Minutes	Average Percent of Scheduled Synchronized Reserve MW that Responded
2017	6	87.6%
2018	8	74.2%
2019	3	86.8%
2020	5	59.5%
2021	5	83.1%
2022 (Jan - Sep)	3	71.2%
2022 (Oct - Dec)	7	50.3%
2023	3	55.6%
2024 (Jan - Sep)	4	53.1%

In the first nine months of 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. Figure 10-17 shows the distribution of resources cleared for synchronized reserve from January 2022 through December 2023, representing approximately 900 resources. Figure 10-18 shows the totals by resource type of the average available synchronized reserve MW from all resources offering tier 2 synchronized reserve and all resources with available synchronized reserve under the new market structure. Figure 10-17 shows that different resource types have made up the bulk of cleared synchronized reserve since the October 1 changes. Many of the resources that have cleared since October 1, 2022, did not clear in the nine months prior to the change. Therefore, resource performance during synchronized reserve events from before and after the change are not directly comparable. Figure 10-18 supports that much of the poor performance seen in the months following the switch is a result of a change of which resources are cleared, not a change by specific resources.

Figure 10-17 Cleared synchronized reserves by type: 2022 through 2023

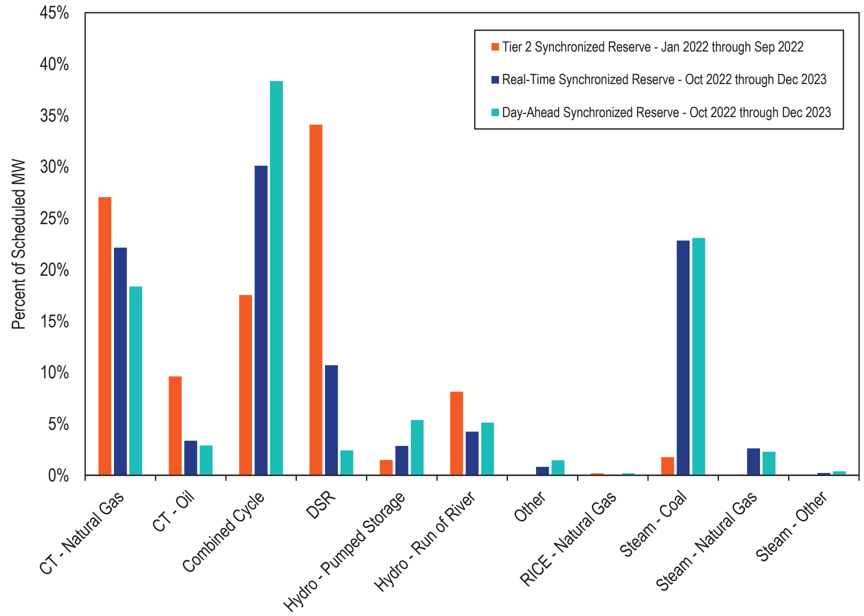
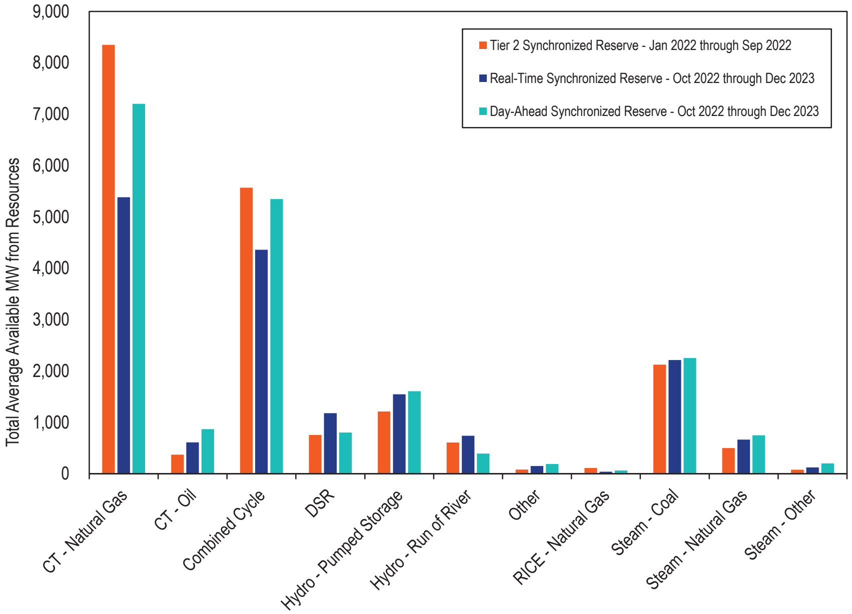


Figure 10-18 Total average available synchronized reserve from offering resources by type: 2022 through 2023



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. PJM's ALL-CALL system, until recently, could take several minutes to contact market operation centers (MOCs) for cleared resources and PJM allows MOCs to notify resources manually by phone, which might take minutes more to contact those resources, which then might take minutes even more to start responding. Previously, PJM's ALL-CALL system itself could be a source of appreciable delay, sometimes contacting scheduled resources minutes after an event began.

The MMU recommends that to minimize 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 respond to the notifications. PJM currently has an optional inter-control room connection protocol (ICCP) signal that some control rooms use, but it was not widely used in 2023 and the first nine months of 2024. This or another form of electronic signal should be required for all resources. Stakeholders approved a joint PJM/MMU proposal to implement an electronic communications and reserve deployment process on July 24, 2024. The new process is not required for all synchronized reserve resources. PJM plans to implement the electronic reserve deployment signal for some resources in December 2024.

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 calculated 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 effective January 1, 2024, is 18 days and was calculated using the events from November 1, 2021 through October 31, 2023.[64]

There are several problems with this penalty structure.[65] 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

64 See "2023 Third Quarter Synchronized Reserve Performance," PJM presentation to the Operations Committee. (December 7, 2023) <https://www.pjm.com/-/media/committees-groups/committees/oc/2023/20231207/20231207-item-07---synchronous-reserve-update.ashx>.

65 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>

overresponse.[66] 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 shortening the applied IPI significantly. 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 nine months of 2024, 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 $682,796 and the total LOC credit was $114,702.

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.

Table 10-22 shows the possible total historical penalty if the historical penalty had been defined differently in a single aspect for the first nine months of 2024. It compares the status quo, the amount if the IPI was defined using only events of 10 or more minutes, the amount if LOC credits were penalized in an amount proportionate to the shortfall, and if aggregate response were not allowed. 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 effect of only using 10-minute events is larger due to the amount of time between the 10-minute events on February 24 and July 8, increasing the amount of time since resources could have last failed to perform.

66 See PJM. "PJM Manual 28: Operating Agreement Accounting," § 6.3 Charges for Synchronized Reserve, Rev. 96 (Sept. 1, 2024).

Table 10-22 Comparison of historical/retroactive penalties using possible different definitions: January through September, 2024

Description	Total Retroactive Penalty
Status Quo	$1,298,830
Using only 10-minute events for IPI	$3,455,902
Including LOC credits in retroactive penalty	$1,531,275
Disallowing aggregate response	$1,310,446
All three changes	$3,948,213

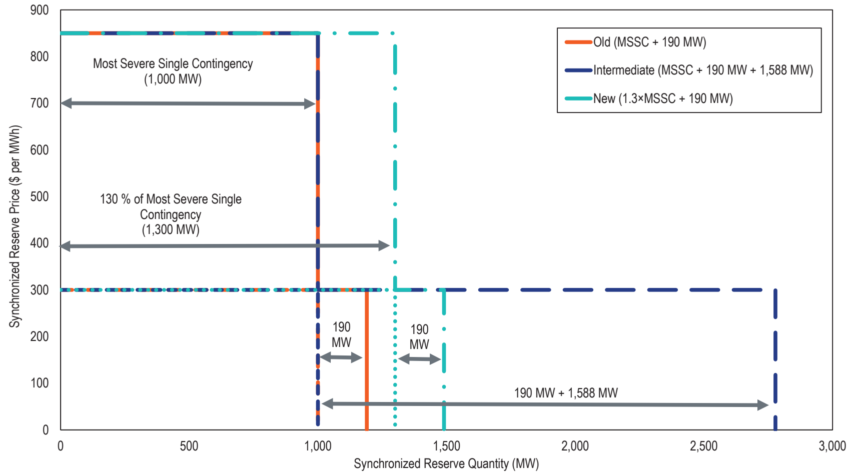
Resources should not be paid for reserves that they do not provide. The MMU recommends reclaiming credits back to the last known fully compliant performance, while providing the opportunity to demonstrate performance between events. Resources do not control when PJM calls 10-minute events, nor do they 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 Performance

In 2023, for the three events that were 10 or more minutes, the average response of synchronized reserve resources was 55.6 percent (Table 10-20). In May 2023, in response to poor 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 MSSC.

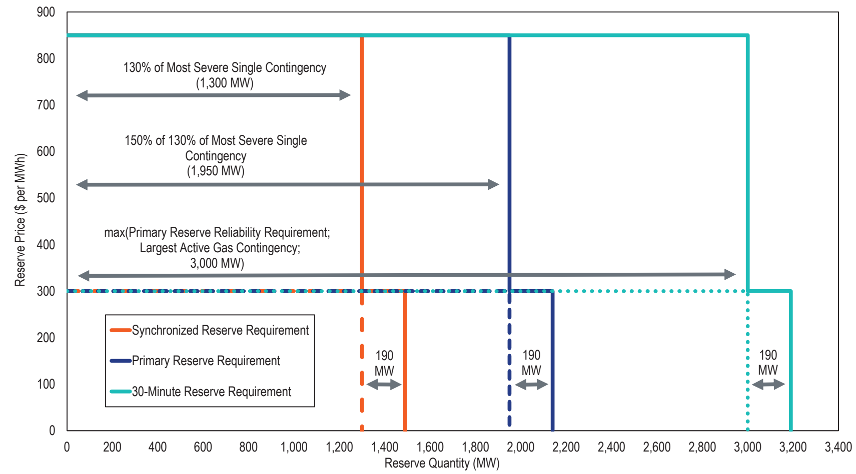
Figure 10-19 compares, for an example MSSC of 1,000 MW, the initial synchronized reserve ORDC from before these changes, the intermediate ORDC with the extension to the second step, and the new ORDC with the increase in the first step.

Figure 10-19 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, whose increase in turn increased the 30-minute reserve reliability requirement. Figure 10-20 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 10-5 shows the original ORDCs for the same example MSSC. As seen in Figure 10-2, and although not shown in Figure 10-20, due to the increase, the 30-minute reserve requirement is now usually equal to the primary reserve requirement.

Figure 10-20 An example of the reserve services' new real-time operating reserve demand curves, 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 requirement 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."[67] Neither temporary nor resource performance criteria are specified. Furthermore, 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 ever uses a subset.[68] However, 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. One was that resource response to spin events has been poor. Another, that the average length of spin events greater than 10 minutes has increased. A third, that PJM was concerned that it was on the path to becoming less able to avoid Disturbance Control Standard (DCS) violations, in which PJM would exceed the NERC-imposed 15-minute limit for recovering Reporting ACE from changes due to Reportable Disturbances.[69] The MMU agrees with the facts in the first and second statements, with caveats, but does not agree with the assumption about DCS events or that any of these reasons support PJM's actions.

The MMU agrees that average event length has increased, but notes that recent DCS event lengths have remained well below requirements, except in one case. On December 26, 2022, during Winter Storm Elliott, PJM recovered from a DCS event in 15 minutes and 52 seconds, longer than NERC's requirement of recovery within 15 minutes. Due to possible extenuating circumstances, NERC has yet to determine whether that recovery was actually a DCS violation. 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 5 minutes. Table 10-23 compares the lengths of recent DCS events with the lengths of their corresponding spin 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, Table 10-23 shows that the lengths of spin events do not suggest that PJM has become closer to having a DCS violation. Table 10-23 also shows that the lengths of DCS events with corresponding spin events from before the changes to the reserve markets were implemented on October 1, 2022, are not significantly different from the lengths of such events since then.

67 See PJM. "PJM Manual 11: Energy & Ancillary Services Market Operations," § 6.3 Charges for Synchronized Reserve, Rev. 132 (Sept. 1, 2024). "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."

68 See PJM. "PJM Manual 12: Balancing Operations," § 4.1.2 Loading Reserves, Rev. 53 (July 24, 2024).

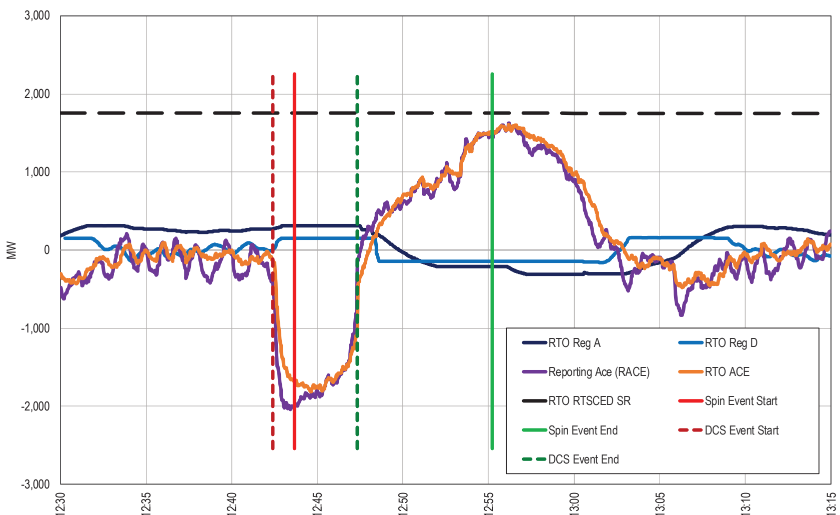
69 See PJM. "PJM Manual 12: Balancing Operations," Rev. 53 (July 24, 2024) Attachment D.

Table 10-23 A comparison of the lengths of recent DCS events with that of their corresponding spin events: January 2022 through September 2024

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

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 ends when Reporting ACE (RACE) recovers to its level at the time of the loss of supply, while the spin events ends based on PJM discretion.

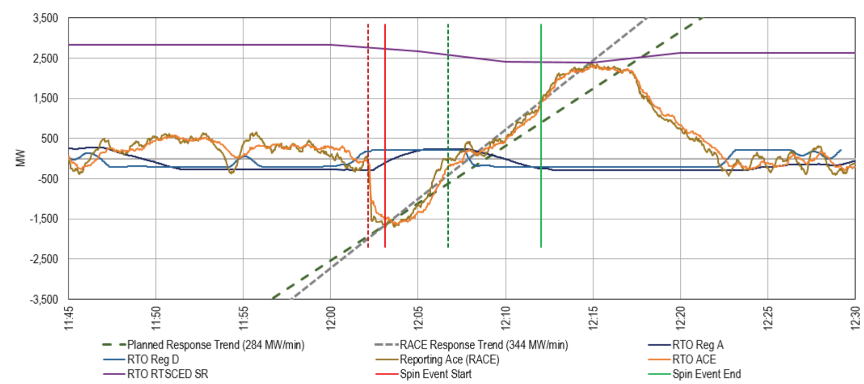
Figure 10-21 DCS Event vs. Spin Event: January 5, 2023



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 reserve 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 14 spin events in the first nine months of 2024, 10 were less than 10 minutes. Because those 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 15 of the 21 spin events for the RTO Reserve Zone that have occurred since the reserve requirement increase, 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. Although 17 of those 21 events lasted less than 10 minutes, PJM evaluated performance as unsatisfactory due to the under-response from the assigned resources. Therefore, PJM maintains the increase to the reserve requirements, but 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.[70] 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 lack of response means 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 5 MW of reserve, then PJM should only be purchasing 5 MW of reserve from them. PJM should not be paying MCP credit 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 months or $1.6 million per month for January 2023 through April 2023. In the first nine months of 2024, the total credits paid for synchronized reserve were $58.5 million dollars or $6.5 million per month. The cost of underperformance by reserve suppliers is being 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.

History of Synchronized Reserve Events

Synchronized reserve is designed to provide relief for disturbances.[71] [72] A disturbance is defined as loss of the lesser of 900 MW and 80 percent of the largest single contingency within 60 seconds. In the absence of a disturbance,

70 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>.

71 *2012 Annual State of the Market Report for PJM*, Appendix E – PJM's DCS Performance.

72 See PJM. "PJM Manual 12: Balancing Operations," § 4.1.2 Loading Reserves, Rev. 53 (July 24, 2024).

PJM operators have used synchronized reserve as a source of energy to provide relief from low ACE. Of the 12 spin events that occurred in 2023, three were explicitly due to low ACE. Of those three events, none were longer than 10 minutes. Of the 14 events that occurred in the first nine months of 2024, one was explicitly due to low ACE. That one event was longer than 10 minutes.

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 2019 through September 2024, PJM experienced 97 synchronized reserve events, approximately 1.6 events per month, with an average duration of 11.2 minutes. Table 10-24 shows these events with their region and their duration rounded to the nearest minute.

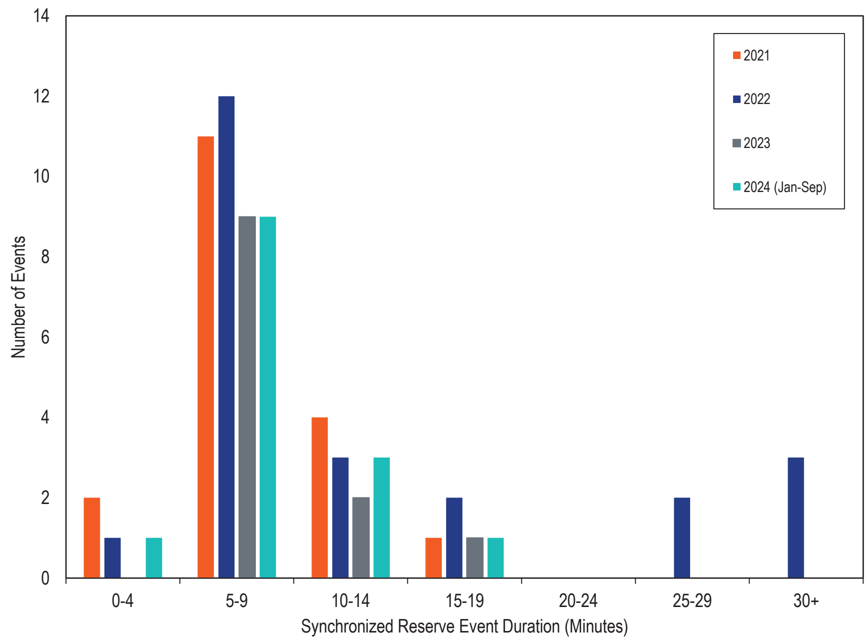
Table 10-24 Synchronized reserve events: January 2019 through September 2024[73]

Effective Time	Region	Duration (Minutes)	Effective Time	Region	Duration (Minutes)	Effective Time	Region	Duration (Minutes)
22-Jan-2019 2230 (EPT)	RTO	8	24-Jan-2021 2232 (EPT)	RTO	6	05-Jan-2023 1243 (EPT)	RTO	12
31-Jan-2019 0126 (EPT)	RTO	5	09-Mar-2021 0751 (EPT)	RTO	11	10-Jan-2023 0706 (EPT)	RTO	18
31-Jan-2019 0926 (EPT)	RTO	9	13-Apr-2021 2005 (EPT)	RTO	9	26-Jan-2023 1452 (EPT)	MAD	7
25-Feb-2019 0025 (EPT)	RTO	9	30-Apr-2021 2030 (EPT)	RTO	12	02-Feb-2023 0606 (EPT)	RTO	8
03-Mar-2019 1231 (EPT)	RTO	9	26-May-2021 1417 (EPT)	RTO	10	28-May-2023 2009 (EPT)	RTO	7
06-Mar-2019 2206 (EPT)	RTO	9	21-Jun-2021 0554 (EPT)	RTO	7	11-Jun-2023 1611 (EPT)	MAD	9
27-Jul-2019 2331 (EPT)	RTO	7	23-Jun-2021 0333 (EPT)	RTO	5	23-Jun-2023 1905 (EPT)	RTO	7
11-Aug-2019 1214 (EPT)	RTO	8	21-Jul-2021 1828 (EPT)	RTO	5	08-Aug-2023 0041 (EPT)	RTO	8
03-Sep-2019 1339 (EPT)	MAD	9	25-Jul-2021 1617 (EPT)	RTO	6	07-Nov-2023 1619 (EPT)	RTO	5
23-Sep-2019 1606 (EPT)	RTO	11	23-Aug-2021 1644 (EPT)	RTO	18	10-Nov-2023 0621 (EPT)	RTO	8
01-Oct-2019 1856 (EPT)	RTO	11	24-Aug-2021 1038 (EPT)	RTO	8	15-Dec-2023 0041 (EPT)	RTO	12
11-Dec-2019 2108 (EPT)	RTO	8	27-Sep-2021 1656 (EPT)	RTO	8	19-Dec-2023 0951 (EPT)	RTO	7
18-Dec-2019 1507 (EPT)	RTO	9	11-Oct-2021 0923 (EPT)	RTO	9			
			16-Oct-2021 0130 (EPT)	RTO	8	13-Jan-2024 0159 (EPT)	RTO	5
20-Jan-2020 1406 (EPT)	MAD	8	12-Nov-2021 1325 (EPT)	RTO	12	25-Jan-2024 1239 (EPT)	RTO	9
23-Jan-2020 1617 (EPT)	RTO	9	30-Nov-2021 0540 (EPT)	RTO	9	29-Jan-2024 1203 (EPT)	RTO	9
07-Feb-2020 1206 (EPT)	RTO	6	30-Nov-2021 0957 (EPT)	RTO	9	24-Feb-2024 1548 (EPT)	MAD	12
08-Feb-2020 0344 (EPT)	RTO	8	08-Dec-2021 0504 (EPT)	RTO	7	04-Apr-2024 1050 (EPT)	RTO	5
10-Feb-2020 2015 (EPT)	RTO	9				13-Apr-2024 0036 (EPT)	RTO	7
18-Feb-2020 1116 (EPT)	RTO	10	03-Jan-2022 1227 (EPT)	RTO	9	03-Jun-2024 1853 (EPT)	RTO	9
08-Mar-2020 0517 (EPT)	MAD	5	03-Mar-2022 1220 (EPT)	RTO	7	29-Jun-2024 2103 (EPT)	RTO	6
13-Apr-2020 2001 (EPT)	RTO	8	06-Apr-2022 1145 (EPT)	RTO	10	08-Jul-2024 1757 (EPT)	RTO	15
03-May-2020 1229 (EPT)	RTO	6	13-Apr-2022 1725 (EPT)	RTO	28	18-Jul-2024 1524 (EPT)	RTO	7
06-Jul-2020 2122 (EPT)	RTO	10	14-Apr-2022 0931 (EPT)	RTO	8	21-Jul-2024 1753 (EPT)	RTO	10
24-Jul-2020 0103 (EPT)	RTO	9	16-May-2022 1532 (EPT)	RTO	11	12-Aug-2024 1710 (EPT)	RTO	10
25-Jul-2020 1639 (EPT)	MAD	11	16-May-2022 1553 (EPT)	RTO	10	18-Aug-2024 1604 (EPT)	RTO	16
10-Sep-2020 0019 (EPT)	RTO	10	23-May-2022 1717 (EPT)	RTO	15	26-Aug-2024 1353 (EPT)	RTO	4
10-Oct-2020 1852 (EPT)	RTO	8	26-May-2022 1409 (EPT)	RTO	6			
12-Oct-2020 0429 (EPT)	RTO	9	22-Jun-2022 1506 (EPT)	RTO	7			
13-Nov-2020 0746 (EPT)	RTO	6	27-Jun-2022 1701 (EPT)	RTO	9			
16-Dec-2020 1638 (EPT)	MAD	10	07-Jul-2022 1721 (EPT)	RTO	8			
			26-Sep-2022 0339 (EPT)	RTO	6			
			29-Sep-2022 1025 (EPT)	RTO	6			
			29-Oct-2022 1412 (EPT)	RTO	12			
			04-Nov-2022 1503 (EPT)	RTO	4			
			14-Nov-2022 22:01 (EPT)	RTO	7			
			29-Nov-2022 1630 (EPT)	RTO	17			
			23-Dec-2022 1014 (EPT)	RTO	11			
			23-Dec-2022 1617 (EPT)	RTO	111			
			24-Dec-2022 0501 (EPT)	RTO	26			
			24-Dec-2022 0223 (EPT)	RTO	31			
			24-Dec-2022 0423 (EPT)	RTO	88			

73 For full history of spinning events, see the *2022 Annual State of the Market Report for PJM*, Appendix E - Ancillary Service Markets.

Figure 10-23 shows spin event durations over the past 4 years. Some events 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 2021 through September 2024



Nonsynchronized Reserve

Nonsynchronized 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, the nonsynchronized reserve market clearing price is $0 per MWh.

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 nine months of 2024.

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 nine months of 2024, the average amount of real-time cleared nonsynchronized reserve was 861.3 MW and the average day-ahead cleared nonsynchronized reserve was 977.6 MW. In the MAD Reserve Subzone, in the first nine months of 2024, the average real-time cleared nonsynchronized reserve was 614.3 MW and the average day-ahead cleared nonsynchronized reserve was 665.7 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 have defined themselves to be emergency only are not considered. Resources that generally qualify as nonsynchronized reserve include run of river hydro, pumped hydro, combustion turbines, diesels, and combined cycles 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 nine months of 2024, an average of 861.3 MW of nonsynchronized reserve was cleared per five-minute interval out of 893.9 eligible 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 nine months of 2024.

Figure 10-24 Daily Average Available Nonsynchronized Reserve: January through September, 2024

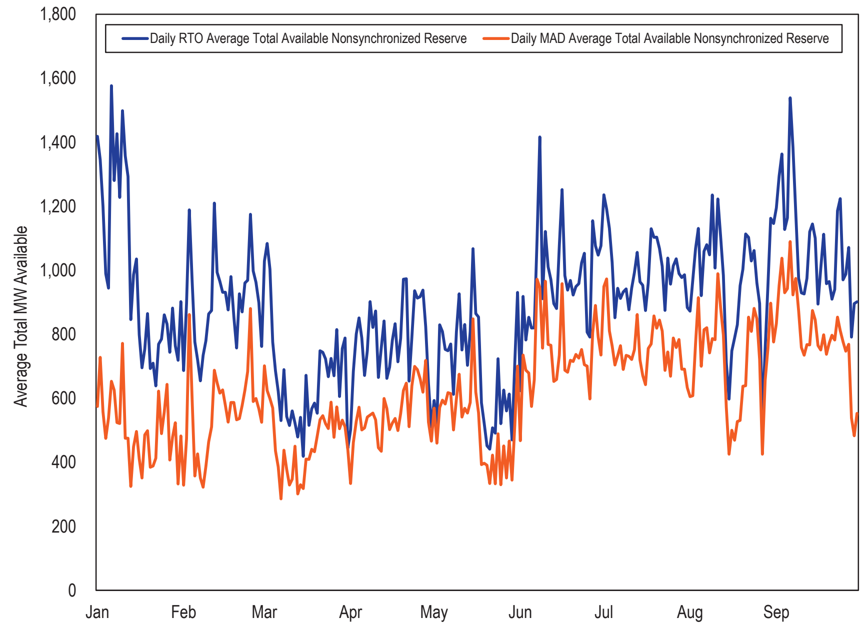
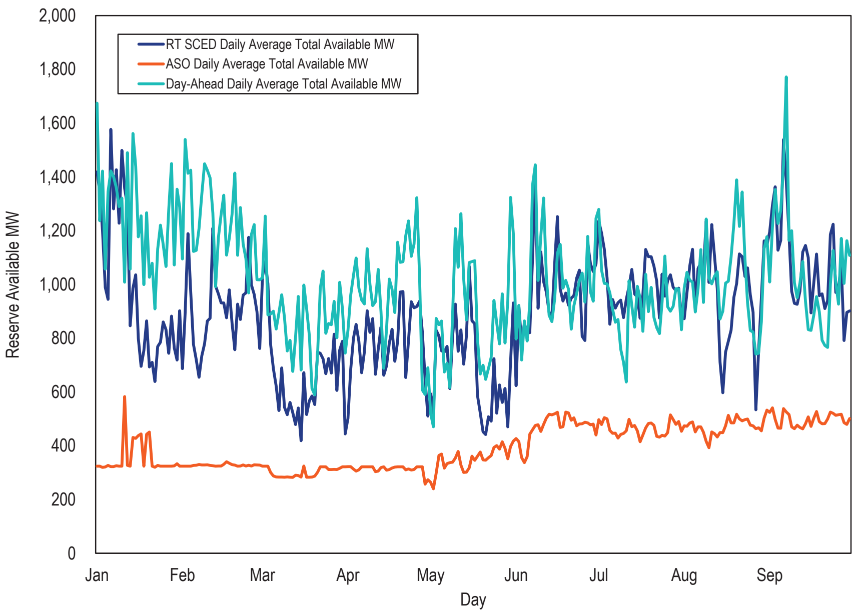


Figure 10-25 shows the daily average total available NSR MW in the ASO, RT SCED, and day-ahead solutions. The available MW in the ASO are consistently lower than in RT SCED due to differences in the applied unit schedules.

Figure 10-25 Daily average total available MW in the day-ahead, ASO, and RT SCED solutions: January through September, 2024



Market Behavior

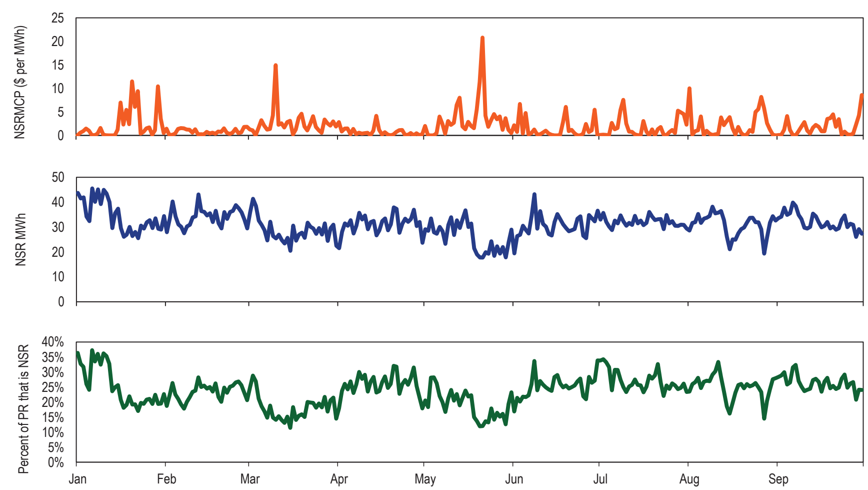
The offer price for nonsynchronized reserve for all resources is cost based, which is $0 per MWh for all resources.

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 nine months of 2024, the real-time weighted average nonsynchronized market clearing price for all intervals was $1.68 per MWh and the real-time average nonsynchronized reserve cleared was 861.3 MW. The day-ahead weighted average nonsynchronized market clearing price for all intervals was $1.42 per MWh and the day-ahead average nonsynchronized reserve cleared MW was 977.6 MW.

Shortage pricing was used in the RTO Reserve Zone for primary reserve on January 20, January 22, January 29, March 10, March 18, April 14, May 21, June 3, July 8, July 28, and September 4. Shortage pricing was used in the MAD Reserve Subzone for primary reserve on January 20, January 21, January 22, and June 3. Conservative operations due to cold weather were in place from January 13 through January 17. The shortage pricing on January 29, June 3, and July 8 occurred during spin events. 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 through September, 2024



The price of nonsynchronized reserve in most intervals of the first nine months of 2024 was greater than $0 per MWh. Table 10-25 shows the number of five-minute intervals with a market clearing price above $0 per MWh. The day-ahead market clears by hour, equivalent to blocks of 12 five-minute intervals. There were 78,900 five-minute intervals in the first nine months of 2024. The nonsynchronized reserve market clearing price (NSRMCP) is equal to the cost of the marginal primary reserve resource.[74] 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 a SR resource with a nonzero cost, then the NSRMCP in that interval will also be nonzero.

Table 10-25 Number of five minute intervals with NSRMCP above $0 per MWh: January through September, 2024

Location	Market	Number of Intervals Where NSRMCP Above $0 per MWh	Percent of Intervals Where NSRMCP Above $0 per MWh
RTO	RT	54,404	69.0%
RTO	DA	54,504	69.1%
MAD	RT	54,883	69.6%
MAD	DA	55,068	69.8%

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 nine months of 2024, the number of such intervals differed for the RTO Reserve Zone and the MAD Reserve Subzone from January 17 through January 24, when PJM increased reserve requirements during conservative operations (Table 10-7) and when PJM used shortage pricing for primary reserve. Table 10-26 shows the intervals for which a nonzero NSRMCP did not equal the SRMCP. In the first nine months of 2024, only three of the seven intervals was an interval of shortage, but all intervals occurred on days with shortage.

74 See PJM. "PJM Manual 11: Energy & Ancillary Services Market Operations," § 4.4.5.2 Determination of Non-Synchronized Reserve Clearing Prices, Rev. 132 (Sept. 1, 2024).

Figure 10-27 Number of intervals per day for which a nonzero NSRMCP equaled the SRMCP: January 2023 through September 2024

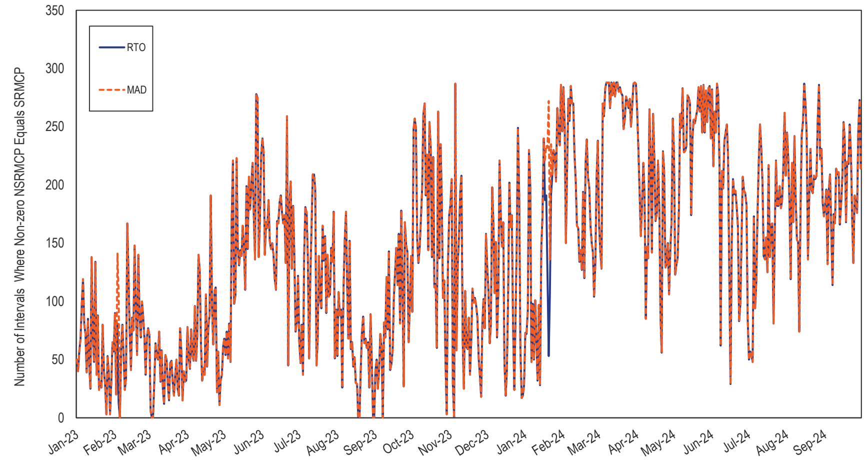


Table 10-26 Intervals with a nonzero NSRMCP in which the NSRMCP did not equal the SRMCP: January through September, 2024

	RTO		MAD	
Interval	NSRMCP	SRMCP	NSRMCP	SRMCP
21-Jan-2024 0400 (EPT)	$0.02	$0.02	$0.02	$0.04
21-Jan-2024 0420 (EPT)	$0.01	$0.01	$0.01	$0.04
21-Jan-2024 0655 (EPT)	$0.04	$0.04	$0.04	$21.23
22-Jan-2024 0325 (EPT)	$0.02	$0.02	$0.02	$0.04
29-Jan-2024 1210 (EPT)	$850.00	$956.74	$850.00	$956.74
03-Jun-2024 1900 (EPT)	$850.00	$1,700.00	$1,150.00	$1,700.00
28-Jul-2024 1730 (EPT)	$850.00	$1,552.06	$850.00	$1,552.06

Table 10-27 shows the effect of fast start pricing on the nonsynchronized reserve market's monthly weighted average market clearing price since October 2022. 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 nine months of 2024, the weighted average real-time price from the pricing run was 32.3 percent higher than the weighted average real-time price from the dispatch run. In the first nine months of 2024, the weighted average day-ahead price from the pricing run was 2.9 percent higher than the weighted average day-ahead price from the dispatch run.

Table 10-27 Comparison of fast start and dispatch RTO pricing: January 2023 through September 2024

		Day-Ahead				Real-Time			
Year	Month	Dispatch-Run MCP	Pricing-Run MCP	Difference	Percent Difference	Dispatch-Run MCP	Pricing-Run MCP	Difference	Percent Difference
2023	Jan	$0.06	$0.07	$0.00	7.4%	$0.23	$0.28	$0.05	22.4%
2023	Feb	$0.05	$0.05	$0.00	0.1%	$0.06	$0.10	$0.05	81.1%
2023	Mar	$0.08	$0.08	$0.00	3.6%	$0.03	$0.06	$0.03	94.3%
2023	Apr	$0.31	$0.32	$0.01	2.1%	$0.24	$0.40	$0.16	69.4%
2023	May	$0.94	$0.94	($0.00)	(0.0%)	$1.59	$2.10	$0.51	31.8%
2023	Jun	$0.88	$0.90	$0.01	1.6%	$0.23	$0.41	$0.17	73.3%
2023	Jul	$2.28	$2.34	$0.06	2.6%	$0.47	$0.78	$0.31	65.0%
2023	Aug	$0.52	$0.55	$0.04	6.8%	$0.11	$0.18	$0.07	64.2%
2023	Sep	$0.68	$0.72	$0.04	5.9%	$0.21	$0.32	$0.11	49.8%
2023	Oct	$5.11	$5.16	$0.05	0.9%	$1.08	$1.71	$0.63	57.8%
2023	Nov	$2.66	$2.70	$0.04	1.5%	$0.32	$0.52	$0.20	63.0%
2023	Dec	$0.39	$0.40	$0.01	3.0%	$0.31	$0.45	$0.13	42.6%
2023	All	$1.00	$1.02	$0.02	2.0%	$0.40	$0.61	$0.20	49.8%
2024	Jan	$0.48	$0.49	$0.01	1.4%	$1.13	$1.38	$0.26	22.6%
2024	Feb	$0.48	$0.48	$0.00	0.3%	$0.58	$0.81	$0.23	40.4%
2024	Mar	$1.57	$1.58	$0.01	0.7%	$1.71	$2.43	$0.72	42.1%
2024	Apr	$2.77	$2.79	$0.02	0.6%	$0.47	$0.73	$0.26	54.1%
2024	May	$2.09	$2.09	($0.00)	(0.2%)	$2.00	$3.12	$1.13	56.5%
2024	Jun	$1.11	$1.19	$0.08	7.1%	$1.11	$1.26	$0.15	13.6%
2024	Jul	$1.56	$1.68	$0.11	7.4%	$1.32	$1.65	$0.32	24.6%
2024	Aug	$1.19	$1.25	$0.06	5.0%	$1.66	$1.99	$0.32	19.4%
2024	Sep	$1.39	$1.44	$0.06	4.1%	$1.31	$1.77	$0.46	35.5%
2024	All	$1.32	$1.36	$0.04	2.9%	$1.25	$1.65	$0.40	32.3%

Table 10-28 Comparison of fast start and dispatch MAD pricing: October 2022 through September 2024

		Day-Ahead				Real-Time			
Year	Month	Dispatch-Run MCP	Pricing-Run MCP	Difference	Percent Difference	Dispatch-Run MCP	Pricing-Run MCP	Difference	Percent Difference
2023	Jan	$0.09	$0.10	$0.00	4.0%	$0.43	$0.45	$0.02	4.2%
2023	Feb	$0.12	$0.12	($0.00)	(0.0%)	$0.16	$0.23	$0.07	44.7%
2023	Mar	$0.12	$0.13	$0.00	3.6%	$0.05	$0.09	$0.04	83.5%
2023	Apr	$0.53	$0.54	$0.01	2.1%	$0.34	$0.59	$0.25	72.0%
2023	May	$1.05	$1.04	($0.00)	(0.3%)	$1.88	$2.50	$0.61	32.7%
2023	Jun	$0.93	$0.94	$0.01	1.0%	$0.27	$0.47	$0.20	76.8%
2023	Jul	$2.23	$2.27	$0.04	1.7%	$0.49	$0.82	$0.33	67.3%
2023	Aug	$0.66	$0.69	$0.03	4.7%	$0.15	$0.24	$0.09	56.0%
2023	Sep	$0.66	$0.69	$0.03	4.1%	$0.35	$0.44	$0.09	26.6%
2023	Oct	$5.27	$5.31	$0.04	0.7%	$1.37	$2.11	$0.73	53.5%
2023	Nov	$3.18	$3.22	$0.04	1.2%	$0.41	$0.67	$0.27	65.6%
2023	Dec	$0.42	$0.43	$0.01	2.2%	$0.42	$0.60	$0.18	42.7%
2023	All	$1.08	$1.10	$0.02	1.4%	$0.53	$0.77	$0.24	45.7%
2024	Jan	$0.67	$0.68	$0.01	1.1%	$2.09	$2.46	$0.36	17.4%
2024	Feb	$0.51	$0.51	$0.00	0.3%	$0.72	$1.01	$0.29	40.9%
2024	Mar	$1.78	$1.79	$0.01	0.8%	$1.98	$2.82	$0.84	42.4%
2024	Apr	$3.16	$3.18	$0.02	0.6%	$0.58	$0.87	$0.29	49.5%
2024	May	$2.12	$2.11	($0.01)	(0.3%)	$2.07	$3.27	$1.20	57.9%
2024	Jun	$1.23	$1.26	$0.04	2.9%	$1.25	$1.41	$0.16	13.1%
2024	Jul	$1.82	$1.93	$0.11	5.9%	$1.43	$1.78	$0.35	24.3%
2024	Aug	$1.32	$1.38	$0.06	4.5%	$1.90	$2.27	$0.38	19.9%
2024	Sep	$1.46	$1.51	$0.05	3.4%	$1.46	$1.98	$0.52	35.4%
2024	All	$1.48	$1.51	$0.03	2.2%	$1.49	$1.96	$0.46	31.1%

In the first nine months of 2024, the weighted average price of nonsynchronized reserve was $1.68 per MWh and the weighted average credit for nonsynchronized reserve was $1.35 per MWh.

Table 10-29 shows the total nonsynchronized reserve payments by month from January 2023 through September 2024. In May 2023 through December 2023, payments increased due to the increased reserve requirements. However, as can be seen in Figure 10-2, Figure 10-26, and Figure 10-27, this large increase in payments was not fully driven by a large increase in the amount of cleared NSR. Instead, as shown by the decrease in the fraction of primary reserve that is nonsynchronized reserve for May 2023 until mid-August 2023, seen in Figure 10-26, this increase was driven by the disproportionate increased use of the more expensive synchronized reserve product to satisfy the increased primary reserve service requirement. This proportionate use ended in August 2023 due to an increase in available NSR MW (Figure 10-24). Higher day-ahead credits in July 2023 are due to prices spikes for hot weather alerts for July 27 and July 28.

Table 10-29 Total nonsynchronized reserve payments and charges by month: January 2023 through September 2024

Year	Month	Day-Ahead Credits	Real-Time and Balancing MCP Credits	LOC Credits	Shortfall Charges	Total Credits
2023	Jan	$73,610	($156,594)	$5,897	NA	($77,087)
2023	Feb	$72,133	($113,616)	$31,461	NA	($10,022)
2023	Mar	$72,194	($37,459)	$3,572	NA	$38,307
2023	Apr	$220,075	($114,010)	$60,599	NA	$166,664
2023	May	$764,690	($602,088)	$477,365	NA	$639,967
2023	Jun	$648,961	($134,877)	$48,934	NA	$563,017
2023	Jul	$1,697,877	($227,431)	$30,765	NA	$1,501,211
2023	Aug	$422,257	($17,911)	$1,642	NA	$405,988
2023	Sep	$503,832	$66,886	$2,149	NA	$572,867
2023	Oct	$2,934,103	$4,297	$115,662	NA	$3,054,062
2023	Nov	$1,789,002	($4,285)	$59,988	NA	$1,844,705
2023	Dec	$387,670	($90,673)	$35,279	NA	$332,276
2023	All	$9,586,405	($1,427,760)	$873,311	NA	$9,031,956
2024	Jan	$549,761	($805,570)	$246,452	NA	($9,357)
2024	Feb	$406,207	($224,893)	$144,292	NA	$325,606
2024	Mar	$907,106	($493,717)	$265,668	NA	$679,056
2024	Apr	$1,854,995	($145,771)	$81,948	NA	$1,791,172
2024	May	$1,236,498	($655,115)	$575,064	NA	$1,156,446
2024	Jun	$879,638	($184,008)	$41,825	NA	$737,454
2024	Jul	$1,271,008	($166,519)	$42,325	NA	$1,146,814
2024	Aug	$952,433	($143,830)	$71,568	NA	$880,171
2024	Sep	$1,072,480	($391,855)	$267,027	NA	$947,653
2024	All	$9,130,125	($3,211,278)	$1,736,169	NA	$7,655,017

Table 10-30 provides the day-ahead and real-time nonsynchronized reserve by fuel type for the first nine months of 2024.

Table 10-30 Day-ahead and real-time nonsynchronized reserve by fuel type: January through September, 2024

Fuel Type	Day-Ahead MWh	Real-Time Scheduled MWh	Day-Ahead Credits	Balancing MCP Credits	LOC Credits	Total Credits
Oil	2,361,944	2,380,226	$5,968,167	($89,581)	$1,484	$5,880,070
Hydro	3,735,183	2,937,941	$2,825,974	($2,929,909)	$1,691,388	$1,587,453
Natural Gas	310,802	337,392	$286,812	($154,783)	$40,873	$172,902
Other	19,752	7,349	$49,173	($37,005)	$2,424	$14,592

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 primary 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.[75] Unlike with synchronized reserve and primary reserve, PJM does not model a 30-minute reserve requirement for the defined reserve subzone.[76] 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 nine months of 2024.

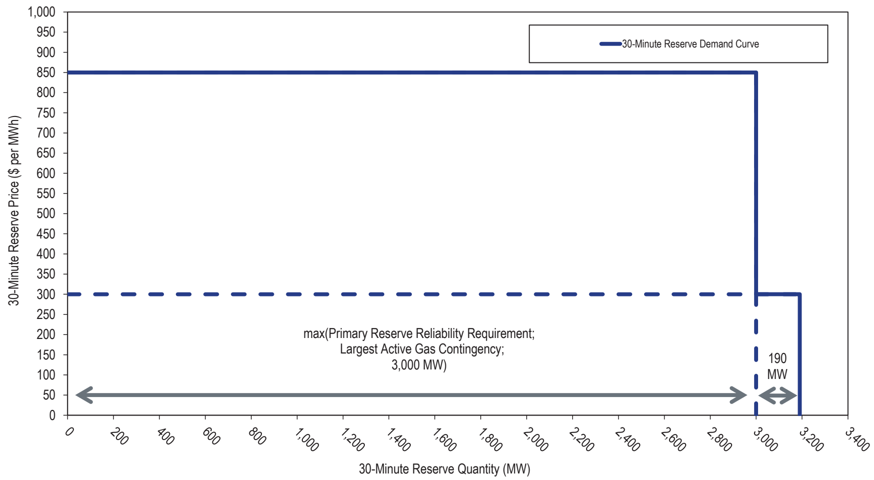
Figure 10-28 shows an example ORDC for 30-minute reserve for when the primary reserve reliability requirement and the largest active gas contingency

75 See PJM. "PJM Manual 11: Energy & Ancillary Services Market Operations" § 4.3 Reserve Requirement Determination, Rev. 132 (Sept. 1,, 2024).

76 See PJM. "PJM Manual 11: Energy & Ancillary Services Market Operations" § 4.3.1 Locational Aspect of Reserves, Rev. 132 (Sept. 1, 2024).

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 nine months of 2024, the average real-time 30-minute requirement was 3,571.1 MW and the average day-ahead 30-minute requirement was 3,642.3 MW (Figure 10-4).

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 nine months of 2024, 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 (Table 10-9).

Market Concentration

Table 10-31 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 nine months of 2024, the RTO Reserve Zone was moderately concentrated in the day-ahead market and unconcentrated in the real-time market.

Table 10-31 PJM 30-minute reserve market HHI: January through September, 2024

Location	Market	Average HHI	Percent of Intervals Max Market Share Above 20%	Description
RTO	RT	909	70.6%	Unconcentrated
RTO	DA	1032	84.6%	Moderately Concentrated

Market Performance

Due to the large amount of available secondary reserve, most 30-minute reserve is procured for little 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 nine months of 2024, no interval was ever short of 30-minute reserves.

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 service requirement, and is cleared for five-minute intervals in real time and 60-minute intervals day ahead. Failure to convert offline secondary reserves to energy at PJM's request results in a shortfall charge.

Unlike synchronized reserves and nonsynchronized reserves, there is no "event" process to deploy secondary reserves. 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).

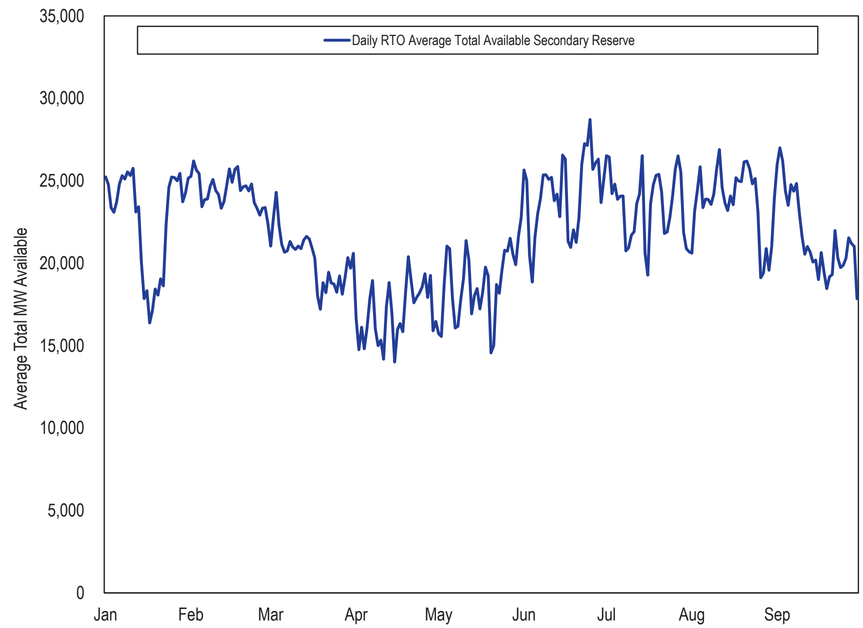
Supply

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.

As with the other reserve products, for most resources, PJM determines the MW available for secondary reserve based on energy offer parameters.[77] Energy storage resources, 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.[78] The use of the secondary reserve maximum output limit requires prior approval by PJM.[79] 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.[80] Certain resource types, including nuclear, wind, and solar units, are by default excluded from providing secondary reserves.

Figure 10-29 shows the daily average total available secondary reserve in the first nine months of 2024. In the first nine months of 2024, the average real-time supply of secondary reserve was 21,791.9 MW.

Figure 10-29 Daily Average Available Secondary Reserve: January through September, 2024



77 See PJM. "PJM Manual 11: Energy & Ancillary Services Market Operations" § 4.2.3 Reserve Market Resource Offer Structure, Rev. 132 (Sept. 1, 2024).
78 See PJM. "PJM Manual 11: Energy & Ancillary Services Market Operations" § 4.2.5.1 Reserve Market Capability for Online Generation Resources, Rev. 132 (Sept. 1, 2024).
79 See PJM. "PJM Manual 11: Energy & Ancillary Services Market Operations" § 4.2.2.1 Communication for Reserve Capability Limitation, Rev. 132 (Sept. 1, 2024).
80 See PJM. "PJM Manual 11: Energy & Ancillary Services Market Operations" § 4.2.5.2 Reserve Market Capability for Offline Generation Resources, Rev. 132 (Sept. 1, 2024).

Market Behavior

For all resources, the secondary reserve offer price is $0 per MWh.[81] For online resources, the energy market opportunity cost is calculated by PJM based on market prices.

Market Performance

Figure 10-30 provides the prices for secondary reserves for the first nine months of 2024. In the first nine months of 2024, the secondary reserve market clearing price in the real-time and day-ahead markets was always $0 per MWh.

Figure 10-30 Secondary reserve prices: January through September, 2024

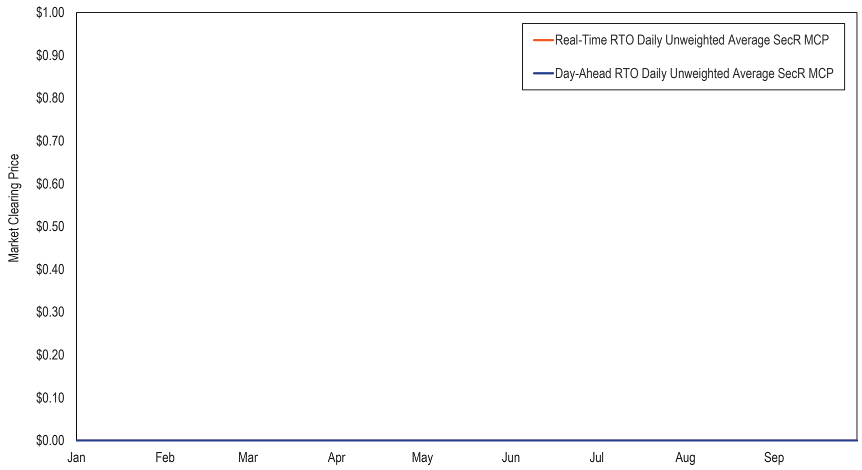


Table 10-32 compares the dispatch run and pricing run market clearing prices for the day-ahead and real-time secondary reserve markets. For both the dispatch run and the pricing run, the real-time values are the LPC prices for each run weighted by the RT SCED MW. For the day-ahead values, these are the DA prices weighted by the DA dispatch MW. In the first nine months of 2024, the day-ahead and real-time prices of secondary reserve were always $0 per MWh in both the pricing run and the dispatch run.

Table 10-32 Comparison of fast start and dispatch pricing components: January 2023 through September 2024

		Day-Ahead				Real-Time			
Year	Month	Dispatch-Run MCP	Pricing-Run MCP	Difference	Percent Difference	Dispatch-Run MCP	Pricing-Run MCP	Difference	Percent Difference
2023	Jan	$0.00	$0.00	$0.00	NA	$0.00	$0.00	$0.00	NA
2023	Feb	$0.00	$0.00	$0.00	NA	$0.00	$0.00	$0.00	NA
2023	Mar	$0.00	$0.00	$0.00	NA	$0.00	$0.00	$0.00	NA
2023	Apr	$0.00	$0.00	$0.00	NA	$0.00	$0.00	$0.00	NA
2023	May	$0.00	$0.00	$0.00	NA	$0.00	$0.00	$0.00	NA
2023	Jun	$0.00	$0.00	$0.00	NA	$0.00	$0.00	$0.00	NA
2023	Jul	$0.00	$0.00	$0.00	NA	$0.00	$0.00	$0.00	NA
2023	Aug	$0.00	$0.00	$0.00	NA	$0.00	$0.00	$0.00	NA
2023	Sep	$0.00	$0.00	$0.00	NA	$0.00	$0.00	$0.00	NA
2023	Oct	$0.00	$0.00	$0.00	NA	$0.00	$0.00	$0.00	NA
2023	Nov	$0.00	$0.00	$0.00	NA	$0.00	$0.00	$0.00	NA
2023	Dec	$0.00	$0.00	$0.00	NA	$0.00	$0.00	$0.00	NA
2023	All	$0.00	$0.00	$0.00	NA	$0.00	$0.00	$0.00	NA
2024	Jan	$0.00	$0.00	$0.00	NA	$0.00	$0.00	$0.00	NA
2024	Feb	$0.00	$0.00	$0.00	NA	$0.00	$0.00	$0.00	NA
2024	Mar	$0.00	$0.00	$0.00	NA	$0.00	$0.00	$0.00	NA
2024	Apr	$0.00	$0.00	$0.00	NA	$0.00	$0.00	$0.00	NA
2024	May	$0.00	$0.00	$0.00	NA	$0.00	$0.00	$0.00	NA
2024	Jun	$0.00	$0.00	$0.00	NA	$0.00	$0.00	$0.00	NA
2024	Jul	$0.00	$0.00	$0.00	NA	$0.00	$0.00	$0.00	NA
2024	Aug	$0.00	$0.00	$0.00	NA	$0.00	$0.00	$0.00	NA
2024	Sep	$0.00	$0.00	$0.00	NA	$0.00	$0.00	$0.00	NA
2024	All	$0.00	$0.00	$0.00	NA	$0.00	$0.00	$0.00	NA

Table 10-33 shows the day-ahead credits, balancing market credits, LOC credits, and effective shortfall charges for secondary reserves from January 2023 through June 2024.[82] In the first nine months of 2024, the weighted average secondary reserve market clearing price was $0.00 per MWh. In the first nine months of 2024, the weighted average credit per MWh, considering the total credits paid and the capped MWh, was $0.02 per MWh.

81 See PJM. "PJM Manual 11: Energy & Ancillary Services Market Operations" § 4.2.3 Reserve Market Resource Offer Structure, Rev. 132 (Sept. 1, 2024).

82 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 10-33 Monthly secondary reserve settlements: January 2023 through September 2024

Year	Month	Total Day-Ahead Credits	Total Balancing MCP Credits	Total LOC Credits	Total Effective Shortfall Charge	Total Credits
2023	Jan	$0	$0	$5,114	$0	$5,114
2023	Feb	$0	$0	$34,120	$0	$34,120
2023	Mar	$0	$0	$12,363	$0	$12,363
2023	Apr	$0	$0	$15,125	$0	$15,125
2023	May	$0	$0	$64,712	$0	$64,712
2023	Jun	$0	$0	$137,072	$0	$137,072
2023	Jul	$0	$0	$351,847	$0	$351,847
2023	Aug	$0	$0	$133,220	$0	$133,220
2023	Sep	$0	$0	$157,624	$0	$157,624
2023	Oct	$0	$0	$120,331	$0	$120,331
2023	Nov	$0	$0	$149,391	$0	$149,391
2023	Dec	$0	$0	$54,212	$0	$54,212
2023	All	$0	$0	$1,235,131	$0	$1,235,131
2024	Jan	$0	$0	$159,892	$0	$159,892
2024	Feb	$0	$0	$96,114	$0	$96,114
2024	Mar	$0	$0	$130,590	$0	$130,590
2024	Apr	$0	$0	$96,468	$0	$96,468
2024	May	$0	$0	$289,740	$0	$289,740
2024	Jun	$0	$0	$125,809	$0	$125,809
2024	Jul	$0	$0	$313,370	$0	$313,370
2024	Aug	$0	$0	$395,898	$0	$395,898
2024	Sep	$0	$0	$114,300	$0	$114,300
2024	All	$0	$0	$1,722,181	$0	$1,722,181

Table 10-34 provides secondary reserve credits by resource type for the first nine months of 2024. Despite clearing a total of tens of thousands of MWh day-ahead, combined-cycle units, coal steam units, and natural-gas steam units cleared zero MWh of secondary reserve in real time.

Table 10-34 Secondary reserve credits by resource type: January through September, 2024

Resource / Fuel Type	Day-Ahead MWh	Real-Time Capped MWh	Day-Ahead Credits	Balancing MCP Credits	LOC Credits	Total Credits
CT - Natural Gas	74,695,427	98,186,441	$0	$0	$1,570,143	$1,570,143
CT - Oil	12,614,170	14,330,360	$0	$0	$53,207	$53,207
Other	36,935	167,101	$0	$0	$38,793	$38,793
Combined Cycle	41,199	0	$0	$0	$23,427	$23,427
RICE - Natural Gas	461,638	390,363	$0	$0	$19,397	$19,397
RICE - Oil	683,647	774,541	$0	$0	$15,339	$15,339
Hydro	2,732	1,027	$0	$0	$1,416	$1,416
Steam - Coal	19,671	0	$0	$0	$352	$352
Steam - Natural Gas	5,162	0	$0	$0	$107	$107

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.

Market Design

PJM's regulation market design is a result of Order No. 755.[83] The objective of PJM's regulation market design should be to minimize the cost to provide regulation using two resource types in a single market.

The regulation market includes resources following two signals: RegA and RegD. Resources responding to either signal help control ACE (area control error). RegA is PJM's slow oscillation regulation signal and is designed for resources with the ability to sustain energy output for long periods of time, with slower ramp rates. RegD is PJM's fast oscillation regulation signal and is designed for resources with limited ability to sustain energy output and with faster ramp rates. Resources must qualify to follow one or both of the RegA and RegD signals, but will be assigned by the market clearing engine to follow only one signal in a given market hour.

83 Order No. 755, 137 FERC ¶ 61,064 at P 2 (2011).

The PJM regulation market design includes three clearing price components: capability ($/MW, based on the MW offered); performance ($/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 marginal benefit factor (MBF) and performance score translate a RegD resource's capability (actual) MW into marginal effective MW and offers into $/effective MW.

The goal of the regulation market solution should be to meet the regulation requirement with the least cost combination of RegA and RegD. When solving for the least cost combination of RegA and RegD MW to meet the regulation requirement, the regulation market will substitute RegD MW for RegA MW when RegD is cheaper. Performance adjusted RegA MW are used as the common unit of measure, called effective MW, of regulation service. All resource MW (RegA and RegD) are converted into effective MW. RegA MW are converted into effective MW by multiplying the RegA MW offered by their performance score. RegD MW are converted into effective MW by multiplying the RegD offered by their performance score and by the MBF. The regulation requirement is defined as the total effective MW required to provide a defined amount of area control error (ACE) control.

The regulation market converts performance adjusted RegD MW into effective MW using the MBF in the PJM design. The MBF is used to convert incremental additions of RegD MW into incremental effective MW. The total effective MW for a given amount of RegD MW equal the area under the MBF curve (the sum of the incremental effective MW contributions). RegA and RegD resources should be paid the same price per effective MW.

The marginal rate of technical substitution (MRTS) is the marginal measure of substitutability of RegD resources for RegA resources in satisfying a defined regulation requirement at feasible combinations of RegA and RegD MW. While resources following RegA and RegD can both provide regulation service in PJM's Regulation Market, PJM's joint optimization is intended to determine and assign the optimal mix of RegA and RegD MW to meet the hourly regulation requirement. The optimal mix is a function of the relative effectiveness and cost of available RegA and RegD resources.

At any valid combination of RegA and RegD, regulation offers are converted to dollars per effective MW using the RegD offer and the MBF associated with that combination of RegA and RegD. The marginal contribution of a RegD MW to effective MW is equal to the MRTS associated with that RegA/RegD combination.

For example, a 1.0 MW RegD resource with a total offer price of $2 per MW with a MBF of 0.5 and a performance score of 100 percent would be calculated as offering 0.5 effective MW (0.5 MBF times 1.00 performance score times 1 MW). The total offer price would be $4 per effective MW ($2 per MW offer divided by the 0.5 effective MW).

Regulation performance scores (0.0 to 1.0) measure the response of a regulating resource to its assigned regulation signal (RegA or RegD) every 10 seconds by measuring: delay, the time delay of the regulation response to a change in the regulation signal; correlation, the correlation between the regulating resource output and the regulation signal; and precision, the difference between the regulation response and the regulation requested.[84] Performance scores are reported on an hourly basis for each resource.

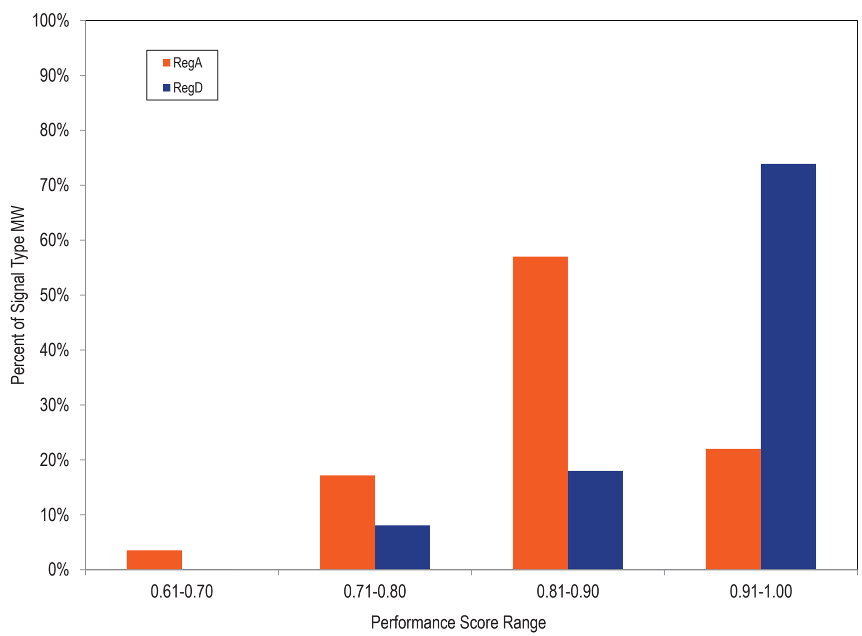
Table 10-35 and Figure 10-31 show the average performance score by resource type and the signal followed in the first nine months of 2024. In these figures, the MW used are actual MW and the performance score is the hourly performance score of the regulation resource.[85] Each category (color bar) is based on the percentage of the full performance score distribution for each resource (or signal) type. As Figure 10-31 shows, 73.9 percent of RegD resources had average performance scores within the 0.91-1.00 range, and 22.0 percent of RegA resources had average performance scores within that range in the first nine months of 2024. In the first nine months of 2023, 67.4 percent of RegD resources had average performance scores within the 0.91-1.00 range, and 21.0 percent of RegA resources had average performance scores within that range.

84 PJM "Manual 12: Balancing Operations," § 4.5.6 Performance Score Calculation, Rev. 54 (July 24, 202).
85 Except where explicitly referred to as effective MW or effective regulation MW, MW means actual MW unadjusted for either MBF or performance factor.

Table 10-35 Hourly average performance score by unit type: January through September, 2024

		Performance Score Range			
		61-70	71-80	81-90	91-100
RegA	Battery	-	-	-	-
	CT	0.0%	1.6%	76.2%	22.1%
	Diesel	0.0%	0.0%	3.1%	96.9%
	DSR	0.0%	0.0%	0.0%	100.0%
	Hydro	3.0%	1.8%	43.1%	52.0%
	Steam	4.0%	24.7%	61.8%	9.1%
RegD	Battery	0.1%	3.9%	22.6%	73.5%
	CT	0.0%	17.7%	16.1%	66.2%
	Diesel	0.0%	0.0%	46.4%	53.6%
	DSR	0.0%	21.4%	2.3%	76.4%
	Hydro	0.0%	0.0%	100.0%	0.0%
	Steam	-	-	-	-

Figure 10-31 Hourly average performance score by regulation signal type: January through September, 2024



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

The MMU identified an issue with the current method of calculating the regulation performance score of a resource. The issue is that the delay and correlation components of the performance score do not accurately reflect how well a unit is responding to the regulation signal. These delay and correlation components can remain high, even when a unit is responding poorly to the regulation signal, and artificially inflate the overall performance score of the unit. For example, during the Winter Storm Elliott event, several units were not able to maintain their response to the regulation signal. These units received a precision score of zero, however, their delay and accuracy scores were near perfect (>0.95). This resulted in several units receiving regulation credits because their overall performance score was approximately 0.65 (each component of the performance score has an equal 1/3 weighting) despite not actually providing regulation. To address this issue, the MMU has proposed to evaluate regulation performance using a precision based performance score, which would only depend on the difference between the regulation signal and the unit's response to that signal.

$$Performance\ Score_{10Sec} = 1 - ABS\left(\frac{RegOutputMW - SignalMW}{AReg}\right)$$

With the total performance score for the clearing interval being the average of each 10 second performance score. This means that, in a simplified 10 second interval, a unit that cleared 10 MW (AREG = 10 MW) responding with a steady 7.5 MW (75 percent of their total capability) to a positive pegged signal (Signal MW = 10; TREG = 100 percent) would logically receive a performance score of 0.75. The MMU presented this recommendation to the regulation market senior task force.

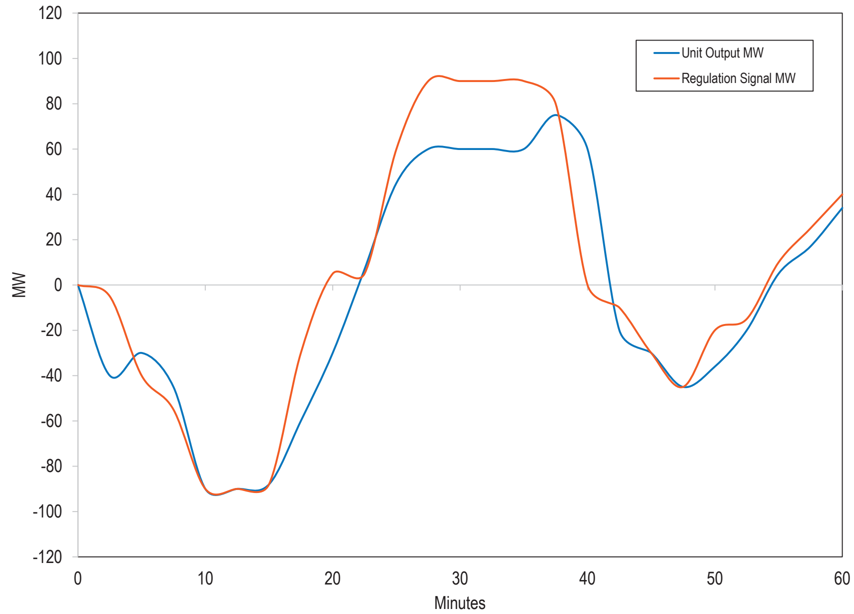
PJM's proposed solution evaluates the 10 second error in a unit's output based on the average regulation signal MW during the entire clearing interval.[86]

$$Performance\ Score_{10Sec} = 1 - ABS\left[\frac{(RegOutputMW - SignalMW)}{\left(\frac{ClearingIntervalAvgSignal + AReg}{2}\right)}\right]$$

This has the effect of scaling each 10 second performance score based on the clearing interval average of the overall regulation signal. Using this equation in the simplified case above would yield a performance score equal to 0.75 only if the clearing interval average signal is pegged, and less than 0.75 when the clearing interval average signal is close to zero.

Figure 10-32 illustrates an example unit that cleared 100 MW of regulation, following the regulation signal for one hour. Based on the MMU's proposed performance score calculation, the unit would have a performance score of 0.8450 for the hour. Using PJM's proposed calculation, that same unit would have a performance score of only 0.6981 for the hour because the clearing interval average signal is small (2.7 MW). If both the regulation signal and the unit's response in this example were shifted up (or down) by 10 MW, the MMU's result would remain the same, because it only depends on the response of the unit to the signal it is supposed to follow. The PJM result however, would change to 0.7249 because the clearing interval average signal would increase to 12.7 MW. PJM's calculation would lead to different results, based solely on the overall clearing interval average of the regulation signal; identical unit performance would yield different performance score results.

Figure 10-32 A unit providing 100 MW of regulation while following an almost neutral regulation signal



Resources are paid Regulation Market Clearing Price (RMCP) credits and lost opportunity cost credits, which are uplift payments. If a resource's lost opportunity costs for an hour are greater than its RMCP credits, that resource receives lost opportunity cost credits equal to the difference. PJM posts clearing prices for the regulation market (RMCCP, RMPCP and RMCP) in dollars per effective MW. The regulation market clearing price (RMCP in $/effective MW) for the hour is the simple average of the 12 five minute RMCPs within the hour. The RMCP is set in each five minute interval based on the marginal offer in each interval. The performance clearing price (RMPCP in $/effective MW) is based on the marginal performance offer (RMPCP) for the hour. The capability clearing price (RMCCP in $/effective MW) is equal to the difference between the RMCP for the hour and the RMPCP for the hour. This

86 The current regulation clearing interval is one hour. The proposed change is to move to a 30 minute clearing interval.

is done so the total of RMPCP plus RMCCP equals the total clearing price (RMCP) but the RMPCP is maximized.

Market solution software relevant to regulation consists of the Ancillary Services Optimizer (ASO) solving hourly; 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 approximately every five minutes. The market clearing price is determined by pricing software (LPC) that looks at the units cleared in the most recently approved RT SCED case, approximately 10 minutes ahead of the target solution time. The marginal prices assigned by the LPC to five minute intervals are averaged over the hour for an hourly regulation market clearing price.

Market Design Issues

PJM's current regulation market design is severely flawed and is not efficient or competitive. The market results do not represent the least cost solution for the defined level of regulation service.

In a well functioning market, every resource should be paid the same clearing price per unit produced. That is not true in the PJM Regulation Market. RegA and RegD resources are not paid the same clearing price in dollars per effective MW. RegD resources are being paid more than the market clearing price. This flaw in the market design has caused operational issues, has caused over investment in RegD resources.

If all MW of regulation were treated the same in both the clearing of the market and in settlements, many of the issues in the PJM Regulation Market would be resolved. However, the current PJM rules result in the payment to RegD resources being up to 1,000 times the correct price.

RegA and RegD have different physical capabilities. In order to permit RegA and RegD to compete in the single PJM Regulation Market, RegD must be translated into the same units as RegA. One MW of RegA is one effective MW. The translation is done using the marginal benefit factor (MBF). As more RegD is added to the market, the relative value of RegD declines, based on its actual performance attributes. For example, if the MBF is 0.001, a MW of RegD is worth 0.001 MW of RegA (or 1/1,000 of a MW of RegA). This is the same thing as saying that 1.0 MW of RegD is equal to 0.001 effective MW when the MBF is 0.001.

Almost all of the issues in PJM's Regulation Market are caused by the inconsistent application of the MBF. Because the MBF is not included in settlements, when the MBF is less than 1.0, RegD resources are paid too much. When the MBF is less than 1.0, each MW of RegD is worth less than 1.0 MW of RegA. The market design buys the correct amount of RegD, but pays RegD as if the MBF were 1.0. In an extreme case, when the MBF is 0.001, RegD MW are paid 1,000 times too much. If the market clearing price is $1.00 per MW of RegA, RegD is paid $1,000 per effective MW. Resolution of this problem requires that PJM pay RegD for the same effective MW it provides in regulation, 0.001 MW.

To address the identified market flaws, the MMU and PJM developed a joint proposal which was approved by the PJM Members Committee on July 27, 2017, and filed with FERC on October 17, 2017. The PJM/MMU joint proposal addresses issues with the inconsistent application of the marginal benefit factor throughout the optimization and settlement process in the PJM Regulation Market. FERC rejected the proposal finding it inconsistent with Order No. 755.

The MBF related issues with the regulation market have been raised in the PJM stakeholder process. In 2015, PJM stakeholders approved an interim, partial solution to the RegD over procurement problem which was implemented on December 14, 2015. The interim solution was designed to reduce the relative value of RegD MW in all hours and to cap purchases of RegD MW during critical performance hours. But the interim solution did not address the fundamental issues in the optimization or the lack of consistency in the application of the MBF.

Additional changes were implemented on January 9, 2017. These modifications included changing the definition of off peak and on peak hours, adjusting the currently independent RegA and RegD signals to be interdependent, and changing the 15 minute neutrality requirement of the RegD signal to a 30 minute neutrality requirement.

The January 9, 2017, design changes appear to have been intended to make RegD more valuable. That is not a reasonable design goal. The design goal should be to determine the least cost way to provide needed regulation. The RegA signal is now slower than it was previously, which may make RegA following resources less useful as ACE control. RegA is now explicitly used to support the conditional energy neutrality of RegD. The RegD signal is now the difference between ACE and RegA. RegA is required to offset RegD when RegD moves in the opposite direction of that required by ACE control in order to permit RegD to recharge. These changes in the signal design will allow PJM to accommodate more RegD in its market solutions. The new signal design is not making the most efficient use of RegA and RegD resources. The explicit reliance on RegA to offset issues with RegD is a significant conceptual change to the design that is inconsistent with the long term design goal for regulation. PJM increased the regulation requirement as part of these changes.

The January 9, 2017, design changes replaced off peak and on peak hours with nonramp and ramp hours with definitions that vary by season. The regulation requirement for ramp hours was increased from 700 MW to 800 MW (Table 10-36). These market changes still do not address the fundamental issues in the optimization or the lack of consistency in the application of the MBF.

Table 10-36 Seasonal regulation requirement definitions[87]

Season	Dates	Nonramp Hours	Ramp Hours
		00:00 - 03:59	04:00 - 08:59
Winter	Dec 1 - Feb 28(29)	09:00 - 15:59	16:00 - 23:59
		00:00 - 04:59	05:00 - 07:59
Spring	Mar 1 - May 31	08:00 - 16:59	17:00 - 23:59
		00:00 - 04:59	05:00 - 13:59
Summer	Jun 1 - Aug 31	14:00 - 17:59	18:00 - 23:59
		00:00 - 04:59	05:00 - 07:59
Fall	Sep 1 - Nov 30	08:00 - 16:59	17:00 - 23:59

87 See PJM. "Regulation Requirement Definition," <http://www.pjm.com/~/media/markets-ops/ancillary/regulation-requirement-definition.ashx>.

Performance Scores

Performance scores, by class and unit, are not an indicator of how well resources contribute to ACE control. Performance scores are an indicator only of how well the resources follow their TREG signal. High performance scores with poor signal design are not a meaningful measure of performance. For example, if ACE indicates the need for more regulation but RegD resources have provided all their available energy, the RegD regulation signal will be in the opposite direction of what is needed to control ACE. So, despite moving in the wrong direction for ACE control, RegD resources would get a good performance score for following the RegD signal and will be paid for moving in the wrong direction.

The RegD signal prior to January 9, 2017, is an example of a signal that resulted in high performance scores, but due to 15 minute energy neutrality built into the signal, ran counter to ACE control at times. Energy neutrality means that energy produced equals energy used within a defined timeframe. With 15 minute energy neutrality, if a battery were following the regulation signal to provide MWh for 7.5 minutes, it would have to consume the same amount of MWh for the next 7.5 minutes. When neutrality correction of the RegD signal is triggered, it overrides ACE control in favor of achieving zero net energy over the 15 minute period. When this occurs, the RegD signal runs counter to the control of ACE and hurts rather than helps ACE. In that situation, the control of ACE, which must also offset the negative impacts of RegD, depends entirely on RegA resources following the RegA signal. High performance scores under the signal design prior to January 9, 2017, was not an indication of good ACE control.

The January 9, 2017, design changes did not address the fundamental issues with the definition of performance or the nature of payments for performance in the regulation market design. The regulation signal should not be designed to favor a particular technology. The signal should be designed to result in the lowest cost of regulation to the market. Only with a performance score based on full substitutability among resource types should payments be based on following the signal. The MRTS must be redesigned to reflect the actual capabilities of technologies to provide regulation. The PJM regulation market design remains fundamentally flawed.

In addition, the absence of a performance penalty, imposed as a reduction in performance score and/or as a forfeiture of revenues, for deselection initiated by the resource owner within the hour, creates a possible gaming opportunity for resources which may overstate their capability to follow the regulation signal. The MMU recommends that there be a penalty enforced as a reduction in performance score and/or a forfeiture of revenues when resource owners elect to deassign assigned regulation resources within the hour, to prevent gaming.

Battery Settlement

The change from 15 to 30 minute signal neutrality, implemented in the January 9, 2017, design changes, resulted in the reduction of performance scores for short duration batteries. In April 2017 several participants filed a complaint against PJM, asserting that these changes discriminated against their battery units.[88] The MMU objected to the complaints. Despite the unsupported assertions in the complaint, PJM settled with the participants. The settlement was approved by FERC on April 7, 2020.[89] Table 10-37 shows the battery units that are part of the settlement. Starting July 1, 2020, the affected battery units began receiving compensation based on the greater of their current performance score, or their rolling average actual hourly performance score for the last 100 hours the resource operated prior to the January 9, 2017, implementation of the 30-minute conditional neutrality. The additional regulation credits received as a result of the settlement, from July 2020 through December 2023, are shown in Table 10-38. From July 2020 through December 2023, the battery settlement has provided $4.7 million in excess regulation credits. The term of the settlement was for 42 months, and ended December 31, 2023.

Table 10-37 Batteries in settlement

Parent Company	Unit	MW	Status
The AES Corporation	Laurel Mountain	32.0	Active
	Warrior Run	10.0	Retired
Energy Capital Partners, LLC	Hazel	20.0	Active
Galt Power, Inc.	Trent	4.0	Retired
	McHenry	20.0	Active
	Beckjord 1	2.0	Active
	Beckjord 2	2.0	Active
Invenergy, LLC	Beech Ridge	31.5	Active
	Grand Ridge 6	4.5	Retired
	Grand Ridge 7	31.5	Active
NextEra Energy, Inc.	Lee Dekalb	20.0	Active
	Garrett	10.4	Active
	Meyersdale	18.0	Active
	Mantua Creek	2.0	Active
Renewable Energy Systems Holdings, LTD	Joliet	20.0	Retired
	West Chicago	20.0	Retired
Sumitomo Corporation	Willey	6.0	Active

Table 10-38 Total excess regulation credits received by settlement batteries: July 2020 through December 2023

	Excess Regulation Credit ($)												
Year	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Total
2020	-	-	-	-	-	-	$49,068	$39,863	$26,064	$56,734	$55,966	$52,532	$280,226
2021	$40,752	$82,768	$76,248	$61,786	$65,797	$60,896	$76,253	$136,365	$112,929	$156,829	$213,585	$118,995	$1,203,204
2022	$230,764	$84,963	$70,375	$128,896	$104,817	$179,703	$160,327	$216,929	$169,958	$143,995	$85,026	$659,729	$2,235,481
2023	$83,125	$76,978	$83,153	$109,917	$129,600	$122,258	$125,028	$106,175	$96,513	$134,478	$88,512	$80,893	$1,236,631
												Grand Total	$4,955,543

In addition to paying uneconomic regulation credits based on inflated performance scores, the settlement also requires that the affected battery units be cleared in the regulation market regardless of whether their offer was economic. As long as the settlement batteries are offered as either self scheduled with a zero offer, or as a zero priced offer, they must be cleared despite the fact that these units would not necessarily have cleared based on economics.[90] In order to comply with this condition, PJM clears additional MW beyond what is needed for the regulation requirement in cases where the settlement battery units did not clear but met the offer rules of the settlement. This results in excess charges to customers for regulation service. Table 10-39

88 See FERC Docket Nos. EL17-64-000 and EL17-65-000.

89 See 170 FERC ¶ 61,258 (2020).

90 See *id.* at P 17.

shows the impact of clearing additional MW beyond what is needed for the regulation requirement, as a result of the entire battery settlement, from July 2020 through December 2023. Other changes in market dynamics starting in the third quarter of 2021 reduced the impact of this settlement rule because most of the settlement units clear based on economics. In 2023, the battery settlement resulted in customers paying $132,376 more than needed, in order to compensate the additional MW from settlement batteries that would not have otherwise cleared. As a result of the entire battery settlement from July 2020 to December 2023, PJM customers over paid for regulation by $5,614,484 (the sum of Table 10-38 and Table 10-39).

Table 10-39 Total excess payments and monthly additional MW cleared due to battery settlement: July 2020 through December 2023

		Battery Settlement Impact	
Year	Month	Regulation Credits	Additional Cleared Regulation MW
2020	Jul	$6,963	171.2
	Aug	$2,810	233.1
	Sep	$7,089	535.2
	Oct	$14,201	631.7
	Nov	$7,287	603.3
	Dec	$18,341	1,127.3
	Total	$56,691	3,301.7
2021	Jan	$49,387	3,149.4
	Feb	$24,776	1,727.7
	Mar	$37,648	3,192.6
	Apr	$78,650	4,872.3
	May	$117,329	7,718.7
	Jun	$2,092	147.4
	Jul	$1,856	26.3
	Aug	$205	8.5
	Sep	$955	26.9
	Oct	$33,819	1,046.2
	Nov	$12,888	238.7
	Dec	$39	4.9
	Total	$359,644	22,159.4
2022	Jan	$3,576	54.5
	Feb	$9,974	384.3
	Mar	$43,880	833.3
	Apr	$829	24.7
	May	$4,056	78.9
	Jun	$904	33.5
	Jul	$10,454	240.9
	Aug	$10,487	234.9
	Sep	$13,474	182.8
	Oct	$5,539	133.1
	Nov	$1,014	83.1
	Dec	$6,043	105.2
	Total	$110,230	2,389.1
2023	Jan	$10,985	47.5
	Feb	$1,495	122.7
	Mar	$5,974	334.9
	Apr	$42,900	1,548.2
	May	$4,484	201.3
	Jun	$3,926	267.5
	Jul	$5,812	187.9
	Aug	$3,638	118.2
	Sep	$34,792	1,183.1
	Oct	$11,526	313.5
	Nov	$4,820	241.6
	Dec	$2,025	119.6
	Total	$132,376	4,685.8
Grand Total		$658,941	32,536.1

Regulation Signal

As with any signal design for substitutable resources, the MBF function should be determined by the ability of RegA and RegD resources to follow their signals, including conditions under which neutrality cannot be maintained by RegD resources. The ability of energy limited RegD to provide ACE control depends on the availability of excess RegA capability to support RegD under the conditional neutrality design. When RegD resources are largely energy limited resources, a correctly calculated MBF would exhibit a rapid decrease in the MBF value for every MW of RegD added. The result is that only a small amount of energy limited RegD is economic. The current and proposed signals and corresponding MBF functions do not reflect these principles or the actual substitutability of resource types.

Through the ongoing stakeholder regulation task force, the MMU has proposed several changes to address the current issues with the regulation signal market design. The MMU proposes that the two signals be combined into one, simplified regulation signal. All units would be cleared based on their total performance adjusted offers, with performance scores used as a tie breaker for equal offers (the status quo). Performance scores would be modified to only include a precision score. The move to a single signal would also eliminate the 30-minute signal neutrality but the regulation market clearing period would be shortened from one hour to 30 minutes. This would allow units with issues providing for a full hour to leave the market if needed without the regulation signal being tailored to uneconomically accommodate specific unit types.

Marginal Benefit Factor Issues

The MBF function, as implemented in the PJM Regulation Market, is not equal to the MRTS between RegA and RegD. The MBF is not consistently applied throughout the market design, from optimization to settlement, and market clearing does not confirm that the resulting combinations of RegA and RegD are realistic and can meet the defined regulation demand. The calculation of total regulation cleared using the MBF is incorrect.[91]

The result has been that the PJM Regulation Market has over procured RegD relative to RegA in most hours, has provided a consistently inefficient market signal to participants regarding the value of RegD in every hour, and has overpaid for RegD. This over procurement has degraded the ability of PJM to control ACE in some hours while at the same time increasing the cost of regulation. When the price paid for RegD is above the level defined by an accurate MBF function, there is an artificial incentive for inefficient entry of RegD resources.

PJM and the MMU filed a joint proposal with FERC on October 17, 2017, to address issues with the inconsistent application of the marginal benefit factor throughout the optimization and settlement process in the PJM Regulation Market, but the proposal was rejected by FERC.[92]

Marginal Benefit Factor Not Correctly Defined

The MBF used in the PJM Regulation Market prior to the December 14, 2015, changes did not accurately reflect the MRTS between RegA and RegD resources under the old market design, and it does not accurately reflect the MRTS between RegA and RegD resources under the current design. The MBF function is incorrectly defined and improperly implemented in the current PJM Regulation Market.

The MBF should be the marginal rate of technical substitution between RegA and RegD MW at different, feasible combinations of RegA and RegD that can be used to provide a defined level of regulation service. The objective of the market design is to find, given the relative costs of RegA and RegD MW, the least cost feasible combination of RegA and RegD MW. If the MBF function is incorrectly defined, or improperly implemented in the market clearing and settlement, the resulting combinations of RegA and RegD will not represent the least cost solution and may not be a feasible way to reach the target level of regulation.

The MBF is not included in PJM's settlement process. This is a design flaw that results in incorrect payments for regulation. The issue results from two FERC orders. From October 1, 2012, through October 31, 2013, PJM implemented a FERC order that required the MBF to be fixed at 1.0 for settlement calculations only. On October 2, 2013, FERC directed PJM to eliminate the use of the

91 The MBF, as used in this report, refers to PJM's incorrectly calculated MBF and not the MBF equivalent to the MRTS.

92 162 FERC ¶ 61,295 (2018), *reh'g denied*, 170 FERC ¶ 61,259 (2020).

MBF entirely from settlement calculations of the capability and performance credits and replace it with the RegD to RegA mileage ratio in the performance credit paid to RegD resources, effective retroactively to October 1, 2012.[93] That rule continues in effect. The result of the current FERC order is that the MBF is used in market clearing to determine the relative value of an additional MW of RegD, but the MBF is not used in the settlement for RegD.

If the MBF were consistently applied, every resource would receive the same clearing price per marginal effective MW. But the MBF is not consistently applied and resources do not receive the same clearing price per marginal effective MW.

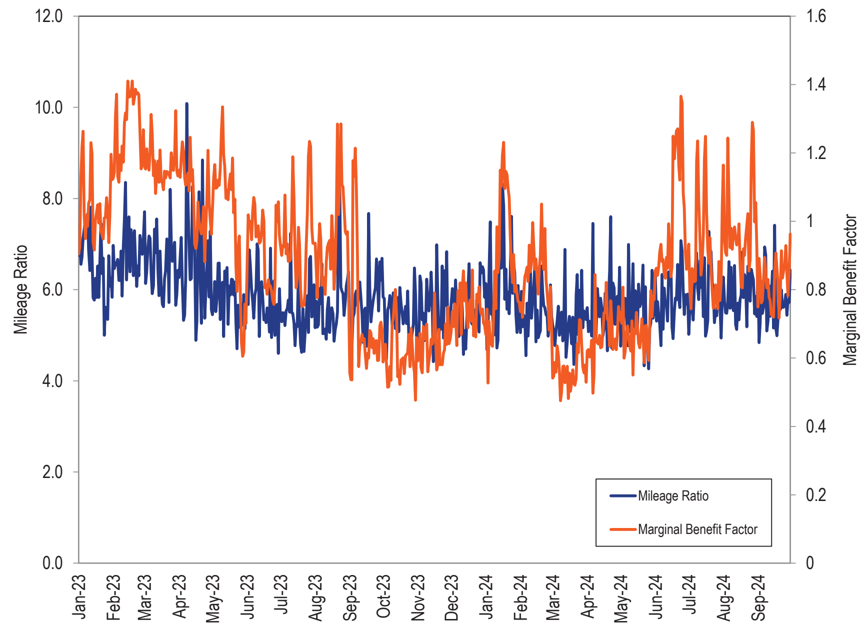
The change in design decreased RegA mileage (the change in MW output in response to regulation signal per MW of capability), increased the proportion of cleared RegD resources' capability that was called by the RegD signal (increased REG for a given MW) to better match offered capability, increased the mileage required of RegD resources and changed the energy neutrality component of the signal from a strict 15 minute neutrality to a conditional 30 minute neutrality. The changes in signal design increased the mileage ratio (the ratio of RegD mileage to RegA mileage). In addition, to adapt to the 30 minute neutrality requirement, some RegD resources decreased their offered capability to maintain their performance.

Figure 10-33 shows the daily average MBF and the mileage ratio. The weighted average mileage ratio decreased from 6.11 in the first nine months of 2023, to 5.71 in the first nine months of 2024 (a decrease of 6.6 percent). The average MBF decreased from 1.01 in the first nine months of 2023, to 0.82 in the first nine months of 2024 (a decrease of 19.0 percent). The high mileage ratios are the result of the mechanics of the mileage ratio calculation. Extreme mileage ratios result when the RegA signal is fixed at a single value (pegged) to control ACE and the RegD signal is not. If RegA is held at a constant MW output, mileage is zero for RegA. The result of a fixed RegA signal is that RegA mileage is very small and therefore the mileage ratio is very large.

93 145 FERC ¶ 61,011 (2013).

These results are an example of why it is not appropriate to use the mileage ratio, rather than the MBF, to measure the relative value of RegA and RegD resources. In these events, RegA resources are providing ACE control by providing a fixed level of MW output which means zero mileage, while RegD resources alternate between helping and hurting ACE control, both of which result in positive mileage.

Figure 10-33 Daily average MBF and mileage ratio: January 2023 through September 2024



The increase in the average mileage ratio caused by the signal design changes introduced on January 9, 2017, caused a large increase in payments to RegD resources on a performance adjusted MW basis.

Table 10-40 shows RegD resource payments on a performance adjusted actual MW basis and RegA resource payments on a performance adjusted MW basis by month, from January 1, 2023, through September 30, 2024. The average regulation market clearing price in the first nine months of 2024 was $9.26 higher than in the first nine months of 2023 (See Table 10-54.) In the first nine months of 2024, RegD resources earned 15.8 percent more per performance adjusted actual MW than RegA resources (24.5 percent in the first nine months of 2023) due to the inclusion of the mileage ratio in RegD MW settlement.

Table 10-40 Average monthly price paid per performance adjusted actual MW of RegD and RegA: January 2023 through September 2024

		Settlement Payments		
Year	Month	RegD ($/Performance Adjusted MW)	RegA ($ Performance Adjusted MW)	Percent RegD Overpayment ($/Performance Adjusted MW)
2023	Jan	$21.52	$17.01	26.6%
	Feb	$21.57	$15.49	39.2%
	Mar	$20.50	$16.82	21.9%
	Apr	$27.77	$23.00	20.8%
	May	$31.40	$24.78	26.7%
	Jun	$27.01	$20.64	30.9%
	Jul	$26.74	$22.53	18.7%
	Aug	$24.85	$20.62	20.5%
	Sep	$27.41	$22.73	20.6%
	Oct	$36.21	$31.66	14.4%
	Nov	$21.56	$19.69	9.5%
	Dec	$22.24	$17.97	23.8%
Yearly		$25.76	$21.12	22.0%
2024	Jan	$42.62	$35.76	19.2%
	Feb	$23.01	$19.04	20.9%
	Mar	$27.25	$22.86	19.2%
	Apr	$24.87	$23.34	6.6%
	May	$40.91	$36.91	10.8%
	Jun	$30.59	$27.62	10.7%
	Jul	$46.18	$39.32	17.5%
	Aug	$33.72	$30.57	10.3%
	Sep	$35.49	$27.58	28.7%
Total		$33.97	$29.33	15.8%

The current settlement process does not result in paying RegA and RegD resources the same price per effective MW. RegA resources are paid on the basis of dollars per effective MW of RegA. RegD resources are not paid in terms of dollars per effective MW of RegA because the MBF is not used in settlements. Instead of being paid based on the MBF, (RMCCP + RMPCP)*MBF, RegD resources are paid based on the mileage ratio (RMCCP + (RMPCP*mileage ratio)). Because the RMCCP component makes up the majority of the overall clearing price, when the MBF is above one, RegD resources can be underpaid on a per effective MW basis by the current payment method, unless offset by a high mileage ratio. When the MBF is less than one, RegD resources are overpaid on a per effective MW basis, unless offset by a low mileage ratio. The average MBF was less than 1.0 in the first nine months of 2024 (0.82).

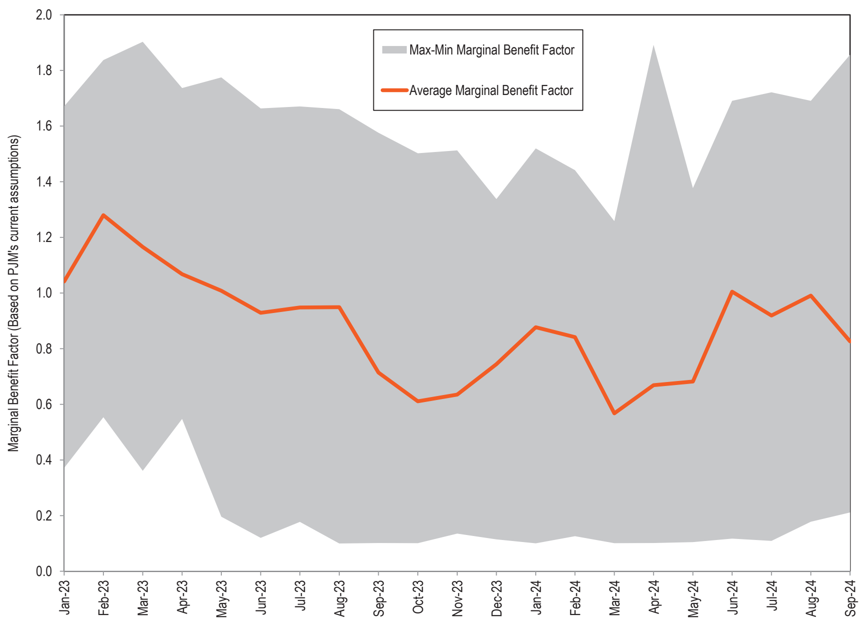
The effect of using the mileage ratio instead of the MBF for purposes of settlement is illustrated in Table 10-41. Table 10-41 shows how much RegD resources are currently being paid, adjusted to a per effective MW basis, on average, in 2023 and the first nine months of 2024 under the current rules, compared to how much RegD resources should have been paid if they were actually paid for effective MW. Using the MBF consistently throughout the PJM regulation market would result in RegA and RegD resources being paid exactly the same on a per effective MW basis. However, the PJM regulation market only uses the MBF in the market clearing and setting of price on a dollar per effective MW basis, it does not use the MBF to convert RegD MW into effective MW for purposes of settlement. Because the MBF is not used to convert RegD MW into effective MW for purposes of settlement, RegD resources are paid the dollar per effective MW price, but this is paid for performance adjusted MW, not for effective MW. This causes the MW value of RegD resources to be inflated in settlement when the MBF is less than one and to be undervalued in settlement when the MBF is greater than one. In the first nine months of 2024, the MBF averaged 0.82, while the average daily mileage ratio was 5.71, resulting in RegD resources being paid $8.7 million more than they would have been paid on an effective MW basis if the MBF were correctly implemented. In the first nine months of 2023, the MBF averaged 1.01, and the average mileage ratio was 6.11, resulting in RegD resources being paid $3.7 million more than they would have been paid if the MBF were correctly implemented.

Table 10-41 Average monthly price paid per effective MW of RegD and RegA under mileage and MBF based settlement: January 2023 through September 2024

		RegD Settlement Payments				
Year	Month	Mileage Based RegD ($/Effective MW)	Marginal Rate of Technical Substitution Based RegD ($/Effective MW)	RegA ($/Effective MW)	Percent RegD Overpayment ($/Effective MW)	Total RegD Overpayment ($)
2023	Jan	$22.25	$17.01	$17.01	30.9%	$293,915
	Feb	$16.90	$15.49	$15.49	9.1%	$63,924
	Mar	$17.10	$16.82	$16.82	1.7%	($115,093)
	Apr	$26.48	$23.00	$23.00	15.1%	$176,675
	May	$32.82	$24.78	$24.78	32.4%	$438,285
	Jun	$32.81	$20.64	$20.64	59.0%	$824,293
	Jul	$29.16	$22.53	$22.53	29.4%	$391,521
	Aug	$35.51	$20.62	$20.62	72.2%	$535,233
	Sep	$47.29	$22.73	$22.73	108.1%	$1,082,569
	Oct	$83.65	$31.66	$31.66	164.2%	$1,940,934
	Nov	$41.59	$19.69	$19.69	111.2%	$910,484
	Dec	$40.18	$17.97	$17.97	123.6%	$1,078,581
Yearly		$35.62	$21.12	$21.12	68.6%	$7,621,320
2024	Jan	$56.67	$35.76	$35.76	58.4%	$879,903
	Feb	$33.20	$19.04	$19.04	74.4%	$670,940
	Mar	$72.24	$22.86	$22.86	216.0%	$1,774,338
	Apr	$48.61	$23.34	$23.34	108.3%	$915,045
	May	$89.43	$36.91	$36.91	142.3%	$1,898,186
	Jun	$33.39	$27.62	$27.62	20.9%	$64,580
	Jul	$57.63	$39.32	$39.32	46.6%	$956,416
	Aug	$36.83	$30.57	$30.57	20.5%	$146,692
	Sep	$49.28	$27.58	$27.58	78.7%	$1,443,266
Total		$53.27	$29.33	$29.33	81.6%	$8,749,365

Figure 10-34 shows, the monthly maximum, minimum and average MBF, for January 2023 through September 2024. The average daily MBF in the first nine months of 2024 was 0.82. The average daily MBF in the first nine months of 2023 was 1.01. The bottom of the MBF range results from PJM's administratively defined MBF minimum threshold of 0.1.

Figure 10-34 Maximum, minimum, and average PJM calculated MBF by month: January 2023 through September 2024



The MMU recommends that the regulation market be modified to incorporate a consistent and correct application of the MBF throughout the optimization, assignment and settlement process.[94]

The overpayment of RegD has resulted in offers from RegD resources that are almost all at an effective cost of $0.00 ($0.00 offers plus self scheduled offers). RegD MW providers are ensured that such offers will clear and will be paid a price determined by the offers of RegA resources. This is evidence of the impact of the flaws in the clearing engine and the overpayment of RegD resources on the offer behavior of RegD resources.

Table 10-42 shows, by month, cleared RegD MW with an effective price of $0.00 (units with zero offers plus self scheduled units) for January 2023 through September 2024. In the first nine months of 2024, an average of 92.7 percent of all RegD MW clearing the market had an effective offer of $0.00. In the first nine months of 2023, an average of 95.3 percent of all cleared RegD MW had an effective cost of $0.00. In the first nine months of 2024, an average of 67.2 percent of all RegD offers were self scheduled, compared to an average of 60.9 percent of all RegD offers in the first nine months of 2023.

The high percentage of self scheduled offers is a result of the incentives created by the flaws in the regulation market. Because self scheduled offers are price takers, they are cleared along with the zero cost offers in the market clearing engine. However, unlike zero cost offers, self scheduled offers do not risk having an LOC added to their offer during the market clearing process, ensuring that self scheduled offers have a zero cost during market clearing. Given the increasing saturation of the regulation market with RegD MW, specifically demand response and battery units which do not receive LOC, market participants eligible for LOC that offer at zero instead of self scheduling, run the risk of an LOC added to their offer, and thus not clearing the market.

The average monthly RegD cleared in the market increased 16.5 MW (9.5 percent), from 174.3 MW in the first nine months of 2023 to 190.8 MW in the first nine months of 2024. The average monthly RegD cleared with an effective cost of zero increased 10.8 MW (6.5 percent), from 166.0 MW in the first nine months of 2023 to 176.8 MW in the first six months of 2024. Self scheduled RegD cleared MW increased 21.5 MW (20.1 percent), from 106.7 MW in the first nine months of 2023 to 128.2 MW in the first nine months of 2024. Average cleared RegD MW with a zero cost offer decreased 10.6 MW (17.9 percent), from 59.3 MW in the first nine months of 2023 to 48.6 MW in the first nine months of 2024. The incorrect way that dual offers are offered and cleared in the regulation market has led to the decrease in the average

94 See "Regulation Market Review," Operating Committee (May 5, 2015) <http://www.pjm.com/~/media/committees-groups/committees/oc/20150505/20150505-item-17-regulation-market-review.ashx>.

monthly RegD cleared and the increase in the average monthly MBF seen in Figure 10-34.

Table 10-42 Average cleared RegD MW and average cleared RegD with an effective price of $0.00 by month: January 2023 through September 2024

		Average Performance Adjusted Cleared RegD MW						
Year	Month	$0.00 Offer	$0.00 Offer Percent of Total	Self Scheduled	Self Scheduled Percentage of Total	Total Effective Cost of Zero	Effective Cost of Zero Percentage of Total	Total
2023	Jan	56.6	33.4%	110.5	65.2%	167.1	98.5%	169.6
	Feb	66.6	43.0%	82.9	53.5%	149.5	96.6%	154.8
	Mar	63.3	41.7%	84.7	55.8%	147.9	97.4%	151.8
	Apr	63.9	39.2%	88.7	54.4%	152.7	93.6%	163.0
	May	55.2	32.8%	100.0	59.5%	155.2	92.3%	168.2
	Jun	59.6	31.5%	120.4	63.6%	179.9	95.1%	189.2
	Jul	57.4	30.4%	124.0	65.6%	181.4	96.0%	189.0
	Aug	52.7	27.9%	120.9	64.0%	173.6	92.0%	188.8
	Sep	58.1	29.9%	128.6	66.3%	186.7	96.2%	194.1
	Oct	57.8	29.4%	130.5	66.4%	188.2	95.8%	196.5
	Nov	56.5	28.9%	129.3	66.1%	185.8	95.0%	195.6
	Dec	57.8	29.4%	128.0	65.2%	185.9	94.6%	196.5
Yearly		58.7	32.6%	112.6	62.6%	171.3	95.2%	179.9
2024	Jan	54.5	28.0%	126.2	64.9%	180.7	92.9%	194.5
	Feb	45.5	24.5%	128.6	69.2%	174.1	93.7%	185.9
	Mar	52.0	26.0%	138.1	68.9%	190.1	94.9%	200.3
	Apr	49.3	25.5%	130.4	67.4%	179.8	92.8%	193.6
	May	50.5	26.3%	126.4	65.9%	177.0	92.3%	191.8
	Jun	41.8	22.5%	131.8	70.9%	173.6	93.4%	185.9
	Jul	46.6	23.8%	131.5	67.3%	178.0	91.1%	195.4
	Aug	48.8	26.0%	121.4	64.6%	170.3	90.6%	188.0
	Sep	48.7	26.8%	119.2	65.6%	167.9	92.4%	181.7
Total		48.7	25.5%	128.2	67.2%	176.9	92.7%	190.9

Incorrect MBF and total effective MW when clearing units with dual product offers

Under PJM market rules, regulation units that have the capability to provide both RegA and RegD MW are permitted to submit an offer for both signal types in the same market hour. While the objective of the PJM market design is to find the least cost combination of RegA and RegD resources to provide the required level of regulation service, the method of clearing the regulation market for an hour in which one or more units has a dual offer is incorrect and leads to solutions that are not the most economic. The result of the flaw is that the MBF in the regulation market clearing phase is incorrectly low compared to the MBF in the market solution phase, too little RegD is cleared relative to the efficient amount, the RegD resources that do clear are underpaid when the resulting MBF is greater than 1.0 and the actual amount of effective MW procured is higher than the regulation requirement.

In order for the clearing engine to provide the correct economic solution when the pool of available resources contains one or more units with dual offers, the calculation would have to be performed iteratively to determine which of the dual offers would provide the least cost solution. But this is not how PJM clears the regulation market when there are dual offer units. PJM rank orders the regulation supply curve by potential effective cost assuming the dual offer resources are available as both RegA and RegD resources simultaneously, and assigns every RegD resource, including dual offer resources, a unit specific benefit factor.

Each dual offer resource is assigned to run as either a RegD or RegA resource based on which of the two offers has a lower effective cost. But PJM does not redefine the supply curve using appropriately recalculated unit specific benefit factors for the remaining RegD resources prior to clearing the market.

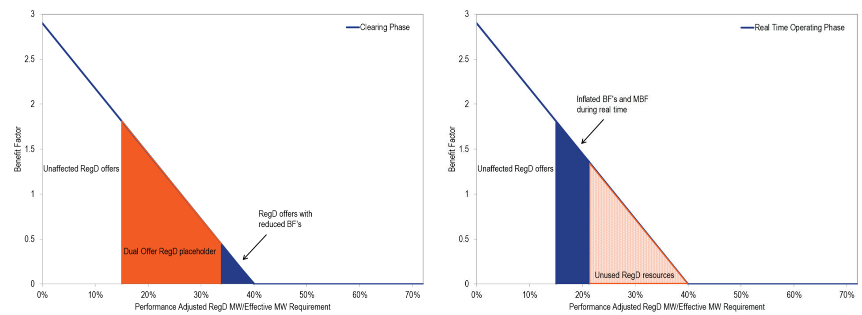
During the clearing phase, the MBF of RegD resources is a function of the RegD MW that clear. The MBF for all RegD resources declines as more RegD resources are cleared. Based on this relationship, in the case where a dual offer unit is assigned to be a RegA resource rather than a RegD resource, the MBF of remaining RegD resources in the supply curve should increase. The placeholder RegD MW from the dual offer should be removed, the cleared MW from below the placeholder should be shifted up the supply/MBF curve, and additional RegD MW offers that were pushed below an MBF of zero and initially not included, should be considered. But PJM does not recalculate the

MBF values for the remaining RegD resources when determining the cleared effective MW needed to satisfy the regulation requirement during the clearing phase. The result is that the MBF in the clearing phase is incorrectly low, and the actual amount of effective MW procured is higher.

After meeting the target effective MW to satisfy the regulation requirement for that hour through the clearing process, the unit specific benefit factors of those displaced units are recalculated in the real-time operating phase and increased based on their actual contribution. The effective MW contributions of those originally displaced units are correctly calculated in the operating phase, but because the supply for that hour has already been set based on their incorrect effective MW, the solution includes more effective MW than calculated in the clearing phase. As a result, the market solution includes more than the target level of effective MW in the actual operating hour.

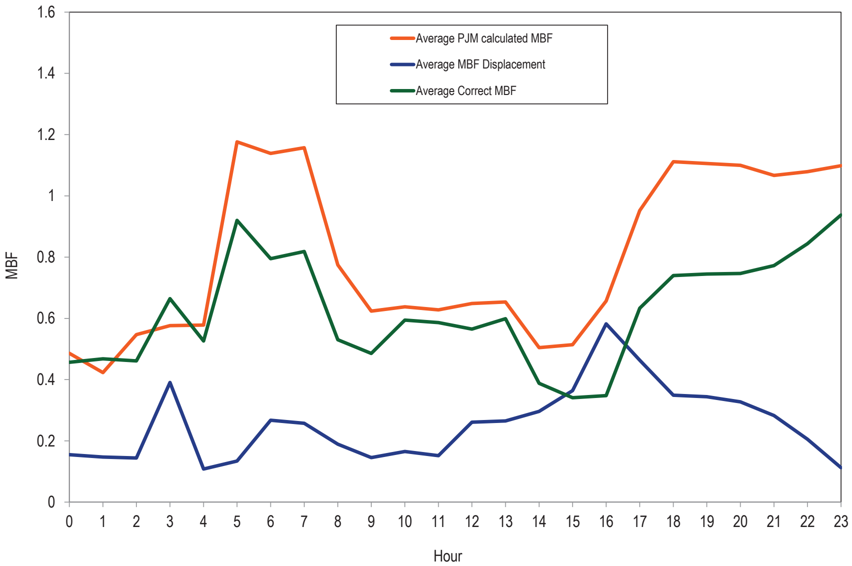
The issue is illustrated in Figure 10-35. The example shows a clearing phase and a real time operating phase. In this example, a 150 MW unit offers both RegA and RegD. The 150 MW unit's position in the RegD effective cost curve and the potential effective MW are represented as the orange area under the curve in the clearing phase. The effective MW of the cleared RegD resources with higher effective costs are represented by the blue triangle in the clearing phase. Not shown are additional RegD MW with higher effective costs that were assigned an MBF of 0 and not cleared. The 150 MW dual offer unit is chosen to operate as a RegA resource in the operational hour. As a result, the cleared supply for RegA in the clearing phase is the same RegA supply realized in the real time operating phase. But that is not the case for the RegD supply. Since the supply curve and unit specific benefit factors of RegD MW are not recalculated in the clearing phase after the 150 MW RegD offer is removed, the amount of effective MW realized in the real-time operating phase is inconsistent with the clearing phase. Because the RegD portion of the 150 MW dual offer unit was not chosen to be RegD MW, the RegD resources represented by the blue triangle in the clearing phase will contribute more effective MW (the blue area in the real-time solution phase) in the real-time solution phase than was assumed in the clearing phase because the MBF in the clearing phase was too low. Since the blue area under the curve in the real-time solution phase is greater than the blue area in the clearing phase and the amount of RegA remains the same between the clearing phase and real-time operating phase, the market will have cleared too many effective MW relative to the effective MW requirement. The MBF in the operating phase is higher than if the clearing had been solved correctly.

Figure 10-35 Clearing phase BF/effective MW reduction, real-time BF/effective MW inflation, and exclusion of available RegD resources



In the first nine months of 2024, 36.9 percent of all hours had at least one unit with a dual offer. In the first nine months of 2024, 23.7 percent of all hours had at least one dual offer unit that was chosen to run as RegA, resulting in an average MBF increase of 0.27 in the operating phase. The average MBF increase due to dual offers clearing as RegA in the first nine months of 2023 was 0.54. This indicates that the amount of MW clearing as RegA from dual offers has increased, and the amount of RegD clearing has been artificially reduced, resulting in a higher MBF of RegD in the market solution in 2023. If the market had been cleared correctly, the correct average MBF would have been significantly lower in real time (operating phase), because additional RegD offers with lower benefit factors that were initially excluded, would have been included after the removal of the dual offer placeholder, reducing the MBF. Figure 10-36 illustrates the PJM calculated average MBF in real time (operating phase), the average amount the MBF is artificially increased (MBF displacement) due to dual offers clearing as RegA, and what the correct average MBF would have been in each hour of the day for the first nine months of 2024 if the clearing solution were solved correctly.

Figure 10-36 Effect of PJM's current dual offer clearing method on the average MBF in each hour of the day: January through September, 2024



Absent the ability to correctly clear dual offers, the MMU recommends that the ability of resources to submit dual offers be removed. Under this revision to the rules, resources could offer as either RegA or RegD in a given hour, but not both within the same market hour.

Price Spikes

Beginning in 2018, extreme price spikes were identified in the regulation market. The price spikes were caused by a combination of the inconsistent application of the MBF in the market design and the discrepancy between the hour ahead estimated LOC and the actual realized within hour LOC.

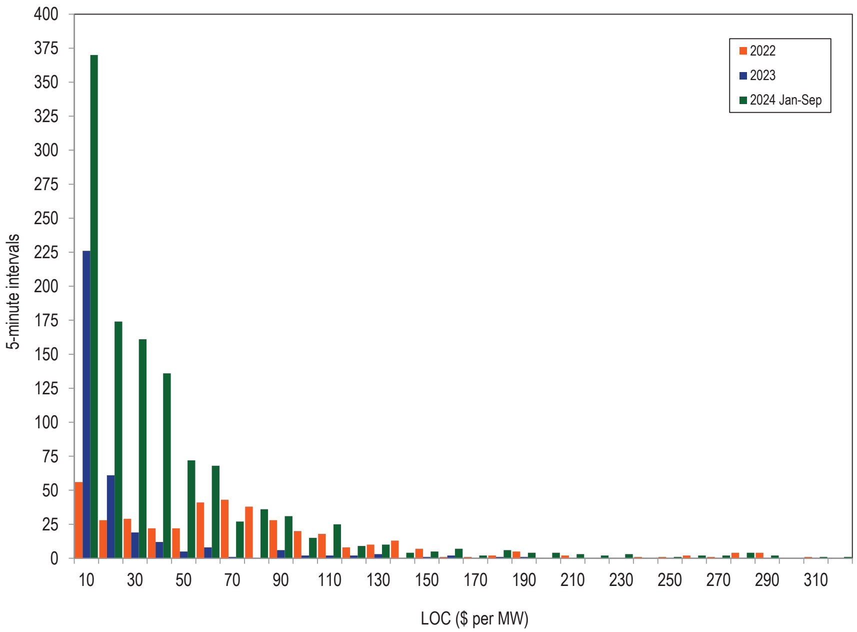
The regulation market is cleared on an hour ahead basis, using offers that are adjusted by dividing each component of an offer (capability, performance, and lost opportunity cost) by the product of the unit specific benefit factor and unit specific performance score. To calculate the hour ahead estimate of the adjusted LOC offer component, hour ahead projections of LMPs are used. Units are then cleared based on the sum of each of their hour ahead adjusted offer components. The actual LOC is used to determine the final, actual interval specific all in offer of RegD resources.

In some cases the estimated LOC is very low or zero but the actual within hour LOC is a positive number. In instances where the MBF of the within hour marginal unit is less than one (e.g. the marginal unit is a RegD unit), this discrepancy in the estimated and realized LOC will cause a large discrepancy between the expected offer price (as low as $0/MW) and the realized offer price of the resource in the actual market result. This will cause a significant price spike in the regulation market. In cases where the MBF of the marginal resource is very low, such as 0.001, the price spikes can be very significant for a small change between expected and actual LOC. In January 2019, FERC approved PJM's proposal to create a 0.1 floor for the MBF to reduce the occurrence of these price spikes.[95] This change reduced the amount and frequency of the price spikes, but it was not designed to eliminate them and it did not eliminate them.

Figure 10-37 shows the LOC in each five minute interval in which the marginal unit had a unit specific benefit factor less than one (e.g. a RegD unit) and the LOC was greater than zero from 2022 through the first nine months of 2024.

95 See 166 FERC ¶ 61,040 (2019).

Figure 10-37 LOC distribution in each five minute interval with a RegD marginal unit and an LOC greater than zero: 2022, 2023, and January through September, 2024



For a RegD resource to clear the regulation market with an MBF of 0.001, the resource's offer, in dollars per marginal effective MW, must be less than or equal to competing offers from RegA MW. A RegD offer of 1 MW with an MBF of 0.001 and a price of $1 per MW, would provide 0.001 effective MW at a price of $1,000 per effective MW. So long as RegA MW are available for less than $1,000 per effective MW, this resource will not clear. The only way for RegD MW to clear to the point where the MBF of the last MW is 0.001, is if the offer price of the relevant resources that clear, including estimated LOC, is $0.00. But, if the same resource(s) has a positive LOC within the hour, based on real-time changes in LMP, the zero priced offer is adjusted to reflect the positive LOC, resulting in an extremely high offer and clearing price for regulation.

While an incorrect estimate of a potential LOC can result in an extremely high price, the resulting regulation market prices are mathematically correct for the price of each effective MW. The prices in every interval reflect the marginal costs of regulation given the resources dispatched and accurately reflect the marginal offer of minimally effective resources which had unexpectedly high LOC components of their within hour offers. But, due to the current market design's failure to use the MBF in settlement, RegD is not paid on a dollar per effective MW basis. This disconnect between the process of setting price and the process of paying resources is the primary source of the market failure in PJM's Regulation Market and the cause of the observed price spikes in the regulation market. In the example, the 0.001 MW from the RegD resource should be paid $1,000 times 0.001 MW or $1.00. But the current rules would pay the RegD resource $1,000 times 1.0 MW or $1,000. If the market clearing and the settlements rules were consistent, the incentive for this behavior would be eliminated. The current rules provide a strong incentive for this behavior.

The prices spikes observed in PJM's Regulation Market are a symptom of a market failure in PJM's Regulation Market caused by an inconsistent application of the MBF between market clearing and market settlement. Due to the inconsistent application of the MBF, the current market results are not consistent with a competitive market outcome. In any market, resources should be paid the marginal clearing price for their marginal contribution. In the regulation market, all resources should be paid the marginal clearing price per effective MW and all resources in the regulation market should be paid for each of their effective MW. PJM's Regulation Market does not do this. PJM's market applies the MBF in determining the relative and total value of RegD MW in the market solution for purposes of market clearing and price, but does not apply the same logic in determining the payment of RegD for purposes of settlement. As a result, market prices do not align with payment for contributions to regulation service in market settlements.

The inconsistent application of the MBF in PJM's regulation market design is generating perverse incentives and perverse market results. The price spikes are a symptom of the problem, not the problem itself.

Uplift Calculation Issues

Regulation uplift is calculated by comparing a resource's regulation offer price plus its regulation lost opportunity cost (including shoulder LOC if applicable) adjusted by the performance score, to the clearing price credits the unit received.[96] If the sum of the resource's offer plus LOC is greater than the amount of clearing price credits received, additional uplift credits are given equal to the difference.

The calculation of regulation uplift during settlements for coal and natural gas units is incorrect, and results in the overpayment of uplift.[97] In order to determine the amount of regulation uplift, the difference between the MW output of the unit while it was providing regulation is compared to the desired MW output of the unit if it had not provided regulation. The desired MW output at LMP used in the calculation of regulation uplift during settlements is determined based on a unit's energy offer and the LMP during the interval being evaluated. But this desired MW does not account for the ability of a unit to actually produce the desired output because it ignores the fact that units have a limited physical ability ramp. It does not take into account the ramp rate. This results in the overpayment of uplift by paying for MW that the unit could not have produced given their energy market output at the beginning of the interval and their ramp rate.

Table 10-43 shows the amount of uplift overpayment by fuel type for the first nine months of 2024, as a result of the ramp rate not being used in the current calculation. The overpayments are calculated using a desired MW level that can be achieved in a five minute market interval based on the units' ramp rates. In the first nine months of 2024, overpayments totaled $20.6 million. Coal units received 69.4 percent of the overpayment while providing 5.1 percent of settled regulation MW.

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.

96 The clearing price for each interval is set by the marginal unit's total offer (capability and performance offers plus LOC), adjusted by the marginal unit's performance score, and does not include any shoulder LOC.

97 Hydro units operate on a schedule rather than an energy bid, therefore a different equation is used to calculate their regulation LOC and uplift. The issue discussed does not effect that calculation. Also, demand response and battery units do not receive uplift.

Table 10-43 Amount of LOC overpayment: January 2023 through September 2024

		Uplift overpayment		
Year	Month	Coal	Natural Gas	Total
2023	Jan	$219,632	$409,362	$628,995
	Feb	$304,776	$399,282	$704,058
	Mar	$606,703	$547,406	$1,154,109
	Apr	$825,524	$602,421	$1,427,946
	May	$528,304	$847,798	$1,376,102
	Jun	$857,736	$787,690	$1,645,426
	Jul	$1,061,210	$508,118	$1,569,328
	Aug	$1,810,618	$511,049	$2,321,667
	Sep	$937,997	$544,952	$1,482,949
	Oct	$395,527	$1,011,206	$1,406,733
	Nov	$307,590	$538,204	$845,794
	Dec	$709,710	$469,619	$1,179,329
	Total	$8,565,327	$7,177,108	$15,742,435
2024	Jan	$1,232,475	$668,296	$1,900,771
	Feb	$776,377	$351,419	$1,127,796
	Mar	$1,004,166	$685,613	$1,689,779
	Apr	$1,554,338	$725,974	$2,280,312
	May	$1,254,186	$954,532	$2,208,717
	Jun	$1,675,670	$636,096	$2,311,766
	Jul	$2,576,400	$674,632	$3,251,032
	Aug	$1,908,099	$496,129	$2,404,228
	Sep	$2,331,876	$1,122,113	$3,453,989
	Total	$14,313,587	$6,314,803	$20,628,390

Market Redesign

PJM proposes to separate the regulation market into two products: one that only needs to respond when the regulation signal is above zero (RegUp), and one that only needs to respond when the regulation signal is below zero (RegDown). This change would also allow units to clear both signals and operate the way they do currently. PJM has not done any systematic testing of the proposal. PJM has not explained what problem this design change is intended to fix, or analyzed what impact this design would have on reliability, or how this will affect the cost of regulation. The MMU recommends a single product market with a single signal.

On June 14, 2024, the FERC approved PJM's proposed market redesign, to be implemented in two phases. Phase one, using one signal and one market price, will go into effect on October 1, 2025, and will implement the proposed changes to the LOC and performance score. Phase two will go into effect on October 1, 2026, and will implement the RegUp and RegDown signal with a separate price for RegUp and for RegDown.[98]

Market Structure

Supply

Table 10-44 shows average hourly offered MW (actual and effective), and average hourly cleared MW (actual and effective) for all hours in the first nine months of 2024.[99] Actual MW are adjusted by the historic 100-hour moving average performance score to get performance adjusted MW, and by the resource specific benefit factor to get effective MW. A resource can choose to follow either signal. For that reason, the sum of each signal type's capability can exceed the full regulation capability. 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.[100] 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 nine months of 2024, the average hourly offered supply of regulation for nonramp hours was 695.5 actual MW (708.3 effective MW). This was a decrease of 6.1 actual MW (a decrease of 3.1 effective MW) from the first nine months of 2023, when the average hourly offered supply of regulation was 689.5 actual MW (705.1 effective MW). In the first nine months of 2024, the average hourly offered supply of regulation for ramp hours was 994.4 actual MW (1,047.0 effective MW). This was a decrease of 16.0 actual MW (a decrease of 0.8 effective MW) from the first nine months of 2023, when the average hourly offered supply of regulation was 1,010.4 actual MW (1,046.2 effective MW).[101]

The ratio of the average hourly offered supply of regulation to average hourly regulation demand (actual cleared MW) for nonramp hours was 1.45 in the first nine months of 2024 (1.45 in the first nine months of 2023). The ratio of the average hourly offered supply of regulation to average hourly regulation demand (actual cleared MW) for ramp hours was 1.42 in the first nine months of 2024 (1.42 in the first nine months of 2023).

Table 10-44 Hourly average actual and effective MW offered and cleared: January through September, 2024[102]

			By Resource Type		By Signal Type	
		All Regulation	Generating Resources	Demand Resources	RegA Following Resources	RegD Following Resources
Actual Offered MW	Ramp	994.4	940.7	53.7	767.2	227.2
	Nonramp	695.5	651.1	44.4	497.4	198.1
Effective Offered MW	Ramp	1,047.0	956.8	90.2	655.3	391.7
	Nonramp	708.3	648.7	59.5	424.2	284.1
Actual Cleared MW	Ramp	698.7	645.3	53.4	488.1	210.5
	Nonramp	479.4	437.0	42.4	285.5	193.9
Effective Cleared MW	Ramp	799.9	710.0	89.9	419.1	380.8
	Nonramp	527.0	468.4	58.6	244.6	282.4

The average hourly offered and cleared actual MW from RegA resources are shown in Figure 10-38. The average hourly offered MW from RegA resources during ramp hours for the first nine months of 2024 was 767.2 actual MW, a decrease of 1.6 percent from the first nine months of 2023 (779.8 actual MW.) The average hourly offered MW from RegA resources during nonramp hours for the first nine months of 2024 was 497.4 actual MW, a decrease of 1.3 percent from the first nine months of 2023 (503.9 actual MW). The average hourly cleared MW from RegA resources during ramp hours for the first nine months of 2024 was 488.1 actual MW, a decrease of 4.7 percent from the first

98 See Docket No. ER24-1772-000.

99 Unless otherwise noted, analysis provided in this section uses PJM market data based on PJM's internal calculations of effective MW values, based on PJM's currently incorrect MBF curve. The MMU is working with PJM to correct the MBF curve.

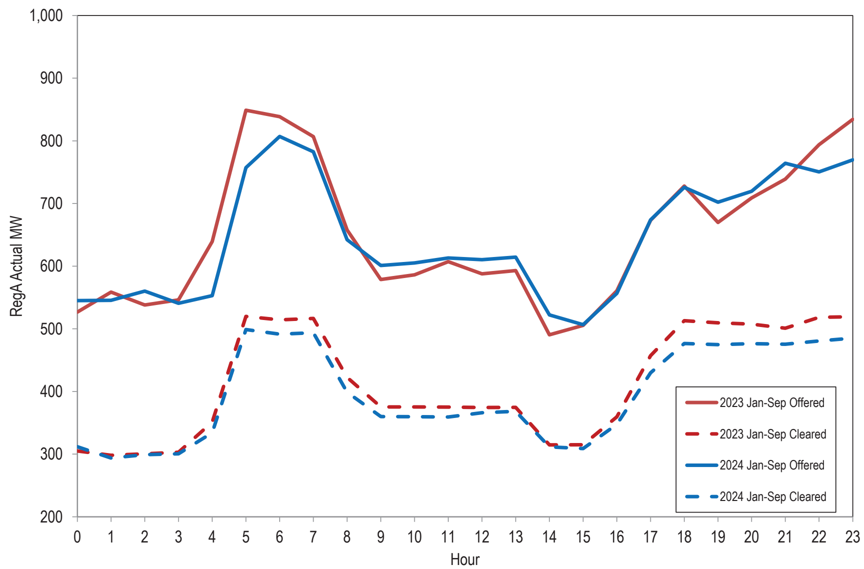
100 See "PJM Manual 11: Energy & Ancillary Services Market Operations," § 3.2.2 Regulation Market Eligibility, Rev. 132 (Sept. 1. 2024).

101 Effective MW equal actual MW multiplied by the performance score and benefit factor for each unit. In the case of RegA, the benefit factor is always equal to one, and performance scores are always less than one, so effective MW of RegA are less than actual MW. For RegD resources effective MW can be larger than actual MW, if the benefit factor is greater than one. When adding RegA and RegD total MW together, actual MW can be larger or smaller than effective MW, depending on the influence of RegA MW and RegD MW.

102 PJM operations treats some nonramp hours as ramp hours, with a regulation requirement of 800 MW rather than 525 MW. All ramp/nonramp analysis performed is based on the requirement used in each hour rather than the definitions given in Table 10-2. A ramp hour occurring during what is normally a nonramp period is treated as a ramp hour.

nine months of 2023 (512.4 actual MW). The average hourly cleared MW from RegA resources during nonramp hours for the first nine months of 2024 was 285.5 actual MW, a decrease of 5.1 percent from the first nine months of 2023 (300.8 actual MW).

Figure 10-38 Average hourly RegA actual MW offered and cleared: January through September, 2023 through 2024[103]



The average hourly offered MW from RegD resources during ramp hours for the first nine months of 2024 was 227.2 actual MW, a decrease of 1.5 percent from the first nine months of 2023 (230.7 actual MW). (Figure 10-39) The average hourly offered MW from RegD resources during nonramp hours for the first nine months of 2024 was 198.1 actual MW, an increase of 6.8 percent from the first nine months of 2023 (185.6 actual MW) (Figure 10-39). The average hourly cleared MW from RegD resources during ramp hours for the first nine months of 2024 was 210.5 actual MW, an increase of 6.7 percent from the first nine months of 2023 (197.2 actual MW). The average hourly cleared MW from RegD resources during nonramp hours for the first nine months of 2024 was 193.9 actual MW, an increase of 10.9 percent from the first nine months of 2023 (174.9 actual MW).

Figure 10-39 Average hourly RegD actual MW offered and cleared: January through September, 2023 through 2024[104]

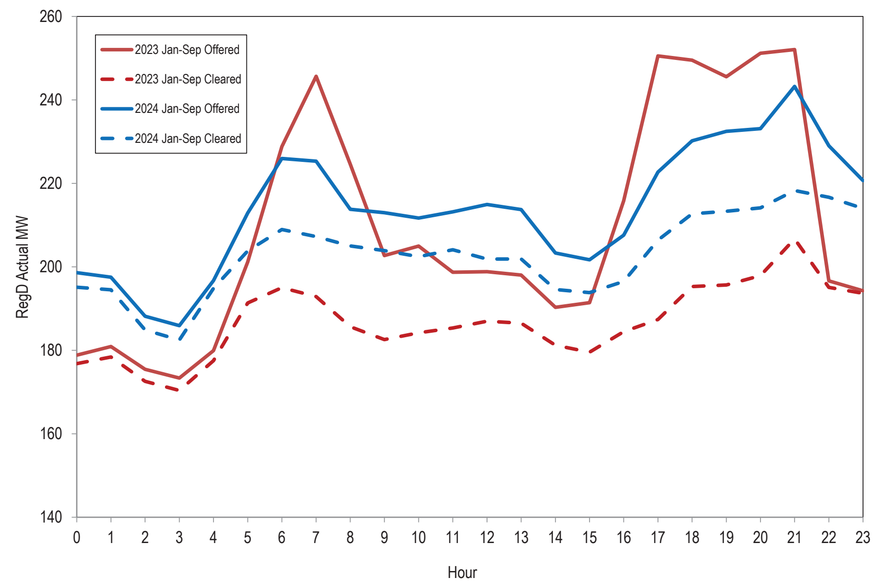


Table 10-46 provides the settled regulation MW by source unit type, the total settled regulation MW provided by all resources, the percent of settled regulation provided by unit type, and the clearing price, uplift, and total regulation credits. In Table 10-46, the MW have been adjusted by the performance score since this adjustment forms the basis of payment for units providing regulation. Total regulation performance adjusted settled MW increased 0.9 percent from 3,398,125.5 MW in the first nine months of 2023 to 3,429,398.0 MW in the first nine months of 2024. The average proportion of regulation provided by demand response units increased the most, by 3.3 percentage points from 5.1 percent in the first nine months of 2023 to 8.5 percent in the first nine months of 2024, which reflected a 65.7 percent increase in the performance adjusted settled regulation MW from DR. Hydro

103 Offered MW includes MW from units that are dual offering as both RegA and RegD.

104 Offered MW includes MW from units that are dual offering as both RegA and RegD.

units had the largest decrease in average proportion of regulation provided, decreasing 3.3 percentage points, from 21.2 percent in the first nine months of 2023 to 17.9 percent in the first nine months of 2024, which reflected a 14.7 percent decrease in the performance adjusted settled regulation MW from Hydro. The total regulation credits in the first nine months of 2024 were $136,542,398, an increase of 38.8 percent from $98,389,098 in the first nine months of 2023. The increase in regulation credits is due, in part, to a higher LOC component of regulation prices as a result of higher energy prices in the first nine months of 2024 compared to the first nine months of 2023.

When a resource offers into the regulation market, an estimated regulation LOC is added by PJM to form a total offer (units self scheduled or not providing in the energy market have a regulation LOC of zero). After a unit clears, the actual five minute interval LMP is used to calculate each unit's regulation LOC, update their total offers, and determine a marginal unit/clearing price in each five minute interval. This within hour calculation of total offers, including LOC, uses each cleared resource's rolling 100 hour average performance score. During settlements, each unit's regulation LOC and total offers are recalculated using each unit's within hour actual performance score. This recalculated LOC and offer using the actual within hour performance score is not used to recalculate the within hour clearing price. This means that the clearing price for the hour will not equal the correct clearing price. Where the resulting market price is lower than an individual resource offer adjusted for the within hour performance score, the resource is paid uplift to make up the difference.

The top 10 units that received the most regulation uplift in the first nine months of 2024 are shown in Table 10-45.

Table 10-45 Top 10 recipients of regulation uplift credits: January through September, 2024

Rank	Parent Company	Unit Name	Fuel Type	Total Regulation Uplift Credit	Share of Total Regulation Uplift Credits
1	American Electric Power Company Inc	AEP MOUNTAINEER 1 F	COAL	$3,108,982	13.5%
2	Dominion Energy Inc	VP BATH COUNTY 1-6 H	HYDRO	$2,561,519	11.1%
3	Dominion Energy Inc	VP BATH COUNTY 1-6 H	HYDRO	$2,364,777	10.3%
4	American Electric Power Company Inc	AEP MITCHELL - KAMMER 2 F	COAL	$2,249,121	9.8%
5	American Electric Power Company Inc	AEP MITCHELL - KAMMER 1 F	COAL	$2,139,868	9.3%
6	American Electric Power Company Inc	AEP MOUNTAINEER 1 F	COAL	$1,738,850	7.6%
7	Constellation Energy Generation LLC	PE MUDDY RUN 1-8 H	HYDRO	$1,244,448	5.4%
8	American Electric Power Company Inc	AEP AMOS 3 F	COAL	$1,146,151	5.0%
9	American Electric Power Company Inc	AEP MITCHELL - KAMMER 1 F	COAL	$1,044,502	4.5%
10	American Electric Power Company Inc	AEP MITCHELL - KAMMER 2 F	COAL	$980,541	4.3%
Total of Top 10				$18,578,759	80.9%
Total Regulation Uplift Credits				$22,974,443	100.0%

The uplift credits received for each unit type are shown in Table 10-46. The total uplift credits received increased 36.1 percent from $16,878,427 in the first nine months of 2023 to $22,974,443 in the first nine months of 2024. This increase, like the increase in total credits, is due in part to higher LOC components of regulation prices and offers as a result of higher energy prices in the first nine months of 2024 compared to the first nine months of 2023. Hydro units had the largest decrease in uplift payments, decreasing from $4,598,449 (27.2 percent of total uplift) in the first nine months of 2023, to $3,361,301 (14.6 percent of total uplift) in the first nine months of 2024.

Table 10-46 PJM regulation by source: January through September, 2023 and 2024[105]

Year (Jan-Sep)	Source	Number of Units	Performance Adjusted Settled Regulation (MW)	Percent of Settled Regulation	Clearing Price Credits	Uplift Credits	Total Regulation Credits
2023	Battery	22	922,307	27.1%	$24,270,437	$0	$24,270,437
	Coal	17	146,249	4.3%	$4,072,044	$6,655,978	$10,728,022
	Hydro	27	720,451	21.2%	$16,642,738	$4,598,449	$21,241,187
	Natural Gas	139	1,434,121	42.2%	$31,671,554	$5,624,000	$37,295,554
	DR	21	174,997	5.1%	$4,853,899	$0	$4,853,899
Total		226	3,398,125.5	100.0%	$81,510,671	$16,878,427	$98,389,098
2024	Battery	22	911,076	26.6%	$31,382,451	$304	$31,382,755
	Coal	19	174,473	5.1%	$6,844,392	$13,075,111	$19,919,502
	Hydro	25	614,237	17.9%	$22,551,361	$3,361,301	$25,912,662
	Natural Gas	141	1,439,637	42.0%	$42,695,360	$6,537,728	$49,233,089
	DR	19	289,975	8.5%	$10,094,391	$0	$10,094,391
Total		226	3,429,398.0	100.0%	$113,567,955	$22,974,443	$136,542,398

Battery Projects in the Queue

Significant flaws in the regulation market design have led to an over procurement of RegD MW primarily in the form of storage capacity. The incorrect market signals have contributed to more storage projects entering PJM's interconnection queue, despite clear evidence that the market design is flawed and despite operational evidence that the RegD market is saturated (Table 10-47).

Table 10-47 Active battery storage projects by submitted year: January 2014 through September 2024

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	35	2,173.5
2020	78	5,800.8
2021	299	23,064.2
2022	138	14,873.5
2023	42	4,977.4
2024 (Jan-Sep)	0	0.0
Total	600	51,351.4

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

The supply of regulation can be affected by regulating units retiring from service. If all units that are requesting retirement through the first nine months of 2024 retire, the supply of regulation in PJM will 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. Prior to October 1, 2012, the regulation requirement was 1.0 percent of the forecast peak load for on peak hours and 1.0 percent of the forecast valley load for off peak hours. Between October 1, 2012, and December 31, 2012, PJM changed the regulation requirement several times. It had been scheduled to be reduced from 1.0 percent of peak load forecast to 0.9 percent on October 1, 2012, but instead it was changed from 1.0 percent of peak load forecast to 0.78 percent of peak load forecast. It was further reduced to 0.74 percent of peak load forecast on November 22, 2012 and reduced again to 0.70 percent of peak load forecast on December 18, 2012. On December 14, 2013, it was reduced to 700 effective MW during peak hours and 525 effective MW during off peak hours. The regulation requirement remained 700 effective MW during peak hours and 525 effective MW during off peak hours until January 9, 2017. A change to the regulation requirement was approved by the RMISTF in 2016, with an implementation date of January 9, 2017. The regulation requirement was increased from 700 effective MW to 800 effective MW during ramp hours (Table 10-36).

Table 10-48 shows the average hourly required regulation by month and the ratio of supply to demand for both actual and effective MW, for ramp and nonramp hours. The average hourly required regulation by month is an average of the ramp and nonramp hours in the month. Changes in the actual MW required to satisfy the regulation requirement are the result of the amount of RegD actual MW cleared. When more RegD MW are cleared, the

MBF is lower, resulting in those actual MW being worth less effective MW, requiring more actual MW to satisfy the requirement. When MBFs are higher, the actual MW of RegD are worth more effective MW, reducing the amount of actual MW needed to satisfy the requirement.

The nonramp regulation requirement of 525.0 effective MW was provided by a combination of cleared RegA and RegD resources equal to 478.5 hourly average performance adjusted actual MW in the first nine months of 2024. This is an increase of 1.7 performance adjusted actual MW from the first nine months of 2023, when the average hourly total regulation cleared performance adjusted actual MW for nonramp hours were 476.8 performance adjusted actual MW. The ramp regulation requirement of 800.0 effective MW was provided by a combination of cleared RegA and RegD resources equal to 697.5 hourly average performance adjusted actual MW in the first nine months of 2024. This is a decrease of 12.2 performance adjusted actual MW from the first nine months of 2023, where the average hourly regulation cleared MW for ramp hours were 709.7 performance adjusted actual MW.[106]

Table 10-48 Required regulation and ratio of supply to requirement January 2023 through September 2024

		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	
Hours	Month	2023	2024	2023	2024	2023	2024	2023	2024
Ramp	Jan	696.1	705.7	800.1	800.1	1.45	1.39	1.30	1.29
	Feb	715.5	691.8	800.0	800.0	1.48	1.36	1.34	1.27
	Mar	719.9	688.5	800.0	800.0	1.48	1.36	1.35	1.27
	Apr	704.6	691.9	800.0	800.0	1.39	1.37	1.29	1.26
	May	712.6	693.1	800.0	800.0	1.43	1.41	1.33	1.30
	Jun	712.7	703.9	800.0	799.8	1.40	1.42	1.30	1.31
	Jul	713.0	701.6	800.0	799.7	1.38	1.45	1.29	1.33
	Aug	708.0	703.2	799.9	800.0	1.43	1.48	1.31	1.35
	Sep	704.9	697.6	800.0	800.0	1.39	1.54	1.28	1.39
	Oct	701.3	-	800.0	-	1.43	-	1.31	-
	Nov	695.0	-	799.9	-	1.41	-	1.30	-
	Dec	692.4	-	800.0	-	1.41	-	1.30	-
Nonramp	Jan	466.3	477.4	525.3	525.1	1.44	1.43	1.32	1.33
	Feb	494.3	473.0	558.1	525.1	1.50	1.41	1.36	1.31
	Mar	463.6	484.8	525.0	525.1	1.43	1.54	1.31	1.42
	Apr	464.4	489.1	524.7	536.8	1.44	1.41	1.33	1.32
	May	475.6	481.8	524.8	525.0	1.50	1.49	1.38	1.37
	Jun	484.6	474.1	525.1	525.4	1.40	1.40	1.31	1.30
	Jul	482.1	479.0	524.7	527.3	1.40	1.44	1.30	1.34
	Aug	475.5	473.9	525.3	525.1	1.51	1.40	1.38	1.30
	Sep	485.0	473.7	525.7	525.5	1.43	1.47	1.33	1.35
	Oct	486.0	-	525.0	-	1.51	-	1.38	-
	Nov	482.4	-	525.3	-	1.41	-	1.32	-
	Dec	480.0	-	525.6	-	1.45	-	1.34	-

106 The supply of performance adjusted MW is less than the demand because the regulation requirement is based on effective MW. Effective MW are performance adjusted MW multiplied by the MBF, and the average MBF in the first nine months of 2024 was 0.82.

Market Concentration

In the first nine months of 2024, the effective MW weighted average HHI of RegA resources was 2571 which is highly concentrated and the effective MW weighted average HHI of RegD resources was 1549 which is moderately concentrated. The effective MW weighted average HHI of all resources was 1327, which is moderately concentrated. The weighted average HHI reflects the fact that different owners have large market shares in the RegA and RegD markets.

Table 10-49 includes a monthly summary of three pivotal supplier (TPS) results. In the first nine months of 2024, the three pivotal supplier test was failed in 95.4 percent of hours. The MMU concludes that the PJM Regulation Market in the first nine months of 2024 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 has submitted a request to the vendor to save all data necessary for verification.

Table 10-49 Regulation market monthly three pivotal supplier results: January 2023 through September 2024

	Percent of Hours Pivotal	
Month	2023	2024
Jan	92.1%	96.2%
Feb	91.6%	98.1%
Mar	96.0%	94.4%
Apr	91.8%	98.8%
May	89.1%	93.3%
Jun	95.0%	96.2%
Jul	96.8%	97.3%
Aug	94.5%	94.6%
Sep	95.3%	90.0%
Oct	95.7%	
Nov	95.8%	
Dec	92.5%	
Average	93.8%	95.4%

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.[107] 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.[108]

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.[109]

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); and the regulation signal type (RegA or RegD). Resources may offer regulation for both the RegA and RegD signals, but will be assigned to follow

107 See "PJM Manual 11: Energy & Ancillary Services Market Operations," § 3.2.1 Regulation Market Eligibility, Rev. 132 (Sept. 1, 2024).
108 Id. at 3.2.2, at p 62.
109 See "PJM Manual 15: Cost Development Guidelines," § 7.8 Regulation Cost, Rev. 45 (Sept. 1, 2024).

only one signal for a given operating hour. Resources have the option to submit a minimum level of regulation they are willing to provide.[110]

All LSEs are required to provide 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 10-52).[111] Figure 10-40 compares average hourly regulation and self scheduled regulation during ramp and nonramp hours on an effective MW basis. Self scheduled regulation averaged 53.3 percent of all effective MW during ramp hours (48.0 percent in the first nine months of 2023) and 69.3 percent of all effective MW during nonramp hours (63.6 percent in the first nine months of 2023) in the first nine months of 2024. Over all hours in the first nine months of 2024, self scheduled regulation averaged 59.6 percent of all effective MW (54.2 percent in the first nine months of 2023) (See Table 10-50). The average hourly 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.[112]

110 See "PJM Manual 11: Energy & Ancillary Services Market Operations," § 3.2.1 Regulation Market Eligibility, Rev. 132 (Sept. 1, 2024).
111 See "PJM Manual 28: Operating Agreement Accounting," § 4.1 Regulation Accounting Overview, Rev. 96 (Sept. 1, 2024).
112 See "PJM Manual 11: Energy & Ancillary Services Market Operations," § 3.2.1 Regulation Market Eligibility, Rev. 132 (Sept. 1, 2024).

Figure 10-40 Nonramp and ramp regulation levels: January 2023 through September 2024

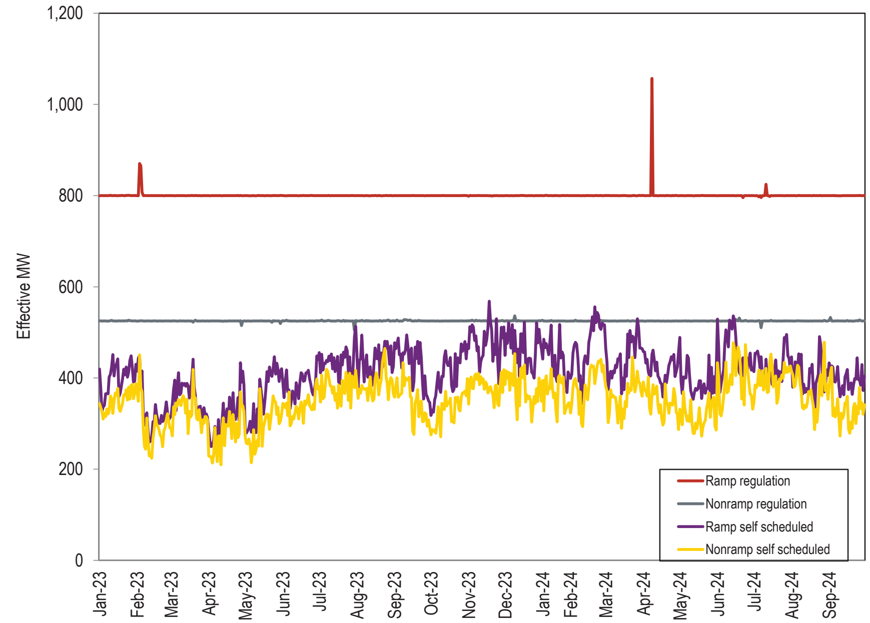


Table 10-50 Total Effective MW and Self Scheduled Effective MW during ramp and non ramp hours: January through September, 2023 and 2024

Year (Jan-Sep)		Effective MW	Self Scheduled Effective MW	Percent Effective MW
2023	Ramp	218,546.9	104,861.5	48.0%
	Non Ramp	143,343.5	91,122.3	63.6%
Total		361,890.3	195,983.8	54.2%
2024	Ramp	213,067.1	113,588.9	53.3%
	Non Ramp	139,681.2	96,799.8	69.3%
Total		352,748.4	210,388.7	59.6%

Table 10-51 shows the role of RegD resources in the regulation market. RegD resources are both a growing proportion of the market (10.9 percent of the total effective MW at the start of the performance based regulation market design in October 2012 and 49.8 percent of the total effective MW in September

2024) and a growing proportion of resources that self schedule (25.0 percent of all self scheduled effective MW in October 2012 and 63.2 percent of all self scheduled effective MW in September 2024). In the first nine months of 2024, the average RegD percentage of total self scheduled effective MW was 63.0 percent, an increase of 3.7 percentage points from the first nine months of 2023, when the average was 59.4 percent.

Table 10-51 RegD self scheduled regulation by month: January 2023 through September 2024

Year	Month	RegD Self Scheduled Effective MW	RegD Effective MW	Total Self Scheduled Effective MW	Total Effective MW	RegD Percent of Total Self Scheduled Effective MW	RegD Percent of Total Effective MW
2023	Jan	217.4	312.5	376.5	674.2	57.7%	46.3%
2023	Feb	178.5	293.4	313.7	685.0	56.9%	42.8%
2023	Mar	180.7	284.8	341.1	641.2	53.0%	44.4%
2023	Apr	188.0	295.4	293.5	639.6	64.0%	46.2%
2023	May	203.1	303.3	322.3	646.8	63.0%	46.9%
2023	Jun	233.1	339.6	368.2	698.4	63.3%	48.6%
2023	Jul	242.0	344.6	416.2	710.1	58.1%	48.5%
2023	Aug	238.1	342.9	418.8	704.9	56.9%	48.6%
2023	Sep	239.1	332.4	389.6	657.5	61.4%	50.6%
2023	Oct	237.5	328.3	364.9	639.6	65.1%	51.3%
2023	Nov	241.7	327.7	423.7	640.5	57.0%	51.2%
2023	Dec	244.8	341.2	424.2	674.2	57.7%	50.6%
Average		220.3	320.5	371.1	667.7	59.5%	48.0%
2024	Jan	247.3	348.5	404.2	708.4	61.2%	49.2%
2024	Feb	247.2	333.6	431.4	674.0	57.3%	49.5%
2024	Mar	251.6	332.6	395.0	639.8	63.7%	52.0%
2024	Apr	246.3	328.7	378.4	646.1	65.1%	50.9%
2024	May	244.2	326.1	347.9	639.6	70.2%	51.0%
2024	Jun	269.3	343.2	432.9	716.4	62.2%	47.9%
2024	Jul	257.8	350.8	415.0	711.5	62.1%	49.3%
2024	Aug	244.2	341.8	391.7	706.5	62.3%	48.4%
2024	Sep	227.2	318.7	359.3	639.7	63.2%	49.8%
Average		248.3	365.5	395.1	675.8	63.0%	49.8%

LSE's can satisfy their obligation to provide regulation by purchasing in the spot market, self scheduling, or through bilateral agreements. Increased self scheduled regulation lowers the requirement for cleared regulation, resulting in fewer MW cleared in the market and lower clearing prices. For total spot market regulation and self scheduled regulation, Table 10-52 shows monthly data for January 2023 through September 2024, and Table 10-53 shows annual data for January through September, 2012 through 2024. Table 10-52 and Table 10-53 are based on settled (purchased) MW.

Table 10-52 Regulation sources: spot market and self scheduled purchases: January 2023 through September 2024

Year	Month	Spot Market Regulation (Unadjusted MW)	Self Scheduled Regulation (Unadjusted MW)
2023	Jan	126,117.0	197,873.7
	Feb	183,580.7	144,902.8
	Mar	154,809.4	181,862.7
	Apr	194,988.7	142,019.7
	May	178,797.9	162,369.6
	Jun	166,079.8	177,662.2
	Jul	143,524.9	210,702.6
	Aug	137,645.3	212,801.4
	Sep	136,353.0	195,056.8
	Oct	152,769.2	191,675.7
	Nov	103,207.6	219,949.2
	Dec	114,297.3	225,054.8
Total		1,792,170.7	2,261,931.1
2024	Jan	154,709.3	206,512.1
	Feb	102,320.8	210,400.6
	Mar	119,518.6	205,632.7
	Apr	129,745.9	187,429.4
	May	162,153.9	166,226.4
	Jun	140,119.8	204,187.0
	Jul	141,454.2	211,045.4
	Aug	154,173.9	193,923.2
	Sep	128,113.1	174,698.6
Total		1,232,309.5	1,760,055.5

Table 10-53 Regulation sources: spot market and self scheduled: January through September, 2012 through 2024

Year (Jan-Sep)	Spot Market Regulation (Unadjusted MW)	Self Scheduled Regulation (Unadjusted MW)
2012	5,110,747.9	1,122,671.9
2013	2,528,830.3	1,478,608.5
2014	1,836,488.7	1,543,266.0
2015	1,897,225.7	1,380,004.7
2016	1,672,795.5	1,598,231.6
2017	1,849,333.5	1,372,996.2
2018	2,124,551.1	1,135,540.8
2019	1,755,035.5	1,405,707.9
2020	1,608,960.6	1,667,128.2
2021	1,766,633.1	1,555,694.7
2022	1,870,452.6	1,201,997.0
2023	1,421,896.6	1,625,251.4
2024	1,232,309.5	1,760,055.5

In the first nine months of 2024, DR provided an average of 53.4 MW of regulation per hour during ramp hours (35.7 MW of regulation per hour during ramp hours in the first nine months of 2023), and an average of 42.4 MW of regulation per hour during nonramp hours (24.1 MW of regulation per hour during nonramp hours in the first nine months of 2023). Generating units supplied an average of 645.3 MW of regulation per hour during ramp hours in the first nine months of 2024 (673.9 MW of regulation per hour during ramp hours in the first nine months of 2023), and an average of 437.0 MW per hour during nonramp hours in the first nine months of 2024 (451.6 MW of regulation per hour during nonramp hours in the first nine months of 2023).

Market Performance

Price

Table 10-54 shows the regulation price and regulation cost per MW for January through September 2009 through 2024. The weighted average RMCP for the first nine months of 2024 was $31.30 per MW. This is an increase of $9.26 per MW, or 42.0 percent, from the weighted average RMCP of $22.04 per MW in the first nine months of 2023. This increase in the regulation clearing price was the result of an increase in energy prices in the first nine months of 2024 and the related increase in the opportunity cost component of RMCP.

Table 10-54 Comparison of average price and cost for regulation: January through September, 2009 through 2024

Year (Jan-Sep)	Weighted Regulation Market Price	Weighted Regulation Market Cost	Regulation Price as Percent of Cost
2009	$24.94	$32.28	77.3%
2010	$19.47	$34.54	56.4%
2011	$17.04	$32.70	52.1%
2012	$15.16	$21.07	71.9%
2013	$33.29	$38.49	86.5%
2014	$50.19	$60.94	82.4%
2015	$35.56	$43.00	82.7%
2016	$16.52	$18.99	87.0%
2017	$15.70	$21.70	72.4%
2018	$28.21	$35.06	80.5%
2019	$14.97	$19.15	78.1%
2020	$12.59	$15.59	80.8%
2021	$20.91	$25.37	82.4%
2022	$51.04	$63.46	80.4%
2023	$22.04	$29.03	75.9%
2024	$31.30	$39.72	78.8%

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. Table 10-55 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 September 2024. In the first nine months of 2024, fast start pricing increased the average regulation market clearing price by 9.0 percent compared to dispatch pricing.

Table 10-55 Comparison of fast start and dispatch pricing: September 2021 through September 2024[113]

		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%
Total		$27.62	$30.21	$28.71	$31.30	9.0%

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

Figure 10-41 shows the capability price, performance price, and the opportunity cost component for the PJM Regulation Market on a performance adjusted 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 10-41 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 predominant component of the total clearing price.

Figure 10-41 Regulation market clearing price components (Dollars per MW): January through September, 2024

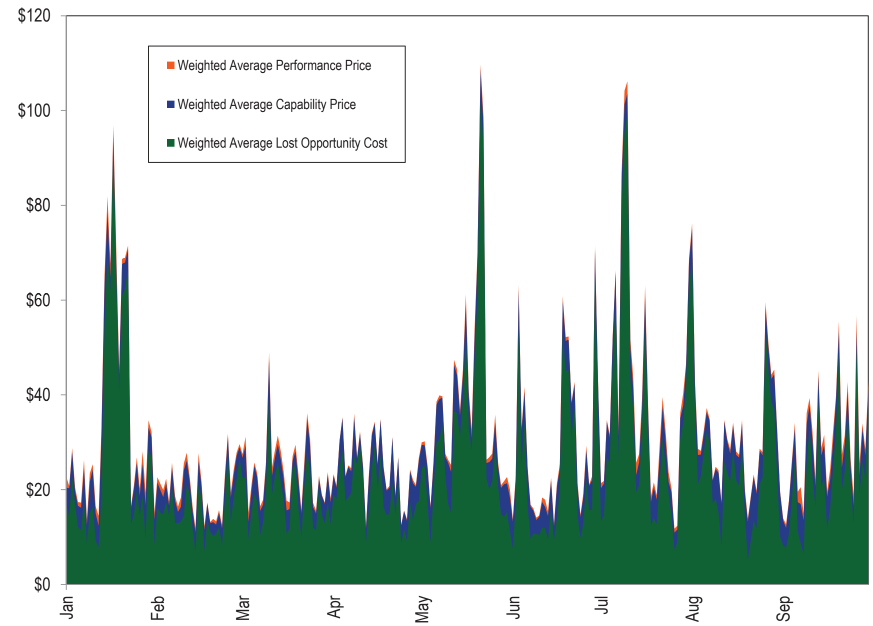


Table 10-56 shows the capability and performance components of the monthly average regulation prices. These components differ from the components of the marginal unit's offers in Figure 10-41 because the performance component of the settlement price for each hour is determined from the average of the highest performance offers in each five minute interval, calculated independent of the marginal unit's offers in those intervals.

Table 10-56 Regulation market monthly component of price (Dollars per MW): January through September, 2024

Month	Weighted Average Regulation Market Capability Clearing Price ($/Perf. Adj. Actual MW)	Weighted Average Regulation Market Performance Clearing Price ($/Perf. Adj. Actual MW)	Weighted Average Regulation Market Clearing Price ($/Perf. Adj. Actual MW)
Jan	$36.70	$1.58	$38.28
Feb	$19.44	$0.98	$20.42
Mar	$22.88	$1.16	$24.04
Apr	$24.52	$0.38	$24.90
May	$37.59	$1.05	$38.64
Jun	$28.96	$0.73	$29.68
Jul	$39.87	$1.48	$41.35
Aug	$31.48	$0.70	$32.18
Sep	$28.31	$1.70	$30.01
Average	$30.21	$1.09	$31.30

Monthly and total annual scheduled regulation MW and regulation charges, as well as monthly average regulation price and regulation cost are shown in Table 10-57. Total scheduled regulation is based on settled performance adjusted MW. The total of all regulation charges in the first nine months of 2024 was $136,716,057, compared to $99,478,949 in the first nine months of 2023.

Table 10-57 Total regulation charges: January 2023 through September 2024

Year	Month	Scheduled Regulation (MW)	Total Regulation Charges ($)	Weighted Average Regulation Market Price ($/MW)	Cost of Regulation ($/MW)	Price as Percent of Cost
2023	Jan	393,338.7	$9,819,046	$18.22	$24.96	73.0%
	Feb	362,742.5	$8,129,962	$16.65	$22.41	74.3%
	Mar	378,020.0	$9,522,499	$18.57	$25.19	73.7%
	Apr	367,767.4	$11,314,002	$24.29	$30.76	79.0%
	May	374,017.5	$12,558,409	$26.14	$33.58	77.8%
	Jun	387,059.0	$11,599,709	$22.38	$29.97	74.7%
	Jul	402,672.4	$12,687,645	$24.54	$31.51	77.9%
	Aug	398,401.7	$11,924,512	$22.39	$29.93	74.8%
	Sep	371,319.8	$11,923,165	$25.08	$32.11	78.1%
	Oct	379,772.9	$15,165,910	$33.51	$39.93	83.9%
	Nov	364,104.7	$9,288,549	$21.30	$25.51	83.5%
	Dec	391,045.4	$9,760,581	$19.15	$24.96	76.7%
	Total	4,570,260.9	$133,996,478	$22.69	$29.32	77.4%
2024	Jan	408,753.4	$20,438,488	$38.28	$50.00	76.6%
	Feb	359,472.4	$9,511,886	$20.42	$26.46	77.2%
	Mar	373,821.3	$11,575,938	$24.04	$30.97	77.6%
	Apr	365,623.4	$11,713,712	$24.90	$32.04	77.7%
	May	370,688.3	$17,378,965	$38.64	$46.88	82.4%
	Jun	394,543.8	$14,952,926	$29.68	$37.90	78.3%
	Jul	409,957.7	$21,913,007	$41.35	$53.45	77.4%
	Aug	404,773.1	$16,222,786	$32.18	$40.08	80.3%
	Sep	354,056.7	$13,008,349	$30.01	$36.74	81.7%
	Total	3,441,690.1	$136,716,057	$31.30	$39.72	78.8%

The capability, performance, and opportunity cost components of the cost of regulation are shown in Table 10-58. Total scheduled regulation is based on settled performance adjusted MW. In the first nine months of 2024, the average total cost of regulation was $39.72 per MW, 37.2 percent higher than $28.96 in the first nine months of 2023. In the first nine months of 2024, the monthly average capability component cost of regulation was $30.24, 44.8 percent higher than $20.89 in the first nine months of 2023. In the first nine months of 2024, the monthly average performance component cost of regulation was $2.76, 2.8 percent lower than $2.84 in the first nine months of 2023. The increase of the average total cost in the first nine months of 2024 versus the first nine months of 2023, was primarily a result of higher LOC values due to higher prices in the energy market.

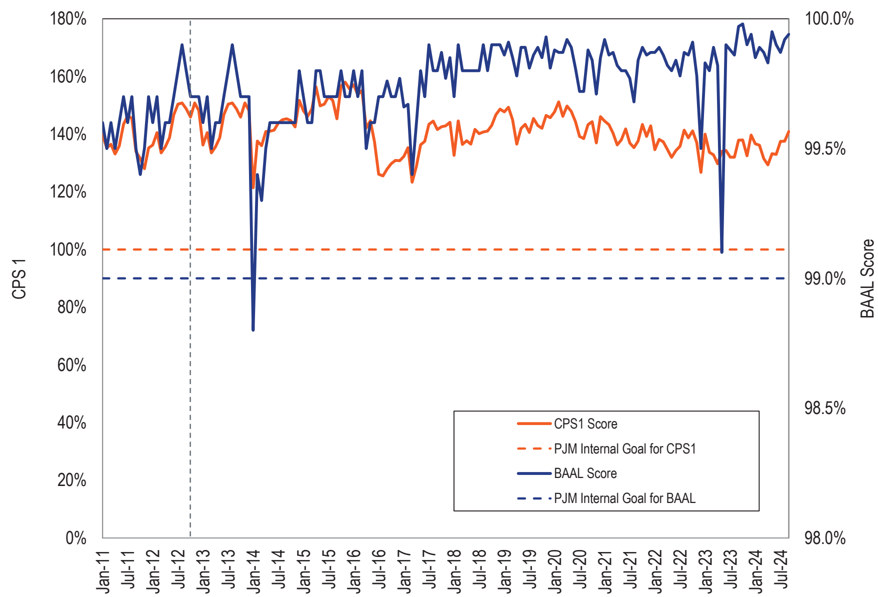
Table 10-58 Components of regulation cost: January 2023 through September 2024

Year	Month	Scheduled Regulation (MW)	Cost of Regulation Capability ($/MW)	Cost of Regulation Performance ($/MW)	Opportunity Cost ($/MW)	Total Cost ($/MW)
2023	Jan	393,338.7	$17.27	$2.44	$5.25	$24.96
	Feb	362,742.5	$15.48	$2.89	$4.04	$22.41
	Mar	378,020.0	$17.77	$1.90	$5.52	$25.19
	Apr	367,767.4	$23.18	$2.60	$4.98	$30.76
	May	374,017.5	$24.58	$3.77	$5.22	$33.58
	Jun	387,059.0	$20.88	$3.80	$5.29	$29.97
	Jul	402,672.4	$23.45	$2.62	$5.43	$31.51
	Aug	398,401.7	$21.34	$2.61	$5.99	$29.93
	Sep	371,319.8	$23.92	$2.97	$5.22	$32.11
	Oct	379,772.9	$32.40	$2.94	$4.59	$39.93
	Nov	364,104.7	$20.83	$1.21	$3.47	$25.51
	Dec	391,045.4	$18.13	$2.68	$4.14	$24.96
Total		4,570,260.9	$21.60	$2.71	$5.01	$29.32
2024	Jan	408,753.4	$36.74	$3.97	$9.29	$50.00
	Feb	359,472.4	$19.47	$2.40	$4.59	$26.46
	Mar	373,821.3	$22.90	$2.93	$5.15	$30.97
	Apr	365,623.4	$24.56	$0.97	$6.51	$32.04
	May	370,688.3	$37.61	$2.58	$6.70	$46.88
	Jun	394,543.8	$28.96	$1.72	$7.21	$37.90
	Jul	409,957.7	$39.90	$3.90	$9.65	$53.45
	Aug	404,773.1	$31.53	$1.76	$6.79	$40.08
	Sep	354,056.7	$28.31	$4.58	$3.85	$36.74
Total		3,441,690.1	$30.24	$2.76	$6.73	$39.72

Performance Standards

PJM's performance as measured by CPS1 and BAAL standards is shown in Figure 10-42 for every month from January 2011 through September 2024 with the dashed vertical line marking the date (October 1, 2012) of the implementation of the Performance Based Regulation Market design.[114] The horizontal dashed lines represent PJM internal goals for CPS1 and BAAL performance.

Figure 10-42 Monthly CPS1 and BAAL performance: January 2011 through September 2024



114 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).[115] Although the issue is being addressed in the stakeholder process, there are currently no firm fuel requirements for black start units.

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.[116] Currently, there is 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 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.[117] Under the current rules PJM has substantial flexibility in procuring black start resources and is responsible for black start resource selection.[118] But PJM's stated principles for system restoration are not fully incorporated into the rules in Schedule 6A. Costs should also be allocated on a regional basis.

The MMU recommends that black start planning and coordination be on a regional basis and not on a zonal basis. Similarly, the region as a whole benefits from black start service, regardless of the transmission zone in which it is located, and the costs of black start service should be shared equally across the region.

115 OATT Schedule 1 § 1.3BB.
116 See OATT Schedule 6A para. 18.
117 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.").
118 See Docket No. ER13-1911-000.

By order issued October 6, 2023, the FERC approved revisions to Schedule 6A concerning fuel assurance for black start units, effective July 12, 2023.[119] The revisions were approved over the protest of the MMU, which identified significant flaws.[120] 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 factor for fuel assured hydro units is arbitrarily doubled from 0.01 to 0.02. The incentive factor for fuel assured units is 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 DER's provision of black start service. 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.

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 planned in service date was June 2024. On August 1, 2022, PJM issued an incremental RFP for black start service in the PECO Zone.[121] On March 26, 2024, PJM made an award for the August 1, 2022 RFP. The planned in service date is December 31, 2026.

On June 20, 2023, PJM issued a RTO wide request for proposals (RFP) in accordance with the five year black start selection process. The RFP is for black start service and fuel assured black start service. In service dates are estimated to be June 1, 2024 through April 2027.

119 See 85 FERC ¶ 91,000.
120 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).
121 RFPs are on the PJM website. <http://www.pjm.com/markets-and-operations/ancillary-services.aspx>.

On April 29, 2024, PJM issued an incremental RFP for fuel assured black start service, because the 2023 RTO wide black start service RFP did not attract offers for fuel assured black start units in all zones. The result illustrated 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. As a result, PJM will procure more black start resources than PJM's target level. Level 1 proposals were due June 18, 2024, and Level 2 proposals were due due August 20, 2024. These proposals will be non binding. Evaluations and awards are projected to be between August 20, 2024, and December 10, 2024. In service dates are projected to be January 1, 2027, for units that will require updates to meet fuel assurance requirements.

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.[122]

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 calculated by taking the Net CONE multiplied by the black start unit's capacity multiplied by an x factor. The x factor is 0.01 for hydro units and 0.02 for CT units. The capital recovery rate is calculated by multiplying the capital investment 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.[123] Total black start charges are allocated monthly to PJM customers based on their zone and nonzone peak transmission use and point to point transmission reservations.[124] It is not clear why it is reasonable to have different charges for black start service across zones as the service is to ensure that PJM as a whole can recover from a large scale outage.

In the first nine months of 2024, total black start charges were $55.2 million, an increase of $5.1 million (10.1 percent) from 2023. In the first nine months of 2024, total revenue requirement charges were $54.9 million, an increase of $5.0 million (10.1 percent) from 2023. In the first nine months of 2024, total uplift charges were $0.3 million, an increase of $0.04 million (16.5 percent) from 2023. Table 10-59 shows total charges for January through September of each year from 2010 through 2024.[125]

Table 10-59 Black start revenue requirement charges: January through September, 2010 through 2024

Jan-Sep	Revenue Requirement Charges	Uplift Charges	Total
2010	$8,527,000	$0	$8,527,000
2011	$9,996,898	$0	$9,996,898
2012	$13,288,491	$0	$13,288,491
2013	$15,728,447	$68,903,357	$84,631,804
2014	$18,395,320	$26,661,658	$45,056,978
2015	$39,718,855	$5,070,944	$44,789,799
2016	$51,565,656	$180,265	$51,745,921
2017	$52,422,434	$186,752	$52,609,186
2018	$48,938,203	$152,720	$49,090,923
2019	$48,231,346	$175,400	$48,406,746
2020	$49,052,199	$163,301	$49,215,499
2021	$50,278,321	$203,620	$50,481,941
2022	$51,357,993	$352,984	$51,710,976
2023	$49,897,290	$261,396	$50,158,686
2024	$54,915,983	$304,435	$55,220,419

Black start zonal charges in the first nine months of 2024 ranged from $0 in the OVEC and REC Zones to $13,812,523 in the AEP Zone. For each zone, Table 10-60 shows black start charges, zonal peak loads, and black start rates (calculated as charges per MW-day).[126] [127]

122 *See* OATT Schedule 6A para. 18.

123 There are no black start units currently using the ALR option.

124 OATT Schedule 6A (paras. 25, 26 and 27 outline how charges are to be applied).

125 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.

126 See "PJM Manual 27: Open Access Transmission Tariff Accounting,"§ 7.3 Black Start Service Charges, Rev. 101 (Nov. 15, 2023).

127 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 10-60 Black start zonal charges: January through September, 2023 and 2024[128]

	Jan-Sep 2023					Jan-Sep 2024				
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	$1,467,408	$8,166	$1,475,574	2,614	$2.07	$1,581,474	$9,364	$1,590,838	2,629	$2.21
AEP	$14,442,323	$35,011	$14,477,333	21,717	$2.44	$13,788,860	$23,663	$13,812,523	22,826	$2.21
APS	$4,165,882	$792	$4,166,674	9,154	$1.67	$4,448,421	$6,602	$4,455,023	9,303	$1.75
ATSI	$4,200,550	$8,976	$4,209,526	12,771	$1.21	$3,718,557	$8,398	$3,726,955	11,963	$1.14
BGE	$26,034	$144	$26,178	6,520	$0.01	$2,818,789	$6,417	$2,825,206	6,406	$1.61
COMED	$6,568,510	$55,516	$6,624,027	21,262	$1.14	$6,278,773	$52,380	$6,331,152	22,467	$1.03
DAY	$145,132	$28,039	$173,171	3,362	$0.19	$177,059	$18,647	$195,707	3,241	$0.22
DUKE	$200,140	$11,487	$211,626	5,166	$0.15	$285,849	$15,060	$300,909	5,135	$0.21
DUQ	$759,994	$0	$759,994	2,715	$1.03	$704,867	$1,199	$706,067	2,534	$1.02
DOM	$3,675,486	$52,043	$3,727,529	21,156	$0.65	$3,513,209	$97,307	$3,610,516	22,189	$0.59
DPL	$881,438	$12,824	$894,262	4,125	$0.79	$942,018	$7,860	$949,878	4,078	$0.85
EKPC	$209,984	$4,052	$214,037	2,994	$0.26	$238,311	$13,893	$252,204	3,755	$0.25
JCPLC	$397,043	$2,484	$399,527	6,123	$0.24	$364,285	$953	$365,238	5,731	$0.23
MEC	$299,790	$9,916	$309,706	3,021	$0.38	$360,972	$7,221	$368,192	2,890	$0.46
OVEC	$0	$0	$0	NA	NA	$0	$0	$0	NA	NA
PECO	$975,591	$3,246	$978,838	8,583	$0.42	$1,058,996	$2,099	$1,061,096	8,163	$0.47
PE	$3,199,680	$8,829	$3,208,509	2,830	$4.15	$3,075,110	$8,340	$3,083,450	2,763	$4.07
PEPCO	$131,050	$1,150	$132,199	5,834	$0.08	$3,377,894	$1,839	$3,379,733	5,872	$2.10
PPL	$3,653,293	$226	$3,653,519	7,489	$1.79	$3,433,316	$176	$3,433,491	7,083	$1.77
PSEG	$1,209,646	$2,857	$1,212,504	10,147	$0.44	$1,212,231	$3,645	$1,215,876	9,561	$0.46
REC	$0	$0	$0	NA	NA	$0	$0	$0	NA	NA
(Imp/Exp/Wheels)	$3,288,316	$15,639	$3,303,954	11,089	$1.09	$3,536,992	$19,373	$3,556,365	10,977	$1.18
Total	$49,897,290	$261,396	$50,158,686	168,671	$1.09	$54,915,983	$304,435	$55,220,419	169,565	$1.19

Table 10-61 provides a revenue requirement estimate by zone for the 2024/2025, 2025/2026, and 2026/2027 Delivery Years.[129] 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.

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

Table 10-61 Black start zonal revenue requirement estimate: 2024/2025 through 2026/2027 Delivery Years[130]

Zone	2024 / 2025 Revenue Requirement	2025 / 2026 Revenue Requirement	2026 / 2027 Revenue Requirement
ACEC	$2,700,000	$2,550,000	$2,400,000
AEP	$15,850,000	$9,100,000	$7,900,000
APS	$6,850,000	$3,150,000	$4,100,000
ATSI	$3,800,000	$3,350,000	$3,150,000
BGE	$3,900,000	$5,150,000	$5,150,000
COMED	$8,550,000	$2,250,000	$1,250,000
DAY	$300,000	$250,000	$150,000
DUKE	$450,000	$300,000	$100,000
DUQ	$1,100,000	$1,100,000	$2,200,000
DOM	$5,150,000	$2,600,000	$1,600,000
DPL	$1,500,000	$1,000,000	$800,000
EKPC	$400,000	$250,000	$100,000
JCPLC	$650,000	$550,000	$450,000
MEC	$600,000	$400,000	$250,000
OVEC	$0	$0	$0
PECO	$1,600,000	$1,350,000	$1,050,000
PE	$4,650,000	$750,000	$400,000
PEPCO	$8,900,000	$8,800,000	$8,750,000
PPL	$5,050,000	$2,450,000	$2,050,000
PSEG	$1,850,000	$800,000	$650,000
REC	$0	$0	$0
Total	$73,850,000	$46,150,000	$42,500,000

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.[131] 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 and incorporated in Attachment DD to the PJM OATT. 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.[132] The CRF table in the tariff included assumptions about tax rates that were significantly too high after the changes to the tax code in 2017. The PJM tariff tables including CRF values should have been changed for both black start and the capacity market when the tax laws changed in 2017.

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.[133] 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 U.S. Internal Revenue Code changed significantly in December 2017.[134] [135] The PJM CRF table did not change to reflect these changes.[136] [137] As a result, CRF values have overcompensated black start units since the changes to the tax code. The new tax law allows for a more accelerated depreciation and reduced the corporate tax rate to 21 percent.

Updated CRF rates, incorporating the tax code changes and applicable to all black start units, should have been implemented immediately. The updated CRF rates should apply to all black start units because the actual tax payments for all black start units were reduced by the tax law changes. Without this change, black start units are receiving and will continue to receive an unexpected and inappropriate windfall.

130 The Net CONE values from the 2024/2025 though the 2026/2027 Base Residual Auctions were used in the base formula rate calculations for black start units and reflected in the estimates.

131 *See* OATT Schedule 6A para. 18.

132 *Id.*

133 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.

134 Tax Cuts and Jobs Act, Pub. L. No. 115-97, 131 Stat. 2096, Stat. 2105 (2017).

135 26 U.S. Code §11(b).

136 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.

137 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).

On April 7, 2021, PJM filed with FERC to update the CRF values for new black start service units.[138] 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 on April 28, 2021.[139] 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.[140] [141] 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.[142] 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."[143] The MMU requested rehearing over the Commission's conclusion that the MMU had requested "retroactive changes to the rates previously paid to generators."[144] [145] The request for rehearing was denied.[146] 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.[147]

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."[148] [149] 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.[150] In March 2023 FERC issued an order establishing hearing and settlement judge procedures.[151] An impasse was declared on August 23, 2023 and a hearing procedural schedule was ordered.[152] [153] Settlement talks continued and in January 2024 Commission Trial Staff moved to suspend the proceeding because a settlement had been reached in principle.[154] The MMU filed comments in opposition to the settlement, and the settlement was not certified to the Commission.[155] [156] The hearing process then resumed, with an initial decision expected to issue in March 2025. 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. The second settlement was certified to the Commission as uncontested because the MMU was deemed to waive its objections because its opposing filing was treated as untimely.[157] The MMU filed its own offer of settlement, but that filing was not certified primarily based on a determination that the offer was a settlement in name only.[158] The MMU will pursue an interlocutory appeal.

There are 49 black start generators that have received payments based on the outdated CRF. Eleven of the units have completed their black start capital cost recovery. Eighteen units started their black start service prior to January 1, 2018, and are currently receiving capital recovery payments. These units would not have been eligible for the TCJA bonus depreciation. The remaining 20 black start generators began their service terms after January 1, 2018, and are currently receiving capital recovery payments. Units with capital investments that began black start service after January 1, 2018, would have

138 *See* Docket No. ER21-1635-000.
139 See Comments of the Independent Market Monitor for PJM, FERC Docket No. ER21-1635-000 (April 28, 2021).
140 Answer and Motion for Leave to Answer of the independent Market Monitor for PJM, ER21-1635 (May 20, 2021).
141 Comments of the Independent Market Monitor for PJM, FERC Docket No. ER21-1635 (July 2, 2021).
142 176 FERC ¶ 61,080 at 42 and 44 (2021).
143 176 FERC ¶ 61,080 at 2 (2021).
144 Id. at 50.
145 Request for Rehearing of the Independent Market Monitor for PJM, FERC Docket No. ER21-1635 (September 9, 2021).
146 177 FERC ¶ 62,017 (2021).
147 177 FERC ¶ 61,202 (2021).
148 *PJM Interconnection, L.L.C., Response to Commission's Show Cause Order*, Docket No. EL21-91 (October 12, 2021).
149 August 10th Order at 47.
150 Errata Filing of the Independent Market Monitor for PJM, Attachment B at 17, Docket No. EL21-91 (November 18, 2022).
151 182 FERC ¶ 61,194 (2023).
152 *Order Declaring Impasse*, EL21-91-000 (August 23, 2023).
153 *Order Adopting Procedural Schedule and Confirming Bench Ruling Regarding Protective Order*, EL21-91-000 (October 12, 2023).
154 Motion of Commission Trial Staff to Suspend Procedural Schedule and Shorten Answer Period, Docket No. EL21-91-003 (January 10, 2024).
155 Comments of the Independent Market Monitor for PJM in Opposition to Offer of Settlement, Docket No. EL21-91-000, -003 (February 20, 2024).
156 186 FERC ¶ 63,019 (2024).
157 See 189 FERC ¶ 63,007 at P 3 (2024). The Market Monitor timely filed opposing comments, but the filing was rejected the following day due to the identification of a sentence as confidential that was no longer confidential in one of the supporting exhibits. Filing the corrected supporting exhibit resulted in a new filing date that was one day late.
158 *Id.* at P 244.

been eligible for bonus depreciation. Table 10-62 shows excess capital recovery payments to be paid by transmission customers and the excess recovery to equity investors that will result if the CRF values are not corrected. If the CRF had been updated to reflect the TCJA on January 1, 2018, the capital recovery payments for the 49 generators would be $424.6 million, $89.7 million lower than capital recovery payments if the current CRF remain in place. Of the $89.7 in excess payments, $25.2 million would go toward income taxes and the remaining $64.5 million would remain with the equity investors.

Table 10-62 CRF excess recovery if CRF not corrected for changes in tax laws[159]

	Capital Recovery Payments 2018 - 2040 ($ millions)	Overpayment ($ millions)
Had CRFs been updated on January 1, 2018	$424.6	
Current CRFs remain in place	$514.3	$89.7

The MMU proposed an update to the CRF that reflects the return of capital already received by existing black start units and eliminates the over recovery that occurs under the PJM proposal. The updated CRF would be set at the level that covers the tax liabilities going forward and results in the required return on and of capital over the CRF term. A description of the MMU's proposal and a formula for calculating the updated CRF are included in the MMU Comments.[160]

Table 10-63 Excess capital recovery payments under MMU proposal

	Capital Recovery Payments 2018 - 2040 ($ millions)	Overpayment ($ millions)
Had CRFs been updated on January 1, 2018	$424.6	
Current CRFs remain in place	$514.3	$89.7
Updated CRFs beginning July 1, 2024	$429.5	$4.9
Updated CRFs beginning January 1, 2025	$448.2	$23.6
Updated CRFs beginning January 1, 2026	$464.5	$39.9

Table 10-63 shows the capital recovery payments under the MMU proposal for several CRF revision dates. Table 10-63 shows that the longer a revision to the CRF is delayed, the effectiveness of solution decreases as units reach the end of their CRF periods. If updated and correct CRF values were in place by July 1, 2024, the overpayment would be reduced to $4.9 million. If updated and correct CRF values were in place by January 1, 2025, possibly the earliest CRF revision date given the hearing schedule, the overpayment would be reduced to $23.6 million.

159 Black start generators in service prior to September 27, 2017, the effective date of the Tax Cuts and Jobs Act (TCJA), are not eligible for bonus depreciation but do benefit from the lower corporate tax rate. Generators placed in black start service on or after September 27, 2017 benefit from the lower tax rate and bonus depreciation.

160 Errata Filing of the Independent Market Monitor for PJM, Attachment B, Section H at 18, Docket No. EL21-91 (November 18, 2022).

NERC – CIP

No black start units have requested new or additional black start NERC – CIP Capital Costs.[161]

Reactive Service and Capability

Suppliers of reactive power are compensated separately for reactive service and reactive capability.

Reactive service, reactive supply and voltage control are provided by generation and other sources of reactive power, including static VAR compensators and capacitor banks. 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.[162] In a 2023 *MISO* case, the Commission affirmed that RTOs and their customers are not required to compensate generation resources for such reactive capability.[163] On October 17, 2024, the Commission issued a final rule, Order No. 904, eliminating separate payments for reactive in all jurisdictional markets, including PJM.[164] PJM needs to make a filing in compliance with Order No. 904. Any transition provisions should not permit payments during the transition that exceed the

161 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."

162 OATT Attachment O.

163 *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 (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).

164 *Compensation for Reactive Power within the Standard Power Factor Range*, Order No. 904, 189 FERC ¶ 61,034 (2024) ("Order No. 904").

level of the reactive revenue offset in the capacity market demand curve, $2,199 per MW-year.

Customers in PJM paid total reactive capability charges of $388.0 million in 2023. Under the current rules, compensation for reactive capability is approved separately for each resource or resource group by FERC per Schedule 2 of the OATT.[165] Reactive capability credits are based on FERC approved filings for individual unit revenue requirements that are typically black box settlements.[166] 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 service. Compensation for reactive power service is based on real-time lost opportunity costs.[167]

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.[168] [169]

Issues with Reactive Capability Market Design

The fundamental question that the Commission addressed in its NOPR is whether market design in the organized wholesale markets requires separate, guaranteed cost of service compensation for reactive capability. The answer is no. All generation resources are required to meet certain reactive capability requirements as a condition to receive interconnection service and no separate compensation is required.[170]

In the PJM market design, investment in resources is fully recoverable through markets. The PJM markets are a complete set of markets that are self sustaining. Unlike some ISO/RTO designs, the PJM market design relies on markets rather than cost of service regulation or bilateral contracts to pay for capacity. Generators will invest in markets when the expected revenues provide for the payment of all costs and a return on and of capital. That is the way competitive markets work. It would be more equitable, more consistent with the PJM competitive market design, and more consistent with appropriate compensation for all generator costs, including reactive, to rely on PJM markets than to continue the outdated mixing of regulatory paradigms.

Even if the PJM design worked in the way asserted by supporters of cost of service payments for reactive, the best possible outcome would be the same as the market outcome. There would be an opportunity to recover all costs. A simple application of Occam's razor implies that the market approach should be used, as it is overwhelmingly more efficient than the current rate case, cost of service approach. Supporters of the cost of service approach have never explained why customers should be required to pay costs that generation resources are not entitled to recover from customers, why a nonmarket approach is required in PJM or why it is preferable to a market approach.

The current process is an inefficient waste of time because it relies on an atavistic regulatory paradigm that is not relevant in the PJM market framework. The *AEP* Method was created, before the creation of the PJM markets, by a regulated utility that had regulatory and financial reasons to want to define some generation costs as transmission costs. At the time, AEP collected both generation and transmission costs under the same cost of service approach. The *AEP* Method was based on three sentences in testimony filed in 1993 that provide no logical, engineering or economic support for allocating a part of generator capital investment to reactive. That testimony was about a subjective decision to reassign costs that were already fully accounted for and not about any asserted costs to provide reactive power that were not recovered elsewhere and not for any asserted additional costs of providing reactive power.[171]

In PJM and its competitive market design, there is no reason to include complex rules that arbitrarily segregate a portion of a resource's capital costs as related to reactive power and that require recovery of that arbitrary portion through guaranteed revenue requirement payments based on burdensome

165 See "PJM Manual 27: Open Access Transmission Tariff Accounting,"§ 3.2 Reactive Supply and Voltage Control Credits, Rev. 101 (Nov. 15, 2023).
166 OATT Schedule 2.
167 See OA Schedule 1 § 3.2.3B.
168 OATT Schedule 2.
169 See "PJM Manual 27: Open Access Transmission Tariff Accounting,"§ 3.3 Reactive Supply and Voltage Control Charges, Rev. 101 (Nov. 15, 2023).
170 See Order No. 904 at PP 89–90.
171 See *Fern Solar LLC*, Initial Brief of the Independent Market for PJM, FERC Docket No. ER20-2186, et al. (February 15, 2023) at 24–31.

cost of service rate proceedings. The practice persists in PJM only because it provides a significant, guaranteed stream of riskless revenue.

Applying cost of service rules is costly, burdensome and unnecessary. Most reactive proceedings for generators in PJM are resolved in black box settlements that fail to address the merits of the cost support provided, result from an unsupported split the difference approach, and that, not surprisingly, produce a wide, unreasonable and discriminatory disparity among the rates per paid per MW-year for the same service.

Payments based on cost of service approaches result in distortionary impacts on PJM markets. Elimination of the reactive revenue requirement and recognition that capital costs are not distinguishable by function would increase prices in the capacity market. The VRR curve would shift to the right, the maximum VRR price would increase and offer caps in the capacity market would increase. The simplest way to address this distortion would be to recognize that all capacity costs are recoverable in the PJM markets.

Order No. 904 will allow PJM to use a market based approach. The interrelated and self sustaining markets in PJM provide the opportunity for all power plants to recover all their costs, including a return on and of capital, including any identifiable reactive costs. There is no reason that part of those capacity costs should be paid directly in a non-market, guaranteed, riskless revenue stream rather than in the market.

The current rules create strong incentives for generators to attempt to maximize the allocation of capital costs to reactive in order to maximize guaranteed, nonmarket revenues. The current process does not actually compensate resources based on their costs of investment in reactive power capability. The *AEP* Method assigns costs between real and reactive power based on a unit's power factor. This is effectively an allocation based on a subjective judgment rather than actual investment. There are few if any identifiable costs incurred by generators in order to provide reactive power. Separately compensating resources based on a judgment based allocation of total capital costs was never and is not now appropriate in the PJM markets. Generating units are fully integrated power plants that produce both the real and reactive power required for grid operation.

There is no logical reason to have a separate fixed payment for any part of the capacity costs of generating units in PJM. If separate cost of service rates for reactive continue, they need to be correctly integrated in the PJM market design.

With the adoption of Order No. 904, the offset for revenue requirements for reactive supply capability should be removed. Investment in generation can and should be compensated entirely through markets. Removing rules for revenue requirements would avoid the significant waste of resources incurred to develop unneeded cost of service rates.

The result would be to pay generators market based rates for both real and reactive capacity.

The PJM market design allows for the competitive investment in generation resources. The addition of separate rules allowing for the recovery of an arbitrarily defined portion of the same investment on a cost of service basis introduces a flaw into the competitive market design. The flaw is exacerbated when separate cost of service proceedings define the revenue requirement cost to supply reactive at values ranging from $993 to $18,750 per MW-year. (See Table 10-68)

The real issue is that the revenue requirement approach is inconsistent with both the theory and mechanics of PJM markets. The impact is to distort market outcomes.

The rules that account for recovery of reactive revenues are built into the auction parameters, specifically, the VRR curve. The PJM market rules explicitly account for recovery of reactive revenues of $2,199 per MW-Year through inclusion in the Net CONE parameter of the capacity market demand (VRR) curve.[172] The Net CONE parameter directly affects clearing prices by affecting both the maximum capacity price and the location of the downward sloping part of the VRR curve. In addition, market sellers, when submitting

172 *See* OATT Attachment DD § 5.10(a)(v)(A).

offers based on net avoidable costs must account for revenues received through cost of service reactive capability rates in the calculation.[173] Unit specific reactive capability rates up to that $2,199 per MW-Year level are at least consistent with that parameter. Reactive capability rates either above or below that level distort capacity market outcomes. For example, a marginal resource with reactive revenue of $5,000 per MW-Year reflected in their net ACR offer would suppress the capacity market clearing price. Conversely, a marginal resource with a reactive revenue of $1,000 per MW-Year reflected in their net ACR offer would inflate the capacity market clearing price.

Interconnection Requirements

A generating facility is not eligible for reactive payments when it is not connected directly to the PJM system and therefore does not provide reactive capability to PJM under Schedule 2, and should not receive payments for a service that it does not and cannot provide. Nonetheless, a number of such resources have requested and received payment for reactive.[174] Under the existing rules it has been necessary to evaluate unit eligibility base on where the unit interconnects with the system.

Schedule 2 provides, "Reactive Supply and Voltage Control from Generation or Other Sources Service is to be provided *directly* by the Transmission Provider" [emphasis added]. PJM cannot rely on resources on an adjacent unmonitored system to directly provide reactive capability because the adjacent unmonitored system is under the control of another entity. PJM cannot attempt to directly dispatch a resource on an adjacent system without knowing the voltage conditions on that system. PJM would have to request assistance and cooperation of the entity responsible for the adjacent unmonitored system. Including a third party in the dispatch decision means PJM is not relying on the resources to directly provide Reactive Supply and Voltage Control Service.

PJM, with the support of the Market Monitor and Commission Trial Staff, has taken the position that for a unit to be eligible for reactive capability compensation under Schedule 2, it must be interconnected to the PJM bulk electric system (BES), as defined by NERC.[175] The Commission largely adopted and applied this approach in its decision in the *Whitetail* case, where it found that the four generating facilities in this case failed "to satisfy the Capability Requirement," which requires that "a generation facility must be operationally capable of providing voltage support to PJM's transmission facilities such that PJM can rely on that generation facility to maintain transmission voltages."[176] The Commission relied on PJM testimony that "these units are not directly connected to the transmission facility," and "[a]s a result of the lack of a direct connection, [the Facilities] would not have the ability to maintain transmission voltages within acceptable limits."[177]

The issue of eligibility is significant because such facilities do not contribute reactive capability to PJM, and based on anticipated power factor levels and the way the *AEP* Method has been applied for calculating reactive rates under Schedule 2, such facilities would receive significantly larger payments per MW than the facilities that do provide reactive power capability useful to PJM.[178] These payments would be for services not provided, and would distort the PJM Capacity Market by paying a large share of the fixed costs of such facilities as reactive. This approach is a faulty, inefficient and noncompetitive market design.

Fleet Reactive Rates

Cost of service rates are established under Schedule 2 of the OATT and may cover rates for single units or a fleet of units.[179] Until the Commission took corrective action, fleet rates remained in place in PJM even when the actual units in the fleet changed as a result of unit retirements or sales of units.[180] New rules require unit owners to give notice of fleet changes in an informational filing or to file a new rate based on the remaining units, but do not yet require unit specific reactive rates.[181]

Table 10-64 identifies fleet rates currently effective in PJM.

173 OATT Attachment DD § 6.8(d).
174 See, e.g., FERC Docket Nos. ER21-2091, ER21-936, ER21-737, ER20-1863 & ER20-1851.
175 See Docket Nos. EL23-32, et al., EL24-56-000, et al., and EL24-41, et al.,
176 Opinion No. 583, 184 FERC ¶ 61,145 at P 72 (2023) (*Whitetail*).
177 *Id.* at P 73.
178 See 80 FERC ¶ 63,006 (1997), *aff'd*, 88 FERC ¶ 61,141 (1999).
179 See, e.g., OATT Schedule 2; 114 FERC ¶ 61,318 (2006).
180 See 149 FERC ¶ 61,132 (2014); 151 FERC ¶ 61,224 (2015); OATT Schedule 2.
181 *Id.*

Table 10-64 Fleet rates currently effective in PJM

Company	Fleet Rates	Number of Resources	FERC Dockets
Indiana Municipal Power Agency	$489,001.00	5	ER05-971-000
PBF Power Marketing (DCRC)	$588,597.00	3	ER14-357
Dominion Virginia Power	$27,500,000.00	66	ER06-554, ER17-512
Ingenco Wholesale Power, LLC	$888,913.24	11	ER20-1863

Fleet rates create confusion about what revenue is properly attributable to each unit in the fleet. Reactive rates should be stated separately for each unit, even if multiple plants or units are considered in a single proceeding. The MMU filed with the Commission to require unit specific rates when PJM proposed limited reforms that could have corrected the oversight and compliance problems posed by fleet rates.[182] But PJM rules require fleet owners only to submit informational filings when a reactive unit is transferred or deactivated.[183] The current rules do not require a rate filing, which would place the burden of proof on the company and allow for cost review.[184]

The MMU also raised issues related to fleet rates in a settlement establishing a fleet rate without specifying the actual portion of the fleet rate attributable to each unit in the fleet.[185] The approach could prevent or inhibit an appropriate adjustment of the fleet requirement if a unit receiving an unspecified portion of such requirement is deactivated or transferred because third parties without access to cost information would bear the burden of proof in a complaint proceeding.[186] The MMU also explained that the approach makes it impossible to calculate cost-based offers from such units in the PJM Capacity Market. The settlement was approved over the MMU's objection on the grounds that the tariff does not prohibit fleet rates.[187]

The MMU recommends that fleet rates be eliminated and that compensation be based on unit specific costs and rates and that rates be appropriately reduced when units with reactive payments retire.

Reactive Costs

In the first nine months of 2024, total reactive charges were $286.2 million, a decrease of $5.5 million (1.88 percent) from 2023. In the first nine months of 2024, total reactive capability charges were $285.2 million, a decrease of $6.0 million (2.06 percent) from 2023. In the first nine months of 2024, total reactive service charges were $1.0 million, an increase of $0.50 million from 2023.

Table 10-65 shows reactive service charges the first nine months for each year from 2010 through 2024.

Table 10-65 Reactive service charges and reactive capability charges: January through September, 2010 through 2024

Jan-Sep	Reactive Service Charges	Reactive Capability Charges	Total
2010	$8,813,427	$181,213,186	$190,026,613
2011	$20,783,028	$190,228,706	$211,011,735
2012	$49,432,233	$204,638,358	$254,070,591
2013	$184,710,913	$207,126,733	$391,837,646
2014	$27,516,739	$210,968,737	$238,485,476
2015	$9,989,075	$206,994,671	$216,983,746
2016	$838,204	$219,793,594	$220,631,798
2017	$14,047,245	$226,620,331	$240,667,577
2018	$12,428,626	$225,234,508	$237,663,134
2019	$465,836	$245,251,333	$245,717,170
2020	$412,336	$257,849,546	$258,261,882
2021	$738,644	$270,223,222	$270,961,867
2022	$1,225,976	$288,498,024	$289,723,999
2023	$500,030	$291,180,807	$291,680,837
2024	$1,005,612	$285,189,155	$286,194,767

182 151 FERC ¶ 61,224 at P 29 (2015).
183 OATT Schedule 2.
184 *Id.*
185 *See* Letter Opposing Settlement, Docket No ER06-554 et al. (June 14, 2017).
186 *Id.*
187 162 FERC ¶ 61,029 (2018).

Table 10-66 shows zonal reactive service charges for the first nine months of 2023 and 2024, reactive capability charges and total charges. Reactive service charges show charges to each zone for reactive service. Reactive capability charges show charges to each zone for reactive capability.

Table 10-66 Reactive service charges and reactive capability charges by zone: January through September, 2023 and 2024

	Jan-Sep 2023			Jan-Sep 2024		
Zone	Reactive Service Charges	Reactive Capability Charges	Total Charges	Reactive Service Charges	Reactive Capability Charges	Total Charges
ACEC	$0	$2,068,267	$2,068,267	$807,871	$1,901,387	$2,709,258
AEP	$117,171	$43,547,314	$43,664,485	$0	$45,140,552	$45,140,552
APS	$0	$16,080,203	$16,080,203	$329	$15,418,866	$15,419,195
ATSI	$0	$20,692,442	$20,692,442	$0	$21,204,112	$21,204,112
BGE	$382,859	$4,889,269	$5,272,128	$44,256	$4,896,325	$4,940,581
COMED	$0	$36,289,333	$36,289,333	$0	$36,301,053	$36,301,053
DAY	$0	$2,073,500	$2,073,500	$0	$2,076,492	$2,076,492
DUKE	$0	$5,892,402	$5,892,402	$0	$5,978,363	$5,978,363
DOM	$0	$39,824,756	$39,824,756	$0	$35,657,319	$35,657,319
DPL	$0	$7,328,818	$7,328,818	$125,907	$7,237,606	$7,363,514
DUQ	$0	$61,070	$61,070	$0	$61,158	$61,158
EKPC	$0	$1,605,379	$1,605,379	$0	$1,607,696	$1,607,696
JCPLC	$0	$5,830,270	$5,830,270	$0	$4,557,838	$4,557,838
MEC	$0	$4,454,378	$4,454,378	$27,249	$4,484,940	$4,512,189
OVEC	$0	$0	$0	$0	$0	$0
PECO	$0	$15,442,531	$15,442,531	$0	$15,342,307	$15,342,307
PE	$0	$11,686,232	$11,686,232	$0	$10,888,933	$10,888,933
PEPCO	$0	$6,473,700	$6,473,700	$0	$6,367,831	$6,367,831
PPL	$0	$26,904,245	$26,904,245	$0	$26,930,678	$26,930,678
PSEG	$0	$20,048,568	$20,048,568	$0	$19,962,416	$19,962,416
REC	$0	$0	$0	$0	$0	$0
(Imp/Exp/Wheels)	$0	$19,988,130	$19,988,130	$0	$19,173,282	$19,173,282
Total	$500,030	$291,180,807	$291,680,837	$1,005,612	$285,189,155	$286,194,767

Table 10-67 shows the units which received reactive service credits in the first none months of 2024.

Table 10-67 Reactive service credits by plant (Total dollars): January through September 2024

	Jan-Sep 2024	
Zone	Plant	Reactive Service Credits
AECO	ACE CARLLS 1 CT	$208,041
AECO	ACE CARLLS 1 CT	$53,901
AECO	ACE CLAYVILLE 1 CT	$7,768
AECO	ACE CUMBERLAND 1 CT	$5,106
AECO	ACE CUMBERLAND 2 CT	$4,830
AECO	ACE SHERMAN 1 CT	$519,379
AECO	ACE VINELAND 11 CT	$8,847
APS	AP CHAMBERSBURG 4-7 D	$329
BGE	BC PERRYMAN 51 F	$44,256
DPL	DPL BAYVIEW 1 D	$22
DPL	DPL BAYVIEW 2 D	$599
DPL	DPL BAYVIEW 3 D	$591
DPL	DPL EASTON DIESEL	$27,238
DPL	DPL GARRISON EC 1 CC	$3,947
DPL	DPL INDIAN RIVER 4 F	$46,169
DPL	DPL TASLEY 10 CT	$47,342
METED	ME MOUNTAIN 1 CT	$9,974
METED	ME MOUNTAIN 2 CT	$10,951
METED	ME TOLNA 2 CT	$6,324
Total		$1,005,612

Table 10-68 shows the settled reactive capability revenue requirements by technology effective on September 1, 2024.[188] 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.

Table 10-68 Total settled reactive revenue requirements by unit type and fuel type: September 1, 2024

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	$121,812,724.67	50,287.4	157	$2,422.33	$259.59	$22,500.00
CT	Gas	$50,679,737.68	28,712.4	261	$1,765.08	$103.64	$19,610.84
CT	Oil	$8,794,083.24	2,803.7	103	$3,136.60	$289.74	$37,878.79
Diesel	Oil	$1,175,428.55	168.1	36	$6,992.44	$395.37	$27,865.62
Diesel	Other - Gas	$793,998.95	114.9	13	$6,910.35	$4,382.50	$20,720.59
FC	Gas	$45,000.00	2.4	1	$18,750.00	$18,750.00	$18,750.00
Hydro	Water	$16,674,453.62	6,424.6	53	$2,595.41	$137.04	$347,222.22
Nuclear	Nuclear	$54,335,315.68	32,534.6	31	$1,670.08	$494.85	$3,911.41
Solar	Solar	$5,840,392.13	1,498.9	13	$3,896.45	$705.15	$15,007.81
Steam	Coal	$42,804,399.74	36,007.4	60	$1,188.77	$321.30	$9,804.78
Steam	Gas	$6,350,180.15	5,726.6	17	$1,108.89	$747.33	$8,555.56
Steam	Oil	$3,351,933.15	3,157.3	10	$1,061.65	$308.89	$2,751.74
Steam	Other - Solid	$340,000.00	34.0	2	$10,000.00	$8,311.11	$10,608.00
Steam	Wood	$1,250,000.00	153.0	3	$8,169.93	$8,169.93	$8,169.93
Wind	Wind	$18,299,020.69	4,891.9	38	$3,740.68	$1,860.80	$9,564.74
All		$332,546,668.24	172,517.2	798	$1,927.61	$103.64	$347,222.22

Frequency Control Definition

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.

188 The total amount in the final row of Table 10-35 is the amount that would be paid if the total rate effective on September 1, 2024 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.

- **Tertiary Frequency Control.** Tertiary frequency control and imbalance control lasting 10 minutes to an hour is called primary reserve.

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 5 percent droop and ±0.036 Hz deadband (or the equivalent or better).[189] PJM filed revisions in compliance with Order No. 842 that substantively incorporated the pro forma agreements into its market rules.[190]

PJM evaluates generators' primary frequency capabilities using two to three frequency events per month, with events being chosen 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.[191] The 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.

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 compensation for all capacity costs, including these, in the PJM markets. The current market design provides compensation, through heat rate adjusted energy offers, for any costs associated with providing frequency response. Because the PJM market design already compensates resources for frequency response capability and any costs associated with providing frequency response, any separate filings submitted on behalf of resources for compensation under section 205 of the Federal Power Act should be rejected as double recovery.

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 IBRs remain operational during and after defined frequency and voltage excursions.[192] To achieve this, IBRs must continue to deliver pre-disturbance levels of active and reactive power, and would only be permitted to trip to avoid equipment damage. This proposal is currently in the final stages of evaluation and adoption.

189 157 FERC ¶ 61,122 (2016).
190 See 164 FERC ¶ 61,224 (2018).
191 See PJM Manual 12: Balancing Operations, § 3.6.2. Rev. 53 (July 24, 2024).
192 See NERC, "PRC-029-1," <https://www.nerc.com> (Accessed November 6, 2024).