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 - synchronized reserve service; and operating reserve - supplemental reserve service.[1] PJM provides scheduling, system control and dispatch, and reactive on a cost 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 thirty 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.

The MMU analyzed measures of market structure, conduct and performance for the PJM Synchronized Reserve Market for the first three months of 2023.

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 and high levels of supplier concentration.
- 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.
- Market design was evaluated as effective. PJM adopted reforms, including several based on MMU recommendations, removing both physical and economic withholding from the market.

1 75 FERC ¶ 61,080 (1996).
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 the first three months of 2023.

Table 10-2 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 is not concentrated.
- Participant behavior was evaluated as competitive because all available reserves are included by the PJM software, so withholding is not possible.
- Market performance was evaluated as competitive because the combination of a competitive market structure and competitive participation resulted in competitive market outcomes.
- The market design was evaluated as effective because the market rules ensure competitive market offers and require repayment of offline cleared secondary reserves that are not available when called on to provide energy in 30 minutes.

The MMU analyzed measures of market structure, conduct and performance for the PJM Regulation Market for the first three months of 2023.

Table 10-3 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 93.2 percent of the hours in the first three months of 2023.
- Participant behavior in the PJM Regulation Market was evaluated as competitive in the first three months of 2023 because market power

mitigation requires competitive offers when the three pivotal supplier test is failed, although the inclusion of a positive margin raises questions.

- 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 ten 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.

Market Structure

- **Supply.** Primary reserve is satisfied by both synchronized reserve (generation or demand response currently synchronized to the grid and available within 10 minutes), and nonsynchronized reserve (generation currently off line but available to start and provide energy within 10 minutes).
- **Demand.** The PJM primary reserve requirement is 150 percent of the largest single contingency plus 190 MW. In the first three months of 2023, the average primary reserve requirement was 2,541.1 MW in the RTO Zone and 2,521.6 in the MAD Subzone.
- **Market Concentration.** Both the Mid-Atlantic Dominion Subzone and the RTO Synchronized Reserve Zone Market were characterized by structural market power in the first three months of 2023. The average HHI for real-time synchronized reserve in the RTO Zone was 1362, which is classified as moderately concentrated. The average HHI for day-ahead synchronized reserve in the RTO Zone was 1321, which is classified as moderately concentrated. The average HHI for real-time synchronized reserve in the MAD Subzone was 4287, which is classified as highly concentrated. The average HHI for day-ahead synchronized reserve in the MAD Subzone was 2934, which is classified as highly concentrated.

Synchronized Reserve Market

Synchronized reserves include all capacity synchronized to the grid and available to satisfy PJM's power balance within ten minutes. This includes online resources loaded below their full output, storage or condensing resources synchronized to the grid but consuming energy, and ten 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 secondary 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 three months of 2023, the average supply of available synchronized reserve was 4,895.5 MW in the RTO Zone of which 2,172.4 MW was located in the MAD Subzone.
- **Demand.** The average hourly synchronized reserve requirement in the first three months of 2023 was 1,670.7 MW in the RTO Reserve Zone and 1,668.9 in the Mid-Atlantic Dominion Reserve Subzone.
- **Market Concentration.** The Mid-Atlantic Dominion Reserve Subzone Market was characterized by structural market power in the first three

months of 2023. The average HHI for real-time synchronized reserve in the RTO Zone was 861, which is classified as unconcentrated. The average HHI for day-ahead synchronized reserve in the RTO Zone was 881, which is classified as unconcentrated. The average HHI for real-time synchronized reserve in the MAD Subzone was 3060, which is classified as highly concentrated. The average HHI for day-ahead synchronized reserve in the MAD Subzone was 2454, which is classified as highly 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.

Market Performance

- **Price.** The weighted average real-time price for synchronized reserve for all cleared market intervals in the MAD Subzone was $1.26 per MWh in the first three months of 2023. The weighted average real-time price for synchronized reserve for all cleared intervals in the RTO Synchronized Reserve Zone was $0.55 per MWh in the first three months of 2023.

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 primary reserve requirement above the synchronized reserve requirement.

Market Structure

- **Supply.** In the first three months of 2023, the average supply of eligible and available nonsynchronized reserve was 940.1 MW in the RTO Zone, of which 594.3 MW was available in the MAD Subzone.
- **Demand.** Demand for nonsynchronized reserve is the primary reserve requirement, which is satisfied jointly by synchronized and nonsynchronized reserves.[3]

Market Conduct

- **Offers.** Generation owners do not submit supply offers for nonsynchronized reserve. 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 offered reserve amount. For all units, the offer price of nonsynchronized reserve is $0 per MWh.[4]

Market Performance

- **Price.** The nonsynchronized reserve price is determined by the marginal primary reserve resource. In the first three months of 2023, the nonsynchronized reserve weighted average real-time price for all intervals in the RTO Reserve Zone was $0.18 per MWh and the weighted average day-ahead price was $0.93 per MWh. In the first three months of 2023, the nonsynchronized reserve weighted average real-time price for all intervals in the MAD Reserve Subzone was $0.52 per MWh and the weighted average day-ahead price was $2.65 per MWh.

3 See PJM. "PJM Manual 11: Energy & Ancillary Services Market Operations," § 4.1 Overview of the PJM Reserve Markets, Rev. 122 (Oct. 1, 2022).
4 See PJM. "PJM Manual 11: Energy & Ancillary Services Market Operations," § 4.2.3 Reserve Market Resource Offer Structure, Rev. 122 (Oct. 1, 2022).

30-Minute Reserve Market

Secondary reserves are the 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. It also includes offline resources that offer a time to start of less than 30 minutes. Secondary reserves can only be used to satisfy the 30-minute reserve requirement.

Market Structure

Supply. In the first three months of 2023, the average cleared 30-minute reserves was 16,489.8 MW in the day-ahead market and 4,443.3 MW in the real-time 30-minute market. Unlike the day-ahead market, the real-time market did not clear all available 30-minute reserves. In the first three months of 2023, an average of 14,528.5 MW of secondary reserves was scheduled in the day-ahead market and 2,170.3 MW of secondary reserves was scheduled in the real-time market.

Demand. The 30-minute reserve requirement is the maximum of: 150 percent of the synchronized reserve requirement; the largest active gas contingency; or 3,000 MW. In the first three months of 2023, the average 30-minute requirement was 3,206.3 MW.

Market Concentration. The 30-minute reserve market was unconcentrated in the first three months of 2023. The HHI for real-time 30-minute reserves was 881. The HHI for day-ahead 30-minute reserves was 439.

Market Behavior

In both the day-ahead and real-time 30-minute reserves markets, PJM uses only lost opportunity costs to determine price, not submitted offers. The offer price of offline secondary reserve is $0.00. For online secondary reserves, PJM calculates an opportunity cost based on LMP. The amount of secondary reserve available from conventional resources are calculated based on the resources' energy offers. Hydroelectric resources, energy storage resources, and load response resources must specify their offered MW separately.

Market Performance

The average day-ahead price for secondary reserves in the first three months of 2023 was $0.00 per MWh. The average real-time price for secondary reserves in the first three months of 2023 was $0.00 per MWh.

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 three months of 2023, the average hourly offered supply of regulation for nonramp hours was 687.2 performance adjusted MW (709.1 effective MW). This was a decrease of 93.5 performance adjusted MW (a decrease of 70.9 effective MW) from the first three months of 2022. In the first three months of 2023, the average hourly offered supply of regulation for ramp hours was 1,043.4 performance adjusted MW (1,059.1 effective MW). This was a decrease of 103.8 performance adjusted MW (a decrease of 82.4 effective MW) from the first three months of 2022, when the average hourly offered supply of regulation was 1,147.2 performance adjusted MW (1,141.6 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 474.7 hourly average performance adjusted actual MW in the first three months of 2023. This is a decrease of 9.8 performance adjusted actual MW from the first three months of 2022, when the average hourly total regulation cleared performance adjusted actual MW for nonramp hours were 465.0 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 710.5 hourly average performance adjusted actual MW in the first three months of 2023. This is a decrease of 4.5 performance adjusted actual MW from the first three months of 2022, where the average hourly regulation cleared MW for ramp hours were 715.0 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 three months of 2023 (1.67 in the first three months of 2022). The ratio of the average hourly offered supply of regulation to average hourly regulation demand (performance adjusted cleared MW) for ramp hours was 1.47 in the first three months of 2023 (1.58 in the first three months of 2022).
- **Market Concentration.** In the first three months of 2023, the three pivotal supplier test was failed in 93.2 percent of hours. In the first three months of 2023, the effective MW weighted average HHI of RegA resources was 2257 which is highly concentrated and the effective MW weighted average HHI of RegD resources was 1907 which is highly concentrated. The effective MW weighted average HHI of all resources was 1317, 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.[5] In the first three months of 2023, there were 150 resources following the RegA signal and 44 resources following the RegD signal.

Market Performance

- **Price and Cost.** The weighted average clearing price for regulation was $17.83 per MW of regulation in the first three months of 2023, a decrease of $27.40 per MW, or 60.6 percent, from the weighted average clearing price of $45.24 per MW in the first three months of 2022. The weighted average cost of regulation in the first three months of 2023 was $24.20 per MW of regulation, a decrease of 55.8 percent, from the weighted average cost of $54.76 per MW in the first three months of 2022.
- **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).[6]

5 See the *2021 State of the Market Report for PJM*, Vol. II, Appendix F "Ancillary Services Markets."
6 OATT Schedule 1 § 1.3BB. There are no ALR units currently providing black start service.

In the first three months of 2023, total black start charges were $16.6 million, including $16.5 million in revenue requirement charges and $0.1 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 three months of 2023 ranged from $0 in the OVEC and REC Zones to $4.8 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 in December 2017. 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.

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.[7] RTOs and their customers are not required to compensate generation resources for such reactive capability.[8] In the first three months of 2023, customers in PJM, nevertheless, paid $96.3 million in nonmarket costs for reactive capability based on a nonmarket view of cost allocation. The current rules permit over recovery of capital costs through reactive capability charges. All capacity costs of generators should be incorporated in the market. The nonmarket approach to reactive capability payments should be eliminated.

Reactive capability charges are based on FERC approved filings for individual unit revenue requirements that are typically black box settlements.[9] Reactive service charges 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.

Total reactive charges increased 0.5 percent from $95.8 million in the first three months of 2022 to $96.3 million in the first three months of 2023. Reactive capability charges increased 0.8 percent from $95.5 million in the first three months of 2022 to $96.3 million in the first three months of 2023. Total zonal reactive service charges ranged from $0 in the REC and OVEC Zones, to $13.4 million in the AEP Zone in the first three months of 2023.

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.[10] 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.[11] 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

7 OATT Attachment O.
8 *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).
9 OATT Schedule 2.
10 Nuclear Regulatory Commission (NRC) regulated facilities are exempt from this provision. Behind the meter generation that is sized to load is also exempt.
11 OATT Attachment O § 4.7.2 (Primary Frequency Response).

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 twelve 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.[12] 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.

Ancillary Services Costs per MWh of Load

Table 10-4 shows PJM ancillary services costs for the first three months of 1999 through 2023, per MWh of load. The rates are calculated as the total charges for the specified ancillary service divided by the total PJM real-time load in MWh.[13] The scheduling, system control, and dispatch category of costs is comprised of PJM scheduling, PJM system control and PJM dispatch; owner scheduling, owner system control and owner dispatch; other supporting facilities; black start services; direct assignment facilities; and Reliability*First* Corporation charges. The cost per MWh of load in Table 10-4 is a different metric than the cost of each ancillary service per MW of that service. The cost per MWh of load includes the effects both of price changes per MW of the ancillary service and changes in total load.

Table 10-4 History of ancillary services costs per MWh of load: January through March, 1999 through 2023[14] [15]

Year (Jan-Mar)	Regulation	Scheduling, Dispatch and System Control	Reactive	Synchronized Reserve	Total
1999	$0.04	$0.23	$0.25	$0.00	$0.52
2000	$0.21	$0.38	$0.37	$0.00	$0.96
2001	$0.49	$0.64	$0.22	$0.00	$1.35
2002	$0.24	$0.67	$0.16	$0.00	$1.07
2003	$0.65	$1.01	$0.22	$0.11	$1.99
2004	$0.54	$1.06	$0.26	$0.17	$2.03
2005	$0.47	$0.80	$0.25	$0.07	$1.59
2006	$0.48	$0.70	$0.28	$0.09	$1.55
2007	$0.58	$0.72	$0.25	$0.11	$1.66
2008	$0.59	$0.73	$0.30	$0.07	$1.69
2009	$0.38	$0.35	$0.34	$0.03	$1.10
2010	$0.34	$0.36	$0.35	$0.05	$1.10
2011	$0.27	$0.32	$0.38	$0.12	$1.09
2012	$0.18	$0.43	$0.48	$0.03	$1.12
2013	$0.28	$0.43	$0.63	$0.04	$1.38
2014	$0.63	$0.40	$0.37	$0.29	$1.68
2015	$0.32	$0.42	$0.36	$0.18	$1.28
2016	$0.11	$0.43	$0.37	$0.04	$0.95
2017	$0.11	$0.47	$0.42	$0.06	$1.06
2018	$0.28	$0.47	$0.41	$0.07	$1.23
2019	$0.10	$0.46	$0.41	$0.04	$1.01
2020	$0.08	$0.45	$0.46	$0.01	$1.00
2021	$0.12	$0.53	$0.46	$0.04	$1.15
2022	$0.31	$0.39	$0.48	$0.07	$1.25
2023	$0.15	$0.51	$0.51	$0.02	$1.19

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 weighed against the benefit the ancillary service provides. The degree to which PJM markets account for these interactions depends on the timing

12 *Id.*; see also "PJM Manual 12: Balancing Operations, Rev. 47 (Oct. 1, 2022). § 3.6 (Primary Frequency Response).

13 The total prices in this table are a load-weighted average system price per MWh by category, even if each category is not charged on that basis. These totals are presented for informational purposes and should not be used to calculate the costs of any specific market activity in PJM.

14 Note: The totals in Table 10-4 account for after the fact billing adjustments made by PJM and may not match totals presented in past reports.

15 Reactive totals include FERC approved rates for reactive capability.

of the product clearing and 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 along 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 longer notice to take actions to prepare for reserve deployment, are not cleared along with energy in the real-time market solution. Inflexible synchronized reserves are cleared hourly by the Ancillary Service Optimizer (ASO) or the Day-Ahead Energy Market. The ASO uses forward looking information about the energy market, flexible synchronized reserves, and regulation to estimate the costs and benefits of using a resource for inflexible synchronized reserves.

Nonsynchronized reserves and offline secondary reserves are cleared with every real-time energy market solution. The energy commitment decisions for the offline resources have already been made when the RT SCED clears the reserves markets. Offline reserves have no lost opportunity cost.

Prices for the regulation and reserve markets are set by the pricing calculator (LPC), which uses the RT SCED solution as an input. The RT SCED partially, but not fully, clears the reserve market. The software determining the prices is not clearing the regulation market. Since the implementation of fast start pricing on September 1, 2021, the pricing calculations in LPC are not the same prices that result from the market clearing in RT SCED.

Recommendations

Regulation Market

- The MMU recommends that all data necessary to perform the regulation market three pivotal supplier test be saved by PJM so that the test can be replicated. (Priority: Medium. First reported 2016. Status: Not adopted.)
- The MMU recommends that the total regulation (TReg) signal sent on a fleet wide basis be eliminated and replaced with individual regulation signals for each unit. (Priority: Low. First reported 2019. Status: Not adopted.)
- The MMU recommends that 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.[16])
- The MMU recommends that the two signal regulation market design be replaced with a one signal regulation market design. (Priority: Medium. New recommendation. 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.[17] FERC rejected.[18])
- The MMU recommends that the lost opportunity cost calculation used in the regulation market be based on the resource's dispatched energy

16 162 FERC ¶ 61,295 (2018), *reh'g denied*, 170 FERC ¶ 61,259 (2020).
17 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.
18 162 FERC ¶ 61,295 (2018), *reh'g denied*, 170 FERC ¶ 61,259 (2020).

offer schedule, not the lower of its price or cost offer schedule. (Priority: Medium. First reported 2010. Status: Not adopted. FERC rejected.[19])

- 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.[20])
- 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 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 Q1, 2022. Status: Not adopted.)

Reserve Markets

- The MMU recommends that PJM replace the static MidAtlantic/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 $7.50 margin be eliminated from the definition of the cost of tier 2 synchronized reserve because it is a markup and not a cost. (Priority: Medium. First reported 2018. Status: Adopted October 1, 2022.)
- The MMU recommends that the variable operating and maintenance cost be eliminated from the definition of the cost of tier 2 synchronized reserve and that the calculation of synchronized reserve variable operations and maintenance costs be removed from Manual 15. (Priority: Medium. First reported 2019. Status: 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 the rule requiring that tier 1 synchronized reserve resources be paid the tier 2 price when the nonsynchronized reserve price is above zero be eliminated immediately and that, under the current rule, tier 1 synchronized reserve resources not be paid the tier 2 price when they do not respond. (Priority: High. First reported 2013. Status: Adopted October 1, 2022.)
- The MMU recommends that the tier 2 synchronized reserve must offer requirement be enforced on a daily and hourly basis. The MMU recommends that PJM define a set of acceptable reasons why a unit can be made unavailable daily or hourly and require unit owners to select a reason in Markets Gateway whenever making a unit unavailable either daily or hourly or setting the offer MW to 0 MW. (Priority: Medium. First reported 2013. Status: Adopted October 1, 2022.)
- The MMU recommends that, for calculating the penalty for a synchronized reserve resource failing to meet its scheduled obligation during a spinning event, the penalty should be based on the actual time since the last spinning event of 10 minutes or longer during which the resource performed because performance is only measured for events 10 minutes or longer and that the tier 2 shortfall penalty should include LOC payments as well as SRMCP and MW of shortfall. (Priority: Medium. First reported 2018. Status: Not adopted.)

19 *Id.*
20 *Id.*
21 *Id.*

- The MMU recommends that aggregation not be permitted to offset unit specific penalties for failure to respond to a synchronized reserve event. (Priority: Medium. First reported 2018. Status: Not adopted.)
- The MMU recommends that PJM eliminate the use of Degree of Generator Performance (DGP) in the synchronized reserve market solution and improve the actual tier 1 estimate. If PJM continues to use DGP, DGP should be documented in PJM's manuals. (Priority: Medium. First reported 2018. Status: Adopted October 1, 2022.)
- The MMU recommends that the VRSA be terminated and, if necessary, replaced by a reserve sharing agreement between PJM and VACAR South, similar to agreements between PJM and other bordering areas. (Priority: Medium. First reported 2020. Status: Adopted October 1, 2022.)
- The MMU recommends that a reason code be attached to every hour in which PJM market operations adds additional DASR MW. (Priority: Medium. First reported 2015. Status: Adopted October 1, 2022.)
- The MMU recommends that PJM modify the DASR market to ensure that all resources cleared incur a real-time performance obligation. (Priority: Low. First reported 2013. Status: Adopted October 1, 2022.)
- The MMU recommends that, in order to mitigate market power, offers in the DASR market be based on opportunity cost only. (Priority: Low. First reported 2009. Modified, 2018. Status: Adopted October 1, 2022.)

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 capacity and energy 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. The 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 service be shared equally across the region. (Priority: medium. New recommendation. 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 the capacity market. (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.[22] Status: Partially adopted.)
- The MMU recommends that 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. Specifically, such eligibility should be determined based on whether a generation facility's point of interconnection is on a transmission line that is a Monitored Transmission Facility as defined by PJM and is on a Reportable Transmission Facility as defined by PJM.[23] (Priority: Medium. First reported 2020. Status: Not adopted.)

22 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.

23 *See* PJM Transmission Facilities (note that this requires you first log into a PJM Tools account. If you do not, then the link sends you to an Access Request page, <https://pjm.com/markets-and-operations/ops-analysis/transmission-facilities>.

Conclusion

The design of the 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. 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.

To address these 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.[25] The PJM/MMU joint proposal addressed issues with the inconsistent application of the marginal benefit factor throughout the optimization and settlement process in the PJM Regulation Market. FERC rejected the joint proposal on March 30, 2018, as being noncompliant with Order No. 755.[26] The MMU and PJM separately filed requests for rehearing, which were denied by order issued March 26, 2020.[27]

The October 1, 2022, changes 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 has occurred since October 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. Overall, the total credits at $2.3 million in October 2022 and $3.5 million in November 2022 were similar to historic months with similar energy prices.

The new reserve market design was tested during Winter Storm Elliott. The day-ahead reserve markets cleared ample reserves but those reserves were not available in real time as a result of forced outages and a maximum generation emergency. When they could not perform, suppliers were required to buy back their day-ahead reserve positions at shortage prices. As a result, customers received payment for reserves, which was not possible under the previous market design. Suppliers were charged and customers received $8.4 million in synchronized reserve credits and $23.8 million in nonsynchronized reserve credits for the month of December 2022.

The benefits of markets are realized under these approaches 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.

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 secondary reserve market results were competitive.

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).
25 18 CFR § 385.211.
26 162 FERC ¶ 61,295 (2018).
27 170 FERC ¶ 61,259 (2020).

PJM Reserve Markets

Reserves resources are scheduled and paid for the availability to respond to a loss of supply on the system by quickly increasing their energy output.

PJM schedules reserves to satisfy defined reserve service requirements. There are three reserve services: the synchronized reserve service, provided by resources that are online and able to respond within 10 minutes; the primary reserve service, provided by resources, online or offline, that are able to respond within 10 minutes; and the 30-minute reserve service, provided by resources, online or offline, able to respond within 30 minutes. Each reserve service requires a specified number of MW, known as that service's reserve requirement, that should be available at all times in order to cover a potential loss of supply event. As a result of transmission limits, there are also locational requirements for each reserve service, except for the 30-minute reserve service.[28] PJM currently allows for one active reserve subzone when satisfying reserve requirements, and the satisfaction of reserve requirements in the subzone counts towards the satisfaction of requirements for the entire RTO Reserve Zone.[29]

The size of a service's requirement depends on the contingencies that service is designed to address.[30] For synchronized reserve, this is the loss, in a single event, of the largest generator or group of generators, called the "most severe single contingency", or MSSC. For primary reserve, this is 150 percent of the MSSC plus 190 MW. For 30-minute reserve, this is the greater of the largest gas contingency, the primary reserve requirement, and 3,000 MW. PJM can temporarily increase reserve requirements due to emergencies and weather alerts, and when risks during maintenance work change the largest contingency. Table 10-5 shows the instances identified by the MMU when PJM increased the reserve requirements during the first three months of 2023. The services are nested, such that 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.

28 See PJM. "PJM Manual 11: Energy & Ancillary Services Market Operations," § 4.3.1 Locational Aspect of Reserves, Rev. 122 (October 1, 2022).
29 See PJM. "PJM Manual 11: Energy & Ancillary Services Market Operations," § 4.4.1 Product and Locational Substitution, Rev. 122 (October 1, 2022).
30 See PJM. "PJM Manual 11: Energy & Ancillary Services Market Operations," § 4.3 Reserve Requirement Determination, Rev. 122 (October 1, 2022).

Table 10-5 Temporary adjustments to 30-minute, primary, and synchronized reserve requirements: January through March, 2023[31]

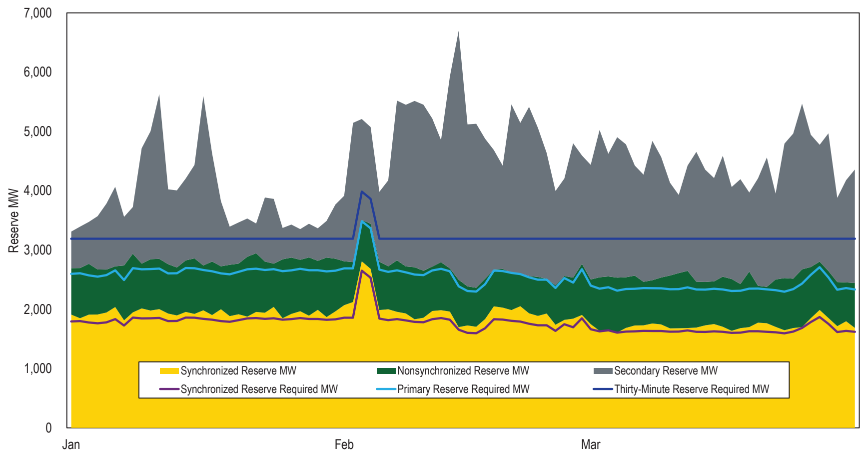
From	To	Number of Hours	Amount of Adjustment
7-Nov-22	2-Feb-23	2,091	30-Minute Reserve (0 MW), Primary Reserve (45 MW), Synchronized Reserve (30 MW)
3-Feb-23	4-Feb-23	28	30-Minute Reserve (895 MW), Primary Reserve (894 MW), Synchronized Reserve (894 MW)

PJM must also comply with reserve requirements imposed by NERC. NERC Performance Standard BAL-002-3, Disturbance Control Standard defines a requirement for synchronized reserve and for primary reserve, but not for 30-minute reserve.

There are three reserve products that can be purchased from resources for satisfying PJM's reserve requirements: synchronized reserves, which are online resources that can respond within 10 minutes; non-synchronized reserves, which are offline generators that can respond within 10 minutes; and secondary reserves, which are resources, online or offline, that can respond in 10 to 30 minutes. A product can only be used to satisfy a reserve service's scheduling requirement if it also meets that service's response time requirement. Figure 10-1 shows how reserve products were scheduled in real time to meet the reserve service requirements in the first three months of 2023. On February 3 and February 4, PJM had increased reserve requirements during conservative operations due to cold weather.

31 The MW values for the first listed adjustment during the first three months of 2023 were previously estimated incorrectly.

Figure 10-1 Daily average reserve products and daily average reserve requirements: January through March, 2023



PJM uses market mechanisms to schedule resources. In general, products that meet stricter response-time requirements, which can be used to satisfy multiple reserve requirements, are priced higher. Synchronized reserve, regarded as the highest quality product, is usually the most expensive. However, PJM seeks to reduce overall cost when purchasing reserves, which are co-optimized with energy. For example, if it is somehow more economic to satisfy the primary reserve requirement using only synchronized reserves, PJM will do so.

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, non-synchronized reserves, and secondary reserves.[32] 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.

In general, the amount of reserve MW available from a resource is calculated by PJM based on the parameters in the resource's energy offer and reserve parameters. Some resources types, such as hydroelectric resources, energy storage resources, and load response resources, can specify offer amounts.[33] In general, resources that choose to participate in the energy market are required to also participate in the reserve market. Exceptions include nuclear, solar, and wind resources, which must request inclusion in the reserve market, and resources that have been automatically deselected from participating in the reserve market for performance reasons.[34] [35] 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.[36]

In general, the amount of reserve MW a resource can provide is based on the resource parameters in that resource's energy offer. However, 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.[37] 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 scheduling of resources to meet PJM's operational requirements includes multiple steps to commit resources, dispatch resources, and calculate clearing prices.[38] Each program in the commitment and dispatching process estimates

32 See PJM. "PJM Manual 11: Energy & Ancillary Services Market Operations," § 4.4.1 Product and Locational Substitution, Rev. 122 (October 1, 2022).

33 See PJM. "PJM Manual 11: Energy & Ancillary Services Market Operations," § 4.2.3 Reserve Market Resource Offer Structure, Rev. 122 (October 1, 2022).

34 See PJM. "PJM Manual 11: Energy & Ancillary Services Market Operations," § 4.2.1 Reserve Market Eligibility, Rev. 122 (October 1, 2022).

35 See PJM. "PJM Manual 11: Energy & Ancillary Services Market Operations," § 4.4.3.1 Deselection of Reserve Resources in Real-Time, Rev. 122 (October 1, 2022).

36 See *id.*

37 See PJM. "PJM Manual 11: Energy & Ancillary Services Market Operations", § 4.2.2.1 Communication for Reserve Capability Limitation, Rev. 122 (October 1, 2022).

38 For more on the market solution software, see the *2022 Annual State of the Market Report for PJM*, Appendix E - Ancillary Service Markets.

future needs, resulting in scheduling reserves on a five-minute basis. The day-ahead market solution software schedules resources by hour, looking ahead to the operating day.[39] The real-time market solution software for reserves consists of: the Ancillary Services Optimizer (ASO) solving hourly; the intermediate term security constrained economic dispatch market solution (IT SCED); and the real-time (short term) security constrained economic dispatch market solution (RT SCED).[40]

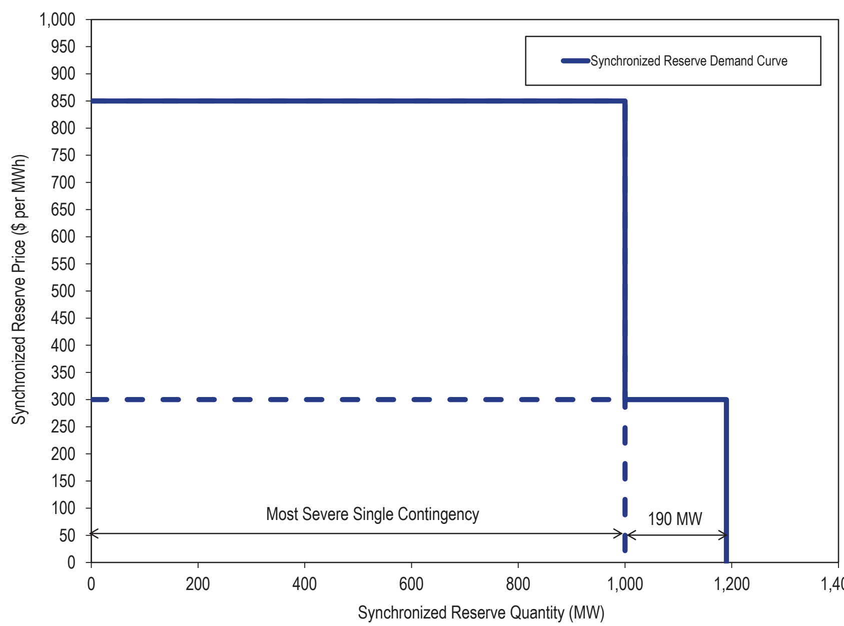
Due to the time taken for their start-up and notification procedures, some resources can only be scheduled in the early steps of PJM's commitment and dispatching process. Depending on their physical run-time requirements, resources are described as either flexible or inflexible. Inflexible resources, such as some demand response resources and condensers, are those that must run for at least one hour and are only committed in real-time by the ASO or manually by a PJM operator. Flexible resources can be committed by RT SCED later in the process.

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.[41]

There is no explicit demand for non-synchronized reserves nor for secondary reserves. There is a defined demand for synchronized reserves, primary reserves, and 30-minute reserves. PJM's administratively defined demand curve for reserves is called the Operating Reserve Demand Curve. The first step of the demand curves for primary, synchronized reserves, and 30-minute reserves are set at the minimum reserve requirement for each product, known as the services' reliability requirements. Since the primary and synchronized minimum reserve requirements are based on the actual output of the most severe single contingency, the MW value of the first step changes in real time based on the real-time dispatch solution. The first step is priced at $850 per MWh. The second step of the extended primary, extended synchronized, and extended 30-minute reserve demand curves extends the reserve requirements, known as the services' extended reserve requirements. The extended requirements are defined as the 30-minute, primary, and synchronized reserve requirements, plus 190 MW, plus any additional requirement due conservative operations, weather alerts, or other system conditions. This 190 MW second step is priced at $300 per MWh. Figure 10-2 shows an example of the updated synchronized reserve demand curve when the output of the single largest unit in the region is 1,000 MW.

39 See PJM. "PJM Manual 11: Energy & Ancillary Services Market Operations", § 4.4.2 Day-ahead Reserve Market Clearing, Rev. 122 (October 1, 2022).
40 See PJM. "PJM Manual 11: Energy & Ancillary Services Market Operations", § 4.4.3 Real-time Reserve Market Clearing, Rev. 122 (October 1, 2022).
41 See *id.*

Figure 10-2 An example of a real-time operating reserve demand curve, including the permanent second step



During periods of shortage pricing, the reserve market clearing prices can be higher than the limit shown in Figure 10-2.

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 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. If the resource clears more in real time, then it is positive. For some services, the amount of MW for which a resource is credited is capped at a value less than the scheduled amount. This capping accounts for things like a resource's real-time energy output, and prevents crediting a resource for a reserve amount that it did not actually provide.

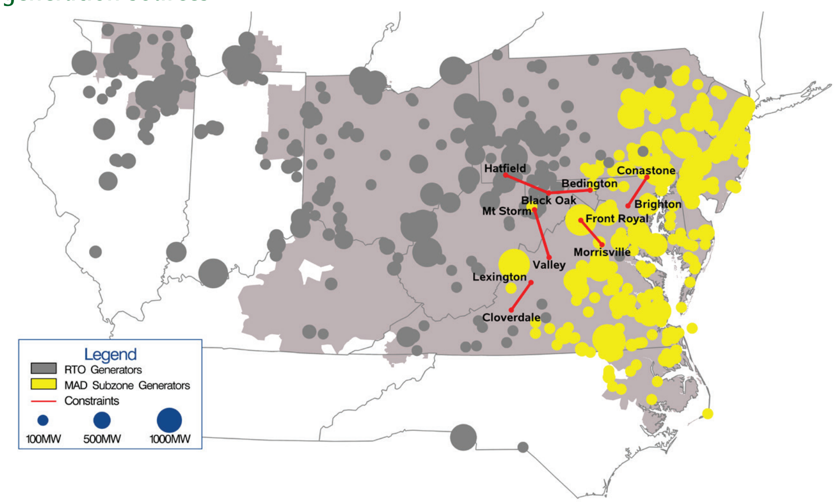
Reserve Subzones

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 requirement. 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 MAD Subzone. The price in MAD may exceed the price in the rest of RTO when the constraints are binding.

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. PJM may need to maintain or operate resources in other local areas to maintain local reliability. Currently, these units are committed out of market for reliability reasons. The value of operating these resources, including generators that are manually committed for reliability, is not reflected in prices. A more efficient way to reflect these requirements would be to have locational reserve requirements that are adjusted based on PJM forecasts and reliability studies. 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.[42] In the first three months of 2023, PJM did not change the subzone.

Figure 10-3 is a map of constraints and major generation sources, showing how the constraints separating the RTO Zone and MAD Subzone are defined by underlying grid topology. The most limiting transmission constraint for power flow from the RTO Zone into the MAD Subzone since August 2017 has been the AP South Interface. The most frequently binding constraints in the first three months of 2023 were Bedington-Black Oak, Brighton-Conastone, and Hunterstown-Conastone.

Figure 10-3 PJM RTO Zone and MAD Subzone map of constraints and generation sources



42 See PJM. "PJM Manual 11: Energy & Ancillary Services Market Operations" § 4.3.2 Creation of New Reserve Subzones, Rev. 122 (Oct. 1, 2022).

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 ACE to zero if it was zero or positive before the event or to its pre-event level if it was negative at the start of the event. 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 Contingency Reserve Restoration Period as 90 minutes.[43] The NERC requirement is 100 percent compliance and status must be reported quarterly. PJM implements this contingency reserve requirement using primary reserves.[44] PJM maintains 10 minute reserves (primary reserve) to ensure reliability in the event of disturbances. 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

The NERC standard requires a control area to carry primary reserve MW equal to or greater than the largest single contingency (MSSC).[45] The largest single contingency is usually the output of the largest generating unit to which PJM adds 190 MW, defined as the extended synchronized reserve requirement. In cases where temporary switching conditions create the risk that a single fault could remove several generators, PJM defines the largest single contingency as the sum of the output of those generators.[46] PJM requires primary reserves equal to 150 percent of the largest single contingency for each market solution (ASO, IT SCED, and RT SCED).[47] The synchronized reserve requirement is calculated for every real-time market dispatch solution. PJM can make temporary adjustments to the primary reserve requirement when grid maintenance or outages change the largest contingency. PJM can also increase the primary and synchronized reserve requirement in cases of hot weather or cold weather alerts or escalating emergency procedures.[48]

In the first three months of 2023, the average primary reserve requirement for the RTO Zone was 2,541.1 MW. The average primary reserve requirement in the MAD Subzone was 2,521.6 MW. The average synchronized reserve requirement in the RTO Zone was 1,762.8 MW. The average synchronized reserve requirement in the MAD Subzone was 1,749.8 MW.

Supply

In the first three months of 2023, the demand for primary reserve was satisfied by synchronized reserves and nonsynchronized reserves. After the synchronized reserve requirement is satisfied, the remainder of the primary reserve requirement is met from the least expensive combination of synchronized and nonsynchronized reserves.

In the first three months of 2023, in the MAD Subzone, there was an average of 594.3 MW of eligible nonsynchronized reserve supply available to meet the demand for primary reserve (Table 10-6). In the RTO Zone, an average of 940.1 MW of nonsynchronized reserve supply was available to meet the average demand of 2,541.1 MW (Table 10-7).

In Table 10-6 and Table 10-7, the average synchronized reserve in the first nine months of 2022 is the sum of tier 1 synchronized reserve, which was estimated, and tier 2 synchronized reserve, which was scheduled.

43 See PJM. "PJM Manual 12: Balancing Operations," Rev. 47 (Oct. 1, 2022) 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 reserve.

44 See PJM. "PJM Manual 10: Pre-Scheduling Operations," § 3.1 Reserve Definitions, Rev. 42 (Oct. 1, 2021).

45 NERC BAL-002-3. "Disturbance Control Standard – Contingency Reserve for Recovery from a Balancing Contingency Event," September 25, 2018. <https://www.nerc.com/pa/Stand/Reliability%20Standards/BAL-002-3.pdf>.

46 See PJM. "PJM Manual 11: Energy & Ancillary Services Market Operations" § 4.3 Reserve Requirement Determination, Rev. 122 (Oct. 1, 2022).

47 See PJM. "PJM Manual 13: Emergency Operations," § 2.2 Reserve Requirements, Rev. 85 (Oct. 1, 2022).

48 See *id.*

Table 10-6 provides the average dispatch solution reserves, by type of reserve, used by the RT SCED market solution to satisfy the primary reserve requirement in the MAD Subzone in the first three months of 2023.

Table 10-6 Average monthly reserves used to satisfy the primary reserve requirement, MAD Subzone: January 2022 through March 2023

Year	Month	Synchronized Reserve MW	Nonsynchronized Reserve MW	Total Primary Reserve MW
2022	Jan	1,667.1	1,344.3	3,011.4
2022	Feb	1,708.6	1,277.3	2,985.8
2022	Mar	1,690.8	1,097.0	2,787.9
2022	Apr	1,576.9	1,190.0	2,766.9
2022	May	1,719.0	1,109.9	2,828.9
2022	Jun	1,785.2	1,288.6	3,073.8
2022	Jul	1,723.0	1,150.0	2,873.0
2022	Aug	1,742.0	1,236.6	2,978.5
2022	Sep	1,618.5	967.2	2,585.8
2022	Average (Jan-Sep)	1,692.3	1,184.5	2,876.9
2022	Oct	1,830.7	810.2	2,640.9
2022	Nov	1,819.6	857.4	2,677.0
2022	Dec	1,896.2	822.8	2,719.1
2022	Average (Oct-Dec)	1,848.8	830.1	2,679.0
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	Average	1,861.2	715.7	2,573.8

Table 10-7 shows the average dispatch solution reserves, by type of reserve, used by the RT SCED market solution to satisfy the primary reserve requirement in the RTO Zone from October 2022 through March 2023.

Table 10-7 Average monthly reserves used to satisfy the primary reserve requirement, RTO Zone: October 2022 through March 2023

Year	Month	Synchronized Reserve MW	Nonsynchronized Reserve MW	Total Primary Reserve MW
2022	Jan	2,070.1	1,900.9	3,970.9
2022	Feb	2,205.8	1,863.6	4,069.4
2022	Mar	1,961.7	1,996.8	3,958.5
2022	Apr	1,748.5	1,694.9	3,443.4
2022	May	2,077.5	1,822.0	3,899.5
2022	Jun	2,187.0	2,099.3	4,286.3
2022	Jul	2,057.3	1,988.3	4,045.6
2022	Aug	2,086.5	2,083.9	4,170.4
2022	Sep	2,040.4	1,850.7	3,891.1
2022	Average (Jan-Sep)	2,048.3	1,922.3	3,970.6
2022	Oct	1,831.7	955.1	2,786.8
2022	Nov	1,822.1	1,011.4	2,833.5
2022	Dec	1,899.9	964.8	2,864.8
2022	Average (Oct-Dec)	1,851.2	977.1	2,828.4
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	Average	1,877.2	799.9	2,673.9

Market Concentration

In the first three months of 2023, for both the day-ahead and real-time markets, the RTO primary reserve market was moderately concentrated, and the MAD primary reserve market was highly concentrated. Table 10-8 shows the average HHI for primary reserves in the first three months of 2023.

Table 10-8 Average primary reserve HHI: January through March, 2023

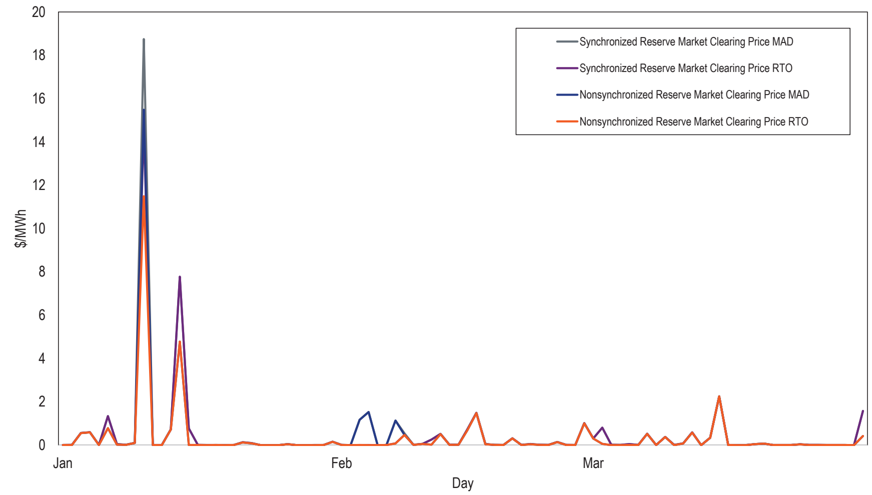
Location	Market	Average HHI	Percent of Intervals Max Market Share Above 20%
RTO	RT	1362	91.0%
RTO	DA	1321	91.6%
MAD	RT	4287	99.8%
MAD	DA	2934	99.8%

Prices

Figure 10-4 shows daily weighted average synchronized and nonsynchronized market clearing prices in the first three months of 2023. The MAD SRMCP and RTO SRMCP prices diverged in 171 five-minute intervals, 0.7 percent of the total 25,908 intervals in the first three months of 2023.

The prices of synchronized reserve and nonsynchronized reserve spiked on January 10, 2023 in the RTO Reserve Zone and the MAD Reserve Subzone. During this time, shortage pricing was used for primary reserve for three intervals and for synchronized reserve for one interval.

Figure 10-4 Daily average market clearing prices ($/MWh) for synchronized reserve and nonsynchronized reserve: January through March, 2023



Synchronized Reserve

All generation 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. While synchronized reserve was a real-time only product, prior to October 1, the new reserve market design includes both day-ahead and real-time synchronized reserve markets.

Synchronized reserve resources can be flexible or inflexible. Inflexible resources are defined as those resources that require an hourly commitment due to minimum run times or staffing constraints. Examples of inflexible reserves are synchronous condensers operating in condensing mode, resources with an economic minimum (EcoMin) equal to economic maximum (EcoMax), offline CTs and hydro that can operate in the condense mode, and demand resources. Inflexible synchronized reserve resources are committed for a full hour by the hour ahead ASO market solution. Inflexible resources require a 30-minute notification time and cannot be released for energy during the operating hour. The inflexible commitments made by the hour ahead ASO solution may satisfy only part of the synchronized reserve requirement. The actual requirement is determined by the RT SCED solution and the requirement not satisfied by inflexible units is satisfied by flexible units. Flexible resources are already online for energy, require no notification time, and can be automatically dispatched. For each MW assigned, the clearing engines determine a product substitution price, i.e. the marginal cost of replacing the reserve MW with energy from other resources. The product substitution cost is a function of the LMPs of the MW of reserve, the marginal cost of energy for the resources providing reserves, and the minimized cost of substituted MW providing energy. At the margin, the price is the sum of the offer price plus the product substitution cost of the marginal unit(s).[49]

Market Structure

For most resources, synchronized reserves consist of any online capacity not being used for energy that can be achieved within ten 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 and demand side 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 reserves assignments.

Demand

Demand for synchronized reserve comes from the reserve requirement for the synchronized reserve service, based on the largest single contingency (also known as the most severe single contingency, or MSSC). The largest single contingency is usually the output of the largest generating unit to which PJM adds 190 MW, defined as the extended synchronized reserve requirement.

A plot of the daily average real-time requirement for synchronized reserve can be seen in Figure 10-1. In the first three months of 2023, the average real-time synchronized requirement in the RTO Reserve Zone was 1,762.8 MW and the average day-ahead requirement was 1,747.6 MW. In the MAD Reserve Subzone, the average real-time synchronized requirement was 1,749.8 MW and the average day-ahead requirement was 1,746.7 MW.

Supply

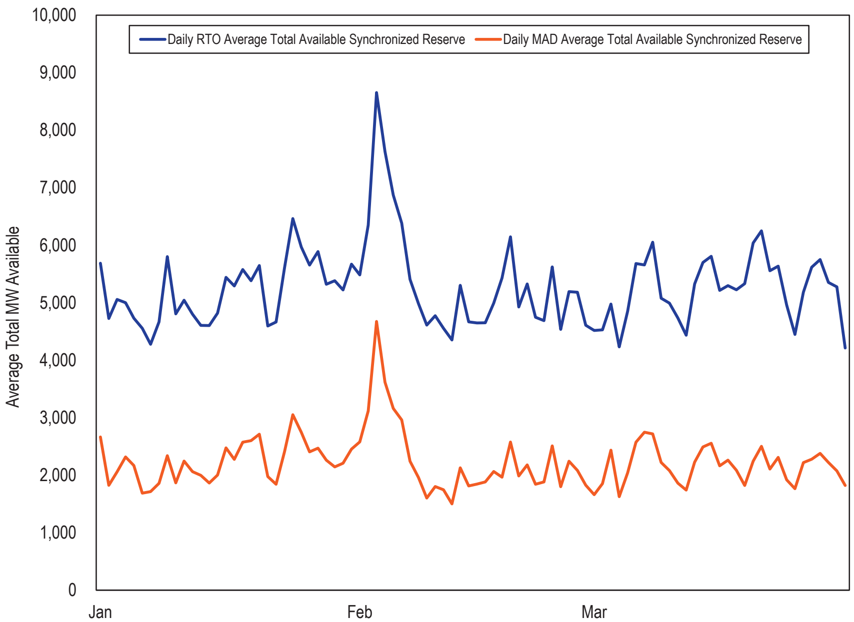
The supply of synchronized reserves consists of all unloaded capacity that can convert to energy in ten minutes from online resources and all synchronized load that can curtail in ten minutes. Any of this capacity that is not offered as dispatchable in the energy market does not have a lost opportunity 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 is the lesser of a resource's 10-minute ramp and the difference between its energy output and its economic maximum output.

In the first three months of 2023, the average supply of daily offered and eligible synchronized reserve was 5,261.5 MW in the RTO Zone, of which 2,220.3 MW was located in the MAD Subzone. Figure 10-5 shows the daily average available synchronized reserve MW.

49 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).

Figure 10-5 Daily Average Available Synchronized Reserve: January through March, 2023



Market Concentration

Table 10-9 provides the average HHI and the percent of intervals during which the maximum market share was above 20 percent for the day-ahead and real-time synchronized reserve markets for the first three months of 2023. In the first three months of 2022, the MAD real-time and day-ahead synchronized reserve markets were highly concentrated. In the first three months of 2023, the RTO real-time market synchronized reserve was unconcentrated and the RTO day-ahead market was moderately concentrated.

Table 10-9 Day-ahead and real-time synchronized reserve Average HHI, January through March, 2023[50]

Location	Market	Average HHI	Percent of Intervals Max Market Share Above 20%
RTO	RT	861	25.5%
RTO	DA	881	27.7%
MAD	RT	3060	99.4%
MAD	DA	2454	92.4%

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 non-performance multiplied by the probability that an event will occur.[51] These values are listed in Table 10-10. For resources that do not set their offer price, the offer price is treated as $0 per MWh.

Table 10-10 Expected values of the synchronized reserve penalty

Year	Month	Value of Expected Penalty ($/MWh)
2022	Oct	$0.02
2022	Nov	$0.02
2022	Dec	$0.11
2023	Jan	$0.09
2023	Feb	$0.14
2023	Mar	$0.11

Market Performance

Figure 10-6 shows the daily unweighted average prices for synchronized reserve in the real-time and day-ahead markets. Higher prices on January 10 are due to the use of shortage pricing for one interval. Higher prices on February 3 and February 4 are due to an increased synchronized reserve requirement during conservative operations due to cold weather.

50 Concentration is calculated from the scheduled MW, which are used to satisfy the synchronized reserve requirement. It is not calculated from the capped MW, which determine how resources are credited.
51 See PJM. "PJM Manual 15: Cost Development Guidelines," § 4.7 Synchronized Reserve, Rev. 42 (October 28, 2022).

Figure 10-6 Day-ahead and real-time synchronized reserve market clearing prices: January through March, 2023

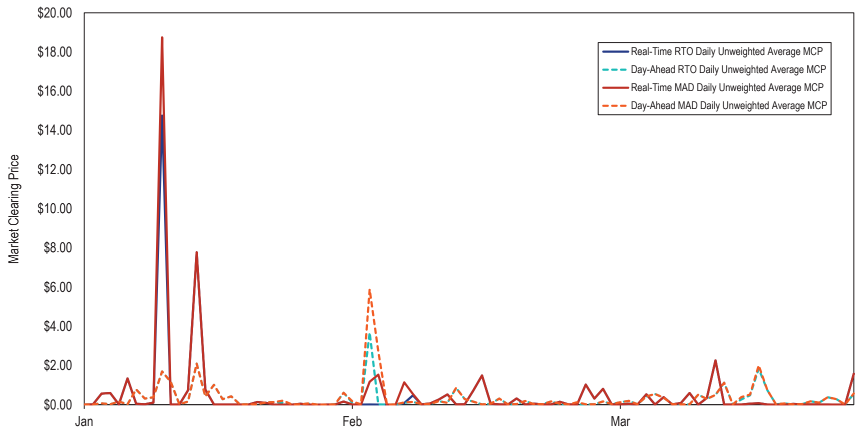


Table 10-11 compares the dispatch-run and pricing-run weighted average prices for the day-ahead and real-time markets. For the real-time values, these are the LPC prices weighted using the RT SCED MW. For the day-ahead values, these are the DA prices weighted using the DA dispatch MW. The prices being compared include the RTO Reserve Zone prices and the reserve subzone prices. PJM dispatchers can update assignments after RT SCED has run, so these weights differ from the weighted average value reported elsewhere in this section.[52]

Table 10-11 Day-ahead and real-time fast start pricing in the synchronized reserve market: October 2022 through March 2023[53]

		Day-Ahead				Real-Time			
Year	Month	Dispatch-Run MCP	Pricing-Run MCP	Difference	Percent Difference	Dispatch-Run MCP	Pricing-Run MCP	Difference	Percent Difference
2022	Oct	$0.41	$0.44	$0.03	6.7%	$0.45	$0.86	$0.41	89.5%
2022	Nov	$1.40	$1.48	$0.08	6.0%	$0.14	$0.34	$0.20	144.7%
2022	Dec	$3.14	$3.33	$0.19	6.2%	$35.71	$31.53	($4.18)	(11.7%)
2023	Jan	$0.34	$0.36	$0.01	3.8%	$0.93	$1.01	$0.09	9.2%
2023	Feb	$0.54	$0.59	$0.04	7.8%	$0.27	$0.38	$0.11	38.9%
2023	Mar	$0.34	$0.35	$0.01	4.3%	$0.15	$0.26	$0.11	68.9%

Table 10-12 shows total synchronized reserve payments by month for October 2022 through March 2023. Balancing credits for all but one month are negative, because, on average, resources buy back their day-ahead positions at higher real-time prices. LOC credits are paid to cover negative balancing credits if PJM has converted the 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. Negative balancing credits and shortfall charges exceeded day-ahead credits and positive balancing credits in December 2022 due to reserve shortages during Winter Storm Elliott, resulting in negative total credits. There were no synchronized reserve events that lasted for 10 or more minutes in February 2023 and March 2023, so there are no shortfall charges for those months in Table 10-12.

Table 10-12 Total payments and charges by month: October 2022 through March 2023

Year	Month	Total Day-Ahead Credits	Total Balancing MCP Credits	Total LOC Credits	Total Shortfall Charges	Total Credits
2022	Oct	$676,211	($67,992)	$1,708,506	$19,273	$2,297,451
2022	Nov	$2,275,752	($121,388)	$1,593,328	$14,882	$3,732,809
2022	Dec	$4,874,437	($15,512,268)	$12,988,842	$11,195,016	($8,844,005)
2023	Jan	$505,419	($114,061)	$983,619	$335,995	$1,038,982
2023	Feb	$735,351	$99,577	$495,474	$0	$1,330,401
2023	Mar	$439,364	($5,106)	$744,883	$0	$1,179,141

Table 10-13 provides the day-ahead and real-time synchronized reserve by resource type and fuel type for the first three months of 2023. 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 assigned MW. As it is this capped value for which a resource is credited, Table 10-13 only shows the capped value, excluding the scheduled MW. During

52 See PJM. "PJM Manual 01: Control Center and Data Exchange Requirements," § 1.7 Dispatch Management Tool (DMT), Rev. 46 (July 27, 2022).
53 The weights used to calculate these weighted average prices are different from previous reports.

Winter Storm Elliott, many resources bought back day-ahead reserve positions at shortage prices, resulting in negative balancing credits and negative total credits for some resources.

Table 10-13 Day-ahead and Real-time Synchronized Reserve by Resource Type and Fuel Type: January through March, 2023

Resource / Fuel Type	Day-Ahead MWh	Real-Time Capped MWh	Day-Ahead Credits	Balancing MCP Credits	LOC Credits	Shortfall Charges	Total Credits
CT - Natural Gas	779,690	776,613	$365,519	$88,709	$1,482,628	$144,439	$1,792,417
Combined Cycle	1,207,330	1,250,187	$746,636	($211,524)	$358,863	$89,963	$804,012
Steam - Coal	1,245,211	1,230,603	$279,426	($22,515)	$186,730	$32,399	$411,243
DSR	48,479	310,973	$75,275	$248,856	$5,103	$54,538	$274,695
Hydro - Run of River	185,623	138,962	$54,101	($3,720)	$43,356	$155	$93,582
Hydro - Pumped Storage	272,585	142,776	$73,682	($75,005)	$51,819	$0	$50,496
CT - Oil	2,611	8,024	$13,838	$19,591	$16,270	$8,104	$41,595
Steam - Other	41,032	5,909	$9,940	($1,573)	$26,079	$1,530	$32,915
Steam - Natural Gas	61,937	47,831	$21,344	($11,155)	$25,808	$3,565	$32,431
RICE - Other	89,693	21,094	$37,294	($49,136)	$25,946	$1,303	$12,801
Steam - Oil	90	974	$1,943	$587	$0	$0	$2,530
CT - Other	0	0	$0	$0	$0	$0	$0
RICE - Natural Gas	790	2,168	$1,137	($2,706)	$1,375	$0	($193)
Battery	0	0	NA	NA	NA	NA	NA
Distributed Gen	0	0	NA	NA	NA	NA	NA
Fuel Cell	0	0	NA	NA	NA	NA	NA
Nuclear	0	0	NA	NA	NA	NA	NA
RICE - Oil	0	0	NA	NA	NA	NA	NA
Solar	0	0	NA	NA	NA	NA	NA
Solar + Storage	0	0	NA	NA	NA	NA	NA
Solar + Wind	0	0	NA	NA	NA	NA	NA
Wind	0	0	NA	NA	NA	NA	NA
Wind + Storage	0	0	NA	NA	NA	NA	NA

Before the October 1 changes, DSR was limited to 33 percent of the cleared synchronized reserves. This limitation was removed. In the first three months of 2023, DSR was more than 33 percent of the cleared synchronized reserves in 7 of 25,908 five-minute intervals. In all of the 7 intervals, DSR exceeded 33 percent of the RT MW, but not the DA MW. During these 7 intervals, on average, DSR made up 62.6 percent of the total synchronized reserve MW. Figure 10-7 and Figure 10-8 show the portion of synchronized reserve provided by DSR. As seen in the figures, the absolute amount of synchronized reserve provided by DSR has not significantly changed, nor has the amount relative to the total amount of synchronized reserve. In most of the six months since the October 1 changes, the daily average amount was lower that it had been.

Figure 10-7 Daily average synchronized reserve from DSR and non-DSR: January through March, 2023

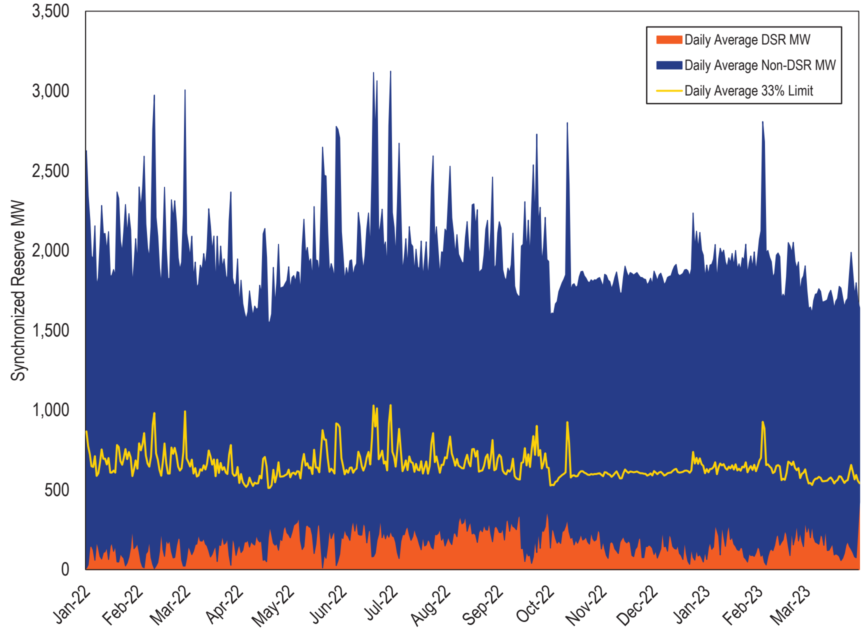
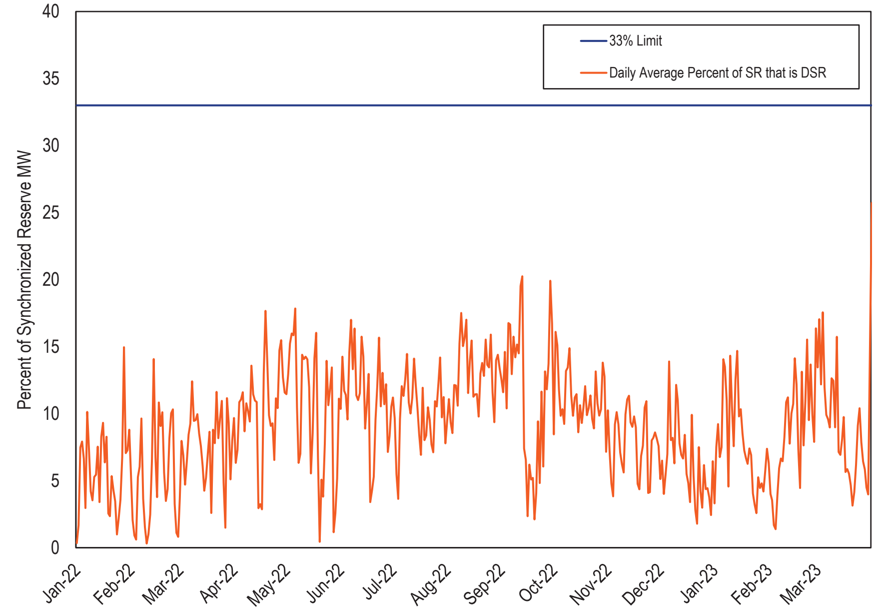


Figure 10-8 Daily average percent of synchronized reserve that is demand response: January through March, 2023



Synchronized Reserve Performance

Resources providing synchronized reserves are paid for being available to respond to a synchronized reserve event. Resources are not directly paid for their response to an event, though they are obligated to provide their full scheduled MW during an event and are charged when failing to do so. If no event occurs, resources are still paid.

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.[54] Cleared synchronized reserve resources are obligated to sustain their final output for the shorter of the length of the event or 30 minutes. Penalties are assessed for

54 See PJM. "PJM Manual 11: Energy & Ancillary Services Market Operations," § 4.2.10 Settlements, Rev. 122 (Oct. 1, 2022).

failure of a scheduled resource to perform during any synchronized reserve event lasting 10 minutes or longer.

In the first three months of 2023, compliance with calls to respond to actual synchronized reserve events was significantly less than 100 percent. Table 10-14 shows the average amount of scheduled synchronized reserve MW that responded to events 10 minutes or longer from January 2016 through March 2023. PJM experienced five synchronized reserve events during Elliott (December 23 and 24). All five of these events were longer than 10 minutes, and three of these events were longer than 30 minutes. Response to these events was below average for other events and reduced the average for the last three months of 2022 (Table 10-14).

Table 10-14 Average synchronized reserve response for events longer than 10 minutes, January 2016 through March 2023

Year	No. of Events Longer than 10 Minutes	Average Percent of Scheduled Synchronized Reserve MW that Responded
2016	7	85.5%
2017	6	87.6%
2018	8	74.2%
2019	3	86.8%
2020	5	59.5%
2021	5	76.9%
2022 (Jan - Sep)	3	51.4%
2022 (Oct - Dec)	7	36.4%
2023 (Jan - Mar)	2	56.9%

The penalty structure when a resource fails to respond fully to a spinning event has two components. The first component is the forfeiture of awarded SRMCP credits in the amount of the MW of shortfall for the day on which the event occurred. The second component is a retroactive charge applied to the 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 minimum of a resource's capped MW assignment during the penalized interval and the resource's penalty obligation on 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, 2023, is 21 days and was calculated using the events from November 1, 2020 through October 31, 2022.[55]

There are several problems with this penalty structure. First, resource owners are permitted to aggregate the response of multiple resources, allowing owners to reduce the penalty obligation of a resource's underresponse by offsetting it with another resource's overresponse.[56] Second, the maximum IPI is calculated using events of any length, even though a resource's compliance is automatically counted as 100 percent for events less than 10 minutes in length, shortening the applied IPI significantly. Third, the second component of the penalty only applies to the SRMCP credits awarded during the IPI, ignoring the LOC credits, even though a large portion of credits is awarded for LOC.

Hence, the penalty structure for synchronized reserve nonperformance is inadequate for providing appropriate performance incentives. Under the penalty structure, it is possible for a resource to not respond to any spin events and yet still be paid for providing synchronized reserve. The MMU continues to recommend that the maximum IPI be defined as the average number of days since the previous spinning event 10 minutes or longer and that the penalty's retroactive charges include the LOC credits in addition to the SRMCP credits. If only events 10 minutes or longer were considered, then the maximum IPI would increase to 82 days from its current level of 21 days. However, implementing this change alone might still have been insufficient to ensure proper response.

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 online 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.

55 See "2022 Third Quarter Synchronized Reserve Performance," PJM presentation to the Operations Committee. (December 8, 2022) <https://www.pjm.com/-/media/committees-groups/committees/oc/2022/20221208/item-12---synchronous-reserve-update.ashx>.
56 See PJM. "PJM Manual 28: Operating Agreement Accounting," § 6.3 Charges for Synchronized Reserve, Rev. 88 (Oct. 1, 2021).

Table 10-15 compares the outcomes of the PJM penalty structure for the first three months of 2023 with the outcomes of the proposed MMU penalty structure following its recommendations. In the first three months of 2023, there were two spinning events that lasted 10 minutes or longer: one on January 5 and one on January 10 (Table 10-16).

Table 10-15 Comparison of synchronized reserve shortfall penalties current IPI vs. MMU recommended: January through March, 2023

Penalty Type	Current PJM Penalty	MMU Recommended Penalty
Day Of Event	$335,995	$372,872
Retroactive Charges	$2,066,056	$3,418,370
Total Penalties	$2,402,052	$3,791,242

Table 10-16 shows synchronized reserve event response compliance for events that lasted 10 minutes or longer as reported by PJM at Operating Committee meetings, using only response from estimated and cleared synchronized reserves. In the first three months of 2023, there were two events that were 10 minutes or longer. 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 ACE must return to the lesser of 0 and the value of the ACE before the disturbance that caused the event.[57] PJM, in practice, not only corrects the ACE disturbance that led to the event but over corrects. In both of the spinning events in the first three months of 2023, the ACE recovered not just to the NERC required level of zero but overshot by over 1,000 MW in both cases.

57 See PJM. "PJM Manual 12: Balancing Operations," Rev. 47 (Oct. 1, 2022) Attachment D.

Table 10-16 Synchronized reserve events 10 minutes or longer, response compliance as reported by PJM[58], RTO Reserve Zone: October 2022 through March 2023

Spin Event	Duration (Minutes)	Synchronized Reserve Scheduled (MW)	Synchronized Reseve Response (MW)	Synchronized Reserve Penalty (MW)	Synchronized Reserve Response Percent
29-Oct-2022 1412 (EPT)	11.9	1,857.9	567.1	1,290.8	30.5%
29-Nov-2022 1630 (EPT)	16.8	1,785.3	949.0	836.3	53.2%
23-Dec-2022 1014 (EPT)	11.1	1,791.4	948.9	842.5	53.0%
23-Dec-2022 1617 (EPT)	111.5	1,845.6	812.3	1,033.3	44.0%
24-Dec-2022 0501 (EPT)	25.7	1,766.5	329.9	1,436.6	18.7%
24-Dec-2022 0223 (EPT)	30.6	1,664.8	534.7	1,130.1	32.1%
24-Dec-2022 0423 (EPT)	87.5	1,097.0	258.6	838.4	23.6%
2022 Average	42.2	1,686.9	628.6	1,058.3	36.4%
05-Jan-2023 1243 (EPT)	11.6	1,713.6	1,010.7	702.9	59.0%
10-Jan-2023 0726 (EPT)	17.5	2,368.1	1,289.7	1,078.4	54.5%
2023 Average	14.5	2,040.9	1,150.2	890.7	56.7%

History of Synchronized Reserve Events

Synchronized reserve is designed to provide relief for disturbances.[59] [60] 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, PJM operators have used synchronized reserve as a source of energy to provide relief from low ACE.

The risk of using synchronized reserves for energy or any other nondisturbance reason is that it reduces the amount of synchronized reserve available for a disturbance. Disturbances are unpredictable. Synchronized reserve has a requirement to sustain its output for only up to 30 minutes. When the need is for reserve extending past 30 minutes, secondary reserve is the appropriate source of the response.

58 *See, for example*, "Systems Operations Report," PJM presentation to the Operating Committee. (April 14, 2022) <https://www.pjm.com/-/media/committees-groups/committees/oc/2022/20220414/item-02---review-of-operating-metrics.ashx> at 10.
59 *2012 State of the Market Report for PJM*, Appendix E – PJM's DCS Performance.
60 See PJM. "PJM Manual 12: Balancing Operations," § 4.1.2 Loading Reserves, Rev. 47 (Oct. 1, 2022).

From January 2018 through March 2023, PJM experienced 93 synchronized reserve events, approximately 1.5 events per month, with an average duration of 11.5 minutes. Table 10-17 shows these events with their region and their duration rounded to the nearest minute.

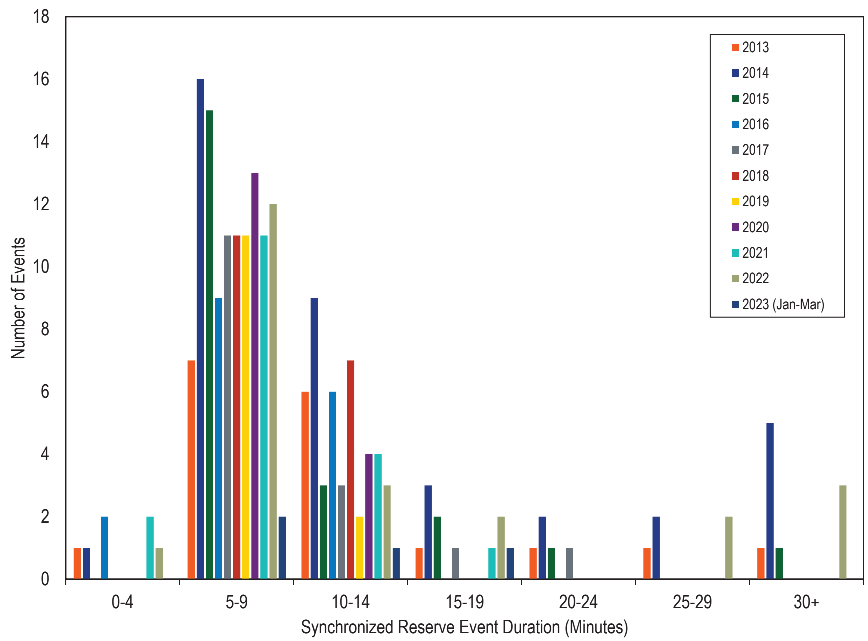
Table 10-17 Synchronized reserve events: January 2018 through March 2023[61]

Effective Time	Region	Duration (Minutes)	Effective Time	Region	Duration (Minutes)	Effective Time	Region	Duration (Minutes)
01-Jan-2018 0241 (EPT)	RTO	7	20-Jan-2020 1406 (EPT)	MAD	8	03-Jan-2022 1227 (EPT)	RTO	9
03-Jan-2018 0300 (EPT)	RTO	13	23-Jan-2020 1617 (EPT)	RTO	9	03-Mar-2022 1220 (EPT)	RTO	7
07-Jan-2018 1415 (EPT)	RTO	9	07-Feb-2020 1206 (EPT)	RTO	6	06-Apr-2022 1145 (EPT)	RTO	10
12-Apr-2018 1328 (EPT)	RTO	10	08-Feb-2020 0344 (EPT)	RTO	8	13-Apr-2022 1725 (EPT)	RTO	28
04-Jun-2018 1022 (EPT)	RTO	6	10-Feb-2020 2015 (EPT)	RTO	9	14-Apr-2022 0931 (EPT)	RTO	8
29-Jun-2018 1521 (EPT)	RTO	9	18-Feb-2020 1116 (EPT)	RTO	10	16-May-2022 1532 (EPT)	RTO	11
30-Jun-2018 0946 (EPT)	RTO	11	08-Mar-2020 0517 (EPT)	MAD	5	16-May-2022 1553 (EPT)	RTO	10
04-Jul-2018 1056 (EPT)	RTO	7	13-Apr-2020 2001 (EPT)	RTO	8	23-May-2022 1717 (EPT)	RTO	15
10-Jul-2018 1545 (EPT)	RTO	13	03-May-2020 1229 (EPT)	RTO	6	26-May-2022 1409 (EPT)	RTO	6
23-Jul-2018 0902 (EPT)	RTO	8	06-Jul-2020 2122 (EPT)	RTO	10	22-Jun-2022 1506 (EPT)	RTO	7
23-Jul-2018 1543 (EPT)	RTO	6	24-Jul-2020 0103 (EPT)	RTO	9	27-Jun-2022 1701 (EPT)	RTO	9
24-Jul-2018 1617 (EPT)	RTO	7	25-Jul-2020 1639 (EPT)	MAD	11	07-Jul-2022 1721 (EPT)	RTO	8
12-Aug-2018 1106 (EPT)	RTO	11	10-Sep-2020 0019 (EPT)	RTO	10	26-Sep-2022 0339 (EPT)	RTO	6
13-Sep-2018 0947 (EPT)	RTO	7	10-Oct-2020 1852 (EPT)	RTO	8	29-Sep-2022 1025 (EPT)	RTO	6
14-Sep-2018 1324 (EPT)	RTO	7	12-Oct-2020 0429 (EPT)	RTO	9	29-Oct-2022 1412 (EPT)	RTO	12
26-Sep-2018 1908 (EPT)	RTO	8	13-Nov-2020 0746 (EPT)	RTO	6	04-Nov-2022 1503 (EPT)	RTO	4
30-Sep-2018 1129 (EPT)	RTO	11	16-Dec-2020 1638 (EPT)	MAD	10	14-Nov-2022 22:01 (EPT)	RTO	7
30-Oct-2018 1040 (EPT)	RTO	11				29-Nov-2022 1630 (EPT)	RTO	17
			24-Jan-2021 2232 (EPT)	RTO	6	23-Dec-2022 1014 (EPT)	RTO	11
22-Jan-2019 2230 (EPT)	RTO	8	09-Mar-2021 0751 (EPT)	RTO	11	23-Dec-2022 1617 (EPT)	RTO	111
31-Jan-2019 0126 (EPT)	RTO	5	13-Apr-2021 2005 (EPT)	RTO	9	24-Dec-2022 0501 (EPT)	RTO	26
31-Jan-2019 0926 (EPT)	RTO	9	30-Apr-2021 2030 (EPT)	RTO	12	24-Dec-2022 0223 (EPT)	RTO	31
25-Feb-2019 0025 (EPT)	RTO	9	26-May-2021 1417 (EPT)	RTO	10	24-Dec-2022 0423 (EPT)	RTO	88
03-Mar-2019 1231 (EPT)	RTO	9	21-Jun-2021 0554 (EPT)	RTO	7			
06-Mar-2019 2206 (EPT)	RTO	9	23-Jun-2021 0333 (EPT)	RTO	5	05-Jan-2023 1243 (EPT)	RTO	12
27-Jul-2019 2331 (EPT)	RTO	7	21-Jul-2021 1828 (EPT)	RTO	5	10-Jan-2023 0726 (EPT)	RTO	18
11-Aug-2019 1214 (EPT)	RTO	8	25-Jul-2021 1617 (EPT)	RTO	6	26-Jan-2023 1443 (EPT)	MAD	7
03-Sep-2019 1339 (EPT)	MAD	9	23-Aug-2021 1644 (EPT)	RTO	18	02-Feb-2023 0606 (EPT)	RTO	8
23-Sep-2019 1606 (EPT)	RTO	11	24-Aug-2021 1038 (EPT)	RTO	8			
01-Oct-2019 1856 (EPT)	RTO	11	27-Sep-2021 1656 (EPT)	RTO	8			
11-Dec-2019 2108 (EPT)	RTO	8	11-Oct-2021 0923 (EPT)	RTO	9			
18-Dec-2019 1507 (EPT)	RTO	9	16-Oct-2021 0130 (EPT)	RTO	8			
			12-Nov-2021 1325 (EPT)	RTO	12			
			30-Nov-2021 0540 (EPT)	RTO	9			
			30-Nov-2021 0957 (EPT)	RTO	9			
			08-Dec-2021 0504 (EPT)	RTO	7			

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

Figure 10-9 shows spin event durations over the past 11 years.[62] 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, which all lasted longer than 30 minutes.

Figure 10-9 Synchronized reserve events duration distribution curve: January 2013 through March 2023



62 These durations were rounded to the nearest minute in previous reports. They are no longer rounded.

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 parameters in offers submitted by resource owners. There is no defined requirement for nonsynchronized reserves. It is available to 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 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 clearing price is zero.

Market Structure

Demand

There is no explicit demand for non-synchronized 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 most economic combination of synchronized and nonsynchronized reserve. While it can be used to fill the 30-minute reserve requirement, as seen in Figure 10-1, nonsynchronized reserve is mainly used for satisfying the primary reserve requirement.

In the RTO Zone, in the first three months of 2023, the average real-time scheduled nonsynchronized reserve was 839.8 MW and the average day-ahead scheduled nonsynchronized reserve was 1,326.4 MW. In the MAD Subzone, in the first three months of 2023, the average real-time scheduled nonsynchronized reserve was 188.7 MW and the average day-ahead scheduled nonsynchronized reserve was 437.9 MW.

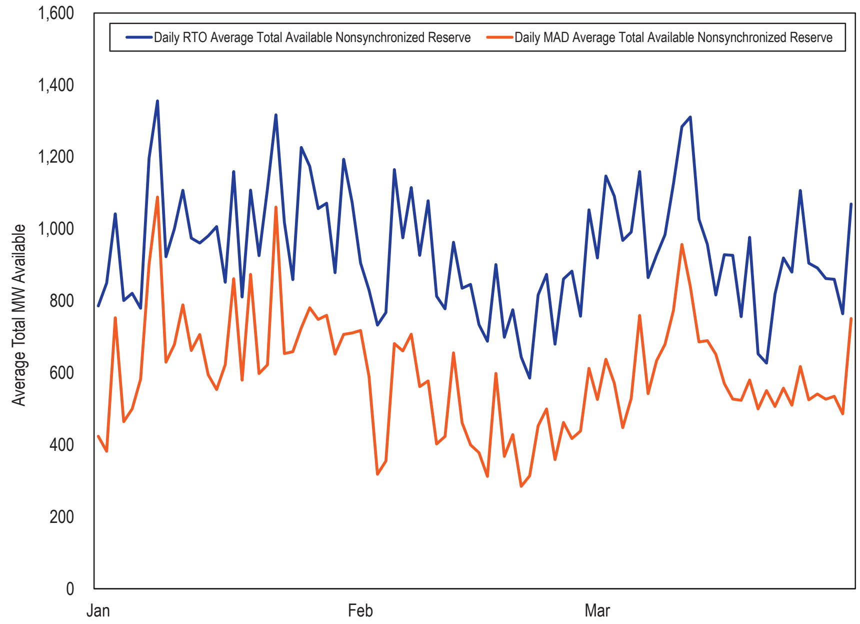
Supply

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 will not be 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 three months of 2023, an average of 839.4 MW of nonsynchronized reserve was scheduled per five minute interval out of 940.1 eligible MW as part of the primary reserve requirement in the RTO Zone. Figure 10-10 shows daily average total nonsynchronized reserve MW available in the first three months of 2023.

Figure 10-10 Daily Average Available Nonsynchronized Reserve: January through March, 2023



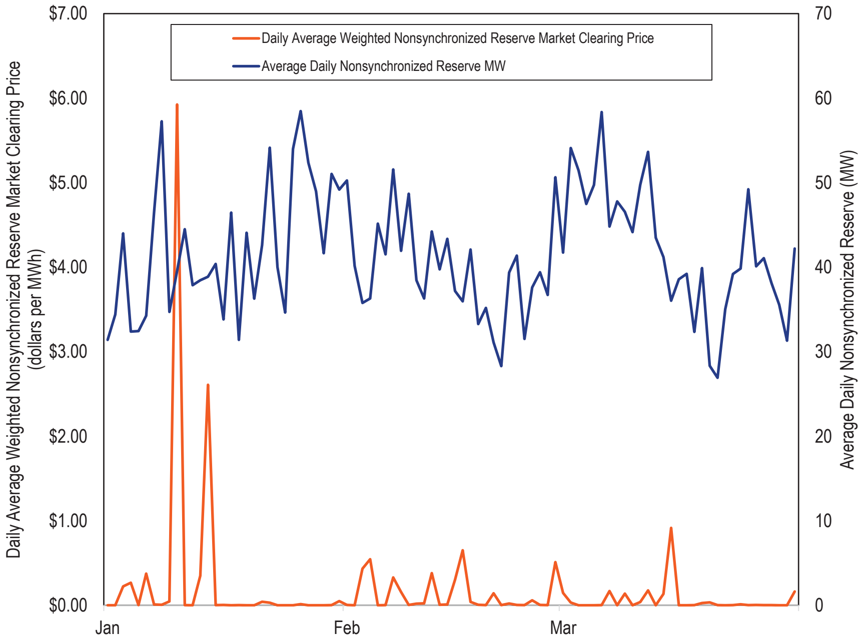
Market Behavior

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 10-11 shows the daily average nonsynchronized reserve market clearing price (NSRMCP) and average credited MW for the RTO Zone. In the first three months of 2023, the real-time weighted average nonsynchronized market clearing price for all intervals was $0.18 per MWh and the real-time average nonsynchronized reserve credited was 839.8 MW. The day-ahead weighted average nonsynchronized market clearing price for all intervals was $0.18 per MWh and the day-ahead average nonsynchronized reserve cleared MW was 1,326.4 MW. Shortage pricing for primary reserve in the RTO and MAD was used for 3 intervals on January 10, 2023, causing a spike in the average price.

Figure 10-11 Daily weighted average RTO Zone nonsynchronized reserve market clearing price and MW purchased: January through March, 2023



The price of nonsynchronized reserve in most intervals of the first three months of 2023 was $0 per MWh. Table 10-18 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 25,908 five-minute intervals in the first three months of 2023.

Table 10-18 Number of five-minute intervals with NSRMCP above $0 per MWh: January through March, 2023

Location	Market	Number of Intervals Where NSRMCP Above $0 per MWh	Percent of Intervals Where NSRMCP Above $0 per MWh
RTO	RT	4,980	19.2%
RTO	DA	2,808	10.8%
MAD	RT	5,134	19.8%
MAD	DA	2,964	11.4%

Table 10-19 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 prices being compared include the RTO Reserve Zone prices and the reserve subzone prices. The weighted average market clearing price for each month is consistently higher in the pricing run than in the dispatch run. In the first three months of 2023, the weighted average real-time price from the pricing run was 2.7 percent lower than the weighted average real-time price from the dispatch run. In the first three months of 2023, the weighted average day-ahead price from the pricing run was 4.0 percent higher than the weighted average day-ahead price from the dispatch run.

Table 10-19 Comparison of fast start and dispatch pricing components: October 2022 through March 2023

		Day-Ahead				Real-Time			
Year	Month	Dispatch-Run MCP	Pricing-Run MCP	Difference	Percent Difference	Dispatch-Run MCP	Pricing-Run MCP	Difference	Percent Difference
2022	Oct	$0.11	$0.11	$0.00	3.2%	$0.01	$0.08	$0.08	1,033.6%
2022	Nov	$0.48	$0.51	$0.02	5.1%	$0.01	$0.01	$0.00	47.4%
2022	Dec	$0.29	$0.30	$0.01	3.9%	$5.14	$4.85	($0.29)	(5.7%)
2023	Jan	$0.07	$0.07	$0.00	4.0%	$0.31	$0.32	$0.01	4.6%
2023	Feb	$0.08	$0.08	($0.00)	(0.0%)	$0.10	$0.15	$0.05	46.0%
2023	Mar	$0.08	$0.08	$0.00	3.6%	$0.03	$0.06	$0.03	94.3%

In the first three months of 2023, the weighted average price of nonsynchronized reserve was $0.18 per MWh and the weighted average credit for nonsynchronized reserve was -$0.03 per MWh. This negative value for the weighted average credit for the first three months of 2023 is due to nonsynchronized reserve resources clearing more MW in the day-ahead market than in the real-time market, leading to negative total balancing MCP credits. (See Table 10-20 and Table 10-21.)

Table 10-20 shows the total nonsynchronized reserve payments by month from October 2022 through March 2023. During Winter Storm Elliot in December 2022, reserve providers had to buy back day-ahead cleared reserves at shortage-level prices in real time when they were on a forced outage, leading to a large negative total of balancing MCP credits.

Table 10-20 Total nonsynchronized payments and charges by month: October 2022 through March 2023

Year	Month	Day-Ahead Credits	Real-Time and Balancing MCP Credits	LOC Credits	Shortfall Charges	Total Credits
2022	Oct	$137,051	($13,639)	$1,051	NA	$124,464
2022	Nov	$395,965	$1,731	$0	NA	$397,696
2022	Dec	$292,838	($24,704,387)	$604,197	NA	($23,807,353)
2023	Jan	$73,610	($155,466)	$4,850	NA	($77,007)
2023	Feb	$72,133	($113,200)	$31,094	NA	($9,973)
2023	Mar	$72,194	($37,214)	$3,368	NA	$38,348

Table 10-21 provides the day-ahead and real-time nonsynchronized reserve by resource type and fuel type for the first three months of 2023. As seen in the table, except for run-of-river hydro units, almost all unit types cleared less MW in the real-time market than in the day-ahead market.

Table 10-21 Day-ahead and real-time nonsynchronized reserve by resource type and fuel type: January through March, 2023

Resource / Fuel Type	Day-Ahead MWh	Real-Time Scheduled MWh	Day-Ahead Credits	Balancing MCP Credits	LOC Credits	Total Credits
CT - Oil	669,906	522,964	$156,581	($13,145)	$7,503	$150,939
Hydro - Run of River	0	277,573	$0	$25,453	$0	$25,453
CT - Other	6,477	4,584	$1,487	($25)	$0	$1,462
RICE - Oil	4,318	2,794	$991	($0)	$0	$991
RICE - Other	926	29	$151	($429)	$0	($278)
CT - Natural Gas	308,739	0	$58,727	($111,326)	$2,697	($49,903)
Hydro - Pumped Storage	1,811,336	918,517	$0	($206,408)	$29,112	($177,296)
Battery	0	0	NA	NA	NA	NA
Combined Cycle	0	0	NA	NA	NA	NA
DSR	0	0	NA	NA	NA	NA
Distributed Gen	0	0	NA	NA	NA	NA
Fuel Cell	0	0	NA	NA	NA	NA
Nuclear	0	0	NA	NA	NA	NA
RICE - Natural Gas	0	0	NA	NA	NA	NA
Solar	0	0	NA	NA	NA	NA
Solar + Storage	0	0	NA	NA	NA	NA
Solar + Wind	0	0	NA	NA	NA	NA
Steam - Coal	0	0	NA	NA	NA	NA
Steam - Natural Gas	0	0	NA	NA	NA	NA
Steam - Oil	0	0	NA	NA	NA	NA
Steam - Other	0	0	NA	NA	NA	NA
Wind	0	0	NA	NA	NA	NA
Wind + Storage	0	0	NA	NA	NA	NA

30-Minute Reserve

The 30-minute reserve service is provided by resources that can respond in 30 minutes. In addition to the reserve products used to satisfy the primary reserve requirement, the 30-minute reserve requirement can also be satisfied by the secondary reserve product. 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 or for 30-minute reserve. The secondary reserve product can only be used to satisfy the 30-minute reserve requirement, and it is cleared for five minute intervals in real time and sixty minute intervals day ahead. Failure to convert offline secondary reserves to energy at PJM's request results in a shortfall charge.

Market Structure

Demand

The 30-minute reserve requirement is equal to the greatest of 3,000 MW, the primary reserve requirement, and the largest active gas contingency, plus 190 MW.[63] Unlike with synchronized reserve and primary reserve, PJM does not model a 30-minute reserve requirement for the defined reserve subzone.[64] However, PJM has the option to define a subzone natural gas contingency reserve requirement using 30-minute reserves. PJM did not exercise this option in the first three months of 2023.

In the first three months of 2023, the average real-time 30-minute requirement was 3,206.3 MW and the average day-ahead 30-minute requirement was 3,206.3 MW (Figure 10-1).

Supply

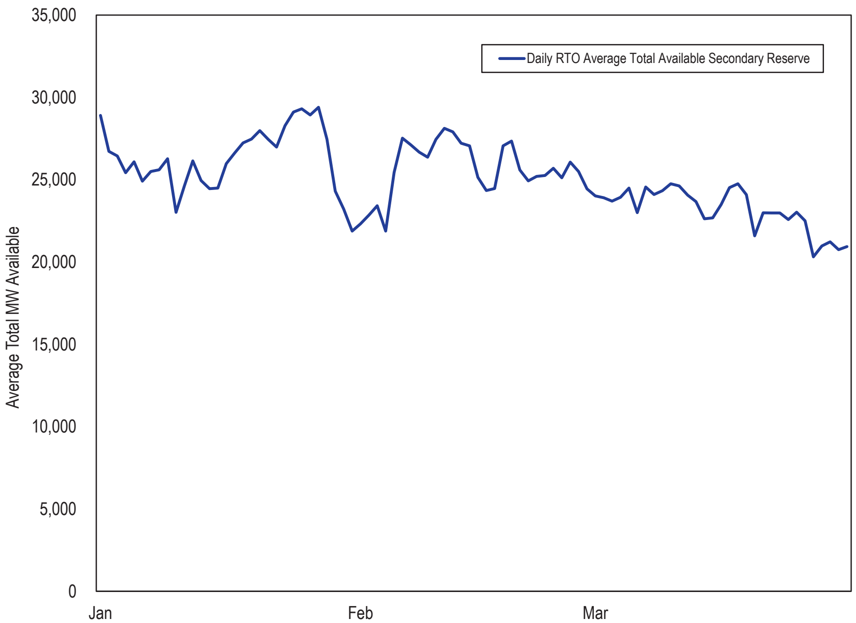
The supply of 30-minute reserves includes all primary reserves plus any synchronized or offline reserves that can convert to energy in 30 minutes. In addition to synchronized reserves and nonsynchronized reserves, the 30-minute reserve requirement can also be satisfied using secondary reserves. Secondary reserves are the 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. It also includes offline resources that offer a time to start of less than 30 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 other reserves, certain resource types, including nuclear, wind, and solar units, are by default excluded from providing secondary reserves.

Secondary reserve can only be used to help satisfy the 30-minute reserve requirement. As with the other reserve products, for most resources, PJM determines the MW available for secondary reserve based on energy offer parameters.[65] 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 scheduled synchronized reserve.[66] The use of the secondary reserve maximum output limit requires prior approval by PJM.[67] Offline resources' secondary reserves are based on the time to start, which is the start-up time plus notification time, and any scheduled nonsynchronized reserve.[68]

Figure 10-12 shows the daily average total available secondary reserve in the first three months of 2023. In the first three months of 2023, the average real-time supply of secondary reserve was 25,010 MW.

63 See PJM. "PJM Manual 11: Energy & Ancillary Services Market Operations" § 4.3 Reserve Requirement Determination, Rev. 122 (Oct. 1, 2022).
64 See PJM. "PJM Manual 11: Energy & Ancillary Services Market Operations" § 4.3.1 Locational Aspect of Reserves, Rev. 122 (Oct. 1, 2022).
65 See PJM. "PJM Manual 11: Energy & Ancillary Services Market Operations" § 4.2.3 Reserve Market Resource Offer Structure, Rev. 122 (Oct. 1, 2022).
66 See PJM. "PJM Manual 11: Energy & Ancillary Services Market Operations" § 4.2.5.1 Reserve Market Capability for Online Generation Resources, Rev. 122 (Oct. 1, 2022).
67 See PJM. "PJM Manual 11: Energy & Ancillary Services Market Operations" § 4.2.2.1 Communication for Reserve Capability Limitation, Rev. 122 (Oct. 1, 2022).
68 See PJM. "PJM Manual 11: Energy & Ancillary Services Market Operations" § 4.2.5.2 Reserve Market Capability for Offline Generation Resources, Rev. 122 (Oct. 1, 2022).

Figure 10-12 Daily Average Available Secondary Reserve: January through March, 2023



Market Concentration

Table 10-22 shows the average HHI of the 30-minute reserve market, including synchronized, nonsynchronized, and secondary reserves, and the percent of intervals for which the maximum market share is above 20 percent. In the first three months of 2023, the RTO Zone was unconcentrated in the day-ahead and real-time markets.

Table 10-22 PJM 30-minute reserve market HHI: January through March, 2023

Location	Market	Average HHI	Percent of Intervals Max Market Share Above 20%
RTO	RT	881	29.2%
RTO	DA	439	0.1%

Market Behavior

The offer price for secondary reserve for all resources is cost based, which is $0 per MWh for offline resources. For online resources, the energy market opportunity cost is calculated by PJM based on market prices.

Market Performance

Figure 10-13 provides the prices for secondary reserves for the first three months of 2023. In the first three months of 2023, the secondary reserve market clearing price in the real-time and day-ahead markets was always $0 per MWh.

Figure 10-13 Secondary reserve prices: January through March, 2023

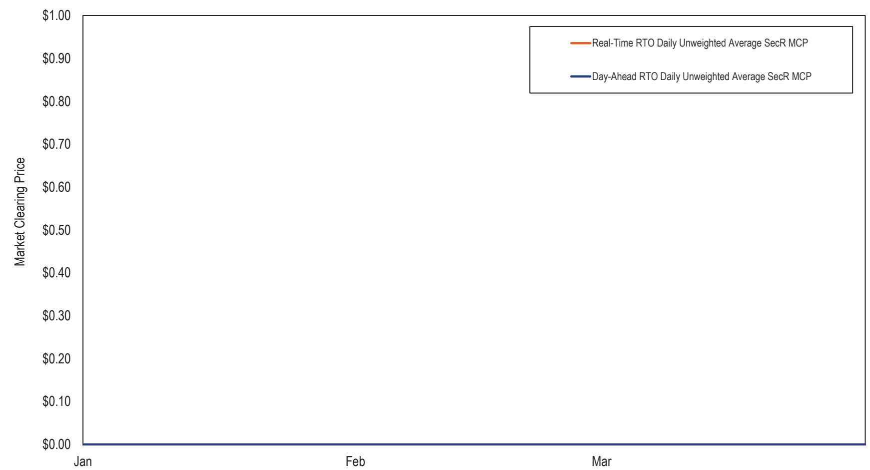


Table 10-23 compares the dispatch-run and pricing-run market clearing prices for the day-ahead and real-time secondary reserve markets. For the real-time values, these are the LPC prices weighted by the RT SCED MW. For the day-ahead values, these are the DA prices weighted by the DA dispatch MW. In the first three months of 2023, the day-ahead price of secondary reserve was always $0 per MWh in both the pricing run and the dispatch run. The real-time secondary reserve market clearing price was above $0 per MWh in the pricing run and dispatch run on December 23 and December 24 during Winter Storm Elliot. It remained $0 per MWh otherwise.

Table 10-23 Comparison of fast start and dispatch pricing components: October 2022 through March 2023

		Day-Ahead				Real-Time			
Year	Month	Dispatch-Run MCP	Pricing-Run MCP	Difference	Percent Difference	Dispatch-Run MCP	Pricing-Run MCP	Difference	Percent Difference
2022	Oct	$0.00	$0.00	$0.00	NA	$0.00	$0.00	$0.00	NA
2022	Nov	$0.00	$0.00	$0.00	NA	$0.00	$0.00	$0.00	NA
2022	Dec	$0.00	$0.00	$0.00	NA	$0.52	$0.53	$0.01	1.0%
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

Table 10-24 shows the day-ahead credits, balancing market credits, LOC credits, and effective shortfall charges for secondary reserves from October 2022 through March 2023.[69] Because the market clearing price for secondary reserve was always $0.00 per MWh in the first three months of 2023, the only credits paid during the first three months of 2023 were LOC credits for resources with non-zero LMPs. In the first three months of 2023, the weighted average secondary reserve market clearing price was $0.00 per MWh. In the first three months of 2023, the weighted average credit per MWh, considering the total credits paid and the capped MWh, was $0.01 per MWh.

During Winter Storm Elliott in December 2022, secondary reserve positions were converted to energy in real-time, resulting in negative balancing credits and offsetting LOC credits. All intervals with non-zero shortfall charges for secondary reserve occurred during Winter Storm Elliott.

Table 10-24 Monthly secondary reserve settlements: October 2022 through March 2023

Year	Month	Total Day-Ahead Credits	Total Balancing MCP Credits	Total LOC Credits	Total Effective Shortfall Charge	Total Credits
2022	Oct	$0	$0	$61,173	$0	$61,173
2022	Nov	$0	$0	$11,744	$0	$11,744
2022	Dec	$0	($3,877,100)	$3,670,094	$41,440	($207,006)
2023	Jan	$0	$0	$5,150	$0	$5,150
2023	Feb	$0	$0	$34,129	$0	$34,129
2023	Mar	$0	$0	$12,363	$0	$12,363

69 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 10-25 provides secondary reserve credits by resource type for the first three months of 2023.

Table 10-25 Secondary reserve credits by resource type: January through March, 2023

Resource / Fuel Type	Day-Ahead MWh	Real-Time Capped MWh	Day-Ahead Credits	Balancing MCP Credits	LOC Credits	Total Credits
CT - Natural Gas	27,361,496	4,052,284	$0	$0	$42,600	$42,600
CT - Oil	3,606,556	558,061	$0	$0	$6,294	$6,294
Combined Cycle	7,111	8,914	$0	$0	$1,053	$1,053
Steam - Coal	2,234	12,295	$0	$0	$860	$860
RICE - Other	7,388	1,024	$0	$0	$358	$358
Steam - Natural Gas	85	278	$0	$0	$182	$182
RICE - Natural Gas	215,230	12,847	$0	$0	$179	$179
Hydro - Run of River	0	11,156	$0	$0	$92	$92
Steam - Other	24	28	$0	$0	$25	$25
CT - Other	6,475	57	$0	$0	$0	$0
Hydro - Pumped Storage	0	270	$0	$0	$0	$0
RICE - Oil	160,419	7,255	$0	$0	$0	$0
Battery	0	0	NA	NA	NA	NA
DSR	0	0	NA	NA	NA	NA
Distributed Gen	0	0	NA	NA	NA	NA
Fuel Cell	0	0	NA	NA	NA	NA
Nuclear	0	0	NA	NA	NA	NA
Solar	0	0	NA	NA	NA	NA
Solar + Storage	0	0	NA	NA	NA	NA
Solar + Wind	0	0	NA	NA	NA	NA
Steam - Oil	0	0	NA	NA	NA	NA
Wind	0	0	NA	NA	NA	NA
Wind + Storage	0	0	NA	NA	NA	NA

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.[70] The objective of PJM's regulation market design is 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.

The PJM regulation market design includes three clearing price components: capability ($/MW, based on the MW being offered); performance ($/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 regulation market solution is intended 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.

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

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.[71] Performance scores are reported on an hourly basis for each resource.

71 PJM "Manual 12: Balancing Operations," § 4.5.6 Performance Score Calculation, Rev. 47 (Oct. 1, 2022).

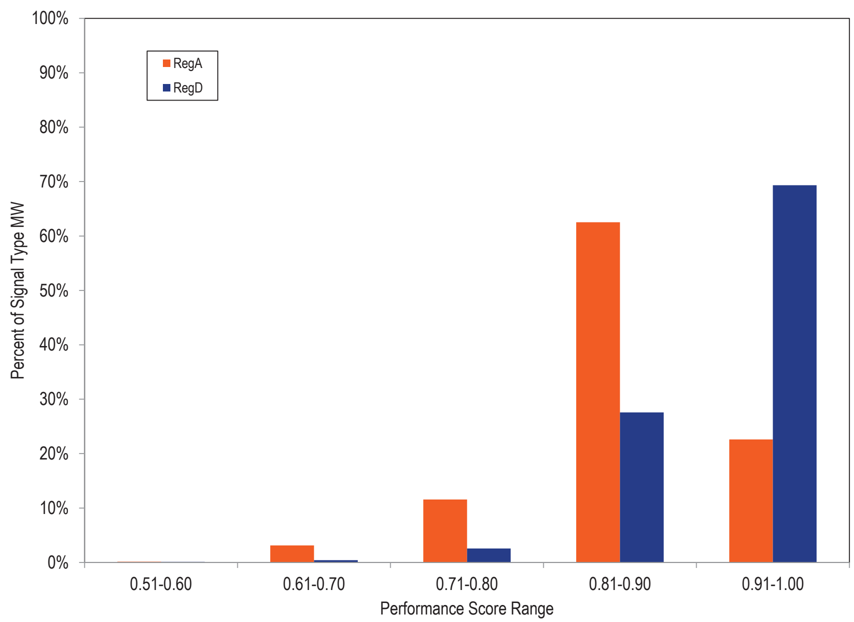
Table 10-26 and Figure 10-14 show the average performance score by resource type and the signal followed in the first three months of 2023. In these figures, the MW used are actual MW and the performance score is the hourly performance score of the regulation resource.[72] Each category (color bar) is based on the percentage of the full performance score distribution for each resource (or signal) type. As Figure 10-14 shows, 69.3 percent of RegD resources had average performance scores within the 0.91-1.00 range, and 22.6 percent of RegA resources had average performance scores within that range in the first three months of 2023. In the first three months of 2022, 81.2 percent of RegD resources had average performance scores within the 0.91-1.00 range, and 16.2 percent of RegA resources had average performance scores within that range.

Table 10-26 Hourly average performance score by unit type: January through March, 2023

		Performance Score Range				
		51-60	61-70	71-80	81-90	91-100
RegA	Battery	-	-	-	-	-
	CT	0.0%	0.0%	2.5%	60.7%	36.8%
	Diesel	0.0%	0.0%	0.0%	15.7%	84.3%
	DSR	0.0%	0.0%	100.0%	0.0%	0.0%
	Hydro	0.0%	0.0%	0.2%	50.4%	49.4%
	Steam	0.2%	4.4%	16.3%	67.7%	11.2%
RegD	Battery	0.1%	0.0%	0.2%	26.9%	72.7%
	CT	0.0%	0.0%	9.8%	64.9%	25.3%
	Diesel	0.0%	0.0%	3.6%	53.4%	42.9%
	DSR	0.0%	0.1%	19.7%	26.4%	53.7%
	Hydro	0.0%	18.1%	0.0%	39.4%	42.5%
	Steam	-	-	-	-	-

72 Except where explicitly referred to as effective MW or effective regulation MW, MW means actual MW unadjusted for either MBF or performance factor.

Figure 10-14 Hourly average performance score by regulation signal type: January through March, 2023



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 with 10 MW of capability will be provided a TREG signal asking for a positive or negative regulation movement between negative and positive 10 MW around its regulation set point.

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 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 10-27). 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 10-27 Seasonal regulation requirement definitions[73]

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

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.[74] 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.[75] Table 10-28 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

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

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

75 See 170 FERC ¶ 61,258 (2020).

additional regulation credits received as a result of the settlement, from July 2020 through the first three months of 2023, are shown in Table 10-29. From July 2020 through the first three months of 2023, the battery settlement has provided $4.0 million in excess regulation credits.

Table 10-28 Batteries in settlement

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

Table 10-29 Excess regulation credits received by settlement batteries: July 2020 through March, 2023

Year	Month	Excess Regulation Credit ($)
2020	Jul	$49,068
	Aug	$39,863
	Sep	$26,064
	Oct	$56,734
	Nov	$55,966
	Dec	$52,532
	Total	$280,226
2021	Jan	$40,752
	Feb	$82,768
	Mar	$76,248
	Apr	$61,786
	May	$65,797
	Jun	$60,896
	Jul	$76,253
	Aug	$136,365
	Sep	$112,929
	Oct	$156,829
	Nov	$213,585
	Dec	$118,995
	Total	$1,203,204
2022	Jan	$230,764
	Feb	$84,963
	Mar	$70,375
	Apr	$128,896
	May	$104,817
	Jun	$179,703
	Jul	$160,327
	Aug	$216,929
	Sep	$169,958
	Oct	$143,995
	Nov	$85,026
	Dec	$659,729
	Total	$2,235,481
2023	Jan	$83,125
	Feb	$76,978
	Mar	$83,153
	Total	$243,256

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.[76] 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 10-30 shows the impact of clearing additional MW beyond what is needed for the regulation requirement, as a result of the battery settlement, in 2022. 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 the first three months of 2023, the battery settlement resulted in customers paying $18,454 more than needed, in order to compensate the additional MW from settlement batteries that would not have otherwise cleared. As a result of the battery settlement, PJM customers in the first three months of 2023 over paid for regulation by $261,710 (the sum of Table 10-29 and Table 10-30).

Table 10-30 Excess payments and monthly additional MW cleared due to battery settlement: January 2022 through March 2023

		Battery Settlement Impact	
Year	Month	Regulation Credits	Additional Cleared Regulation MW
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
	Total	$18,454	505.1

76 See *id.* at P 17.

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.

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.[77]

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.[78]

77 The MBF, as used in this report, refers to PJM's incorrectly calculated MBF and not the MBF equivalent to the MRTS.
78 162 FERC ¶ 61,295 (2018), *reh'g denied*, 170 FERC ¶ 61,259 (2020).

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 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.[79] 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.

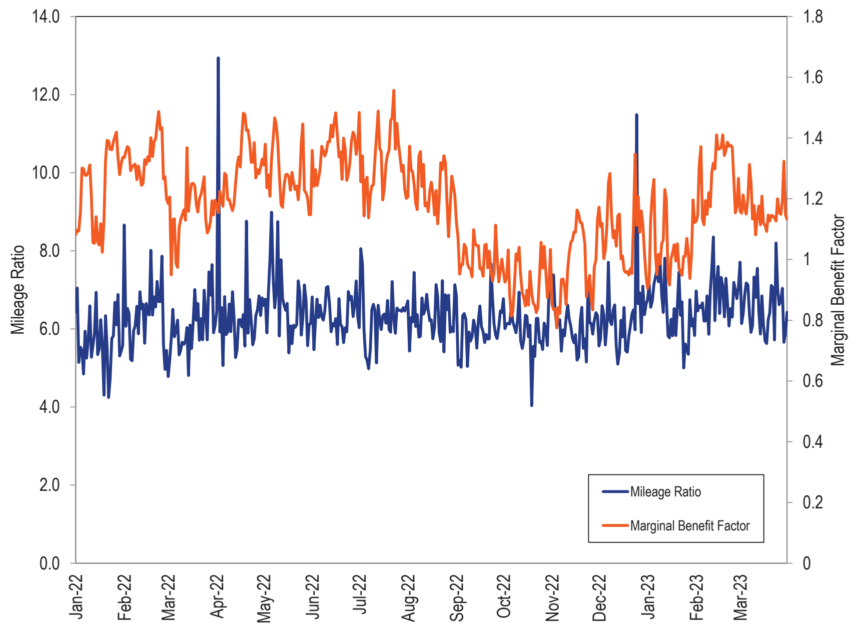
The change in design decreased RegA mileage (the change in MW output in response to regulation signal per MW of capability), increased the proportion of cleared RegD resources' capability that was called by the RegD signal (increased REG for a given MW) to better match offered capability, increased the 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 10-15 shows the daily average MBF and the mileage ratio. The weighted average mileage ratio increased from 6.05 in the first three months of 2022, to 6.62 in the first three months of 2023 (an increase of 9.5 percent). The average MBF decreased from 1.24 in the first three months of 2022, to 1.16 in the first three months of 2023 (a decrease of 6.7 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.

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.

79 145 FERC ¶ 61,011 (2013).

Figure 10-15 Daily average MBF and mileage ratio: January 2022 through March 2023



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 10-31 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, 2022, through March 31, 2022. The average regulation market clearing price in the first three months of 2023 was $27.40 higher than in the first three months of 2022 (See Table 10-45.) In the first three months of 2023, RegD resources earned 28.6 percent more per performance adjusted actual MW than RegA resources (17.4 percent in the first three months of 2022) due to the inclusion of the mileage ratio in RegD MW settlement.

Table 10-31 Average monthly price paid per performance adjusted actual MW of RegD and RegA: January 2022 through March 2023

		Settlement Payments		
Year	Month	RegD ($/Performance Adjusted MW)	RegA ($/Performance Adjusted MW)	Percent RegD Overpayment ($/Performance Adjusted MW)
2022	Jan	$74.63	$68.59	8.8%
	Feb	$39.28	$31.51	24.6%
	Mar	$33.90	$25.56	32.6%
	Apr	$60.31	$49.00	23.1%
	May	$49.81	$41.57	19.8%
	Jun	$63.28	$54.47	16.2%
	Jul	$60.45	$53.40	13.2%
	Aug	$71.87	$63.64	12.9%
	Sep	$55.22	$46.90	17.7%
	Oct	$44.84	$36.33	23.4%
	Nov	$27.32	$22.41	21.9%
	Dec	$122.69	$117.10	4.8%
Yearly		$58.87	$48.46	21.5%
2023	Jan	$21.52	$17.01	26.6%
	Feb	$21.57	$15.49	39.2%
	Mar	$20.50	$16.82	21.9%
Total		$21.19	$16.47	28.6%

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 greater than 1.0 in the first three months of 2023 (1.16).

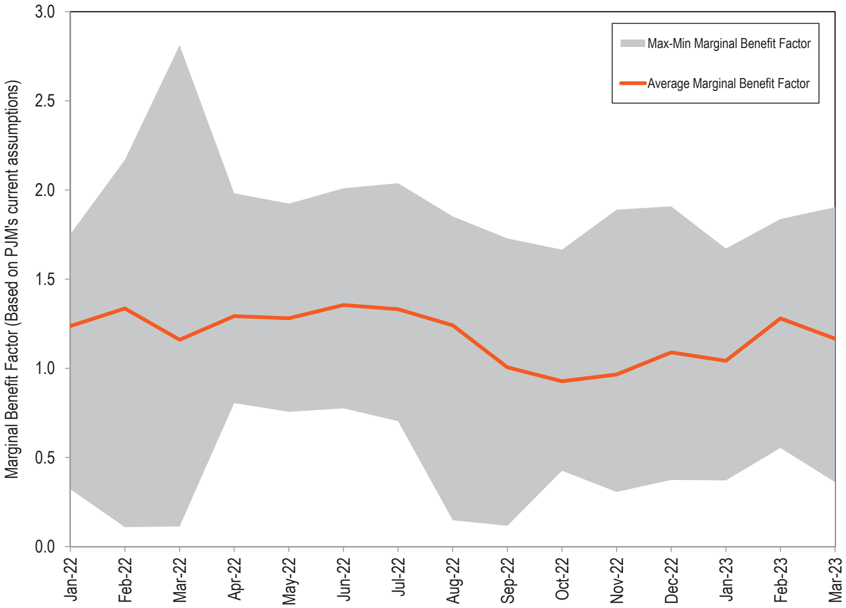
The effect of using the mileage ratio instead of the MBF for purposes of settlement is illustrated in Table 10-32. Table 10-32 shows how much RegD resources are currently being paid, adjusted to a per effective MW basis, on average, in 2022 and the first three months of 2023 under the current rules, 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 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 three months of 2023, the MBF averaged 1.16, while the average daily mileage ratio was 6.62, resulting in RegD resources being paid $242,746 more than they would have been paid on an effective MW basis if the MBF were correctly implemented. In the first three months of 2022, the MBF averaged 1.24, and the average mileage ratio was 6.05, resulting in RegD resources being paid $1.82 million less than they would have been paid if the MBF were correctly implemented. The shift from underpayment to overpayment of RegD resources between the first three months of 2022 and the first three months of 2023 is the result of an incorrect calculation of the MBF, as a result of the way dual offers are handled by PJM. This error has led to a decrease in the amount of RegD cleared and a resulting increase in the MBF of RegD resources. The higher MBF values have not been accurately reflected in settlement.

Table 10-32 Average monthly price paid per effective MW of RegD and RegA under mileage and MBF based settlement: January 2022 through March 2023

		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 ($)
2022	Jan	$62.73	$68.59	$68.59	(8.5%)	($1,580,376)
	Feb	$29.38	$31.51	$31.51	(6.8%)	($516,687)
	Mar	$31.86	$25.56	$25.56	24.7%	$281,052
	Apr	$46.90	$49.00	$49.00	(4.3%)	($550,585)
	May	$39.30	$41.57	$41.57	(5.4%)	($582,040)
	Jun	$47.78	$54.47	$54.47	(12.3%)	($1,133,591)
	Jul	$45.45	$53.40	$53.40	(14.9%)	($1,438,918)
	Aug	$60.51	$63.64	$63.64	(4.9%)	($1,069,872)
	Sep	$55.46	$46.90	$46.90	18.2%	$239,007
	Oct	$50.03	$36.33	$36.33	37.7%	$916,419
	Nov	$31.77	$22.41	$22.41	41.8%	$514,986
	Dec	$104.29	$117.10	$117.10	(10.9%)	($3,113,242)
Yearly		$50.68	$51.12	$51.12	(0.8%)	($8,033,848)
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)
Total		$18.81	$16.47	$16.47	14.2%	$242,746

Figure 10-16 shows, the monthly maximum, minimum and average MBF, for January 2022 through March 2023. The average daily MBF in the first three months of 2023 was 1.16. The average daily MBF in the first three months of 2022 was 1.24. The bottom of the MBF range results from PJM's administratively defined MBF minimum threshold of 0.1. The increase in the maximum and average MBF compared to previous years is due to an incorrect calculation of the MBF, as a result of the way dual offers are handled by PJM. This error has led to a decrease in the amount of RegD cleared, and an increase in the MBF.

Figure 10-16 Maximum, minimum, and average PJM calculated MBF by month: January 2022 through March 2023



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.[80]

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 10-33 shows, by month, cleared RegD MW with an effective price of $0.00 (units with zero offers plus self scheduled units) for January 2022 through March 2023. In the first three months of 2023, an average of 97.5 percent of all RegD MW clearing the market had an effective offer of $0.00. In the first three months of 2022, an average of 97.3 percent of all cleared RegD MW had an effective cost of $0.00. In the first three months of 2023, an average of 58.2 percent of all RegD offers were self scheduled, compared to an average of 59.7 percent of all RegD offers in the first three months of 2022.

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 6.5 MW (4.3 percent), from 152.2 MW in the first three months of 2022 to 158.7 MW in the first three months of 2023. The average monthly RegD cleared with an effective cost of zero increased 6.8 MW (4.6 percent), from 148.0 MW in the first three months of 2022 to 154.8 MW in the first three months of 2023. Self scheduled RegD cleared MW increased 1.7 MW (1.9 percent), from 91.0 MW in the first three months of 2022 to 92.7 MW in the first three months of 2023. Average cleared RegD MW with a zero cost offer increased 5.1 MW (8.9 percent), from 57.1 MW in the first three months of 2022 to 62.2 MW in the first three months of 2023. The incorrect way that dual offers are offered and cleared in the regulation market has led to the decrease in the average monthly RegD cleared and the increase in the average monthly MBF seen in Figure 10-16.

80 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>.

Table 10-33 Average cleared RegD MW and average cleared RegD with an effective price of $0.00 by month: January 2022 through March 2023

		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
2022	Jan	51.8	33.8%	95.5	62.2%	147.4	96.0%	153.5
	Feb	59.6	40.6%	84.1	57.2%	143.8	97.8%	147.0
	Mar	59.7	38.2%	93.3	59.7%	153.0	98.0%	156.2
	Apr	52.9	36.8%	84.3	58.5%	137.2	95.3%	144.0
	May	52.5	37.0%	85.7	60.4%	138.1	97.4%	141.8
	Jun	51.6	34.1%	89.2	59.0%	140.8	93.1%	151.2
	Jul	59.9	38.4%	84.9	54.4%	144.8	92.8%	156.1
	Aug	62.1	38.6%	92.2	57.3%	154.4	95.9%	160.9
	Sep	65.2	39.6%	95.2	57.9%	160.5	97.5%	164.6
	Oct	66.6	38.5%	100.8	58.3%	167.4	96.7%	173.1
	Nov	65.1	39.1%	99.3	59.6%	164.4	98.8%	166.4
	Dec	56.5	33.9%	107.9	64.8%	164.4	98.8%	166.4
Yearly		58.6	37.4%	92.8	59.2%	151.4	96.5%	156.8
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
Total		62.0	39.0%	93.0	58.6%	155.0	97.6%	158.9

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.

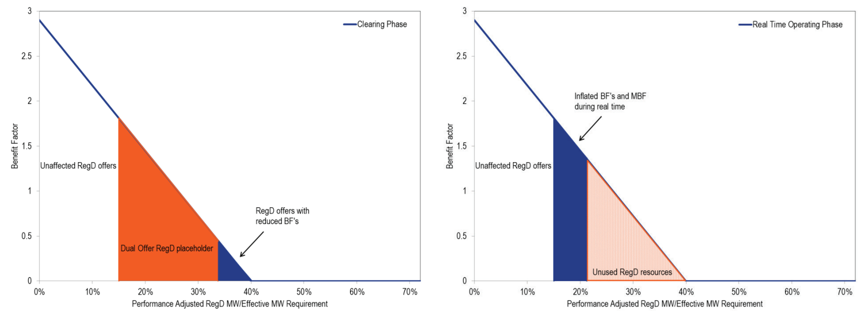
Each dual offer resource is assigned to run as either a RegD or RegA resource based on which of the two offers has a lower effective cost. But PJM does not redefine the supply curve using appropriately recalculated unit specific benefit factors for the remaining RegD resources prior to clearing the market.

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.

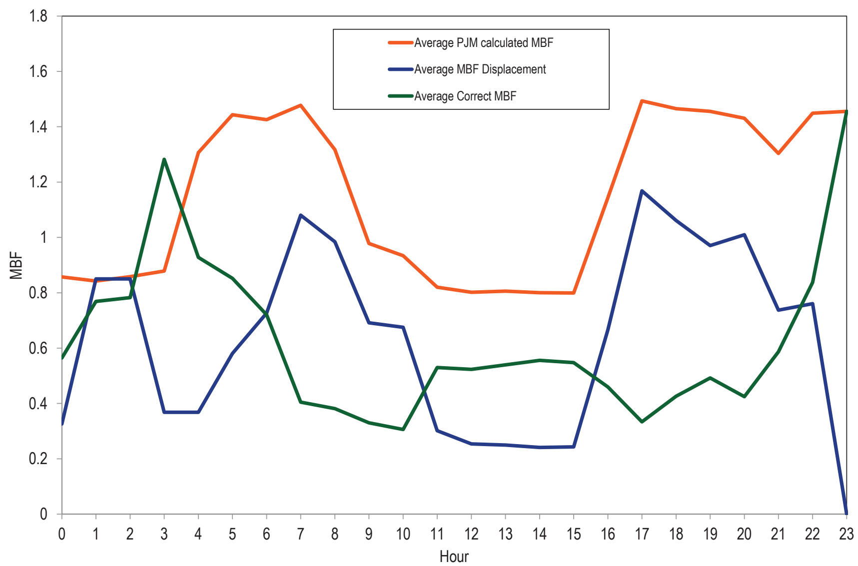
The issue is illustrated in Figure 10-17. The example shows a clearing phase and a real time operating phase. In this example, a 150 MW unit offers both RegA and RegD. The 150 MW unit's position in the RegD effective cost curve and the potential effective MW are represented as the orange area under the 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 10-17 Clearing phase BF/effective MW reduction, real-time BF/ effective MW inflation, and exclusion of available RegD resources



In the first three months of 2023, all hours had at least one unit with a dual offer. In the first three months of 2023, 50.7 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 0.76 in the operating phase. The average MBF increase due to dual offers clearing as RegA in the first three months of 2022 was 0.75. 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 higher MBF of RegD in the market solution in the first three months of 2023. In the first three months of 2023, 3,124 dual offers from generating units were cleared as RegA, an increase of 98.9 percent from the first three months of 2022 (1,571 dual offers clearing as RegA). 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 10-18 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 three months of 2023 if the clearing solution were solved correctly.

Figure 10-18 Effect of PJM's current dual offer clearing method on the average MBF in each hour of the day: January through March, 2023



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.

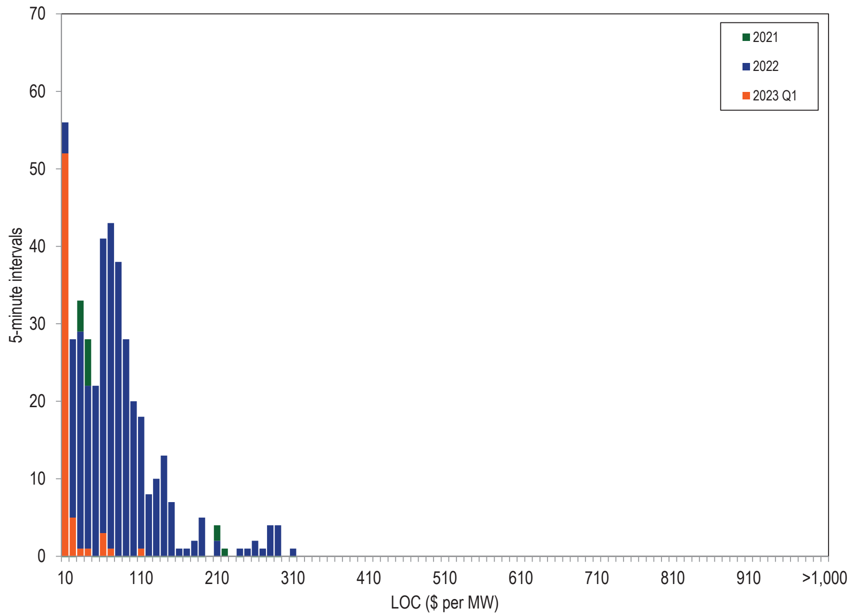
The regulation market is cleared on an hour ahead basis, using offers that are adjusted by dividing each component of an offer (capability, performance, and lost opportunity cost) by the product of the unit specific benefit factor and unit specific performance score. To calculate the hour ahead estimate 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.[81] 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 10-19 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 2021 through the first three months of 2023.

81 See 166 FERC ¶ 61,040 (2019).

Figure 10-19 LOC distribution in each five minute interval with a RegD marginal unit and an LOC greater than zero: 2021 through March 2023



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.[82] 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.[83] 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 10-34 shows the amount of uplift overpayment by fuel type for the first three months of 2023, 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 three month of 2023, overpayments totaled $2.5 million. Coal units received 45.5 percent of the overpayment while providing 2.7 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.

82 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.

83 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 10-34 Amount of LOC overpayment: January 2022 through March 2023

		Uplift Overpayment		
Year	Month	Coal	Natural Gas	Total
2022	Jan	$1,959,942	$2,308,232	$4,268,174
	Feb	$432,077	$1,103,635	$1,535,711
	Mar	$297,947	$990,141	$1,288,088
	Apr	$1,447,659	$1,627,371	$3,075,030
	May	$625,195	$1,318,174	$1,943,369
	Jun	$752,995	$1,529,581	$2,282,575
	Jul	$2,816,672	$1,359,550	$4,176,222
	Aug	$1,945,760	$1,772,383	$3,718,143
	Sep	$409,138	$973,280	$1,382,418
	Oct	$749,413	$1,217,687	$1,967,100
	Nov	$335,976	$567,153	$903,129
	Dec	$383,864	$6,817	$2,356,842
Total		$12,156,637	$14,774,004	$28,896,802
2023	Jan	$219,632	$409,362	$628,995
	Feb	$304,776	$399,282	$704,058
	Mar	$606,703	$547,406	$1,154,109
Total		$1,131,111	$1,356,050	$2,487,162

Winter Storm Elliott

During emergency events, PJM has the authority to suspend all regulation assignments.[84] During such suspensions and for ten minutes after the end of the event, performance scores for regulating resources are not calculated.[85] PJM suspended regulation assignments during the evening peak on December 23, 2022, and on the morning of December 24, 2022.

During Elliott, PJM did not have enough MW available to clear and satisfy the regulation requirement of 800 MW for three hours on December 24, 2022 (0600-0800). The average hourly regulation requirement shortfall was 118.3 MW.

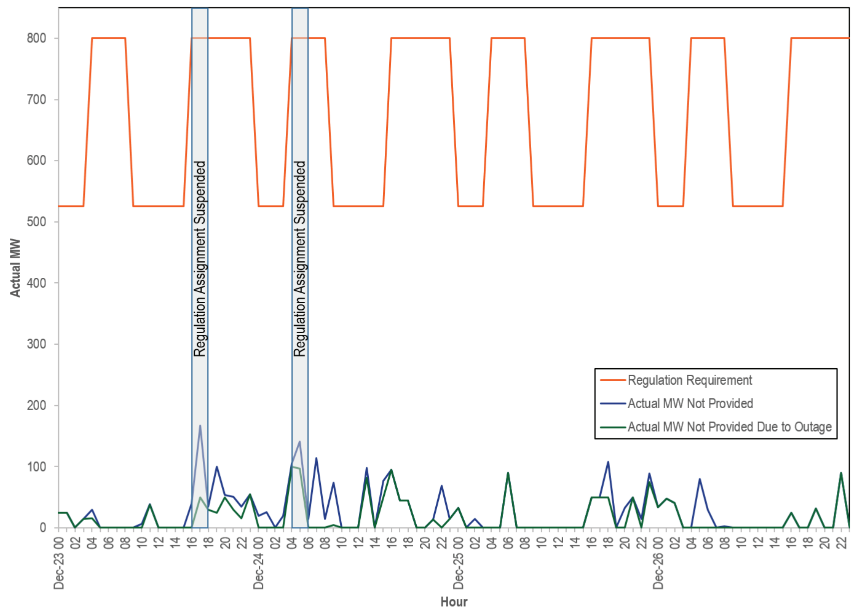
In addition, multiple units were committed for regulation in the hour ahead clearing, but did not provide regulation in real time. Figure 10-20 shows the amount of regulation actual MW that were committed, but did not provide

84 See "PJM Manual 13: Emergency Operations," § 2.3.2, Rev. 86 (Nov. 03, 2022).

85 See "PJM Manual 12: Balancing Operations," § 4.4.8, Rev. 47 (Oct. 01, 2022).

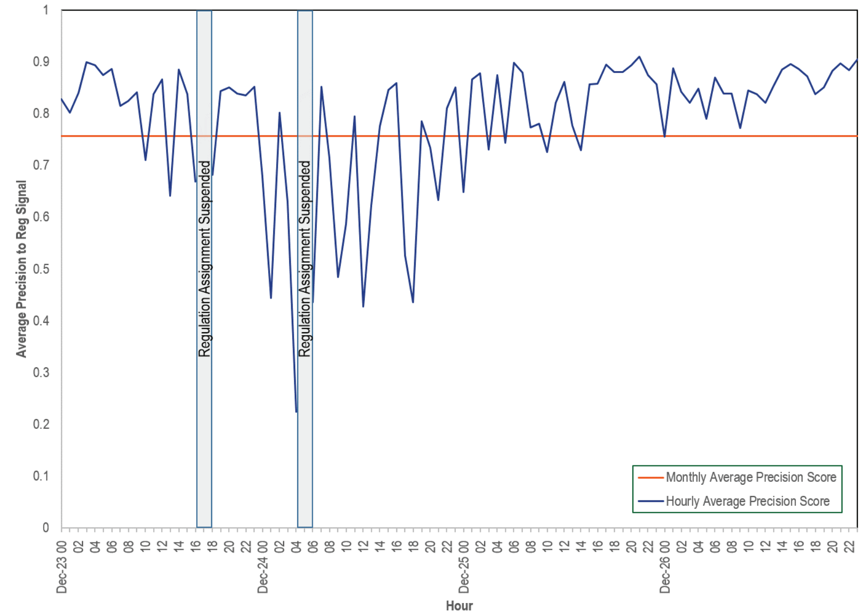
regulation in real time, and the committed MW that did not provide regulation due to an outage. An hourly average of 26.7 MW were committed but did not provide regulation from December 23 through December 26. Of the average shortfall, an average of 16.5 MW was the result of unit outages.

Figure 10-20 Committed regulation actual MW that dropped out of real time



Some battery units that provided regulation in this period were not able to sustain the output called for by PJM. Figure 10-21 shows the average hourly precision score of all battery units in operation, from December 23 through December 26, as well as the average precision score for the rest of the month (December 1 through December 22; December 27 through 31) of all battery units for December 2022.[86]

Figure 10-21 Average hourly and rest of month RegD precision score of battery units



The overall effect of Elliot on units in the regulation market can be seen in Figure 10-22, where the average precision score of each unit type during the event is compared to the average precision score during the rest of December 2022. With the exception of hydro units, all unit types had a drop in their average precision score as a result of outages during the event, being committed in the hour ahead clearing and then not providing regulation in real time, and/or sustained (pegged) signals the units could not maintain.

86 Flaws in the current performance score calculations allow two of the three components to remain high, even when the unit is performing poorly, or not at all. The precision component of the unit's response to the regulation signal is the best indicator of actual performance.

Table 10-35 Average precision score by unit type during Winter Storm Elliot and the rest of December 2022

	Average Precision Score		
Unit Type	Rest of Month (Dec. 1-22; 27-31)	Winter Storm Elliot (Dec. 23-26)	Percent Change
Battery	84.8%	80.5%	(4.3%)
Coal	56.2%	54.7%	(1.5%)
Hydro	85.9%	86.3%	0.4%
Natural Gas	75.3%	71.5%	(3.8%)
DR	70.9%	62.5%	(8.4%)

Market Structure

Supply

Table 10-36 shows average hourly offered MW (actual and effective), and average hourly cleared MW (actual and effective) for all hours in the first three months of 2023.[87] 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.[88] Eligible MW are calculated from the hourly offers from units with daily offers and units that are offered as unavailable for the day, but still offer MW into some hours. Units with daily offers are permitted to offer above or below their daily offer from hour to hour. As a result of these hourly MW adjustments, the average hourly Eligible MW can be higher than the Offered MW.

In the first three months of 2023, the average hourly offered supply of regulation for nonramp hours was 687.2 actual MW (709.1 effective MW). This was a decrease of 93.5 actual MW (a decrease of 70.9 effective MW) from the first three months of 2022, when the average hourly offered supply of regulation was 780.8 actual MW (780.0 effective MW). In the first three months of 2023, the average hourly offered supply of regulation for ramp hours was 1,043.4 actual MW (1,059.1 effective MW). This was a decrease of 103.8 actual MW (a decrease of 82.4 effective MW) from the first three months of 2022, when the average hourly offered supply of regulation was 1,147.2 actual MW (1,141.6 effective MW).[89] The decrease in the average hourly offered supply actual MW in both ramp and non ramp hours was primarily the result of reduced regulation offers from coal units (Table 10-38). Coal units provide RegA. The decrease in RegA supply resulted in more RegD MW clearing (effective MW greater than actual MW due to RegD MW being multiplied by the benefit factor). This drop in regulation supply from coal is consistent with the significant drop in energy supply from coal units. The energy output of coal units in the first three months of 2023 was down 40.1 percent compared to the first three months of 2022.[90]

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 three months of 2023 (1.67 in the first three months of 2022). The ratio of the average hourly offered supply of regulation to average hourly regulation demand (actual cleared MW) for ramp hours was 1.47 in the first three months of 2023 (1.58 in the first three months of 2022).

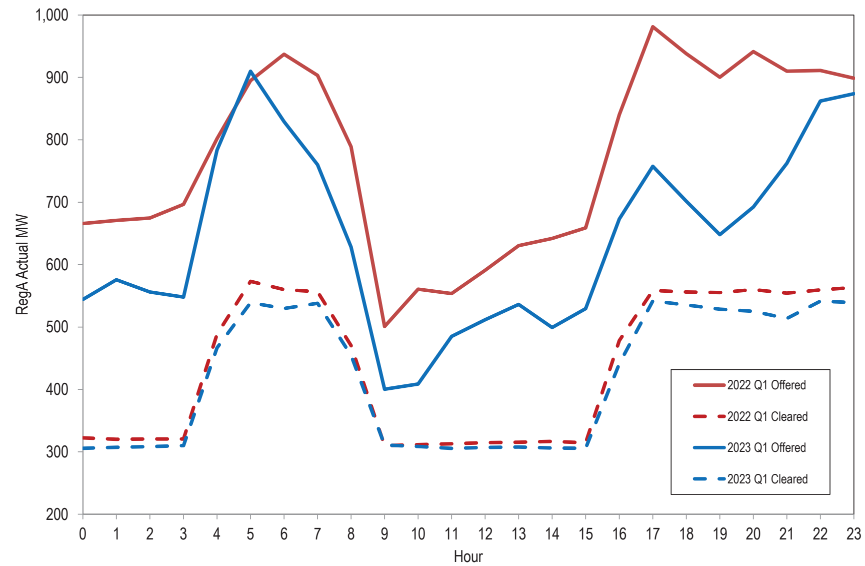
87 Unless otherwise noted, analysis provided in this section uses PJM market data based on PJM's internal calculations of effective MW values, based on PJM's currently incorrect MBF curve. The MMU is working with PJM to correct the MBF curve.
88 See "PJM Manual 11: Energy & Ancillary Services Market Operations," § 3.2.2 Regulation Market Eligibility, Rev. 124 (April 26, 2023).
89 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.
90 See Energy Production by Fuel Source in the 2023 State of the Market Report for PJM, Section 3: Energy Market, Table 3-53.

Table 10-36 Hourly average actual and effective MW offered and cleared: January through March, 2023[91]

			By Resource Type		By Signal Type	
		All Regulation	Generating Resources	Demand Resources	RegA Following Resources	RegD Following Resources
Actual Offered MW	Ramp	1,043.4	1,019.5	23.9	783.8	259.6
	Nonramp	687.2	666.8	20.5	509.0	178.3
Effective Offered MW	Ramp	1,059.1	1,027.1	32.0	681.4	377.7
	Nonramp	709.1	688.1	21.0	438.8	270.3
Actual Cleared MW	Ramp	709.5	685.7	23.7	531.8	177.7
	Nonramp	473.4	453.8	19.7	310.5	162.9
Effective Cleared MW	Ramp	800.1	768.1	31.9	467.9	332.1
	Nonramp	534.8	514.3	20.4	272.2	262.5

The average hourly offered and cleared actual MW from RegA resources are shown in Figure 10-22. The average hourly offered MW from RegA resources during ramp hours for the first three months of 2023 was 783.8 actual MW, a decrease of 15.0 percent from the first three months of 2022 (922.4 actual MW.) The average hourly offered MW from RegA resources during nonramp hours for the first three months of 2023 was 509.0 actual MW, a decrease of 17.8 percent from the first three months of 2022 (619.5 actual MW). The average hourly cleared MW from RegA resources during ramp hours for the first three months of 2023 was 531.8 actual MW, a decrease of 5.1 percent from the first three months of 2022 (560.6 actual MW). The average hourly cleared MW from RegA resources during nonramp hours for the first three months of 2023 was 310.5 actual MW, a decrease of 1.8 percent from the first three months of 2022 (316.2 actual MW).

Figure 10-22 Average hourly RegA actual MW offered and cleared: January through March, 2022 through 2023[92]



The average hourly offered MW from RegD resources during ramp hours for the first three months of 2023 was 259.6 actual MW, an increase of 15.4 percent from the first three months of 2022 (224.9 actual MW). (Figure 10-24) The average hourly offered MW from RegD resources during nonramp hours for the first three months of 2023 was 178.3 actual MW, an increase of 10.5 percent from the first three months of 2022 (161.3 actual MW) (Figure 10-23). The average hourly cleared MW from RegD resources during ramp hours for the first three months of 2023 was 177.7 actual MW, an increase of 8.5 percent from the first three months of 2022 (163.7 actual MW). The average hourly cleared MW from RegD resources during nonramp hours for the first three months of 2023 was 162.9 actual MW, an increase of 7.4 percent from the first three months of 2022 (151.6 actual MW).

91 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.

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

Figure 10-23 Average hourly RegD actual MW offered and cleared: January through March, 2022 through 2023[93]

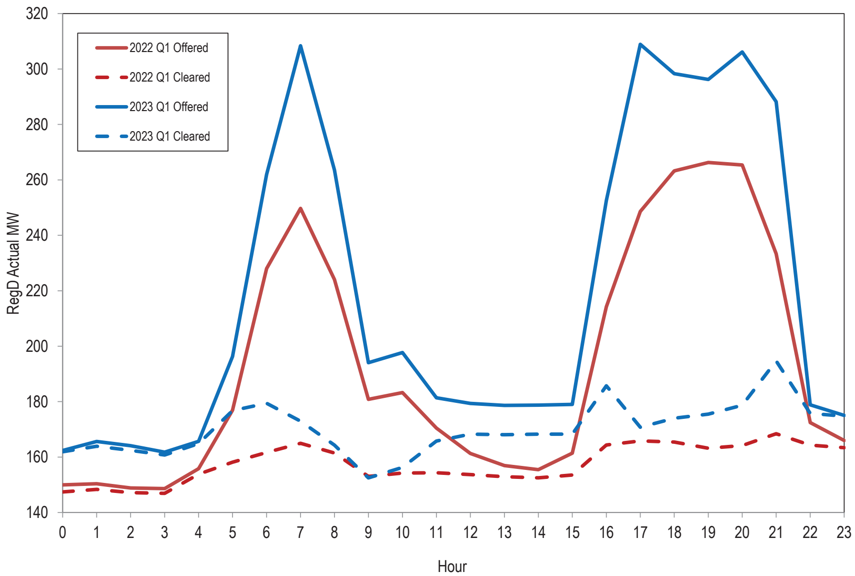


Table 10-37 provides the settled regulation MW by source unit type, the total settled regulation MW provided by all resources, the percent of settled regulation provided by unit type, and the clearing price, uplift, and total regulation credits. In Table 10-37 the MW have been adjusted by the performance score since this adjustment forms the basis of payment for units providing regulation. Total regulation performance adjusted settled MW decreased 0.1 percent from 1,119,076.7 MW in the first three months of 2022 to 1,118,113.7 MW in the first three months of 2023. The average proportion of regulation provided by hydro units increased the most, by 2.2 percent from the first three months of 2022 to the first three months of 2023. Coal units had the largest decrease in average proportion of regulation provided, decreasing 3.6 percent, from the first three months of 2022 to the first three months of 2023. The total regulation credits in the first three months of 2023 were $27,395,836, a decrease of 55.4 percent from $61,415,566 in the first three months of 2022. The decrease in regulation credits is due, in part, to a lower LOC component of regulation prices as a result of lower energy prices in the first three months of 2023 compared to the first three months of 2022.

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 ten units that received the most uplift in the first three months of 2023 are shown in Table 10-37.

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

Table 10-37 Top 10 recipients of regulation uplift credits: January through March, 2023

Rank	Parent Company	Unit Name	Fuel Type	Total Regulation Uplift Credit	Share of Total Regulation Uplift Credits
1	Dominion Energy Inc	VP BATH COUNTY 1-6 H	HYDRO	$1,176,238	21.2%
2	Constellation Energy Generation LLC	PE MUDDY RUN 1-8 H	HYDRO	$1,079,499	19.5%
3	American Electric Power Company Inc	AEP MOUNTAINEER 1 F	COAL	$680,660	12.3%
4	Ontario Power Generation Inc	AP LKLYN 1-4 H	HYDRO	$323,679	5.8%
5	American Municipal Power Inc	FE FREMONT ENERGY CENTER 3 CC	NATURAL GAS	$222,100	4.0%
6	Lotus Infrastructure Partners	PE PHILLIPS ISL LINWOOD 1 CC	NATURAL GAS	$115,275	2.1%
7	American Electric Power Company Inc	AEP AMOS 3 F	COAL	$112,253	2.0%
8	Vistra Energy Corp	COM 935 KENDALL 1 CC	NATURAL GAS	$105,817	1.9%
9	Vistra Energy Corp	COM 935 KENDALL 2 CC	NATURAL GAS	$104,072	1.9%
10	American Electric Power Company Inc	AEP MITCHELL - KAMMER 1 F	COAL	$87,419	1.6%
Total of Top 10				$4,007,011	72.3%
Total Regulation Uplift Credits				$5,545,489	100.0%

The uplift credits received for each unit type are shown in Table 10-38. The total uplift credits received increased 34.1 percent from $8,420,254 in the first three months of 2022 to $5,545,489 in the first three months of 2023. This decrease, like the decrease in total credits, is due in part to lower LOC components of regulation prices and offers as a result of lower energy prices in the first three months of 2023 compared to the first three months of 2022. Hydro units had the largest increase in uplift payments, increasing from $1,297,320 (15.4 percent of total uplift) in the first three months of 2022, to $2,706,801 (48.8 percent of total uplift) in the first three months of 2023.

Table 10-38 PJM regulation by source: January through March, 2022 and 2023[94]

Year	Source	Number of Units	Performance Adjusted Settled Regulation (MW)	Percent of Settled Regulation	Clearing Price Credits	Uplift Credits	Total Regulation Credits
2022	Battery	18	284,398	25.4%	$14,351,654	$0	$14,351,654
	Coal	17	70,382	6.3%	$4,175,594	$2,788,677	$6,964,272
	Hydro	24	243,166	21.7%	$12,588,992	$1,297,320	$13,886,312
	Natural Gas	113	499,599	44.6%	$20,797,332	$4,334,257	$25,131,589
	DR	23	21,532	1.9%	$1,081,740	$0	$1,081,740
Total		195	1,119,076.7	100.0%	$52,995,313	$8,420,254	$61,415,566
2023	Battery	18	288,053	25.8%	$6,284,068	$0	$6,284,068
	Coal	22	30,144	2.7%	$648,657	$1,180,484	$1,829,140
	Hydro	27	267,958	24.0%	$4,889,389	$2,706,801	$7,596,191
	Natural Gas	101	491,125	43.9%	$9,090,638	$1,658,204	$10,748,842
	DR	17	40,834	3.7%	$937,595	$0	$937,595
Total		185	1,118,113.7	100.0%	$21,850,346	$5,545,489	$27,395,836

94 Biomass data have been added to the natural gas category for confidentiality purposes.

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 10-39).

Table 10-39 Active battery storage projects by submitted year: 2014 through March 2023

Year	Number of Storage Projects	Total Capacity (MW)
2014	1	10.0
2015	4	41.0
2016	0	0.0
2017	1	2.0
2018	13	550.1
2019	55	3,609.4
2020	149	9,408.9
2021	309	23,762.1
2022	143	15,723.5
2023	17	1,325.0
Total	692	54,432.0

The supply of regulation can be affected by regulating units retiring from service. If all units that are requesting retirement through the first three months of 2023 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 10-27).

Table 10-40 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 474.7 hourly average performance adjusted actual MW in the first three months of 2023. This is an increase of 9.8 performance adjusted actual MW from the first three months of 2022, when the average hourly total regulation cleared performance adjusted actual MW for nonramp hours were 465.0 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 710.5 hourly average performance adjusted actual MW in the first three months of 2023. This is a decrease of 4.5 performance adjusted actual MW from the first three months of 2022, where the average hourly regulation cleared MW for ramp hours were 715.0 performance adjusted actual MW.[95]

95 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 three months of 2023 was 1.16.

Table 10-40 Required regulation and ratio of supply to requirement: January 2022 through March 2023

		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	2022	2023	2022	2023	2022	2023	2022	2023
Ramp	Jan	720.6	696.1	800.0	800.1	1.51	1.45	1.37	1.30
	Feb	729.4	715.5	800.0	800.0	1.71	1.48	1.52	1.34
	Mar	723.0	719.9	800.0	800.0	1.54	1.48	1.39	1.35
	Apr	729.3	-	800.0	-	1.47	-	1.34	-
	May	720.2	-	800.0	-	1.54	-	1.38	-
	Jun	714.4	-	800.0	-	1.60	-	1.44	-
	Jul	720.3	-	800.0	-	1.55	-	1.40	-
	Aug	710.9	-	800.0	-	1.60	-	1.43	-
	Sep	704.3	-	800.0	-	1.53	-	1.38	-
	Oct	703.3	-	800.0	-	1.45	-	1.32	-
	Nov	698.8	-	800.0	-	1.43	-	1.29	-
	Dec	705.2	-	798.5	-	1.49	-	1.33	-
Nonramp	Jan	467.4	466.3	525.0	525.3	1.62	1.44	1.45	1.32
	Feb	466.9	494.3	525.0	558.1	1.78	1.50	1.56	1.36
	Mar	468.8	463.6	525.1	525.0	1.63	1.43	1.46	1.31
	Apr	469.1	-	525.1	-	1.56	-	1.41	-
	May	461.5	-	525.3	-	1.60	-	1.43	-
	Jun	459.6	-	525.8	-	1.66	-	1.48	-
	Jul	459.9	-	525.1	-	1.64	-	1.47	-
	Aug	461.3	-	525.3	-	1.65	-	1.48	-
	Sep	465.0	-	525.2	-	1.59	-	1.43	-
	Oct	468.0	-	525.1	-	1.59	-	1.43	-
	Nov	463.5	-	525.5	-	1.52	-	1.38	-
	Dec	468.6	-	525.1	-	1.50	-	1.36	-

Market Concentration

In the first three months of 2023, the effective MW weighted average HHI of RegA resources was 2257 which is highly concentrated and the effective MW weighted average HHI of RegD resources was 1907 which is highly concentrated. The effective MW weighted average HHI of all resources was 1317, 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 10-41 includes a monthly summary of three pivotal supplier (TPS) results. In the first three months of 2022, the three pivotal supplier test was failed in 93.2 percent of hours. The MMU concludes that the PJM Regulation Market in the first three months of 2023 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 10-41 Regulation market monthly three pivotal supplier results: January 2021 through March 2023

	Percent of Hours Pivotal		
Month	2021	2022	2023
Jan	91.4%	94.5%	92.1%
Feb	88.7%	84.1%	91.6%
Mar	87.2%	90.1%	96.0%
Apr	88.5%	92.8%	
May	83.9%	91.4%	
Jun	86.4%	85.7%	
Jul	86.4%	88.2%	
Aug	76.3%	86.4%	
Sep	82.9%	86.1%	
Oct	91.9%	86.7%	
Nov	86.7%	91.0%	
Dec	80.1%	92.2%	
Average	85.9%	89.1%	93.2%

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.[96] 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.[97]

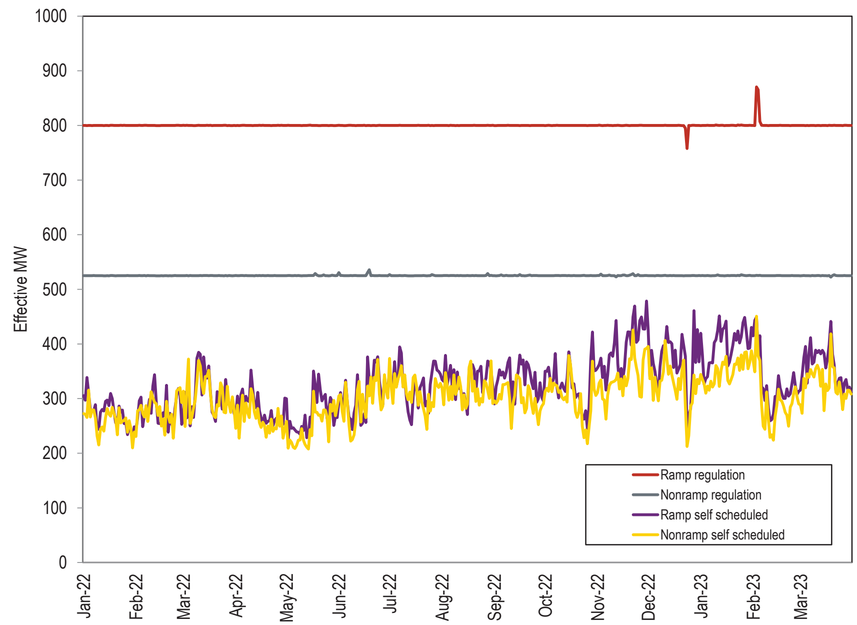
96 See "PJM Manual 11: Energy & Ancillary Services Market Operations," § 3.2.1 Regulation Market Eligibility, Rev. 124 (April 26, 2023).
97 Id. at 3.2.2, at p 62.

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.[98]

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 only one signal for a given operating hour. Resources have the option to submit a minimum level of regulation they are willing to provide.[99]

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 10-44).[100] Figure 10-24 compares average hourly regulation and self scheduled regulation during ramp and nonramp hours on an effective MW basis. Self scheduled regulation averaged 45.3 percent of all effective MW during ramp hours (35.9 percent in the first three months of 2022) and 61.2 percent of all effective MW during nonramp hours (53.5 percent in the first three months of 2022) in the first three months of 2023. Over all hours in the first three months of 2023, self scheduled regulation averaged 51.7 percent of all effective MW (42.9 percent in the first three months of 2022) (See Table 10-42). 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.[101]

Figure 10-24 Nonramp and ramp regulation levels: January 2022 through March 2023



98 See "PJM Manual 15: Cost Development Guidelines," § 7.8 Regulation Cost, Rev. 42 (Oct. 28, 2022).
99 See "PJM Manual 11: Energy & Ancillary Services Market Operations," § 3.2.1 Regulation Market Eligibility, Rev. 124 (April 26, 2023).
100 See "PJM Manual 28: Operating Agreement Accounting," § 4.1 Regulation Accounting Overview, Rev. 90 (Jan. 25, 2023).
101 See "PJM Manual 11: Energy & Ancillary Services Market Operations," § 3.2.1 Regulation Market Eligibility, Rev. 122 (Oct. 1, 2022).

Table 10-42 Total Effective MW and Self Scheduled Effective MW during ramp and non ramp hours: January through March, 2022 and 2023

Year		Effective MW	Self Scheduled Effective MW	Percent Effective MW
2022	Ramp	72,001.0	25,862.5	35.9%
	Non Ramp	47,252.8	25,266.7	53.5%
Total		119,253.9	51,129.3	42.9%
2023	Ramp	72,147.2	32,688.9	45.3%
	Non Ramp	47,261.1	29,282.0	62.0%
Total		119,408.3	61,970.8	51.9%

Table 10-43 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 44.4 percent of the total effective MW in March 2023) and a growing proportion of resources that self schedule (25.0 percent of all self scheduled effective MW in October 2012 and 53.0 percent of all self scheduled effective MW in March 2023). In the first three months of 2023, the average RegD percentage of total self scheduled effective MW was 55.9 percent, a decrease of 15.7 percentage points from the first three months of 2022, when the average was 71.6 percent.

Table 10-43 RegD self scheduled regulation by month: January 2022 through March 2023

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
2022	Jan	211.8	295.7	267.8	674.0	79.1%	43.9%
2022	Feb	193.7	285.2	278.7	674.0	69.5%	42.3%
2022	Mar	202.1	285.3	305.6	639.8	66.1%	44.6%
2022	Apr	191.5	274.9	270.0	639.6	70.9%	43.0%
2022	May	191.2	276.4	258.3	639.8	74.0%	43.2%
2022	Jun	201.5	296.7	302.4	697.2	66.6%	42.6%
2022	Jul	192.7	299.8	321.1	696.9	60.0%	43.0%
2022	Aug	205.6	308.3	328.0	697.0	62.7%	44.2%
2022	Sep	196.4	300.0	314.3	639.3	62.5%	46.9%
2022	Oct	207.5	307.4	312.0	640.0	66.5%	48.0%
2022	Nov	203.2	300.5	360.2	640.7	56.4%	46.9%
2022	Dec	225.1	307.7	349.4	673.2	64.4%	45.7%
2022 Average		201.9	294.8	305.6	662.6	66.6%	44.5%
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%
Average		192.2	296.9	343.7	666.8	55.9%	44.5%

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 10-44 shows monthly data for 2022 and 2023, and Table 10-44 shows annual data for the first three months of 2012 through the first three months of 2023. Table 10-44 and Table 10-45 are based on settled (purchased) MW.

Table 10-44 Regulation sources: spot market and self scheduled purchases: January 2022 through March 2023

Year	Month	Spot Market Regulation (Unadjusted MW)	Self Scheduled Regulation (Unadjusted MW)
2022	Jan	257,948.1	110,706.4
2022	Feb	220,778.9	113,317.3
2022	Mar	208,538.9	145,113.8
2022	Apr	215,631.5	116,433.1
2022	May	219,531.8	111,742.8
2022	Jun	217,223.5	134,779.2
2022	Jul	188,416.3	158,033.3
2022	Aug	193,928.6	158,307.5
2022	Sep	148,455.0	153,563.6
2022	Oct	196,730.2	152,760.3
2022	Nov	138,069.0	174,439.7
2022	Dec	183,940.9	172,713.5
	Total	2,389,192.7	1,701,910.6
2023	Jan	126,117.0	197,873.7
2023	Feb	183,580.7	144,902.8
2023	Mar	154,809.4	181,862.7
	Total	464,507.1	524,639.2

Table 10-45 Regulation sources: spot market and self scheduled: January through March, 2012 through 2023

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

In the first three months of 2023, DR provided an average of 23.7 MW of regulation per hour during ramp hours (13.5 MW of regulation per hour during ramp hours in the first three months of 2022), and an average of 19.7 MW of regulation per hour during nonramp hours (10.2 MW of regulation per hour during nonramp hours in the first three months of 2022). Generating units supplied an average of 685.7 MW of regulation per hour during ramp hours in the first three months of 2023 (710.8 MW of regulation per hour during ramp hours in the first three months of 2022), and an average of 453.8 MW per hour during nonramp hours in the first three months of 2023 (457.6 MW of regulation per hour during nonramp hours in the first three months of 2022).

Market Performance

Price

Table 10-46 shows the regulation price and regulation cost per MW for the first three months of 2009 through the first three months of 2023. The weighted average RMCP for the first three months of 2023 was $17.83 per MW. This is a decrease of $27.40 per MW, or 60.64 percent, from the weighted average RMCP of $45.24 per MW in the first three months of 2022. This decrease in the regulation clearing price was the result of a decrease in energy prices in the first three months of 2023 and the related increase in the opportunity cost component of RMCP.

Table 10-46 Comparison of average price and cost for regulation: January through March, 2009 through 2023

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

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 10-47 shows the effect of fast start pricing on the regulation market monthly capability component of price and the total regulation market clearing price from September 2021 through March 2023. In the first three months of 2023, fast start pricing increased the average regulation market clearing price by 3.3 percent compared to dispatch pricing.

Table 10-47 Comparison of fast start and dispatch pricing: September 2021 through March 2023[102]

		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%)
Yearly		$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%
Total		$16.30	$16.87	$17.27	$17.83	3.3%

Figure 10-25 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.

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

Figure 10-25 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 10-25 Regulation market clearing price components (Dollars per MW): January through March, 2023

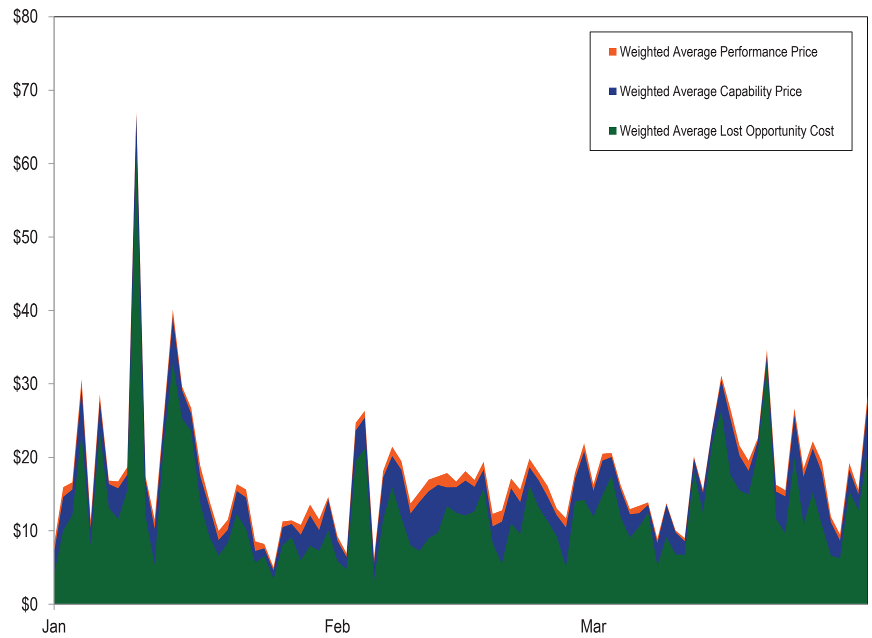


Table 10-48 shows the capability and performance components of the monthly average regulation prices. These components differ from the components of the marginal unit's offers in Figure 10-26 because the performance component of the settlement price for each hour is determined from the average of the highest performance offers in each five minute interval, calculated independent of the marginal unit's offers in those intervals.

Table 10-48 Regulation market monthly component of price (Dollars per MW): January through March, 2023

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	$17.25	$0.97	$18.22
Feb	$15.48	$1.17	$16.65
Mar	$17.80	$0.77	$18.57
Average	$16.87	$0.97	$17.83

Monthly and total annual scheduled regulation MW and regulation charges, as well as monthly average regulation price and regulation cost are shown in Table 10-49. Total scheduled regulation is based on settled performance adjusted MW. The total of all regulation charges in the first three months of 2023 was $27,446,107 million, compared to $61,421,382 million in the first three months of 2022.

Table 10-49 Total regulation charges: January 2022 through March 2023

Year	Month	Scheduled Regulation (MW)	Total Regulation Charges ($)	Weighted Average Regulation Market Price ($/MW)	Cost of Regulation ($/MW)	Price as Percent of Cost
2022	Jan	384,969.5	$34,046,042	$72.56	$88.44	82.1%
2022	Feb	349,755.8	$14,317,381	$33.53	$40.94	81.9%
2022	Mar	367,002.2	$13,057,959	$27.73	$35.58	77.9%
2022	Apr	355,900.6	$23,257,413	$51.27	$65.35	78.5%
2022	May	360,870.6	$19,641,413	$43.60	$54.43	80.1%
2022	Jun	384,946.7	$25,593,008	$54.48	$66.48	82.0%
2022	Jul	396,606.5	$28,295,746	$56.04	$71.34	78.5%
2022	Aug	391,060.2	$32,350,728	$65.87	$82.73	79.6%
2022	Sep	346,887.7	$21,260,643	$50.73	$61.29	82.8%
2022	Oct	377,096.5	$19,140,156	$38.70	$50.76	76.3%
2022	Nov	352,936.7	$11,434,507	$24.21	$32.40	74.7%
2022	Dec	396,206.2	$53,758,750	$113.81	$135.68	83.9%
Yearly		4,550,354.2	$296,241,818	$53.53	$65.10	82.2%
2023	Jan	393,338.7	$9,812,256	$18.22	$24.95	73.0%
2023	Feb	362,742.5	$8,127,171	$16.65	$22.40	74.3%
2023	Mar	378,020.0	$9,506,681	$18.57	$25.15	73.9%
Total		1,134,101.3	$27,446,107	$17.83	$24.20	73.7%

The capability, performance, and opportunity cost components of the cost of regulation are shown in Table 10-50. Total scheduled regulation is based on settled performance adjusted MW. In the first three months of 2023, the average total cost of regulation was $24.20 per MW, 55.8 percent lower than $54.76 in the first three months of 2022. In the first three months of 2023, the monthly average capability component cost of regulation was $16.86, 61.3 percent lower than $43.54 in the first three months of 2022. In the first three months of 2023, the monthly average performance component cost of regulation was $2.40, 35.1 percent lower than $3.71 in the first three months of 2022. The decrease of the average total cost in the first three months of 2023 versus the first three months of 2022, was primarily a result of lower LOC values due to higher prices in the energy market.

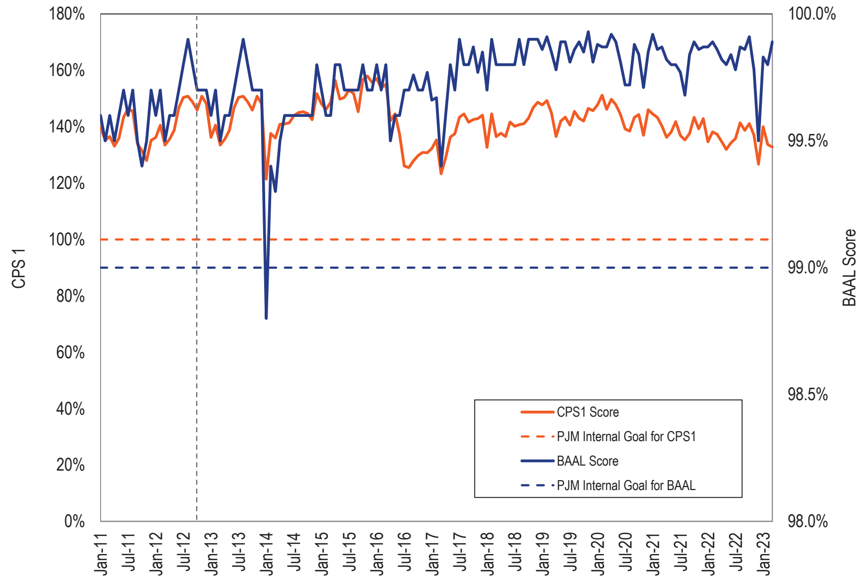
Table 10-50 Components of regulation cost: January 2022 through March 2023

Year	Month	Scheduled Regulation (MW)	Cost of Regulation Capability ($/MW)	Cost of Regulation Performance ($/MW)	Opportunity Cost ($/MW)	Total Cost ($/MW)
2022	Jan	384,969.5	$72.12	$3.22	$13.10	$88.44
	Feb	349,755.8	$32.50	$3.77	$4.66	$40.94
	Mar	367,002.2	$26.45	$4.35	$4.78	$35.58
	Apr	355,900.6	$49.80	$5.67	$9.88	$65.35
	May	360,870.6	$43.22	$4.19	$7.02	$54.43
	Jun	384,946.7	$53.72	$4.38	$8.38	$66.48
	Jul	396,606.5	$56.22	$3.59	$11.53	$71.34
	Aug	391,060.2	$66.80	$4.32	$11.61	$82.73
	Sep	346,887.7	$51.27	$4.87	$5.16	$61.29
	Oct	377,096.5	$36.74	$4.84	$9.18	$50.76
	Nov	352,936.7	$23.08	$2.86	$6.46	$32.40
	Dec	396,206.2	$112.30	$3.06	$20.33	$135.68
Yearly		4,550,354.2	$51.78	$4.00	$9.32	$65.10
2023	Jan	393,338.7	$17.27	$2.44	$5.24	$24.95
	Feb	362,742.5	$15.48	$2.89	$4.04	$22.40
	Mar	378,020.0	$17.77	$1.90	$5.48	$25.15
Total		1,134,101.3	$16.86	$2.40	$4.93	$24.20

Performance Standards

PJM's performance as measured by CPS1 and BAAL standards is shown in Figure 10-26 for every month from January 2011 through March 2023 with the dashed vertical line marking the date (October 1, 2012) of the implementation of the Performance Based Regulation Market design.[103] The horizontal dashed lines represent PJM internal goals for CPS1 and BAAL performance.

Figure 10-26 Monthly CPS1 and BAAL performance: January 2011 through March 2023



103 See *2019 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).[104] 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.[105] 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.[106] Under the current rules PJM has substantial flexibility in procuring black start resources and is responsible for black start resource selection.[107] 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.

104 OATT Schedule 1 § 1.3BB.
105 *See* OATT Schedule 6A para. 18.
106 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.").
107 *See* Docket No. ER13-1911-000.

On April 7, 2021, PJM issued an incremental RFP for additional 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 is June 2024. On August 1, 2022, PJM issued an incremental RFP for additional black start service in the PECO Zone. PJM plans to make a decision by the end of June 2023.[108]

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.[109]

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.[110] 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.[111] 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.

108 RFPs issued can be found on the PJM website. See PJM. <http://www.pjm.com/markets-and-operations/ancillary-services.aspx>.
109 *See* OATT Schedule 6A para. 18.
110 There are no black start units currently using the ALR option.
111 OATT Schedule 6A (paras. 25, 26 and 27 outline how charges are to be applied).

In the first three months of 2023, total black start charges were $16.6 million, a decrease of $0.945 million (5.4 percent) from 2022. In the first three months of 2023, total revenue requirement charges were $16.48 million, a decrease of $0.929 million (5.33 percent) from 2022. In the first three months of 2023, total uplift charges were $0.109 million, a decrease of $0.016 million (12.97 percent) from 2022. Table 10-51 shows total charges for each year from 2010 through 2023.[112]

Table 10-51 Black start revenue requirement charges: January through March, 2010 through 2023

Jan-Mar	Revenue Requirement Charges	Uplift Charges	Total
2010	$2,673,689	$0	$2,673,689
2011	$2,793,709	$0	$2,793,709
2012	$3,864,301	$0	$3,864,301
2013	$5,412,855	$22,210,646	$27,623,501
2014	$5,104,104	$7,561,533	$12,665,637
2015	$10,276,712	$4,699,965	$14,976,676
2016	$16,677,315	$57,082	$16,734,396
2017	$17,731,836	$63,384	$17,795,220
2018	$16,840,283	$23,309	$16,863,592
2019	$15,938,101	$36,188	$15,974,289
2020	$15,944,660	$40,587	$15,985,247
2021	$16,483,246	$86,695	$16,569,941
2022	$17,408,156	$125,306	$17,533,462
2023	$16,479,646	$109,056	$16,588,702

Black start zonal charges in 2023 ranged from $0 in the OVEC and REC Zones to $4,821,152 in the AEP Zone. For each zone, Table 10-52 shows black start charges, zonal peak loads, and black start rates (calculated as charges per MW-day).[113] [114] Customers paid an average of $1.10 per MW-day for black start service in 2022.

112 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.
113 See "PJM Manual 27: Open Access Transmission Tariff Accounting,"§ 7.3 Black Start Service Charges, Rev. 97 (Feb. 1, 2023).
114 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 10-52 Black start zonal charges: January through March, 2022 and 2023[115]

	Jan-Mar 2022					Jan-Mar 2023				
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	$499,119	$0	$499,119	2,631	$2.11	$481,828	$0	$481,828	2,614	$2.05
AEP	$4,884,320	$0	$4,884,320	21,925	$2.48	$4,820,407	$745	$4,821,152	21,717	$2.47
APS	$1,611,837	$3,755	$1,615,592	8,865	$2.02	$1,614,258	$792	$1,615,050	9,154	$1.96
ATSI	$1,376,245	$0	$1,376,245	12,604	$1.21	$1,384,503	$8,976	$1,393,479	12,771	$1.21
BGE	$10,339	$0	$10,339	6,486	$0.02	$8,602	$0	$8,602	6,520	$0.01
COMED	$2,342,398	$3,773	$2,346,170	21,167	$1.23	$2,191,967	$35,761	$2,227,728	21,262	$1.16
DAY	$60,173	$24,487	$84,660	3,330	$0.28	$46,116	$28,039	$74,155	3,362	$0.25
DUKE	$98,924	$14,831	$113,755	5,306	$0.24	$61,956	$2,188	$64,144	5,166	$0.14
DUQ	$256,407	$0	$256,407	2,759	$1.03	$253,233	$0	$253,233	2,715	$1.04
DOM	$1,291,854	$67,128	$1,358,982	20,405	$0.74	$978,415	$19,368	$997,783	21,156	$0.52
DPL	$313,377	$1,609	$314,987	4,006	$0.87	$283,316	$0	$283,316	4,125	$0.76
EKPC	$85,168	$0	$85,168	2,851	$0.33	$66,151	$0	$66,151	2,994	$0.25
JCPLC	$149,542	$0	$149,542	6,169	$0.27	$127,626	$0	$127,626	6,123	$0.23
MEC	$140,901	$0	$140,901	3,072	$0.51	$87,866	$4,866	$92,732	3,021	$0.34
OVEC	$0	$0	$0	NA	NA	$0	$0	$0	NA	NA
PECO	$365,311	$1,651	$366,962	8,479	$0.48	$312,720	$1,399	$314,119	8,583	$0.41
PE	$1,089,932	$0	$1,089,932	2,900	$4.18	$1,062,363	$0	$1,062,363	2,830	$4.17
PEPCO	$83,724	$0	$83,724	5,829	$0.16	$43,281	$0	$43,281	5,834	$0.08
PPL	$1,213,849	$401	$1,214,250	7,517	$1.79	$1,214,124	$226	$1,214,350	7,489	$1.80
PSEG	$446,680	$0	$446,680	10,064	$0.49	$396,267	$0	$396,267	10,147	$0.43
REC	$0	$0	$0	NA	NA	$0	$0	$0	NA	NA
(Imp/Exp/Wheels)	$1,088,054	$7,672	$1,095,726	10,417	$1.17	$1,044,647	$6,695	$1,051,343	10,635	$1.10
Total	$17,408,156	$125,306	$17,533,462	166,781	$1.17	$16,479,646	$109,056	$16,588,702	168,218	$1.10

115 Peak load for each zone is used to calculate the black start rate per MW day.

Table 10-53 provides a revenue requirement estimate by zone for the 2022/2023, 2023/2024, and 2024/2025 Delivery Years.[116] 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.

Table 10-53 Black start zonal revenue requirement estimate: 2022/2023 through 2024/2025 Delivery Years[117]

Zone	2022 / 2023 Revenue Requirement	2023 / 2024 Revenue Requirement	2024 / 2025 Revenue Requirement
ACEC	$2,100,000	$2,100,000	$2,100,000
AEP	$20,600,000	$20,700,000	$15,800,000
APS	$6,950,000	$6,950,000	$6,950,000
ATSI	$5,950,000	$5,950,000	$3,950,000
BGE	$50,000	$350,000	$3,500,000
COMED	$9,400,000	$9,650,000	$9,650,000
DAY	$250,000	$250,000	$250,000
DUKE	$350,000	$400,000	$400,000
DUQ	$1,100,000	$1,100,000	$1,100,000
DOM	$5,250,000	$5,350,000	$5,350,000
DPL	$1,250,000	$1,350,000	$1,350,000
EKPC	$300,000	$350,000	$350,000
JCPLC	$550,000	$650,000	$650,000
MEC	$500,000	$550,000	$550,000
OVEC	$0	$0	$0
PECO	$1,400,000	$1,550,000	$1,550,000
PE	$4,550,000	$4,650,000	$4,650,000
PEPCO	$250,000	$650,000	$5,550,000
PPL	$5,250,000	$5,300,000	$5,300,000
PSEG	$1,750,000	$1,800,000	$1,800,000
REC	$0	$0	$0
Total	$67,800,000	$69,650,000	$70,800,000

116 The System Restoration Strategy Task Force requested that the MMU provide estimated black start revenue requirements.

117 The 2024/2025 estimated revenue requirement is based on the CONE values for the 2023/2024 RPM Base Residual Auction because the 2024/2025 RPM Base Residual Auction has not been run.

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.[118] 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.[119] 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.[120] 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.

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

119 *Id.*

120 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.

The U.S. Internal Revenue Code changed significantly in December 2017.[121] The PJM CRF table did not change to reflect these changes.[122] [123] As a result, CRF values have overcompensated black start units since the changes to the tax code. The new tax law allow 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 be 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.

On April 7, 2021, PJM filed with FERC to update the CRF values for new black start service units.[124] 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.[125] 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.[126] [127] 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.[128] 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."[129] The MMU requested rehearing over the Commission's conclusion that the MMU had requested "retroactive changes to the rates previously paid to generators."[130] [131] The request for rehearing was denied.[132] 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.[133]

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."[134] [135] The MMU responded with analysis showing that PJM's proposal for maintaining the outdated CRF values would result in $126 million of over recovery of black start capital investments.[136] Table 10-54 shows the over recovery of capital payments by resources awarded black start service prior to Jun 6, 2021 as result of PJM's continued application of the old CRF rate.

Table 10-54 CRF over recovery if CRF not corrected for changes in tax laws[137]

	Excess Payback ($ millions)	Percent
Began black start service prior to the effective date of the TCJA	$36.0	28.4%
Began black start service on or after the effective date of the TCJA	$90.7	71.6%
Total	$126.8	

The MMU also 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, pays a return at

121 Tax Cuts and Jobs Act, Pub. L. No. 115-97, 131 Stat. 2096, Stat. 2105 (2017)
122 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.
123 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).
124 *See* Docket No. ER21-1635-000.
125 See Comments of the Independent Market Monitor for PJM, FERC Docket No. ER21-1635-000 (April 28, 2021), which can be accessed at <http://www.monitoringanalytics.com/filings/2021/IMM_Comments_Docket_No_ER21-1635_20210428.pdf>.
126 Answer and Motion for Leave to Answer of the independent Market Monitor for PJM, ER21-1635 (May 20, 2021).
127 Comments of the Independent Market Monitor for PJM, FERC Docket No. ER21-1635 (July 2, 2021).
128 176 FERC ¶ 61,080 at 42 and 44 (2021).
129 176 FERC ¶ 61,080 at 2 (2021).
130 Id. at 50.
131 Request for Rehearing of the Independent Market Monitor for PJM, FERC Docket No. ER21-1635 (September 9, 2021).
132 177 FERC ¶ 62,017 (2021).
133 177 FERC ¶ 61,202 (2021).
134 *PJM Interconnection, L.L.C., Response to Commission's Show Cause Order*, Docket No. EL21-91 (October 12, 2021).
135 August 10th Oder at 47.
136 Errata Filing of the Independent Market Monitor for PJM, Attachment B at 17, Docket No. EL21-91 (November 18, 2022).
137 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.

the required rates on the remaining capital investment, pays back the full investment 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.[138]

In an order on March 24, 2023, FERC "set for hearing and settlement judge procedures the determination of whether, as a result of changes from the TCJA, the existing CRF values result in a Capital Cost Recovery Rate for generating units that were selected to provide Black Start Service prior to June 6, 2021 that is unjust and unreasonable."[139]

NERC – CIP

No black start units have requested new or additional black start NERC – CIP Capital Costs.[140]

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.[141] In a 2023 MISO case, the Commission affirmed that RTOs and their customers are not required to compensate generation resources for such reactive capability.[142] Customers in PJM, nevertheless, pay $384.0 million in nonmarket costs for reactive capability based on a nonmarket view of cost allocation.

Compensation for reactive capability is approved separately for each resource or resource group by FERC per Schedule 2 of the OATT.[143] Reactive capability charges are based on FERC approved filings for individual unit revenue requirements that are typically black box settlements.[144] Reactive service charges 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.[145]

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.[146] [147]

In 2016, FERC began to reexamine its policies on reactive compensation.[148] On November 18, 2021, the FERC issued a notice of inquiry (NOI) concerning reactive power capability compensation.[149] The Market Monitor responded to the NOI.[150] The Commission's finding in the 2023 MISO case affirms that RTOs and their customers are not required to compensate generation resources for reactive capability.[151] Although this policy had been the practice in CAISO

138 Id. (Attachment B, Section H at 18).
139 182 FERC ¶ 61,194 at 32.
140 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."
141 OATT Attachment O.
142 *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).
143 See "PJM Manual 27: Open Access Transmission Tariff Accounting,"§ 3.2 Reactive Supply and Voltage Control Credits, Rev. 97 (Feb. 1, 2023).
144 OATT Schedule 2.
145 See OA Schedule 1 § 3.2.3B.
146 OATT Schedule 2.
147 See "PJM Manual 27: Open Access Transmission Tariff Accounting,"§ 3.3 Reactive Supply and Voltage Control Charges, Rev. 97 (Feb. 1, 2023).
148 See *Reactive Supply Compensation in Markets Operated by Regional Transmission Organizations and Independent System Operators*, Docket No. AD16-17-000 (March 17, 2016) (Notice of Workshop).
149 *Reactive Power Capability Compensation*, 177 FERC ¶ 61,118 (2021).
150 See Comments of the Independent Market Monitor for PJM, Docket No. RM22-2-000 (February 22, 2022); Reply Comments of the Independent Market Monitor for PJM, Docket No. RM22-2-000 (March 23, 2022); see also Comments of the Independent Market Monitor for PJM, Docket No. AD16-17-000 (July 29, 2016).
151 *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).

and SPP, MISO shows that an RTO can remove compensation for reactive capability from its market rules.[152]

Issues with Reactive Capability Market Design

The NOI inquires about reactive power capability compensation under the *AEP* Method, alternative methods of compensation, and resources interconnected at the distribution level. The fundamental question 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.[153] 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.

152 See *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); CAISO, 119 FERC ¶ 61,199 at P 28 (2007), *order on reh'g*, 121 FERC ¶ 61,196 (2007); *see also* SPP, 178 FERC ¶ 61,088, at PP 29–31 (2022); 179 FERC ¶ 61,103, at PP 20-21 (2022)

153 Attachment O.

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.[154]

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 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 and 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.

154 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.

The NOI presents an opportunity to address the reactive issue using a market based approach. The best approach would be to issue a rule eliminating cost of service rates for reactive capability and allowing for recovery of capacity costs through existing markets, including a removal of any offset for reactive revenue in offers and in the capacity market demand (VRR) curve. A second best approach would be to limit the revenue requirement that could be filed for under the OATT Schedule 2 to a level less than or equal to the reactive revenue credit included in the capacity market design, in the VRR curve Net CONE value, currently $2,199 per MW-year.

As with all things in PJM markets, it is easy to focus on extreme complexity and lose sight of the big picture. The complexity includes power factors and power factor testing and convoluted and arbitrary allocation factors. The big picture here is that in PJM, the interrelated and self sustaining markets 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 existence of the current option creates 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.

The best and straightforward solution is to remove revenue requirements for reactive supply capability and to remove the offset. 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 $13,044 to $964 per MW-year. (See Table 10-58)

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.[155] 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 offers based on net avoidable costs must account for revenues received through cost of service reactive capability rates in the calculation.[156] 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

155 *See* OATT Attachment DD § 5.10(a)(v)(A).
156 OATT Attachment DD § 6.8(d).

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. In a number of cases now pending, the Market Monitor has challenged the eligibility of resources filing under OATT Schedule 2 because they are interconnected to facilities that PJM does not monitor and does not rely on to provide reactive capability.[157]

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.

The best place to understand PJM's role regarding the Lines is in the Designated Facilities List contained in the PJM manual on Transmission Operations referenced in the definition of Transmission Provider. PJM Manual 3 (Transmission Operations) sets forth the criteria for determining Monitored Transmission Facilities and the criteria for determining Reportable Transmission Facilities. PJM explains that "Monitored Transmission Facilities are monitored and controlled for limit violations using PJM's Security Analysis programs."[158] PJM explains that transmission facilities are "reportable if a change of its status can affect, or has the potential to affect, a transmission constraint on any Monitored Transmission Facility," or "if it impedes the free-flowing ties within the PJM RTO and/or adjacent areas."[159] The Monitored and Reportable Transmission Facilities are included in the Transmission Facilities List. The Transmission Facilities List is located on the PJM website.

PJM's criteria for defining Monitored Transmission Facilities and the criteria for defining Reportable Transmission Facilities determine which power lines constitute the PJM transmission system and which do not.

A resource interconnected on power lines that fail to meet the criteria defining Monitored Transmission Facilities *and* the criteria for defining Reportable Transmission Facilities are not interconnected to PJM's transmission facilities. PJM is not the Transmission Provider for such power lines. PJM does not directly rely on resources to provide Reactive Supply and Voltage Control Service, and they are therefore ineligible for compensation under Schedule 2.[160]

In an initial decision issued July 15, 2022, the first decision addressing the issue, the Presiding Judge found: "Schedule 2 contains two eligibility criteria for generation facilities: (1) that the facility must be under the control of PJM, and (2) that the 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."[161] The Judge determined that none of the facilities in the four cases at hearing "satisfy the second criterion."[162] In the initial decision, the Presiding Judge did not accept the MMU's theory of the case on eligibility, but the initial decision found that power flow evidence could not use off system reactive capability to support voltage levels on the transmission system.[163] The initial decision provides a reasonable resolution to the eligibility issue. The principal advantage of

157 See, e.g., FERC Docket Nos. ER21-2091, ER21-936, ER21-737, ER20-1863 & ER20-1851.

158 See PJM Manual 03: Transmission Operations, Rev. 63 (Nov. 16, 2022).

159 See PJM, PJM Transmission Providers Facilities List On-Line Help (Last Updated: May 4, 2017), which can be accessed at: <trans-fac-help.ashx (pjm.com)>.

160 A facility that does not meet the criteria defining Reportable Transmission Facilities but does meet the criteria for defining Monitored Transmission Facilities is also not eligible under Schedule 2. If PJM does not operate the Lines, they are not PJM's transmission facilities. There is no evidence that PJM would rely on a resource to provide Reactive Supply and Voltage Control Service if the resource was located on a portion of the grid that PJM was monitoring but not operating. Coordination with the responsible operator would still be needed.

161 See 180 FERC ¶ 63,009 at P 5 (2022).

162 *Id.*

163 *Id.*

the MMU's approach is that it provides for a general finding that PJM lacks capability to rely on off system resources for reactive capability based on the information available to PJM dispatchers regardless of what power flow analyses show. The issue will be decided by the Commission.

The issue of eligibility is significant because the number of facilities interconnecting at points that are not on the PJM system is expected to increase. 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.[164] These payments are for services not provided, but also 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 and 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.[165] 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.[166] 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.[167]

Table 10-55 identifies fleet rates currently effective in PJM.

Table 10-55 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

164 See 80 FERC ¶ 63,006 (1997), *aff'd*, 88 FERC ¶ 61,141 (1999).
165 See, e.g., OATT Schedule 2; 114 FERC ¶ 61,318 (2006).
166 See 149 FERC ¶ 61,132 (2014); 151 FERC ¶ 61,224 (2015); OATT Schedule 2.
167 *Id.*

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.[168] But PJM rules require fleet owners only to submit informational filings when a reactive unit is transferred or deactivated.[169] The current rules do not require a rate filing, which would place the burden of proof on the company and allow for cost review.[170]

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.[171] 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.[172] 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.[173]

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 three months of 2023, total reactive charges were $96.3 million, an increase of $0.5 million (0.5 percent) from 2022. In the first three months of 2023, total reactive capability charges were $96.3 million, an increase of $0.7 million (0.8 percent) from 2022. In the first three months of 2023, total reactive service charges were $0.0 million, a decrease of $0.2 million (100.0 percent) from 2022.

168 151 FERC ¶ 61,224 at P 29 (2015).
169 OATT Schedule 2.
170 *Id.*
171 *See* Letter Opposing Settlement, Docket No ER06-554 et al. (June 14, 2017).
172 *Id.*
173 162 FERC ¶ 61,029 (2018).

Table 10-56 shows reactive service charges for the first three months of each year from 2010 through 2023.

Table 10-56 Reactive service charges and reactive capability charges: January through March, 2010 through 2023

Jan-Mar	Reactive Service Charges	Reactive Capability Charges	Total
2010	$1,462,979	$60,140,250	$61,603,229
2011	$7,901,985	$61,525,380	$69,427,366
2012	$22,774,605	$68,171,375	$90,945,980
2013	$55,579,356	$68,330,702	$123,910,058
2014	$7,589,161	$70,631,766	$78,220,927
2015	$6,330,318	$69,482,495	$75,812,813
2016	$250,496	$72,742,919	$72,993,415
2017	$5,872,960	$75,383,924	$81,256,884
2018	$6,054,364	$74,884,662	$80,939,026
2019	$124,821	$80,560,451	$80,685,272
2020	$45,745	$85,367,740	$85,413,485
2021	$705,618	$89,263,898	$89,969,516
2022	$231,202	$95,529,569	$95,760,770
2023	$0	$96,254,033	$96,254,033

Table 10-57 shows zonal reactive service charges for 2022 and 2023, 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 10-57 Reactive service charges and reactive capability charges by zone: January through March, 2022 and 2023

	Jan-Mar 2022			Jan-Mar 2023		
Zone	Reactive Service Charges	Reactive Capability Charges	Total Charges	Reactive Service Charges	Reactive Capability Charges	Total Charges
ACEC	$0	$1,057,110	$1,057,110	$0	$729,962	$729,962
AEP	$0	$12,248,882	$12,248,882	$0	$13,367,105	$13,367,105
APS	$0	$5,430,477	$5,430,477	$0	$5,619,367	$5,619,367
ATSI	$0	$7,693,246	$7,693,246	$0	$7,155,544	$7,155,544
BGE	$0	$1,635,182	$1,635,182	$0	$1,633,896	$1,633,896
COMED	$0	$10,345,046	$10,345,046	$0	$11,481,877	$11,481,877
DAY	$0	$693,467	$693,467	$0	$692,922	$692,922
DUKE	$0	$2,629,533	$2,629,533	$0	$1,969,123	$1,969,123
DOM	$225,700	$12,300,517	$12,526,217	$0	$13,274,101	$13,274,101
DPL	$5,502	$2,553,565	$2,559,067	$0	$2,375,054	$2,375,054
DUQ	$0	$140,537	$140,537	$0	$20,408	$20,408
EKPC	$0	$536,908	$536,908	$0	$536,485	$536,485
JCPLC	$0	$1,856,165	$1,856,165	$0	$2,047,068	$2,047,068
MEC	$0	$1,489,735	$1,489,735	$0	$1,488,564	$1,488,564
OVEC	$0	$0	$0	$0	$0	$0
PECO	$0	$4,958,443	$4,958,443	$0	$5,242,037	$5,242,037
PE	$0	$4,306,240	$4,306,240	$0	$4,302,853	$4,302,853
PEPCO	$0	$2,630,930	$2,630,930	$0	$2,182,354	$2,182,354
PPL	$0	$9,056,346	$9,056,346	$0	$9,021,376	$9,021,376
PSEG	$0	$7,713,084	$7,713,084	$0	$6,738,988	$6,738,988
REC	$0	$0	$0	$0	$0	$0
(Imp/Exp/Wheels)	$0	$6,254,156	$6,254,156	$0	$6,374,949	$6,374,949
Total	$231,202	$95,529,569	$95,760,770	$0	$96,254,033	$96,254,033

Table 10-58 shows the units which received reactive service credits in the first three months of 2023. In the first three months of 2023 there were no reactive service credits.

Table 10-58 Reactive service credits by plant (Total dollars): January through March, 2023

	Jan-Mar 2023	
Zone	Plant	Reactive Service Credits
	None	$0
Total		$0

Table 10-59 shows the settled reactive capability revenue requirements by technology effective on March 1, 2023.[174] 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 10-59 Total settled reactive revenue requirements by unit type and fuel type: March 1, 2023

Unit Type	Fuel Type	Total Revenue Requirement per Year	MW	Number of Resources	Requirement per MW-year
CC	Gas	$123,835,318.40	49,428.4	155	$2,505.35
CT	Gas	$45,501,159.43	28,273.7	247	$1,609.31
CT	Oil	$4,618,995.17	3,239.4	111	$1,425.88
Diesel	Gas	$1,380,092.00	105.8	5	$13,044.35
Diesel	Oil	$1,029,458.66	168.1	36	$6,124.08
Diesel	Other - Gas	$914,468.84	114.6	11	$7,979.66
FC	Gas	$45,000.00	2.6	1	$17,307.69
Hydro	Water	$17,816,173.03	6,890.4	52	$2,585.65
Nuclear	Nuclear	$57,524,969.57	32,607.3	31	$1,764.17
Solar	Solar	$3,409,893.89	424.1	15	$8,040.31
Steam	Coal	$53,331,122.69	41,201.1	67	$1,294.41
Steam	Gas	$5,202,743.36	5,603.6	18	$928.46
Steam	Oil	$3,489,074.18	2,852.3	9	$1,223.25
Steam	Other - Solid	$340,000.00	34.0	2	$10,000.00
Steam	Wood	$207,796.25	153.0	3	$1,358.15
Wind	Wind	$18,664,267.97	4,820.9	37	$3,871.53
Total		$337,310,533.44	175,919.3	800	$1,917.42

Frequency Response

On February 15, 2018, the Commission issued Order No. 842, which modified the pro forma large and small generator interconnection agreements and procedures to require newly interconnecting generating facilities, both synchronous and nonsynchronous, to include equipment for primary frequency response capability as a condition to receive interconnection service.[175] 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). 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.[176] The performance of each unit is evaluated quarterly.

PJM filed revisions in compliance with Order No. 842 that substantively incorporated the pro forma agreements into its market rules.[177]

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 capacity market. 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.

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

174 The total amount in the final row of Table 10-32 is the amount that would be paid if the total rate effective on March 1, 2023 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.
175 157 FERC ¶ 61,122 (2016).
176 See PJM Manual 12 (Balancing Operations) § 3.6.2.
177 See 164 FERC ¶ 61,224 (2018).

is to arrest and stabilize the system until other measures (secondary and tertiary frequency response) become active.

- **Secondary Frequency Control.** Secondary frequency control is called regulation. In PJM it begins to respond within 10 to 15 seconds and can continue up to an hour. Regulation is controlled by PJM which detects the grid frequency, calculates a counterbalancing signal, and transmits that signal to all regulating resources.
- **Tertiary Frequency Control.** Tertiary frequency control and imbalance control lasting 10 minutes to an hour is called primary reserve.