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] 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, the PJM DASR Market, and the PJM Regulation Market in the first six months of 2021.

Table 10-1 The tier 2 synchronized reserve market results were competitive

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

- The tier 2 synchronized reserve market structure was evaluated as not competitive because of high levels of supplier concentration.
- Participant behavior was evaluated as competitive because the market rules require 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 mixed. Market power mitigation rules result in competitive outcomes despite high levels of supplier concentration. However, tier 1 reserves are inappropriately compensated when the nonsynchronized reserve market clears with a nonzero price.

1 75 FERC ¶ 61,080 (1996).
2 Energy imbalance service refers to the real-time energy market.

Table 10-2 The day-ahead scheduling reserve market results were competitive

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

- The DASR market would have failed a three pivotal supplier test in 45.8 percent of hours where the DASRMCP was greater than $0.01 in the first six months of 2021.
- Participant behavior was evaluated as mixed because while most offers were equal to marginal costs, a significant proportion of offers reflected economic withholding.
- Market performance was evaluated as competitive because there were adequate offers in every hour to satisfy the requirement and the clearing prices reflected those offers, although there is concern about offers above the competitive level affecting prices. The day-ahead scheduling reserve market clearing price was above $0 in 448 hours in the first six months of 2021. In 98.1 percent of hours when the clearing price was above $0, the clearing price was the offer price of the marginal unit. In the remaining 1.9 percent of hours, the price included lost opportunity cost.
- Market design was evaluated as mixed because the DASR product does not include performance obligations. Offers should be based on opportunity cost only, to ensure competitive outcomes and that market power cannot be exercised.

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 87.7 percent of the hours in the first six months of 2021.

- Participant behavior in the PJM Regulation Market was evaluated as competitive in the first six months of 2021 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

PJM's primary reserves are made up of resources, both synchronized and nonsynchronized, that can provide energy within 10 minutes. Primary reserve is PJM's implementation of the NERC 15-minute contingency reserve requirement.[3]

PJM determines the primary reserve requirement based on the most severe single contingency plus 190 MW in every approved RT SCED case. Every real-time market solution calculates the available tier 1 synchronized reserve. The required synchronized reserve and nonsynchronized reserve are calculated and dispatched in every real-time market solution, and there are associated clearing prices (SRMCP and NSRMCP) assigned every five minutes. Scheduled resources are credited based on a dispatched assignment and a five minute clearing price.

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 most severe single contingency plus 190 MW. In the first six months of 2021, the average primary reserve requirement was 2,427.3 MW in the RTO Zone and 2,427.2 in the MAD Subzone.

Tier 1 Synchronized Reserve

Synchronized reserve is provided by generators and demand response resources synchronized to the grid and capable of increasing output or decreasing load within 10 minutes in response to a PJM declared synchronized reserve event. Synchronized reserve consists of tier 1 and tier 2 synchronized reserves.

Tier 1 synchronized reserve is the capability of online resources following economic dispatch to ramp up in 10 minutes from their current output in response to a synchronized reserve event. There is no formal market for tier 1 synchronized reserve.

- **Supply.** No offers are made for tier 1 synchronized reserves. The market solution estimates tier 1 synchronized reserve as available 10 minute ramp from the energy dispatch. In the first six months of 2021, there was an average hourly supply of 1,611.4 MW of tier 1 available in the RTO Zone and an average hourly supply of 807.9 MW of tier 1 synchronized reserve available within the MAD Subzone.
- **Demand.** The synchronized reserve requirement is calculated for each real-time dispatch solution as the most severe single contingency plus 190 MW within both the RTO Zone and the MAD Subzone.
- **Tier 1 Synchronized Reserve Event Response.** Tier 1 synchronized reserve is paid when a synchronized reserve event occurs and it responds. When a synchronized reserve event is called, all tier 1 response is paid for increasing its output (or reducing load for demand response) at the rate of $50 per MWh in addition to LMP.[4] This is the Synchronized Energy Premium Price.

3 See PJM. "Manual 10: Pre-Scheduling Operations," § 3.1.1 Day-ahead Scheduling (Operating Reserve, Rev. 39 (Nov. 19, 2020).

4 See PJM. "Manual 11: Energy & Ancillary Services Market Operations,"§ 4.2.10 Settlements, Rev. 115 (June 1, 2021).

- **Issues.** The competitive offer for tier 1 synchronized reserves is zero, as there is no incremental cost associated with the ability to ramp up from the current economic dispatch point and the appropriate payment for responding to an event is the synchronized energy premium price of $50 per MWh. The tariff requires payment of the tier 2 synchronized reserve market clearing price to tier 1 resources whenever the nonsynchronized reserve market clearing price rises above zero. This requirement is unnecessary and inconsistent with efficient markets. This change had a significant impact on the cost of tier 1 synchronized reserves, resulting in a windfall payment of $89,719,045 to tier 1 resources in 2014, $34,397,441 in 2015, $4,948,084 in 2016, $2,197,514 in 2017, $4,732,025 in 2018, and $3,217,178 in 2019. The nonsynchronized reserve market clearing price was above $0 in 2,015 intervals (1.9 percent of intervals) in 2020 resulting in a payment to tier 1 resources of $3,319,263. In the first six months of 2021, the nonsynchronized reserve market clearing price was above $0 in 29.6 percent of all intervals resulting in a net payment of $2,372,703.

Tier 2 Synchronized Reserve Market

Tier 2 synchronized reserve is part of primary reserve and is comprised of resources that are synchronized to the grid, that may incur costs to be synchronized, and that have an obligation to respond to PJM declared synchronized reserve events. Tier 2 synchronized reserve is penalized for failure to respond to a PJM declared synchronized reserve event. In PJM the required amount of synchronized reserve is defined to be no less than the largest single contingency, and 10 minute primary reserve as no less than 150 percent of the largest single contingency, plus 190 MW. This is stricter than the NERC standard of the greater of 80 percent of the largest single contingency or 900 MW.[5]

When the synchronized reserve requirement cannot be met with tier 1 synchronized reserve, PJM uses the tier 2 synchronized reserve market to satisfy the balance of the requirement. The tier 2 synchronized reserve market includes the PJM RTO Reserve Zone and a subzone, the Mid-Atlantic Dominion Reserve Subzone (MAD).

5 NERC (June 2, 2020) <NERC Reliability Standard BAL 002-2 Glossary_of_Terms.pdf>.

Market Structure

- **Supply.** In the first six months of 2021, the supply of daily offered and eligible tier 2 synchronized reserve was 36,322.9 MW in the RTO Zone of which 4,649.6 MW was located in the MAD Subzone.
- **Demand.** The average hourly synchronized reserve requirement was 1,699.5 MW in the RTO Reserve Zone and 1,672.6 in the Mid-Atlantic Dominion Reserve Subzone. The hourly average cleared tier 2 synchronized reserve was 239.7 MW in the MAD Subzone and 612.6 MW in the RTO.
- **Market Concentration.** Both the Mid-Atlantic Dominion Subzone Tier 2 Synchronized Reserve Market and the RTO Synchronized Reserve Zone Market were characterized by structural market power in the first six months of 2021.

  The average HHI for tier 2 synchronized reserve in the RTO Zone was 5235 which is classified as highly concentrated.

Market Conduct

- **Offers.** There is a must offer requirement for tier 2 synchronized reserve. All nonemergency generation capacity resources are required to submit a daily offer for tier 2 synchronized reserve, unless the unit type is exempt. Tier 2 synchronized reserve offers from generating units are subject to an offer cap of marginal cost plus $7.50 per MW, plus opportunity cost which is calculated by PJM. PJM automatically enters an offer of $0 for tier 2 synchronized reserve when an offer is not entered by the owner.

Market Performance

- **Price.** The weighted average price for tier 2 synchronized reserve for all cleared hours in the MAD subzone was $5.54 per MW in the first six months of 2021. The weighted average price for tier 2 synchronized reserve for all cleared intervals in the RTO Synchronized Reserve Zone was $5.48 per MW in the first six months of 2021.

Nonsynchronized Reserve Market

Nonsynchronized reserve is part of primary reserve and includes the RTO Reserve Zone and the Mid-Atlantic Dominion Reserve Subzone (MAD). 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 fill the primary reserve requirement above the synchronized reserve requirement. Generation owners do not submit supply offers for nonsynchronized reserve. 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 (based on offer parameters), and on the resource opportunity costs calculated by PJM.

Market Structure

- **Supply.** In the first six months of 2021, the average supply of eligible and available nonsynchronized reserve was 1,537.3 MW in the RTO Zone.
- **Demand.** Demand for nonsynchronized reserve equals the primary reserve requirement minus the tier 1 synchronized reserve estimate and minus the scheduled tier 2 synchronized reserve.[6]
- **Market Concentration.** The MMU calculates that the three pivotal supplier test would have been failed in 95.6 percent of intervals where the price was above $0.01 in the first six months of 2021.

Market Conduct

- **Offers.** Generation owners do not submit supply offers. Nonemergency generation resources that are available to provide energy and can start in 10 minutes or less are considered available for nonsynchronized reserves by the market solution software. PJM calculates the associated offer prices based on PJM calculations of resource specific opportunity costs.

Market Performance

- **Price.** The nonsynchronized reserve price is determined by the opportunity cost of the marginal nonsynchronized reserve unit. The nonsynchronized reserve weighted average price for all intervals in the RTO Reserve Zone was $0.25 per MW in the first six months of 2021.

Secondary Reserve (DASR)

There is no NERC standard for secondary reserve. PJM defines secondary reserve in the day-ahead market as reserves (online or offline available for dispatch) that can be converted to energy in 30 minutes. PJM defines a secondary reserve requirement but is not required to maintain this level of secondary reserve in real time.

PJM maintains a day-ahead, offer-based market for 30 minute day-ahead secondary reserve. The PJM Day-Ahead Scheduling Reserve Market (DASR) has no performance obligations except that a unit which clears the DASR market may not be on an outage in real time.[7] If DASR units are on an outage in real time or cleared DASR MW are not available, the DASR payment is not made.

Market Structure

- **Supply.** The DASR market is a must offer market. Any resources that do not make an offer have their offer set to $0.00 per MW. DASR is calculated by the day-ahead market solution as the lesser of the 30 minute energy ramp rate or the economic maximum MW minus the day-ahead dispatch point for all resources that can provide energy within 30 minutes of a request from PJM Dispatch. In the first six months of 2021, the average available hourly DASR was 17,368.1 MW.[8]
- **Demand.** The DASR requirement is the sum of the PJM requirement and the Dominion requirement based on the VACAR reserve sharing agreement. For November 2020 through October 2021, the DASR requirement is 4.72 percent of peak load forecast. The average hourly DASR MW purchased

6 See PJM. "Manual 11: Energy & Ancillary Services Market Operations," § $b.2.2 Non-Synchronized Reserve Zones and Levels, Rev. 115 (June 1, 2021). "Because Synchronized Reserve may be utilized to meet the Primary Reserve requirement, there is no explicit requirement for non-synchronized reserves."

7 See PJM, "Manual 11: Energy & Ancillary Services Market Operations," § 11.2.7 Day-Ahead Scheduling Reserve Performance, Rev. 115 (June 1, 2021).

8 The average hourly available DASR MW are modified from previously reported values due to a calculation error which has been fixed.

in the first six months of 2021 was 4,563.4 MW, a reduction from the 4,987.2 hourly MW in 2020.

- **Concentration.** The three pivotal supplier test would have failed in 216 hours in the first six months of 2021.

Market Conduct

- **Withholding.** Economic withholding remains an issue in the DASR Market. The direct marginal cost of providing DASR is zero. PJM calculates the opportunity cost for each resource. All offers by resource owners greater than zero constitute economic withholding. In the first six months of 2021, 39.3 percent of daily unit offers were above $0.00 and 15.8 percent of daily unit offers were above $5.
- **DR.** Demand resources are eligible to participate in the DASR Market. Some demand resources have entered offers for DASR. No demand resources cleared the DASR market in the first six months of 2021.

Market Performance

- **Price.** In the first six months of 2021, the weighted average DASR price for all hours when the DASRMCP was above $0.00 was $0.95.

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 six months of 2021, the average hourly offered supply of regulation for nonramp hours was 758.5 performance adjusted MW (751.6 effective MW). This was an increase of 57.4 performance adjusted MW (an increase of 45.7 effective MW) from the first six months of 2020. In the first six months of 2021, the average hourly offered supply of regulation for ramp hours was 1,072.8 performance adjusted MW (1,093.8 effective MW). This was an increase of 91.3 performance adjusted MW (an increase of 65.1 effective MW) from the first six months of 2020, when the average hourly offered supply of regulation was 981.5 performance adjusted MW (1,028.7 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 RegA and RegD resources equal to 491.3 hourly average performance adjusted actual MW in the first six months of 2021. This is an increase of 1.7 performance adjusted actual MW from the first six months of 2020, when the average hourly total regulation cleared performance adjusted actual MW for nonramp hours were 489.6 performance adjusted actual MW. The ramp regulation requirement of 800.0 effective MW was provided by a combination of RegA and RegD resources equal to 707.3 hourly average performance adjusted actual MW in the first six months of 2021. This is an increase of 3.2 performance adjusted actual MW from the first six months of 2020, where the average hourly regulation cleared MW for ramp hours were 704.1 performance adjusted actual MW.

  The ratio of the average hourly offered supply of regulation to average hourly regulation demand (performance adjusted cleared MW) for ramp hours was 1.52 in the first six months of 2021 (1.39 in the first six months of 2020). The ratio of the average hourly offered supply of regulation to average hourly regulation demand (performance adjusted cleared MW) for nonramp hours was 1.54 in the first six months of 2021 (1.43 in the first six months of 2020).

- **Market Concentration.** In the first six months of 2021, the three pivotal supplier test was failed in 87.7 percent of hours. In the first six months of 2021, the actual MW weighted average HHI of RegA resources was 2288 which is highly concentrated and the weighted average HHI of RegD resources was 1670 which is moderately concentrated. The weighted average HHI of all resources was 1218, 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.[9] In the first six months of 2021, there were 219 resources following the RegA signal and 50 resources following the RegD signal.

Market Performance

- **Price and Cost.** The weighted average clearing price for regulation was $17.46 per MW of regulation in the first six months of 2021, an increase of $5.73 per MW, or 48.9 percent, from the weighted average clearing price of $11.73 per MW in the first six months of 2020. The weighted average cost of regulation in the first six months of 2021 was $21.66 per MW of regulation, an increase of 46.4 percent, from the weighted average cost of $14.79 per MW in the first six months of 2020.

- **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).[10]

In the first six months of 2021, total black start charges were $33.6 million, including $33.3 million in revenue requirement charges and $0.2 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 six months of 2021 ranged from $0.02 per MW-day in the BGE Zone (total charges were $22,716) to $4.13 per MW-day in the PE Zone (total charges were $2,176,976).

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, CRF values have overcompensated black start units since the changes to the tax code.

9 See the *2019 State of the Market Report for PJM*, Vol. II, Appendix F "Ancillary Services Markets."

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

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. The current rules permit double recovery of some fixed costs.

Reactive capability charges are based on FERC approved filings that permit recovery based on an outdated cost of service approach.[11] All capacity costs of generators should be incorporated in the capacity market. The nonmarket cost of service approach to reactive capability payments should be eliminated. 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 4.81 percent from $174.8 million in the first six months of 2020 to $182.5 million in 2021. Reactive capability charges increased 4.51 percent from $174.6 million in the first six months of 2020 to $182.460 million in 2021. Total reactive service charges in the first six months of 2021 ranged from $0 in the REC and OVEC Zones, to $25.0 million in the AEP Zone.

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.[12] PJM filed revisions in compliance with Order No. 842 that incorporated the pro forma agreements into its market rules.[13]

The PJM Tariff requires that all new generator interconnection customers (Nuclear Regulatory Commission regulated facilities are exempt from this provision) have hardware and/or software that provides frequency responsive real power control with the ability to sense changes in system frequency and autonomously adjust real power output in a direction to correct for frequency deviations. This includes a governor or equivalent controls capable of operating with a maximum five percent droop and a +/- 0.036 deadband.[14] In addition to resource capability, resource owners must comply by setting control systems to autonomously adjust real power output in a direction to correct for frequency deviations.

The response of generators within PJM to NERC identified frequency events remains under evaluation. A frequency event is declared when the frequency goes outside +/-40mHz for 60 continuous seconds. The NERC BAL-003-2 requirement for balancing authorities (PJM is a balancing authority) uses a threshold value (L_{10}) equal to -261.1 MW/0.1 Hz and has selected four events between June 1, 2020 and December 31, 2020 as well as two events in January of 2021 to evaluate.

Ancillary Services Costs per MWh of Load

Table 10-4 shows PJM ancillary services costs for the first six months of 1999 through 2021, 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.[15] 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.

11 OATT Schedule 2.
12 See 157 FERC ¶ 61,122 (2016).
13 See 164 FERC ¶ 61,224 (2018).
14 OATT Attachment O § 4.7.2 (Primary Frequency Response).
15 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.

Table 10-4 History of ancillary services costs per MWh of load: January through June, 1999 through 2021[16 17]

Year (Jan-Jun)	Regulation	Scheduling, Dispatch and System Control	Reactive	Synchronized Reserve	Total
1999	$0.08	$0.23	$0.27	$0.00	$0.58
2000	$0.26	$0.32	$0.33	$0.00	$0.91
2001	$0.50	$0.73	$0.22	$0.00	$1.45
2002	$0.31	$0.81	$0.19	$0.00	$1.31
2003	$0.57	$1.06	$0.24	$0.16	$2.03
2004	$0.53	$1.07	$0.26	$0.16	$2.02
2005	$0.58	$0.80	$0.27	$0.11	$1.76
2006	$0.48	$0.74	$0.29	$0.08	$1.59
2007	$0.61	$0.71	$0.27	$0.09	$1.68
2008	$0.73	$0.52	$0.34	$0.08	$1.67
2009	$0.38	$0.32	$0.36	$0.04	$1.10
2010	$0.34	$0.36	$0.37	$0.06	$1.13
2011	$0.33	$0.36	$0.40	$0.10	$1.19
2012	$0.20	$0.43	$0.47	$0.03	$1.13
2013	$0.26	$0.43	$0.65	$0.03	$1.37
2014	$0.46	$0.43	$0.42	$0.20	$1.51
2015	$0.29	$0.42	$0.37	$0.14	$1.22
2016	$0.11	$0.43	$0.39	$0.05	$0.98
2017	$0.13	$0.49	$0.43	$0.06	$1.11
2018	$0.24	$0.47	$0.42	$0.08	$1.21
2019	$0.11	$0.46	$0.44	$0.04	$1.05
2020	$0.09	$0.49	$0.49	$0.02	$1.09
2021	$0.14	$0.51	$0.50	$0.05	$1.20

Market Procurement of Real-Time Ancillary Services

PJM uses market mechanisms to varying degrees in the procurement of ancillary services, including primary 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 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. Resources categorized as flexible tier 2 reserve, those that can provide reserves by backing down according to their ramp rate, are jointly cleared along with energy in every real-time market solution. Given the joint clearing of energy and flexible tier 2, the synchronized reserve market clearing price should always cover the opportunity cost of providing flexible tier 2. PJM should never need to pay uplift to flexible tier 2. The uplift paid to flexible tier 2 results from issues with the dispatch and pricing software timing. Inflexible tier 2 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 tier 2 reserves are cleared hourly by the Ancillary Service Optimizer (ASO). The ASO uses forward looking information about the energy market, flexible tier 2, tier 1, and regulation to estimate the costs and benefits of using a resource for inflexible tier 2 synchronized reserves.

Nonsynchronized reserves are cleared with every real-time energy market solution, but their costs are not fully known by the real-time energy market software (RT SCED) because the resources are offline. PJM uses an estimate of the cost of using a resource for nonsynchronized reserve instead of energy from a previously solved IT SCED solution. IT SCED runs every 15 minutes looking ahead at target dispatch times up to two hours in the future. The energy commitment decisions for the offline resources have already been made when the RT SCED clears the nonsynchronized reserve market. RT SCED compares the IT SCED estimated cost of nonsynchronized reserve clearing to the RT SCED determined cost of synchronized reserve clearing in satisfying the primary reserve requirement. Nonsynchronized reserve clearing indirectly interacts with energy clearing through both products' substitutability with synchronized reserves.

Prices for the regulation and reserve markets are set by the pricing calculator (LPC), which is based on the RT SCED solution. The software determining the prices (RT SCED) is partially, but not fully clearing the reserve market. The software determining the prices is not clearing the regulation market.

16 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.
17 Reactive totals include FERC approved rates for reactive capability.

Recommendations

- 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.[18])
- 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.[19] FERC rejected.[20])
- The MMU recommends that the lost opportunity cost calculation used in the regulation market be based on the resource's dispatched energy offer schedule, not the lower of its price or cost offer schedule. (Priority: Medium. First reported 2010. Status: Not adopted. FERC rejected.[21])
- The MMU recommends that, to prevent gaming, there be a penalty enforced in the regulation market as a reduction in performance score and/or a forfeiture of revenues when resource owners elect to deassign assigned regulation resources within the hour. (Priority: Medium. First reported 2016. Status: Not adopted. FERC rejected.[22])
- The MMU recommends enhanced documentation of the implementation of the regulation market design. (Priority: Medium. First reported 2010. Status: Not adopted. FERC rejected.[23])
- 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 Q1, 2021. Status: Not adopted.)
- 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: Not adopted.)
- 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: Not adopted.)
- 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: Not adopted.)
- 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

18 162 FERC ¶ 61,295 (2018), *reh'g denied*, 170 FERC ¶ 61,259 (2020).
19 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.
20 162 FERC ¶ 61,295 (2018), *reh'g denied*, 170 FERC ¶ 61,259 (2020).
21 *Id.*
22 *Id.*
23 *Id.*

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: Not adopted.)

- 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: Partially adopted.)
- The MMU recommends that, for calculating the penalty for a tier 2 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. (Priority: Medium. First reported 2018. Status: Not adopted.)
- The MMU recommends that aggregation not be permitted to offset unit specific penalties for failure to respond to a synchronized reserve event. (Priority: Medium. First reported 2018. Status: Not adopted.)
- The MMU recommends that PJM 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: Not adopted.)
- The MMU recommends that the details of VACAR Reserve Sharing Agreement (VRSA) be made public, including any responsibilities assigned to PJM and including the amount of reserves that Dominion commits to meet its obligations under the VRSA. (Priority: Medium. First reported 2020. Status: Not adopted.)
- 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: Not adopted.)
- 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: Not adopted.)
- 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: Not adopted.)
- 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: Not adopted.)
- 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 for oil tanks shared with other resources that only a proportionate share of the minimum tank suction level (MTSL) be allocated to black start service. The MMU further recommends that the PJM tariff be updated to clearly state how the MTSL will be calculated for black start units sharing oil tanks. (Priority: Medium. First reported 2017. 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 0.90 power factor that PJM has determined is necessary. (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.[24] 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.[25] (Priority: Medium. First reported 2020. Status: Not adopted.)

Conclusion

The design of the PJM Regulation Market is significantly flawed.[26] 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. 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.[27] 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 joint proposal on March 30, 2018, as being noncompliant with Order No. 755.[28] The MMU and PJM separately filed requests for rehearing, which were denied by order issued March 26, 2020.[29]

The structure of the tier 2 synchronized reserve market has been evaluated and the MMU has concluded that these markets are not structurally competitive as they are characterized by high levels of supplier concentration and inelastic demand. As a result, these markets are operated with market clearing prices and with offers based on the marginal cost of producing the product plus a margin. As a result of these requirements, the conduct of market participants within these market structures has been consistent with competition, and the market performance results have been competitive. However, the $7.50 margin is not a cost. The margin is effectively a rule-based form of economic withholding and is therefore not consistent with a competitive outcome. The $7.50 margin should be eliminated. The variable operating and maintenance component of the synchronized reserve offer should also be eliminated. All variable operating and maintenance costs are incurred to provide energy and to make units available to provide energy. There are no variable operating and maintenance costs associated with providing synchronized reserve.

Participant performance has not been adequate for tier 2 synchronized reserve. Compliance with calls to respond to actual synchronized reserve events remains significantly less than 100 percent. Actual participant performance means that the penalty structure is not an adequate incentive for performance.

The rule that requires payment of the tier 2 synchronized reserve price to tier 1 synchronized reserve resources when the nonsynchronized reserve price is greater than zero, is inefficient and results in a substantial windfall payment

24 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.
25 *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>.
26 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).
27 18 CFR § 385,211 (2017)
28 162 FERC ¶ 61,295.
29 170 FERC ¶ 61,259.

to the holders of tier 1 synchronized reserve resources. Tier 1 resources have no obligation to perform and pay no penalties if they do not perform, and tier 1 resources do not incur any costs when they are part of the tier 1 estimate in the market solution. Tier 1 resources are already paid for their response if they do respond to a synchronized reserve event. Tier 1 resources require no additional payment. If tier 1 resources wish to be paid as tier 2 resources, the rules provide the opportunity to make competitive offers in the tier 2 market and take on the associated obligations. Overpayment of tier 1 resources based on this rule has added more than $100 million to the cost of primary reserve since 2014.

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, although the $7.50 margin should be removed. The MMU concludes that the DASR market results were competitive, although offers above the competitive level continue to affect prices.

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. NERC standards set the Contingency Event Recovery Period as 15 minutes and Contingency Reserve Restoration Period as 90 minutes.[30] The NERC requirement is 100 percent compliance and status must be reported quarterly. PJM implements this contingency reserve requirement using primary reserves.[31] 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

PJM requires that 150 percent of the largest single contingency on the system be maintained as primary reserve plus 190 MW. PJM can make temporary adjustments to the primary reserve requirement when grid maintenance or outages change the largest contingency or in cases of hot weather alerts or cold weather alerts.

The primary reserve market requirement is set equal to 150 percent of the largest single contingency for each market solution, ASO, IT SCED, and RT SCED. This is usually the output of the largest generating unit to which PJM adds 190 MW. In cases where temporary switching conditions create the risk that a single fault could remove several generators, PJM will define the largest single contingency as the sum of the output of those generators.[32]

PJM can also increase the primary and synchronized reserve requirement in cases of hot weather or cold weather alerts or escalating emergency procedures.[33] Such additional reserves are committed as part of the hourly (ASO) and five minute (RT SCED) processes. In the first six months of 2021, the average primary reserve requirement for the RTO Zone was 2,427.3 MW. The average primary reserve requirement in the MAD Subzone was also 2,427.2 MW. These averages include the hours when PJM raised the requirements.

30 See PJM "Manual 12: Balancing Operations," Rev. 42 (January 27, 2021) 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."
31 See PJM "Manual 10: Pre-Scheduling Operations," § 3.1.1 Day-ahead Scheduling (Operating) Reserve, Rev. 39 (Nov. 19, 2020).
32 PJM Manual 11: Energy & Ancillary Services Market Operations, Rev. 115 (June 1, 2021)
33 PJM Manual 11: Energy & Ancillary Services Market Operations, Rev. 115 (June 1, 2021), p. 84

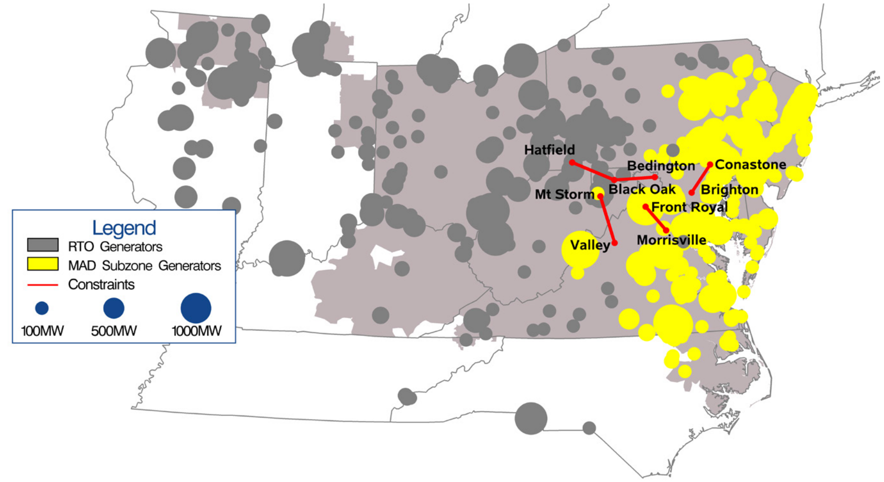
The MMU identified instances when PJM increased the primary and synchronized reserve requirements (Table 10-5).

Table 10-5 Temporary adjustments to primary and synchronized reserve: January through June, 2021

From	To	Number of Hours	Amount of Adjustment
6-Mar-21	8-Mar-21	34	Primary Reserve (255 MW), Synchronized Reserve (170 MW)
15-Mar-21	29-Mar-21	230	Primary Reserve (230 MW), Synchronized Reserve (160 MW)
14-Jun-21	17-Jun-21	64	Primary Reserve (0 MW), Synchronized Reserve (0 MW)

Transmission constraints can limit the deliverability of reserves within the RTO, requiring the definition of a subzone. PJM defines a single subzone, the Mid-Atlantic Dominion (MAD) Subzone (Figure 10-1).[34] Figure 10-1 is a map of constraints and major generation sources. The constraints separating the RTO Zone and MAD Subzone are defined by underlying grid topology. The RTO Zone into MAD Subzone constraints reflect limits on the transmission line capacity that separate the RTO Zone and MAD Subzone. If, in the case of a spinning event, the current economic dispatch plus the current synchronized market dispatch would overload the constraint, then all additional synchronized reserve MW must be cleared from the unconstrained side of the constraints. When this occurs, the synchronized reserve prices between the RTO Zone and the MAD Subzone will diverge. PJM operators are authorized to define additional separate subzones under certain conditions.[35] In practice, PJM has always maintained only the MAD Subzone but for any market solution several distinct constraining paths are analyzed and the most limiting one becomes the definition for that solution.

Figure 10-1 PJM RTO Zone and MAD Subzone map of constraints and generation sources



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 frequent constraint is Brighton-Conastone, then Bedington-Black Oak, and Dooms-Cunningham.

The NERC standard requires a control area to carry primary reserve MW equal to or greater than the most severe single contingency (MSSC) plus 190 MW.[36] PJM requires primary reserves in the amount of 150 percent of the largest single contingency with at least 100 percent of the requirement made up of synchronized reserves.[37] In the first six months of 2021, the average synchronized reserve requirement was 1,682.2 MW in the MAD Subzone and 1,682.3 MW in the RTO Zone. The synchronized reserve requirement is calculated for every real-time market dispatch solution.

34 Additional subzones may be defined by PJM to meet system reliability needs. PJM will notify stakeholders in such an event. See "PJM Manual 11: Energy & Ancillary Services Market Operations," § 4.2.2 Synchronized Reserve Requirement Determination, Rev. 115 (June 19, 2021).

35 PJM Manual 11: Energy & Ancillary Services Market Operations, Rev. 115 (June 1, 2021), p. 86.

36 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>.

37 "PJM Manual 13: Emergency Operations," Rev 78 (Jan. 27, 2021), p. 18.

Supply

The demand for primary reserve is satisfied by tier 1 synchronized reserves, tier 2 synchronized reserves and nonsynchronized reserves, subject to the requirement that synchronized reserves equal 100 percent of the largest contingency. After the synchronized reserve requirement is satisfied, the remainder of primary reserves is from the least expensive combination of synchronized and nonsynchronized reserves.

Estimated tier 1 is credited against PJM's primary reserve requirement as well as PJM's synchronized reserve requirement. In the MAD Subzone, an average of 807.9 MW of tier 1 was identified by the dispatch solutions as available in the first six months of 2021 (Table 10-6).[38] Tier 1 synchronized reserve fully satisfied the MAD Subzone synchronized reserve requirement or reduced the need for tier 2 synchronized reserve to self scheduled reserves in 4.1 percent of dispatch solutions in the first six months of 2021. In the RTO Zone, an average of 1,611.4 MW of tier 1 was available (Table 10-7) fully satisfying the synchronized reserve requirement in 39.9 percent of real-time dispatch solutions.

Regardless of online/offline state, all nonemergency generation capacity resources must submit a daily offer for tier 2 synchronized reserve in Markets Gateway prior to the offer submission deadline (14:15 the day prior to the operating day). Resources listed as available for tier 2 synchronized reserve without a synchronized reserve offer will have their offer price automatically set to $0.00. Offer MW and other non-cost offer parameters can be changed during the operating day. Owners who opt in for intraday updates may change their offer price up to 65 minutes before the hour. Certain unit types including nuclear, wind, solar, and energy storage resources, are expected to have zero MW tier 2 synchronized reserve offer quantities.[39]

After tier 1 is estimated, the remainder of the synchronized reserve requirement is met by tier 2.

38 ASO, Ancillary Services Optimizer. This is the hour-ahead market software that optimizes ancillary services with energy. ASO schedules hourly the Tier 2 Synchronized Reserve, Regulation, and Nonsynchronized Reserves.

39 See PJM "Manual 11: Energy & Ancillary Services Market Operations," § 4.2 PJM Synchronized Reserve Market Business Rules, Rev. 115 (June 1, 2021).

In the first six months of 2021, in the MAD Subzone, there was an average of 1,244.8 MW of eligible nonsynchronized reserve supply available to meet the average demand for primary reserve. (Table 10-7) In the RTO Zone, an average of 1,744.4 MW of supply was available to meet the average demand of 1,537.3 MW (Table 10-7).

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 from January 2020 through June 2021.

Table 10-6 Average reserves used to satisfy the primary reserve requirement, MAD Subzone: January 2020 through June 2021

Year	Month	Tier 1 Total MW	Tier 2 Synchronized Reserve MW	Nonsynchronized Reserve MW	Total Primary Reserve MW
2020	Jan	1,276.6	325.9	1,249.0	2,851.5
2020	Feb	1,026.9	193.6	1,219.6	2,440.1
2020	Mar	980.7	259.0	1,231.8	2,471.4
2020	Apr	1,150.5	199.9	1,067.7	2,418.1
2020	May	911.1	200.5	1,177.5	2,289.0
2020	Jun	1,276.2	142.5	976.6	2,395.4
2020	Jul	995.4	210.5	1,216.0	2,421.9
2020	Aug	881.4	148.3	1,200.6	2,230.3
2020	Sep	1,016.9	88.5	1,123.2	2,228.6
2020	Oct	724.1	290.2	1,247.8	2,262.2
2020	Nov	566.4	257.2	1,188.8	2,012.5
2020	Dec	689.0	252.2	1,319.6	2,260.8
2020	Average	957.9	214.0	1,184.8	2,356.8
2021	Jan	835.6	251.1	1,330.6	2,417.3
2021	Feb	974.9	215.1	1,242.7	2,432.7
2021	Mar	881.9	213.2	1,162.6	2,257.7
2021	Apr	689.7	315.5	1,274.8	2,280.0
2021	May	651.4	247.5	1,141.4	2,040.2
2021	Jun	834.6	198.8	1,263.7	2,297.1
2021	Average	811.4	240.2	1,236.0	2,369.2

Table 10-7 shows the average dispatch solution reserves, by type of reserve, satisfying the primary reserve requirement in the RTO Zone in January 2020 through June 2021.

Table 10-7 Average monthly reserves used to satisfy the primary reserve requirement, RTO Zone: January 2020 through June 2021

Year	Month	Tier 1 Total MW	Tier 2 Synchronized Reserve MW	Nonsynchronized Reserve MW	Total Primary Reserve MW
2020	Jan	2,416.4	486.8	1,364.8	4,268.0
2020	Feb	2,284.2	283.3	1,279.6	3,847.1
2020	Mar	2,155.1	458.7	1,365.6	3,979.4
2020	Apr	2,228.6	342.1	1,174.0	3,744.7
2020	May	2,128.3	297.4	1,250.6	3,676.3
2020	Jun	2,728.9	283.7	1,082.7	4,095.3
2020	Jul	2,109.4	402.2	1,363.5	3,875.1
2020	Aug	1,972.1	398.8	1,387.0	3,757.9
2020	Sep	2,053.8	299.4	1,271.0	3,624.1
2020	Oct	1,381.3	778.2	1,612.3	3,771.7
2020	Nov	1,499.7	683.9	1,509.5	3,693.1
2020	Dec	1,512.4	697.0	1,648.3	3,857.7
2020	Average	2,039.2	450.9	1,359.1	3,849.2
2021	Jan	1,761.2	506.7	1,512.5	3,780.4
2021	Feb	1,848.8	600.3	1,515.2	3,964.3
2021	Mar	1,705.5	593.1	1,454.1	3,752.7
2021	Apr	1,313.5	748.3	1,589.6	3,651.2
2021	May	1,371.4	790.1	1,569.2	3,731.2
2021	Jun	1,708.1	610.3	1,573.6	3,892.0
2021	Average	1,618.1	641.5	1,535.7	3,832.5

Supply and Demand

The market solution software relevant to 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).

All dispatch solutions determine the actual primary reserves required as 150 percent of the largest contingency plus 190 MW. Of this, synchronized reserves must be 100 percent of the largest contingency plus 190 MW.

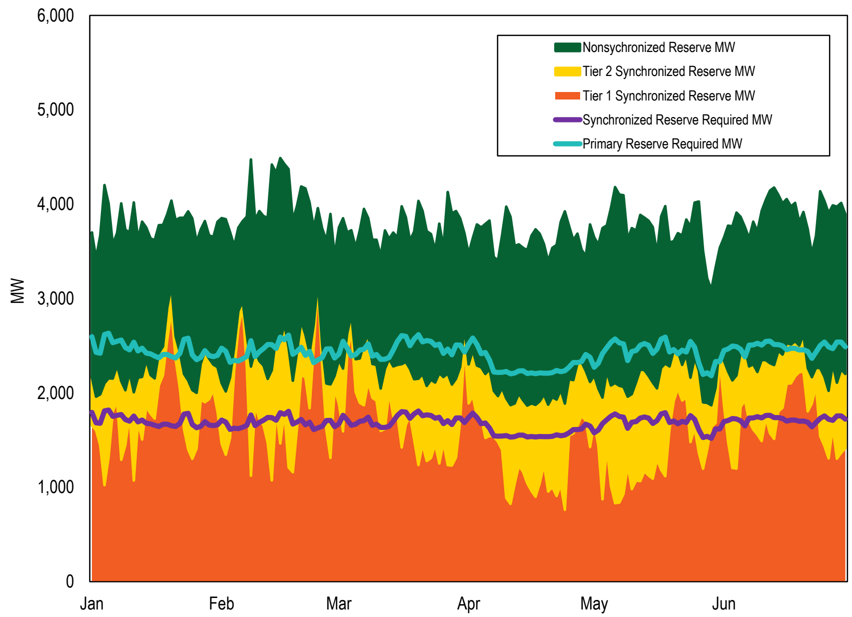
If the tier 1 synchronized reserve plus ASO committed inflexible tier 2 synchronized reserve does not meet the requirement, RT SCED will commit available flexible tier 2 synchronized reserve. If there is an excess of synchronized reserve, the RT SCED may decommit previously committed flexible synchronized reserve.

The ASO satisfied the primary reserve requirement for the RTO Zone and the MAD Subzone in all hours of the first six months of 2021. RT SCED for the MAD Subzone satisfied the primary reserve requirement in all but nine dispatch solutions. Three of the dispatch solutions, occurred during temporary increases in the required synchronized reserve and nonsynchronized reserve on March 17 and March 22.

The market solution first estimates how much tier 1 synchronized reserve is available. If there is enough tier 1 MW available to satisfy the synchronized reserve requirement, then RT SCED economically assigns available synchronized reserve and nonsynchronized reserve to meet the remaining primary reserve requirement. If there is not enough tier 1 synchronized reserve then the remaining synchronized reserve requirement is filled with tier 2 synchronized reserve. After synchronized reserve is assigned, the primary reserve requirement is filled by economically assigning synchronized reserve and nonsynchronized reserve.

Figure 10-2 shows how the market solutions satisfy the primary reserve requirement for the RTO Zone.

Figure 10-2 RTO reserve zone primary reserve MW by source (Daily Averages): January through June, 2021



In the first six months of 2021, tier 1 and tier 2 were both essential to satisfying the synchronized reserve requirement. Tier 1 synchronized reserve remains the major contributor to satisfying the synchronized reserve requirement in both the RTO Zone and the MAD Subzone.

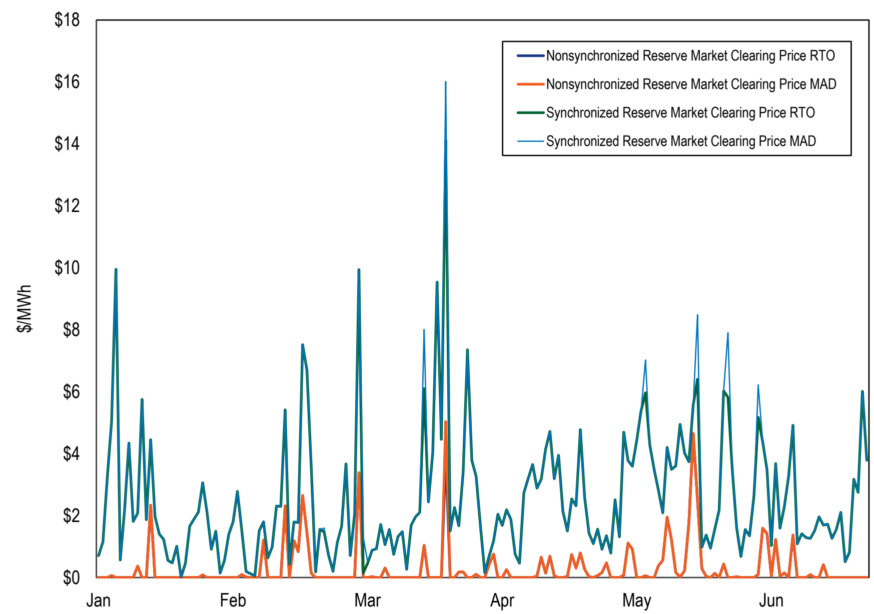
Price and Cost

The price of primary reserves results from the demand curve for primary reserves and the supply of primary reserves. The demand curve is modeled in each of the primary reserve clearing engines (ASO, IT SCED, RT SCED). The demand curve for primary reserves has two steps, with an $850 penalty factor for primary reserve levels ranging from 0 MW to a MW amount equal to 150 percent of the MSSC and a constraint with a $300 penalty factor for primary reserves ranging from 150 percent of MSSC to 150 percent of MSSC plus 190 MW.

The supply of primary reserves is made up of available tier 1 and tier 2 synchronized reserves and nonsynchronized reserves. Offer prices for synchronized reserve are capped at $7.50 plus costs plus opportunity costs.

Figure 10-3 shows daily weighted average synchronized and nonsynchronized market clearing prices in the first six months of 2021. The MAD SRMCP and RTO SRMCP price diverged in 25 five minute intervals in the first six months of 2021.

Figure 10-3 Daily average market clearing prices ($/MW) for synchronized reserve and nonsynchronized reserve: January through June, 2021



PJM's primary reserves are made up of three components, tier 1 synchronized reserve, tier 2 synchronized reserve, and nonsynchronized reserve, each with its own price and cost determinants and interdependent scheduling algorithms. The overall price and cost to customers, including uplift credits, for meeting the BAL-002-3 primary reserve requirement is calculated by combining the three components. Each of these three components is shown in Table 10-8. The Cost per MW column is the total credits divided by the total MW of reserves.

The ratio of price to cost for all primary reserve during first six months of 2021 was 64.5 percent. While tier 1 has zero actual incremental cost, estimated tier 1 is paid the tier 2 clearing price in any hour where nonsynchronized reserves clears at a nonzero price.

Table 10-8 Primary reserve requirement components, RTO Reserve Zone: January through June 2021

Primary Reserve Product	MW Share of Credited Primary Reserve Requirement	MWh	Credits Paid	Price Per MW Reserve	Cost Per MW Reserve
Tier 1 Synchronized Reserve Response	NA	1,615	$101,063	NA	$62.57
Tier 1 Synchronized Reserve in Market Solution	2.3%	154,363	$2,372,703	$26.63	$26.63
Tier 2 Synchronized Reserve Scheduled	28.4%	1,900,050	$15,863,821	$5.44	$8.35
Non Synchronized Reserve Scheduled	69.2%	4,625,059	$5,904,407	$0.25	$1.28
Primary Reserve (total of above)	100.0%	6,681,087	$24,241,994	$2.34	$3.63

Tier 1 Synchronized Reserve

Tier 1 synchronized reserve is a component of primary reserve comprised of online resources following economic dispatch and able to ramp up from their current output in response to a synchronized reserve event. The tier 1 synchronized reserve for a unit is estimated as the lesser of the available 10 minute ramp or the difference between the economic dispatch point and the synchronized reserve maximum output. By default the synchronized reserve maximum for a resource is equal to its economic maximum. Resource owners may request a lower synchronized reserve maximum if a physical limitation exists.[40] Tier 1 resources are identified by the market solution. Tier 1 synchronized reserve has an incremental cost of zero. Tier 1 synchronized reserve is paid under two circumstances. Tier 1 reserves are paid when they respond to a synchronized reserve event. Tier 1 reserves are paid the synchronized reserve market clearing price when the nonsynchronized reserve market clearing price is above $0.

While PJM relies on tier 1 resources to respond to a synchronized reserve event, tier 1 resources are not obligated to respond during an event. Tier 1 resources are credited if they do respond but are not penalized if they do not.

Market Structure

Supply

All generating resources operating on the PJM system with the exception of those assigned to tier 2 synchronized reserve are available for tier 1 synchronized reserve and any response to a spinning event will be credited at the Synchronized Energy Premium Price.

Beginning in 2014, DGP (Degree of Generator Performance) was introduced as a metric to improve the accuracy of the tier 1 MW estimate used by the market solution. The available tier 1 MW estimated by the market solution for each resource is based upon its economic dispatch, and submitted synchronized reserve ramp rate, adjusted by its DGP. PJM communicates to generation operators whose tier 1 MW is part of the market solution the latest estimate of units' tier 1 MW and units' current DGP.[41] DGP should be documented in PJM's market rules.[42] DGP violates the basic PJM principle that generation owners are solely responsible for their own offers. In addition, DGP is a crude estimate of ramp rates and does not account for the actual discontinuities along unit offer curves.

The supply of tier 1 synchronized reserve available to the market solution is adjusted by eliminating tier 1 MW from unit types that cannot reliably provide synchronized reserve. These unit types are nuclear, wind, solar,

40 See PJM "Manual 11: Energy & Ancillary Services Market Operations," § 4.2.1 Synchronized Reserve Market Eligibility, Rev. 115 (June 1, 2021).

41 PJM. Ancillary Services, "Communication of Synchronized Reserve Quantities to Resource Owners," (May 6, 2015). <http://www.pjm.com/~/media/markets-ops/ancillary/communication-of-synchronized-reserve-quantities-to-resource-owners.ashx>

42 See PJM, Generation Performance Monitor and Degree of Generator Performance Whitepaper. <http://www.pjm.com/-/media/etools/oasis/system-information/generation-performance-monitor-and-degree-of-generator-performance-white-paper.ashx>.

landfill gas, energy storage, and hydro units.[43] These unit types are credited the synchronized energy premium price, like any other responding unit, if they respond to a spinning event. These units will not, however, be paid as tier 1 resources when the nonsynchronized reserve market clearing price goes above $0. There is a review process for resources excluded by default from the tier 1 estimate that request to be included.[44] PJM also excludes units, regardless of type, that it deems unreliable as tier 1, though it allows those resources to provide tier 2 synchronized reserve.

Table 10-9 provides tier 1 synchronized reserve supplied by unit and fuel type in the first six months of 2021, including all tier 1 credited for responding to synchronized reserve events and paid when the nonsychronized reserve price exceeded $0 per MW.

Table 10-9 Supply of tier 1 synchronized reserve by unit and fuel type: January through June, 2021

Unit / Fuel Type	Percent by MW	Percent by Credits
Steam - Coal	43.1%	49.0%
Combined Cycle	35.8%	29.8%
Hydro - Run of River	6.3%	7.3%
CT - Natural Gas	5.6%	5.3%
Wind	3.2%	3.0%
Solar	3.0%	2.7%
Steam - Natural Gas	1.1%	1.1%
RICE - Natural Gas	0.8%	0.7%
Hydro - Pumped Storage	0.6%	0.5%
Steam - Other	0.4%	0.4%
Nuclear	0.0%	0.1%
DSR	0.0%	0.1%
RICE - Other	0.0%	0.0%
CT - Oil	0.0%	0.0%
CT - Other	0.0%	0.0%
Battery	0.0%	0.0%
RICE-Oil	0.0%	0.0%

In the first six months of 2021, the SCED market solutions estimated that tier 1 MW from an average of 59 units could have an average of 1,734.1 MW of ramp available in a spinning event. For the seven spinning events in January through June 2021, PJM Settlements paid a total of 1,620.0 MW intervals from an average of 343 distinct units for an average 1,853.2 MW of real-time MW increase. Settlements include units like wind, solar, nuclear, and demand response which are not a part of the estimated tier 1 in the SCED market solutions.

By observing spin event response recorded in PJM's SCADA data, the MMU estimates actual response as the sum of the products contributing to total ACE increase from the time the event is initiated to 10 minutes after the event is initiated. Total increase in ACE is a summation not only of tier 1 response, but also of tier 2 response, regulation A and regulation D actual response (RegD response is sometimes a MW increase and sometimes a MW decrease), and changes to net imports/exports across PJM's boundaries (sometimes an increase and sometimes a decrease in MW).

In the RTO Reserve Zone, the average estimated tier 1 synchronized reserve was 1,744.4 MW (Table 10-7). In 39.9 percent of dispatch solutions, the estimated tier 1 synchronized reserve was greater than the synchronized reserve requirement, meaning that the synchronized reserve requirement was met entirely by tier 1 synchronized reserve plus self scheduled tier 2.

In the first six months of 2021, the average estimated tier 1 synchronized reserve within the MAD Subzone was 807.9 MW (Table 10-6). In 4.1 percent of dispatch solutions the estimated tier 1 synchronized reserve available within the MAD Subzone plus self scheduled tier 2 in MAD was greater than the synchronized reserve requirement and no tier 2 market needed to be cleared.

Demand

There is no required amount of tier 1 synchronized reserve. The estimated tier 1 MW are used to satisfy the total required amounts of synchronized and primary reserve.

The ancillary services market solution treats the cost of estimated tier 1 synchronized reserve as $0, even when the nonsynchronized reserve market

43 See PJM. "Manual 11: Energy & Ancillary Services Market Operations," § 4.2.1 Synchronized Reserve Market Eligibility, Rev. 115 (June 1, 2021).
44 See PJM. "Manual 11: Energy & Ancillary Services Market Operations," § 4.2.1 Synchronized Reserve Market Eligibility, Rev. 115 (June 1, 2021).

clearing price is above $0. As a result, the optimization cannot and does not minimize the total cost of primary reserves. The MMU recommends that tier 1 synchronized reserve not be paid when the nonsynchronized reserve market clearing price is above $0.

Supply and Demand

The price of synchronized reserves results from the demand curve for synchronized reserves and the supply of synchronized reserves. The demand curve is modeled in each of the synchronized reserve clearing engines (ASO, IT SCED, RT SCED). The demand curve for synchronized reserves has two steps, with an $850 penalty factor for synchronized reserve levels ranging from 0 MW to a MW amount equal to 100 percent of the MSSC and a constraint with a $300 penalty factor for synchronized reserves ranging from 100 percent of MSSC to 100 percent of MSSC plus 190 MW.

When solving for the synchronized reserve requirement the market solution first estimates the amount of tier 1 available from the energy dispatch. If the requirement is not filled by tier 1, it then commits tier 2 beginning with all self scheduled synchronized reserve.

In the MAD Subzone, the market solution takes all tier 1 MW estimated to be available within the MAD Subzone as well as the synchronized reserve MW estimated to be available within the MAD Subzone from the RTO Zone (green area of Figure 10-2). If the total tier 1 synchronized reserve is less than the synchronized reserve requirement, the remainder of the synchronized reserve requirement is filled with tier 2 synchronized reserve.

Tier 1 Synchronized Reserve Payments

Tier 1 synchronized reserve is awarded credits under two distinct circumstances. In response to a spinning event, all resources (except scheduled tier 2 resources) are paid for increasing output (or reducing load for demand response) at the rate of $50 per MWh in addition to LMP.[45] This is the Synchronized Energy Premium Price. Spinning event response is calculated as the highest output between 9 minutes and 11 minutes after the event is declared minus the lowest output between one minute before and one minute after the event is declared. Generator outputs are measured and reported to PJM every four seconds via SCADA. Total response credited to a resource is capped at 110 percent of estimated capability. These rules apply to all resources that are not scheduled tier 2 resources. As a result, spinning event response involves more MW response than the original estimate of tier 1. Many resources that are not included in PJM's estimate of tier 1 nevertheless respond to spinning events and in accordance with the PJM Tariff are paid the Synchronized Energy Premium Price. This can include incidental response from nuclear units or steam turbines running at maximum output. Such response is expected when the response is measured as the highest output for the two minute period around the end of an event minus lowest output from the two minute period around the start of an event. Tier 1 synchronized reserve that is part of the estimate (at market solution time) when there is no spinning event is also credited for its full estimated MW whenever the nonsynchronized reserve market clearing price is above $0.

In the event that the nonsynchronized reserve market clearing price is above $0 and there is a spinning event, estimated tier 1 is credited with the lesser of its actual response or its estimated capability times the SRMCP. Tier 1 synchronized reserve not part of the estimate is credited the SRMCP times its actual response.[46] In the first six months of 2021, the nonsynchronized reserve market clearing price was above $0 in 5.6 percent of intervals.

In the first six months of 2021, tier 1 synchronized reserve spinning event response credits of $101,063 were paid for seven spinning events averaging 8.7 minutes. Table 10-10 shows the number of spinning events each month, the credits paid for tier 1 response, the number of MWh credited, and the actual response in MW.

45 See PJM. "Manual 11: Energy & Ancillary Services Market Operations,"§ 4.2.10 Settlements, Rev. 115 (June 1, 2021).

46 See PJM "Manual 28: Operating Agreement Accounting," Rev. 84 (Dec. 17, 2020) p. 54.

Table 10-10 Tier 1 synchronized reserve event response costs: January 2020 through June 2021

Year	Month	Number of Spinning Events	Total Tier 1 Spinning Event Credits	Total Tier 1 Spinning Event Credited (MWh)	Total Tier 1 Spinning Response from Event Start to Event End (MW)
2020	Jan	2	$22,200	453.2	5,438.8
2020	Feb	4	$56,595	1,148.2	13,778.8
2020	Mar	1	$3,514	70.3	843.5
2020	Apr	1	$5,873	118.2	1,418.5
2020	May	1	$11,302	226.0	2,712.6
2020	Jun	0	NA	NA	NA
2020	Jul	3	$34,249	699.8	8,397.2
2020	Aug	0	NA	NA	NA
2020	Sep	1	$11,390	236.2	2,843.1
2020	Oct	2	$23,038	460.8	5,713.0
2020	Nov	1	$7,964	159.3	2,019.3
2020	Dec	1	$10,050	201.0	2,426.1
2020	Total	17	$186,176	3,773.0	45,590.9
2021	Jan	1	$6,796	97.1	1,165.0
2021	Feb	0	NA	NA	NA
2021	Mar	1	$15,729	291.7	1,715.8
2021	Apr	2	$40,442	732.2	4,677.7
2021	May	1	$21,822	331.7	2,618.6
2021	Jun	2	$16,275	162.6	3,183.0
2021	Total	7	$101,063	1,615.3	13,360.1

Paying Tier 1 the Tier 2 Price

Tier 1 synchronized reserve has zero marginal cost and the corresponding competitive price for tier 1 synchronized reserves is also zero. However, the PJM rules artificially create a marginal cost of tier 1 when the price of nonsynchronized reserve is greater than zero and tier 1 is paid the tier 2 price. The PJM market solutions do not include that marginal cost and therefore do not solve for the efficient level of tier 1, tier 2 and nonsynchronized reserve in those cases. When called to respond to a spinning event, tier 1 is compensated at the Synchronized Energy Premium Price (Table 10-12). However, the shortage pricing tariff changes (October 1, 2012) modified the pricing of tier 1 so that tier 1 synchronized reserve is paid the tier 2 synchronized reserve market clearing price whenever the nonsynchronized reserve market clearing price rises above zero. The rationale for this change was and is unclear, but it has had a significant impact on the cost of tier 1 synchronized reserves (Table 10-11). In the first six months of 2021, the nonsynchronized reserve market clearing price was above $0.00 in 29.6 percent of all intervals. For those intervals, tier 1 synchronized reserve was paid $2,372,703 for an average of 620.2 MW per interval.

Table 10-11 Price of tier 1 synchronized reserve attributable to a nonsynchronized reserve price above zero: January 2020 through June 2021

Year	Month	Number of Intervals When NSRMCP>$0	Weighted Average SRMCP When NSRMCP>$0	Total Tier 1 MWh When NSRMCP>$0	Total Tier 1 Credits When NSRMCP>$0	Average Tier 1 MWh When NSRMCP>$0
2020	Jan	0	NA	NA	NA	NA
2020	Feb	0	NA	NA	NA	NA
2020	Mar	0	NA	NA	NA	NA
2020	Apr	27	$6.12	3,654.9	$22,372	456.9
2020	May	24	$6.20	3,105.4	$19,262	310.5
2020	Jun	116	$7.58	17,163.0	$130,140	490.4
2020	Jul	166	$11.18	22,696.6	$253,682	687.8
2020	Aug	309	$12.52	42,499.8	$531,928	708.3
2020	Sep	50	$3.94	7,277.5	$28,658	519.8
2020	Oct	944	$11.86	148,481.8	$1,760,874	1,124.9
2020	Nov	255	$13.55	32,994.0	$447,060	673.4
2020	Dec	124	$8.20	15,282.5	$125,286	527.0
2020	Total	2015	$9.02	293,155.5	$3,319,263	611.0
2021	Jan	31	$20.78	3,625.7	$75,337	604.3
2021	Feb	160	$16.36	19,953.0	$326,372	739.0
2021	Mar	60	$93.20	7,768.9	$724,083	517.3
2021	Apr	196	$8.14	24,971.2	$203,196	531.3
2021	May	644	$10.65	74,895.9	$797,736	720.2
2021	Jun	183	$10.63	23,148.4	$245,979	609.2
2021	Total	1274	$26.63	154,363.1	$2,372,703	620.2

The additional payments to tier 1 synchronized reserves under the shortage pricing rule are a windfall. The additional payment does not create an incentive to provide more tier 1 synchronized reserves. The additional payment is not a payment for performance; all estimated tier 1 receives the higher payment regardless of whether they provide any response during any spinning event. Tier 1 resources are not obligated to respond to synchronized reserve events. In the first six months of 2021, there were three spinning events of 10 minutes or longer. In those events, an average of 53.1 percent of the estimated tier 1 responded and 76.3 percent of tier 2 responded.

The MMU recommends that the rule requiring the payment of tier 1 synchronized reserve resources when the nonsynchronized reserve price is above zero be eliminated immediately.[47] Tier 1 should be compensated only for a response to synchronized reserve events, as it was before the shortage pricing changes. This compensation requires that when a synchronized reserve event is called, all tier 1 response is paid the synchronized energy premium price.

PJM's current tier 1 compensation rules are presented in Table 10-12.

Table 10-12 Tier 1 compensation as currently implemented by PJM

Tier 1 Compensation by Type of Interval as Currently Implemented by PJM		
Interval Parameters	No Synchronized Reserve Event	Synchronized Reserve Event
NSRMCP=$0	T1 credits = $0	T1 credits = Synchronized Energy Premium Price * actual response MWi
NSRMCP>$0	T1 credits = T2 SRMCP * estimated tier 1 MW	T1 credits = T2 SRMCP * min(estimated tier 1 MW, actual response MWi)

The MMU's recommended compensation rules for tier 1 MW are in Table 10-13.

Table 10-13 Tier 1 compensation as recommended by MMU

Tier 1 Compensation by Type of Hour as Recommended by MMU		
Interval Parameters	No Synchronized Reserve Event	Synchronized Reserve Event
NSRMCP=$0	T1 credits = $0	T1 credits = Synchronized Energy Premium Price * actual response MWi
NSRMCP>$0	T1 credits = $0	T1 credits = Synchronized Energy Premium Price * actual response MWi

47 This recommendation was presented as a proposal, "Tier 1 Compensation," to the Markets and Reliability Committee Meeting, October 22, 2015. The MMU proposal and a PJM counterproposal were both rejected.

Tier 2 Synchronized Reserve Market

Synchronized reserve is provided by generators or demand response resources synchronized to the grid and capable of increasing output or decreasing load within 10 minutes. Synchronized reserve consists of tier 1 and tier 2 synchronized reserves. When the synchronized reserve requirement cannot be met by tier 1 synchronized reserve, PJM clears a market to satisfy the requirement with tier 2 synchronized reserve. Tier 2 synchronized reserve is provided by online resources, either synchronized to the grid but not producing energy, or dispatched to provide synchronized reserve at an operating point below their economic dispatch point. Tier 2 synchronized reserve is also provided by demand resources that have offered to reduce load in the event of a synchronized reserve event. Tier 2 synchronized reserves are committed to be available in the event of a synchronized reserve event. Tier 2 resources have a must offer requirement. Some tier 2 resources are scheduled by the ASO 60 minutes before the operating hour and are committed to provide synchronized reserve for the entire hour. Tier 2 resources are paid the higher of the SRMCP or their offer price plus lost opportunity cost (LOC). Demand response resources are paid the clearing price (SRMCP).

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 tier 2 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 tier 2 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.

During the operating hour, RT SCED can dispatch additional tier 2 resources. RT SCED can redispatch online tier 1 generating resources as tier 2 synchronized reserve to meet the synchronized and primary reserve requirements within the operational hour. Resources that are redispatched as tier 2 within the hour are expected to maintain their available ramp and are paid the SRMCP plus any lost opportunity costs that exceed the SRMCP.

Market Structure

Supply

PJM has a must offer tier 2 synchronized reserve requirement. All nonemergency generating resources are required to submit tier 2 synchronized reserve offers. All online, nonemergency generating resources are deemed available to provide both tier 1 and tier 2 synchronized reserve although certain unit types are exempt. If PJM issues a primary reserve warning, voltage reduction warning, or manual load dump warning, all offline emergency generation capacity resources available to provide energy must submit an offer for tier 2 synchronized reserve.[48]

In the first six months of 2021, the Mid Atlantic Dominion (MAD) Reserve Subzone averaged 4,649.6 MW of tier 2 synchronized reserve offers, and the RTO Reserve Zone averaged 36,322.9 MW of tier 2 synchronized reserve offers (Figure 10-6).

The supply of tier 2 synchronized reserve offered in the first six months of 2021 was sufficient to cover the ASO hourly requirement net of tier 1 in both the RTO Reserve Zone and the MAD Reserve Subzone.

The largest portion of cleared tier 2 synchronized reserve in the first six months of 2021 was from CTs running on natural gas or oil (Table 10-14). Although demand resources are limited to providing no more than 33 percent of the total synchronized reserve requirement, the amount of tier 2 synchronized reserve required in any hour is often much less than the full synchronized reserve requirement because so much of it is met with tier 1 synchronized reserve. This means that in some hours demand resources make up considerably more than 33 percent of the cleared tier 2 MW. Demand resources often offer at a price of $0, do not incur an LOC, and clear even when the price is $0. As a result, their share of credits in the synchronized reserve market is much less than their share of cleared MW.

48 See PJM "Manual 11: Energy & Ancillary Services Market Operations," § 4.2.1 Synchronized Reserve Market Eligibility, Rev. 115 June 1, 2021).

Table 10-14 Supply of Generation Tier 2 Synchronized Reserve by Unit Type and Fuel Type: January through June, 2021

Unit / Fuel Type	Percent by MW	Percent by Credits
CT - Natural Gas	34.9%	44.4%
DSR	30.7%	13.9%
CT - Oil	11.2%	8.7%
Combined Cycle	9.7%	22.7%
Hydro - Run of River	8.2%	3.8%
Steam - Coal	4.2%	5.1%
RICE - Natural Gas	0.5%	0.7%
Hydro - Pumped Storage	0.5%	0.4%
Steam - Natural Gas	0.1%	0.1%
Battery	0.0%	0.0%
CT - Other	0.0%	0.0%
Fuel Cell	0.0%	0.0%
Nuclear	0.0%	0.0%
RICE - Other	0.0%	0.0%
Solar	0.0%	0.0%
Solar + Storage	0.0%	0.0%
Solar + Wind	0.0%	0.0%
Steam - Oil	0.0%	0.0%
Steam - Other	0.0%	0.0%
Wind	0.0%	0.0%
Wind + Storage	0.0%	0.0%

Demand

On July 12, 2017, PJM adopted a dynamic synchronized reserve requirement set equal to 100 percent of the most severe single contingency (MSSC) as the first step, and extended by a 190 MW second step.[49] There are two circumstances in which PJM may alter the base portion of the synchronized reserve requirement from its 100 percent of the largest contingency value. Reserve requirements may be increased during a temporary switching condition when transmission outages or configuration problems cause several generation resources to

49 See the *2021 Quarterly State of the Market Report: January through June*, Section 3: Energy Market, at "Operating Reserve Demand Curves".

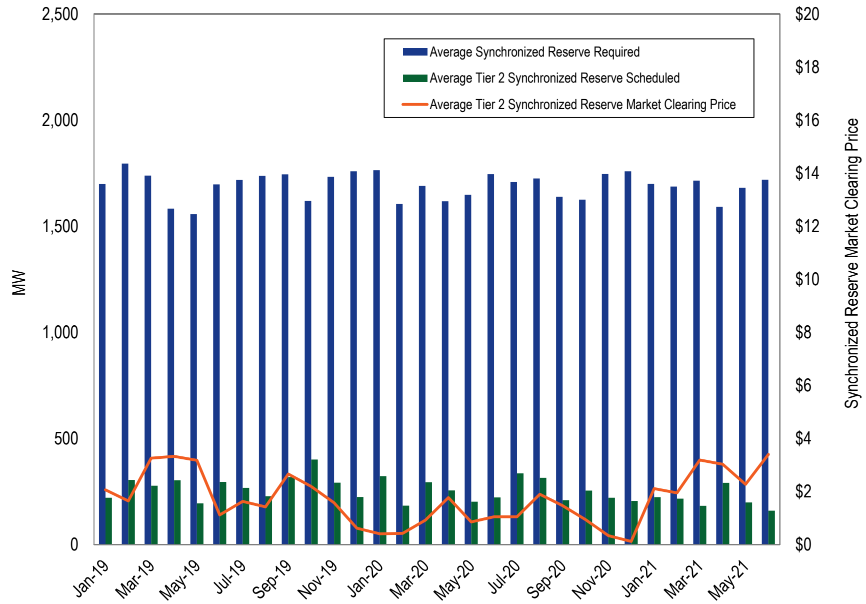
be subject to a single contingency. When PJM operators anticipate periods of high load, they may bring on additional units to account for increased operational uncertainty in meeting load. When a Hot Weather Alert, Cold Weather Alert or an emergency procedure (as defined in Manual 11 § 4.2.2 Synchronized Reserve Requirement Determination) has been issued for the operating day, operators may increase the synchronized reserve requirement up to the full amount of the additional MW brought on line.[50]

In the first six months of 2021, the average synchronized reserve requirement was 1,699.5 MW in the RTO Zone and 1,672.6 the MAD Subzone. These averages include temporary increases to the synchronized reserve requirement.

The RTO Reserve Zone scheduled and identified an average of 613.0 MW of tier 2 synchronized reserves in the first six months of 2021. Of this, an average of 531.3 MW was scheduled hourly.

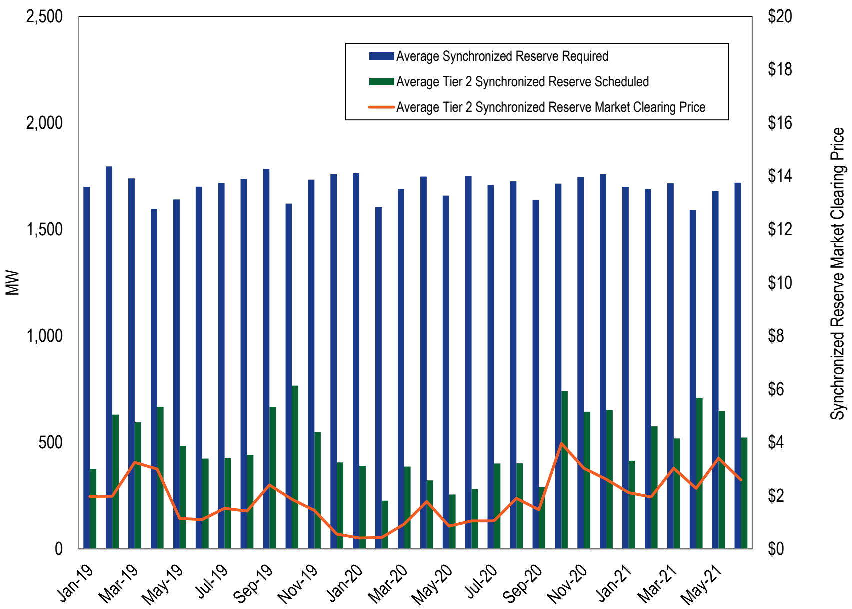
Figure 10-4 and Figure 10-5 show the average monthly synchronized reserve required and the average monthly tier 2 synchronized reserve MW scheduled (PJM scheduled plus self scheduled) from January 2019 through March 2021, for MAD Reserve Subzone and the RTO Reserve Zone. There were 33 intervals of shortage in 2019. There were 13 spinning events in 2019 but only two lasted longer than 10 minutes. There were seven intervals of shortage in 2020 and 16 spinning events with three longer than 10 minutes. In the first six months of 2021 there were four intervals of shortage and seven spinning events.

Figure 10-4 MAD hourly average tier 2 synchronized reserve scheduled MW: January 2018 through June 2021



50 PJM "Manual 11: Energy & Ancillary Services Market Operations," § 4.2.2 Synchronized Reserve Requirement Determination, Rev. 115 (June 1, 2021).

Figure 10-5 RTO hourly average tier 2 synchronized reserve scheduled MW: January 2019 through June 2021



Market Concentration

The average HHI for tier 2 synchronized reserve cleared intervals in the Mid-Atlantic Dominion Subzone Tier 2 Synchronized Reserve Market in the first six months of 2021 was 5235, which is defined as highly concentrated. In 85.0 percent of all cleared pricing intervals the maximum market share was greater than or equal to 40 percent.

The average HHI for tier 2 synchronized reserve for cleared pricing intervals of the RTO Zone Tier 2 Synchronized Reserve Market in the first six months of 2021 was 3919, which is defined as highly concentrated. In 55.5 percent of cleared intervals there was a maximum market share greater than or equal to 40 percent.

In the MAD Subzone, flexible synchronized reserve was 9.7 percent of all tier 2 synchronized reserve in the first six months of 2021. In the RTO Zone, flexible synchronized reserve was 13.0 percent of all tier 2 synchronized reserve in the first six months of 2021.

The market structure results indicate that the RTO Zone and Mid-Atlantic Dominion Subzone Tier 2 Synchronized Reserve Markets are not structurally competitive.

Market Behavior

Offers

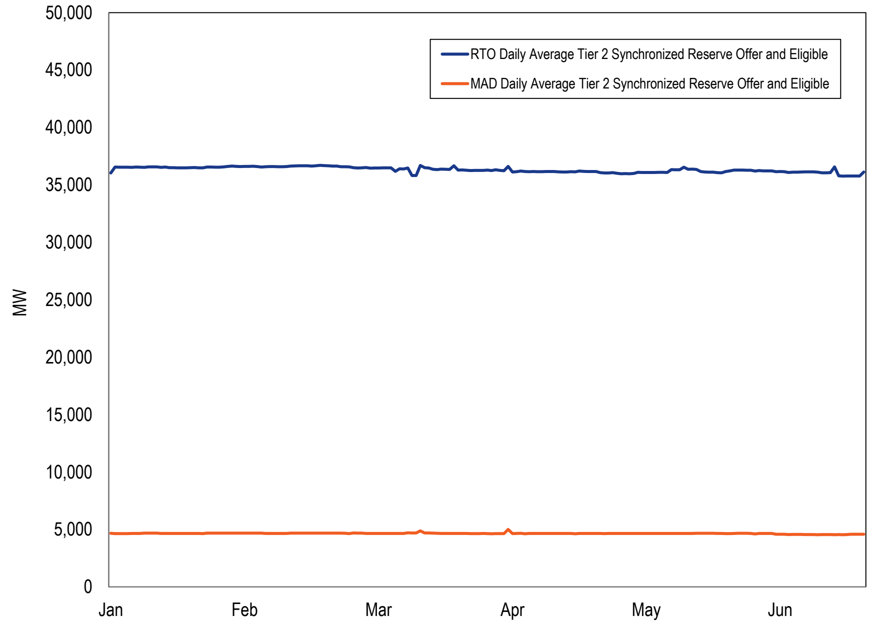
Daily cost-based offers are submitted for each unit by the unit owner. For generators the offer must include, when relevant, a tier 1 synchronized reserve ramp rate, a tier 1 synchronized reserve maximum, self scheduled status, synchronized reserve availability, synchronized reserve offer quantity (MW), tier 2 synchronized reserve offer price, energy use for tier 2 condensing resources (MW), condense to gen cost, shutdown costs, condense startup cost, condense hourly cost, condense notification time, and spin as a condenser status. The synchronized reserve offer price made by the unit owner is subject to an offer cap of marginal cost plus a markup of $7.50 per MW. The tier 1 synchronized reserve ramp rate must be greater than or equal to the real-time economic ramp rate. If the synchronized reserve ramp rate is greater than the economic ramp rate it must be justified by the submission of actual data from previous synchronized reserve events.[51] All suppliers are paid the higher of the market clearing price or their offer plus their unit specific opportunity cost. The offer quantity is limited to the economic maximum. PJM monitors this offer by checking to ensure that all offers are greater than or equal to 90 percent of the resource's ramp rate times 10 minutes. A resource that is unable to participate in the synchronized reserve market during a given hour may set its hourly offer to zero MW. Certain defined resource types are not required to offer tier 2 because they cannot reliably provide synchronized reserve. These include: nuclear, wind, solar, landfill gas and energy storage resources.[52]

51 See PJM "Manual 11: Energy & Ancillary Services Market Operations," § 4.2.1 Synchronized Reserve Market Eligibility Rev. 115 (June 1, 2021).
52 See PJM "Manual 11: Energy & Ancillary Services Market Operations," § 4.2.1 Synchronized Reserve Market Eligibility Rev. 115 (June 1, 2021).

Figure 10-6 shows the daily average of hourly offered tier 2 synchronized reserve MW for both the RTO Synchronized Reserve Zone and the Mid-Atlantic Dominion Synchronized Reserve Subzone.

PJM has a tier 2 synchronized reserve must offer requirement for all generation that is online, nonemergency, and physically able to operate with an output less than dictated by economic dispatch. Tier 2 synchronized reserve offers are made on a daily basis with hourly updates permitted. Daily offers can be changed as a result of maintenance status or physical limitations only and are required regardless of online/offline state.[53] The tier 2 synchronized reserve market is not cleared based on daily offers but based on hourly updates to the daily offers. As a result of hourly updates the actual amount of eligible tier 2 MW can change significantly every hour (Figure 10-6). Changes to the hourly offer status are only permitted when resources are physically unable to provide tier 2. Changes to hourly eligibility levels are the result of online status, minimum/maximum runtimes, minimum notification times, maintenance status and grid conditions including constraints. However, resource operators can make their units unavailable for an hour or block of hours without having to provide a reason.

Figure 10-6 Tier 2 synchronized reserve hourly offer and eligible volume (MW): January through June, 2021



Although tier 2 synchronized reserve has a must offer requirement, there are a large number of hours when many units make themselves unavailable for tier 2 synchronized reserve.

The MMU recommends that the tier 2 synchronized reserve must offer requirement be enforced. 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 to 0 MW.[54]

53 See *id.* ("Regardless of online/offline state, all non-emergency generation capacity resources must submit a daily offer for Tier 2 Synchronized Reserve in eMKT…").

54 PJM adopted a new business rule in the third quarter of 2017 to enforce compliance with the tier 2 must-offer requirement. PJM enters a zero dollar offer price for all units with a must offer obligation for tier 2 synchronized reserves.

Market Performance

Price

The price of tier 2 synchronized reserve is calculated in real time every five minutes by the RTSCED market solution for the RTO Reserve Zone and the MAD Subzone. The tier 2 synchronized reserve market price is determined not only by the offer price of each cleared MW of tier 2, but additionally by the net cost of jointly optimizing the dispatch of energy and synchronized reserve. 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).[55] The number of marginal units by schedule type is shown in Table 10-15.

Table 10-15 Schedule used for LOC of marginal units in RTSCED Tier 2 Synchronized Reserve Market LOC calculation: January through June, 2021

Number of Marginal Units	Percent of Marginal Units with LOC Based on Cost Schedule	Percent of Marginal Units with LOC Based on Price Schedule
80,850	7.9%	92.1%

In the first six months of 2021, the RTSCED cleared the RTO tier 2 synchronized reserve market in 60.4 percent of all dispatch solutions. In all other intervals there was enough tier 1 synchronized reserve to cover the synchronized reserve requirement. For intervals when the synchronized reserve requirement could not be met with tier 1, the market cleared an average of 612.6 MW of synchronized reserve (including 140.3 MW of demand response) at a MW weighted average price of $5.04 per hour.

The market clearing price for the MAD Subzone diverged from the RTO Zone in 25 intervals during the first six months of 2021.

55 PJM Manual 11: Energy & Ancillary Services Market Operations, Rev. 115 (June 1, 2021), p. 92.

Supply, demand, and performance are reflected in the price of synchronized reserve (Table 10-16).

Table 10-16 RTO Zone, average SRMCP and average scheduled, tier 1 estimated and demand response MW in RT SCED market solutions: January 2020 through June 2021

Year	Month	Weighted Average Synchronized Reserve Market Clearing Price	Average Interval Tier 2 Generation Synchronized Reserve Purchased (MW)	Average Interval Tier 1 Synchronized Reserve Estimated (MW)	Average Interval Demand Response Cleared (MW)
2020	Jan	$0.41	322.4	2,410.7	67.2
2020	Feb	$0.42	183.7	2,285.5	42.6
2020	Mar	$0.93	293.8	2,142.0	92.8
2020	Apr	$1.77	255.0	2,223.8	66.5
2020	May	$0.85	202.5	2,130.4	52.6
2020	Jun	$1.05	221.9	2,723.9	58.6
2020	Jul	$1.05	335.4	2,102.5	65.3
2020	Aug	$1.90	314.7	1,961.6	86.5
2020	Sep	$1.47	209.6	2,054.2	79.2
2020	Oct	$3.96	575.1	1,380.2	165.3
2020	Nov	$3.03	502.6	1,500.4	141.4
2020	Dec	$2.61	507.7	1,506.8	145.0
2020	Average	$1.62	327.0	2,035.2	88.6
2021	Jan	$5.74	243.7	1,760.6	88.1
2021	Feb	$4.84	325.0	1,845.7	136.5
2021	Mar	$6.84	309.3	1,704.9	122.6
2021	Apr	$3.74	380.7	1,313.3	164.5
2021	May	$6.18	407.9	1,372.3	186.3
2021	Jun	$5.55	322.4	1,699.5	142.6
2021	Average	$5.48	331.5	1,616.1	140.1

Settlement Cost

As a result of changing grid conditions, load forecasts, and unexpected generator performance, prices do not always cover the full cost to customers, including the final LOC for each resource. Because price formation occurs within the hour (on a five minute basis) but inflexible synchronized reserve commitment occurs prior to the hour, the realized, within hour price can be zero even when some tier 2 synchronized reserve is cleared. All resources cleared in the market are guaranteed to be made whole and are paid if the SRMCP does not compensate them for their offer plus LOC.

The full cost of tier 2 synchronized reserve including payments for the clearing price and out of market costs is calculated and compared to the price. The closer the price to cost ratio is to 100 percent, the more the market price reflects the full cost of tier 2 synchronized reserve. The price to cost ratio shows much tier 2 compensation results from price rather than uplift. A lower price to cost ratio indicates higher uplift.

In the first six months of 2021, the price to cost (including self scheduled) ratio of the RTO zone tier 2 synchronized reserve market averaged 65.1 percent, which was higher than the 50.6 percent price to cost ratio for 2020 (Table 10-17). Prices were significantly higher in the first six months of 2021 ($5.81) than they were in 2020 ($2.57) because of increases in the synchronized reserve requirement. The market clearing solution includes a constraint that forces all remaining synchronized reserve to be cleared from the MAD Subzone (ref. Figure 10-1) when one of the constraints defining MAD binds. RTO/MAD prices diverged in only 25 intervals in the first six months of 2021. The average tier 2 synchronized reserve price in the RTO differed from the average Tier 2 synchronized reserve price in MAD by less than $0.01.

Table 10-17 RTO Zone tier 2 synchronized reserve MW, credits, price, and cost: January 2020 through June 2021

Year	Month	Tier 2 Credited MW	Tier 2 SRMCP Credits	LOC Credits	Weighted Synchronized Reserve Market Clearing Price	Tier 2 Synchronized Reserve Cost	Price/Cost Ratio
2020	Jan	177,649	$244,383	$575,741	$1.38	$4.62	29.8%
2020	Feb	76,770	$127,375	$147,292	$1.66	$3.58	46.4%
2020	Mar	180,688	$440,691	$329,176	$2.44	$4.26	57.2%
2020	Apr	161,868	$909,181	$307,374	$5.62	$7.52	74.7%
2020	May	113,879	$320,911	$340,727	$2.82	$5.81	48.5%
2020	Jun	152,400	$468,431	$526,993	$3.07	$6.53	47.0%
2020	Jul	250,123	$881,318	$2,530,837	$3.53	$13.64	25.9%
2020	Aug	234,393	$1,076,888	$1,412,986	$4.59	$10.62	43.3%
2020	Sep	149,778	$581,505	$523,833	$3.88	$7.38	52.6%
2020	Oct	415,190	$3,364,375	$1,210,422	$8.13	$11.02	73.8%
2020	Nov	353,269	$1,884,507	$738,252	$5.35	$7.42	72.0%
2020	Dec	380,153	$1,854,411	$819,880	$4.94	$7.03	70.2%
2020		2,646,160	$12,153,976	$9,463,512	$3.95	$7.45	53.0%
2021	Jan	235,289	$1,350,486	$277,227	$5.74	$6.92	83.0%
2021	Feb	304,466	$1,355,042	$1,053,117	$4.45	$7.91	56.3%
2021	Mar	315,327	$2,326,081	$1,447,580	$7.44	$11.97	62.1%
2021	Apr	385,229	$1,351,927	$655,823	$3.52	$5.21	67.5%
2021	May	437,210	$2,831,105	$1,275,730	$6.54	$9.39	69.7%
2021	Jun	222,529	$1,098,124	$841,578	$4.95	$8.72	56.8%
2021		1,900,050	$10,312,766	$5,551,055	$5.44	$8.35	65.1%

Performance

Tier 1 resource owners are paid for the actual amount of synchronized reserve they provide in response to a synchronized reserve event.[56] Tier 2 resource owners are paid for being available but are not paid based on the actual response to a synchronized reserve event. The MMU has identified and quantified the actual performance of scheduled tier 2 synchronized reserve resources when called on to deliver during synchronized reserve events since 2011.[57] When synchronized reserve resources self schedule or clear the Tier 2 Synchronized Reserve Market they are obligated to provide their full scheduled tier 2 MW during a synchronized reserve event. Actual synchronized reserve event response is determined by final output minus initial output where final output is the largest output between 9 and 11 minutes after start of the event,

56 See *id.* at 98.
57 See *2011 State of the Market Report for PJM*, Vol. II, Section 9, "Ancillary Services," at 250.

and initial output is the lowest output between one minute before the event and one minute after the event.[58] Tier 2 resources are obligated to sustain their final output for the shorter of the length of the event or 30 minutes. Penalties are assessed for failure of a scheduled tier 2 resource to perform during any synchronized reserve event lasting 10 minutes or longer.

Tier 2 performance has not been adequate. Compliance with calls to respond to actual synchronized reserve events remains significantly less than 100 percent. For the spinning events 10 minutes or longer in 2016, the average tier 2 synchronized reserve response was 85.5 percent of all scheduled MW. In 2017, the response rate was 87.6 percent. In 2018, the response rate was 74.2 percent. In 2019, the response rate was 86.8 percent. In 2020, there were five spinning events 10 minutes or longer with an average response rate of 59.5 percent of scheduled tier 2 MW. There were three spinning events in the first six months of 2021 that were 10 minutes or longer. They had a tier 2 synchronized reserve response rate of 76.3 percent. Actual participant performance means that the penalty structure is not adequate to incent performance.

The penalty structure when a tier 2 resource fails to respond fully to a spinning event includes two components. The resource forfeits all SRMCP credits and LOC credits in the amount of the MW shortage for the day on which the event occurred. The resource also receives a penalty for all hours in the Immediate Past Interval (IPI) in the amount of MW it falls short of its scheduled MW. The penalty is applied only to the SRMCP credits, not to the LOC credits. The penalty period is calculated as the lesser of the average number of days between spinning events over the past two years (ISI) or the number of days since the resource last failed to respond fully. There are several problems with this penalty structure. Resource owners are permitted to aggregate the response of multiple units to offset an underresponse from one unit with an overresponse from a different unit to reduce an underresponse penalty.[59] The IPI uses the last spinning event when the resource did comply. But for all spin events less than 10 minutes, compliance is automatically counted as 100 percent. This incorrectly truncates the IPI. The penalty applies only to the SRMCP credits not the LOC credits. But most credits awarded are for LOC (Table 10-18).

Under the current penalty structure it is possible for a resource to not respond to any spin events and yet be paid for providing tier 2. The current penalty structure for tier 2 synchronized reserve nonperformance is not adequate to provide appropriate performance incentives.

The IPI is defined as the number of days between spinning events, regardless of duration. This definition artificially shortens the period since the last requirement to perform. The MMU continues to recommend that the IPI be defined as the number of days between spinning events 10 minutes or longer. In the first two quarters of 2021, PJM had seven spin events. Three of those events were 10 minutes or longer, March 9, April 30, and May 26. The previous 10 minute event was on December 16, 2020. If only events 10 minutes or longer were considered, the IPI would increase to 71 days from its current level of 29 days. Use of the currently defined average IPI is not appropriate. 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. Even using the proposed IPI the penalties may be insufficient to ensure response. A tier 2 shortfall penalty should include LOC payments as well as SRMCP and MW of shortfall.

Table 10-18 Comparison of tier 2 shortfall penalties under current IPI vs. MMU recommended IPI: January through June, 2021

Actual SRMCP Credits Using Current IPI	Actual Retroactive Penalty Charges Using Current IPI	Retroactive Penalty Using MMU Recommended IPI	Retroactive Penalty Using MMU Recommended IPI and LOC Forfeiture
$1,190,407	$121,752	$236,960	$395,716

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 unit specific, so the obligation to respond should also be unit specific. Any potentially offsetting response from an affiliated tier 1 resource should have been included as part of the

58 See PJM "Manual 11: Energy & Ancillary Services Market Operations," § 4.2.10 Settlements Rev. 115 (June 1, 2021).
59 See PJM "Manual 28: Operating Agreement Accounting,"§ 6.3 Charges for Synchronized Reserve, Rev. 84 (Dec. 17, 2020.)

reserves in the tier 1 estimate. Any potentially offsetting response from a tier 2 resource should have been included in that tier 2 offer.

The MMU recommends that aggregation not be permitted to offset unit specific penalties for failure to respond to a synchronized reserve event.

Spinning event response data as reported by PJM in its Operating Committee meetings is shown in Table 10-19. The tier 1 estimate is from the most recent RT SCED market solution. The tier 1 estimate includes estimated ramp only from the units that are eligible and excludes resources that have ramp available but are not part of the estimate.

Tier 1 synchronized reserve that responds to a spinning event receives a bonus payment of $50 per MWh, based on a calculation using SCADA data, regardless of whether PJM included those reserves in the estimate.

Table 10-19 shows synchronized reserve event response compliance for tier 1 and tier 2 reserves as reported by PJM, using only response from tier 1 estimated and tier 2 cleared reserves. Actual synchronized reserve response is the total increase in MW from all resources from the moment the spinning event is called to ten minutes after. To determine the actual tier 1 response, the calculation would subtract tier 2 response, changes in assigned regulation output (net compliance level to both RegA and RegD), and changes to net power flow across PJM's interface boundary. The overall response to spinning events is adequate or more than adequate to meet NERC requirements. PJM not only corrects the ACE disturbance that led to the event but over corrects. In eight of the 10 spinning events the ACE recovers not just to the NERC required level (which is the lesser of 0 or the value before the disturbance which caused the event) but overshoots.

Table 10-19 Synchronized reserve events 10 minutes or longer, tier 1 and tier 2 response compliance as reported by PJM, RTO Reserve Zone: January 2019 through June 2021

Spin Event (Day, EPT Time)	Duration (Minutes)	Tier 1 Estimate (Market Solution MW Adj by DGP)	Response from Tier 1 DGP Estimated (MW)	Tier 2 Scheduled (MW)	Tier 2 Response (MW)	Tier 2 Penalty (MW)	DGP Estimated Tier 1 Response Percent	Tier 2 Response Percent
Sep 23, 2019 12:07	11	1,485.1	1,212.1	723.2	632.1	91.1	81.6%	87.4%
Oct 1, 2019 14:56	11	265.4	143.7	1,177.4	1,016.4	161.0	54.1%	86.3%
2019 Average	11	924.7	664.1	723.2	632.1	91.1	71.8%	87.4%
Feb 18, 2020 20:15	10	2,216.1	1,434.8	40.0	1.7	38.3	64.7%	4.3%
Jul 6, 2020 21:22	10	1,464.0	526.1	479.7	415.1	64.6	35.9%	86.5%
Jul 25, 2020 16:39	11	868.4	421.6	302.3	264.8	37.5	48.5%	87.6%
Sep 10, 2020 00:29	10	1,275.4	453.6	782.6	782.6	0.0	35.6%	100.0%
Dec 16, 2020 16:49	10	268.4	196.9	527.6	413.2	114.4	73.4%	78.3%
2020 Average	10	1,218.5	606.6	426.4	375.5	51.0	49.7%	59.5%
Mar 9, 2021 07:50	10	1,354.9	635.4	884.0	540.8	343.2	46.9%	61.2%
Apr 30, 2021 16:30	12	1,487.6	610.2	508.3	407.2	101.1	41.0%	80.1%
May 26, 2021 10:17	10	1,138.4	811.0	685.2	600.2	85.0	71.2%	87.6%
2021 Average	11	1,327.0	685.5	692.5	516.1	176.4	53.1%	76.3%

Until April 2019, PJM's ASO market solution software allowed operators to bias the inflexible tier 2 synchronized reserve solution by forcing the software to assume a different tier 1 MW value than the actual estimate. PJM, in response to the MMU recommendation, no longer uses tier 1 biasing in any of its market solutions. Biasing means manually modifying (decreasing or increasing) the tier 1 synchronized reserve estimate of the market solution.

Tier 1 biasing was never referenced in PJM manuals or any public document. PJM could resume tier 1 biasing at its discretion. Although tier 1 biasing has been discontinued, PJM can and does still deselect tier 1 resources based on PJM judgment. The impact of tier 1 deselection can be very significant (Table 10-20 and Table 10-21).

Table 10-20 Units deselected for tier 1 by market solutions but awarded credits for actual response: 2021

Spinning Event	Number of Units Awarded T1 Credits	Number Units Deselected by RTSCED Awarded T1 Credits	Total T1 Credits Awarded	Percent of T1 Credits Awarded to Units Deselected for T1	Total T1 Credited MW	Percent of T1 MW Awarded Credits But Deselected
1/24/2021 3:22	1513	280	$6,592	46.0%	1,582.2	46.0%
3/9/2021 12:50	1515	938	$14,658	46.4%	1,918.9	85.0%
4/13/2021 20:05	1497	374	$18,496	38.3%	4,439.0	38.3%
4/30/2021 20:30	1496	705	$20,868	44.5%	2,921.5	76.3%
5/26/2021 14:17	1492	864	$21,233	49.0%	5,095.8	49.0%
6/21/2021 5:54	1494	545	$10,301	28.9%	2,119.0	33.7%
6/23/2021 3:33	1492	354	$5,735	50.5%	1,376.5	50.5%

Table 10-21 Comparison of market solution tier 1 estimate, tier 1 response with PJM Settlements tier 1 MW credited: January 2020 through June 2021

Start Time	Duration (Minutes)	PJM Market Solution DGP Estimated Tier 1 Estimate MW	PJM Market Solution DGP Estimated Tier 1 Response MW	PJM Settlements Tier 1 Credited Response MW
Jan 20, 2020 14:06	7.8	1,903.6	765.9	1,306.3
Jan 23, 2020 16:17	8.7	2,084.6	1,073.0	1,860.4
Feb 7, 2020 12:06	6.4	1,233.0	730.2	2,883.9
Feb 8, 2020 03:44	8.4	1,961.4	826.1	1,517.6
Feb 10, 2020 20:15	9.6	1,333.3	824.3	1,573.8
Feb 18 2020 11:16	10.0	2,216.1	1,434.8	2,528.6
Mar 8, 2020 05:17	5.6	1,541.4	660.1	843.5
Apr 13, 2020 19:53	7.9	433.0	207.2	886.5
May 3, 2020 12:23	6.6	4,154.4	1,369.6	2,260.5
Jul 6, 2020 21:22	10.4	1,464.0	526.1	1,554.5
Jul 24, 2020 01:03	9.9	1,562.7	852.8	1,762.7
Jul 25, 2020 16:39	11.7	868.4	421.6	961.5
Sep 10, 2020 00:19	9.5	1,275.4	453.6	1,417.0
Oct 10, 2020 18:52	7.7	2,134.3	1,234.3	2,187.8
Oct 12, 2020 04:29	9.3	1,625.8	670.5	1,229.2
Nov 13, 2020 11:36	5.9	1,687.9	882.4	1,682.8
Dec 16, 2020 16:38	10.0	268.4	196.9	1,213.0
Jan 25, 2021 03:32	6.5	2,134.5	577.9	1,582.2
Mar 9, 2021 12:50	10.8	1,354.9	635.4	1,918.9
Apr 13, 2021 20:05	8.8	2,093.4	975.6	4,439.0
Apr 30, 2021 20:30	11.6	1,487.6	610.2	2,921.5
May 26, 2021 14:17	10.0	1,138.4	811.0	5,095.8
Jun 21, 2021 05:54	6.9	2,340.8	1,764.1	2,119.0
Jun 23, 2021 03:33	4.7	2,277.0	1,367.8	1,376.5

History of Synchronized Reserve Events

Synchronized reserve is designed to provide relief for disturbances.[60] [61] A disturbance is defined as loss of the lesser of 900 MW or 80 percent of the most severe 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. The use of synchronized reserve is an expensive solution during an hour when the hour ahead market solution and reserve dispatch indicate no shortage of primary reserve. PJM's primary reserve levels have been sufficient to recover from disturbances and should remain available in the absence of disturbances.

From January 2010 through June 2021, PJM experienced 265 synchronized reserve events (Table 10-22), approximately two events per month. During this period, synchronized reserve events had an average duration of 11.1 minutes.

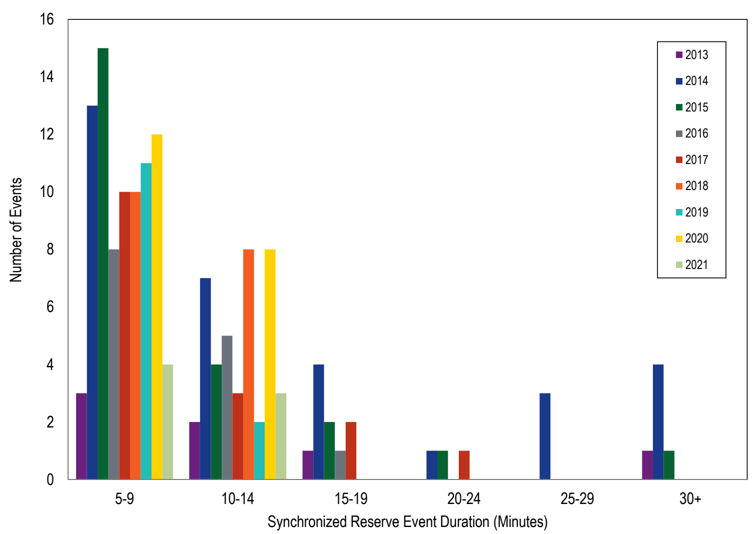
60 *2013 State of the Market Report for PJM*, Appendix F – PJM's DCS Performance, at 451–452.
61 See PJM "Manual 12: Balancing Operations," Rev. 42 (Jan. 27, 2021) § 4.1.2 Loading Reserves.

Table 10-22 Synchronized reserve events: January 2017 through June 2021[62]

Effective Time	Region	Duration (Minutes)	Effective Time	Region	Duration (Minutes)	Effective Time	Region	Duration (Minutes)	Effective Time	Region	Duration (Minutes)	Effective Time	Region	Duration (Minutes)
JAN-08-2017 03:21	RTO	7	JAN-01-2018 02:41	RTO	7	JAN-22-2019 22:30	RTO	8	JAN-20-2020 14:06	MAD	8	JAN-24-2021 22:32	RTO	6
JAN-09-2017 19:24	RTO	9	JAN-03-2018 03:00	RTO	13	JAN-31-2019 01:26	RTO	5	JAN-23-2020 16:17	RTO	9	MAR-9-2021 07:51	RTO	11
JAN-10-2017 13:05	MAD	9	JAN-07-2018 14:15	RTO	9	JAN-31-2019 09:26	RTO	9	FEB-07-2020 12:06	RTO	6	APR-13-2021 20:05	RTO	9
JAN-15-2017 20:13	RTO	8	APR-12-2018 13:28	RTO	10	FEB-25-2019 00:25	RTO	9	FEB-08-2020 03:44	RTO	8	APR-30-2021 20:30	RTO	12
JAN-23-2017 09:08	RTO	7	JUN-04-2018 10:22	RTO	6	MAR-03-2019 12:31	RTO	9	FEB-10-2020 20:15	RTO	9	MAY-26-2021 14:17	RTO	10
FEB-13-2017 18:30	RTO	7	JUN-29-2018 15:21	RTO	9	MAR-06-2019 22:06	RTO	9	FEB-18-2020 11:16	RTO	10	JUN-21-2021 05:54	RTO	7
FEB-14-2017 00:11	RTO	6	JUN-30-2018 09:46	RTO	11	JUL-27-2019 23:31	RTO	7	MAR-08-2020 05:17	MAD	5	JUN-23-2021 03:33	RTO	5
FEB-15-2017 06:37	RTO	6	JUL-04-2018 10:56	RTO	7	AUG-11-2019 12:14	RTO	8	APR-13-2020 20:01	RTO	8			
MAR-23-2017 06:48	RTO	24	JUL-10-2018 15:45	RTO	13	SEP-03-2019 13:39	MAD	9	MAY-03-2020 12:29	RTO	6			
APR-08-2017 11:53	RTO	10	JUL-23-2018 09:02	RTO	8	SEP-23-2019 16:06	RTO	11	JUL-06-2020 21:22	RTO	10			
MAY-08-2017 04:18	RTO	10	JUL-23-2018 15:43	RTO	6	OCT-01-2019 18:56	RTO	11	JUL-24-2020 01:03	RTO	9			
JUN-08-2017 03:39	RTO	10	JUL-24-2018 16:17	RTO	7	DEC-11-2019 21:08	RTO	8	JUL-25-2020 16:39	MAD	11			
JUN-20-2017 05:38	RTO	9	AUG-12-2018 11:06	RTO	11	DEC-18-2019 15:07	RTO	9	SEP-10-2020 00:19	RTO	10			
SEP-04-2017 20:18	MAD	15	SEP-13-2018 09:47	RTO	7				OCT-10-2020 18:52	RTO	8			
SEP-07-2017 09:16	RTO	9	SEP-14-2018 13:24	RTO	7				OCT-12-2020 04:29	RTO	9			
SEP-21-2017 14:15	RTO	16	SEP-26-2018 19:08	RTO	8				NOV-13-2020 07:46	RTO	6			
			SEP-30-2018 11:29	RTO	11				DEC-16-2020 16:38	MAD	10			
			OCT-30-2018 10:40	RTO	11									

Figure 10-7 shows spin event durations over the past eight years.

Figure 10-7 Synchronized reserve events duration distribution curve: January 2013 through June 2021



62 For full history of spinning events, see the *2019 State of the Market Report for PJM*, Appendix E - Ancillary Service Markets.

Nonsynchronized Reserve Market

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 market mechanism for nonsynchronized reserve does not include any direct participation by market participants. 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 and on the associated resource opportunity costs calculated by PJM. Generation owners do not submit supply offers. Since nonsynchronized reserve is a lower quality product, its clearing price is less than or equal to the synchronized reserve market clearing price. In most hours, the nonsynchronized reserve clearing price is zero.

Market Structure

Demand

Demand for primary reserve is established by PJM as one and a half times the largest contingency. Demand for primary reserve is calculated dynamically in every synchronized and nonsynchronized reserve market solution. After filling the synchronized reserve requirement the balance of primary reserve can be made up by the most economic combination of synchronized and nonsynchronized reserve. In practice this means that the primary reserve requirement minus the scheduled synchronized reserve is the nonsynchronized requirement for the interval. PJM may increase the primary reserve requirement to cover times when a single contingency could cause an outage of several generating units or in times of high load conditions causing operational uncertainty.[63]

The average scheduled nonsynchronized reserve in the RTO Zone in the first six months of 2021 was 1,537.3 MW. The average scheduled nonsynchronized reserve in the MAD Subzone for primary reserve was 1,235.7 MW.

Supply

Figure 10-2 shows that when tier 1 synchronized reserve does not fully meet the synchronized reserve requirement, then most of the primary reserve requirement (blue line) in excess of the synchronized reserve requirement (purple line) is satisfied by nonsynchronized reserve (green area).

There are no offers for nonsynchronized reserve. 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 set themselves as unavailable or have set their output to be emergency only will not be considered. The market solution considers the offered MW to be the lesser of the economic maximum or the ramp rate times 10 minutes minus the startup and notification time. The market supply curve is constructed from the nonsynchronized units' opportunity cost of providing reserves. PJM and generation owners may agree upon exceptions to the requirements.

Nonsynchronized reserve resources are scheduled economically based on estimated LOC until the Primary Reserve requirement is filled. The nonsynchronized reserve market clearing price is determined every five minutes based on the LOC of the marginal unit. When a unit clears the nonsynchronized reserve market and is scheduled, it is committed to remain offline and available to provide 10 minute reserves.

Resources that generally qualify as nonsynchronized reserve include run of river hydro, pumped hydro, combustion turbines, combined cycles that can

63 See PJM "Manual 11: Energy and Ancillary Services Market Operations," § 4.2.2 Synchronized Reserve Requirement Determination, Rev. 115 (June 1, 2021).

start in 10 minutes or less, and diesels.[64] In the first six months of 2021, an average of 1,243.4 MW of nonsynchronized reserve was scheduled per five minute interval out of 1,320.1 eligible MW as part of the primary reserve requirement in the RTO Zone. If only intervals when the price was greater than $0 are looked at, then an average of 635.4 MW of nonsynchronized reserve is scheduled out of 983.5 MW available.

In the first six months of 2021, CTs provided 88.4 percent of scheduled nonsynchronized reserve (Table 10-23). Natural gas was the primary fuel for nonsynchronized reserve.

Table 10-23 Supply of nonsynchronized reserve by fuel and unit type: January through June, 2021

Unit / Fuel Type	Percent by MW	Percent by Credits
CT - Natural Gas	51.9%	62.1%
CT - Oil	36.5%	27.7%
Hydro - Run of River	11.1%	10.0%
Hydro - Pumped Storage	0.2%	0.1%
CT - Other	0.2%	0.1%
Combined Cycle	0.0%	0.0%
Steam - Coal	0.0%	0.0%
RICE - Natural Gas	0.0%	0.0%
Steam - Natural Gas	0.0%	0.0%
Battery	0.0%	0.0%
RICE - Other	0.0%	0.0%
Fuel Cell	0.0%	0.0%
Nuclear	0.0%	0.0%
Solar	0.0%	0.0%
Solar + Storage	0.0%	0.0%
Solar + Wind	0.0%	0.0%
Steam - Oil	0.0%	0.0%
Steam - Other	0.0%	0.0%
Wind	0.0%	0.0%
Wind + Storage	0.0%	0.0%

Market Concentration

The supply of nonsynchronized reserves in the Mid-Atlantic Dominion Subzone and the RTO Zone was highly concentrated in the first six months of 2021.

Table 10-24 Nonsynchronized reserve market pivotal supplier test: January through June, 2021

Year	Month	Number Intervals of Clearing Price > $0.01	Percent of Intervals NSRMCP>$0.02 Pivotal
2021	Jan	30	100.0%
2021	Feb	130	89.8%
2021	Mar	56	83.9%
2021	Apr	163	100.0%
2021	May	615	100.0%
2021	Jun	186	100.0%
2021	Average	197	95.6%

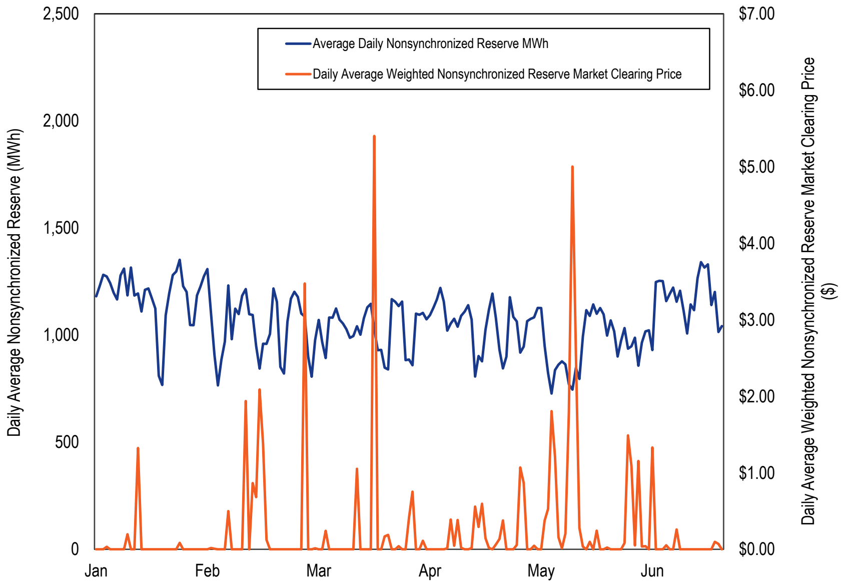
Price

The settled price of nonsynchronized reserve is calculated in real time every five minutes for the RTO Reserve Zone and the Mid-Atlantic Dominion Reserve Subzone.

Figure 10-8 shows the daily average nonsynchronized reserve market clearing price (NSRMCP) and average scheduled MW for the RTO Zone. In the first six months of 2021, the weighted average nonsynchronized market clearing price was $0.25 per MW. The average nonsynchronized reserve scheduled was 1,065.7 MW.

64 See PJM "Manual 11: Energy & Ancillary Services Market Operations," § 4b.2 Non-Synchronized Reserve Market Business Rules, Rev. 115 (June 1, 2021)

Figure 10-8 Daily average RTO Zone nonsynchronized reserve market clearing price and MW purchased: January through June, 2021



Price and Cost

As a result of changing grid conditions, load forecasts, incorrect LMP and lost opportunity cost projections, and unexpected generator performance, prices frequently do not cover the full LOC of each resource. All resources cleared in the market are guaranteed to be made whole and are paid uplift credits if the NSRMCP does not fully compensate them. When real-time LMP is greater than the generator's incremental energy offer at economic minimum, then an LOC is paid, even if LMP revenue would not have covered the unit's start and no load costs.[65]

The full cost to customers of nonsynchronized reserve, including payments for the clearing price and uplift costs is calculated and compared to the price (Table 10-25). The closer the price to cost ratio comes to one, the more compensation is provided through market prices rather than uplift.

In the first six months of 2021, the average price of nonsynchronized reserve was $0.25. The average cost per MW of nonsynchronized reserve was $1.28.

Resources that are not synchronized to the grid are generally off because it is not economic for them to produce energy. A resource scheduled for nonsynchronized reserve is obligated to remain unsynchronized even if its LMP changes and it becomes economic to start. In that case, the unit has a positive LOC.

65 See PJM "Manual 11: Energy & Ancillary Services Market Operations," § 2.16 Minimum Capacity Emergency in Day-ahead Market, Rev. 115 (June 1, 2021).

Table 10-25 RTO zone nonsynchronized reserve MW, charges, price, and cost: January 2020 through June 2021

Market	Year	Month	Total Nonsynchronized Reserve MW	Total Nonsynchronized Reserve Charges	Weighted Nonsynchronized Reserve Market Price	Nonsynchronized Reserve Cost	Price/Cost Ratio
RTO Zone	2020	Jan	775,929	$377,336	$0.00	$0.49	NA
RTO Zone	2020	Feb	758,614	$138,939	$0.00	$0.18	NA
RTO Zone	2020	Mar	806,059	$170,156	$0.00	$0.21	NA
RTO Zone	2020	Apr	665,747	$644,306	$0.02	$0.97	2.1%
RTO Zone	2020	May	774,183	$425,791	$0.01	$0.55	1.1%
RTO Zone	2020	Jun	619,391	$649,601	$0.11	$1.05	10.4%
RTO Zone	2020	Jul	767,222	$648,118	$0.24	$0.84	28.4%
RTO Zone	2020	Aug	799,233	$1,106,678	$0.49	$1.38	35.4%
RTO Zone	2020	Sep	761,617	$750,028	$0.02	$0.98	2.0%
RTO Zone	2020	Oct	773,420	$1,588,183	$0.93	$2.05	45.2%
RTO Zone	2020	Nov	725,048	$809,177	$0.36	$1.12	31.9%
RTO Zone	2020	Dec	851,859	$921,357	$0.07	$1.08	6.4%
RTO Zone	2020	Total	9,078,323	$8,229,669	$0.19	$0.91	18.10%
RTO Zone	2021	Jan	878,568	$531,437	$0.05	$0.60	8.3%
RTO Zone	2021	Feb	706,486	$600,304	$0.27	$0.85	31.8%
RTO Zone	2021	Mar	760,807	$1,612,035	$0.34	$2.12	16.0%
RTO Zone	2021	Apr	752,203	$422,508	$0.14	$0.56	25.8%
RTO Zone	2021	May	725,702	$1,795,780	$0.53	$2.47	21.3%
RTO Zone	2021	Jun	801,295	$942,343	$0.19	$1.18	16.3%
RTO Zone	2021	Total	4,625,059	$5,904,407	$0.25	$1.28	19.9%

Secondary Reserve (DASR)

There is no NERC standard for secondary reserve. PJM defines secondary reserve as reserves (online or offline available for dispatch) that can be converted to energy in 30 minutes. PJM defines a secondary reserve requirement but does not currently have a defined reserve product to maintain this reserve requirement in real time.

PJM maintains a day-ahead, offer based market for 30 minute day-ahead secondary reserve. The Day-Ahead Scheduling Reserve Market (DASR) has no performance obligations except that a unit which clears the DASR market is required to be available for dispatch in real time.[66]

Market Structure

Supply

Both generation and demand resources are eligible to offer DASR. DASR offers consist of price only. Available DASR MW are calculated by the market clearing engine. DASR MW are the lesser of the energy ramp rate per minute for online units times 30 minutes, or the economic maximum MW minus the day-ahead dispatch point. For offline resources capable of being online in 30 minutes, the DASR quantity is the economic maximum. In the first six months of 2021, the average available hourly DASR was 17,368.1 MW, a 3.7 percent decrease from 2020. The DASR hourly MW purchased averaged 4,563.4 MW.[67]

PJM excludes resources that cannot reliably provide reserves in real time from participating in the DASR market. Such resources include nuclear, run of river hydro, self scheduled pumped hydro, wind, solar, and energy storage resources.[68] The intent of this proposal is to limit cleared DASR resources to those resources actually capable of providing reserves in the real-time market. Owners of excluded resources may request an exemption from their default noneligibility.

Of the scheduled DASR MW cleared in the first six months of 2021, 84.1 percent was from CTs (Table 10-26).

66 See PJM "Manual 11: Energy & Ancillary Services Market Operations," § 10.5 Aggregation for Economic and Emergency Demand Resources, Rev. 115 (June 1, 2021).

67 The average hourly available DASR MW are modified from previously reported values because of a calculation error which has been fixed.

68 See PJM "Manual 11: Energy & Ancillary Services Market Operations," § 11.2.2 Day-Ahead Scheduling Reserve Market Eligibility, Rev. 115 (June 1, 2021).

Table 10-26 Scheduled DASR by fuel and unit type: January through June, 2021

Unit Types	Percentage of DASR MW	Percentage of DASR Credits
CT - Natural Gas	66.1%	64.8%
CT - Oil	18.0%	17.5%
Hydro - Pumped Storage	9.4%	7.2%
Combined Cycle	3.9%	5.1%
Steam - Coal	2.1%	2.1%
Steam - Natural Gas	0.2%	2.0%
RICE - Oil	0.2%	0.8%
RICE - Other	0.1%	0.3%
RICE - Natural Gas	0.0%	0.2%
Steam - Other	0.0%	0.0%
Nuclear	0.0%	0.0%
CT - Other	0.0%	0.0%
Battery	0.0%	0.0%
Fuel Cell	0.0%	0.0%
Hydro - Run of River	0.0%	0.0%
Solar	0.0%	0.0%
Solar + Storage	0.0%	0.0%
Solar + Wind	0.0%	0.0%
Steam - Oil	0.0%	0.0%
Wind	0.0%	0.0%
Wind + Storage	0.0%	0.0%

Demand

Secondary reserve (30 minute reserve) requirements are determined by PJM for each reliability region. In the ReliabilityFirst (RFC) region, secondary reserve requirements are calculated based on historical under forecasted load rates and generator forced outage rates.[69] The DASR requirement is calculated daily and is equal to the peak load forecast for the ReliabilityFirst region (RFC) and EKPC times the sum of the forced outage rate and the load forecast error, plus Dominion's share of the VACAR contingency reserve commitment. Effective November 1, 2020 through October 31, 2021, the day-ahead scheduling reserve requirement is 4.72 percent of the peak load forecast. This is based on a 2.18 percent load forecast error component and a 2.60 percent forced outage rate component. The DASR requirement is applicable for all hours of the operating day.

69 See PJM "Manual 13: Emergency Operations," § 2.2 Reserve Requirements, Rev. 78 (Jan. 27, 2021).

The DASR requirement can be increased by PJM operators under conditions of "hot weather or cold weather alert or max emergency generation alert or other escalating emergency."[70] The amount of additional DASR MW that may be required is the Adjusted Fixed Demand (AFD) determined by a Seasonal Conditional Demand (SCD) factor.[71] The SCD factor is calculated separately for the winter (November through March) and summer (April through October) seasons. The SCD factor is calculated every year based on the top 10 peak load days from the prior year. For November 2020 through October 2021, the SCD values are 2.12 percent for winter and 4.72 percent for summer. PJM Dispatch may also schedule additional Day-Ahead Scheduling Reserves as deemed necessary for conservative operations.[72] PJM has defined the reasons for conservative operations to include, potential fuel delivery issues, forest/brush fires, extreme weather events, environmental alerts, solar disturbances, unknown grid operating state, physical or cyber attacks.[73] The result is substantial discretion for PJM to increase the demand for DASR under a variety of circumstances. PJM invoked adjusted fixed demand in 84 hours during the first six months of 2021.

The MMU recommends that PJM modify the DASR market to ensure that all resources cleared incur a real-time performance obligation. The MMU further recommends that PJM attach a reason code to all hours when adjusted fixed demand is dispatched.

70 PJM. "Energy and Reserve Pricing & Interchange Volatility Final Proposal Report," <http://www.pjm.com/~/media/committees-groups/committees/mrc/20141030/20141030-item-04-erpiv-final-proposal-report.ashx>.

71 See PJM "Manual 11: Energy & Ancillary Services Market Operations," § 11.2.1 Day-Ahead Scheduling Reserve Market Requirement. Rev. 115 (June 1, 2021)

72 See PJM "Manual 11: Energy & Ancillary Services Market Operations," § 11.2.1 Day-Ahead Scheduling Reserve Market Reserve Requirement, Rev. 115 (June 1, 2021).

73 See PJM "Manual 13: Emergency Operations," § 3.2 Conservative Operations, Rev. 78 (Jan. 27, 2021).

Market Concentration

DASR market three pivotal supplier test results are provided in Table 10-27.

Table 10-27 DASR market three pivotal supplier test results and number of hours with DASRMCP above $0.01: January 2020 through June 2021

Year	Month	Number of Hours When DASRMCP > $0	Percent of Hours Where DASRMCP>0 Pivotal
2020	Jan	1	33.3%
2020	Feb	1	50.0%
2020	Mar	1	100.0%
2020	Apr	17	70.8%
2020	May	70	49.3%
2020	Jun	73	22.7%
2020	Jul	89	42.0%
2020	Aug	73	22.7%
2020	Sep	59	66.3%
2020	Oct	86	50.6%
2020	Nov	47	67.1%
2020	Dec	35	50.7%
2020	Average	46	0.0%
2021	Jan	28	32.1%
2021	Feb	32	46.9%
2021	Mar	24	41.7%
2021	Apr	129	47.3%
2021	May	79	59.5%
2021	Jun	156	47.4%
2021	Average	75	45.8%

Market Conduct

PJM rules allow any unit with reserve capability that can be converted into energy within 30 minutes to offer into the DASR market.[74] Units that do not offer have their offers set to $0.00 per MW during the day-ahead market clearing process.

Economic withholding remains an issue in the DASR market. The marginal cost of providing DASR is zero. All offers greater than zero constitute economic withholding. In the first six months of 2021, 39.3 percent of generation units offered DASR at a daily price above $0.00 per MW. In the first six months of 2021 15.8 percent of daily offers were above $5.00 per MW.

The MMU recommends that market solutions for the DASR market be based on opportunity cost only in order to eliminate economic withholding.

Market Performance

In the first six months of 2021, the DASR market cleared at a price above $0.00 per MW in 10.3 percent of all hours. The weighted average DASR price for all cleared hours was $0.10 per MW. The average cleared MW in all hours was 4563.4 MW. The average cleared MW in all hours when the DASRMCP was above $0.00 was 5,395.6 MW. The highest DASR price was $20.00 per MW for a total of five hours in the first six months of 2021: two hours on June 6, one hour on June 28, and two hours on June 29.

The introduction of Adjusted Fixed Demand (AFD) on March 1, 2015, created a bifurcated market. In 2015, PJM added AFD to the normal 5.93 percent of forecast load in 367 hours. In 2016, PJM added AFD to the normal 5.7 percent of forecast load in 522 hours. In 2017, PJM added AFD to the normal 5.52 percent of forecast load in 336 hours. In 2018, PJM added AFD to the normal 5.28 percent in 598 hours. In 2019, PJM added AFD to the normal 5.29 percent in 447 hours. In 2020, PJM added AFD to the normal 5.07 percent in 430 hours. There were no AFD hours in the first four months of 2021. There were 25 AFD hours in May and 115 AFD hours in June. The difference in market clearing price, MW cleared, obligation incurred, and charges to PJM load are substantial. Table 10-28 shows the differences in price and MW between AFD hours and non-AFD hours in 2021.

74 See PJM "Manual 11: Energy & Ancillary Services Market Operations," § 11.2.2 Day-Ahead Scheduling Reserve Market Eligibility, Rev. 115 (June 1, 2021).

Table 10-28 Impact of Adjusted Fixed Demand on DASR prices and demand: January through June, 2021

Metric	Number of Hours	Weighted Day-Ahead Scheduling Reserve Market Clearing Price (DASRMCP)	Average Hourly Total DASR MW
All hours	4,344	$0.10	4,563.4
All hours when DASRMCP > $0	448	$0.95	5,395.6
All hours when AFD used	139	$2.24	8,397.9

While the new rules allow PJM operators' substantial discretion to add to DASR demand for a variety of reasons, the rationale for each specific increase is not always clear. The MMU recommends that PJM Market Operations attach a reason code to every hour in which PJM operators add additional DASR MW above the default DASR hourly requirement. The addition of such a code would make the reason explicit, increase transparency and facilitate analysis of the use of PJM's ability to add DASR MW.

Comparing the Normal Hour column against the AFD Hour column for five metrics (Table 10-29) shows that the use of AFD for 84 hours in the first six months of 2021 significantly increased the cost of DASR. Table 10-29 shows that the cost increase was a result of a substantial increase in DASR MW cleared. The average DASR clearing price in 2021 was $0.27 for hours when the clearing price was above $0.00 and $2.89 during hours when adjusted fixed demand was invoked by PJM Dispatch.

Table 10-29 DASR market, regular hours vs. adjusted fixed demand hours: January 2020 through June 2021

		Number of Hours DASRMCP > $0		Weighted DASRMCP		Average PJM Load MW		Hourly Average Cleared DASR MW		Average Hourly DASR Credits	
Year	Month	Normal Hour	AFD Hour	Normal Hour	AFD Hour	Normal Hour	AFD Hour	Normal Hour	AFD Hour	Normal Hour	AFD Hour
2020	Jan	1	NA	$0.00	NA	89,919	NA	4939	NA	$2	NA
2020	Feb	1	NA	$0.00	NA	88,655	NA	4863	NA	$2	NA
2020	Mar	1	NA	$0.00	NA	78,508	NA	4449	NA	$1	NA
2020	Apr	17	NA	$0.00	NA	70,687	NA	4045	NA	$0	NA
2020	May	70	NA	$0.01	NA	71,826	NA	4106	NA	$57	NA
2020	Jun	73	48	$1.28	$1.87	110,779	97,191	6512	10250	$8,788	20,556
2020	Jul	89	358	$3.20	$2.41	123,379	110,399	8269	9055	$27,660	22,838
2020	Aug	73	24	$1.71	$5.74	118,231	110,971	6051	10223	$10,535	59,981
2020	Sep	59	NA	$0.39	NA	102,265	NA	5064	NA	$1,982	NA
2020	Oct	86	NA	$0.31	NA	80,004	NA	4195	NA	$1,295	NA
2020	Nov	47	NA	$0.21	NA	89,150	NA	4484	NA	$928	NA
2020	Dec	35	NA	$0.20	NA	100,845	NA	4820	NA	$977	NA
2020		552	430	$0.61	$2.55	93,687	106,187	5,150	9,843	$4,352	$34,458
2021	Jan	28	NA	$0.08	NA	106,153	NA	4,847	NA	$380	NA
2021	Feb	32	NA	$0.17	NA	108,947	NA	4,974	NA	$815	NA
2021	Mar	24	NA	$0.17	NA	92,014	NA	4,327	NA	$732	NA
2021	Apr	129	NA	$0.21	NA	83,962	NA	3,986	NA	$846	NA
2021	May	68	11	$0.58	$1.78	99,007	105,454	4,661	9,521	$2,785	$18,160
2021	Jun	83	73	$0.41	$4.00	115,654	118,725	5,170	8,952	$2,124	$42,697
2021		364	84	$0.27	$2.89	100,956	112,090	4,661	9,236	$1,280	$30,428

Table 10-30 shows total number of hours when a DASR market cleared at a price above $0 along with average load, cleared MW, additional MW under AFD, and total charges for the DASR market in January 2020 through June 2021.

Table 10-30 DASR market all hours of DASR market clearing price greater than $0: January 2020 through June 2021

Year	Month	Number of Hours DASRMCP > $0	Weighted DASR Market Clearing Price	Average Hourly RT Load MW	Total PJM Cleared DASR MW	Total PJM Cleared Additional DASR MW	Total Credits
2020	Jan	1	$0.08	111,016	14,817	0	$1,462
2020	Feb	1	$0.16	109,218	15,961	0	$1,524
2020	Mar	1	$0.17	92,457	4,532	0	$861
2020	Apr	17	NA	NA	NA	0	NA
2020	May	70	$0.29	96,413	146,365	0	$42,334
2020	Jun	73	$1.28	110,779	1,015,850	491,982	$2,357,557
2020	Jul	89	$3.20	123,379	2,753,429	3,241,749	$17,386,688
2020	Aug	73	$1.71	118,232	1,349,321	245,362	$3,788,869
2020	Sep	59	$0.39	102,265	531,772	0	$207,765
2020	Oct	86	$0.31	80,004	851,671	0	$262,925
2020	Nov	47	$0.21	89,150	385,608	0	$79,842
2020	Dec	35	$0.20	100,845	438,634	0	$88,929
2020	Total	552	$0.73	103,069	7,507,960	3,979,093	$24,218,756
2021	Jan	28	$0.08	106,153	135,710	0	$10,640
2021	Feb	32	$0.17	108,947	159,163	0	$26,076
2021	Mar	24	$0.17	92,014	103,839	0	$17,564
2021	Apr	129	$0.21	83,962	514,243	0	$109,180
2021	May	79	$0.75	99,905	421,673	53,470	$389,148
2021	Jun	156	$2.09	117,091	1,082,585	337,734	$3,293,168
2021	Total	448	$0.58	101,345	2,417,214	391,204	$3,845,775

When the DASR requirement is increased by PJM dispatch, the reserve requirement frequently cannot be met without redispatching online resources which significantly affects the price by creating an LOC. Adjusted Fixed Demand related increases in the DASR requirement (Table 10-30) in 2020 caused prices to increase. The lack of Adjusted Fixed Demand in January through April of 2021 helped keep DASR price and cost lower than in 2020.

Regulation Market

Regulation matches generation with very 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.[75] 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

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

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

The regulation market converts performance adjusted RegD MW into effective MW using the MBF in the PJM design. The MBF is used to convert incremental additions of RegD MW into incremental effective MW. The total effective MW for a given amount of RegD MW equal the area under the MBF curve (the sum of the incremental effective MW contributions). RegA and RegD resources should be paid the same price per marginal 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.[76] Performance scores are reported on an hourly basis for each resource.

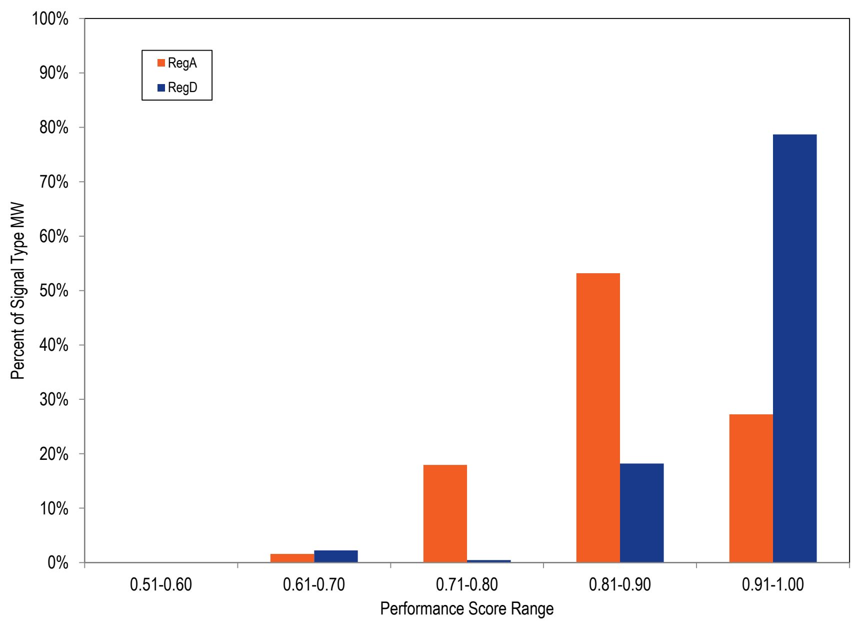
Table 10-31 and Figure 10-9 show the average performance score by resource type and the signal followed in the first six months of 2021. In these figures, the MW used are actual MW and the performance score is the hourly performance score of the regulation resource.[77] Each category (color bar) is based on the percentage of the full performance score distribution for each resource (or signal) type. As Figure 10-9 shows, 78.7 percent of RegD resources had average performance scores within the 0.91-1.00 range, and 27.2 percent of RegA resources had average performance scores within that range in the first six months of 2021. In the first six months of 2020, 78.3 percent of RegD resources had average performance scores within the 0.91-1.00 range, and 36.8 percent of RegA resources had average performance scores within that range.

76 PJM "Manual 12: Balancing Operations," § 4.5.6 Performance Score Calculation, Rev. 42 (Jan. 27, 2021).
77 Except where explicitly referred to as effective MW or effective regulation MW, MW means actual MW unadjusted for either MBF or performance factor.

Table 10-31 Hourly average performance score by unit type: January through June, 2021

		Performance Score Range				
		51-60	61-70	71-80	81-90	91-100
RegA	Battery	-	-	-	-	-
	CT	-	0.4%	3.3%	41.0%	55.3%
	Diesel	-	-	-	-	91.2%
	DSR	-	0.0%	29.3%	56.7%	14.0%
	Hydro	-	-	0.0%	35.2%	64.8%
	Steam	0.0%	2.3%	26.1%	61.3%	10.3%
RegD	Battery	-	2.4%	0.1%	16.4%	80.7%
	CT	-	0.0%	24.9%	75.1%	0.0%
	Diesel	-	-	0.0%	100.0%	-
	DSR	0.0%	0.0%	10.5%	51.9%	37.6%
	Hydro	-	0.0%	-	40.5%	59.5%
	Steam	-	-	-	-	-

Figure 10-9 Hourly average performance score by regulation signal type: January through June, 2021



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 10-32). 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 10-32 Seasonal regulation requirement definitions[78]

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.

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

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 with FERC, stating that these changes discriminated against their battery units.[79] The MMU objected to these complaints. On April 7, 2020, FERC approved a settlement between PJM and the complainants.[80] 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 FERC settlement also requires that the affected battery units be cleared in the regulation market regardless of whether their offer would have cleared under normal circumstances, as long as they are offered as either self scheduled with a zero offer, or as a zero priced offer.[81] 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 10-33 shows the impact of clearing additional MW beyond what is needed for the regulation requirement, as a result of the battery settlement. Through the first six months of 2021, the battery settlement has resulted in customers paying $309,882 more than needed to compensate the settlement batteries.

Table 10-33 Excess payments and MW cleared due to battery settlement: January through June, 2021

	Battery Settlement Impact	
Month	Regulation Credits	Additional Cleared Regulation MW
Jan	$49,387	3,149.4
Feb	$24,776	1,727.7
Mar	$37,648	3,192.6
Apr	$78,650	4,872.3
May	$117,329	7,718.7
Jun	$2,092	147.4
Total	$309,882	20,808.0

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

80 See 170 FERC ¶ 61,258.

81 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.[82]

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

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

throughout the optimization and settlement process in the PJM Regulation Market, but the proposal was rejected by FERC.[83]

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.[84] 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.

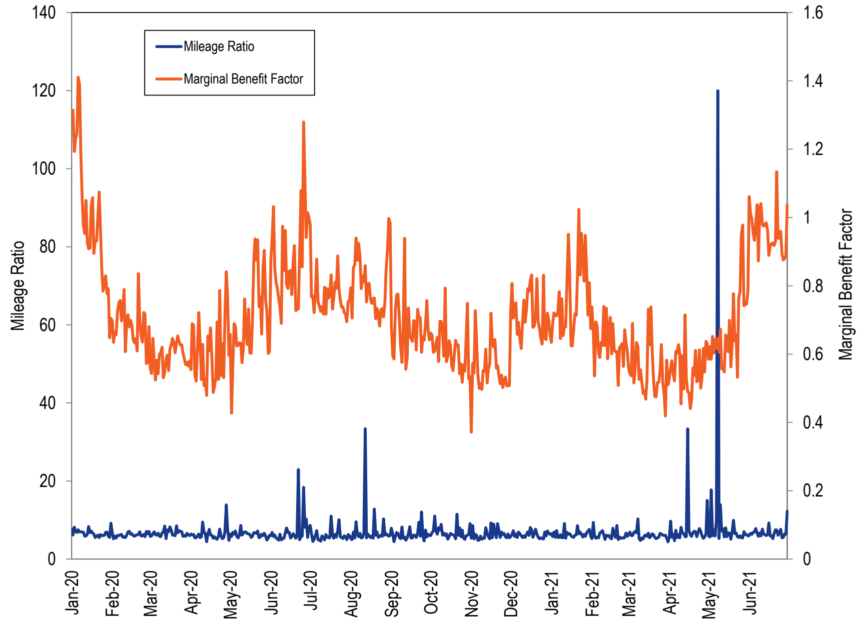
The change in design decreased RegA mileage (the change in MW output in response to regulation signal per MW of capability), increased the proportion of cleared RegD resources' capability that was called by the RegD signal (increased REG for a given MW) to better match offered capability, increased the 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 10-10 shows the daily average MBF and the mileage ratio. The weighted average mileage ratio increased from 6.56 in the first six months of 2020, to 7.31 in the first six months of 2021 (an increase of 11.4 percent). The average MBF decreased from 0.74 in the first six months of 2020, to 0.69 in the first six months of 2021 (a decrease of 7.5 percent). This decrease was primarily due to the additional RegD MW clearing as a result of the FERC settlement ruling, which went into effect on July 1, 2020. 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.

83 162 FERC ¶ 61,295 (2018), *reh'g denied*, 170 FERC ¶ 61,259 (2020).
84 145 FERC ¶ 61,011 (2013).

Figure 10-10 Daily average MBF and mileage ratio: January 2020 through June 2021



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 10-34 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, 2020, through June 30, 2021. The average regulation market clearing price in the first six months of 2021 was $6.51 higher than in the first six months of 2020 (See Table 10-49). Coupled with the lower average MBF, RegD continued to be overpaid compared to RegA on a performance adjusted actual MW basis. In the first six months of 2021, RegD resources earned 22.1 percent more per performance adjusted actual MW than RegA resources (24.7 percent in the first six months of 2020) due to the inclusion of the mileage ratio in RegD MW settlement.

Table 10-34 Average monthly price paid per performance adjusted actual MW of RegD and RegA: January 2020 through June 2021

		Settlement Payments		
Year	Month	RegD ($/Performance Adjusted MW)	RegA ($/Performance Adjusted MW)	Percent RegD Overpayment ($/Performance Adjusted MW)
2020	Jan	$16.51	$13.05	26.5%
	Feb	$11.83	$9.57	23.6%
	Mar	$11.06	$8.60	28.6%
	Apr	$14.29	$11.45	24.8%
	May	$14.72	$12.46	18.2%
	Jun	$15.09	$11.85	27.3%
	Jul	$18.02	$15.63	15.3%
	Aug	$18.11	$14.83	22.2%
	Sep	$12.68	$10.33	22.7%
	Oct	$21.82	$17.31	26.0%
	Nov	$19.45	$15.25	27.5%
	Dec	$18.18	$15.34	18.6%
Yearly		$16.01	$13.00	23.2%
2021	Jan	$14.29	$11.43	25.1%
	Feb	$23.87	$19.90	19.9%
	Mar	$20.81	$17.93	16.0%
	Apr	$20.86	$16.73	24.6%
	May	$20.22	$16.42	23.2%
	Jun	$23.01	$18.40	25.1%
Average		$20.44	$16.74	22.1%

The current settlement process does not result in paying RegA and RegD resources the same price per effective MW. RegA resources are paid on the basis of dollars per effective MW of RegA. RegD resources are not paid in terms of dollars per effective MW of RegA because the MBF is not used in settlements. Instead of being paid based on the MBF, (RMCCP + RMPCP)*MBF, RegD resources are paid based on the mileage ratio (RMCCP + (RMPCP*mileage ratio)). Because the RMCCP component makes up the majority of the overall clearing price, when the MBF is above one, RegD resources can be underpaid on a per effective MW basis by the current payment method, unless offset by a high mileage ratio. When the MBF is less than one, RegD resources are overpaid on a per effective MW basis, unless offset by a low mileage ratio. The average MBF was less than 1.0 in the first six months of 2021 (0.69).

The effect of using the mileage ratio instead of the MBF for purposes of settlement is illustrated in Table 10-35. Table 10-35 shows how much RegD resources are currently being paid, adjusted to a per effective MW basis, on average, in every month in 2020 and the first six months of 2021 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. In the first six months of 2021, the MBF averaged 0.69, while the average daily mileage ratio was 7.31, resulting in RegD resources being paid $6.2 million more than they would have been paid on an effective MW basis if the MBF were correctly implemented. In the first six months of 2020, the MBF averaged 0.75, and the average mileage ratio was 6.56, resulting in RegD resources being paid $3.5 million more than they would have been paid if the MBF were correctly implemented.

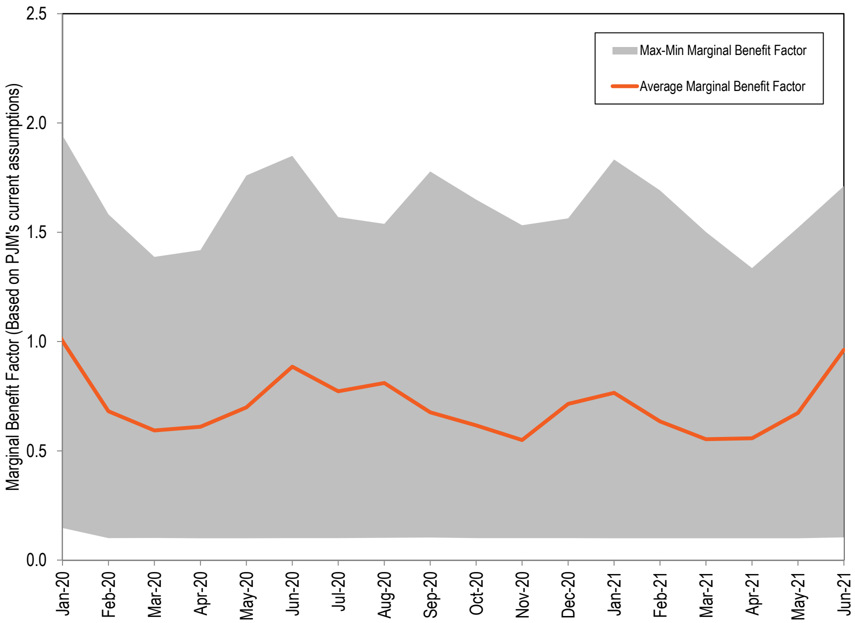
Table 10-35 Average monthly price paid per effective MW of RegD and RegA under mileage and MBF based settlement: January 2020 through June 2021[85]

		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 ($)
2020	Jan	$19.61	$13.05	$13.05	50.3%	$318,560
	Feb	$25.79	$9.57	$9.57	169.5%	$505,037
	Mar	$29.47	$8.60	$8.60	242.6%	$665,219
	Apr	$38.85	$11.45	$11.45	239.4%	$745,528
	May	$37.37	$12.46	$12.46	199.9%	$746,137
	Jun	$25.00	$11.85	$11.85	111.0%	$548,730
	Jul	$34.99	$15.63	$15.63	123.9%	$657,628
	Aug	$31.78	$14.83	$14.83	114.4%	$753,199
	Sep	$28.51	$10.33	$10.33	175.9%	$661,906
	Oct	$69.18	$17.31	$17.31	299.6%	$1,534,621
	Nov	$63.11	$15.25	$15.25	313.8%	$1,319,529
	Dec	$43.39	$15.34	$15.34	182.9%	$886,873
Yearly		$37.30	$13.00	$13.00	186.9%	$9,342,966
2021	Jan	$30.47	$11.43	$11.43	166.6%	$558,397
	Feb	$88.91	$19.90	$19.90	346.7%	$1,310,283
	Mar	$61.03	$17.93	$17.93	240.4%	$1,277,850
	Apr	$65.99	$16.73	$16.73	294.3%	$1,492,094
	May	$39.55	$16.42	$16.42	140.9%	$1,081,445
	Jun	$26.57	$18.40	$18.40	44.4%	$457,543
Average		$51.54	$16.74	$16.74	207.8%	$6,177,612

Figure 10-11 shows, the monthly maximum, minimum and average MBF, for January 2020 through June 2021. The average daily MBF in the first six months of 2021 was 0.69. The average daily MBF in the first six months of 2020 was 0.75. The bottom of the MBF range results from PJM's administratively defined MBF minimum threshold of 0.1.

85 There was an error in previously reported versions of this table. The total RegD overpayment column was overstated. The correct values are included here.

Figure 10-11 Maximum, minimum, and average PJM calculated MBF by month: January 2020 through June 2021



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.[86]

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 10-36 shows, by month, cleared RegD MW with an effective price of $0.00 (units with zero offers plus self scheduled units) for January 2020 through June 2021. In the first six months of 2021, an average of 99.7 percent of all RegD MW clearing the market had an effective offer of $0.00. In the first six months of 2020, an average of 99.7 percent of all cleared RegD MW had an effective cost of $0.00. In the first six months of 2021, an average of 74.9 percent of all RegD offers were self scheduled, compared to an average of 76.5 percent of all RegD offers in the first six months of 2020.

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 4.6 MW (2.4 percent), from 190.9 MW in the first six months of 2020 to 195.5 MW in the first six months of 2021. The average monthly RegD cleared with an effective cost of zero increased 4.6 MW (2.4 percent), from 190.4 MW in the first six months of 2020 to 195.0 MW in the first six months of 2021. Self scheduled RegD cleared MW increased 0.5 MW (0.4 percent), from 145.9 MW in the first six months of 2020 to 146.5 MW in the first six months of 2021. Average cleared RegD MW with a zero cost offer increased 4.1 MW (9.1 percent), from 44.5 MW in the first six months of 2020 to 48.5 MW in the first six months of 2021. The increase in the average monthly RegD cleared resulted in the reduction of the average monthly MBF seen in Figure 10-11.

86 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 10-36 Average cleared RegD MW and average cleared RegD with an effective price of $0.00 by month: January 2020 through June 2021

		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
2020	Jan	32.1	18.8%	137.2	80.5%	169.2	99.4%	170.3
	Feb	48.8	24.6%	149.6	75.4%	198.5	100.0%	198.5
	Mar	48.0	24.4%	148.1	75.5%	196.1	100.0%	196.1
	Apr	47.1	24.0%	149.3	75.9%	196.4	99.9%	196.7
	May	43.2	22.6%	147.6	77.3%	190.8	99.9%	191.0
	Jun	47.7	24.7%	143.8	74.5%	191.4	99.2%	192.9
	Jul	47.9	24.0%	151.0	75.7%	199.0	99.8%	199.4
	Aug	48.2	24.5%	147.5	74.9%	195.6	99.3%	196.9
	Sep	40.7	21.3%	149.7	78.4%	190.4	99.7%	191.0
	Oct	46.2	23.7%	148.7	76.1%	194.9	99.8%	195.3
	Nov	50.3	25.3%	148.5	74.7%	198.8	100.0%	198.9
	Dec	47.2	24.1%	147.9	75.7%	195.1	99.8%	195.4
Yearly		45.6	23.6%	147.4	76.2%	193.0	99.7%	193.5
2021	Jan	49.6	26.1%	139.9	73.7%	189.6	99.9%	189.8
	Feb	52.4	25.6%	152.3	74.4%	204.7	100.0%	204.7
	Mar	47.2	23.3%	155.4	76.7%	202.6	100.0%	202.6
	Apr	48.6	24.0%	154.0	76.0%	202.7	100.0%	202.7
	May	47.5	24.8%	143.8	75.0%	191.3	99.9%	191.6
	Jun	45.8	25.2%	133.3	73.4%	179.2	98.6%	181.7
Average		48.5	24.8%	146.4	74.9%	194.9	99.7%	195.4

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.

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.

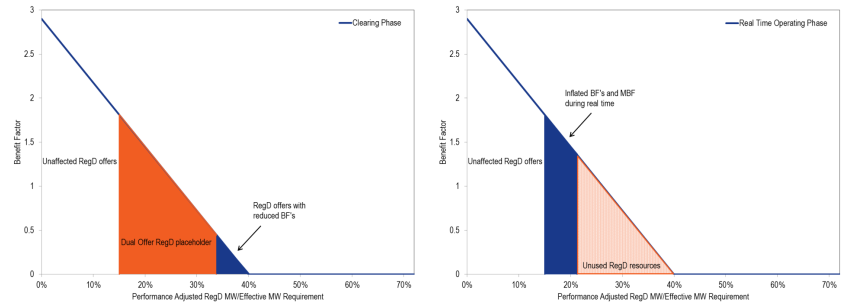
Each dual offer resource is assigned to run as either a RegD or RegA resource based on which of the two offers has a lower effective cost. But PJM does not redefine the supply curve using appropriately recalculated unit specific benefit factors for the remaining RegD resources prior to clearing the market.

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.

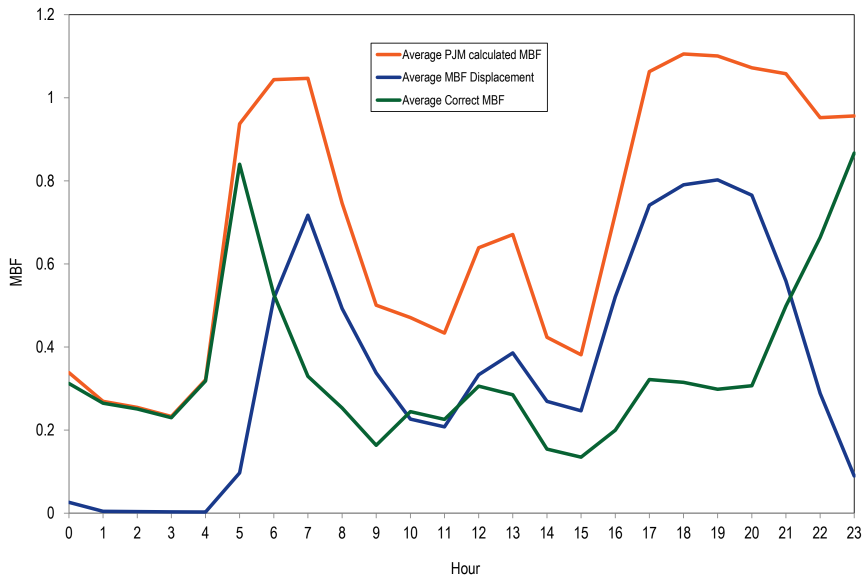
The issue is illustrated in Figure 10-12. The example shows a clearing phase and a real time operating phase. In this example, a 150 MW unit offers both RegA and RegD. The 150 MW unit's position in the RegD effective cost curve and the potential effective MW are represented as the orange area under the 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 10-12 Clearing phase BF/effective MW reduction, real-time BF/effective MW inflation, and exclusion of available RegD resources



In the first six months of 2021, all hours had at least one unit with a dual offer. In the first six months of 2021, 92.8 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 0.48 in the operating phase. 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 10-13 illustrates the PJM calculated average MBF in real time (operating phase), the average 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 six months of 2021 if the clearing solution were solved correctly.

Figure 10-13 Effect of PJM's current dual offer clearing method on the average MBF in each hour of the day: January through June, 2021



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.

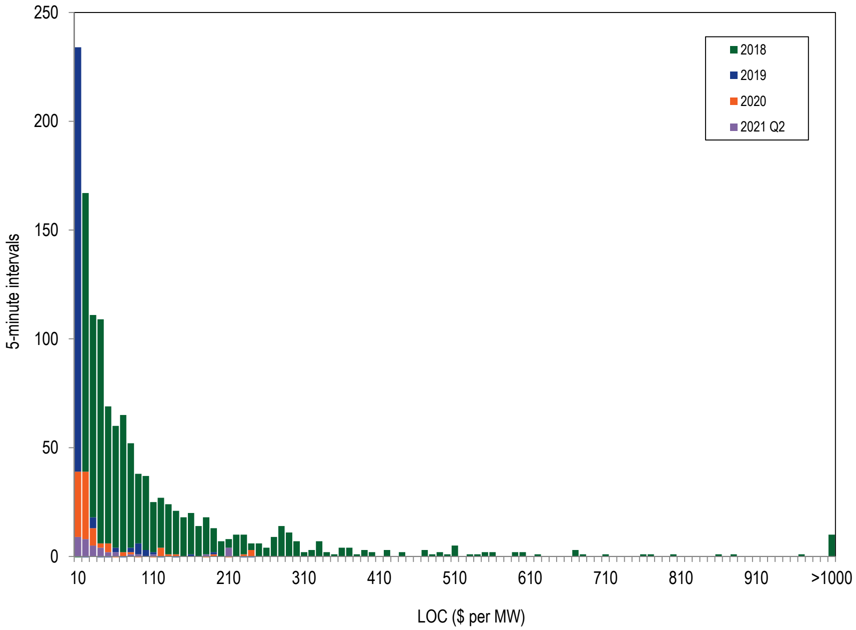
The regulation market is cleared on an hour ahead basis, using offers that are adjusted by dividing each component of an offer (capability, performance, and lost opportunity cost) by the product of the unit specific benefit factor and unit specific performance score. To calculate the hour ahead estimate 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.[87] 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 10-14 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 in 2018, 2019, 2020, and in the first six months of 2021.

87 See 166 FERC ¶ 61,040 (2019).

Figure 10-14 LOC distribution in each five minute interval with a RegD marginal unit and an LOC greater than zero: 2018 through June 2021



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.

Lost Opportunity Cost Calculation Issues

The final calculation of regulation LOC during settlements results in the overpayment of uplift in some cases. In order to determine the amount of regulation LOC, 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 amount of MW output at LMP used in the calculation of regulation LOC 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 or inability of a unit to actually produce the desired output because it does not take into account the physical limitations of the unit's ability to ramp. This can result in overpayment of uplift by paying for MW that the unit would never have been able to achieve, given their energy market output at the beginning of the interval and their ramp rate.

Table 10-37 shows the amount of uplift overpayment by fuel type for the first six months of 2021. The overpayments are calculated using a desired MW level that can be achieved based on the units' ramp rates. In the first six months of 2021, overpayments totaled $3,409,442. Coal units receive the majority of the overpayment while only providing 9.4 percent of settled regulation MW.

Table 10-37 Amount of LOC overpayment: January through June, 2021

	Uplift overpayment		
Month	Coal	Natural Gas	Total
Jan	$193,493	$158,574	$352,066
Feb	$192,078	$317,746	$509,824
Mar	$264,985	$429,131	$694,115
Apr	$193,678	$214,241	$407,919
May	$467,981	$178,919	$646,900
Jun	$565,172	$233,445	$798,618
Total	$1,877,387	$1,532,055	$3,409,442

Market Structure

Supply

Table 10-38 shows average hourly offered MW (actual and effective), and average hourly cleared MW (actual and effective) for all hours in the first six months of 2021.[88] 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.[89] 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 six months of 2021, the average hourly offered supply of regulation for nonramp hours was 758.5 actual MW (751.6 effective MW). This was an increase of 57.4 actual MW (an increase of 45.7 effective MW) from the first six months of 2020, when the average hourly offered supply of regulation was 701.1 actual MW (705.9 effective MW). In the first six months of 2021, the average hourly offered supply of regulation for ramp hours was 1,072.8 actual MW (1,093.8 effective MW). This was an increase of 91.3 actual MW (an increase of 65.1 effective MW) from the first six months of 2020, when the average hourly offered supply of regulation was 981.5 actual MW (1,028.7 effective MW).

The ratio of the average hourly offered supply of regulation to average hourly regulation demand (actual cleared MW) for ramp hours was 1.52 in the first six months of 2021 (1.39 in the first six months of 2020). The ratio of the

88 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.
89 See "PJM Manual 11: Energy & Ancillary Services Market Operations," § 3.2.2 Regulation Market Eligibility, Rev. 115 (June 1, 2021).

average hourly offered supply of regulation to average hourly regulation demand (actual cleared MW) for nonramp hours was 1.54 in the first six months of 2021 (1.43 in the first six months of 2020).

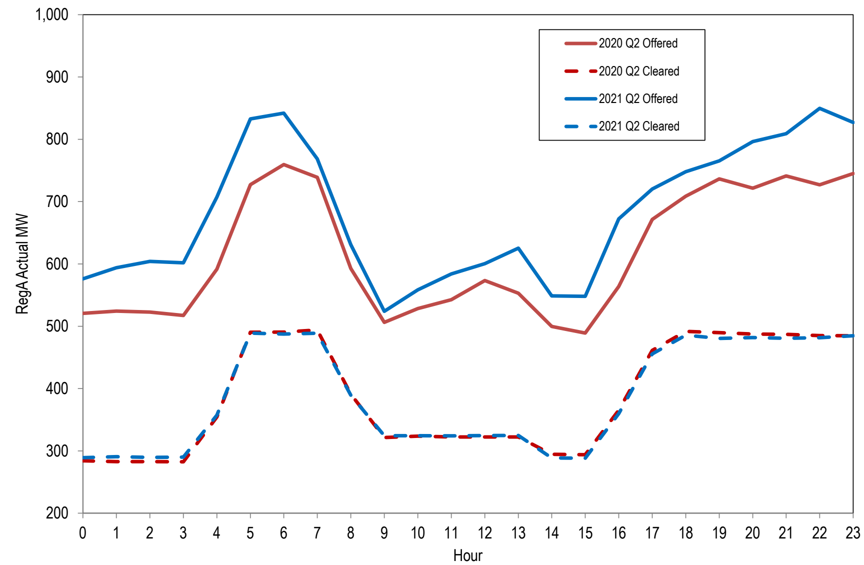
Table 10-38 Hourly average actual and effective MW offered and cleared: January through June, 2021[90]

			By Resource Type		By Signal Type	
		All Regulation	Generating Resources	Demand Resources	RegA Following Resources	RegD Following Resources
Actual Offered MW	Ramp	1,072.8	1,062.4	10.4	810.5	262.4
	Nonramp	758.5	751.5	7.0	554.8	203.7
Effective Offered MW	Ramp	1,093.8	1,081.3	12.5	698.7	395.1
	Nonramp	751.6	745.2	6.5	474.6	277.1
Actual Cleared MW	Ramp	707.1	696.8	10.3	487.6	219.4
	Nonramp	491.6	484.7	6.9	289.0	202.6
Effective Cleared MW	Ramp	800.0	787.5	12.5	423.5	376.5
	Nonramp	525.3	518.9	6.4	248.6	276.6

The average hourly offered and cleared actual MW from RegA resources are shown in Figure 10-15. The average hourly offered MW from RegA resources during ramp hours for the first six months of 2021 was 810.5 actual MW, an increase of 9.6 percent from the first six months of 2020 (739.7 actual MW.) The average hourly offered MW from RegA resources during nonramp hours for the first six months of 2021 was 554.8 actual MW, an increase of 11.5 percent from the first six months of 2020 (497.6 actual MW). The average hourly cleared MW from RegA resources during ramp hours for the first six months of 2021 was 487.6 actual MW, a decrease of 0.5 percent from the first six months of 2020 (490.3 actual MW). The average hourly cleared MW from RegA resources during nonramp hours for the first six months of 2021 was 289.0 actual MW, an increase of 0.2 percent from the first six months of 2020 (288.3 actual MW).

90 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.

Figure 10-15 Average hourly RegA actual MW offered and cleared: January through June, 2020 through 2021



The average hourly offered MW from RegD resources during ramp hours for the first six months of 2021 was 262.4 actual MW, an increase of 8.5 percent from the first six months of 2020 (241.8 actual MW). (Figure 10-16) The average hourly offered MW from RegD resources during nonramp hours for the first six months of 2021 was 203.7 actual MW, an increase of 0.1 percent from the first six months of 2020 (203.5 actual MW) (Figure 10-16). The average hourly cleared MW from RegD resources during ramp hours for the first six months of 2021 was 219.4 actual MW, an increase of 2.6 percent from the first six months of 2020 (213.9 actual MW). The average hourly cleared MW from RegD resources during nonramp hours for the first six months of 2021 was 202.6 actual MW, an increase of 0.6 percent from the first six months of 2020 (201.4 actual MW). These increases in the amount of RegD offered and cleared MW were the result of the battery settlement that went into effect on July 1, 2020. If settlement battery units do not clear through the normal clearing process, PJM clears those units anyway, procuring excess MW beyond the regulation requirement and charging customers for the excess.

Figure 10-16 Average hourly RegD actual MW offered and cleared: January through June, 2020 through 2021

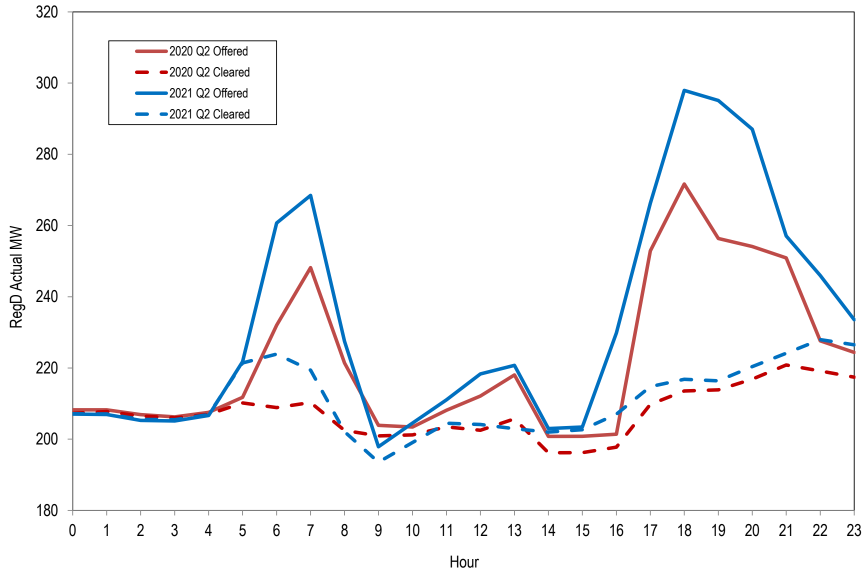


Table 10-39 provides the settled regulation MW by source unit type, the total settled regulation MW provided by all resources, the percent of settled regulation provided by unit type, and the clearing price, uplift, and total regulation credits. In Table 10-39 the MW have been adjusted by the performance score since this adjustment forms the basis of payment for units providing regulation. Total regulation performance adjusted settled MW increased 0.3 percent from 2,291,864.0 MW in the first six months of 2020 to 2,299,445.8 MW in the first six months of 2021. The average proportion of regulation provided by battery units had the largest increase (2.1 percent), providing 33.7 percent of regulation in the first six months of 2020 and 35.8 percent of regulation in the first six months of 2021. Natural gas units had the largest decrease in average proportion of regulation provided (4.5 percent), decreasing from 38.9 percent in 2020, to 34.4 percent in the first six months of 2021. The total regulation credits in the first six months of 2021 were $49,803,839, an increase of 48.6 percent from $33,526,208 in the first six months of 2020. The increase in regulation credits is due, in part, to a higher LOC component of regulation prices as a result of higher energy prices in the first six months of 2021 compared to the first six months of 2020.

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 and has provided regulation, their regulation LOC is calculated again during settlements, using the actual LMP. If this actual regulation LOC causes the unit's total offer to be larger than the clearing price, the unit receives uplift credits. The uplift credits received for each unit type are shown in Table 10-39. The total uplift credits received increased 42.2 percent from $4,117,883 in the first six months of 2020 to $5,854,455 in the first six months of 2021. This increase, like the increase in total credits, is due in part to higher LOC components of regulation prices and offers as a result of higher energy prices in the first six months of 2021 compared to the first six months of 2020. Natural gas units had the largest increase in uplift payments, increasing from $919,134 (22.3 percent of total) in the first six months of 2020, to $2,213,556 (37.8 percent of total) in the first six months of 2021. Coal units had the largest decrease in uplift payments, decreasing from $1,829,075 (44.4 percent of total) in the first six months of 2020, to $1,788,061 (30.5 percent of total) in the first six months of 2021.

Table 10-39 PJM regulation by source: January through June, 2020 and 2021[91]

	2020 (Jan-Jun)						2021 (Jan-Jun)					
Source	Number of Units	Performance Adjusted Settled Regulation (MW)	Percent of Settled Regulation	Clearing Price Credits	Uplift Credits	Total Regulation Credits	Number of Units	Performance Adjusted Settled Regulation (MW)	Percent of Settled Regulation	Clearing Price Credits	Uplift Credits	Total Regulation Credits
Battery	22	771,719	33.7%	$10,752,327	$0	$10,752,327	22	822,396	35.8%	$17,138,298	$0	$17,138,298
Coal	19	172,273	7.5%	$2,287,764	$1,829,075	$4,116,839	19	216,231	9.4%	$3,786,446	$1,788,061	$5,574,507
Hydro	26	413,316	18.0%	$5,066,814	$1,369,675	$6,436,489	27	436,673	19.0%	$8,142,453	$1,852,838	$9,995,291
Natural Gas	146	891,543	38.9%	$10,658,211	$919,134	$11,577,344	170	791,997	34.4%	$14,177,799	$2,213,556	$16,391,355
DR	21	43,013	1.9%	$643,210	$0	$643,210	18	32,149	1.4%	$704,387	$0	$704,387
Total	234	2,291,864.0	100.0%	$29,408,325	$4,117,883	$33,526,208	256	2,299,445.8	100.0%	$43,949,383	$5,854,455	$49,803,839

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 10-40).

Table 10-40 Active battery storage projects by submitted year: 2014 through June 2021

Year	Number of Storage Projects	Total Capacity (MW)
2014	1	10.0
2015	5	61.0
2016	0	0.0
2017	1	2.0
2018	19	690.1
2019	62	4,008.7
2020	158	9,872.6
2021	151	13,240.4
Total	397	27,884.8

The supply of regulation can be affected by regulating units retiring from service. If all units that are requesting retirement through the first six months of 2021 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 10-32).

Table 10-41 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

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

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 RegA and RegD resources equal to 491.3 hourly average performance adjusted actual MW in the first six months of 2021. This is an increase of 1.7 performance adjusted actual MW from the first six months of 2020, when the average hourly total regulation cleared performance adjusted actual MW for nonramp hours were 489.6 performance adjusted actual MW. The ramp regulation requirement of 800.0 effective MW was provided by a combination of RegA and RegD resources equal to 707.3 hourly average performance adjusted actual MW in the first six months of 2021. This is an increase of 3.2 performance adjusted actual MW from the first six months of 2020, where the average hourly regulation cleared MW for ramp hours were 704.1 performance adjusted actual MW.

Table 10-41 Required regulation and ratio of supply to requirement: January 2020 through June 2021

		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	2020	2021	2020	2021	2020	2021	2020	2021
Ramp	Jan	712.9	713.2	800.1	800.0	1.36	1.59	1.25	1.42
	Feb	694.3	709.7	800.0	800.0	1.31	1.53	1.22	1.37
	Mar	692.5	713.8	800.1	800.0	1.33	1.54	1.24	1.38
	Apr	707.5	702.8	800.1	800.0	1.41	1.48	1.29	1.33
	May	711.8	705.5	800.1	800.0	1.42	1.45	1.31	1.32
	Jun	705.5	698.8	800.0	799.9	1.52	1.50	1.38	1.36
	Jul	702.8	-	800.1	-	1.57	-	1.42	-
	Aug	705.1	-	800.0	-	1.47	-	1.34	-
	Sep	694.8	-	799.8	-	1.46	-	1.33	-
	Oct	696.0	-	800.1	-	1.46	-	1.33	-
	Nov	700.9	-	800.1	-	1.43	-	1.30	-
	Dec	705.5	-	800.1	-	1.56	-	1.40	-
Nonramp	Jan	479.5	495.1	525.1	525.2	1.43	1.52	1.33	1.42
	Feb	495.9	500.4	525.1	525.1	1.45	1.59	1.37	1.47
	Mar	493.1	495.9	525.1	525.2	1.36	1.59	1.29	1.47
	Apr	492.7	490.9	525.2	525.1	1.46	1.51	1.36	1.41
	May	486.6	487.1	525.3	525.5	1.45	1.54	1.36	1.43
	Jun	490.0	478.6	525.1	525.4	1.45	1.50	1.36	1.39
	Jul	498.1	-	525.4	-	1.46	-	1.38	-
	Aug	489.8	-	525.0	-	1.43	-	1.35	-
	Sep	484.8	-	525.2	-	1.46	-	1.36	-
	Oct	491.3	-	525.2	-	1.50	-	1.41	-
	Nov	501.8	-	525.5	-	1.50	-	1.41	-
	Dec	500.8	-	525.1	-	1.63	-	1.50	-

Market Concentration

In the first six months of 2021, the effective MW weighted average HHI of RegA resources was 2288 which is highly concentrated and the weighted average HHI of RegD resources was 1670 which is moderately concentrated. The weighted average HHI of all resources was 1218, 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 10-42 includes a monthly summary of three pivotal supplier (TPS) results. In the first six months of 2021, 87.7 percent of hours had three or fewer pivotal suppliers. The MMU concludes that the PJM Regulation Market in the first six months of 2021 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 is not saved. PJM has submitted a request to the vendor to save all data necessary for verification.

Table 10-42 Regulation market monthly three pivotal supplier results: 2019 through June 2021

	Percent of Hours Pivotal		
Month	2019	2020	2021
Jan	77.8%	99.1%	91.4%
Feb	76.0%	97.4%	88.7%
Mar	93.3%	98.3%	87.2%
Apr	93.1%	96.5%	88.5%
May	94.0%	94.9%	83.9%
Jun	91.0%	89.8%	86.4%
Jul	92.7%	89.0%	
Aug	93.1%	94.6%	
Sep	93.3%	93.3%	
Oct	96.1%	94.0%	
Nov	90.7%	91.0%	
Dec	96.1%	83.6%	
Average	90.6%	93.5%	87.7%

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.[92] 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 14:15 the day before the operating day.[93]

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.[94]

Up until one hour 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.[95]

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).[96] Figure 10-17 compares average hourly regulation and self scheduled regulation during ramp and nonramp hours on an effective MW basis. 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.[97]

92 See "PJM Manual 11: Energy & Ancillary Services Market Operations," § 3.2.1 Regulation Market Eligibility, Rev. 115 (June 1, 2021).
93 Id. at 3.2.2, at p 62.
94 See "PJM Manual 15: Cost Development Guidelines," § 7.8 Regulation Cost, Rev. 37 (Dec. 9, 2020).
95 See "PJM Manual 11: Energy & Ancillary Services Market Operations," § 3.2.1 Regulation Market Eligibility, Rev. 115 (June 1, 2021).
96 See "PJM Manual 28: Operating Agreement Accounting," § 4.1 Regulation Accounting Overview, Rev. 84 (Dec. 17, 2020).
97 See "PJM Manual 11: Energy & Ancillary Services Market Operations," § 3.2.1 Regulation Market Eligibility, Rev. 115 (June 1, 2021).

Self scheduled regulation comprised an average of 49.0 percent during ramp hours and 63.4 percent during nonramp hours in the first six months of 2021.

Figure 10-17 Nonramp and ramp regulation levels: January 2020 through June 2021

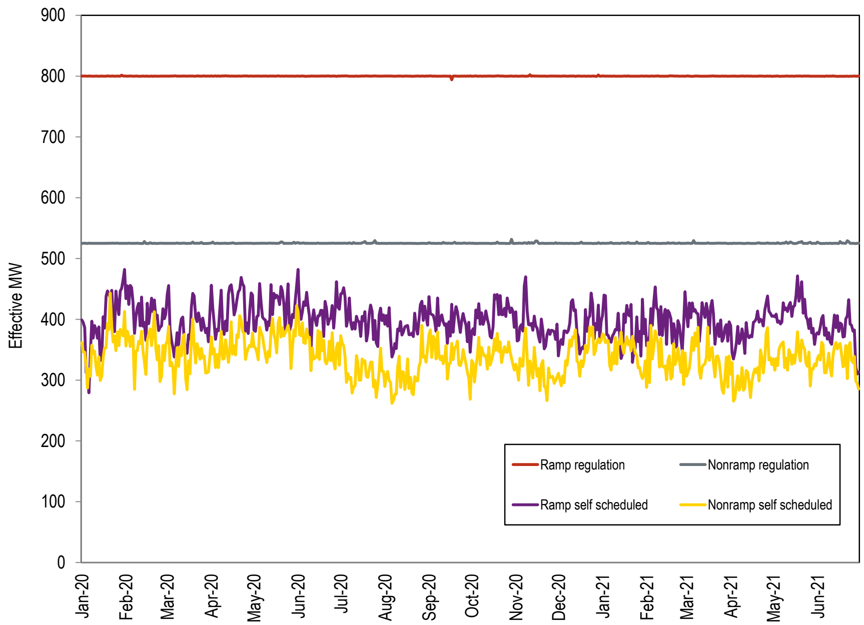


Table 10-43 shows the role of RegD resources in the regulation market. RegD resources are both a growing proportion of the market (10.9 percent of the total effective MW at the start of the performance based regulation market design in October 2012 and 47.3 percent of the total effective MW in June 2021) and a growing proportion of resources that self schedule (25.0 percent of all self scheduled effective MW in October 2012 and 73.5 percent of all self scheduled effective MW in June 2021). In the first six months of 2021, the average RegD percentage of total self scheduled effective MW was 72.3 percent, an increase of 2.3 percentage points from the first six months of 2020, when the average was 70.0 percent. This increase in RegD self scheduling has led to the increased amount of RegD cleared (Table 10-36), and the decrease in the MBF (Figure 10-11).

Table 10-43 RegD self scheduled regulation by month: January 2020 through June 2021

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
2020	Jan	253.3	311.9	376.5	674.0	67.3%	46.3%
2020	Feb	263.6	333.5	385.3	674.0	68.4%	49.5%
2020	Mar	257.9	319.9	358.9	639.9	71.9%	50.0%
2020	Apr	267.2	318.1	382.9	639.7	69.8%	49.7%
2020	May	274.6	312.2	388.5	639.8	70.7%	48.8%
2020	Jun	281.8	335.1	390.5	696.7	72.2%	48.1%
2020	Jul	252.6	343.3	369.3	697.1	68.4%	49.2%
2020	Aug	258.7	341.0	357.2	697.0	72.4%	48.9%
2020	Sep	275.4	317.2	363.3	639.6	75.8%	49.6%
2020	Oct	265.7	319.2	368.3	639.8	72.1%	49.9%
2020	Nov	255.1	321.4	346.5	640.6	73.6%	50.2%
2020	Dec	262.1	329.8	366.8	674.0	71.4%	48.9%
2020 Average		264.0	325.2	371.2	662.7	71.2%	49.1%
2021	Jan	250.5	322.4	367.7	674.0	68.1%	47.8%
2021	Feb	262.0	335.3	366.7	674.3	71.4%	49.7%
2021	Mar	263.0	321.7	359.0	639.9	73.3%	50.3%
2021	Apr	266.0	325.9	343.1	639.6	77.5%	51.0%
2021	May	256.8	320.6	368.0	639.9	69.8%	50.1%
2021	Jun	266.5	329.9	362.7	697.0	73.5%	47.3%
2021 Average		260.8	326.0	361.2	660.8	72.3%	49.4%

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. Of the LSEs' obligation to provide regulation in the first six months of 2021, 48.5 percent was purchased in the PJM market, 47.2 percent was self scheduled, and 4.3 percent was purchased bilaterally (Table 10-44). Table 10-45 shows the total regulation by source including spot market regulation, self scheduled regulation, and bilateral regulation for January through June, 2012 through 2021. Table 10-44 and Table 10-45 are based on settled (purchased) MW.

Table 10-44 Regulation sources: spot market, self scheduled, bilateral purchases: January 2020 through June 2021

Year	Month	Spot Market Regulation (Unadjusted MW)	Spot Market Percent of Total	Self Scheduled Regulation (Unadjusted MW)	Self Scheduled Percent of Total	Bilateral Regulation (Unadjusted MW)	Bilateral Percent of Total	Total Regulation (Unadjusted MW)
2020	Jan	179,061.4	46.2%	190,434.8	49.1%	18,166.0	4.7%	387,662.1
2020	Feb	160,674.9	43.8%	185,702.6	50.6%	20,815.5	5.7%	367,193.0
2020	Mar	175,560.8	46.5%	181,566.1	48.1%	20,266.0	5.4%	377,392.8
2020	Apr	154,642.4	42.4%	187,819.3	51.5%	22,195.5	6.1%	364,657.2
2020	May	167,682.0	44.2%	191,949.3	50.5%	20,125.5	5.3%	379,756.8
2020	Jun	192,336.9	49.3%	178,239.7	45.7%	19,479.5	5.0%	390,056.1
2020	Jul	189,151.3	46.4%	198,595.7	48.7%	19,997.5	4.9%	407,744.5
2020	Aug	207,948.6	51.1%	181,392.4	44.6%	17,756.0	4.4%	407,097.0
2020	Sep	181,955.4	49.6%	171,428.3	46.7%	13,358.0	3.6%	366,741.7
2020	Oct	178,179.3	46.9%	186,687.3	49.1%	15,309.5	4.0%	380,176.1
2020	Nov	180,188.6	48.9%	172,941.0	46.9%	15,668.5	4.2%	368,798.1
2020	Dec	189,587.0	47.8%	188,798.6	47.6%	18,505.0	4.7%	396,890.6
Total		2,156,968.5	47.0%	2,215,555.1	48.2%	221,642.5	4.8%	4,594,166.0
2021	Jan	186,762.8	46.6%	192,708.2	48.1%	21,466.0	5.4%	400,937.0
2021	Feb	172,967.1	47.4%	174,470.7	47.9%	17,095.5	4.7%	364,533.3
2021	Mar	182,812.8	47.3%	189,176.1	48.9%	14,910.0	3.9%	386,898.9
2021	Apr	190,444.5	51.0%	170,255.4	45.6%	12,763.0	3.4%	373,462.9
2021	May	171,841.5	44.5%	198,026.9	51.3%	16,270.0	4.2%	386,138.5
2021	Jun	211,800.7	54.2%	163,167.4	41.8%	15,526.0	4.0%	390,494.1
Total		1,116,629.4	48.5%	1,087,804.8	47.2%	98,030.5	4.3%	2,302,464.7

Table 10-45 Regulation sources: January through June, 2012 through 2021

Year (Jan-Jun)	Spot Market Regulation (Unadjusted MW)	Spot Market Percent of Total	Self Scheduled Regulation (Unadjusted MW)	Self Scheduled Percent of Total	Bilateral Regulation (Unadjusted MW)	Bilateral Percent of Total	Total Regulation (Unadjusted MW)
2012	3,065,069.1	76.0%	847,576.2	21.0%	122,641.0	3.0%	4,035,286.2
2013	1,740,438.6	64.9%	849,955.3	31.7%	92,120.0	3.4%	2,682,513.9
2014	1,370,386.4	57.9%	889,917.5	37.6%	106,365.5	4.5%	2,366,669.4
2015	1,282,300.1	55.7%	894,595.8	38.8%	126,408.6	5.5%	2,303,304.4
2016	1,139,515.1	48.5%	1,086,532.7	46.3%	122,808.5	5.2%	2,348,856.3
2017	1,176,249.8	52.2%	948,195.8	42.1%	128,534.5	5.7%	2,252,980.1
2018	1,390,856.8	61.6%	757,440.3	33.5%	110,201.5	4.9%	2,258,498.6
2019	1,085,870.9	49.8%	980,572.5	45.0%	114,334.0	5.2%	2,180,777.4
2020	1,029,923.1	45.4%	1,115,710.1	49.2%	121,048.0	5.3%	2,266,681.2
2021	1,116,629.4	48.5%	1,087,804.8	47.2%	98,030.5	4.3%	2,302,464.7

In the first six months of 2021, DR provided an average of 10.3 MW of regulation per hour during ramp hours (13.5 MW of regulation per hour during ramp hours in the first six months of 2020), and an average of 6.9 MW of regulation per hour during nonramp hours (10.1 MW of regulation per hour during nonramp hours in the first six months of 2020). Generating units supplied an average of 696.8 MW of regulation per hour during ramp hours in the first six months of 2021 (690.8 MW of regulation per hour during ramp hours in the first six months of 2020), and an average of 484.7 MW per hour during nonramp hours in the first six months of 2021 (479.6 MW of regulation per hour during nonramp hours in the first six months of 2020).

Market Performance

Price

Table 10-49 shows the regulation price and regulation cost per MW for January through June, 2009 through 2021. The weighted average RMCP for the first six months of 2021 was $17.46 per MW. This is an increase of $5.73 per MW, or 48.9 percent, from the weighted average RMCP of $11.73 per MW in the first six months of 2020. This increase in the regulation clearing price was the result of an increase in energy prices in the first three months of 2021 and the related decrease in the opportunity cost component of RMCP.

Figure 10-18 shows the capability price, performance price, and the opportunity cost component for the PJM Regulation Market on a performance adjusted MW basis. The regulation clearing price is determined based on the marginal unit's total offer (RCP + RPP + PJM calculated LOC). Then the maximum performance offer price (RPP) of any of the cleared units is used to set the marginal performance clearing price for the purposes of settlements. The difference between the marginal total clearing price and the highest performance clearing price (RMPCP) is the marginal capability clearing price (RMCCP). The capability price presented here is equal to the clearing price, minus the maximum cleared performance offer price. This data is based on actual five minute interval operational data.

Figure 10-18 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 10-18 Regulation market clearing price components (Dollars per MW): January through June, 2021

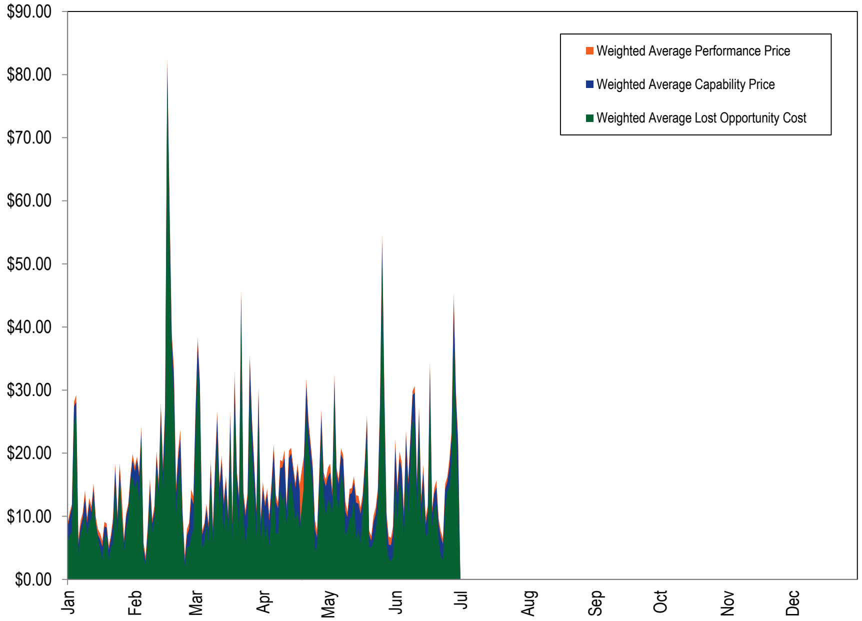


Table 10-46 shows the capability and performance components of the monthly average regulation prices. These components differ from the components of the marginal unit's offers in Figure 10-18 because the performance component of the settlement price for each hour is determined from the average of the highest performance offers in each five minute interval, calculated independent of the marginal unit's offers in those intervals.

Table 10-46 Regulation market monthly component of price (Dollars per MW): January through June, 2021

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	$11.26	$0.86	$12.12
Feb	$19.53	$1.07	$20.60
Mar	$18.30	$0.87	$19.20
Apr	$15.76	$1.59	$17.34
May	$15.59	$1.03	$16.62
Jun	$18.17	$1.05	$19.22
Average	$16.38	$1.08	$17.46

Monthly and total annual scheduled regulation MW and regulation charges, as well as monthly average regulation price and regulation cost are shown in Table 10-47. Total scheduled regulation is based on settled performance adjusted MW. The total of all regulation charges in the first six months of 2021 was $49.9 million, compared to $33.5 million in the first six months of 2020.

Table 10-47 Total regulation charges: January 2020 through June 2021

Year	Month	Scheduled Regulation (MW)	Total Regulation Charges ($)	Weighted Average Regulation Market Price ($/MW)	Cost of Regulation ($/MW)	Price as Percent of Cost
2020	Jan	387,662.1	$6,495,664	$13.70	$16.76	81.7%
2020	Feb	367,193.0	$4,630,253	$10.12	$12.61	80.3%
2020	Mar	377,392.8	$4,619,257	$9.06	$12.24	74.0%
2020	Apr	364,657.2	$5,646,138	$12.10	$15.48	78.1%
2020	May	379,756.8	$6,078,957	$12.97	$16.01	81.0%
2020	Jun	390,056.1	$6,072,212	$12.31	$15.57	79.1%
2020	Jul	407,744.5	$7,732,029	$16.14	$18.96	85.1%
2020	Aug	407,097.0	$7,566,611	$15.36	$18.59	82.6%
2020	Sep	366,741.7	$4,909,677	$10.88	$13.39	81.2%
2020	Oct	380,176.1	$8,168,776	$17.64	$21.49	82.1%
2020	Nov	368,798.1	$7,381,789	$15.95	$20.02	79.7%
2020	Dec	396,890.6	$7,562,483	$15.79	$19.05	82.9%
Yearly		4,594,166.0	$76,860,642	$13.55	$16.73	81.0%
2021	Jan	400,937.0	$6,038,564	$12.12	$15.06	80.5%
2021	Feb	364,533.3	$9,401,619	$20.60	$25.79	79.9%
2021	Mar	386,898.9	$8,793,373	$19.20	$22.73	84.5%
2021	Apr	373,462.9	$7,945,154	$17.34	$21.27	81.5%
2021	May	386,138.5	$8,049,501	$16.62	$20.85	79.8%
2021	Jun	390,494.1	$9,646,216	$19.22	$24.70	77.8%
Total		2,302,464.7	$49,874,426	$17.46	$21.66	80.6%

The capability, performance, and opportunity cost components of the cost of regulation are shown in Table 10-48. Total scheduled regulation is based on settled performance adjusted MW. In the first six months of 2021, the average total cost of regulation was $21.66 per MW, 46.4 percent higher than $14.79 in the first six months of 2020. In the first six months of 2021, the monthly average capability component cost of regulation was $16.82, 48.2 percent higher than $11.35 in the first six months of 2020. In the first six months of 2021, the monthly average performance component cost of regulation was $2.27, 39.8 percent higher than $1.62 in the first six months of 2020. The increase of the average total cost in the first six months of 2021 versus the first six months of 2020, was primarily a result of higher LOC values due to higher prices in the energy market.

Table 10-48 Components of regulation cost: January 2020 through June 2021

Year	Month	Scheduled Regulation (MW)	Cost of Regulation Capability ($/MW)	Cost of Regulation Performance ($/MW)	Opportunity Cost ($/MW)	Total Cost ($/MW)
2020	Jan	387,662.1	$13.32	$1.80	$1.64	$16.76
	Feb	367,193.0	$9.90	$1.35	$1.36	$12.61
	Mar	377,392.8	$8.71	$1.46	$2.07	$12.24
	Apr	364,657.2	$11.68	$1.77	$2.03	$15.48
	May	379,756.8	$12.66	$1.39	$1.95	$16.01
	Jun	390,056.1	$11.74	$1.94	$1.88	$15.57
	Jul	407,744.5	$15.74	$1.54	$1.68	$18.96
	Aug	407,097.0	$14.80	$2.01	$1.78	$18.59
	Sep	366,741.7	$10.42	$1.49	$1.47	$13.39
	Oct	380,176.1	$16.90	$2.80	$1.78	$21.49
	Nov	368,798.1	$15.21	$2.70	$2.11	$20.02
	Dec	396,890.6	$15.40	$1.72	$1.94	$19.05
Yearly		4,594,166.0	$13.09	$1.83	$1.81	$16.73
2021	Jan	400,937.0	$11.71	$1.67	$1.68	$15.06
	Feb	364,533.3	$19.90	$2.52	$3.37	$25.79
	Mar	386,898.9	$18.70	$1.86	$2.16	$22.73
	Apr	373,462.9	$16.63	$2.66	$1.98	$21.27
	May	386,138.5	$15.87	$2.40	$2.58	$20.85
	Jun	390,494.1	$18.45	$2.54	$3.71	$24.70
Total		2,302,464.7	$16.82	$2.27	$2.57	$21.66

Table 10-49 provides a comparison of the average price and cost for PJM regulation. The ratio of regulation market price to the cost of regulation in the first six months of 2021 was 80.6 percent, a 1.7 percent increase from 79.3 percent in the first six months of 2020.

Table 10-49 Comparison of average price and cost for regulation: January through March, June, September, and December, 2009 through 2021[98]

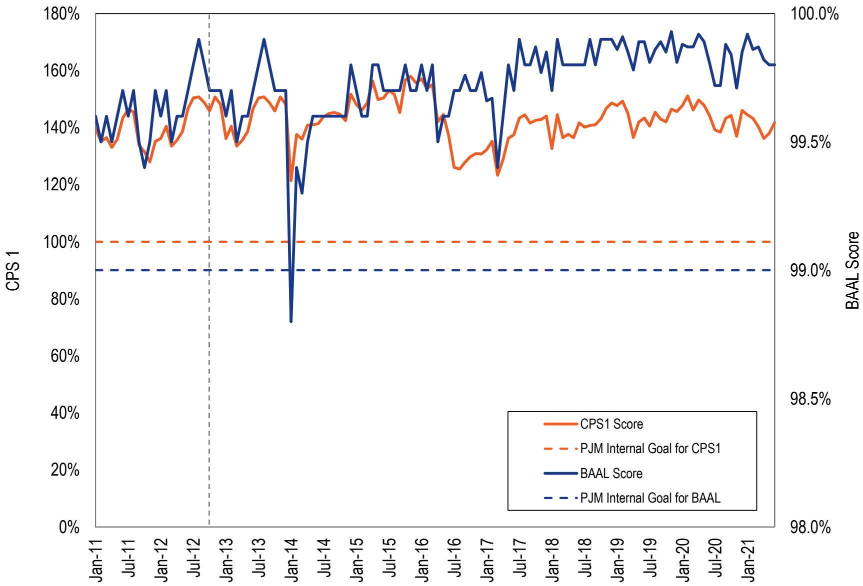
	Jan-Mar			Jan-Jun			Jan-Sep			Jan-Dec		
Year	Weighted Regulation Market Price	Weighted Regulation Market Cost	Regulation Price as Percent Cost	Weighted Regulation Market Price	Weighted Regulation Market Cost	Regulation Price as Percent Cost	Weighted Regulation Market Price	Weighted Regulation Market Cost	Regulation Price as Percent Cost	Weighted Regulation Market Price	Weighted Regulation Market Cost	Regulation Price as Percent Cost
2009	$22.25	$34.06	65.3%	$25.23	$33.82	74.6%	$24.94	$32.28	77.3%	$23.00	$30.68	75.0%
2010	$17.97	$31.24	57.5%	$18.33	$31.43	58.3%	$19.47	$34.54	56.4%	$18.00	$32.86	54.8%
2011	$11.52	$25.03	46.0%	$15.31	$31.00	49.4%	$17.04	$32.70	52.1%	$16.49	$29.72	55.5%
2012	$12.62	$16.75	75.3%	$13.89	$18.34	75.7%	$15.16	$21.07	71.9%	$19.02	$25.32	75.1%
2013	$33.91	$39.36	86.2%	$32.04	$37.04	86.5%	$33.29	$38.49	86.5%	$30.85	$35.79	86.2%
2014	$92.97	$112.30	82.8%	$62.71	$75.97	82.5%	$50.19	$60.94	82.4%	$44.49	$53.82	82.7%
2015	$47.91	$58.23	82.3%	$40.94	$49.57	82.6%	$35.56	$43.00	82.7%	$31.92	$38.36	83.2%
2016	$15.55	$17.92	86.8%	$15.90	$18.30	86.9%	$16.52	$18.99	87.0%	$15.73	$18.13	86.7%
2017	$13.89	$18.47	75.2%	$15.08	$20.67	73.0%	$15.70	$21.70	72.4%	$16.79	$23.03	72.9%
2018	$40.33	$49.60	81.3%	$32.97	$40.76	80.9%	$28.21	$35.06	80.5%	$25.32	$31.94	79.3%
2019	$14.05	$18.49	76.0%	$13.85	$18.12	76.5%	$14.97	$19.15	78.1%	$16.27	$20.32	80.1%
2020	$10.99	$13.91	79.0%	$11.73	$14.79	79.3%	$12.59	$15.59	80.8%	$13.55	$16.73	81.0%
2021	$17.18	$21.01	81.8%	$17.46	$21.66	80.6%						

98 There was an error in previously reported values for 2009 through 2012 in this table. The correct values are included here.

Performance Standards

PJM's performance as measured by CPS1 and BAAL standards is shown in Figure 10-19 for every month from January 2011 through June 2021 with the dashed vertical line marking the date (October 1, 2012) of the implementation of the Performance Based Regulation Market design.[99] The horizontal dashed lines represent PJM internal goals for CPS1 and BAAL performance.

Figure 10-19 Monthly CPS1 and BAAL performance: January 2011 through June 2021



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).[100] Although PJM has raised the issue, there are 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.[101]

PJM defines required black start capability zonally, while recognizing that the most effective way to provide black start service may be across zones. Under the current rules PJM has substantial flexibility in procuring black start resources and is responsible for black start resource selection.

On April 7, 2021, PJM issued an incremental RFP for additional black start service in the BGE and PEPCO Zones. The RFP is a two stage process. Level one submissions were due May 10, 2021. Level two submissions were due May 31, 2021. The expected award by date is November 1, 2021. The planned in service date is April 1, 2023.[102]

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.[103] Black start resources can choose to recover fixed costs under a formula rate based on zonal Net CONE and unit ICAP rating, a cost recovery rate based on incremental black start NERC-CIP compliance capital costs, or a cost recovery rate based on FERC-approved rate plus capital costs for new investment. In addition, PJM applies a cost recovery rate based on incremental black start equipment capital costs.

Black start uplift (operating reserve) charges are paid to units committed in real time to provide black start service or for black start testing.[104] Total

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

100 OATT Schedule 1 § 1.3BB.
101 *See* OATT Schedule 6A para. 18.
102 RFPs issued can be found on the PJM website. See PJM. <http://www.pjm.com/markets-and-operations/ancillary-services.aspx>.
103 *See* OATT Schedule 6A para. 18.
104 There are no black start units currently using the ALR option.

black start charges are allocated monthly to PJM customers proportionally to their zone and nonzone peak transmission use and point to point transmission reservations.[105] It is not clear why it is reasonable to have different charges for black start service across zones as the service is to ensure that PJM as a whole can recover from a large scale outage.

In the first six months of 2021, total black start charges were $33.6 million, an increase of $0.1 million (0.2 percent) from 2020. Uplift charges for black start service increased from $0.1 million in the first six months of 2020 to $0.2 million (12.0 percent) in the first six months of 2021. Table 10-50 shows total charges in the first six months of each year from 2010 through 2021.[106]

Table 10-50 Black start revenue requirement charges: January through June, 2010 through 2021

Jan-Jun	Revenue Requirement Charges	Uplift Charges	Total
2010	$5,481,206	$0	$5,481,206
2011	$5,968,676	$0	$5,968,676
2012	$7,873,702	$0	$7,873,702
2013	$10,584,683	$48,075,584	$58,660,267
2014	$10,874,608	$14,339,174	$25,213,781
2015	$23,348,866	$5,036,053	$28,384,918
2016	$33,778,388	$168,645	$33,947,033
2017	$35,617,856	$146,223	$35,764,079
2018	$33,363,286	$126,698	$33,489,984
2019	$32,100,135	$138,612	$32,238,747
2020	$33,343,875	$141,918	$33,485,793
2021	$33,390,578	$158,989	$33,549,567

105 OATT Schedule 6A (paras. 25, 26 and 27 outline how charges are to be applied).
106 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.

Black start zonal charges in the first six months of 2021 ranged from $0.02 per MW-day in the BGE Zone (total charges were $22,716) to $4.13 per MW-day in the PE Zone (total charges were $2,176,976). For each zone, Table 10-51 shows black start charges, the sum of monthly zonal peak loads multiplied by the number of days of the month in which the peak load occurred, and black start rates (calculated as charges per MW-day). Customers paid an average of $1.16 per MW-day for black start service in the first six months of 2021.

Table 10-51 Black start zonal charges: January through June, 2020 and 2021[107]

	Jan-Jun 2020					Jan-Jun 2021				
Zone	Revenue Requirement Charges	Uplift Charges	Total Charges	Peak Load (MW)	Black Start Rate ($/MW-day)	Revenue Requirement Charges	Uplift Charges	Total Charges	Peak Load (MW)	Black Start Rate ($/MW-day)
ACEC	$1,286,452	$6,898	$1,293,350	2,737	$2.60	$1,246,941	$11,402	$1,258,343	2,635	$2.64
AEP	$8,652,683	$24,095	$8,676,778	22,498	$2.12	$9,847,406	$38,346	$9,885,752	21,615	$2.53
APS	$1,927,379	$1,159	$1,928,537	9,596	$1.10	$2,342,366	$1,135	$2,343,500	8,638	$1.50
ATSI	$2,793,265	$8,483	$2,801,747	12,567	$1.22	$2,797,431	$0	$2,797,431	12,465	$1.24
BGE	$115,679	$628	$116,307	6,706	$0.10	$22,622	$95	$22,716	6,700	$0.02
COMED	$3,615,728	$11,262	$3,626,990	20,949	$0.95	$4,615,330	$5,910	$4,621,240	20,220	$1.26
DAY	$109,424	$14,120	$123,544	3,259	$0.21	$111,464	$13,958	$125,422	3,309	$0.21
DUKE	$177,374	$12,764	$190,137	5,052	$0.21	$184,189	$12,598	$196,787	4,975	$0.22
DUQ	$22,051	$0	$22,051	2,662	$0.05	$22,124	$0	$22,124	2,668	$0.05
DOM	$2,260,458	$20,791	$2,281,249	19,931	$0.63	$2,613,229	$40,029	$2,653,258	20,061	$0.73
DPL	$1,098,424	$8,843	$1,107,267	4,098	$1.48	$981,018	$3,986	$985,005	4,086	$1.33
EKPC	$167,450	$1,641	$169,091	3,074	$0.30	$160,108	$2,076	$162,184	2,720	$0.33
JCPLC	$2,366,888	$3,058	$2,369,946	6,057	$2.15	$374,792	$2,564	$377,356	5,903	$0.35
MEC	$209,077	$6,766	$215,843	2,986	$0.40	$215,213	$1,726	$216,938	2,976	$0.40
OVEC	$0	$0	$0	NA	NA	$0	$0	$0	NA	NA
PECO	$682,750	$1,261	$684,011	8,428	$0.45	$720,631	$2,199	$722,830	8,148	$0.49
PE	$2,184,989	$8,372	$2,193,361	3,015	$4.00	$2,164,350	$12,625	$2,176,976	2,911	$4.13
PEPCO	$1,227,454	$2,657	$1,230,111	6,191	$1.09	$152,642	$607	$153,249	5,887	$0.14
PPL	$1,175,960	$161	$1,176,121	7,939	$0.81	$2,433,825	$0	$2,433,825	7,260	$1.85
PSEG	$1,683,863	$2,350	$1,686,214	9,753	$0.47	$846,256	$2,966	$849,222	9,557	$0.49
REC	$0	$0	$0	NA	NA	$0	$0	$0	NA	NA
(Imp/Exp/Wheels)	$1,586,527	$6,610	$1,593,137	7,879	$1.11	$1,538,640	$6,769	$1,545,409	7,348	$1.16
Total	$33,343,875	$141,918	$33,485,793	165,375	$1.11	$33,390,578	$158,989	$33,549,567	160,080	$1.16

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

Table 10-52 provides a revenue requirement estimate by zone for the 2021/2022, 2022/2023, and 2023/2024 Delivery Years.[108] Revenue requirement values are rounded up to the nearest $50,000 to reflect 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.

Table 10-52 Black start zonal revenue requirement estimate: 2021/2022 through 2023/2024 Delivery Years[109]

Zone	2021 / 2022 Revenue Requirement	2022 / 2023 Revenue Requirement	2023 / 2024 Revenue Requirement
ACEC	$2,150,000	$2,150,000	$2,150,000
AEP	$21,700,000	$21,500,000	$21,500,000
APS	$10,400,000	$10,350,000	$10,350,000
ATSI	$5,900,000	$5,900,000	$5,900,000
BGE	$50,000	$50,000	$50,000
COMED	$10,050,000	$9,400,000	$9,400,000
DAY	$300,000	$250,000	$250,000
DUKE	$450,000	$350,000	$350,000
DUQ	$2,150,000	$2,100,000	$2,100,000
DOM	$5,550,000	$5,350,000	$5,350,000
DPL	$1,350,000	$1,250,000	$1,250,000
EKPC	$400,000	$300,000	$300,000
JCPLC	$650,000	$550,000	$550,000
MEC	$550,000	$450,000	$450,000
OVEC	$0	$0	$0
PECO	$1,600,000	$1,350,000	$1,350,000
PE	$4,650,000	$4,550,000	$4,550,000
PEPCO	$300,000	$200,000	$200,000
PPL	$5,350,000	$5,200,000	$5,200,000
PSEG	$1,950,000	$1,850,000	$1,850,000
REC	$0	$0	$0
Total	$75,500,000	$73,100,000	$73,100,000

108 The System Restoration Strategy Task Force requested that the MMU provide estimated black start revenue requirements.
109 The 2023/2024 estimated revenue requirement is based on the CONE values for the 2022/2023 RPM Base Residual Auction because the 2023/2024 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.[110] 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, including 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 (Table 10-53). The 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.[111] The CRF table in the tariff includes assumptions about tax rates that are no longer correct. The CRF values are significantly too high as a result. 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.

Table 10-53 Existing CRF table for black start units

Age of Black Start Unit (Years)	Term of Black Start Unit Commitment (Years)	Levelized CRF
1 to 5	20	0.125
6 to 10	15	0.146
11 to 15	10	0.198
16+	5	0.363

The existing CRF table includes the column header, term of black start unit 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

110 *See* OATT Schedule 6A para. 18.
111 *Id.*

the life of the unit.[112] There is no need for such short recovery periods for black start investment costs. Two periods, based on unit age, are more than adequate.

The U.S. Internal Revenue Code changed significantly in December 2017. The PJM CRF table did not change to reflect these changes. As a result, CRF values have overcompensated black start units since the changes to the tax code. The new depreciation rules allow for a more accelerated depreciation and therefore lower taxes. The tax code also reduced the corporate tax rate to 21 percent which also reduces taxes.

Updated CRF rates, incorporating the tax code changes, 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 windfall.

Table 10-54 includes updated CRF values based on the new tax code. The second column is the cost recovery period and not the commitment period.

Table 10-54 Updated CRF table for black start units

Age of Black Start Unit (Years)	Black Start Cost Recovery Period (Years)	Updated Levelized CRF
1 to 5	20	0.101
6 to 10	15	0.116
11 to 15	10	0.147
16+	5	0.246

Overcompensation amounts vary with the project investment and the CRF recovery period (Table 10-55). For a new black start unit with an investment cost of $21 million, the overcompensation is $12,180,000 over the 20 year recovery period. For a new black start unit with an investment of $21 million, the overcompensation is $12,285,000 over the five year recovery period.

112 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.

Table 10-55 Lifetime recovery of black start units with old and updated CRF

Example	Old CRF Rate	Updated CRF Rate	Project Investment	Old CRF Lifetime Recovery	Updated CRF Lifetime Recovery	Updated Lifetime Difference
1	0.125	0.101	$9,000,000	$22,500,000	$18,180,000	$4,320,000
2	0.125	0.101	$15,000,000	$37,500,000	$30,300,000	$7,200,000
3	0.125	0.101	$21,000,000	$52,500,000	$42,420,000	$10,080,000
1	0.146	0.116	$9,000,000	$19,710,000	$15,660,000	$4,050,000
2	0.146	0.116	$15,000,000	$32,850,000	$26,100,000	$6,750,000
3	0.146	0.116	$21,000,000	$45,990,000	$36,540,000	$9,450,000
1	0.198	0.147	$9,000,000	$17,820,000	$13,230,000	$4,590,000
2	0.198	0.147	$15,000,000	$29,700,000	$22,050,000	$7,650,000
3	0.198	0.147	$21,000,000	$41,580,000	$30,870,000	$10,710,000
1	0.363	0.246	$9,000,000	$16,335,000	$11,070,000	$5,265,000
2	0.363	0.246	$15,000,000	$27,225,000	$18,450,000	$8,775,000
3	0.363	0.246	$21,000,000	$38,115,000	$25,830,000	$12,285,000

Table 10-56 shows the total excess payments to black start units that will result if the CRF issue is not addressed. The table includes the excess payments for units in service prior to the 2017 tax law change and excess payments for units in service after the 2017 tax law change. For the pre 2017 units, the updated CRF rates were changed to reflect only the change in the tax rate, and for the post 2017 units, the updated CRF rates were changed to reflect both the change in the tax rate and the change in the tax depreciation treatment.

Table 10-56 Lifetime difference of black start units with updated CRF

Years	Existing Annual Revenue Requirement Total	Updated Annual Revenue Requirement Total	Difference Per Year Total	Updated Lifetime Difference Total
Pre 2017 Units	$53,402,977	$46,637,692	$6,765,285	$38,078,930
Post 2017 Units	$28,217,475	$19,902,490	$8,314,985	$58,811,154
Total	$81,620,451	$66,540,182	$15,080,269	$96,890,084

For the future, the CRF should be updated and posted at least annually to reflect changes in federal or state taxes, including depreciation treatment and tax rates. The tariff should include an explicit statement of the formula and define the components of the formula. Existing black start resources constructed prior to the new tax law and to which the new tax law depreciation rules did not apply should use a CRF calculated using the depreciation rules applicable to the investment in the resources, the current tax rate and the current interest rate.

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, including those that are currently in service and those not yet in service. The CRF rates for units going into service since the change in the tax code should incorporate applicable changes to depreciation treatment and tax rates. The CRF rates for units constructed prior to the new tax law and to which the new tax law depreciation rules did not apply should incorporate only the applicable changes to the tax rate. The black start units should be required to commit to providing black start service for the life of the unit.

On April 7, 2021, PJM filed with FERC to replace the CRF values with a description of the components of the CRF formula.[113] Rather than fix the inaccurate CRF values used for existing black units, PJM's filing would make the use of inaccurate values permanent. PJM should instead apply the filed formula, including rebilling those units that have been overpaid. PJM should include the CRF formula in the tariff in addition to the components of CRF so that the tariff includes the complete filed rate. The MMU filed a protest to the April 7th filing on April 28, 2021.[114]

NERC – CIP

Currently, no black start units have requested new or additional black start NERC – CIP Capital Costs.[115]

Minimum Tank Suction Level (MTSL)

Some units that participate in the PJM energy market have oil tanks. All oil tanks at PJM units have a MTSL regardless of whether the units provide black start service (unless they use direct current pumps). The MTSL is the amount of fuel at the bottom of a tank which cannot be recovered for use.

PJM has required that customers pay black start unit owners carrying cost recovery for one hundred percent of the MTSL for tanks which are shared with units in the energy market. These tanks were sized to meet the needs of the generating units, which use significantly more fuel than the black start units. In some instances the MTSL is greater than the total amount of fuel that the black start unit needs to operate to meet its black start obligations. When a black start diesel is added at the site of an oil fired generating unit, the additional MTSL is zero.

Figure 10-20 illustrates that the size of the oil tank does not change with the addition of the black start unit. Figure 10-21 shows how the MTSL could be proportionally divided between the generator and the black start unit. The tank is 4,000,000 gallons with an MTSL of 800,000 gallons leaving 3,200,000 gallons of usable fuel. The black start unit running 16 hours using 12,000 gallons per hour would need a total of 192,000 gallons, or six percent of the total usable fuel. Assigning six percent of the MTSL (800,000 gallons) would yield 48,000 gallons which could be assigned to the black start proportion for the MTSL.

The MMU recommends that for oil tanks which are shared with other resources that only a proportionate share of the MTSL be allocated for black start units. The MMU further recommends that the PJM tariff be updated to clearly state how the MTSL will be calculated for black start units sharing oil tanks. PJM has filed to correct the rules consistent with the Market Monitor's recommendation.[116]

113 *See* Docket No. ER21-1635-000.
114 See Comments of the Independent Market Monitor for PJM, FERC Docket No. ER21-1635-000, which can be accessed at <http://www.monitoringanalytics.com/filings/2021/IMM_Comments_Docket_No_ER21-1635_20210428.pdf>.
115 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."
116 See FERC Docket No. ER21-1635-000.

Figure 10-20 Oil tank MTSL not changed from addition of black start generator

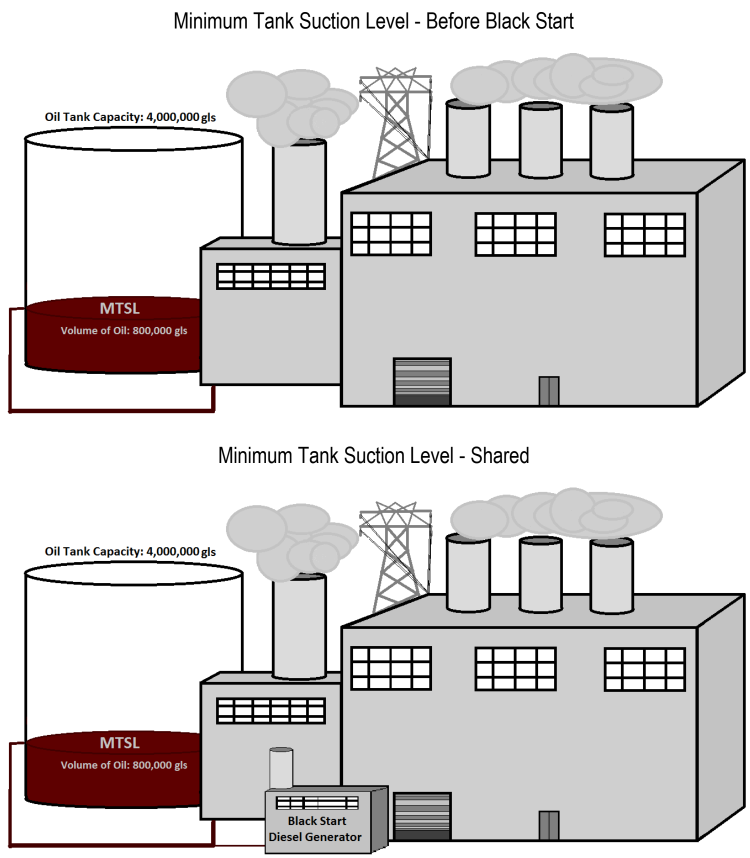
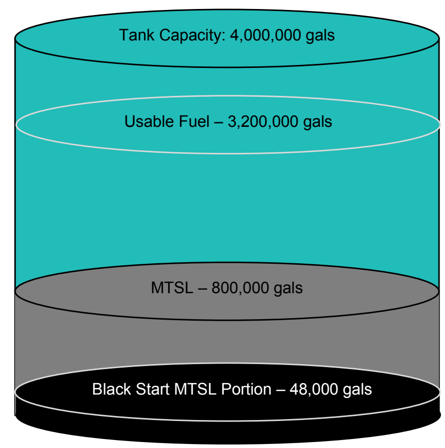


Figure 10-21 Oil tank black start MTSL portion



Reactive Power Service and Capability

Suppliers of reactive power are compensated separately for reactive power service and reactive capability. Compensation for reactive power service is determined based on real-time lost opportunity costs. Compensation for reactive capability is approved separately for each resource or resource group by FERC per Schedule 2 of the OATT. Resources may obtain FERC approval to recover a share of resources' fixed costs by calculating a reactive revenue requirement, the reactive capability rate, and to collect such rates from PJM transmission customers.[117]

Any reactive service provided operationally that involves a MW reduction outside of its normal operating range or a startup for reactive power will be logged by PJM operators and paid uplift based on lost opportunity costs.

117 See "PJM Manual 27: Open Access Transmission Tariff Accounting,"§ 3.2 Reactive Supply and Voltage Control Credits, Rev. 93, (Aug. 31, 2020).

Reactive Service, Reactive Supply and Voltage Control are provided by generation and other sources of reactive power (such as static VAR compensators and capacitor banks).[118] PJM in its role as the independent RTO and transmission provider determines the reactive capability it needs from all sources in order to reliably operate the grid. PJM, as part of its Interconnection Agreement, requires that all resources over 20 MW be able to operate at a power factor of 0.90 lagging to 0.95 leading throughout their entire operating range. This requirement ensures that even under extreme conditions every generator will be able to operate within the voltage schedule assigned to them by PJM. Reactive power helps maintain appropriate voltages on the transmission system and must be sourced locally.

Total reactive capability charges are the sum of FERC approved reactive supply revenue requirements which are posted monthly on the PJM website.[119] Zonal reactive supply revenue requirement charges are allocated monthly to PJM customers proportionally to their zone and to any nonzone (i.e. outside of the PJM Region) peak transmission use and daily average point to point transmission reservations.[120] [121]

In 2016, FERC began to reexamine its policies on reactive compensation.[122] Changes in the default capabilities of generators, disparities between nameplate values and tested values and questions about the way the allocation factors have been calculated have called continued reliance on the *AEP* method into question.[123] The continued use of fleet rates rather than unit specific rates is also an issue.

Recommended Market Approach to Reactive Costs

The best approach for recovering reactive capability costs is through markets where markets are available as they are in PJM. The best approach for recovering reactive capability costs in PJM is through the capacity market. The capacity market already incorporates reactive costs and reactive revenues. The treatment of reactive costs in the PJM market needs to be modified so that the capacity market incorporates reactive costs and revenues in a more efficient manner.

Reactive capability is an integral part of all generating units; no generating unit is built without reactive capability.[124] There is no reason that the fixed costs of reactive capability either can be or should be separated from the total fixed costs of a generating unit. There is no reason that reactive capability should be compensated outside the markets when the units participate in organized markets. Reactive capability is a precondition for participating in organized markets. Resources must invest in the equipment needed to have minimum reactive capability as a condition of receiving interconnection service from PJM and other markets.[125] The Commission has recently extended the interconnection service requirement to have reactive capability to wind and solar units, which had previously been exempt.[126] Reactive capability is a requirement for participating in organized markets and is therefore appropriately treated as part of the gross cost of new entry in organized markets.

The current FERC review provides an excellent opportunity to discard an anachronistic cost of service approach that has not been working well and that is inconsistent with markets and is unnecessary in organized markets. Increased reliance on markets for the recovery of reactive capability costs would promote efficiency and consistency. Customers, market administrators and regulators would be better served by a simpler and more effective competition based approach. The MMU recommends that separate payments for reactive capability be eliminated and the cost of reactive capability be recovered in the capacity market.

118 OATT Schedule 2.

119 See PJM. Markets & Operations: Billing, Settlements & Credit, "Reactive Revenue Requirements,"<http://www.pjm.com/~/media/markets-ops/settlements/reactive-revenue-requirements-table-may-2016.ashx> (June 8, 2016).

120 OATT Schedule 2.

121 See "PJM Manual 27: Open Access Transmission Tariff Accounting,"§ 3.3 Reactive Supply and Voltage Control Charges, Rev. 93 (Aug. 31, 2020).

122 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).

123 See 88 FERC ¶ 61,141 (1999).

124 See Order No. 827, 155 FERC ¶ 61,277 at P 9 (2016) ("[T]he equipment needed for a wind generator to provide reactive power has become more commercially available and less costly, such that the cost of installing equipment that is capable of providing reactive power is comparable to the costs of a traditional generator.").

125 See 18 CFR § 35.28(f)(1); Order No. 2003, FERC Stats. & Regs. ¶ 31,146, Appendix G (Large Generator Interconnection Agreement (LGIA)), *order on reh'g*, Order No. 2003-A, FERC Stats. & Regs. ¶ 31,160, *order on reh'g*, Order No. 2003-B, FERC Stats. & Regs. ¶ 31,171 (2004), *order on reh'g*, Order No. 2003-C, FERC Stats. & Regs. ¶ 31,190 (2005), *aff'd sub nom.* Nat'l Ass'n of Regulatory Util. Comm'rs v. FERC, 475 F.3d 1277 (D.C. Cir. 2007), *cert. denied*, 552 U.S. 1230 (2008); Order No. 2006, FERC Stats. & Regs. ¶ 31,180, Attachment F (Small Generator Interconnection Agreement), *order on reh'g*, Order No. 2006-A, FERC Stats. & Regs. ¶ 31,196 (2005), *order granting clarification*, Order No. 2006-B, FERC Stats. & Regs. ¶ 31,221 (2006).

126 Order No. 827, 155 FERC ¶ 61,277 (2016); *see also* 151 FERC ¶ 61,097 at P 28 (2015).

Improvements to Current Approach

Reactive compensation must be integrated into PJM's competitive market design. Reactive capability rates recover through cost of service rates exactly the same investment that capacity markets price at market based rates.

If OATT Schedule 2 reactive capability payments are not eliminated, then the MMU recommends, at a minimum, that steps be taken to ensure that payments only go the generating units that specifically support PJM grid operations and are fully subject to PJM dispatch, are based on capability that PJM needs to maintain system stability and do not constitute double recovery.

FERC has initiated a number of investigations into the basis for reactive rates, and the MMU has intervened in and is participating in those proceedings.[127] The only FERC proceeding that has provided an opportunity for the MMU to raise its concerns at hearing has been *Panda Stonewall LLC*.[128] The initial decision issued in that case sidesteps the issues identified by the MMU, and the error is repeated in the order on the initial decision.[129] The MMU's request for rehearing is pending. These issues must be squarely addressed for PJM to have an even minimally satisfactory market design related to compensating investment in reactive capability that cannot be differentiated from investment in capacity.

Power Factor Capped at PJM Determined Level of Need

Under the *AEP* method, units must establish their MVAR rating based on "the capability of the generators to produce VARs."[130] Typically this has meant reliance on manufacturers' specified nameplate power factor.[131] More recently, the Commission has, in the *Wabash* Orders, required that "reactive power revenue requirement filings must include reactive power test reports."[132] Noting a difference between tested reactive MVAR ratings and nameplate MVAR ratings, the Commission has, in a number of cases, set the issue of MVAR rating degradation for hearing.[133]

The Commission has identified a significant issue. The MVAR rating has a significant influence on the level of the requirements and should accurately reflect the MVAR capability actually available to maintain reliability. However, power ratings, whether based on nameplate or testing, do not establish MVAR capability that is properly relevant to reactive capability rates in PJM. PJM determines the level of reactive capability it needs in its role as the independent RTO and transmission provider. Generation owners should not be permitted through uncoordinated reactive capability rates to substitute their assessment for PJM's.

The most fundamental point about power factors is that PJM requires that all generating units have a 0.90 power factor throughout their full operating range in order to obtain interconnection service.[134] There is no reason to pay any provider of reactive capability based on a power factor exceeding the 0.90 power factor that PJM has determined is necessary.

The PJM required power factor value is the only value reasonably included in reactive capability rates because that is what PJM has determined it needs from each generator. Generators should not be permitted to make investment decisions that unnecessarily increase the cost of reactive capability. Individual owners have a conflict of interest concerning such decisions and are not authorized under the OATT to change PJM's determinations on the required power factor.

Eligibility for Reactive Rates Under Schedule 2

Reactive capability rates should not be confused with compensation for operating to provide reactive power at PJM's direction. Reactive service is supplied during normal operation as needed and directed by PJM dispatchers. Most reactive service is provided with no impact to operational dispatch.

127 See e.g., FERC Dockets Nos. EL16-32, EL16-44, EL16-51, EL16-54, EL16-65, EL16-66, EL16-79, EL16-89, EL16-90, EL16-98, EL16-72, EL16-100, EL16-103, EL16-118, EL16-1004, ER16-1456, ER16-2217, EL17-19, EL17-38, EL17-39, EL17-49, ER17-259 and ER17-801.
128 See Docket No. EL17-1821.
129 167 FERC ¶ 63,010 (2019), *order on initial decision*, 174 FERC ¶ 61,266 (2021).
130 *AEP mimeo* at 31.
131 See, e.g., *id.*
132 154 FERC ¶ 61,246 at P 28 (2016); see also 154 FERC ¶ 61,246 at P 29 (*Wabash* Orders).
133 See, e.g., 154 FERC ¶ 61,087 at P 10 (2016) ("The Informational Filing contains information that raises concerns about the justness and reasonableness of Ironwood's reactive power rate, including, but not limited to, the degradation of the Facility's current MVAR capability as compared with the MVAR capability that was originally used to calculate the revenue requirement for Reactive Service included in Ironwood's reactive power rate.").
134 *See supra* footnote 27.

When a need for reactive service requires that a unit's MW output be reduced outside of its normal operational range, or when a unit is started to provide reactive power, it is logged by PJM dispatchers and will be paid reactive service credits in the zone or zones where the reactive service was provided.

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.[135]

In another case, the issues of whether a battery incurs any incremental costs to provide reactive and the applicability of the AEP method to a battery have been raised.[136]

The issue of eligibility is significant because the number of facilities interconnecting at points that are not on the PJM system (off 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.[137] 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.

Offset Cap on Reactive Capability Rates

In addition to effectively capping the appropriate level of the power factor, the PJM market rules also effectively cap the appropriate level of reactive capability rates overall.

Under the current capacity market rules, the gross costs of the entire plant, including any reactive costs, are included in the gross Cost of New Entry (CONE) and the revenues from reactive service capability rates are an offset to the gross CONE. The result is that, conceptually, the cost of reactive included in the offset is not part of net CONE.[138] This is logically consistent with the separate collection of reactive costs through a cost of service rate in that there is no double counting if the revenue offset is done accurately. Under this approach there is a separate collection of reactive capability costs. This approach also requires that any capacity resource calculating unit specific net revenues must include the cost of service reactive revenues in the calculation.

The revenue offset is defined as a fixed number in the OATT and is currently set equal at $2,199/MW-year.[139] This is the average annual reactive capability revenue for combustion turbines from 2005 through 2007, based on the actual costs reported to the Commission in reactive service filings.

The PJM market rules explicitly account for recovery of reactive revenues of $2,199 per MW-year. Reactive capability rates up to that level do not result in double recovery. Reactive capability rates above that level do result in double recovery because costs that would support a rate exceeding $2,199 per MW-year continue to be recoverable in the PJM Capacity Market.

The $2,199 offset is a simple rule that established a just and reasonable reconciliation of different regulatory approaches in the same market design. The offset assumes a defined level of revenues are received under cost of service rates and nets them from the parameters used in the capacity market. Those parameters define the operation of the market so that just and reasonable capacity prices are established. Reactive rates cannot be just and reasonable if they do not account for the market design in which PJM units operate.

To the extent that the Commission decides that PJM and other markets should continue to rely on a cost of service method to compensate reactive capability, the rules should be modified to improve the accuracy of the calculations of reactive capability cost. Double compensation should not be permitted as a

135 See, e.g., FERC Docket Nos. ER21-2091, ER21-936, ER21-737, ER20-1863 & ER20-1851.
136 See FERC Docket No. ER21-864.
137 *See American Electric Power Service Corp.*, 80 FERC ¶ 63,006 (1997), *aff'd*, 88 FERC ¶ 61,141 (1999).
138 See OATT Attachment DD § 5.10(a)(iv).
139 *See* OATT Attachment DD § 5.10(a)(v).

combined result of market based capacity prices and cost of service rates. No recovery above the $2,199 per MW-year level should be provided as direct compensation for reactive capability under the current approach.

Reactive capability rate schedules must be accurate, and they must also coordinate properly with the PJM market rules. Revenues received for reactive capability are revenues for ancillary services that should be netted against avoidable costs whenever avoidable cost rate offers are submitted in RPM capacity market auctions.[140] Participants have not been properly including reactive revenues in capacity market offers, and the MMU has notified participants of its compliance concerns. The identification of revenues for reactive capability on a unit specific basis is necessary for the calculation of accurate avoidable cost rate offers and is needed to avoid disputes that could interfere with the orderly administration of RPM auctions. The MMU has sought to address these issues through participation in proceedings at FERC concerning reactive capability rates for PJM units.[141]

Losses

The estimated capability costs also include estimated heating losses relative to MVAR output.[142] Heating losses are variable costs and not fixed costs and should not be included in the definition of reactive capability costs.[143] Heating losses can be accurately calculated for each hour of operation if each unit had an accurate, recent D-curve test. Heating losses are variable costs and should not be included in the cost of reactive capability. The production of reactive power slightly reduces the MWh output of the generator as the generator follows its D-curve. The value of this heating loss component is generally estimated based on estimated operation and associated estimated losses and estimated market prices, treated as a fixed cost, and included in the cost of reactive capability. Losses are minimal and occur during normal operations and should not be treated as a fixed cost. Losses can be better and more accurately accounted for as a variable cost based on actual unit operations and market conditions.

Fleet 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.[144] 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.[145] 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.[146]

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.[147] But PJM rules require fleet owners only to submit informational filings when a reactive unit is transferred or deactivated.[148] The current rules do not require a rate filing, which would place the burden of proof on the company and allow for cost review.[149]

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.[150] 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.[151] The MMU also explained that the approach makes it impossible to calculate cost-based offers from such units in the PJM Capacity Market. The

140 See OATT Attachment DD §§ 6.4, 6.8(d).
141 The MMUs has to date participated in nearly 150 reactive matters. See, e.g., FERC Dockets Nos. EL16-44 et al.; ER16-1456; EL16-57 et al.; EL16-51 et al.; ER16-1004; EL16-32; EL16-72; EL16-66; EL16-65; EL16-54; EL16-90 et al.; EL16-103 et al.; EL16-89 et al.; EL16-98 et al.; EL16-79 et al.; EL16-80 et al.; EL16-81 et al.; EL16-82 et al.; EL16-83 et al.; ER16-2217 et al.; EL17-19; EL16-118.
142 See, e.g., *id.* at P 10 n12, citing *PPL Energy Plus, LLC*, Letter Order, Docket No. ER08-1462-000 (Sept. 24, 2008); 125 FERC ¶ 61,280 at P 35 (2008).
143 See Transcript, *Reactive Supply Compensation in Markets Operated by Regional Transmission System Operators Workshop*, AD16-17-000 (June 30, 2016) at 26:21–27:23.
144 See, e.g., OATT Schedule 2; 114 FERC ¶ 61,318 (2006).
145 See 149 FERC ¶ 61,132 (2014); 151 FERC ¶ 61,224 (2015); OATT Schedule 2.
146 *Id.*
147 151 FERC ¶ 61,224 at P 29 (2015).
148 OATT Schedule 2.
149 *Id.*
150 *See* Letter Opposing Settlement, Docket No ER06-554 et al. (June 14, 2017).
151 *Id.*

settlement was approved over the MMU's objection on the grounds that the tariff does not prohibit fleet rates.[152]

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 six months of 2021, total reactive charges were $183.2 million, a 4.81 percent increase from the $174.8 million for first six months of 2020. Reactive capability charges increased from $174.6 million in the first six months of 2020 to $182.5 million in 2021 and reactive service charges increased from $0.2 million in the first six months of 2020 to $0.7 million in 2021. All $0.7 million in 2021 were paid for reactive service provided by 9 units in 335 hours.

Table 10-57 shows reactive service charges in the first six months of 2020 and 2021, reactive capability charges and total charges. Reactive service charges show charges to each zone for reactive service provided and not credits to plants in each zone. Reactive capability charges show charges to each zone for reactive capability.

152 162 FERC ¶ 61,029 (2018).

Table 10-57 Reactive service charges and reactive capability charges by zone: January through June, 2020 and 2021

	Jan-Jun 2020			Jan-Jun 2021		
Zone	Reactive Service Charges	Reactive Capability Charges	Total Charges	Reactive Service Charges	Reactive Capability Charges	Total Charges
ACEC	$0	$2,148,065	$2,148,065	$0	$2,151,268	$2,151,268
AEP	$0	$24,503,533	$24,503,533	$21,582	$24,952,838	$24,974,420
APS	$0	$8,720,081	$8,720,081	$0	$9,828,354	$9,828,354
ATSI	$0	$12,308,365	$12,308,365	$0	$12,690,936	$12,690,936
BGE	$0	$3,475,593	$3,475,593	$0	$3,327,671	$3,327,671
COMED	$0	$19,237,746	$19,237,746	$0	$20,801,101	$20,801,101
DAY	$0	$1,409,138	$1,409,138	$0	$1,411,239	$1,411,239
DUKE	$0	$4,773,572	$4,773,572	$0	$4,780,690	$4,780,690
DOM	$0	$20,080,331	$20,080,331	$0	$23,324,289	$23,324,289
DPL	$10,508	$5,083,932	$5,094,440	$0	$5,321,662	$5,321,662
DUQ	$0	$285,574	$285,574	$0	$286,000	$286,000
EKPC	$16,326	$1,091,005	$1,107,331	$0	$1,092,632	$1,092,632
JCPLC	$171,332	$3,729,705	$3,901,036	$0	$3,777,383	$3,777,383
MEC	$4,631	$3,069,238	$3,073,869	$8,696	$3,073,814	$3,082,511
OVEC	$0	$0	$0	$0	$0	$0
PECO	$0	$10,522,743	$10,522,743	$0	$10,489,676	$10,489,676
PE	$0	$8,267,011	$8,267,011	$0	$8,605,617	$8,605,617
PEPCO	$0	$5,572,369	$5,572,369	$0	$5,135,938	$5,135,938
PPL	$0	$17,538,674	$17,538,674	$705,618	$18,494,088	$19,199,705
PSEG	$0	$13,946,991	$13,946,991	$0	$13,951,191	$13,951,191
REC	$0	$0	$0	$0	$0	$0
(Imp/Exp/Wheels)	$0	$8,825,232	$8,825,232	$0	$8,963,378	$8,963,378
Total	$202,796	$174,588,899	$174,791,695	$735,896	$182,459,765	$183,195,661

Table 10-58 shows the units which have received reactive service credits for the first six months of 2021.

Table 10-58 Reactive service credits by plant: January through June, 2021

	Jan-Jun 2021	
Zone	Plant	Reactive Service Credits
AEP	AEP CEREDO 1 CT	$1,565
AEP	AEP CEREDO 4 CT	$1,340
AEP	AEP CLINCH RIVER 2 F	$18,677
METED	ME MOUNTAIN 1 CT	$8,696
PPL	PL HARWOOD 1-2 CT	$16,031
PPL	PL HAZELTON 1 CT	$65,744
PPL	PL HAZELTON 2 CT	$265,634
PPL	PL HAZELTON 3 CT	$197,731
PPL	PL HAZELTON 4 CT	$160,478
Total		$735,897

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.[153] 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 filed revisions in compliance with Order No. 842 that substantively incorporated the pro forma agreements into its market rules.[154]

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, and Tertiary Frequency Control.

- **Inertial Response.** Inertial response to frequency excursion is the natural resistance of rotating mass turbine generators to change in their stored kinetic energy. This response is immediate and resists short term changes to ACE from the instant of the disturbance up to twenty seconds after the disturbance.
- **Primary Frequency Response.** Primary frequency response is a response to a disturbance based on a local detection of frequency and local operational control settings. Primary frequency response begins within a few seconds and extends up to a minute. The purpose of primary frequency response is to arrest and stabilize the system until other measures (secondary and tertiary frequency response) become active.
- **Secondary Frequency Control.** Secondary frequency control is called regulation. In PJM it begins taking effect within 10 to 15 seconds and can maintain itself for several minutes up to an hour in some cases. It 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 available in PJM as Primary Reserve. It is initiated by an all call from the PJM control center.

153 157 FERC ¶ 61,122 (2016).
154 See 164 FERC ¶ 61,224 (2018).

VACAR Reserve Sharing Agreement

The VACAR Reserve Sharing Agreement (VRSA) is a combination of agreements among the entities in the VACAR subregion including Dominion.[155] VACAR is a subregion of the SERC Reliability Corporation (SERC) region. The agreement remained in effect in 2020. The agreement requires that each entity maintain primary reserves to meet the VACAR contingency reserve commitment (VACAR reserves) and deploy such reserves in the case of an emergency (e.g. loss of a unit in VACAR).[156] Dominion is the only party to the VRSA that is also a transmission owner and a generation owner in PJM. The VRSA is not a public agreement. PJM is not a party to the VRSA. However, as the reliability coordinator for Dominion Virginia Power, PJM is responsible for scheduling Dominion's required reserves in the SERC region as described in the PJM manuals.[157]

155 VRSA entities: Dominion, Duke Energy Progress, Duke Energy Carolinas, South Carolina Electric & Gas Company, South Carolina Public Service Authority and Cube Hydro Carolinas.
156 *See* SERC Regional Criteria, Contingency Reserve Policy, NERC Reliability Standard BAL-002 at 10-11.
157 See PJM. "Manual 13: Emergency Operations," Rev. 78 (Jan. 27, 2021).

PJM procures synchronized reserves and primary reserves for the PJM region, including Dominion. The synchronized reserve and primary reserve requirements are equal to the largest single contingency and 150 percent of the largest contingency. The requirement is procured separately for the RTO and the MidAtlantic Dominion area (MAD) when the largest contingency is located outside of MAD. All units in PJM that meet the synchronized or primary reserve operating parameter requirements are eligible to meet the synchronized and primary requirements as long as PJM does not deselect them.

PJM procures Day-Ahead Scheduling Reserves (DASR) for the PJM region, including Dominion, as Secondary Reserves. The DASR requirement is calculated daily and is equal to the peak load forecast for the ReliabilityFirst region (RFC) and EKPC times the sum of the forced outage rate and the load forecast error, plus Dominion's share of the VACAR contingency reserve commitment. All units in PJM that meet the DASR operating parameter requirements are eligible to meet the DASR requirement.[158] There is no requirement that a specific amount of DASR be located in Dominion. Equation 10-1 shows the DASR requirement calculation.[159]

Equation 10-1: DASR Requirement Formula

$$\text{DASR Requirement} = (\text{RFC and EKPC Peak}) \times (\text{FOR} + \text{LFE}) + \text{DOM VACAR}$$

Issues

PJM is expected to implement its ORDC proposal on May 1, 2022. Under the ORDC, it will not be possible for Dominion to hold reserves to meet its obligations under the VRSA without double counting the reserves Dominion has in PJM or withholding such reserves from PJM. Under the ORDC proposal, it will not be possible for Dominion to meet both the VRSA and the PJM reserve rules.

158 DASR can be provided by units that do not clear the day-ahead energy market and can start within 30 minutes or by units that clear the day-ahead energy market and can ramp up within 30 minutes.
159 During cold weather alerts and hot weather alerts, the DASR requirement is increased to procure additional reserves.

Recommendations

The Market Monitor recommends that the details of VACAR Reserve Sharing Agreement (VRSA) be made public, including any responsibilities assigned to PJM and including the amount of reserves that Dominion commits to meet its obligations under the VRSA.

The Market Monitor 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.