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 formulaic rates or cost.

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 for the first nine months of 2019.

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 competitive, 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 less than one percent of cleared hours in the first nine months of 2019. The day-ahead scheduling reserve market structure remains evaluated as not competitive based on persistent structural issues.
- 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. Offers above $0.00 were part of the clearing price in all but three of the 803 hours when the clearing price was above $0.00.
- 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 competitive

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

- The regulation market structure was evaluated as not competitive because the PJM Regulation Market failed the three pivotal supplier (TPS) test in 93.3 percent of the hours in the first nine months of 2019.
- Participant behavior in the PJM Regulation Market was evaluated as competitive for the first nine months of 2019 because market power

mitigation requires competitive offers when the three pivotal supplier test is failed and there was no evidence of generation owners engaging in noncompetitive behavior.

- Market performance was evaluated as competitive, despite significant issues with the market design.
- 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]

On April 1, 2018, PJM implemented five minute settlements. PJM determines the primary reserve requirement based on the most severe single contingency every five minutes. The market solution calculates the available tier 1 synchronized reserve every five minutes. In every five minute interval, the required synchronized reserve and nonsynchronized reserve are calculated and dispatched, and there are associated clearing prices (SRMCP and NSRMCP). Scheduled resources are credited based on their five minute assignment and 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. In the first nine months of 2019, the average primary reserve requirement was 2,474.8 MW in the RTO Zone and 2,530.9 MW in the MAD Subzone.

Tier 1 Synchronized Reserve

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 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 nine months of 2019, there was an average hourly supply of 2,185.1 MW of tier 1 available in the RTO Zone. In the first nine months of 2019, there was an average hourly supply of 1,574.7 MW of tier 1 synchronized reserve available within the MAD Subzone.
- **Demand.** The synchronized reserve requirement is calculated for each five minute interval as the most severe single contingency within both the RTO Zone and the MAD Subzone. The requirement can be met with tier 1 or tier 2 synchronized reserves.
- **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

3 See PJM. "Manual 10: Pre-Scheduling Operations," § 3.1.1 Day-ahead Scheduling (Operating Reserve, Rev. 38 (Aug. 22, 2019).

of $50 per MWh in addition to LMP.[4] This is the Synchronized Energy Premium Price.

- **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 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 $2,295,217 in the first nine months of 2019.

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. PJM has established a required amount of synchronized reserve as no less than the largest single contingency, and a 10 minute primary reserve at no less than 150 percent of the largest single contingency. 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 a market to satisfy the balance of the requirement with tier 2 synchronized reserve. The Tier 2 Synchronized Reserve Market includes the PJM RTO Reserve Zone and a subzone, the Mid-Atlantic Dominion Reserve Subzone (MAD).

4 See PJM. "Manual 11: Energy & Ancillary Services Market Operations,"§ 4.2.10 Settlements, Rev. 107 (Sep. 26, 2019).
5 NERC (August 12, 2019) <NERC Reliability Standard BAL 002-2 Glossary_of_Terms.pdf>.

Market Structure

- **Supply.** In the first nine months 2019, the supply of offered and eligible tier 2 synchronized reserve was 28,609.4 MW in the RTO Zone of which 5,484.6 MW was located in the MAD Subzone.
- **Demand.** The average hourly synchronized reserve requirement was 1,713.8 MW in the RTO Reserve Zone and 1,697.8 MW for the Mid-Atlantic Dominion Reserve Subzone. The hourly average cleared tier 2 synchronized reserve was 280.6 MW in the MAD Subzone and 536.9 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 nine months 2019.

  The average HHI for tier 2 synchronized reserve in the RTO Zone was 5505 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/intervals in the Mid-Atlantic Dominion (MAD) Subzone in the first nine months of 2019 was $3.07 per MW, a decrease of $1.85 from the same period in 2018.

  The weighted average price for tier 2 synchronized reserve for all cleared hours/intervals in the RTO Synchronized Reserve Zone was $3.19 per

MW in the first nine months of 2019, a decrease of $2.59 from the same period in 2018.

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 nine months of 2019, the average hourly supply of eligible nonsynchronized reserve was 3,953.1 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] The actual amount of nonsynchronized reserve scheduled often exceeds the demand and the corresponding price is $0.00. In the RTO Zone, the market scheduled an hourly average of 1,461.9 MW of nonsynchronized reserve in the first nine months of 2019.
- **Market Concentration.** The MMU calculates that the three pivotal supplier test would have been failed in 61.3 percent of hours in the first nine months of 2019.

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 hours in the RTO Reserve Zone was $0.20 per MW in the first nine months of 2019. The price cleared above $0.00 in 0.9 percent of hours.

Secondary Reserve

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 have a goal 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 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

6 See PJM. "Manual 11: Energy & Ancillary Services Market Operations," § $b.2.2 Non-Synchronized Reserve Zones and Levels, Rev. 107 (Sep. 26, 2019). "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. 107(Sep. 26, 2019).

point for all online units. In the first nine months of 2019, the average available hourly DASR was 44,547.9 MW.

- **Demand.** The DASR requirement for 2019 is 5.29 percent of peak load forecast, which is up 0.01 percent from in 2018. The average hourly DASR MW purchased in the first nine months of 2019 was 5,511.0 MW. This is a reduction from the 5,625.4 hourly MW in 2018.
- **Concentration.** In the first nine months of 2019, the DASR Market failed the three pivotal supplier test in less than one percent of hours.

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 nine months of 2019, a daily average of 39.6 percent of units offered above $0.00. A daily average of 16.6 percent of units offered 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 nine months of 2019.

Market Performance

- **Price.** In the first nine months of 2019, the weighted average DASR price for all hours when the DASRMCP was above $0.00 was $1.24.

Regulation Market

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

Market Structure

- **Supply.** In the first nine months of 2019, the average hourly eligible supply of regulation for nonramp hours was 1,062.1 performance adjusted MW (801.2 effective MW). This was a decrease of 37.2 performance adjusted MW (a decrease of 56.5 effective MW) from the first nine months of 2018, when the average hourly eligible supply of regulation was 1,099.3 performance adjusted MW (857.7 effective MW). In the first nine months of 2019, the average hourly eligible supply of regulation for ramp hours was 1,357.8 performance adjusted MW (1,127.6 effective MW). This was a decrease of 53.3 performance adjusted MW (a decrease of 64.1 effective MW) from the first nine months of 2018, when the average hourly eligible supply of regulation was 1,411.1 performance adjusted MW (1,191.8 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 470.7 hourly average performance adjusted actual MW in the first nine months of 2019. This is a decrease of 16.1 performance adjusted actual MW from the first nine months of 2018, when the average hourly total regulation cleared performance adjusted actual MW for nonramp hours were 486.8 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 722.8 hourly average performance adjusted actual MW in the first nine months of 2019. This is a decrease of 27.1 performance adjusted actual MW from the first nine months of 2018, where the average hourly regulation cleared MW for ramp hours were 750.0 performance adjusted actual MW.

The ratio of the average hourly eligible supply of regulation to average hourly regulation demand (performance adjusted cleared MW) for ramp hours was 1.88 in the first nine months of 2019 (unchanged from the first nine months of 2018). The ratio of the average hourly eligible supply of regulation to average hourly regulation demand (performance adjusted cleared MW) for nonramp hours was 2.25 in the first nine months of 2019 (2.26 in the first nine months of 2018).

- **Market Concentration.** In the first nine months of 2019, the three pivotal supplier test was failed in 93.3 percent of hours. In the first nine months of 2019, the effective MW weighted average HHI of RegA resources was 2362 which is highly concentrated and the weighted average HHI of RegD resources was 1307 which is moderately concentrated.[8] The weighted average HHI of all resources was 1366, 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 nine months of 2019, there were 213 resources following the RegA signal and 59 resources following the RegD signal.

Market Performance

- **Price and Cost.** The weighted average clearing price for regulation was $14.97 per MW of regulation in the first nine months of 2019. This is a decrease of $13.25 per MW, or 47.0 percent, from the weighted average clearing price of $28.21 per MW in the first nine months of 2018. The weighted average cost of regulation in the first nine months of 2019 was $19.14 per MW of regulation. This is a decrease of $15.91 per MW, or 45.4 percent, from the weighted average cost of $35.05 per MW in the first nine months of 2018.

- **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, RegD and RegA resources would be paid 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 marginal benefit factor is not used in settlements. When the marginal benefit factor is above 1.0, RegD resources are generally (depending on the mileage ratio) underpaid on a per effective MW basis. When the MBF is less than one, RegD resources are generally overpaid on a per effective MW basis.

- **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. Correctly defined, the MBF represents the Marginal Rate of Technical Substitution (MRTS) between RegA and RegD. Correctly implemented, the MBF would be consistently applied in the Regulation Market clearing and settlement. 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 a consistently inefficient market signal to participants regarding the value of RegD to the market in every hour. This over procurement of RegD can also degrade the ability of PJM to control ACE.

- **Changes to the Regulation Market.** The MMU and PJM developed a joint proposal to address the significant flaws in the regulation market design which was approved by the PJM Members Committee on July 27, 2017, and filed with FERC on October 17, 2017. The proposal addresses issues with the inconsistent application of the marginal benefit factor throughout

8 HHI results are based on market shares of effective MW, defined as regulation capability MW adjusted by performance score and resource specific benefit factor, consistent with the way the regulation market is cleared.

9 See the 2018 State of the Market Report for PJM, Vol. 2, Appendix F "Ancillary Services Markets."

the optimization and settlement process in the PJM Regulation Market. On March 30, 2018, this joint proposal was rejected by FERC.[10] The MMU and PJM filed requests for rehearing.[11]

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).[12]

In the first nine months of 2019, total black start charges were $48.37 million, including $48.21 million in revenue requirement charges and $0.160 million in operating reserve 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 factor. Black start operating reserve charges are paid to units scheduled in the Day-Ahead Energy Market or committed in real time to provide black start service under the ALR option or for black start testing. Black start zonal charges in the first nine months of 2019 ranged from $0.04 per MW-day in the DLCO Zone (total charges were $33,657) to $4.03 per MW-day in the PENELEC Zone (total charges were $3,299,265).

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).

Reactive capability charges are based on FERC approved filings that permit recovery based on a cost of service approach.[13] 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. Reactive service charges are paid for scheduling in the Day-Ahead Energy Market and committing units in real time that provide reactive service. In the first nine months of 2019, total reactive charges were $258.68 million, a 3.2 percent increase from $250.76 million in the first nine months of 2018. Reactive capability charges increased from $238.35 million in the first nine months of 2018 to $258.23 million in the first nine months of 2019 and reactive service charges decreased from $12.41 million in the first nine months of 2018 to $0.45 million in 2019. Total reactive service charges in the first nine months of 2019 ranged from $0 in the RECO and OVEC Zones, to $36.00 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 non-synchronous, to include equipment for primary frequency response capability as a condition to receive interconnection service.[14] PJM filed revisions in compliance with Order No. 842 that substantively incorporated the pro forma agreements into its market rules.[15]

The PJM Tariff requires that all new generator interconnection customers (NRC 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.[16] PJM is currently studying individual unit response to NERC identified frequency events and evaluating compliance.

10 162 FERC ¶ 61,295.
11 FERC Docket No. ER18-87-002.
12 OATT Schedule 1 § 1.3BB.
13 OATT Schedule 2.
14 See 157 FERC ¶ 61,122 (2016).
15 See 164 FERC ¶ 61,224 (2018).
16 PJM OATT (ER18-1629-000) October 1, 2018, 4.7.2 Primary Frequency Response, p. 3.

Ancillary Services Costs per MWh of Load: January through September, 1999 through 2019

Table 10-4 shows PJM ancillary services costs for the first nine months of 1999 through 2019, 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. The scheduling, system control, and dispatch category of costs is comprised of PJM scheduling, PJM system control and PJM dispatch; owner scheduling, owner system control and owner dispatch; other supporting facilities; black start services; direct assignment facilities; and Reliability*First* Corporation charges. The cost per MWh of load in Table 10-4 is a different metric than the cost of each ancillary service per MW of that service. The cost per MWh of load includes the effects both of price changes per MW of the ancillary service and changes in total load.

Table 10-4 History of ancillary services costs per MWh of load: January through September, 1999 through 2019[17] [18]

Year (Jan-Sep)	Regulation	Scheduling, Dispatch and System Control	Reactive	Synchronized Reserve	Total
1999	$0.16	$0.22	$0.25	$0.00	$0.63
2000	$0.33	$0.29	$0.31	$0.00	$0.93
2001	$0.55	$0.70	$0.22	$0.00	$1.47
2002	$0.42	$0.82	$0.19	$0.00	$1.43
2003	$0.53	$1.01	$0.23	$0.13	$1.90
2004	$0.50	$0.99	$0.25	$0.14	$1.88
2005	$0.78	$0.73	$0.26	$0.11	$1.88
2006	$0.55	$0.74	$0.28	$0.07	$1.64
2007	$0.65	$0.72	$0.27	$0.06	$1.70
2008	$0.78	$0.44	$0.33	$0.07	$1.62
2009	$0.36	$0.34	$0.36	$0.04	$1.10
2010	$0.38	$0.36	$0.36	$0.06	$1.16
2011	$0.36	$0.37	$0.38	$0.09	$1.20
2012	$0.23	$0.42	$0.44	$0.03	$1.12
2013	$0.27	$0.42	$0.67	$0.03	$1.39
2014	$0.36	$0.43	$0.40	$0.14	$1.33
2015	$0.25	$0.42	$0.36	$0.12	$1.15
2016	$0.11	$0.43	$0.37	$0.05	$0.96
2017	$0.13	$0.48	$0.42	$0.06	$1.09
2018	$0.20	$0.47	$0.42	$0.06	$1.15
2019	$0.11	$0.47	$0.44	$0.04	$1.06

17 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.
18 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 so that the test can be replicated. (Priority: Medium. First reported 2016. 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, pending rehearing request before FERC.[19])
- 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.[20] FERC rejected, pending rehearing request before FERC.[21])
- 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, pending rehearing request before FERC.[22])
- 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, pending rehearing request before FERC.[23])
- The MMU recommends enhanced documentation of the implementation of the Regulation Market design. (Priority: Medium. First reported 2010.

19 FERC Docket No. ER18-87.
20 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.
21 FERC Docket No. ER18-87.
22 Id.
23 Id.

Status: Not adopted. FERC rejected, pending rehearing request before FERC.[24])

- The MMU recommends that all data necessary to perform the regulation market three pivotal supplier test be saved so that the test can be replicated. (Priority: Medium. First reported 2016. Status: Adopted, 2018.)
- 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 $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 rule requiring that tier 1 synchronized reserve resources are paid the tier 2 price when the nonsynchronized reserve price is above zero be eliminated immediately and that, under the current rule, tier 1 synchronized reserve resources not be paid the tier 2 price when they do not respond. (Priority: High. First reported 2013. Status: 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 PJM be more explicit and transparent about why tier 1 biasing is used in defining demand in the Tier 2 Synchronized Reserve Market. The MMU recommends that PJM define rules for estimating tier 1 MW, define rules for the use and amount of tier 1 biasing and identify the rule based reasons for each instance of biasing. (Priority: Medium. First reported 2012. Status: Not 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 definition of the IPI be changed from the average number of days between events to the actual number of days since the last event greater than 10 minutes. (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 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 offers in the DASR Market be based on opportunity cost only in order to eliminate market power. (Priority: Low. First reported 2009. Modified, 2018. 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 all resources, new and existing, have a requirement to include and maintain equipment for primary frequency

24 Id.

response capability as a condition of interconnection service and that compensation is provided through the capacity and energy markets. (Priority: Medium. First reported 2018. 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 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. (Priority: Low. First reported 2017. Status: Not adopted.)
- The MMU recommends that 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. New recommendation.[25] Status: Not adopted.)

Conclusion

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.[26]

The design of the PJM Regulation Market is significantly flawed. 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.[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 market power and is therefore not consistent with a competitive outcome. The $7.50 margin should be eliminated. Participant performance has not been adequate. Compliance with calls to respond to actual synchronized reserve events remains 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. For the six spinning events 10 minutes or longer in 2017, the response was 87.6 percent of scheduled tier 2 MW. For the seven spinning events longer

25 The MMU has discussed this recommendation in state of the market reports since 2016 but this is the first time it has been reported as a formal MMU recommendation.
26 Order No. 755, 137 FERC ¶ 61,064 at PP 197–200 (2011).
27 18 CFR § 385,211 (2017)
28 162 FERC ¶ 61,295 (2018).
29 The MMU filed its request for rehearing on April 27, 2018, and PJM filed its request for rehearing on April 30, 2018.

than 10 minutes in 2018, the response was 74.2 percent of scheduled tier 2 MW. There was only one spinning event that lasted longer than 10 minutes in the first nine months of 2019. This one spinning event in the first nine months of 2019 occurred on September 23. In the September 23 event, tier 2 response was 87.4 percent of the amount scheduled and tier 1 response was 71.8 percent of DGP estimated amount. Actual participant performance means that the penalty structure is not adequate to incent 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 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. 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 added $89.7 million to the cost of primary reserve in 2014, $34.1 million in 2015, $4.9 million in 2016, $2.2 million in 2017, $4.7 million in 2018, and $2.3 million in the first nine months of 2019.

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 competitive, although 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 currently 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. 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. In cases where temporary switching conditions create the risk that a single fault could remove

30 See PJM "Manual 12: Balancing Operations," Rev. 39 (Feb. 21, 2019) 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. 38 (Aug. 22, 2019).

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 nine months of 2019, the average five minute interval primary reserve requirement for the RTO Zone was 2,477.6 MW. The average five minute interval primary reserve requirement in the MAD Subzone was 2,453.6 MW. These averages include the hours when PJM raised the requirements.

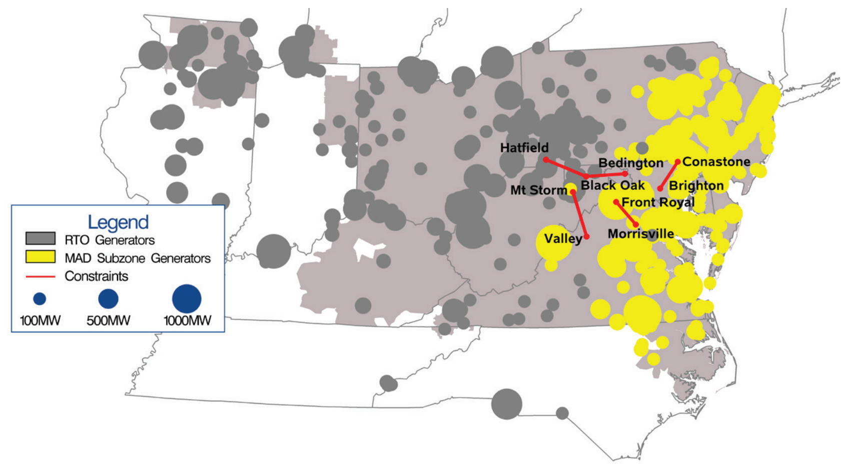
The MMU identified instances when PJM increased the primary and synchronized reserve requirements (Table 10-5). The amounts of the increases are estimated against average requirement levels before and after the periods of increase.

Table 10-5 Temporary adjustments to primary and synchronized reserve in 2019

From	To	Number of Hours	Amount of Adjustment
12-Feb-19	12-Feb-19	10	Primary Reserve (1,350 MW), Synchronized Reserve (1,000 MW)
4-Mar-19	5-Mar-19	24	Primary Reserve (220 MW), Synchronized Reserve (150 MW)
29-Apr-19	3-May-19	61	Primary Reserve (65 MW), Synchronized Reserve (50 MW)
7-May-19	7-May-19	6	Primary Reserve (280 MW), Synchronrized Reserve (230 MW)
6-Jun-19	6-Jun-19	5	Primary Reserve (600 MW), Synchronized Reserve (400 MW)
11-Jun-19	11-Jun-19	5	Primary Reserve (600 MW), Synchronized Reserve (300 MW)
17-Jun-19	19-Jun-19	24	Primary Reserve (220 MW), Synchronized Reserve (150 MW)
10-Sep-19	13-Sep-19	52	Primary Reserve (625 MW), Synchronized Reserve (425 MW)

Transmission constraints limit the deliverability of reserves within the RTO, requiring the definition of 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.

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, which includes Brighton-Conastone, Belmont-Stonewall, Bedington-Black Oak, Cloverdale-Lexington, and Mt. Storm-Valley constraints.

The NERC standard requires a control area to carry primary reserve MW equal to or greater than the most severe single contingency (MSSC).[35] 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

32 PJM Manual 11: Energy & Ancillary Services Market Operations, Rev. 107 (Sep 26, 2019), p. 84
33 PJM Manual 11: Energy & Ancillary Services Market Operations, Rev. 107(Sep. 26, 2019), p. 84
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. 107 (Sep. 26, 2019).
35 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>.

synchronized reserves.[36] In the first nine months of 2019, the five minute average synchronized reserve requirement in the RTO Zone was 1,713.8 MW. The five minute average synchronized reserve requirement in the MAD Subzone was 1,697.8 MW. The synchronized reserve requirement is calculated every five minutes.

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 hourly 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 1,576.0 MW of tier 1 was identified by the RT SCED market solution as available in the first nine months of 2019 (Table 10-6).[37] 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 12.9 percent of intervals in the first nine months of 2019. In the RTO Zone, an average of 2,179.5 MW of tier 1 was available (Table 10-7) fully satisfying the synchronized reserve requirement in 59.4 percent of intervals.

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.[38]

After tier 1 is estimated, the remainder of the synchronized reserve requirement is met by tier 2. In the RTO Zone, there were 29,209.1 MW of tier 2 synchronized reserve offered daily. Of this, 5,463.9 MW were located in the MAD Subzone and available to meet the average MAD tier 2 hourly demand of 280.0 MW (Table 10-6).

In the MAD Subzone, there was an average of 3,054.2 MW of eligible nonsynchronized reserve supply available to meet the average interval demand for primary reserve. (Table 10-7) In the RTO Zone, an average of 3,953.1 MW supply was available to meet the average interval demand of 1,774.5 MW (Table 10-7).

Table 10-6 provides the average interval reserves, by type of reserve, used by the RT SCED market solution to satisfy the primary reserve requirement in the MAD Subzone from January 2018 through September 2019.

36 "PJM Manual 13: Emergency Operations," Rev 72 (Sep. 26, 2019), p. 18.
37 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.
38 See PJM "Manual 11: Energy & Ancillary Services Market Operations," § 4.2 PJM Synchronized Reserve Market Business Rules, Rev. 107 (Sep. 26, 2019).

Table 10-6 Average hourly reserves used to satisfy the primary reserve requirement, MAD Subzone: January 2018 through September 2019

Year	Month	Tier 1 Total MW	Tier 2 Synchronized Reserve MW	Nonsynchronized Reserve MW	Total Primary Reserve MW
2018	Jan	1,371.1	290.4	1,454.0	3,382.4
2018	Feb	1,408.1	264.3	1,461.1	3,504.1
2018	Mar	1,313.3	350.3	1,642.3	3,529.1
2018	Apr	1,192.8	453.7	1,226.4	3,175.5
2018	May	1,191.3	462.4	1,063.7	2,913.2
2018	Jun	1,445.7	185.6	1,195.9	3,239.7
2018	Jul	1,380.1	367.8	1,312.2	3,212.9
2018	Aug	1,334.4	460.1	1,228.5	3,052.2
2018	Sep	1,377.5	383.5	1,007.8	2,916.0
2018	Oct	1,356.5	356.0	602.4	2,705.8
2018	Nov	1,442.4	259.5	798.0	2,813.3
2018	Dec	1,542.6	363.8	1,103.4	3,081.2
2018	Average	1,363.0	349.8	1,174.6	3,127.1
2019	Jan	1,653.3	220.6	1,407.0	3,060.4
2019	Feb	1,630.0	304.7	1,554.3	3,184.4
2019	Mar	1,537.9	277.7	1,601.1	3,139.1
2019	Apr	1,368.4	303.4	1,590.7	2,959.2
2019	May	1,451.2	194.0	1,432.1	2,883.7
2019	Jun	1,676.6	295.6	1,440.5	3,117.2
2019	Jul	1,674.9	267.3	1,336.9	3,012.4
2019	Aug	1,684.2	284.5	1,465.8	3,150.1
2019	Sep	1,507.6	382.1	1,538.5	3,046.2
2019	Average	1,576.0	281.1	1,485.2	3,061.4

Table 10-7 shows the average hourly reserves, by type of reserve, used by the RT SCED market solution to satisfy the primary reserve requirement in the RTO Zone for January 2018 through September 2019.

Table 10-7 Average monthly reserves used to satisfy the primary reserve requirement, RTO Zone: January 2018 through September 2019

Year	Month	Tier 1 Total MW	Tier 2 Synchronized Reserve MW	Nonsynchronized Reserve MW	Total Primary Reserve MW
2018	Jan	1,792.5	466.6	2,189.8	3,982.2
2018	Feb	1,899.6	379.0	2,207.8	4,107.5
2018	Mar	1,552.4	541.8	2,394.6	3,947.0
2018	Apr	1,034.6	895.0	2,374.9	3,409.5
2018	May	1,318.7	786.6	1,984.7	3,303.3
2018	Jun	2,150.5	344.3	1,927.9	4,078.3
2018	Jul	2,036.8	532.1	1,972.3	4,009.2
2018	Aug	1,948.1	625.8	1,862.3	3,810.3
2018	Sep	1,825.1	602.6	1,717.4	3,542.5
2018	Oct	1,383.0	778.3	1,682.7	3,065.7
2018	Nov	1,596.0	639.6	1,649.7	3,245.6
2018	Dec	1,523.2	382.5	1,578.3	3,101.4
2018	Average	1,671.7	581.2	1,961.9	3,633.5
2019	Jan	2,540.4	375.6	1,542.2	4,458.2
2019	Feb	2,060.9	629.8	1,818.6	4,509.3
2019	Mar	1,965.2	593.7	1,848.0	4,407.0
2019	Apr	1,593.8	666.6	1,878.5	4,139.0
2019	May	2,022.4	483.7	1,657.0	4,163.0
2019	Jun	2,520.3	424.1	1,862.6	4,807.1
2019	Jul	2,601.7	425.6	1,652.5	4,679.8
2019	Aug	2,472.6	498.9	1,871.8	4,843.3
2019	Sep	1,837.9	753.1	1,905.1	4,496.1
2019	Average	2,179.5	539.0	1,781.8	4,500.3

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).

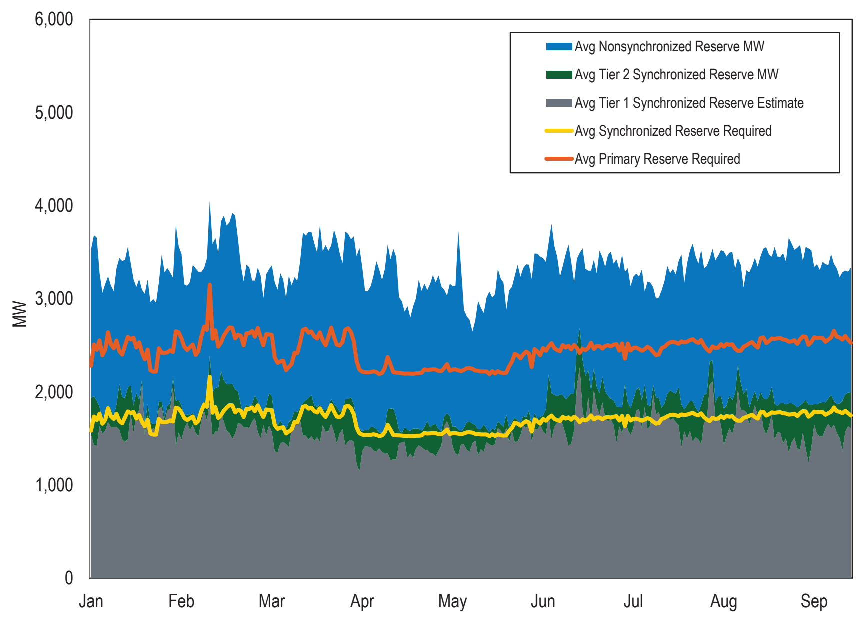
All market solutions determine the actual primary reserves required each hour as 150 percent of the largest contingency plus 190 MW. Of this, synchronized reserves must be 100 percent of the largest contingency plus 190 MW.

PJM's Ancillary Services Optimizer (ASO) optimizes the three components of primary reserve an hour ahead of the first interval of each operating hour. Using forecast LMPs, ASO calculates the tier 1 synchronized reserve available for the operating hour based on economic dispatch. The ASO compares the amount of estimated tier 1 synchronized reserve to the required synchronized reserve less self-scheduled synchronized reserve. If the synchronized reserve requirement is not met, the ASO clears, in economic order, inflexible tier 2 synchronized reserve and identifies flexible synchronized reserve sufficient to meet the remaining synchronized reserve requirement. ASO commits the economic inflexible resources from this solution to provide synchronized reserve for all intervals during the hour. This is inflexible Tier 2 Synchronized Reserve. All resources committed for inflexible tier 2 synchronized reserve are notified of their commitment via Markets Gateway thirty minutes before the operating hour. The economic flexible resources identified in the ASO solution are not committed as synchronized reserves prior to the hour.

Ten to 14 minutes before each interval of the operating hour RT SCED runs. 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 in an interval, the RT SCED may decommit previously committed flexible synchronized reserve.

Figure 10-2 illustrates how the ASO satisfied the primary reserve requirement (orange line) for the Mid-Atlantic Dominion Subzone. For the Mid-Atlantic Dominion Reserve Subzone the market solutions must first satisfy the synchronized reserve requirement (yellow line) which is calculated hourly in the MAD Subzone. The market solutions first estimate how much tier 1 synchronized reserve (green area) is available. If there is enough tier 1 MW available to satisfy the synchronized reserve requirement, then they jointly optimize the synchronized reserve and nonsynchronized reserve to assign the remaining primary reserve up to the 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 (green area). After synchronized reserve is assigned, the primary reserve requirement is filled by jointly optimizing synchronized reserve and nonsynchronized reserve (light blue area). Since nonsynchronized reserve is priced lower than or equal to synchronized reserve, almost all primary reserve above the synchronized reserve requirement is filled by nonsynchronized reserve.

Figure 10-2 Mid-Atlantic Dominion subzone primary reserve MW by source (Daily Averages): January through September, 2019



The solution method is the same for the RTO Reserve Zone.[39] Figure 10-3 shows how the market solutions satisfy the primary reserve requirement for the RTO Zone.

Figure 10-3 RTO reserve zone primary reserve MW by source (Daily Averages): January through September, 2019

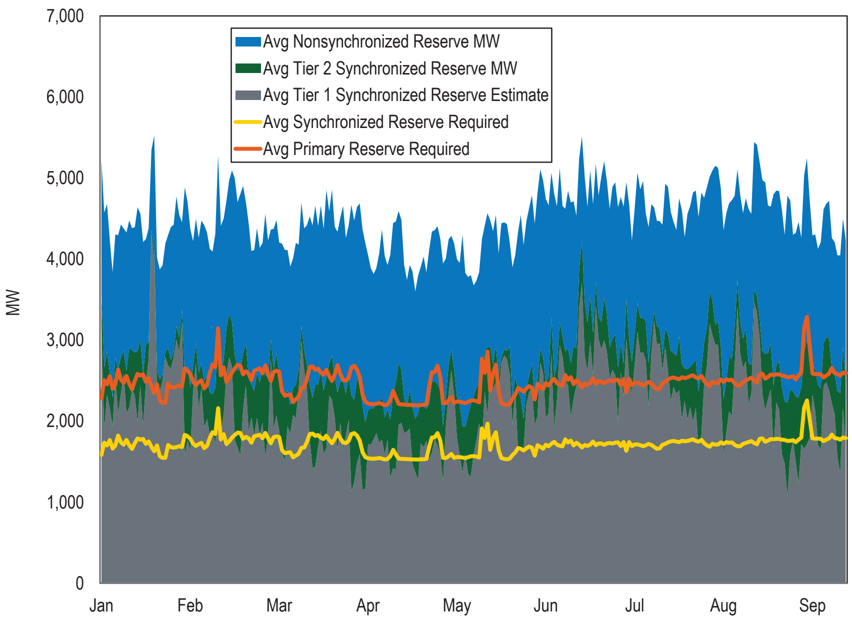


Figure 10-2 shows that within the MAD Subzone, Tier 1, Tier 2 from MAD, and Tier 2 from the RTO are all essential to satisfying the synchronized reserve requirement. Figure 10-3 shows that tier 1 synchronized reserve remains the major contributor to satisfying the synchronized reserve requirement in the RTO Zone.

39 Although tier 1 has a price of zero, changes made with shortage pricing on November 1, 2012, have given tier 1 a very high cost in some hours. This high cost raises questions about the economics of the solution method used by the ASO, IT SCED, and RT SCED market solutions which assume zero cost.

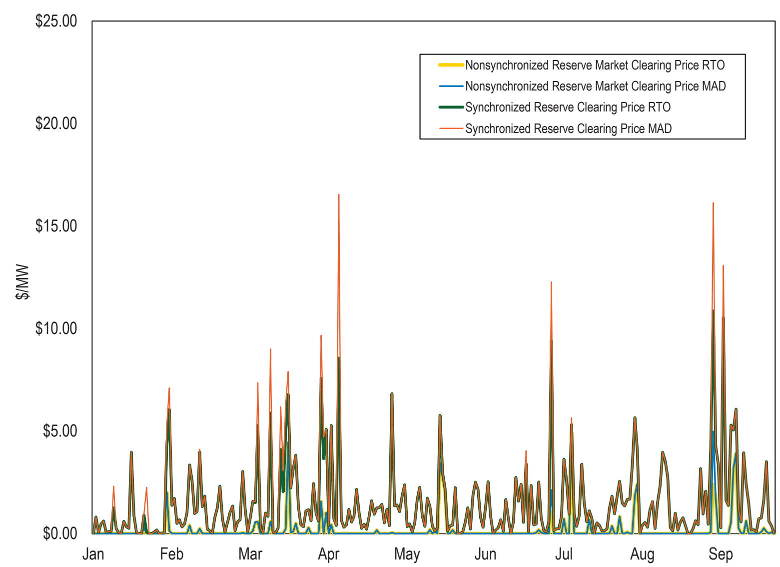
Price and Cost

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 10-4 shows daily weighted average synchronized and nonsynchronized market clearing prices in the first nine months of 2019.

Figure 10-4 Daily average market clearing prices ($/MW) for synchronized reserve and nonsynchronized reserve: January through September, 2019



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 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.

On a combined basis, the ratio of price to cost for all primary reserve during the first nine months 2019 was 43.0 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 non-zero price. Table 10-8 shows that the cost of tier 1 reserves is $23.30 per MW when the price of nonsynchronized reserve is greater than zero, or more than four times the cost of tier 2 reserves which is $4.79 per MW.

Table 10-8 Primary reserve requirement components, RTO Reserve Zone: January through September, 2019

Product	MW Share of Primary Reserve Requirement	MW	Credits Paid	Price Per MW Reserve	Cost Per MW Reserve
Tier 1 Synchronized Reserve Response	NA	2,985	$149,282	NA	$50.00
Tier 1 Synchronized Reserve in Market Solution	1.0%	98,503	$2,295,217	$0.00	$23.30
Tier 2 Synchronized Reserve Scheduled	28.5%	2,834,264	$13,576,310	$3.19	$4.79
Non Synchronized Reserve Scheduled	70.5%	7,002,727	$8,233,987	$0.20	$1.18
Primary Reserve (total of above)	100.0%	9,938,480	$24,254,796	$1.05	$2.44

Tier 1 Synchronized Reserve

Tier 1 synchronized reserve is a component of primary reserve comprised of all 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 January 2015, 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. DGP is calculated for all online resources for each market solution. DGP measures how closely the unit has been following economic dispatch for the past 30 minutes. The available tier 1 MW estimated by the market solution for each resource is based upon its economic dispatch, and energy schedule ramp rate or 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. DGP violates the basic PJM principle that generation owners are solely responsible for their own offers. In addition,

40 See PJM "Manual 11: Energy & Ancillary Services Market Operations," § 4.2.1 Synchronized Reserve Market Eligibility, Rev. 107 (Sep. 26, 2019).

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>

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 from the DGP estimate tier 1 MW from unit types that cannot reliably provide synchronized reserve. These unit types are nuclear, wind, solar, landfill gas, energy storage, and hydro units (Table 10-10).[42] These units will be 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 from the tier 1 estimate that wish to be included.[43] This limitation by unit type necessarily restricts the fuel type supplying tier 1 synchronized reserve (Table 10-9).

Table 10-9 Supply of Tier 1 Synchronized Reserve by Fuel Type: January through September, 2019

Fuel	Percentage of Tier 1 MW	Percentage of Tier 1 Credits
Natural Gas	57.3%	57.9%
Coal	30.2%	28.6%
Hydro	8.0%	7.5%
LFG	1.7%	2.2%
Solar	0.9%	1.2%
Wind	0.8%	1.3%
MSW	0.5%	0.7%
Waste Coal	0.3%	0.2%
Biomass	0.1%	0.1%
Nuclear	0.1%	0.1%

Table 10-10 Supply of Tier 1 Synchronized Reserve by Unit Type: January through September, 2019

Unit Type	Percentage of Tier 1 MW	Percentage of Tier 1 Credits
CC	45.7%	44.1%
Steam	33.8%	32.3%
CT	8.6%	10.8%
Hydro	8.0%	7.5%
Diesel	2.0%	2.7%
Solar	0.9%	1.2%
Wind	0.8%	1.3%
Nuclear	0.1%	0.1%
DSR	0.1%	0.1%

In the first nine months of 2019, the market solutions estimated tier 1 MW from an average of 142 units that could contribute ramp in a spinning event. In the RTO Reserve Zone, the average interval estimated tier 1 synchronized reserve was 2,170.5 MW (Table 10-11). In 59.4 percent of intervals, 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 nine months of 2019, the average estimated tier 1 synchronized reserve available was 1,571.7 MW in the MAD Subzone of which 578.5 MW was available from the RTO (Table 10-12). In 13.1 percent of RT SCED intervals, 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.

42 See PJM. "Manual 11: Energy & Ancillary Services Market Operations," § 4.2.1 Synchronized Reserve Market Eligibility, Rev. 107 (Sep. 26, 2019)
43 See PJM. "Manual 11: Energy & Ancillary Services Market Operations," § 4.2.1 Synchronized Reserve Market Eligibility, Rev. 107 (Sep. 26, 2019)

Table 10-11 Monthly average interval market solutions for tier 1 synchronized reserve (MW): January 2018 through September 2019

Year	Month	Average Interval Tier 1 Local To MAD	Tier 1 Synchronized Reserve From RTO Zone	Average Interval Tier 1 Used in MAD	Average Interval Tier 1 Used in RTO Zone
2018	Jan	814.2	554.9	1,369.1	1,796.0
2018	Feb	765.6	640.3	1,406.0	1,886.0
2018	Mar	746.1	571.6	1,317.7	1,559.7
2018	Apr	434.1	756.2	1,190.3	1,028.6
2018	May	540.6	654.5	1,195.1	1,340.3
2018	Jun	825.7	613.4	1,439.1	2,113.7
2018	Jul	865.6	509.0	1,374.5	2,058.2
2018	Aug	835.4	493.2	1,328.6	1,923.0
2018	Sep	836.7	540.7	1,377.4	1,805.3
2018	Oct	617.9	737.1	1,355.0	1,393.8
2018	Nov	880.2	566.4	1,446.6	1,611.5
2018	Dec	1,101.1	421.2	1,522.2	2,025.8
2018	Average	771.9	588.2	1,360.1	1,711.9
2019	Jan	1,265.1	383.4	1,648.5	2,518.6
2019	Feb	999.1	630.9	1,629.9	2,052.6
2019	Mar	928.9	607.0	1,535.9	1,937.1
2019	Apr	665.7	703.5	1,369.2	1,593.3
2019	May	869.5	578.0	1,447.5	1,987.7
2019	Jun	1,154.9	509.5	1,664.5	2,523.7
2019	Jul	1,139.0	521.2	1,660.2	2,579.8
2019	Aug	1,178.8	504.2	1,683.0	2,477.1
2019	Sep	737.6	769.3	1,506.9	1,864.4
2019	Average	993.2	578.5	1,571.7	2,170.5

Demand

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

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

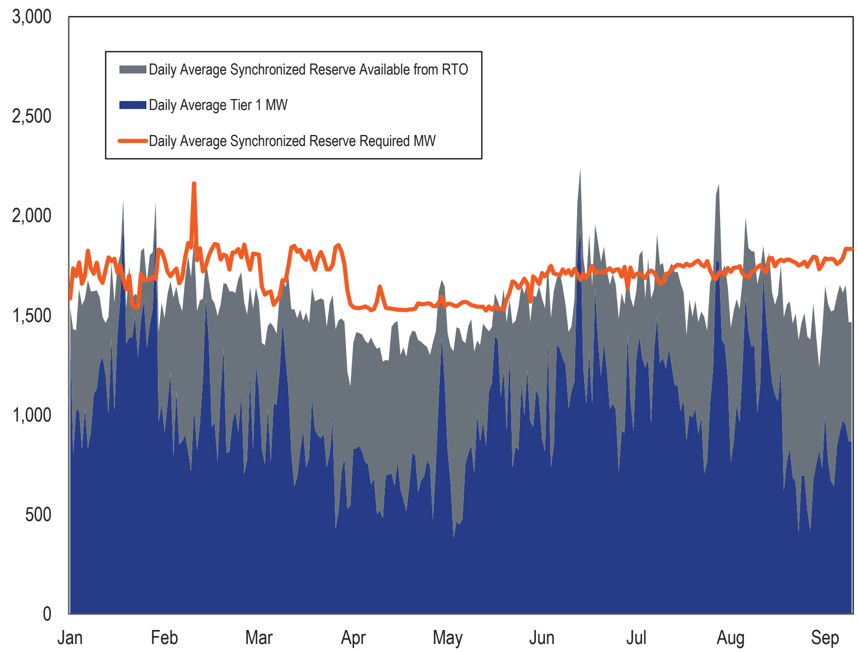
Supply and Demand

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 subtracts the amount of self scheduled synchronized reserve from the requirement and then estimates the amount of tier 1.

In the MAD Subzone, the market solution takes all tier 1 MW estimated to be available within the MAD Subzone (blue area of Figure 10-5) as well as the synchronized reserve MW estimated to be available within the MAD Subzone from the RTO Zone (gray area of Figure 10-5) up to the synchronized reserve requirement. 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 (white area below the synchronized reserve required line in Figure 10-5).

Figure 10-5 Daily average tier 1 synchronized reserve supply (MW) in the MAD Subzone: January through September, 2019



Tier 1 Synchronized Reserve Event Response

Tier 1 synchronized reserve is awarded credits when a synchronized reserve event occurs and it responds. Tier 1 synchronized reserve resources are paid for increasing output (or reducing load for demand response) at the rate of \$50 per MWh in addition to LMP.[44] This is the Synchronized Energy Premium Price. During a synchronized reserve event, tier 1 credits are awarded to all units that increase their output during the event regardless of their estimated tier 1 MW, or tier 1 deselection status at market clearing time, unless the units have cleared the tier 2 market. 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. Total response credited to a resource is capped at 110 percent of estimated capability.

In the first nine months of 2019, tier 1 synchronized reserve spinning event response credits of \$149,282 were paid for 10 spinning events covering 20 intervals. The average tier 1 response over the six spinning events was 285.5 MWh (Table 10-12).

Table 10-12 Tier 1 synchronized reserve event response costs: January 2018 through September 2019

		Synchronized Reserve Events			Hours When NSRMCP>\$0		
Year	Month	Total MWh	Total Credits	Average MWh Per Event	Total MWh	Total Credits	Average MW Per Hour
2018	Jan	6,081.6	\$1,146,858	676.3	39,047.0	\$2,394,953	1,259.6
2018	Feb	0.0	\$0	NA	0.0	NA	NA
2018	Mar	0.0	\$0	NA	9,906.4	\$176,651	990.6
2018	Apr	287.4	\$14,969	534.0	2,584.1	\$48,880	143.6
2018	May	0.0	\$0	NA	5,564.8	\$191,459	347.8
2018	Jun	1,422.0	\$71,416	1,422.0	3,545.3	\$20,354	590.9
2018	Jul	1,511.8	\$76,588	518.6	1,762.9	\$4,888	440.7
2018	Aug	534.2	\$26,716	534.2	1,380.3	\$15,568	460.1
2018	Sep	1,026.8	\$53,492	513.4	18,255.9	\$478,289	553.2
2018	Oct	144.1	\$7,205	144.0	60,896.0	\$1,212,173	609.0
2018	Nov	0.0	\$0	NA	12,278.0	\$184,777	341.1
2018	Dec	0.0	\$0	NA	770.0	\$4,034	192.5
2018		11,007.8	\$1,397,244	620.4	155,990.7	\$4,732,025	539.0
2019	Jan	784.8	\$39,244	261.6	2,671.7	\$96,303	445.3
2019	Feb	228.4	\$11,422	228.4	2,733.0	\$35,529	390.4
2019	Mar	633.7	\$31,688	316.9	12,050.0	\$436,108	446.3
2019	Apr	0.0	\$0	NA	3,065.4	\$115,550	383.2
2019	May	0.0	\$0	NA	38,102.7	\$398,500	952.6
2019	Jun	0.0	\$0	NA	2,089.8	\$12,776	522.4
2019	Jul	79.4	\$3,971	79.4	7,574.0	\$419,285	504.9
2019	Aug	394.9	\$19,743	394.9	1,899.8	\$126,928	474.9
2019	Sep	864.3	\$43,214	432.1	28,317.0	\$654,238	629.3
2019		2,985.4	\$149,282	285.5	98,503.4	\$2,295,217	527.7

44 See PJM. "Manual 11: Energy & Ancillary Services Market Operations,"§ 4.2.10 Settlements, Rev. 107 (Sep. 26, 2019).

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 10-14). 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 10-13). The nonsynchronized reserve market clearing price was above $0.00 in 156 hours in the first nine months of 2019. For those 156 hours, tier 1 synchronized reserve resources were paid a weighted average synchronized reserve market clearing price of $31.64 per MW and earned $2,295,217 in credits.

Table 10-13 Price of tier 1 synchronized reserve attributable to a nonsynchronized reserve price above zero: January 2018 through September 2019

Year	Month	Total Hours When NSRMCP>$0	Weighted Average SRMCP for Hours When NSRMCP>$0	Total Tier 1 MWh Credited for Hours When NSRMCP>$0	Total Tier 1 Credits Paid When NSRMCP>$0	Average Tier 1 MWh Paid
2018	Jan	31	$61.34	39,047.0	$2,394,953	1,259.6
2018	Feb	0	NA	NA	NA	NA
2018	Mar	10	$17.83	9,906.4	$176,651	990.6
2018	Apr	18	$18.91	2,584.0	$48,880	143.6
2018	May	16	$34.41	5,564.8	$191,459	347.8
2018	Jun	6	$5.74	3,545.3	$20,354	590.9
2018	Jul	4	$2.77	1,762.9	$4,888	440.7
2018	Aug	3	$11.27	1,380.3	$15,568	460.1
2018	Sep	33	$26.20	18,256.0	$478,289	553.2
2018	Oct	100	$19.91	60,896.0	$1,212,173	609.0
2018	Nov	36	$15.05	12,278.0	$184,777	341.1
2018	Dec	4	$5.24	770.0	$4,034	192.5
2018		261	$19.88	155,990.7	$4,732,026	539.0
2019	Jan	6	$36.05	2,671.7	$96,303	445.3
2019	Feb	7	$13.00	2,733.0	$35,529	390.4
2019	Mar	27	$36.19	12,049.7	$436,108	446.3
2019	Apr	8	$37.69	3,065.4	$115,550	383.2
2019	May	40	$10.46	38,102.7	$398,500	952.6
2019	Jun	4	$6.11	2,089.8	$12,776	522.4
2019	Jul	15	$55.36	7,574.0	$419,285	504.9
2019	Aug	4	$66.81	1,899.8	$126,928	474.9
2019	Sep	45	$23.10	28,317.0	$654,238	629.3
2019		156	$31.64	98,502.9	$2,295,217	527.7

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 nine months of 2019, there has only been one spinning event of 10 minutes or longer. In that event of September 23, 71.8 percent of the 924.7 MW of DGP estimated Tier 1 responded and 87.4 percent of the 723.2 MW of tier 2 responded. A total of 1,998.0 MW of tier 1 did respond. However, all resources that were included in the tier 1 estimates were paid the tier 2 price for their full estimated MW when the nonsynchronized reserve (NSR) price was greater than zero. Unlike tier 1 resources, tier 2 synchronized reserve resources are paid the market clearing price for tier 2 because they stand ready to respond and incur costs to do so, have an obligation to perform and pay penalties for nonperformance.

When the next MW of nonsynchronized reserve required to satisfy the primary reserve requirement increases in price from $0.00 per MW to $0.01 per MW, the cost of all tier 1 MW increases significantly.

In the first nine months of 2019, tier 1 synchronized reserve was paid $149,282 for responding to synchronized reserve events. During the same time period, tier 1 synchronized reserve was paid a windfall of $2,295,217 simply because the NSRMCP was greater than $0.00 in 40 hours. Table 10-12 provides a comparison of the cost of tier 1 as used for spinning events and the cost when compensated because the NSRMCP was greater than $0.

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.[45] 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 10-14.

45 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.

Table 10-14 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 10-15.

Table 10-15 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

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 an 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. Tier 2 resources are scheduled by the ASO 60 minutes before the operating hour, are committed to provide synchronized reserve for the entire hour, and 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 and demand resources. Tier 2 synchronized reserve inflexible resources are committed for a full hour by the hour ahead market solution. Inflexible resources 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 every five minutes by the RT SCED solution and the requirement not satisfied by inflexible units is satisfied by flexible units for the interval.

During the operating hour, the IT SCED and the RT SCED market solutions software can dispatch additional resources flexibly. A flexible commitment is one in which the IT SCED or RT SCED redispatches 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 required to maintain their available ramp and are paid the SRMCP plus any lost opportunity costs or energy use 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.[46]

In the first nine months of 2019, the Mid Atlantic Dominion (MAD) Reserve Subzone averaged 5,473.4 MW of tier 2 synchronized reserve offers, and the RTO Reserve Zone averaged 29,238.5 MW of tier 2 synchronized reserve offers (Figure 10-9).

The supply of tier 2 synchronized reserve offered in the first nine months of 2019 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 from generation in the first nine months of 2019 was from CTs (Table 10-17). 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. DR MW were 2.9 percent of cleared plus self-scheduled tier 2 synchronized reserve in the first nine months of 2019.

Table 10-16 Supply of Generation Tier 2 Synchronized Reserve by Fuel Type: January through September, 2019

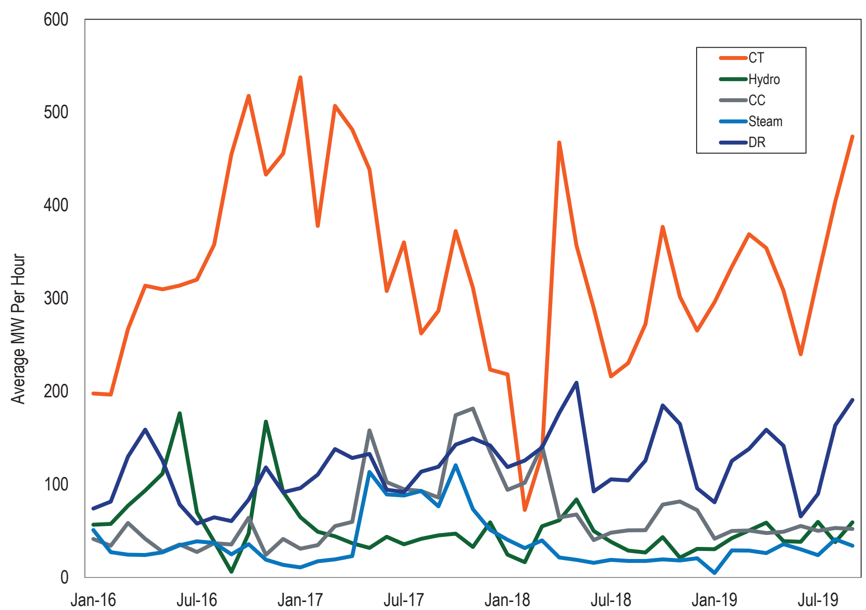
Fuel	Percentage of Tier 2 MW	Percentage of Tier 2 Credits
Natural Gas	64.1%	74.6%
Light Oil	22.9%	18.2%
Hydro	9.8%	3.0%
Coal	2.9%	3.9%
Waste Oil	0.2%	0.2%
Diesel	0.0%	0.0%
Biomass	0.0%	0.0%
LFG	0.0%	0.0%

46 See PJM "Manual 11: Energy & Ancillary Services Market Operations," § 4.2.1 Synchronized Reserve Market Eligibility, Rev. 107 (Sep.26, 2019).

Table 10-17 Supply of Tier 2 Synchronized Reserve by Unit Type: January through September, 2019

Unit Type	Percentage of Tier 2 MW	Percentage of Tier 2 Credits
CT	69.5%	68.2%
CC	14.8%	15.7%
Hydro	9.5%	2.7%
Steam	3.1%	3.9%
DSR	2.9%	9.2%
Diesel	0.2%	0.3%

Figure 10-6 Cleared tier 2 synchronized reserve average MW per hour by unit type, RTO Zone: January 2016 through September 2019



Demand

On July 12, 2017, PJM adopted a dynamic synchronized reserve requirement set equal to 100 percent of the most severe single contingency (MSSC), determined in each five minute interval by RT SCED. There are two circumstances in which PJM may alter 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 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.[47]

In the first nine months of 2019, the average synchronized reserve requirement per interval in the RTO Zone was 1,713.8 MW and the average synchronized reserve requirement in the MAD Subzone was 1,697.8 MW. These averages include temporary increases to the synchronized reserve requirement.

The RTO Reserve Zone purchased an interval average of 536.2 MW of tier 2 synchronized reserves in the first nine months of 2019. Of this, an average of 280.2 MW cleared within the MAD Subzone.

Figure 10-7 and Figure 10-8 show the average monthly synchronized reserve required and the average monthly tier 2 synchronized reserve MW scheduled (PJM scheduled plus self scheduled) from January 2016 through September 2019, for the RTO Reserve Zone and MAD Reserve Subzone. There were 21 intervals of shortage in the first nine months of 2019. There were ten spinning events in the first nine months of 2019 but only one lasted longer than 10 minutes (September 23, 2019).

47 PJM "Manual 11: Energy & Ancillary Services Market Operations," § 4.2.2 Synchronized Reserve Requirement Determination, Rev. 107 (Sep 26, 2019).

Figure 10-7 MAD hourly average tier 2 synchronized reserve scheduled MW: January 2016 through September 2019

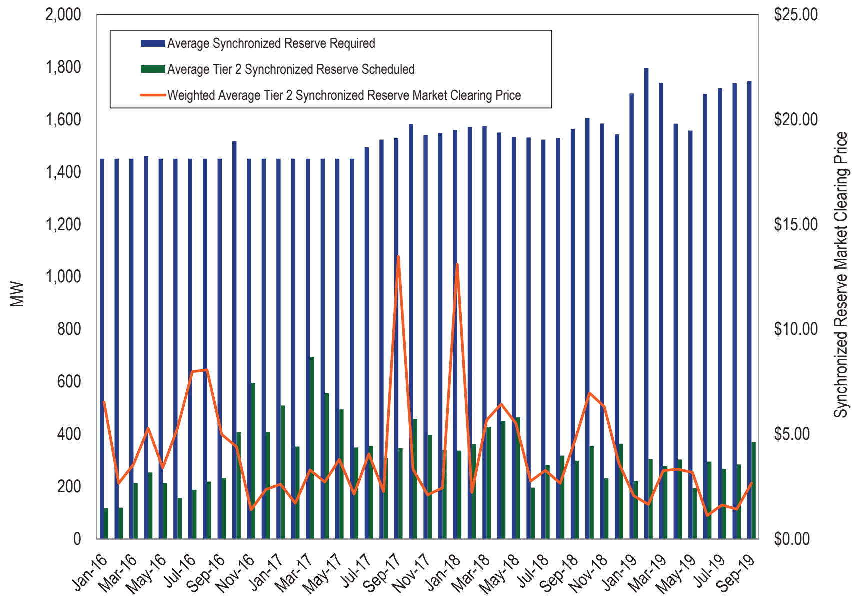
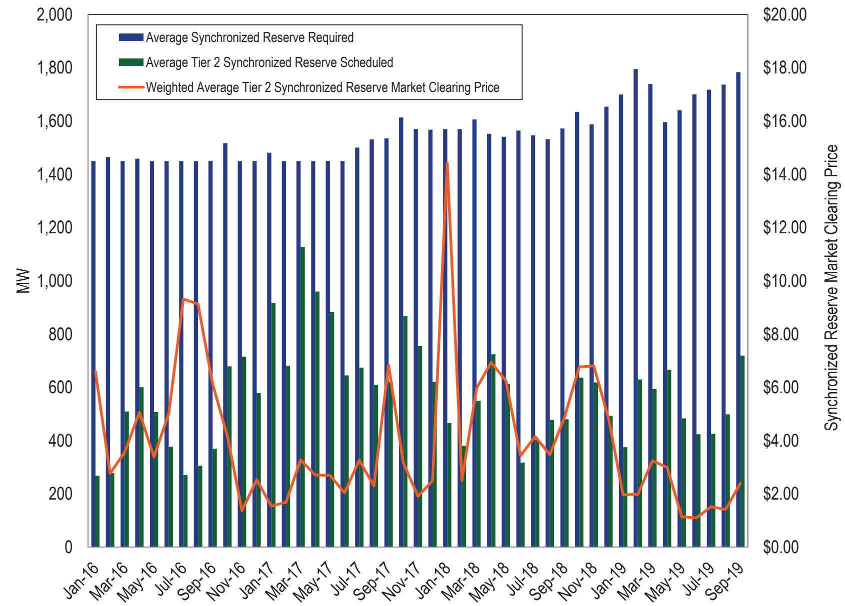


Figure 10-8 RTO hourly average tier 2 synchronized reserve scheduled MW: January 2016 through September 2019



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 nine months of 2019 was 4319, which is defined as highly concentrated. In 62.6 percent of all cleared intervals the maximum market share greater than or equal to 40 percent.

The average HHI for tier 2 synchronized reserve for cleared intervals of the RTO Zone Tier 2 Synchronized Reserve Market in the first nine months of 2019 was 5505, which is defined as highly concentrated. In 94.3 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 9.5 percent of all tier 2 synchronized reserve in the first nine months of 2019. In the RTO Zone, flexible synchronized reserve assigned was 24.0 percent of all tier 2 synchronized reserve during the same period.

In the first nine months of 2019 9.7 percent of hours would have failed the three pivotal supplier test in the RTO Zone and MAD Subzone for all cleared hours of the inflexible Synchronized Reserve Market in the hour ahead market (Table 10-18).

Table 10-18 Three pivotal supplier test results for the RTO Zone and MAD Subzone: January 2018 through September 2019

Year	Month	MAD Reserve Subzone Pivotal Supplier Hours	RTO Reserve Zone Pivotal Supplier Hours
2018	Jan	65.5%	19.5%
2018	Feb	31.4%	0.0%
2018	Mar	41.2%	13.6%
2018	Apr	17.4%	9.2%
2018	May	15.2%	6.6%
2018	Jun	16.0%	9.3%
2018	Jul	15.4%	11.2%
2018	Aug	13.6%	7.0%
2018	Sep	17.3%	8.3%
2018	Oct	10.6%	11.2%
2018	Nov	16.0%	15.1%
2018	Dec	8.5%	11.6%
2018	Average	22.3%	10.2%
2019	Jan	3.8%	3.4%
2019	Feb	6.6%	6.8%
2019	Mar	2.6%	2.6%
2019	Apr	2.7%	2.7%
2019	May	1.8%	1.8%
2019	Jun	13.0%	11.2%
2019	Jul	20.7%	16.9%
2019	Aug	21.1%	18.5%
2019	Sep	25.8%	20.2%
2019	Average	10.9%	9.3%

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.[48] 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 0.00 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.[49]

Figure 10-9 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. In the first nine months of 2019, the ratio of eligible tier 2 synchronized reserve to synchronized reserve required across the RTO was 14.7.

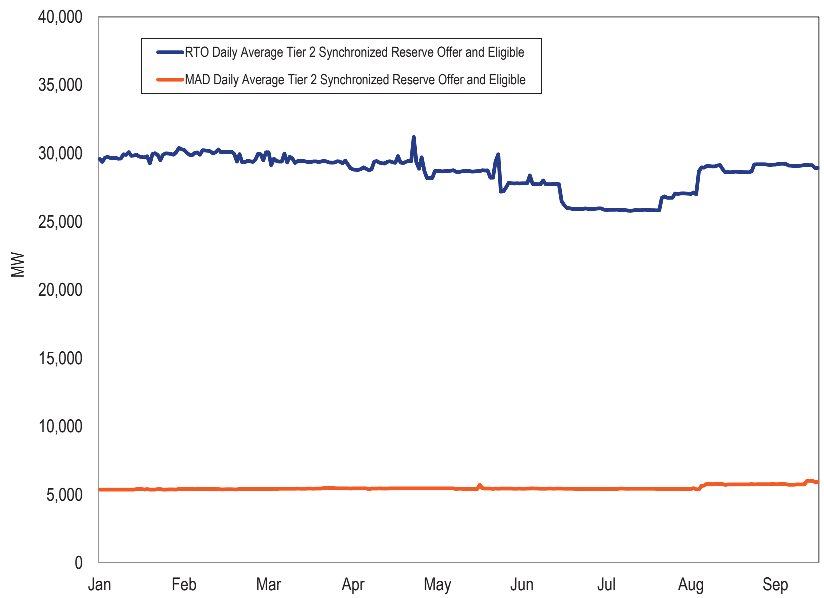
PJM has a tier 2 synchronized reserve must offer requirement for all generation that is online, nonemergency, and physically able to operate with an output

48 See PJM "Manual 11: Energy & Ancillary Services Market Operations," § 4.2.1 Synchronized Reserve Market Eligibility Rev. 107 (Sep. 26, 2019).

49 See PJM "Manual 11: Energy & Ancillary Services Market Operations," § 4.2.1 Synchronized Reserve Market Eligibility Rev. 107 (Sep. 26, 2019).

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.[50] 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 10-9). 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 10-9 Tier 2 synchronized reserve hourly offer and eligible volume (MW): January through September, 2019

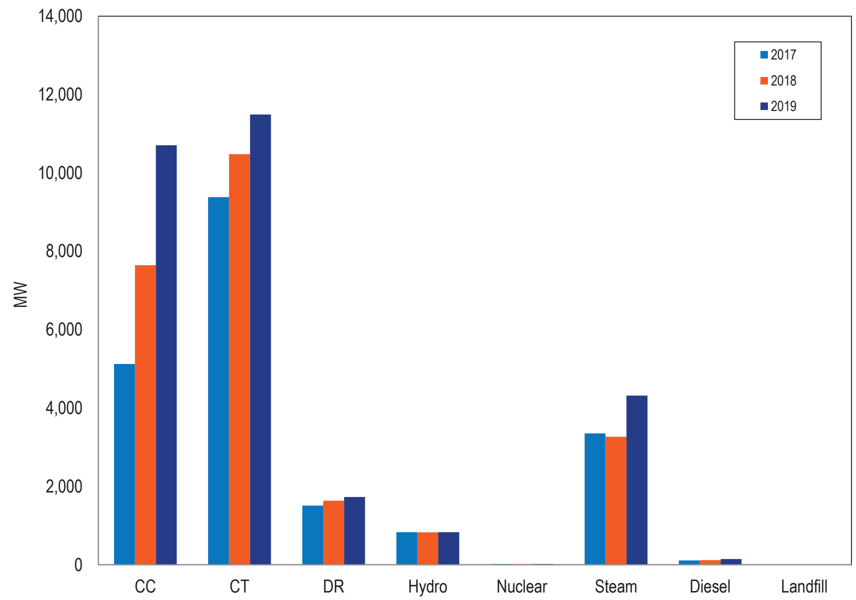


While over 97 percent of resources have tier 2 synchronized reserve offers, there remain a large number of hours when many units make themselves unavailable for tier 2 synchronized reserve.

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 MW to 0 MW.[51]

Figure 10-10 shows average full RTO daily offer MW volume by unit type in the first nine months of 2017 through 2019.

Figure 10-10 RTO daily tier 2 synchronized reserve offers by unit type (MW): January through September, 2017 through 2019



50 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…").

51 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 for the RTO Reserve Zone and the MAD Subzone.

In the first nine months of 2019 there was enough tier 1 synchronized reserve plus self-scheduled tier 2 reserve to cover the full requirement in 13.1 percent of cleared intervals. For the first nine months of 2019 the MAD tier 2 market cleared an average of 280.6 MW at a weighted average clearing price of $3.07 compared to an average of 348.7 MW $4.92 in the same period of 2018 (Table 10-19).

In the first nine months of 2019, the RTO tier 2 market cleared an average of 536.9 MW at a weighted average price of $3.19 compared to an average of 490.3 MW at $5.78 in the same period of 2018 (Table 10-20).

In 99.87 percent of cleared intervals, the synchronized reserve market clearing price was the same for both the MAD Subzone and the RTO Zone. The 0.13 percent of intervals when the price diverged only occurred during periods of high prices where the average MAD SRMCP was $275.11 and average RTO SRMCP was $164.48.

Supply, performance, and demand are reflected in the price of synchronized reserve. (Figure 10-7 and Figure 10-8).

Table 10-19 MAD Subzone, average SRMCP and average scheduled, tier 1 estimated and demand response MW: January 2018 through September 2019

Year	Month	Weighted Average Synchronized Reserve Market Clearing Price	Average Tier 2 Generation Synchronized Reserve Purchased (MW)	Average Hourly Tier 1 Synchronized Reserve Estimated Hour Ahead (MW)	Average Hourly Demand Response Cleared (MW)
2018	Jan	$13.10	211.7	1,371.1	125.6
2018	Feb	$2.22	181.4	1,408.1	180.6
2018	Mar	$5.67	271.5	1,313.3	156.0
2018	Apr	$6.58	359.6	1,192.8	90.4
2018	May	$5.62	349.3	1,191.3	114.5
2018	Jun	$2.93	146.3	1,445.7	49.7
2018	Jul	$3.29	223.7	1,380.1	59.1
2018	Aug	$2.83	269.5	1,334.4	48.6
2018	Sep	$4.94	238.0	1,377.5	60.8
2018	Oct	$7.28	277.2	1,356.5	76.6
2018	Nov	$6.91	192.6	1,442.4	39.1
2018	Dec	$3.29	222.9	1,524.4	33.7
2018	Average	$5.39	245.3	1,361.5	86.2
2019	Jan	$2.05	221.9	1,650.6	26.5
2019	Feb	$1.73	307.3	1,629.9	32.4
2019	Mar	$3.14	279.4	1,536.7	44.9
2019	Apr	$2.82	305.2	1,368.8	59.5
2019	May	$2.76	196.5	1,449.2	48.4
2019	Jun	$2.27	294.9	1,669.8	23.9
2019	Jul	$4.05	267.5	1,667.0	24.6
2019	Aug	$3.07	285.1	1,683.3	26.0
2019	Sep	$5.72	367.8	1,505.8	42.3
2019	Average	$3.07	280.6	1,573.5	36.5

Table 10-20 RTO zone average SRMCP and average scheduled, tier 1 estimated and demand response MW: January 2018 through September 2019

Year	Month	Weighted Average Synchronized Reserve Market Clearing Price	Average Tier 2 Generation Synchronized Reserve Purchased (MW)	Average Hourly Tier 1 Synchronized Reserve Estimated Hour Ahead (MW)	Average Hourly Demand Response Cleared (MW)
2018	Jan	$14.42	348.3	1,792.5	117.4
2018	Feb	$2.50	257.6	1,899.6	123.6
2018	Mar	$5.97	412.0	1,552.5	137.6
2018	Apr	$7.06	633.8	1,034.6	90.4
2018	May	$6.19	498.1	1,318.7	114.0
2018	Jun	$3.38	211.6	2,150.5	106.0
2018	Jul	$4.32	291.6	2,036.8	113.1
2018	Aug	$3.74	355.9	1,948.1	122.1
2018	Sep	$5.63	356.1	1,825.1	124.2
2018	Oct	$7.42	512.7	1,383.0	123.9
2018	Nov	$7.32	451.5	1,596.0	167.0
2018	Dec	$4.38	377.3	2,021.6	116.2
2018	Average	$6.15	392.2	1,728.7	121.3
2019	Jan	$2.26	378.7	2,528.7	72.9
2019	Feb	$1.96	634.4	2,056.8	118.2
2019	Mar	$3.48	598.6	1,948.4	136.5
2019	Apr	$3.10	667.6	1,593.4	157.8
2019	May	$2.61	494.0	2,003.4	134.1
2019	Jun	$2.55	420.5	2,522.5	53.9
2019	Jul	$4.30	423.6	2,590.4	68.7
2019	Aug	$3.34	498.8	2,474.0	82.5
2019	Sep	$5.07	715.7	1,887.7	133.3
2019	Average	$3.19	536.9	2,178.4	106.4

Cost

As a result of changing grid conditions, load forecasts, and unexpected generator performance, prices do not always cover the full cost including the final LOC for each resource. Because price formation occurs within the hour (on a five minute basis integrated over the hour) 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. A price to cost ratio close to 100 percent is an indicator of an efficient synchronized reserve market design.

In the first nine months of 2019, the price to cost (including self scheduled) ratio of the RTO Zone Tier 2 Synchronized Reserve Market averaged 39.9 percent (Table 10-21); the price to cost ratio of the MAD Subzone (Table 10-22) averaged 43.3 percent.

Table 10-21 RTO Zone tier 2 synchronized reserve MW, credits, price, and cost: January 2018 through September 2019

Zone	Year	Month	Tier 2 Credited MW	Tier 2 Credits	LOC Credits	Weighted Average Synchronized Reserve Market Clearing Price	Tier 2 Synchronized Reserve Cost	Price/Cost Ratio
RTO Zone	2018	Jan	251,473	$3,736,516	$3,597,281	$14.86	$29.16	50.9%
RTO Zone	2018	Feb	167,661	$432,250	$475,401	$2.58	$5.41	47.6%
RTO Zone	2018	Mar	305,748	$1,829,286	$955,726	$5.98	$9.11	65.7%
RTO Zone	2018	Apr	513,898	$3,676,407	$2,979,772	$7.15	$12.95	55.2%
RTO Zone	2018	May	424,953	$2,693,398	$3,328,585	$6.34	$14.17	44.7%
RTO Zone	2018	Jun	178,862	$617,449	$1,027,023	$3.45	$9.19	37.5%
RTO Zone	2018	Jul	242,712	$1,063,555	$794,436	$4.38	$7.66	57.2%
RTO Zone	2018	Aug	284,146	$1,071,340	$1,407,424	$3.77	$8.72	43.2%
RTO Zone	2018	Sep	280,391	$1,597,878	$1,418,818	$5.70	$10.76	53.0%
RTO Zone	2018	Oct	437,122	$3,294,095	$1,904,130	$7.54	$11.89	63.4%
RTO Zone	2018	Nov	324,837	$2,417,158	$1,454,718	$7.44	$11.92	62.4%
RTO Zone	2018	Dec	287,288	$1,259,020	$962,818	$4.38	$7.73	56.7%
RTO Zone	2018		3,699,091	$23,688,351	$20,306,132	$6.13	$11.56	53.1%
RTO Zone	2019	Jan	198,030	$447,932	$1,021,911	$2.26	$7.42	30.5%
RTO Zone	2019	Feb	329,482	$644,828	$1,464,022	$1.96	$6.40	30.6%
RTO Zone	2019	Mar	384,207	$1,338,602	$2,131,555	$3.48	$9.03	38.6%
RTO Zone	2019	Apr	382,642	$1,187,948	$1,662,252	$3.10	$7.45	41.7%
RTO Zone	2019	May	294,931	$768,953	$902,854	$2.61	$5.67	46.0%
RTO Zone	2019	Jun	238,489	$609,117	$598,266	$2.55	$5.06	50.4%
RTO Zone	2019	Jul	255,474	$1,098,202	$2,419,557	$4.30	$13.77	31.2%
RTO Zone	2019	Aug	320,989	$1,071,987	$1,063,553	$3.34	$6.65	50.2%
RTO Zone	2019	Sep	430,020	$2,191,848	$2,312,339	$5.07	$10.47	48.4%
RTO Zone	2019		2,834,264	$9,359,417	$13,576,310	$3.19	$7.99	39.9%

Table 10-22 MAD Subzone tier 2 synchronized reserve MW, credits, price, and cost: January 2018 through September 2019

Zone	Year	Month	Tier 2 Credited MW	Tier 2 Credits	Weighted Average Synchronized Reserve Market Clearing Price	Tier 2 Synchronized Reserve Cost	Price/Cost Ratio
MAD Subzone	2018	Jan	246,978	$3,908,791	$13.10	$24.89	52.6%
MAD Subzone	2018	Feb	121,873	$537,031	$2.22	$4.41	50.4%
MAD Subzone	2018	Mar	201,995	$1,548,772	$5.67	$7.67	74.0%
MAD Subzone	2018	Apr	258,116	$3,020,632	$6.58	$11.70	56.2%
MAD Subzone	2018	May	259,906	$3,164,879	$5.62	$12.18	46.1%
MAD Subzone	2018	Jun	100,506	$593,608	$2.93	$5.91	49.5%
MAD Subzone	2018	Jul	158,652	$832,799	$3.29	$5.25	62.7%
MAD Subzone	2018	Aug	195,521	$1,354,403	$2.83	$6.93	40.8%
MAD Subzone	2018	Sep	166,472	$1,204,564	$4.94	$7.24	68.3%
MAD Subzone	2018	Oct	206,868	$2,222,948	$7.28	$10.75	67.8%
MAD Subzone	2018	Nov	136,323	$1,642,482	$6.91	$12.05	57.4%
MAD Subzone	2018	Dec	166,883	$856,328	$3.29	$5.13	64.2%
MAD Subzone	2018		2,220,094	$20,887,236	$5.39	$9.51	56.7%
MAD Subzone	2019	Jan	112,251	$655,861	$2.05	$5.84	35.1%
MAD Subzone	2019	Feb	141,165	$604,896	$1.73	$4.29	40.5%
MAD Subzone	2019	Mar	177,502	$1,096,369	$3.14	$6.18	50.9%
MAD Subzone	2019	Apr	163,121	$882,886	$2.82	$5.41	52.0%
MAD Subzone	2019	May	109,987	$519,107	$2.76	$4.72	58.5%
MAD Subzone	2019	Jun	132,344	$490,618	$2.27	$3.71	61.4%
MAD Subzone	2019	Jul	142,123	$574,936	$4.05	$16.72	24.2%
MAD Subzone	2019	Aug	159,378	$488,997	$3.07	$6.60	46.5%
MAD Subzone	2019	Sep	205,095	$1,175,659	$5.72	$10.26	55.7%
MAD Subzone	2019		1,342,966	$6,489,329	$3.07	$7.08	43.3%

Performance

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.[52] 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, and initial output is the lowest output between one minute before the event and one minute after the event.[53] 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.

In the first nine months of 2019, there were 10 spinning events and only one lasted more than 10 minutes. The MMU has reported synchronized reserve event response levels and recommended that PJM take action to increase compliance rates. Most resources respond at 100 percent but some resources consistently fail to fully respond.

A tier 2 resource is penalized for all hours in the Immediate Past Interval (IPI) in the amount of MW it falls short of its scheduled MW during an event and for any hour in that day for which it cleared. 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. For 2018, PJM uses the average number of days between spinning events from November 2016 through October 2018 which is 19 days. Resource owners are permitted to aggregate the response of multiple units to offset an under response from one unit with an overresponse from a different unit to reduce an under response penalty.

The penalty for a tier 2 resource failing to meet its scheduled obligation during a spinning event involves two components. First, the resource foregoes payment for the MW of under-response for all cleared hours of the day of the event. Second, the resource is charged a penalty in the amount of its MW under-response against all of its cleared hours of synchronized reserve during the Immediate Past Interval (IPI) or since the resource last failed to respond to a spinning event, whichever is less. IPI is calculated yearly on December 1 as the average number of days between spinning events over the past two years. Participants with more than one resource can aggregate their response from over responders to offset under responders during an event.[54]

52 See 2011 State of the Market Report for PJM, Vol. 2, Section 9, "Ancillary Services," at 250.

53 See PJM "Manual 11: Energy & Ancillary Services Market Operations," § 4.2.10 Settlements Rev. 107 (Sep. 26, 2019).

54 See PJM "Manual 28: Operating Agreement Accounting,"§ 6.3 Charges for Synchronized Reserve, Rev. 82 (July25, 2019.)

The penalty structure for tier 2 synchronized reserve nonperformance is flawed. The current penalty rule structure has a number of design issues which limit its effectiveness in providing an incentive for tier 2 MW to respond to spin events.

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.

Under the current penalty structure nonperformance is only defined for spinning events of 10 minutes or longer. For events of less than 10 minutes, all resources, regardless of actual performance, are considered to have performed perfectly. But 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 IPI should be defined as the number of days between spinning events 10 minutes or longer. If only events 10 minutes or longer were considered, the IPI would increase to almost double its current 20 days. Regardless, use of an 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. That is the only way to capture the actual failure to perform of the resource and the only way to provide an appropriate performance incentive.

In addition, allowing an organization to aggregate responses from all online resources is a mistake because it weakens the incentive to perform and creates an incentive to withhold reserves from other resources. The obligation to respond is unit specific. Any potentially offsetting response from an affiliated tier 1 resource should have been included as part of the 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.

Based on an analysis of the most heavily scheduled resources in the tier 2 synchronized reserve market, the MMU concludes that under the current penalty structure, completely unresponsive resources would be paid for providing reserves (Table 10-23). The analysis covered the period from the April 1, 2018, which was the date that five minute pricing was introduced, through December 31, 2018. For resources that completely fail to respond for all spinning events, resource owners would earn 58.2 percent of what they would earn from a perfect response.

Table 10-23 Tier 2 synchronized reserve market penalties, actual vs. hypothetical under proposed IPI change: April 1, 2018, through December 31, 2018

Total Scheduled MWh	Actual Spinning Event Shortfall MWh	Credits for Hypothetical T2 Response of 100%	Credits for Hypothetical T2 Response of 0%	Actual T2 Credits	Actual Credits Under IMM Proposed IPI Change
24,926	609	$1,350,022	$786,492	$1,345,571	$1,343,272

The MMU recommends that the definition of the IPI be changed from the average number of days between events to the actual number of days since the last spinning event that lasted more than 10 minutes.

Tier 1 resource owners are paid for the actual amount of synchronized reserve they provide in response to a synchronized reserve event.[55] Tier 2 resource owners are paid for being available but are not paid based on the actual response to a synchronized reserve event. Tier 1 resource owners do not have an obligation to respond and are not penalized for a failure to respond. Tier 2 resource owners are penalized for a failure to respond.

The data in Table 10-24 comes from several different sources. Tier 1 Estimate is the estimate done by the most recent five minute market solution. The Tier 1 Estimate takes only those units which are DGP eligible and estimates their available ramp. It is an accurate, conservative estimate of available tier 1 synchronized reserve. Actual tier 1 response is taken from real-time SCADA data. Actual tier 1 data is used to calculate settlement credits for tier 1 response from all units including those which are not part of the DGP estimate

55 See *id.* at 98.

used by the five minute market solution. Because the market solution estimate is very conservative the actual response is usually higher than the estimate at market solution time.

Table 10-24 Synchronized reserve events 10 minutes or longer, tier 2 response compliance, RTO Reserve Zone: January 2018 through September 2019

Spin Event (Day, EPT Time)	Duration (Minutes)	Tier 1 Estimate (MW Adj by DGP)	Tier 1 Response (MW)	Tier 2 Scheduled (MW)	Tier 2 Response (MW)	Tier 2 Penalty (MW)	Tier 1 Response Percent	Tier 2 Response Percent
Jan 3, 2018 03:00	13	1,896.7	509.9	112.6	57.6	55.0	26.9%	51.2%
Apr 12, 2018 17:28	10	1,063.3	1,635.4	464.6	372.5	92.1	153.8%	80.2%
Jun 30, 2018 09:46	11	2,710.1	3,993.8	71.6	56.8	14.8	147.4%	79.3%
Jul 10, 2018 15:45	12	784.3	2,219.5	494.6	308.8	185.8	283.0%	62.4%
Aug 12, 2018 11:06	11	1,824.5	2,915.0	274.5	229.8	44.7	159.8%	83.7%
Sep 30, 2018 11:29	11	1,430.9	2,355.8	231.2	216.9	14.3	164.6%	93.8%
Oct 30, 2018 06:40	11	239.7	816.0	607.7	431.5	176.2	340.4%	71.0%
2018 Average	11	1,421.4	2,063.6	322.4	239.1	83.3	145.2%	74.2%
Sep 23, 2019 12:07	11	924.7	664.1	723.2	632.1	91.1	71.8%	87.4%
2019 Average	11	924.7	664.1	723.2	632.1	91.1	71.8%	87.4%

History of Synchronized Reserve Events

Synchronized reserve is designed to provide relief for disturbances.[56] [57] A disturbance is defined as loss of 1,000 MW of generation and/or transmission resources 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 indicated 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 disturbance.

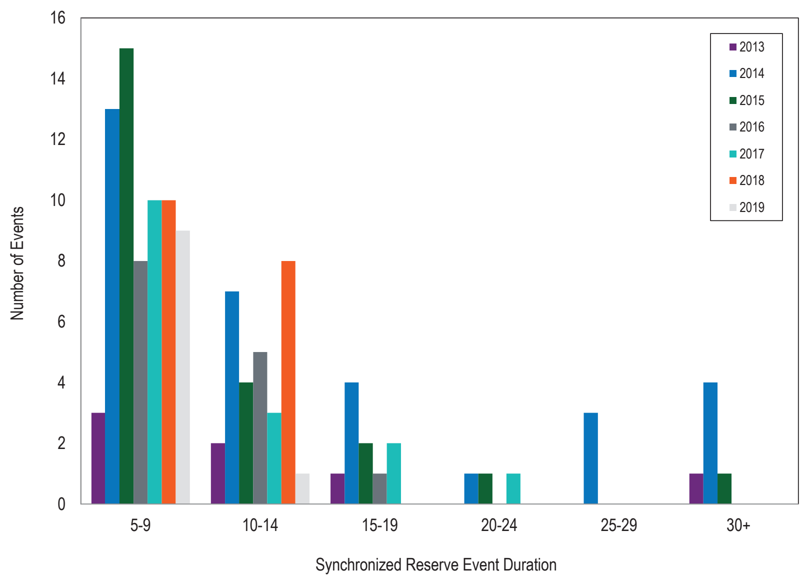
From January 1, 2010, through September 30, 2019, PJM experienced 230 synchronized reserve events (Table 10-25), approximately 2.2 events per month. During this period, synchronized reserve events had an average duration of 11.7 minutes.

56 2013 State of the Market Report for PJM, Appendix F – PJM's DCS Performance, at 451–452.
57 See PJM "Manual 12: Balancing Operations," Rev. 39 (Feb. 21, 2019) § 4.1.2 Loading Reserves.

Table 10-25 Synchronized reserve events: January 2017 through September 2019[58]

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-09-2017 19:24	RTO	9	JAN-03-2018 03:00	RTO	13	JAN-31-2019 01:26	RTO	5
JAN-10-2017 13:05	MAD	9	JAN-07-2018 14:15	RTO	9	JAN-31-2019 09:26	RTO	9
JAN-15-2017 20:13	RTO	8	APR-12-2018 13:28	RTO	10	FEB-25-2019 00:25	RTO	9
JAN-23-2017 09:08	RTO	7	JUN-04-2018 10:22	RTO	6	MAR-03-2019 12:31	RTO	9
FEB-13-2017 18:30	RTO	7	JUN-29-2018 15:21	RTO	9	MAR-06-2019 22:06	RTO	9
FEB-14-2017 00:11	RTO	6	JUN-30-2018 09:46	RTO	11	JUL-27-2019 23:31	RTO	7
FEB-15-2017 06:37	RTO	6	JUL-04-2018 10:56	RTO	7	AUG-11-2019 12:14	RTO	8
MAR-23-2017 06:48	RTO	24	JUL-10-2018 15:45	RTO	13	SEP-03-2019 13:39	RTO	9
APR-08-2017 11:53	RTO	10	JUL-23-2018 09:02	RTO	8	SEP-23-2019 16:06	RTO	11
MAY-08-2017 04:18	RTO	10	JUL-23-2018 15:43	RTO	6			
JUN-08-2017 03:39	RTO	10	JUL-24-2018 16:17	RTO	7			
JUN-20-2017 05:38	RTO	9	AUG-12-2018 11:06	RTO	11			
SEP-04-2017 20:18	MAD	15	SEP-13-2018 09:47	RTO	7			
SEP-07-2017 09:16	RTO	9	SEP-14-2018 13:24	RTO	7			
SEP-21-2017 14:15	RTO	16	SEP-26-2018 19:08	RTO	8			
			SEP-30-2018 11:29	RTO	11			
			OCT-30-2018 10:40	RTO	11			

Figure 10-11 Synchronized reserve events duration distribution curve: January 2013 through September 2019



58 For full history of spinning events, see the 2018 State of the Market Report for PJM, Appendix F - 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.[59]

The average scheduled nonsynchronized reserve in the RTO Zone in the first nine months 2019 was 1,461.9 MW. The average scheduled nonsynchronized reserve in the MAD Subzone for primary reserve in the first nine months 2019 was 1,274.9 MW.

Supply

Figure 10-2 shows that most of the primary reserve requirement (orange line) in excess of the synchronized reserve requirement (yellow line) is satisfied by nonsynchronized reserve (light blue 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.

The market solution optimizes synchronized reserve, nonsynchronized reserve, and energy to satisfy the primary reserve requirement at the lowest cost. Nonsynchronized reserve resources are scheduled economically based on LOC until the Primary Reserve requirement is filled. The nonsynchronized reserve market clearing price is determined at the end of the hour 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 for the hour and available to provide 10 minute reserves.

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

59 See PJM "Manual 11: Energy and Ancillary Services Market Operations," § 4.2.2 Synchronized Reserve Requirement Determination, Rev. 107 (Sep. 26, 2019).

can start in 10 minutes or less, and diesels.[60] In the first nine months of 2019, an average of 1,461.9 MW of nonsynchronized reserve was scheduled hourly out of 3,953.1 eligible MW as part of the primary reserve requirement in the RTO Zone.

In the first nine months of 2019, CTs provided 85.5 percent of scheduled nonsynchronized reserve (Table 10-27). Natural gas was the primary fuel for nonsynchronized reserve in the first nine months of 2019 (Table 10-26).

Table 10-26 Supply of Nonsynchronized Reserve by Fuel Type: January through September, 2019

Fuel	Percentage of NSR MW	Percentage of NSR Credits
Natural Gas	53.2%	63.2%
Light Oil	30.0%	26.8%
Hydro	14.5%	7.7%
Diesel	2.3%	1.9%
LFG	0.1%	0.1%

Table 10-27 Supply of Nonsynchronized Reserve by Unit Type: January through September, 2019

Unit Type	Percentage of NSR MW	Percentage of NSR Credits
CT	85.5%	92.3%
Hydro	14.5%	7.7%

Market Concentration

The supply of nonsynchronized reserves in the Mid-Atlantic Dominion Subzone and the RTO Zone was highly concentrated in the first nine months of 2019.

60 See PJM "Manual 11: Energy & Ancillary Services Market Operations," § 4b.2 Non-Synchronized Reserve Market Business Rules, Rev. 107 (Sep. 26, 2019)

Table 10-28 Nonsynchronized reserve market pivotal supplier test: January 2018 through September 2019

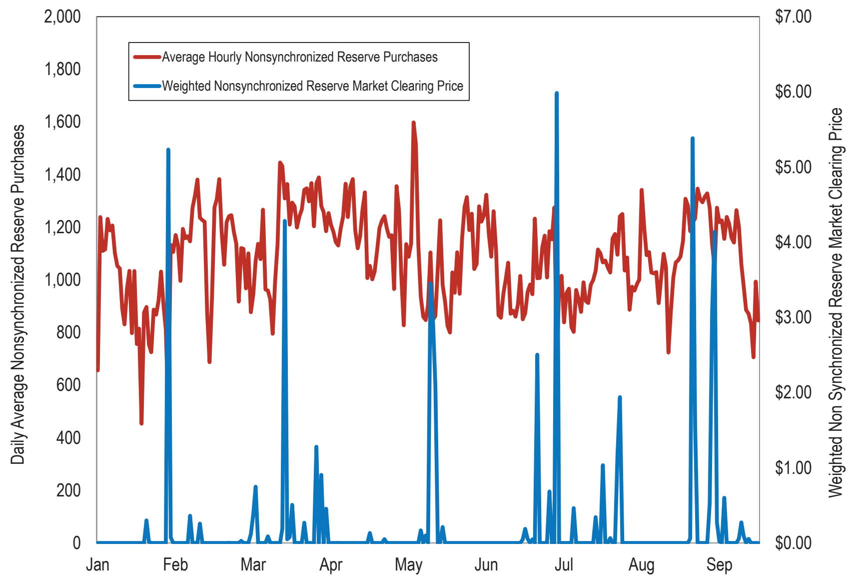
Year	Month	Non Synchronized Reserve Three Pivotal Supplier Hours
2018	Jan	87.2%
2018	Feb	88.0%
2018	Mar	93.5%
2018	Apr	16.0%
2018	May	6.9%
2018	Jun	58.0%
2018	Jul	76.8%
2018	Aug	55.9%
2018	Sep	16.7%
2018	Oct	12.1%
2018	Nov	5.2%
2018	Dec	21.5%
2018	Average	44.8%
2019	Jan	71.4%
2019	Feb	81.0%
2019	Mar	53.2%
2019	Apr	62.9%
2019	May	54.2%
2019	Jun	44.4%
2019	Jul	73.0%
2019	Aug	64.0%
2019	Sep	47.9%
2019	Average	61.3%

Price

The 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 10-12 shows the daily average nonsynchronized reserve market clearing price (NSRMCP) and average scheduled MW for the RTO Zone. In the first nine months of 2019, the average nonsynchronized market clearing price was $0.20 per MW. The hourly average nonsynchronized reserve scheduled was 1,086.1 MW. The market cleared at a price greater than $0 in 0.9 percent of all intervals. The maximum interval clearing price was $600.00 per MW on July 1, 2019, which was the result of a shortage of reserves.

Figure 10-12 Daily average RTO Zone nonsynchronized reserve market clearing price and MW purchased: January through September, 2019



Price and Cost

As a result of changing grid conditions, load forecasts, and unexpected generator performance, prices sometimes 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 offer at economic minimum, then an LOC is paid.[61]

The full cost of nonsynchronized reserve including payments for the clearing price and uplift costs is calculated and compared to the price (Table 10-29). The closer the price to cost ratio comes to one, the more the market price reflects the full cost of nonsynchronized reserve.

61 See PJM "Manual 11: Energy & Ancillary Services Market Operations," § 2.16 Minimum Capacity Emergency in Day-ahead Market, Rev. 107 (Sep. 26, 2019).

In the first nine months 2019, the price to cost ratio for the RTO Zone was 16.1 percent.

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.

Both nonsynchronized reserve markets cleared at a price above $0 in 0.9 percent of hours.

Table 10-29 RTO zone nonsynchronized reserve MW, charges, price, and cost: 2018 through September 2019

Market	Year	Month	Total Nonsynchronized Reserve MW	Total Nonsynchronized Reserve Charges	Weighted Nonsynchronized Reserve Market Price	Nonsynchronized Reserve Cost	Price/Cost Ratio
RTO Zone	2018	Jan	873,930	$4,616,906	$0.94	$5.28	17.7%
RTO Zone	2018	Feb	886,683	$249,232	$0.00	$0.28	0.0%
RTO Zone	2018	Mar	954,515	$1,693,691	$0.05	$1.77	3.0%
RTO Zone	2018	Apr	968,046	$1,385,351	$0.12	$1.52	7.9%
RTO Zone	2018	May	898,840	$1,894,687	$0.31	$2.66	11.8%
RTO Zone	2018	Jun	870,244	$1,026,193	$0.01	$1.22	1.2%
RTO Zone	2018	Jul	823,952	$639,914	$0.00	$0.74	0.7%
RTO Zone	2018	Aug	769,348	$858,148	$0.01	$1.05	1.4%
RTO Zone	2018	Sep	727,163	$986,756	$0.55	$1.52	36.1%
RTO Zone	2018	Oct	757,591	$1,590,789	$1.37	$2.60	52.8%
RTO Zone	2018	Nov	728,020	$566,419	$0.14	$0.74	19.5%
RTO Zone	2018	Dec	733,417	$348,069	$0.00	$0.44	0.8%
RTO Zone	2018	Total	9,991,749	$15,856,155	$0.29	$1.65	17.8%
RTO Zone	2019	Jan	691,682	$808,141	$0.16	$1.29	12.0%
RTO Zone	2019	Feb	777,009	$549,304	$0.02	$0.67	3.3%
RTO Zone	2019	Mar	865,531	$1,209,490	$0.22	$1.35	16.2%
RTO Zone	2019	Apr	870,167	$1,441,716	$0.09	$1.70	5.6%
RTO Zone	2019	May	779,072	$624,877	$0.29	$0.94	31.0%
RTO Zone	2019	Jun	727,972	$458,230	$0.01	$0.61	1.7%
RTO Zone	2019	Jul	707,373	$870,865	$0.34	$1.52	22.2%
RTO Zone	2019	Aug	764,814	$429,814	$0.10	$0.57	18.2%
RTO Zone	2019	Sep	819,107	$1,841,551	$0.54	$2.39	22.6%
RTO Zone	2019	Total	7,002,727	$8,233,987	$0.20	$1.23	16.1%

Secondary Reserve

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 have a goal 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.[62]

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 nine months of 2019, the average available hourly DASR was 44,547.9 MW, a 13.8 percent increase from the same time period in 2018. The DASR hourly MW purchased averaged 5,511.0 MW.

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.[63] 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.

62 See PJM "Manual 11: Energy & Ancillary Services Market Operations," § 10.5 Aggregation for Economic and Emergency Demand Resources, Rev. 107 (Sep. 26, 2019).
63 See PJM "Manual 11: Energy & Ancillary Services Market Operations," § 11.2.2 Day-Ahead Scheduling Reserve Market Eligibility, Rev. 107 (Sep. 26, 2019).

Of the 5,511.0 MW average hourly DASR cleared in the first nine months 2019, 80.7 percent was from CTs (Table 10-31). Demand response resources did not provide any DASR MW in the first nine months of 2019. Most DASR MW was provided by natural gas fueled resources (Table 10-30).

Table 10-30 Scheduled DASR by Fuel Type: January through September, 2019

Fuel	Percentage of DASR MW	Percentage of DASR Credits
Natural Gas	65.7%	69.8%
Coal	5.9%	7.3%
Diesel	9.6%	5.3%
Hydro	9.4%	4.3%
Light Oil	9.1%	12.6%
LFG	0.1%	0.4%
Waste Coal	0.1%	0.1%

Table 10-31 Scheduled DASR by Unit Type: January through September, 2019

Unit Type	Percentage of DASR MW	Percentage of DASR Credits
CT	80.7%	77.2%
Hydro	9.4%	4.3%
Steam	6.3%	8.6%
CC	3.2%	8.8%
Diesel	0.4%	1.2%

Demand

Secondary reserve (30 minute reserve) requirements are determined by PJM for each reliability region. In the Reliability*First* (RFC) region, secondary reserve requirements are calculated based on historical under forecasted load rates and generator forced outage rates.[64] The RFC and Dominion secondary reserve requirements are added together to form a single RTO DASR requirement defined as the sum of a percent of the load forecast error and forced outage rate times the daily peak load forecast. Effective January 1, 2019, the day-ahead scheduling reserve requirement is 5.29 percent of the peak load forecast. This is based on a 2.18 percent load forecast error component and a 3.11 percent forced outage rate component. The DASR requirement is applicable for all hours of the operating day.

64 See PJM "Manual 13: Emergency Operations," § 2.2 Reserve Requirements, Rev. 73 (October 31, 2019).

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."[65] The amount of additional DASR MW that may be required is the Adjusted Fixed Demand (AFD) determined by a Seasonal Conditional Demand (SCD) factor.[66] 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 2018 through October 2019, the SCD values are 3.75 percent for winter and 2.45 percent for summer. For November 2019 through October 2020, the SCD values will be 2.80 percent for winter and 2.42 percent for summer. PJM Dispatch may also schedule additional Day-Ahead Scheduling Reserves as deemed necessary for conservative operations.[67] 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.[68] The result is substantial discretion for PJM to increase the demand for DASR under a variety of circumstances. PJM invoked adjusted fixed demand on 18 days during the first nine months 2019. The 39 hours with the highest DASR market clearing price during the first nine months of 2019 were all on these days.

The MMU recommends that PJM modify the DASR Market to ensure that all resources cleared incur a real-time performance obligation.

Market Concentration

DASR market three pivotal supplier test results are provided in Table 10-32

65 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>.

66 See PJM "Manual 11: Energy & Ancillary Services Market Operations," § 11.2.1 Day-Ahead Scheduling Reserve Market Requirement. Rev. 107 (Sep. 26, 2019)

67 See PJM "Manual 11: Energy & Ancillary Services Market Operations," § 11.2.1 Day-Ahead Scheduling Reserve Market Reserve Requirement, Rev. 107 (Sep. 26, 2019).

68 See PJM "Manual 13: Emergency Operations," § 3.2 Conservative Operations, Rev. 73, (October 31, 2019).

Table 10-32 DASR market three pivotal supplier test results and number of hours with DASRMCP above $0: January 2018 through September 2019

Year	Month	Number of Hours When DASRMCP > $0	Percent of Hours Pivotal
2018	Jan	197	7.6%
2018	Feb	14	40.9%
2018	Mar	66	0.0%
2018	Apr	189	0.5%
2018	May	339	5.6%
2018	Jun	101	11.8%
2018	Jul	190	11.5%
2018	Aug	161	16.8%
2018	Sep	146	22.6%
2018	Oct	117	0.0%
2018	Nov	20	0.0%
2018	Dec	10	0.0%
2018	Average	151	9.8%
2019	Jan	32	1.5%
2019	Feb	22	1.4%
2019	Mar	24	0.0%
2019	Apr	15	0.0%
2019	May	43	0.0%
2019	Jun	72	0.0%
2019	Jul	237	0.0%
2019	Aug	173	0.0%
2019	Sep	182	0.0%
2019	Average	89	0.3%

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.[69] 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 nine months of 2019, 39.6 percent of generation units offered DASR at a daily price above $0.00, compared to 38.8 percent in 2018.

69 See PJM "Manual 11: Energy & Ancillary Services Market Operations," § 11.2.2 Day-Ahead Scheduling Reserve Market Eligibility, Rev. 107 (Sep. 26, 2019).

In the first nine months of 2019, 16.6 percent of daily offers were above $5.00 per MW.

The MMU recommends that offers in the DASR Market be based on opportunity cost only in order to eliminate market power.

Market Performance

In the first nine months of 2019, the DASR Market cleared at a price above $0.00 in 12.3 percent of hours. The weighted average DASR price for all hours was $0.35. The average cleared MW in all hours was 5,511.0 MW. The average cleared MW in all hours when the DASRMCP was above $0.00 was 7,498.0 MW. The highest DASR price was $20.00 during 13 hours in Q3 of 2019.

The introduction of Adjusted Fixed Demand (AFD) on March 1, 2015, created a bifurcated market (Table 10-33 and Table 10-34)). 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 the first nine months of 2019, PJM added AFD to the normal 5.29 percent in 423 hours. The difference in market clearing price, MW cleared, obligation incurred, and charges to PJM load are substantial. Table 10-33 shows the differences in price and MW between AFD hours and non-AFD hours.

Table 10-33 Impact of Adjusted Fixed Demand on DASR prices and demand: January through September, 2019

Metric	Year	Number Hours	Weighted Day-Ahead Scheduling Reserve Market Clearing Price (DASRMCP)	Average Hourly Total DASR MW
All Hours	Jan-Sep 2019	6,552	$0.35	5,511.0
All Hours when DASRMCP > $0	Jan-Sep 2020	803	$2.10	7,498.0
All Hours when AFD is used	Jan-Sep 2021	423	$2.41	10,428.0

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 adds 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 10-34) shows that the use of AFD for 598 hours in 2018, and 248 hours in the first nine months of 2019 significantly increased the cost of DASR. Table 10-34 shows that the cost increase was a result of a substantial increase in DASR MW cleared.

Table 10-34 DASR Market, regular hours vs. adjusted fixed demand hours: January 2018 through September 2019

		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
2018	Jan	197	120	$0.94	$3.56	97,785	119,404	5,220	9,164	$5,479	$32,627
2018	Feb	14	0	$0.00	NA	89,397	NA	5,066	NA	$16	NA
2018	Mar	66	0	$0.03	NA	87,295	NA	4,906	NA	$147	NA
2018	Apr	190	0	$0.10	NA	79,086	NA	4,508	NA	$444	NA
2018	May	339	72	$1.96	$8.99	82,800	91,483	4,758	10,886	$10,491	$97,845
2018	Jun	101	94	$0.75	$3.70	89,867	108,143	5,366	8,839	$4,369	$32,747
2018	Jul	190	168	$2.00	$5.97	97,978	109,671	5,899	9,949	$13,650	$59,428
2018	Aug	161	72	$0.71	$4.47	100,580	116,844	6,050	9,438	$4,540	$42,177
2018	Sep	146	72	$1.69	$7.70	87,995	115,611	5,117	12,483	$9,859	$96,066
2018	Oct	117	0	$0.20	NA	81,077	NA	4,665	NA	$948	NA
2018	Nov	20	0	$0.00	NA	85,755	NA	4,774	NA	$4	NA
2018	Dec	12	0	$0.00	NA	89,847	NA	5,121	NA	$2	NA
2018		1553	598	$0.39	$4.88	89,122	110,193	5,121	10,126	$4,162	$60,148
2019	Jan	8	24	$0.00	$0.28	95,058	117,071	5,359	8,907	$20	$2,521
2019	Feb	6	16	$0.00	$0.20	91,649	116,426	5,201	10,812	$6	$2,175
2019	Mar	24	NA	$0.01	NA	86,172	NA	4,915	NA	$42	NA
2019	Apr	15	NA	$0.01	NA	75,107	NA	4,406	NA	$37	NA
2019	May	43	NA	$0.02	NA	79,257	NA	4,544	NA	$77	NA
2019	Jun	31	42	$0.03	$1.72	85,713	105,502	5,138	11,076	$139	$19,030
2019	Jul	137	101	$0.16	$2.74	102,486	115,059	6,179	10,207	$984	$27,931
2019	Aug	127	46	$0.11	$4.52	95,624	110,089	5,846	11,056	$631	$49,980
2019	Sep	163	19	$0.20	$3.52	87,318	105,508	5,234	11,840	$1,055	$41,682
2019		554	248	$0.06	$2.10	88,709	111,609	5,202	10,650	$332	$23,886

Table 10-35 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 2018 and the first nine months of 2019.

Table 10-35 DASR Market all hours of DASR market clearing price greater than $0: January 2018 through September 2019

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
2018	Jan	197	$2.66	101,276	3,869,914	481,887	$2,327,273
2018	Feb	14	$0.13	89,397	3,404,236	0	$10,436
2018	Mar	66	$0.32	87,295	3,650,839	0	$109,491
2018	Apr	190	$0.37	79,086	3,247,134	0	$319,905
2018	May	339	$3.73	83,640	3,586,629	395,742	$3,734,941
2018	Jun	101	$4.08	92,253	3,953,938	235,382	$2,315,966
2018	Jul	190	$6.09	100,619	4,506,459	562,931	$5,980,639
2018	Aug	161	$2.86	102,154	4,543,607	201,820	$2,228,076
2018	Sep	146	$5.55	90,756	3,779,739	434,532	$3,270,385
2018	Oct	117	$1.25	95,642	3,470,604	0	$705,607
2018	Nov	20	$0.03	100,565	3,447,112	0	$2,753
2018	Dec	10	$0.03	105,913	3,810,223	0	$1,310
2018	Average	129	$2.26	94,050	3,772,536	192,691	$1,750,565
2018	Total	1,551	$2.26	94,050	45,270,434	2,312,294	$21,006,782
2019	Jan	32	$0.61	123,223	297,046	97,612	$182,645
2019	Feb	22	$0.31	111,730	220,097	85,339	$67,211
2019	Mar	24	$0.26	105,987	123,430	0	$31,569
2019	Apr	15	$0.39	90,323	67,501	0	$26,475
2019	May	43	$0.28	98,135	204,957	0	$57,122
2019	Jun	72	$2.12	117,694	689,662	251,804	$1,460,362
2019	Jul	237	$2.55	125,398	1,965,812	439,584	$5,016,482
2019	Aug	173	$3.03	120,698	1,327,657	251,704	$4,022,640
2019	Sep	182	$1.57	106,434	1,101,852	122,368	$1,734,343
2019	Total	802	$1.24	111,069	5,998,014	1,248,410	$12,598,850

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 10-35) in the first nine months of 2019 caused prices to increase.

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.[70] The objective of PJM's regulation market design is to minimize the cost to provide regulation using two resource types in a single market.

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

The PJM regulation market design includes three clearing price components: capability ($/MW, based on the MW being offered); performance ($/mile, based on the total MW movement requested by the control signal, known as mileage); and lost opportunity cost ($/MW of lost revenue from the energy market as a result of providing regulation). The marginal benefit factor (MBF) and performance score translate a RegD resource's capability (actual) MW into marginal effective MW and offers into $/effective MW.

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

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/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/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

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

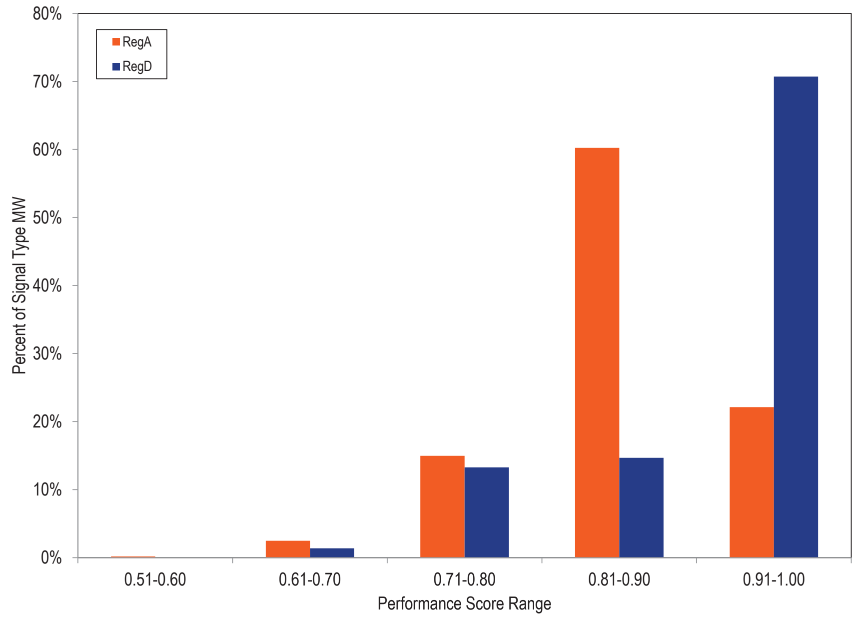
output and the regulation signal; and precision, the difference between the regulation response and the regulation requested.[71] Performance scores are reported on an hourly basis for each resource.

Table 10-36 and Figure 10-13 show the average performance score by resource type and the signal followed in the first nine months of 2019. In these figures, the MW used are actual MW and the performance score is the hourly performance score of the regulation resource.[72] Each category is based on the percentage of the full performance score distribution for each resource (or signal) type. As Figure 10-13 shows, 70.7 percent of RegD resources had average performance scores within the 0.91-1.00 range, and 22.1 percent of RegA resources had average performance scores within that range, in the first nine months of 2019. These scores are higher than the scores for both product types in the first nine months of 2018, where 43.5 percent of RegD resources had average performance scores within the 0.91-1.00 range, and 18.1 percent of RegA resources had average performance scores within that range.

Table 10-36 Hourly average performance score by unit type: January through September, 2019

		Performance Score Range				
		51-60	61-70	71-80	81-90	91-100
RegA	Battery	-	-	-	-	-
	CT	-	0.1%	15.7%	53.5%	30.7%
	Diesel	-	-	-	-	100.0%
	DSR	-	12.2%	22.8%	61.8%	3.2%
	Hydro	-	-	0.9%	35.2%	63.9%
	Steam	0.2%	3.3%	19.4%	68.4%	8.7%
RegD	Battery	-	0.5%	12.5%	10.6%	76.4%
	CT	-	0.4%	43.9%	52.7%	3.0%
	Diesel	-	-	2.2%	97.8%	-
	DSR	0.0%	0.1%	26.7%	26.9%	46.2%
	Hydro	-	21.2%	-	38.2%	40.5%
	Steam	-	-	-	-	-

Figure 10-13 Hourly average performance score by regulation signal type: January through September, 2019



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 cleared 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. 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

71 PJM "Manual 12: Balancing Operations," § 4.5.6 Performance Score Calculation, Rev. 39 (Feb. 21, 2019).
72 Except where explicitly referred to as effective MW or effective regulation MW, MW means actual MW unadjusted for either MBF or performance factor.

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 every five minutes. The market clearing price is determined by pricing software (LPC) that looks at the units cleared in the RT SCED 15 minutes ahead of the pricing interval. The marginal price as identified by the LPC for each of these intervals is then averaged over the hour for an hourly regulation market clearing price.

Market Design Issues

PJM's current regulation market design is severely flawed and does not follow the appropriate basic design logic. 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, and has caused significant price spikes in PJM's Regulation Market that continued in the first nine months of 2019.

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 MW 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. On March 30, 2018, FERC rejected the proposal finding it inconsistent with Order No. 755.[73] Both PJM and the MMU have filed requests for rehearing.[74]

73 162 FERC ¶ 61,295 (2018).
74 See FERC Docket No. ER18-87-002.

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 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 10-37). 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 10-37 Seasonal regulation requirement definitions[75]

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

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

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.

Regulation Signal

With any signal design for substitutable resources, the MBF function should be determined by the ability of RegA and RegD resources to follow the signal, 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. This means 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.

MBF 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.[76]

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. In 2015, this over procurement began to degrade 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.

The PJM/MMU joint proposal, filed with FERC on October 17, 2017, addresses issues with the inconsistent application of the marginal benefit factor throughout the optimization and settlement process in the PJM Regulation Market.[77]

Marginal Benefit Factor Not Correctly Defined

The MBF used in the PJM Regulation Market 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 modified 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

76 The MBF, as used in this report, refers to PJM's incorrectly calculated MBF and not the MBF equivalent to the MRTS.
77 18 CFR § 385.211 (2017)

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.[78] 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.

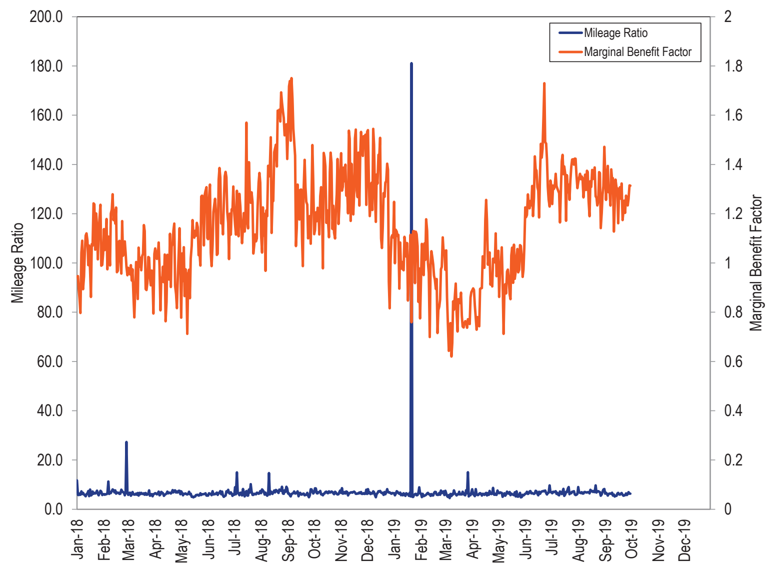
The change in design decreased RegA mileage (the change in MW output in response to regulation signal per MW of capability), increased the proportion of cleared RegD resources' capability that was called by the RegD signal (increased REG for a given MW) to better match offered capability, increased the 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, RegD resources decreased their offered capability to maintain their performance. The reduction in offered capability reduced the amount of RegD MW clearing and increased the amount of RegA MW clearing, meaning a higher MBF in every hour.

78 145 FERC ¶ 61,011 (2013).

Figure 10-14 shows the daily average MBF and the mileage ratio. The weighted average mileage ratio increased from 6.65 in the first nine months of 2018, to 7.09 in the first nine months of 2019 (an increase of 6.7 percent). The high mileage ratio values are the result of the mechanics of the mileage ratio calculation. The 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.

Figure 10-14 Daily average MBF and mileage ratio: January 2018 through September 2019



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 10-38 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, 2018, through September 30, 2019. In 2018, RegD resources earned 32.8 percent more per performance adjusted actual MW than RegA resources. In the first nine months of 2019, RegD resources earned 39.7 percent more per performance adjusted actual MW than RegA resources due to the inclusion of the mileage ratio in RegD MW settlement.

Table 10-38 Average monthly price paid per performance adjusted actual MW of RegD and RegA: January 2018 through September 2019

		Settlement Payments		
Year	Month	RegD ($/Performance Adjusted MW)	RegA ($/Performance Adjusted MW)	Percent Performance Adjusted RegD/RegA Overpayment
2018	Jan	$86.14	$78.36	9.9%
	Feb	$21.92	$12.22	79.3%
	Mar	$27.46	$21.76	26.2%
	Apr	$33.75	$26.41	27.8%
	May	$36.74	$29.36	25.1%
	Jun	$24.05	$18.06	33.2%
	Jul	$25.40	$18.79	35.2%
	Aug	$24.70	$15.92	55.2%
	Sep	$29.33	$20.09	46.0%
	Oct	$30.20	$19.45	55.3%
	Nov	$22.17	$14.39	54.0%
	Dec	$20.15	$12.44	61.9%
Average		$31.96	$24.07	32.8%
2019	Jan	$19.00	$13.89	36.8%
	Feb	$16.64	$11.68	42.4%
	Mar	$18.29	$13.79	32.6%
	Apr	$20.44	$15.85	28.9%
	May	$16.36	$12.04	36.0%
	Jun	$17.62	$10.66	65.3%
	Jul	$22.81	$15.78	44.6%
	Aug	$21.22	$13.99	51.7%
	Sep	$26.45	$20.35	29.9%
Average		$19.89	$14.24	39.7%

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 currently 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. The average MBF was greater than 1.0 in the first nine months of 2018 (1.14), however, RegD resources were still overpaid on average compared to payment on a per effective MW basis. In the first nine months of 2019, the average MBF was equal to 1.11.

The effect of using the mileage ratio instead of the MBF to convert RegD MW into effective MW for purposes of settlement is illustrated in Table 10-39. Table 10-39 compares the monthly average payment to RegD per effective MW under the current settlement process to the monthly average payment RegD resources should have received using the MBF to convert RegD MW to effective MW. This also shows that using the MBF would result in RegA and RegD resources being paid exactly the same on a per effective MW basis. The MBF averaged more than 1.0 in the first nine months of 2018 (1.14), while the average daily mileage ratio was 6.65, resulting in RegD resources being paid $18.7 million more than they would have been if the MBF were correctly implemented. In the first nine months of 2019, the MBF averaged 1.11, while the average daily mileage ratio was 7.09, resulting in RegD resources being paid $3.23 million more than they would have been if the MBF were correctly implemented.

Table 10-39 Average monthly price paid per effective MW of RegD and RegA under mileage and MBF based settlement: January 2018 through September 2019

Year	Month	RegD Settlement Payments: Mileage Based RegD ($/Effective MW)	RegD Settlement Payments: Marginal Rate of Technical Substitution Based RegD ($/Effective MW)	RegA ($/Effective MW)	Percent RegD Overpayment	Total RegD Overpayment ($)
2018	Jan	$70.22	$78.36	$78.36	(10.4%)	($1,127,265)
	Feb	$16.69	$12.22	$12.22	36.5%	$560,643
	Mar	$21.85	$21.76	$21.76	0.4%	$11,868
	Apr	$28.52	$28.08	$28.08	1.6%	$56,125
	May	$32.51	$31.22	$31.22	4.1%	$166,582
	Jun	$21.11	$15.48	$15.48	36.3%	$736,671
	Jul	$138.39	$17.84	$17.84	675.7%	$15,177,248
	Aug	$36.26	$13.14	$13.14	175.9%	$3,086,258
	Sep	$20.86	$20.42	$20.42	2.2%	$56,086
	Oct	$22.31	$18.49	$18.49	20.7%	$503,136
	Nov	$13.19	$12.64	$12.64	4.4%	$70,761
	Dec	$14.55	$12.46	$12.46	16.8%	$287,209
Yearly		$36.70	$23.64	$23.64	55.2%	$20,404,205
2019	Jan	$17.55	$14.65	$14.65	19.8%	$387,830
	Feb	$14.94	$10.85	$10.85	37.7%	$482,828
	Mar	$20.72	$12.64	$12.64	64.0%	$905,586
	Apr	$27.93	$21.67	$21.67	28.9%	$724,705
	May	$12.93	$10.30	$10.30	25.5%	$327,045
	Jun	$13.12	$11.26	$11.26	16.6%	$260,619
	Jul	$18.76	$18.18	$18.18	3.2%	$84,937
	Aug	$14.22	$13.56	$13.56	4.9%	$96,762
	Sep	$18.74	$20.82	$20.82	(10.0%)	($267,920)
Yearly		$17.66	$14.89	$14.89	18.6%	$3,226,104

Figure 10-15 shows, for January 2018 through September 2019, the maximum, minimum and average MBF, by month. The average MBF in the first nine months of 2018 was 1.14. The average MBF in the first nine months of 2019 was 1.11.

Figure 10-15 Maximum, minimum, and average PJM calculated MBF by month: January 2018 through September 2019

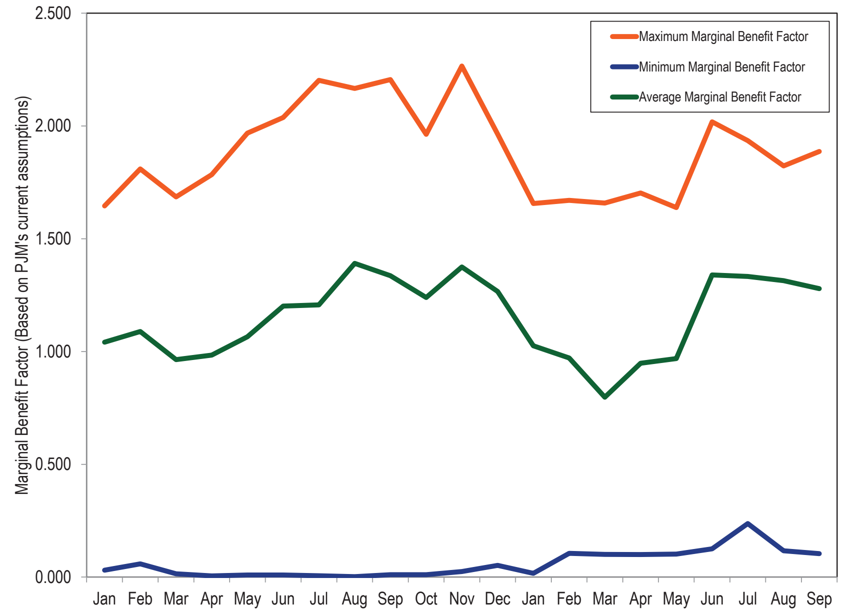


Table 10-40 shows actual and effective MW that were eligible and cleared during the first nine months of 2018 and 2019.

Table 10-40 Actual and effective RegD MW eligible and cleared: January through September, 2018 and 2019

	RegD MW		
	2018 (Jan-Sep)	2019 (Jan-Sep)	Change
Actual Eligible	271.6	325.5	19.9%
Effective Eligible	288.6	310.6	7.6%
Actual Cleared	162.3	166.5	2.6%
Effective Cleared	276.5	296.7	7.3%

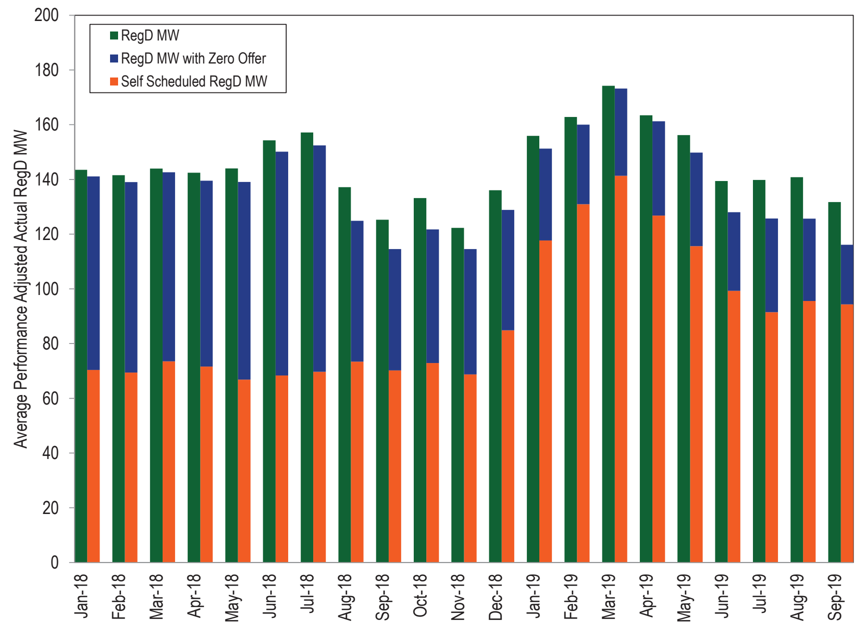
The MMU recommends that the Regulation Market be modified to incorporate a consistent and correct application of the MBF throughout the optimization, assignment and settlement process.[79]

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 $0.00 and self scheduled offers will be cleared 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 over payment of RegD resources on the offer behavior of RegD resources.

Figure 10-16 shows, by month, the proportion of cleared RegD MW with an effective price of $0.00 from January 1, 2018, through September 30, 2019. In the first nine months of 2019, 94.3 percent of all RegD MW clearing the market had an effective offer of $0.00. In the first nine months of 2018, 96.3 percent of all cleared RegD MW had an effective cost of $0.00. In the first nine months of 2019, 73.9 percent of all RegD offers were self scheduled, compared to 49.3 percent of all RegD offers in the first nine months of 2018.

The increase in 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 prior to any zero cost offers in the market clearing engine. Given the increasing saturation of the regulation market with RegD MW, market participants that offer at zero instead of self scheduling run the risk of not clearing the market. The average monthly RegD cleared in the market increased 5.8 percent in the first nine months of 2019 compared to the first nine months of 2018.

Figure 10-16 Average cleared RegD MW and average cleared RegD with an effective price of $0.00 by month: January 2018 through September 2019



Price Spikes

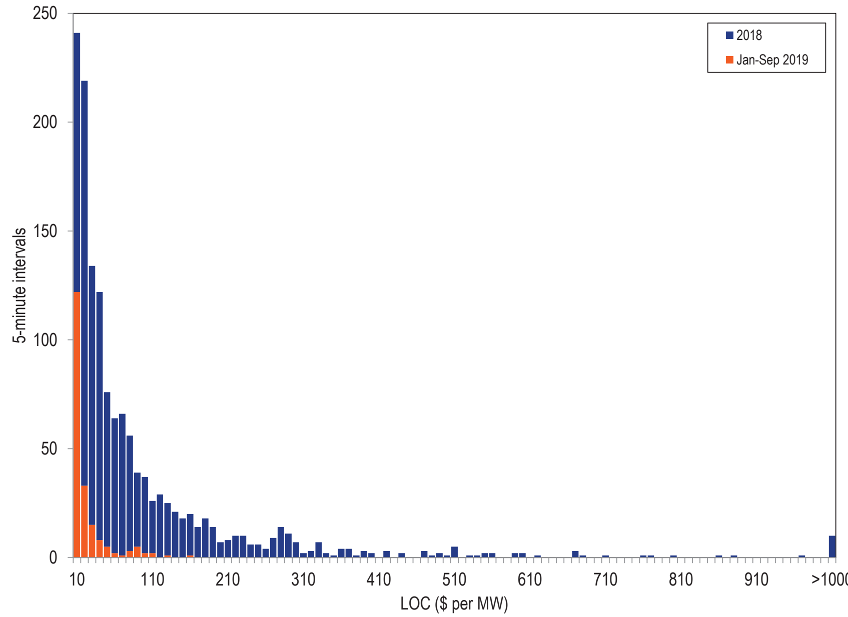
Beginning in 2018, extreme price spikes were identified in the regulation market. The price spikes were caused by a combination of the inconsistent application of the MBF in the market design and the discrepancy between the hour ahead estimated LOC and the actual realized within hour LOC.

79 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>.

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 was very low (less than one), this discrepancy in the estimated and realized LOC will cause a large discrepancy between the expected offer price (as low as $0/MW) of that resource in the clearing of the market engine, and the realized offer price of the resource, after it is cleared, in the actual market result. This will cause a significant and unexpected 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, FERC approved PJM's proposal to create a 0.1 floor for the MBF to reduce the occurrence of these price spikes.[80] 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. PJM's new MBF floor of 0.1 did not and will not eliminate unjust and unreasonable outcomes for market participants. PJM's market change does not correct the underlying problem with the current market design because it does not address the overpayment of RegD MW when the MBF is less than 1.0. Correspondingly, RegD is still underpaid when the MBF is greater than 1.0. Figure 10-17 shows the LOC in each five-minute interval in which a RegD unit was the marginal unit and the LOC was greater than zero in 2018 versus the first nine months of 2019.

Figure 10-17 LOC distribution in each five-minute interval with a RegD marginal unit and an LOC greater than zero: 2018 and January through September, 2019



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/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.

80 See 166 FERC ¶ 61,040 (2019).

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 make use of 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. The market failure in PJM's Regulation Market is 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.

Market Structure

Supply

Table 10-41 shows actual capability MW, actual average daily offer MW, average hourly eligible MW (actual and effective), and average hourly cleared MW (actual and effective) for all hours in the first nine months of 2019.[81] 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 daily offers from units that are offered as available for the day. Eligible MW are calculated from the hourly offers from units with daily offers and units that are offered as unavailable for the day, but still offer MW into some hours. Units with daily offers are permitted to offer above or below their daily offer from hour to hour. As a result of these hourly MW adjustments, the average hourly Eligible MW can be higher than the Offered MW.

In the first nine months of 2019, the average hourly eligible supply of regulation for nonramp hours was 1,062.1 actual MW (801.2 effective MW). This was a decrease of 37.2 actual MW (a decrease of 56.5 effective MW) from the first nine months of 2018, when the average hourly eligible supply of regulation was 1,099.3 actual MW (857.7 effective MW). In the first nine months of 2019, the average hourly eligible supply of regulation for ramp hours was 1,357.8 actual MW (1,127.6 effective MW). This was a decrease of 53.3 actual MW (a decrease of 64.1 effective MW) from the first nine months of 2018, when the average hourly eligible supply of regulation was 1,411.1 actual MW (1,191.8 effective MW).

81 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.

The ratio of the average hourly eligible supply of regulation to average hourly regulation demand (actual cleared MW) for ramp hours was 1.88 in the first nine months of 2019 (unchanged from the first nine months of 2018). The ratio of the average hourly eligible supply of regulation to average hourly regulation demand (actual cleared MW) for nonramp hours was 2.25 in the first nine months of 2019 (2.26 in the first nine months of 2018).

Table 10-41 PJM regulation capability, daily offer and hourly eligible: January through September, 2019[82 83]

			By Resource Type		By Signal Type	
		All Regulation	Generating Resources	Demand Resources	RegA Following Resources	RegD Following Resources
Capability MW	Daily	11,285.1	11,251.9	33.2	10,899.8	662.1
Offered MW	Daily	5,994.2	5,968.3	26.0	5,597.1	397.1
Actual Eligible MW	Ramp	1,357.8	1,332.4	25.4	1,021.0	336.8
	Nonramp	1,062.1	1,039.4	22.7	748.5	313.6
Effective Eligible MW	Ramp	1,127.6	1,097.2	30.4	775.1	352.5
	Nonramp	801.2	780.2	20.9	534.8	266.3
Actual Cleared MW	Ramp	723.9	706.9	17.0	550.3	173.6
	Nonramp	471.0	456.7	14.3	311.9	159.1
Effective Cleared MW	Ramp	800.0	770.2	29.8	470.4	329.6
	Nonramp	528.6	508.2	20.4	266.7	261.8

Table 10-42 PJM regulation by source: January through September, 2018 and 2019[84]

	2018 (Jan-Sep)				2019 (Jan-Sep)			
Source	Number of Units	Performance Adjusted Settled Regulation (MW)	Percent of Settled Regulation	Total Regulation Credits	Number of Units	Performance Adjusted Settled Regulation (MW)	Percent of Settled Regulation	Total Regulation Credits
Battery	23	758,087	21.7%	$27,143,323	24	830,956	24.5%	$16,472,536
Coal	37	337,934	9.7%	$16,572,934	19	262,284	7.7%	$6,947,315
Hydro	28	682,585	19.5%	$24,040,207	25	623,305	18.4%	$12,779,787
Natural Gas	168	1,649,390	47.2%	$50,442,658	165	1,588,027	46.8%	$25,775,991
DR	30	68,494	2.0%	$2,306,400	26	88,680	2.6%	$1,824,937
Total	286	3,496,490.7	100.0%	$120,505,522	259	3,393,252.5	100.0%	$63,800,565

Table 10-42 provides the settled regulation MW by source unit type, the total settled regulation MW provided by all resources, and the percent of settled regulation provided by unit type. In Table 10-42 the MW have been adjusted by the performance score since this adjustment forms the basis of payment for units providing regulation. Total regulation performance adjusted settled MW decreased 3.0 percent from 3,496,490.7 MW in the first nine months of 2018 to 3,393,252.5 MW in the first nine months of 2019. The average proportion of regulation provided by battery units had the largest increase (2.8 percent), providing 21.7 percent of regulation in the first nine months of 2018 and 24.5 percent of regulation in the first nine months of 2019. Coal units had the largest decrease in average proportion of regulation provided (1.9 percent), decreasing from 9.7 percent in the first nine months of 2018, to 7.7 percent in the first nine months of 2019. The total regulation credits in the first nine months of 2019 were $63,800,565, down 47.1 percent from $120,505,522 in the first nine months of 2018. The reduction in regulation credits is due, in part, to a lower LOC component of regulation prices as a result of lower energy prices in 2019 compared to 2018.

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 led 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 10-43).

82 Average Daily Offer MW excludes units that have offers but are unavailable for the day.
83 Total offer capability is defined as the sum of the maximum daily offer volume for each offering unit during the period, without regard to the actual availability of the resource or to the day on which the maximum was offered.
84 Biomass data have been added to the natural gas category for confidentiality purposes.

Table 10-43 Active battery storage projects in the PJM queue system by submitted year: 2012 to 2019

Year	Number of Storage Projects	Total Capacity (MW)
2012	1	4.5
2013	0	0.0
2014	1	10.0
2015	7	66.0
2016	2	39.7
2017	3	2.5
2018	29	962.0
2019	48	2,570.7
Total	91	3,655.3

The supply of regulation can be affected by regulating units retiring from service. If all units that are requesting retirement through the end of the first nine months of 2019 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 10-37).

Table 10-44 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.

The nonramp regulation requirement of 525.0 effective MW was provided by a combination of RegA and RegD resources equal to 470.7 hourly average performance adjusted actual MW in the first nine months of 2019. This is a decrease of 16.1 performance adjusted actual MW from the first nine months of 2018, when the average hourly total regulation cleared performance adjusted actual MW for nonramp hours were 486.8 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 722.8 hourly average performance adjusted actual MW in the first nine months of 2019. This is a decrease of 27.1 performance adjusted actual MW from the first nine months of 2018, where the average hourly regulation cleared MW for ramp hours were 750.0 performance adjusted actual MW.

Table 10-44 Required regulation and ratio of supply to requirement: January through September, 2018 and 2019

		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	2018	2019	2018	2019	2018	2019	2018	2019
Ramp	Jan	756.8	719.3	800.0	799.9	1.88	2.10	1.49	1.51
	Feb	738.7	710.3	799.9	799.9	1.90	2.10	1.48	1.53
	Mar	742.9	707.6	800.0	799.9	1.86	1.92	1.43	1.39
	Apr	747.4	718.8	799.9	799.9	1.76	1.81	1.39	1.36
	May	747.2	717.5	800.1	800.0	1.76	1.81	1.42	1.35
	Jun	746.4	728.5	800.0	800.0	1.88	1.81	1.51	1.37
	Jul	756.2	737.2	800.0	800.0	1.91	1.78	1.54	1.39
	Aug	760.4	733.3	800.1	799.9	1.94	1.79	1.53	1.39
	Sep	754.0	733.1	797.3	800.0	1.98	1.78	1.57	1.39
	Oct	752.0	-	800.0	-	1.92	-	1.49	-
	Nov	747.3	-	800.1	-	2.13	-	1.63	-
	Dec	742.3	-	800.1	-	2.08	-	1.55	-
Nonramp	Jan	497.6	465.5	525.1	525.5	2.27	2.57	1.71	1.72
	Feb	482.0	466.6	525.2	525.1	2.37	2.67	1.70	1.83
	Mar	486.6	484.6	525.2	538.0	2.35	2.30	1.67	1.55
	Apr	488.1	472.4	525.0	525.1	2.03	2.18	1.47	1.48
	May	481.5	465.9	524.9	525.6	2.13	2.15	1.55	1.41
	Jun	482.7	466.9	524.9	526.8	2.36	2.18	1.68	1.42
	Jul	488.8	482.1	525.0	541.5	2.24	2.06	1.63	1.41
	Aug	483.5	463.7	525.1	525.3	2.32	2.14	1.65	1.43
	Sep	490.5	469.0	535.1	525.3	2.33	2.08	1.66	1.43
	Oct	477.2	-	525.1	-	2.30	-	1.60	-
	Nov	471.1	-	525.1	-	2.61	-	1.83	-
	Dec	466.5	-	525.1	-	2.74	-	1.89	-

Market Concentration

In the first nine months of 2019, the effective MW weighted average HHI of RegA resources was 2362 which is highly concentrated and the weighted average HHI of RegD resources was 1307 which is moderately concentrated.[85] The weighted average HHI of all resources was 1366, which is moderately concentrated. The HHI of RegA resources and the HHI of RegD resources reflect the fact that different owners have large market shares in the RegA and RegD markets.

Table 10-45 includes a monthly summary of three pivotal supplier (TPS) results. In the first nine months of 2019, 93.3 percent of hours had three or fewer pivotal suppliers. The MMU concludes that the PJM Regulation Market in the first nine months of 2019 was characterized by structural market power.

Table 10-45 Regulation market monthly three pivotal supplier results: January 2017 through September 2019

	Percent of Hours Pivotal		
Month	2017	2018	2019
Jan	90.6%	88.7%	77.8%
Feb	93.1%	77.5%	76.0%
Mar	92.7%	83.9%	93.3%
Apr	92.9%	90.3%	93.1%
May	88.7%	87.8%	94.0%
Jun	89.2%	79.9%	91.0%
Jul	91.0%	79.4%	92.7%
Aug	88.0%	79.6%	93.1%
Sep	82.6%	78.6%	93.3%
Oct	68.1%	82.1%	
Nov	72.5%	78.2%	
Dec	79.3%	74.2%	
Average	85.7%	81.7%	89.4%

85 HHI results are based on market shares of effective MW, defined as regulation capability MW adjusted by performance score and resource specific benefit factor, consistent with the way the regulation market is cleared.

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.[86] When offering into the regulation market, regulating resources must submit a cost-based offer and may submit a price-based offer (capped at $100/MW) by 2:15 pm the day before the operating day.[87]

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/MW margin. The $12.00 margin embeds market power in the regulation offers and is not part of the cost of regulation. 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.[88]

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.[89]

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 10-47).[90] Figure 10-18 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.[91] Self scheduled regulation comprised an average of 43.0 percent during ramp hours and 58.8 percent during nonramp hours in the first nine months of 2019.

86 See "PJM Manual 11: Energy & Ancillary Services Market Operations," § 3.2.1 Regulation Market Eligibility, Rev. 107 (Sep. 26, 2019).
87 Id. at 3.2.2, at p 62.
88 See "PJM Manual 15: Cost Development Guidelines," § 7.8 Regulation Cost, Rev. 32 (May 13, 2019).
89 See "PJM Manual 11: Energy & Ancillary Services Market Operations," § 3.2.1 Regulation Market Eligibility, Rev. 107 (Sep. 26, 2019).
90 See "PJM Manual 28: Operating Agreement Accounting," § 4.1Regulation Accounting Overview, Rev. 82 (July 25, 2019).
91 See "PJM Manual 11: Energy & Ancillary Services Market Operations," § 3.2.1 Regulation Market Eligibility, Rev. 107 (Sep. 26, 2019).

Figure 10-18 Nonramp and ramp regulation levels: January 2018 through September 2019[92]

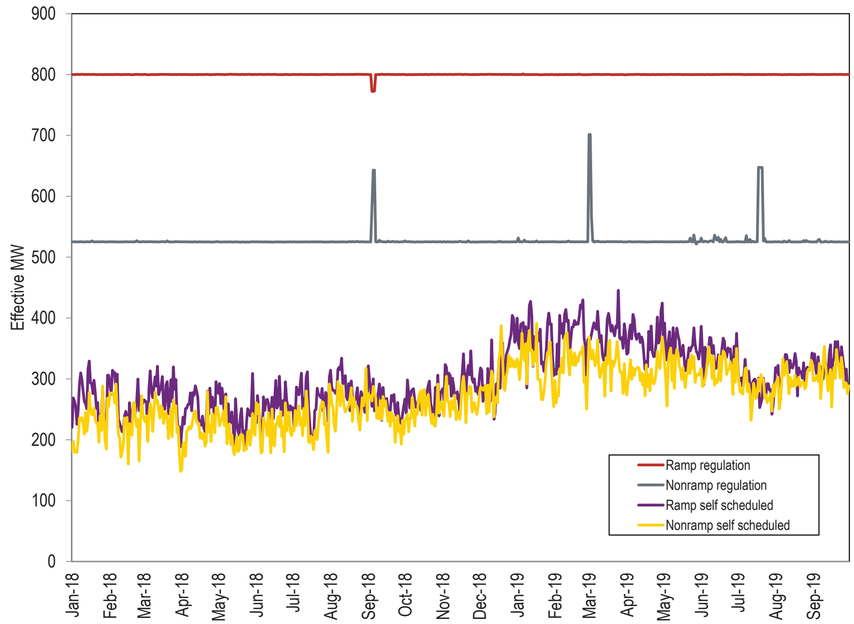


Table 10-46 shows the role of RegD resources in the regulation market. RegD resources are both a growing proportion of the market (10.9 percent of the total effective MW at the start of the performance based regulation market design in October 2012 and 42.1 percent of the total effective MW in September 2019) and a growing proportion of resources that self schedule (25.0 percent of all self scheduled MW in October 2012 and 63.7 percent of all self scheduled MW in September 2019). In the first nine months of 2019, the average RegD percentage of total self scheduled MW was 65.9 percent, an increase of 10.7 percent from the first nine months of 2018, when the average was 55.2 percent. The increase in the effective MW share of RegD in 2016 was a result of the use of the unit block method of calculating the MBF over the previous price block method.

92 The effective MW increases during the nonramp hours of September 2018, March 2019, and July 2019 were a result of PJM operations treating those hours as ramp hours, with a regulation requirement of 800 MW rather than 525 MW.

Table 10-46 RegD self scheduled regulation by month: October 2012 through September 2019

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
2012	Oct	66.3	71.8	264.7	658.1	25.0%	10.9%
2012	Nov	74.4	88.3	196.5	716.5	37.9%	12.3%
2012	Dec	82.5	88.8	188.8	701.1	43.7%	12.7%
2013	Jan	35.7	82.5	133.6	720.0	26.7%	11.5%
2013	Feb	84.8	90.2	212.2	724.3	39.9%	12.5%
2013	Mar	80.1	119.3	279.8	680.7	28.6%	17.5%
2013	Apr	82.3	106.9	266.0	594.1	30.9%	18.0%
2013	May	74.0	109.0	268.2	616.2	27.6%	17.7%
2013	Jun	79.6	122.7	334.9	730.6	23.8%	16.8%
2013	Jul	77.6	120.4	303.6	822.9	25.6%	14.6%
2013	Aug	83.6	127.6	366.0	756.8	22.8%	16.9%
2013	Sep	112.2	152.1	381.6	669.9	29.4%	22.7%
2013	Oct	120.2	163.7	349.6	613.3	34.4%	26.7%
2013	Nov	133.9	175.7	396.5	663.3	33.8%	26.5%
2013	Dec	136.5	180.7	313.6	663.5	43.5%	27.2%
2013 Average		91.7	129.2	300.5	688.0	30.6%	19.0%
2014	Jan	132.9	193.5	261.1	663.6	50.9%	29.2%
2014	Feb	134.3	193.4	289.0	663.6	46.5%	29.1%
2014	Mar	131.8	193.8	287.2	663.8	45.9%	29.2%
2014	Apr	126.8	212.4	270.8	663.7	46.8%	32.0%
2014	May	121.7	248.5	265.6	663.6	45.8%	37.4%
2014	Jun	123.3	231.0	365.5	663.9	33.7%	34.8%
2014	Jul	126.4	235.5	352.7	663.5	35.8%	35.5%
2014	Aug	117.6	229.8	368.2	663.6	31.9%	34.6%
2014	Sep	121.0	242.6	393.8	663.6	30.7%	36.6%
2014	Oct	116.1	255.4	352.7	663.6	32.9%	38.5%
2014	Nov	113.5	235.1	347.5	664.2	32.7%	35.4%
2014	Dec	116.7	254.3	353.0	663.6	33.1%	38.3%
2014 Average		123.5	227.1	325.6	663.7	38.9%	34.2%
2015	Jan	116.4	250.1	304.8	663.7	38.2%	37.7%
2015	Feb	111.3	245.8	242.6	663.5	45.9%	37.0%
2015	Mar	113.8	255.2	229.9	663.8	49.5%	38.5%
2015	Apr	110.1	248.2	283.7	663.7	38.8%	37.4%
2015	May	121.8	265.1	266.7	663.6	45.7%	39.9%
2015	Jun	158.9	283.1	321.2	663.7	49.5%	42.6%
2015	Jul	161.4	278.3	314.0	663.8	51.4%	41.9%
2015	Aug	159.5	276.0	300.7	663.6	53.0%	41.6%
2015	Sep	155.4	289.2	286.0	663.5	54.3%	43.6%
2015	Oct	147.1	299.0	292.8	663.4	50.2%	45.1%
2015	Nov	164.9	302.1	298.1	664.2	55.3%	45.5%
2015	Dec	144.6	317.2	260.7	663.9	55.5%	47.8%
2015 Average		138.8	275.8	283.4	663.7	48.9%	41.6%
2016	Jan	187.7	335.9	295.3	663.8	63.6%	50.6%
2016	Feb	179.9	339.0	274.6	663.6	65.5%	51.1%
2016	Mar	182.6	340.8	280.1	663.7	65.2%	51.3%
2016	Apr	182.2	339.5	287.0	663.5	63.5%	51.2%
2016	May	183.9	341.1	301.5	663.5	61.0%	51.4%
2016	Jun	178.8	340.5	302.4	663.6	59.1%	51.3%
2016	Jul	165.2	337.5	273.3	663.5	60.4%	50.9%
2016	Aug	165.8	338.5	283.2	663.5	58.5%	51.0%
2016	Sep	160.9	341.4	279.9	663.6	57.5%	51.4%
2016	Oct	168.6	340.0	283.0	663.5	59.6%	51.2%
2016	Nov	156.2	338.0	259.8	664.3	60.1%	50.9%
2016	Dec	162.2	342.7	274.7	663.6	59.0%	51.6%
2016 Average		172.8	339.6	282.9	663.7	61.1%	51.2%
2017	Jan	187.1	334.9	318.0	673.9	58.8%	49.7%
2017	Feb	192.7	337.8	296.6	674.2	65.0%	50.1%
2017	Mar	172.2	315.3	297.5	638.5	57.9%	49.4%
2017	Apr	159.9	306.4	255.0	639.6	62.7%	47.9%
2017	May	167.6	297.0	265.7	639.7	63.1%	46.4%
2017	Jun	178.6	315.6	284.3	696.9	62.8%	45.3%
2017	Jul	171.9	310.3	290.0	703.1	59.3%	44.1%
2017	Aug	176.7	314.0	286.3	700.9	61.7%	44.8%
2017	Sep	156.9	297.8	259.0	640.4	60.6%	46.5%
2017	Oct	158.6	295.3	263.7	639.7	60.1%	46.2%
2017	Nov	158.6	298.1	261.7	640.4	60.6%	46.5%
2017	Dec	147.7	290.8	260.6	674.0	56.7%	43.1%
2017 Average		169.0	293.8	278.2	663.4	60.8%	46.7%
2018	Jan	130.6	274.3	247.4	673.8	52.8%	40.7%
2018	Feb	131.1	276.6	245.5	674.0	53.4%	41.0%
2018	Mar	126.6	270.9	249.4	639.8	50.8%	42.3%
2018	Apr	124.8	266.5	232.3	639.6	53.7%	41.7%
2018	May	124.7	275.7	223.0	639.6	55.9%	43.1%
2018	Jun	136.0	298.4	241.5	696.8	56.3%	42.8%
2018	Jul	138.5	294.6	248.3	696.9	55.8%	42.3%
2018	Aug	159.6	274.3	271.6	697.0	58.8%	39.4%
2018	Sep	150.1	256.7	251.4	644.3	59.7%	39.8%
2018	Oct	148.0	266.6	256.6	639.6	57.7%	41.7%
2018	Nov	144.0	252.9	274.8	640.4	52.4%	39.5%
2018	Dec	172.0	273.0	308.5	674.0	55.7%	40.5%
2018 Average		140.5	263.8	254.2	663.0	55.2%	41.2%
2019	Jan	223.0	303.6	345.8	674.0	64.5%	45.0%
2019	Feb	243.3	311.5	350.8	673.9	69.4%	46.2%
2019	Mar	240.9	314.2	347.0	647.6	69.4%	48.5%
2019	Apr	230.5	305.2	332.6	639.6	69.3%	47.7%
2019	May	213.2	297.2	330.9	639.9	64.4%	46.4%
2019	Jun	206.3	289.1	331.9	697.6	62.1%	41.4%
2019	Jul	188.5	290.3	285.9	703.1	65.9%	41.3%
2019	Aug	200.3	290.2	309.4	696.9	64.7%	41.6%
2019	Sep	198.9	269.4	312.2	639.8	63.7%	42.1%
2019 Average		216.1	312.1	327.4	334.2	65.9%	44.5%

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 nine months of 2019, 52.6 percent was purchased in the PJM market, 42.2 percent was self scheduled, and 5.2 percent was purchased bilaterally (Table 10-47). Table 10-48 shows the total regulation by source including spot market regulation, self scheduled regulation, and bilateral regulation for the first nine months of each year from 2012 to 2019. Table 10-47 and Table 10-48 are based on settled (purchased) MW.

Table 10-47 Regulation sources: spot market, self scheduled, bilateral purchases: January 2018 through September 2019

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)
2018	Jan	241,902.0	60.7%	134,251.7	33.7%	22,447.0	5.6%	398,600.6
2018	Feb	222,860.7	62.0%	120,581.1	33.6%	15,846.5	4.4%	359,288.3
2018	Mar	213,265.0	57.0%	141,161.2	37.7%	19,749.0	5.3%	374,175.3
2018	Apr	221,787.2	60.9%	125,524.8	34.5%	16,941.5	4.7%	364,253.5
2018	May	237,448.1	64.3%	115,879.6	31.4%	15,670.0	4.2%	368,997.7
2018	Jun	253,593.9	64.5%	120,041.8	30.5%	19,547.5	5.0%	393,183.2
2018	Jul	259,675.4	63.3%	128,317.0	31.3%	22,103.0	5.4%	410,095.4
2018	Aug	247,312.4	60.3%	132,757.8	32.4%	29,987.0	7.3%	410,057.2
2018	Sep	226,706.5	63.0%	117,025.7	32.5%	16,302.0	4.5%	360,034.2
2018	Oct	221,319.3	59.9%	129,259.5	35.0%	19,042.5	5.2%	369,621.3
2018	Nov	196,229.7	54.8%	136,284.0	38.0%	25,716.0	7.2%	358,229.7
2018	Dec	213,255.5	54.6%	157,304.7	40.3%	20,237.5	5.2%	390,797.7
Total		2,755,355.7	60.5%	1,558,388.9	34.2%	243,589.5	5.3%	4,557,334.1
2019	Jan	190,256.0	50.0%	170,091.0	44.7%	20,426.0	5.4%	380,773.0
2019	Feb	173,403.6	50.4%	154,652.2	45.0%	15,841.0	4.6%	343,896.8
2019	Mar	176,012.6	48.1%	175,580.7	47.9%	14,679.0	4.0%	366,272.3
2019	Apr	170,454.4	49.1%	158,313.1	45.6%	18,133.0	5.2%	346,900.4
2019	May	165,667.4	46.4%	166,367.6	46.6%	25,305.0	7.1%	357,340.1
2019	Jun	210,077.0	54.5%	155,567.8	40.3%	19,950.0	5.2%	385,594.8
2019	Jul	249,261.1	61.9%	134,210.8	33.3%	19,405.5	4.8%	402,877.5
2019	Aug	232,920.9	58.3%	146,362.4	36.6%	20,246.5	5.1%	399,529.8
2019	Sep	187,018.5	53.2%	144,562.1	41.1%	20,200.0	5.7%	351,780.6
Total		1,755,071.5	52.6%	1,405,707.9	42.2%	174,186.0	5.2%	3,334,965.3

Table 10-48 Regulation sources: January through September, 2012 through 2019

Jan-Sep	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	5,110,747.9	79.7%	1,122,671.9	17.5%	180,121.0	2.8%	6,413,540.8
2013	2,528,830.3	60.8%	1,478,608.5	35.5%	152,328.5	3.7%	4,159,767.3
2014	1,836,488.7	51.8%	1,543,266.0	43.5%	166,857.0	4.7%	3,546,611.7
2015	1,897,225.7	54.7%	1,380,004.7	39.8%	193,529.1	5.6%	3,470,759.5
2016	1,672,795.5	47.8%	1,598,231.6	45.7%	226,803.5	6.5%	3,497,830.6
2017	1,849,333.5	54.1%	1,372,996.2	40.2%	196,759.5	5.8%	3,419,089.2
2018	2,124,551.1	61.8%	1,135,540.8	33.0%	178,593.5	5.2%	3,438,685.4
2019	1,755,071.5	52.6%	1,405,707.9	42.2%	174,186.0	5.2%	3,334,965.3

In the first nine months of 2019, DR provided an average of 17.0 MW of regulation per hour during ramp hours (12.2 MW of regulation per hour during ramp hours in the first nine months of 2018), and an average of 14.3 MW of regulation per hour during nonramp hours (10.8 MW of regulation per hour during off peak hours in the first nine months of 2018). Generating units supplied an average of 706.9 MW of regulation per hour during ramp hours in the first nine months of 2019 (738.4 MW of regulation per hour during ramp hours in the first nine months of 2018), and an average of 456.7 MW per hour during nonramp hours in the first nine months of 2019 (476.1 MW of regulation per hour during nonramp hours in the first nine months of 2018).

Market Performance

Price

Table 10-52 shows the regulation price and regulation cost per MW for the first nine months of each year from 2009 through 2019. The weighted average RMCP for the first nine months of 2019 was $14.97 per MW. This is a decrease of $13.25 per MW, or 47.0 percent, from the weighted average RMCP of $28.21 per MW in the first nine months of 2018. This decrease in the regulation clearing price was the result of a decrease in energy prices in the first nine months of 2019 and the related decrease in the opportunity cost component of RMCP.

Figure 10-19 shows the daily weighted average regulation market clearing price, 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). This means that 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 10-19 illustrates that the opportunity cost (dark blue line) is the largest component of the clearing price.

Figure 10-19 Regulation market-clearing price, opportunity cost and offer price components (Dollars per MW): January through September, 2019

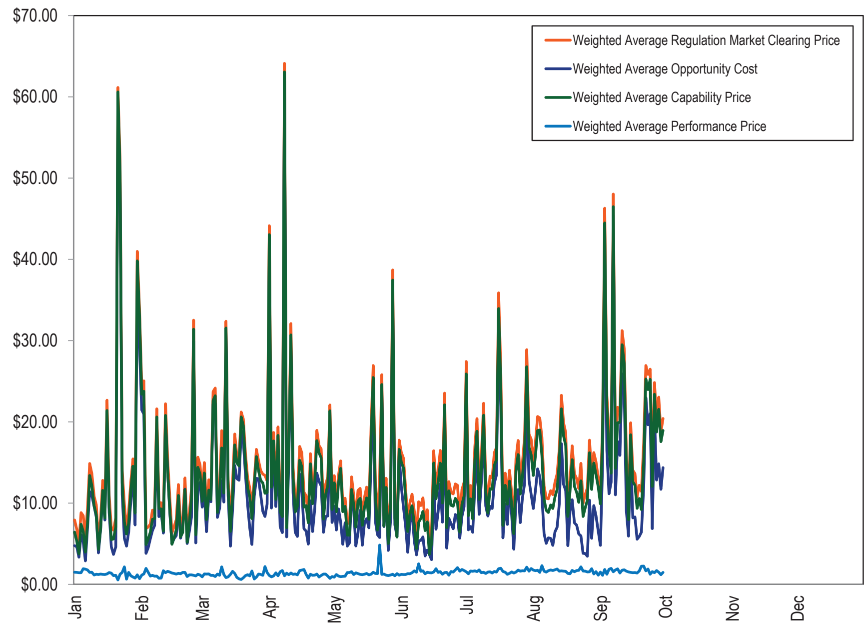


Table 10-49 shows the capability and performance components of the monthly average regulation prices. These components differ from the components of the marginal unit's offers in Figure 10-19 because the performance component of the settlement price for each hour is determined from the average of the highest performance offers in each five minute interval, calculated independent of the marginal unit's offers in those intervals.

Table 10-49 PJM regulation market monthly component of price (Dollars per MW): January through September, 2019

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	$13.42	$1.29	$14.71
Feb	$11.05	$1.25	$12.30
Mar	$13.84	$1.16	$15.00
Apr	$15.75	$1.22	$16.96
May	$11.57	$1.33	$12.90
Jun	$9.84	$1.53	$11.37
Jul	$14.57	$1.58	$16.16
Aug	$12.97	$1.64	$14.62
Sep	$19.30	$1.61	$20.91
Average	$12.58	$1.30	$13.88

Monthly, total annual, and total year to date scheduled regulation MW and regulation charges, as well as monthly and monthly average regulation price and regulation cost are shown in Table 10-50. Total scheduled regulation is based on settled performance adjusted MW. The total of all regulation charges for the first nine months of 2019 was $63.8 million, compared to $120.5 million for the first nine months of 2018.

Table 10-50 Total regulation charges: January 2018 through September 2019

Year	Month	Scheduled Regulation (MW)	Total Regulation Charges ($)	Weighted Average Regulation Market Price ($/MW)	Cost of Regulation ($/MW)	Price as Percent of Cost
2018	Jan	398,600.6	$39,149,046	$80.73	$98.22	82.2%
2018	Feb	359,288.3	$6,270,251	$12.80	$17.45	73.4%
2018	Mar	374,175.3	$10,735,641	$23.73	$28.69	82.7%
2018	Apr	364,253.5	$12,882,261	$27.70	$35.37	78.3%
2018	May	368,997.7	$14,087,966	$30.84	$38.18	80.8%
2018	Jun	393,183.2	$8,933,758	$18.64	$22.72	82.0%
2018	Jul	410,095.4	$9,716,064	$19.42	$23.69	82.0%
2018	Aug	410,057.2	$9,079,650	$17.22	$22.14	77.8%
2018	Sep	360,034.2	$9,660,676	$20.92	$26.83	78.0%
2018	Oct	369,621.3	$10,342,063	$20.81	$27.98	74.4%
2018	Nov	358,229.7	$7,530,728	$15.28	$21.02	72.7%
2018	Dec	390,797.7	$7,118,936	$13.39	$18.22	73.5%
Yearly		4,554,652.8	$145,465,939	$25.33	$31.94	79.3%
2019	Jan	380,773.0	$7,272,344	$14.71	$19.10	77.0%
2019	Feb	343,896.8	$5,651,921	$12.30	$16.43	74.9%
2019	Mar	366,272.3	$7,204,760	$15.00	$19.67	76.3%
2019	Apr	346,900.4	$7,528,065	$16.96	$21.70	78.2%
2019	May	357,340.1	$6,111,192	$12.90	$17.10	75.5%
2019	Jun	385,594.8	$5,747,998	$11.37	$14.91	76.3%
2019	Jul	402,877.5	$8,166,587	$16.16	$20.27	79.7%
2019	Aug	399,529.8	$7,351,497	$14.62	$18.40	79.5%
2019	Sep	351,780.6	$8,803,781	$20.91	$25.03	83.5%
Year to date		3,334,965.3	$63,838,145	$14.97	$19.14	78.2%

The capability, performance, and opportunity cost components of the cost of regulation are shown in Table 10-51. Total scheduled regulation is based on settled performance adjusted MW. In the first nine months of 2019, the average total cost of regulation was $19.14 per MW, 45.4 percent lower than $35.05 in the first nine months of 2018. In the first nine months of 2019, the monthly average capability component cost of regulation was $14.10, 48.1 percent lower than $27.16 in the first nine months of 2018. In the first nine months of 2019, the monthly average performance component cost of regulation was $2.87, 19.4 percent lower than $3.55 in the first nine months of 2018. The reduction of the average total cost in the first nine months of 2019 versus the first nine months of 2018, was primarily a result of lower LOC values due to lower prices in the energy market.

Table 10-51 Components of regulation cost: January 2018 through September 2019

Year	Month	Scheduled Regulation (MW)	Cost of Regulation Capability ($/MW)	Cost of Regulation Performance ($/MW)	Opportunity Cost ($/MW)	Total Cost ($/MW)
2018	Jan	398,600.6	$80.22	$3.76	$14.24	$98.22
	Feb	359,288.3	$11.17	$4.46	$1.82	$17.45
	Mar	374,175.3	$22.92	$2.91	$2.86	$28.69
	Apr	364,253.5	$26.78	$3.57	$5.02	$35.37
	May	368,997.7	$29.85	$3.78	$4.55	$38.18
	Jun	393,183.2	$17.76	$2.92	$2.04	$22.72
	Jul	410,095.4	$18.25	$3.08	$2.36	$23.69
	Aug	410,057.2	$16.04	$3.48	$2.62	$22.14
	Sep	360,034.2	$19.46	$4.15	$3.23	$26.83
	Oct	369,621.3	$19.19	$4.99	$3.80	$27.98
	Nov	358,229.7	$14.20	$3.36	$3.46	$21.02
	Dec	390,797.7	$12.31	$3.29	$2.61	$18.22
Yearly		4,554,652.8	$24.22	$3.63	$4.08	$31.94
2019	Jan	380,773.0	$13.91	$2.68	$2.51	$19.10
	Feb	343,896.8	$11.51	$2.67	$2.26	$16.43
	Mar	366,272.3	$14.33	$2.63	$2.71	$19.67
	Apr	346,900.4	$16.18	$2.65	$2.88	$21.70
	May	357,340.1	$12.27	$2.46	$2.37	$17.10
	Jun	385,594.8	$10.35	$3.10	$1.46	$14.91
	Jul	402,877.5	$15.06	$3.19	$2.01	$20.27
	Aug	399,529.8	$13.59	$3.31	$1.50	$18.40
	Sep	351,780.6	$20.01	$2.98	$2.03	$25.03
Year to date		3,334,965.3	$14.10	$2.87	$2.18	$19.14

Table 10-52 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 nine months of 2019 was 78.2 percent, a 2.9 percent decrease from 80.5 percent in the first nine months of 2018.

Table 10-52 Comparison of average price and cost for PJM regulation: January through September, 2009 through 2019

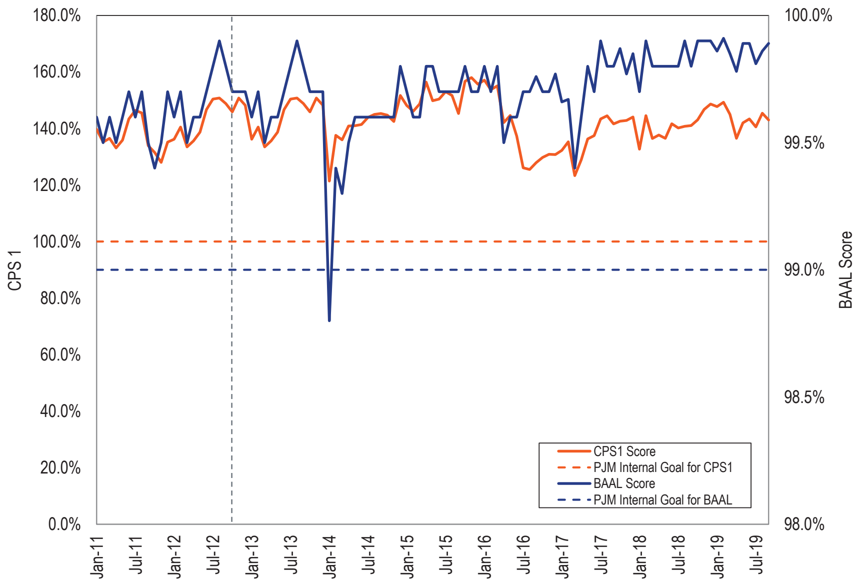
Jan-Sep	Weighted Regulation Market Price	Weighted Regulation Market Cost	Regulation Price as Percent Cost
2009	$24.94	$32.28	77.3%
2010	$19.47	$34.54	56.4%
2011	$17.04	$32.70	52.1%
2012	$15.16	$21.07	71.9%
2013	$33.29	$38.49	86.5%
2014	$50.19	$60.94	82.4%
2015	$35.56	$43.00	82.7%
2016	$16.52	$18.99	87.0%
2017	$15.70	$21.70	72.4%
2018	$28.21	$35.05	80.5%
2019	$14.97	$19.14	78.2%

Performance Standards

PJM's performance as measured by CPS1 and BAAL standards is shown in Figure 10-20 for every month from January 2011 through September 2019 with the dashed vertical line marking the date (October 1, 2012) of the implementation of the Performance Based Regulation Market design.[93] The horizontal dashed lines represent PJM internal goals for CPS1 and BAAL performance. While PJM did not meet its internal goal for BAAL performance in January 2014, PJM remained in compliance with the applicable NERC standards.

93 See 2018 State of the Market Report for PJM, Appendix F: Ancillary Services.

Figure 10-20 PJM monthly CPS1 and BAAL performance: January 2011 through September 2019



Black Start Service

Black start service is necessary to ensure 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 when disconnected from the grid.

PJM does not have a market to provide black start service, but compensates black start resource owners on the basis of an incentive rate or for the costs associated with providing this service.

PJM defines required black start capability zonally, while recognizing that the most effective way to provide black start service may be across zones, and ensures the availability of black start service by charging transmission customers according to their zonal load ratio share and compensating black start unit owners. Substantial rule changes to the black start restoration and procurement strategy were implemented on February 28, 2013, following a stakeholder process in the System Restoration Strategy Task Force (SRSTF) and the Markets and Reliability Committee (MRC) that approved the PJM and MMU joint proposal for system restoration. These changes gave PJM substantial flexibility in procuring black start resources and made PJM responsible for black start resource selection.

On July 1, 2013, PJM initiated its first RTO-wide request for proposals (RFP) under the new rules.[94] [95] PJM identified zones with black start shortages and began awarding contracts on January 14, 2014. PJM and the MMU coordinated closely during the selection process.

PJM issued two additional RFPs in 2014. On April 11, 2014, PJM sought additional black start in the AEP Zone and one proposal was selected. On November 24, 2014, PJM sought additional black start in Northeastern Ohio and Western Pennsylvania, but no proposals were selected because they did not meet the bid requirements. On July 28, 2015, PJM issued an Incremental Request for Proposals, for Northeastern Ohio and Western Pennsylvania together. On August 8, 2016, PJM made one award which will cover both areas.

On February 1, 2018, PJM issued its second RTO wide request for proposals (RFP) in accordance with the five year black start selection process. The RFP process is a two-tiered process. Level one submissions were due March 8, 2018. On March 30, 2018, PJM notified participants if a level two response would be requested. Level two bidders were requested by PJM to provide their detailed proposal by May 31, 2018. From November 28, 2018, through December 21, 2018, PJM awarded seven proposals.

On February 1, 2019, PJM issued an incremental RFP for additional black start service in the BGE Zone. The RFP is a two stage process. Level one

94 See PJM. "RTO-Wide Five-Year Selection Process Request for Proposal for Black Start Service," (July 1, 2013).
95 RFPs issued can be found on the PJM website. See PJM. <http://www.pjm.com/markets-and-operations/ancillary-services.aspx>.

submissions were due February 25, 2019. On March 8, 2019, PJM notified participants if a level two response would be requested. Level two bidders were requested by PJM to provide their detailed proposals by May 1, 2019. Bids have been received and PJM plans to complete the review of the level two proposals and issue an award by September 1, 2019. The expected in service date is April 1, 2021.

Total black start charges are the sum of black start revenue requirement charges and black start 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. Section 18 of Schedule 6A of the OATT specifies how to calculate each component of the revenue requirement formula. 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 incremental black start equipment capital costs. Black start operating reserve charges are paid to units scheduled in the Day-Ahead Energy Market or committed in real time to provide black start service under the automatic load rejection (ALR) option or for black start testing. Total black start charges are allocated monthly to PJM customers proportionally to their zone and nonzone peak transmission use and point to point transmission reservations.[96]

In the first nine months of 2019, total black start charges were $48.368 million, a decrease of $0.762 million (-1.6 percent) from the same nine month period in 2018. Operating reserve charges for black start service decreased from $0.191 million in the first nine months of 2018 to $0.160 million in the first nine months of 2019. Table 10-53 shows total revenue requirement charges from 2010 through 2019. Prior to December 2012, PJM did not define a separate black start operating reserve category. Starting December 1, 2012, PJM defined a separate black start operating reserve category. By April 2015, all ALR units had been replaced and no longer provided black start service which resulted in decreased operating reserve charges.

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

Table 10-53 Black start revenue requirement charges: January through September, 2010 through 2019

Jan-Sep	Revenue Requirement Charges	Operating Reserve Charges	Total
2010	$8,527,000	$0	$8,527,000
2011	$9,996,898	$0	$9,996,898
2012	$13,288,491	$0	$13,288,491
2013	$15,728,447	$68,903,357	$84,631,804
2014	$18,395,320	$26,661,658	$45,056,978
2015	$39,718,855	$5,070,944	$44,789,799
2016	$51,565,656	$180,265	$51,745,921
2017	$52,422,434	$186,752	$52,609,186
2018	$48,940,298	$190,781	$49,131,080
2019	$48,208,418	$159,867	$48,368,284

Black start zonal charges in the first nine months of 2019 ranged from $0.04 per MW-day in the DLCO Zone (total charges were $33,657) to $4.03 per MW-day in the PENELEC Zone (total charges were $3,299,265). For each zone, Table 10-54 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). For black start service, point to point transmission customers paid on average $1.05 per MW-day of reserve capacity during the first nine months of 2019.

Table 10-54 Black start zonal charges: January through September, 2018 and 2019[97]

	Jan-Sep 2018						Jan-Sep 2019					
Zone	Revenue Requirement Charges	Operating Reserve Charges	Total Charges	Peak Load (MW)	Days	Black Start Rate ($/MW-day)	Revenue Requirement Charges	Operating Reserve Charges	Total Charges	Peak Load (MW)	Days	Black Start Rate ($/MW-day)
AECO	$2,057,440	$14,518	$2,071,958	2,541	273	$2.99	$2,028,149	$8,011	$2,036,161	2,591	273	$2.88
AEP	$13,142,244	$39,193	$13,181,437	21,647	273	$2.23	$12,971,807	$45,020	$13,016,827	22,739	273	$2.10
APS	$2,930,362	$3,945	$2,934,307	8,755	273	$1.23	$2,922,052	$1,102	$2,923,155	9,342	273	$1.15
ATSI	$2,297,019	$934	$2,297,953	12,052	273	$0.70	$3,979,965	$1,482	$3,981,448	12,825	273	$1.14
BGE	$944,860	$3,371	$948,231	6,448	273	$0.54	$283,260	$956	$284,215	6,627	273	$0.16
ComEd	$3,468,613	$13,815	$3,482,428	20,351	273	$0.63	$3,156,493	$12,470	$3,168,963	21,349	273	$0.54
DAY	$179,681	$2,330	$182,011	3,225	273	$0.21	$157,663	$1,176	$158,840	3,337	273	$0.17
DEOK	$661,568	$0	$661,568	5,036	273	$0.48	$264,062	$0	$264,062	5,195	273	$0.19
DLCO	$36,936	$0	$36,936	2,682	273	$0.05	$33,657	$0	$33,657	2,795	273	$0.04
Dominion	$3,047,547	$9,576	$3,057,123	19,661	273	$0.57	$2,659,768	$19,300	$2,679,068	21,232	273	$0.46
DPL	$1,691,436	$9,602	$1,701,039	3,813	273	$1.63	$1,663,278	$12,448	$1,675,726	4,002	273	$1.53
EKPC	$287,245	$844	$288,089	2,860	273	$0.37	$250,757	$1,964	$252,721	3,431	273	$0.27
JCPL	$5,126,105	$9,035	$5,135,141	5,721	273	$3.29	$5,073,428	$7,186	$5,080,614	5,977	273	$3.11
Met-Ed	$447,524	$46,466	$493,990	2,897	273	$0.62	$344,957	$16,637	$361,594	3,028	273	$0.44
OVEC	$0	$0	$0	NA	273	NA	$0	$0	$0	NA	273	NA
PECO	$1,170,817	$2,460	$1,173,277	8,141	273	$0.53	$1,016,448	$3,169	$1,019,617	8,608	273	$0.43
PENELEC	$3,391,667	$3,319	$3,394,986	2,890	273	$4.30	$3,297,981	$1,284	$3,299,265	2,997	273	$4.03
Pepco	$1,888,538	$14,986	$1,903,524	6,097	273	$1.14	$1,846,793	$8,759	$1,855,553	6,412	273	$1.06
PPL	$895,260	$7,873	$903,134	7,401	273	$0.45	$837,500	$7,279	$844,779	7,681	273	$0.40
PSEG	$3,156,191	$861	$3,157,052	9,567	273	$1.21	$3,115,037	$4,526	$3,119,564	9,978	273	$1.15
RECO	$0	$0	$0	NA	273	NA	$0	$0	$0	NA	273	NA
(Imp/Exp/Wheels)	$2,119,244	$7,653	$2,126,896	6,890	273	$1.13	$2,305,361	$7,096	$2,312,457	8,067	273	$1.05
Total	$48,940,298	$190,781	$49,131,080	158,675		$1.13	$48,208,418	$159,867	$48,368,284	168,213		$1.05

Table 10-55 provides a revenue requirement estimate by zone for the 2019/2020, 2020/2021 and 2021/2022 delivery years.[98] 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. Prior to November 26, 2017, new black start units were not paid until their costs had been provided with appropriate support and approved. In some cases black start units were completed and went into service before costs had been supported and therefore costs were not approved. In these cases the unit did not receive any payments until the costs were appropriately supported. Once their costs were approved the units received all payments going back to the in service date. The result was a lumpy payment by load for black start service. After November 26, 2017, PJM accrued payments for the black start units each month, until the units costs were supported and approved in order to smooth out monthly payments for black start service.

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

Table 10-55 Black start zonal revenue requirement estimate: 2019/2020 through 2021/2022 delivery years

Zone	2019 / 2020 Revenue Requirement	2020 / 2021 Revenue Requirement	2021 / 2022 Revenue Requirement
AECO	$2,850,000	$2,700,000	$2,150,000
AEP	$18,750,000	$21,550,000	$21,650,000
APS	$4,100,000	$5,150,000	$10,400,000
ATSI	$5,900,000	$5,900,000	$5,900,000
BGE	$350,000	$50,000	$50,000
ComEd	$5,450,000	$9,700,000	$9,850,000
DAY	$250,000	$250,000	$300,000
DEOK	$400,000	$400,000	$450,000
DLCO	$100,000	$400,000	$2,150,000
Dominion	$4,350,000	$6,000,000	$6,100,000
DPL	$2,350,000	$2,350,000	$1,450,000
EKPC	$400,000	$400,000	$400,000
JCPL	$7,150,000	$800,000	$850,000
Met-Ed	$500,000	$450,000	$550,000
OVEC	$0	$0	$0
PECO	$1,450,000	$1,450,000	$1,600,000
PENELEC	$4,650,000	$4,600,000	$4,700,000
Pepco	$2,600,000	$750,000	$450,000
PPL	$1,800,000	$4,700,000	$4,750,000
PSEG	$4,350,000	$1,850,000	$1,900,000
RECO	$0	$0	$0
Total	$67,750,000	$69,450,000	$75,650,000

NERC – CIP

Currently, no black start units have requested new or additional black start NERC – CIP Capital Costs.[99]

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 10-21 illustrates that the size of the oil tank does not change with the addition of the black start unit. Figure 10-22 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.

99 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."

Figure 10-21 Oil tank MTSL not changed from addition of black start generator

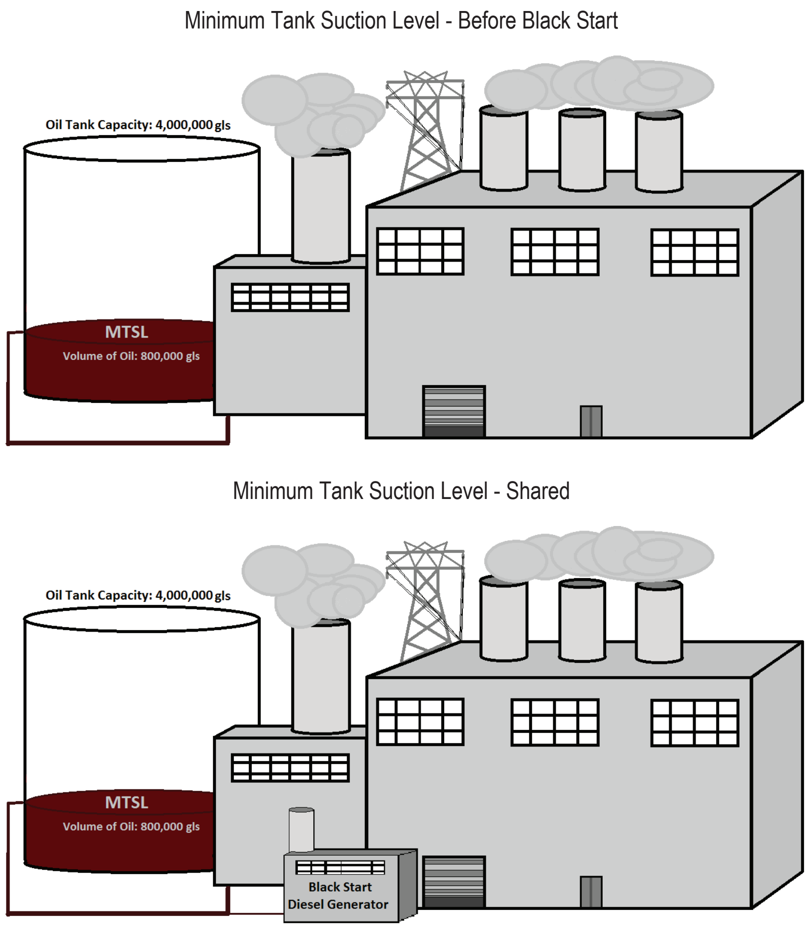
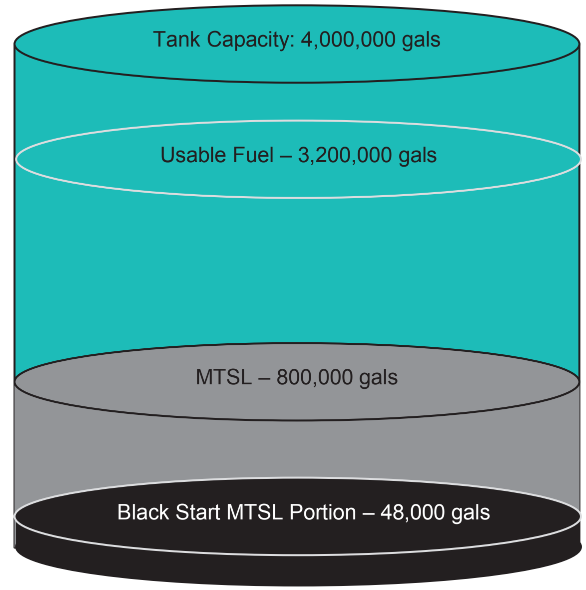


Figure 10-22 Oil tank black start MTSL portion



Reactive Service

Suppliers of reactive power are compensated separately for reactive capability, day-ahead operating reserves, and for real-time lost opportunity costs. Compensation for reactive capability must be 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.[100]

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 awarded uplift or LOC credits.

100 See "PJM Manual 27: Open Access Transmission Tariff Accounting,"§ 3.2 Reactive Supply and Voltage Control Credits, Rev. 90, (Dec. 6, 2018).

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).[101] 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. While a fixed requirement for reactive power is not established, 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.[102] 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 point to point transmission reservations.[103]

In 2016, the FERC began to reexamine its policies on reactive compensation.[104] 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.[105] 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 and some other RTOs/ISOs. 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.[106] 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.[107] The Commission has recently extended the interconnection service requirement to have reactive capability to wind and solar units, which previously had been exempt.[108] 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 will 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.

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.

101 OATT Schedule 2.

102 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).

103 OATT Schedule 2.

104 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).

105 See 88 FERC ¶ 61,141 (1999).

106 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.").

107 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).

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

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 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.[109] The only FERC proceeding that has provided an opportunity for the MMU to raise its concerns at hearing has been *Panda Stonewall LLC*.[110] The initial decision issued in that case sidesteps the issues identified by the MMU.[111] 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."[112] Typically this has meant reliance on manufacturers' specified nameplate power factor.[113] More recently, the Commission has, in the *Wabash* Orders, required that "reactive power revenue requirement filings must include reactive power test reports."[114] 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.[115]

The Commission has identified a significant issue.[116] 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.

PJM determined in 1999 that nameplate MVAR and power factor ratings do not reflect the value to the system operator of a unit's reactive output after it is interconnected at a specific location. Only operator evaluation of reactive capability can provide a meaningful measure of reactive capability.

The most fundamental point about power factors is that PJM requires that all generating units have a 0.90 power factor in order to obtain interconnection service.[117] 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.

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. 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.

109 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.
110 See Docket No. EL17-1821.
111 167 FERC ¶ 63,010 (April 26, 2019).
112 *AEP mimeo* at 31.
113 See, e.g., *id.*
114 154 FERC ¶ 61,246 at P 28 (2016); see also 154 FERC ¶ 61,246 at P 29 (*Wabash* Orders).
115 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.").
116 154 FERC ¶ 61,246 at P 28 (2016); see also 154 FERC ¶ 61,246 at P 29.

117 *See supra* footnote 27.

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.[118] 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.[119] This is the average annual reactive revenue for combustion turbines from 2005 through 2007, based on the actual costs reported to the Commission in reactive service filings of CTs, as developed by the MMU.

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.

118 See OATT Attachment DD § 5.10(a)(iv).
119 See OATT Attachment DD § 5.10(a)(v).

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 combined result of market based capacity prices and cost of service rates.

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.[120] 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.[121]

Losses

The estimated capability costs also include estimated heating losses relative to MVAR output.[122] Heating losses are variable costs and not fixed costs and should not be included in the definition of reactive capability costs.[123] 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

120 See OATT Attachment DD §§ 6.4, 6.8(d).
121 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.
122 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).
123 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.

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.[124] 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.[125] 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.[126]

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.[127] But PJM rules require fleet owners only to submit informational filings when a reactive unit is transferred or deactivated.[128] The current rules do not require a rate filing, which would place the burden of proof on the company and allow for cost review.[129]

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.[130] 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.[131] The MMU also explained that the approach makes it impossible to calculate cost-based offers from such units in the PJM Capacity Market. The settlement was approved over the MMU's objection on the grounds that the tariff does not prohibit fleet rates.[132]

The MMU recommends that fleet rates be eliminated and that compensation be based on unit specific costs and rates.

Reactive Costs

In the first nine months of 2019, total reactive charges were $258.7 million, a 3.2 percent increase from the $250.8 million for the first nine months of 2018. Reactive capability charges increased from $238.3 million in the first nine months 2018 to $258.2 million in 2019 and reactive service charges decreased from $12.4 million in the first nine months of 2018 to $0.45 million in the first nine months of 2019. All $0.45 million in the first nine months of 2019 were paid for reactive service provided by 23 units in 104 hours.

Table 10-56 shows reactive service charges in the first nine months of 2018 and 2019, 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.

124 See, e.g., OATT Schedule 2; 114 FERC ¶ 61,318 (2006).
125 See 149 FERC ¶ 61,132 (2014); 151 FERC ¶ 61,224 (2015); OATT Schedule 2.
126 Id.
127 151 FERC ¶ 61,224 at P 29 (2015).
128 OATT Schedule 2.
129 Id.
130 See Letter Opposing Settlement, Docket No ER06-554 et al. (June 14, 2017).
131 Id.
132 162 FERC ¶ 61,029 (2018).

Table 10-56 Reactive service charges and reactive capability charges by zone: January through September, 2018 and 2019

	Jan-Sep 2018			Jan-Sep 2019		
Zone	Reactive Service Charges	Reactive Capability Charges	Total Charges	Reactive Service Charges	Reactive Capability Charges	Total Charges
AECO	$7	$3,262,827	$3,262,834	$0	$3,220,440	$3,220,440
AEP	$775,231	$30,906,777	$31,682,008	$14,233	$35,983,652	$35,997,885
APS	$0	$11,686,243	$11,686,243	$13,823	$11,774,288	$11,788,111
ATSI	$0	$16,213,493	$16,213,493	$696	$19,700,232	$19,700,929
BGE	$30,956	$6,095,433	$6,126,390	$0	$5,543,285	$5,543,285
ComEd	$10,790,803	$28,786,314	$39,577,117	$0	$29,683,563	$29,683,563
DAY	$0	$3,382,775	$3,382,775	$0	$2,112,619	$2,112,619
DEOK	$0	$5,951,863	$5,951,863	$0	$7,505,391	$7,505,391
Dominion	$22,293	$28,629,559	$28,651,851	$182,436	$28,920,858	$29,103,294
DPL	$257,310	$7,629,540	$7,886,850	$102,319	$7,393,200	$7,495,519
DLCO	$0	$430,486	$430,486	$0	$428,142	$428,142
EKPC	$175,743	$1,644,625	$1,820,368	$0	$1,635,666	$1,635,666
JCPL	$0	$7,095,604	$7,095,604	$0	$5,474,178	$5,474,178
Met-Ed	$0	$3,355,219	$3,355,219	$0	$4,473,048	$4,473,048
OVEC	$0	$0	$0	$0	$0	$0
PECO	$0	$17,067,202	$17,067,202	$0	$16,145,838	$16,145,838
PENELEC	$357,599	$8,976,358	$9,333,958	$137,176	$9,721,968	$9,859,145
Pepco	$0	$7,078,887	$7,078,887	$0	$8,475,942	$8,475,942
PPL	$0	$18,322,300	$18,322,300	$0	$26,117,160	$26,117,160
PSEG	$0	$20,552,524	$20,552,524	$0	$20,736,024	$20,736,024
RECO	$0	$0	$0	$0	$0	$0
(Imp/Exp/Wheels)	$0	$11,278,069	$11,278,069	$0	$13,181,067	$13,181,067
Total	$12,409,942	$238,346,098	$250,756,040	$450,685	$258,226,560	$258,677,245

Frequency Response

On February 15, 2018, the Commission issued Order No. 842, which modified the proforma 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.[133] 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.[134]

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 fifteen seconds and can maintain itself for several minutes up to an hour in some cases.

133 157 FERC ¶ 61,122 (2016).

134 See 164 FERC ¶ 61,224 (2018).

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.