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 2018.

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.

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 day-ahead scheduling reserve market structure was evaluated as not competitive because market participants failed the three pivotal supplier test in 9.8 percent of all cleared hours in 2018.
- 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 96.4 percent of cleared hours when the clearing price was above $0.
- 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 81.7 percent of the hours in 2018.
- Participant behavior in the PJM Regulation Market was evaluated as competitive for 2018 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.

1 75 FERC ¶ 61,080 (1996).
2 Energy imbalance service refers to the Real-Time Energy Market.

- 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 2018, the average primary reserve requirement was 2,267.8 MW in the RTO Zone and 2,247.3 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. 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 2018, there was an average hourly supply of 1,711.9 MW of tier 1 available in the RTO Zone. In 2018, there was an average hourly supply of 771.9 MW of tier 1 synchronized reserve available within the MAD Subzone and an additional 588.2 MW of tier 1 available to the MAD Subzone from the RTO Zone.
- **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 the average of five minute LMPs during the event plus $50 per MWh.[4] This is the Synchronized Energy Premium Price.

  Of the Degree of Generator Performance (DGP) adjusted tier 1 synchronized reserve MW estimated at market clearing, 63.3 percent actually responded during the seven synchronized reserve events of 10 minutes or longer in 2018.
- **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

3 See PJM. "Manual 10: Pre-Scheduling Operations," § 3.1.1 Day-ahead Scheduling (Operating Reserve, Rev. 37 (Dec. 10, 2018).

4 See PJM. "Manual 11: Energy & Ancillary Services Market Operations,"§ 4.2.10 Settlements, Rev. 104 (Feb. 7, 2019).

the five-minute LMP plus $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, and $4,732,025 in 2018.

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, that have an obligation to respond, that have penalties for failure to respond, and that must be dispatched in order to satisfy the synchronized reserve requirement.

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).

Market Structure

- **Supply.** In 2018, the supply of offered and eligible tier 2 synchronized reserve was 26,086.3 MW in the RTO Zone of which 7,230.9 MW was located in the MAD Subzone. 2,821.0 MW of DSR was available in the RTO Zone.
- **Demand.** The average hourly synchronized reserve requirement was 1,577.8 MW in the RTO Reserve Zone and 1,564.3 MW for the Mid-Atlantic Dominion Reserve Subzone. The hourly average cleared tier 2 synchronized reserve was 352.4 MW in the MAD Subzone and 598.4 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 2018.

  In 2018 10.2 percent of hours would have failed a three pivotal supplier test. In 2018, the average HHI for tier 2 synchronized reserve in the RTO Zone was 5007 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 was $5.39 per MW in 2018, an increase of $2.11 from 2017.

  The weighted average price for tier 2 synchronized reserve for all cleared hours/intervals in the RTO Synchronized Reserve Zone was $6.15 per MW in 2018, an increase of $2.37 from 2017.

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 2018, the average hourly supply of eligible nonsynchronized reserve was 3,683.2 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.[5] In the RTO Zone, the market scheduled an hourly average of 1,968.8 MW of nonsynchronized reserve in 2018.
- **Market Concentration.** The MMU calculates that the three pivotal supplier test would have failed in 44.8 percent of hours. In 2018, the weighted average HHI for cleared nonsynchronized reserve in the RTO Zone was 4443, which is highly concentrated.

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 $0.29 per MW in 2018. The price cleared above $0.00 in 1.0 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.[6] If DASR units are on an outage in real time or cleared DASR MW are not available, the DASR payment is not made.

Market Structure

- **Supply.** The DASR Market is a must offer market. Any resources that do not make an offer have their offer set to $0.00 per MW. DASR is calculated by the day-ahead market solution as the lesser of the 30 minute energy ramp rate or the economic maximum MW minus the day-ahead dispatch point for all online units. In 2018, the average available hourly DASR was 39,595.6 MW.
- **Demand.** The DASR requirement for 2018 is 5.28 percent of peak load forecast, down from 5.52 percent in 2017. The average DASR MW purchased in 2018 was 5,690.1 MW per hour, compared to 4,477.3 MW per hour in 2017.
- **Concentration.** In 2018, the DASR Market would have failed the three pivotal supplier test in 9.8 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 2018, a daily average of 38.8 percent of units offered above $0.00. A daily average of 15.8 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 2018.

Market Performance

- **Price.** In 2018, the weighted average DASR price for all hours when the DASRMCP was above $0.00 was $3.49.

5 See PJM. "Manual 11: Energy & Ancillary Services Market Operations," § $b.2.2 Non-Synchronized Reserve Zones and Levels, Rev. 104 (February 7, 2019). "Because Synchronized Reserve may be utilized to meet the Primary Reserve requirement, there is no explicit requirement for non-synchronized reserves."

6 See PJM, "Manual 11: Energy & Ancillary Services Market Operations," § 11.2.7 Day-Ahead Scheduling Reserve Performance, Rev. 104 (February 7, 2019).

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 ability. 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 function (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 2018, the average hourly eligible supply of regulation for nonramp hours was 1,125.5 performance adjusted MW (876.2 effective MW). This was a decrease of 10.6 performance adjusted MW (a decrease of 7.1 effective MW) from 2017, when the average hourly eligible supply of regulation was 1,136.1 performance adjusted MW (869.0 effective MW). In 2018, the average hourly eligible supply of regulation for ramp hours was 1,438.3 performance adjusted MW (1,204.1 effective MW). This was an increase of 11.1 performance adjusted MW (an increase of 20.7 effective MW) from 2017, when the average hourly eligible supply of regulation was 1,427.2 performance adjusted MW (1,183.4 effective MW).
- **Demand.** Prior to January 9, 2017, the hourly regulation demand was set to 525.0 effective MW for nonramp hours and 700.0 effective MW for ramp hours. Starting January 9, 2017, the hourly regulation demand was set to 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 483.0 hourly average performance adjusted actual MW in 2018. This is a decrease of 5.1 performance adjusted actual MW from 2017, when the average hourly total regulation cleared performance adjusted actual MW for nonramp hours were 488.1 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 749.3 hourly average performance adjusted actual MW in 2018. This is an increase of 29.1 performance adjusted actual MW from 2017, where the average hourly regulation cleared MW for ramp hours were 720.2 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 1.92 in 2018. This is a decrease of 3.22 percent from 2017, when the ratio was 1.98. The ratio of the average hourly eligible supply of regulation to average hourly regulation demand (performance adjusted cleared MW) for nonramp hours was 2.33 in 2018, unchanged from the ratio in 2017.
- **Market Concentration.** In 2018, the three pivotal supplier test was failed in 81.7 percent of hours. In 2018, the effective MW weighted average HHI of RegA resources was 2419 which is highly concentrated and the weighted average HHI of RegD resources was 1546 which is also highly concentrated.[7] The weighted average HHI of all resources was 1125, 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

7 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.

RegD.[8] In 2018, there were 227 resources following the RegA signal and 69 resources following the RegD signal.

Market Performance

- **Price and Cost.** The weighted average clearing price for regulation was $25.33 per MW of regulation in 2018. This is an increase of $8.55 per MW, or 50.9 percent, from the weighted average clearing price of $16.78 per MW in 2017. The weighted average cost of regulation in 2018 was $31.94 per MW of regulation. This is an increase of $8.90 per MW, or 38.6 percent, from the weighted average cost of $23.04 per MW in 2017.
- **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 Function.** The marginal benefit factor (MBF) is intended to measure the operational substitutability of RegD resources for RegA resources. The marginal benefit factor function is incorrectly defined and applied in the PJM market clearing. Correctly defined, the MBF function 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 function 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 the optimization and settlement process in the PJM Regulation Market. On March 30, 2018, this joint proposal was rejected by FERC.[9] The MMU and PJM have filed requests for rehearing.[10]

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).[11]

In 2018, total black start charges were $64.7 million, including $64.4 million in revenue requirement charges and $0.303 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 2018 ranged from $0.07 per MW-day in the DLCO Zone (total charges were $72,167) to $4.26 per MW-day in the PENELEC Zone (total charges were $4,496,206).

Reactive

Reactive service, reactive supply and voltage control are provided by generation and other sources of reactive power (measured in MVAr). Reactive power helps

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

9 162 FERC ¶ 61,295.

10 FERC Docket No. ER18-87-002.

11 OATT Schedule 1 § 1.3BB.

maintain appropriate voltage levels on the transmission system and is essential to the flow of real power (measured in MW).

Reactive capability revenue requirements are based on FERC approved filings that permit recovery based on a cost of service approach.[12] 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 2018, total reactive charges were $342.0 million, a 3.1 percent increase from $331.7 million in 2017. Reactive capability revenue requirement charges increased from $311.3 million in 2017 to $328.8 million in 2018 and reactive service charges decreased from $20.4 million in 2017 to $13.1 million in 2018. Total reactive service charges in 2018 ranged from $0 in the RECO Zone, which has no generating units, to $50.8 million in the ComEd 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.[13] PJM filed revisions in compliance with Order No. 842 that substantively incorporated the pro forma agreements into its market rules.[14]

Ancillary Services Costs per MWh of Load: 1999 through 2018

Table 10-4 shows PJM ancillary services costs for 1999 through 2018, 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 ReliabilityFirst 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: 1999 through 2018[15 16]

Year	Regulation	Scheduling, Dispatch and System Control	Reactive	Synchronized Reserve	Total
1999	$0.15	$0.23	$0.26	$0.00	$0.64
2000	$0.39	$0.26	$0.29	$0.00	$0.94
2001	$0.53	$0.71	$0.22	$0.00	$1.46
2002	$0.42	$0.86	$0.20	$0.01	$1.49
2003	$0.50	$1.05	$0.24	$0.15	$1.94
2004	$0.51	$0.93	$0.26	$0.13	$1.83
2005	$0.80	$0.72	$0.26	$0.11	$1.89
2006	$0.53	$0.74	$0.29	$0.08	$1.64
2007	$0.63	$0.72	$0.29	$0.06	$1.70
2008	$0.70	$0.38	$0.34	$0.08	$1.50
2009	$0.34	$0.29	$0.36	$0.05	$1.04
2010	$0.36	$0.35	$0.45	$0.07	$1.23
2011	$0.32	$0.36	$0.41	$0.09	$1.18
2012	$0.26	$0.41	$0.46	$0.04	$1.17
2013	$0.25	$0.41	$0.76	$0.04	$1.46
2014	$0.33	$0.42	$0.40	$0.12	$1.27
2015	$0.23	$0.42	$0.37	$0.11	$1.13
2016	$0.11	$0.41	$0.38	$0.05	$0.95
2017	$0.14	$0.47	$0.43	$0.06	$1.10
2018	$0.18	$0.46	$0.43	$0.06	$1.13

Recommendations

- 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.[17])
- 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

12 OATT Schedule 2.
13 See 157 FERC ¶ 61,122 (2016).
14 See 164 FERC ¶ 61,224 (2018).

15 Note: The totals Table 10-4 account for after the fact billing adjustments made by PJM and may not match totals presented in past reports.
16 Reactive totals include FERC approved rates for reactive capability.
17 FERC Docket No. ER18-87.

reported 2010. Status: Not adopted.[18] FERC rejected, pending rehearing request before FERC.[19])

- The MMU recommends that the lost opportunity cost calculation used in the Regulation Market be based on the resource's dispatched energy offer schedule, not the lower of its price or cost offer schedule. (Priority: Medium. First reported 2010. Status: Not adopted. FERC rejected, pending rehearing request before FERC.[20])
- 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.[21])
- The MMU recommends enhanced documentation of the implementation of the Regulation Market design. (Priority: Medium. First reported 2010. Status: Not adopted. FERC rejected, pending rehearing request before FERC.[22])
- 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 Q3, 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 Q3, 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 Q3, 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. New recommendation. Status: Not adopted.)
- The MMU recommends that a reason code be attached to every hour in which PJM market

18 This recommendation was adopted by PJM for the Energy Market. Lost opportunity costs in the Energy Market are calculated using the schedule on which the unit was scheduled to run. In the Regulation Market, this recommendation has not been adopted, as the LOC continues to be calculated based on the lower of price or cost in the energy market offer.
19 FERC Docket No. ER18-87.
20 *Id.*
21 *Id.*
22 *Id.*

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 Q3, 2018. Status: Not adopted.)
- The MMU recommends that all resources, new and existing, have a requirement to include and maintain equipment for primary frequency response capability as a condition of interconnection service and that compensation is provided through the capacity and energy markets. (Priority: Medium. New recommendation. 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 capability to operate under the proposed deadband (+/- 0.036 HZ) and droop (5 percent) settings in order to provide frequency control be mandated as a condition of interconnection and that such capability be required of both new and existing resources. The MMU recommends that no additional compensation be provided as the current PJM market design provides adequate compensation. (Priority: Low. First reported 2017. 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.[23]

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.[24] 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.[25] The MMU and PJM have separately filed requests for rehearing.[26]

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

23 Order No. 755, 137 FERC ¶ 61,064 at PP 197–200 (2011).
24 18 CFR § 385,211 (2017)
25 162 FERC ¶ 61,295 (2018).
26 The MMU filed its request for rehearing on April 27, 2018, and PJM filed its request for rehearing on April 30, 2018.

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 than 10 minutes in 2018, the response was 74.2 percent of scheduled tier 2 MW. Actual participant performance implies 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, and $4.7 million in 2018.

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 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. PJM defines its Contingency Event Recovery Period as 15 minutes and its Contingency Reserve Restoration Period as 90 minutes.[27] The NERC requirement is 100 percent compliance and status must be reported quarterly. PJM implements this contingency reserve requirement using primary reserves.[28] 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.

Market Structure

Demand

PJM requires that 150 percent of the largest 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 calculated dynamically for each market solution, ASO, IT SCED, and RT SCED, as 150 percent of the most severe single contingency (MSSC).

PJM can, for conservative operations, raise the primary and synchronized reserve requirement. Such additional reserves are committed as part of the hourly (ASO) and five minute (RTSCED) processes. In 2018, the average five minute interval primary reserve requirement for the

27 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."

28 See PJM "Manual 10: Pre-Scheduling Operations," § 3.1.1 Day-ahead Scheduling (Operating) Reserve, Rev. 37 (Dec. 10, 2018).

RTO Zone was 2,267.8 MW. The average five minute interval primary reserve requirement in the MAD Subzone was 2,247.3 MW. These averages include the hours when PJM raised the requirements.

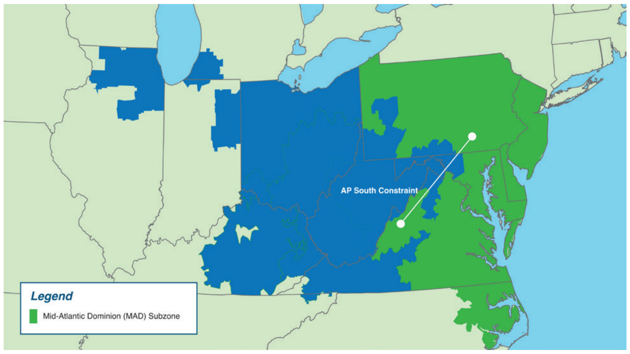
The MMU identified instances when PJM increased the primary and synchronized reserve requirements (see Table 10-5) from their levels prior to and following the identified increases. The amounts of the increases are calculated against average requirement levels before and after the periods of increase.

Table 10-5 Temporary adjustments to primary and synchronized reserve in 2018

From	To	Number of Hours	Amount of Adjustment
8-Jan-18	8-Jan-18	5	Primary reserve (450MW), Synchronized reserve (300MW)
28-Feb-18	3-Mar-18	55	Primary reserve (450MW), Synchronized reserve (300MW)
7-Mar-18	7-Mar-18	5	Primary reserve (450MW), Synchronized reserve (300MW)
15-Mar-18	15-Mar-18	18	Primary reserve (450MW), Synchronized reserve (300MW)
25-Apr-18	25-Apr-18	8	Primary reserve (950MW), Synchronized reserve (1,430MW)
14-Jun-18	14-Jun-18	4	Primary reserve (1,250MW), Synchronized reserve (850MW)
15-Jun-18	15-Jun-18	12	Primary reserve (2,050MW), Synchronized reserve (1,350MW)
18-Jul-18	19-Jul-18	17	Primary reserve (500MW), Synchronized reserve (300MW)
19-Jul-18	20-Jul-18	21	Primary reserve (500MW), Synchronized reserve (300MW)
7-Sep-18	7-Sep-18	2	Primary reserve (1,400MW), Synchronized reserve (950MW)
11-Sep-18	11-Sep-18	12	Primary reserve (1,700MW), Synchronized reserve (1,150MW)
18-Sep-18	18-Sep-18	4	Primary reserve (800MW), Synchronized reserve (500MW)
19-Sep-18	19-Sep-18	4	Primary reserve (650MW), Synchronized reserve (400MW)
20-Sep-18	20-Sep-18	4	Primary reserve (650MW), Synchronized reserve (400MW)
21-Sep-18	21-Sep-18	4	Primary reserve (650MW), Synchronized reserve (400MW)
24-Oct-18	24-Oct-18	10	Primary reserve (200MW), Synchronized reserve (100MW)

Transmission constraints limit the deliverability of reserves within the RTO, requiring the definition of the Mid-Atlantic Dominion (MAD) Subzone (Figure 10-1).[29]

Figure 10-1 PJM RTO Zone and MAD Subzone geography



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, Bedington-Black Oak, Cloverdale-Lexington, and Mt. Storm-Valley.

The NERC standard requires a control area to carry primary reserve MW equal to, or greater than the MSSC.[30] PJM requires primary reserves in the amount of 150 percent of the MSSC with at least 100 percent of the MSSC made up of synchronized reserves. In 2018, the five minute average synchronized reserve requirement in the RTO Zone was 1,577.8 MW. In 2018, the five minute average synchronized reserve requirement in the MAD Subzone was 1,564.3 MW. Beginning July 12, 2017, 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 1,361.0 MW of tier 1 was identified by the RT SCED market solution as available in 2018 (Table 10-7).[31] Of that 1,361.0 MW, an average of 591.4 MW was available from outside the MAD Subzone. 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 8.8 percent of intervals in 2018. In the RTO Zone, an average of 1,728.7 MW of tier 1 was available (Table 10-7) fully

29 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. 101 (Jan. 9, 2019).

30 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>

31 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.

satisfying the synchronized reserve requirement in 50.3 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. Prior to November 1, 2017, owners were permitted to make resources unavailable for tier 2 synchronized reserve daily or hourly, but only if they were physically unavailable. After November 1, 2017, 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.[32]

After tier 1 is estimated, the remainder of the synchronized reserve requirement is met by tier 2. In the RTO Zone, there were 26,086.3 MW of tier 2 synchronized reserve offered daily. Of this, 7,230.9 MW were located in the MAD Subzone (Figure 10-10) and available to meet the average tier 2 hourly demand of 2,247.3 MW (Table 10-6).

In the MAD Subzone, there was an average of 3,125.9 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 3,677.9 MW supply was available to meet the average interval demand of 2,267.8 MW (Table 10-6).

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 2017, through 2018.

Table 10-6 Average monthly reserves used to satisfy the primary reserve requirement, MAD Subzone: 2017 through 2018

Year	Month	Tier 1 Total MW	Tier 2 Synchronized Reserve MW	Nonsynchronized Reserve MW	Total Primary Reserve MW
2017	Jan	981.6	356.1	865.7	2,203.5
2017	Feb	1,111.6	233.2	725.3	2,070.1
2017	Mar	767.4	453.3	1,087.8	2,308.5
2017	Apr	896.9	362.4	987.8	2,247.1
2017	May	1,164.6	376.8	933.6	2,475.0
2017	Jun	1,373.0	379.6	808.0	2,560.6
2017	Jul	1,391.9	353.3	801.1	2,546.3
2017	Aug	1,438.3	226.9	759.5	2,424.7
2017	Sep	1,419.2	339.7	786.1	2,545.0
2017	Oct	1,364.2	348.1	913.5	2,625.8
2017	Nov	1,392.1	245.9	825.5	2,463.5
2017	Dec	1,411.5	160.0	816.3	2,387.8
2017		1,226.0	319.6	859.2	2,404.8
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		1,363.0	349.8	1,174.6	3,127.1

Table 10-7 provides the average monthly reserves, by type of reserve, used by the RT SCED market solution to satisfy the primary reserve requirement in the RTO Zone for January 2017 through December 2018.

32 See PJM "Manual 11: Energy & Ancillary Services Market Operations," § 4.2 PJM Synchronized Reserve Market Business Rules, Rev. 101(Jan. 9, 2019).

Table 10-7 Average monthly reserves used to satisfy the primary reserve requirement, RTO Zone: 2017 through 2018

Year	Month	Tier 1 Total MW	Tier 2 Synchronized Reserve MW	Nonsynchronized Reserve MW	Total Primary Reserve MW
2017	Jan	1,020.4	730.6	1,282.3	2,308.2
2017	Feb	1,172.0	508.3	1,067.0	2,253.2
2017	Mar	654.2	693.1	1,538.6	2,204.0
2017	Apr	805.1	623.0	1,403.6	2,216.5
2017	May	924.1	560.7	1,334.5	2,257.5
2017	Jun	1,413.5	568.8	1,118.7	2,533.0
2017	Jul	1,540.1	667.6	1,131.6	2,675.7
2017	Aug	1,512.8	517.0	1,074.7	2,589.9
2017	Sep	1,368.9	496.6	1,070.3	2,442.3
2017	Oct	1,104.3	528.5	1,338.5	2,971.3
2017	Nov	1,173.6	465.6	1,201.3	2,840.5
2017	Dec	1,308.4	417.8	1,113.1	2,839.3
2017		1,166.4	564.8	1,222.9	2,510.9
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	1,933.7	587.9	1,722.4	3,656.1
2018		1,705.9	598.3	1,973.9	3,679.8

Supply and Demand

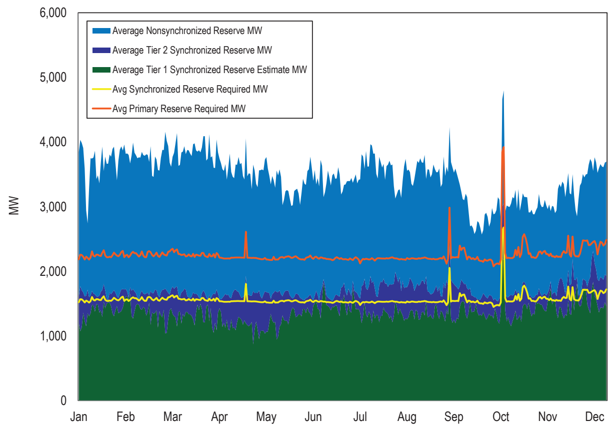
The market solution software relevant to reserves consists of: the Ancillary Services Optimizer (ASO) solving hourly; the intermediate term security constrained economic dispatch market solution (IT SCED); and the real-time (short term) security constrained economic dispatch market solution (RT SCED).

All market solutions determine the actual primary reserves required each hour as one hundred and fifty percent of the largest contingency based on generation and transmission resources. Of this, synchronized reserves must be one hundred percent of the largest contingency. The ASO first assigns self-scheduled synchronized reserves and then estimates the amount of tier 1 synchronized reserves available. The ASO clears inflexible tier 2 synchronized reserve and identifies flexible synchronized reserve sufficient to meet the remaining synchronized reserve requirement.

IT SCED runs at 15 minute intervals and jointly optimizes energy and reserves given the ASO's inflexible unit commitments. IT SCED estimates available tier 1 synchronized reserve and can commit additional reserves (flexibly or inflexibly) if needed. RT SCED runs at five minute intervals and produces load forecasts up to 20 minutes ahead. The RT SCED estimates the available tier 1, provides a real-time ancillary services solution and can commit additional flexible tier 2 resources if needed.

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 up to the synchronized reserve is filled with tier 2 synchronized reserve (dark blue 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): 2018



The solution method is the same for the RTO Reserve Zone.[33] 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): 2018

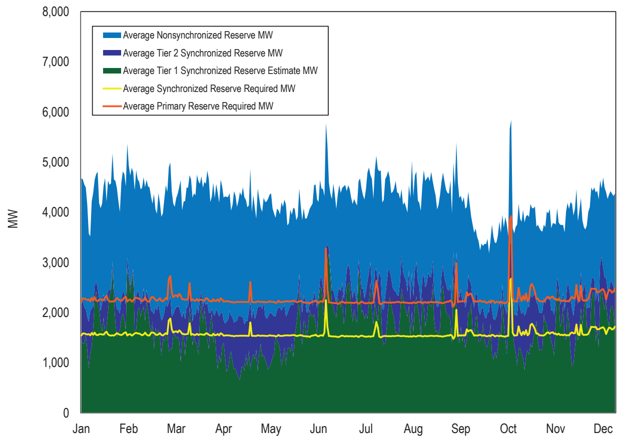


Figure 10-2 shows that within the MAD subzone, Tier 1, Tier 2 from MAD, and Tier 2 from the RTO are all essential to satisfying the synchronized reserve requirement. Figure 10-3 shows that tier 1 synchronized reserve remains the major contributor to satisfying the synchronized reserve requirement in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

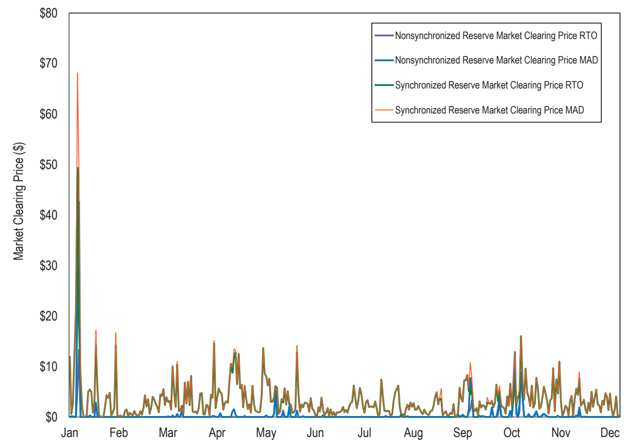
Price and Cost

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 non-synchronized 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 2018.

Figure 10-4 Daily average market clearing prices ($/MW) for synchronized reserve and nonsynchronized reserve: 2018



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 2018 was 38.8 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 $30.34 per MW when the price of nonsynchronized reserve is greater than zero, or more than three times the cost of tier 2 reserves which is $11.71 per MW.

33 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.

Table 10-8 Primary reserve requirement components, RTO Reserve Zone: 2018

Product	MW Share of Primary Reserve Requirement	MW	Credits Paid	Price Per MW Reserve	Cost Per MW Reserve
Tier 1 Synchronized Reserve Response	NA	15,783	$1,397,244	NA	$88.53
Tier 1 Synchronized Reserve Estimated	1.1%	155,991	$4,732,025	$0.00	$30.34
Tier 2 Synchronized Reserve Scheduled	26.6%	3,684,810	$43,995,208	$6.15	$11.59
Non Synchronized Reserve Scheduled	72.2%	9,991,749	$15,856,155	$0.29	$1.59
Primary Reserve (total of above)	100.0%	13,848,333	$65,980,632	$1.85	$4.76

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.[34] 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.[35] DGP should be documented in PJM's Market Rules.

The supply of tier 1 synchronized reserve available to the market solution is adjusted by eliminating tier 1 MW from unit types that cannot reliably provide synchronized reserve. These unit types are nuclear, wind, solar, landfill gas, energy storage, and hydro units.[36] 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.[37]

In 2018, the market solutions estimated tier 1 MW from an average of 151 units that could contribute ramp in a spinning event. The average DGP score was 0.839. In 2018, in the RTO Reserve Zone, the average interval estimated tier 1 synchronized reserve was 1,711.9 MW (Table 10-9). In 60.0 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.

34 See PJM "Manual 11: Energy & Ancillary Services Market Operations," § 4.2.1 Synchronized Reserve Market Eligibility, Rev. 101 (Jan. 9, 2019).

35 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>

36 See PJM "Manual 11: Energy & Ancillary Services Market Operations," § 4.2.1 Synchronized Reserve Market Eligibility, Rev. 101 (Jan. 9, 2019).

37 See PJM "Manual 11: Energy & Ancillary Services Market Operations," § 4.2.1 Synchronized Reserve Market Eligibility, Rev. 101 (Jan. 9, 2019).

In 2018, the average interval estimated tier 1 synchronized reserve was 1,360.1 MW in the MAD Subzone and 588.2 MW were available from the RTO (Table 10-9). In 17.5 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. In all other intervals synchronized reserve from the RTO was required to satisfy the requirement.

Table 10-9 Monthly average interval market solutions for tier 1 synchronized reserve (MW): 2017 through 2018

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
2017	Jan	529.3	452.3	981.6	1,020.4
2017	Feb	526.1	585.5	1,111.6	1,172.0
2017	Mar	292.6	474.8	767.4	654.2
2017	Apr	288.2	608.8	896.9	805.1
2017	May	386.5	778.1	1,164.6	924.1
2017	Jun	559.5	813.5	1,373.0	1,413.5
2017	Jul	693.8	698.1	1,391.9	1,540.1
2017	Aug	583.1	855.2	1,438.3	1,512.8
2017	Sep	564.7	854.5	1,419.2	1,368.9
2017	Oct	465.7	898.4	1,364.2	1,104.3
2017	Nov	469.7	922.4	1,392.1	1,173.6
2017	Dec	539.8	871.7	1,411.5	1,308.4
2017		491.6	734.4	1,226.0	1,166.4
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		771.9	588.2	1,360.1	1,711.9

Demand

There is no required amount of tier 1 synchronized 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.

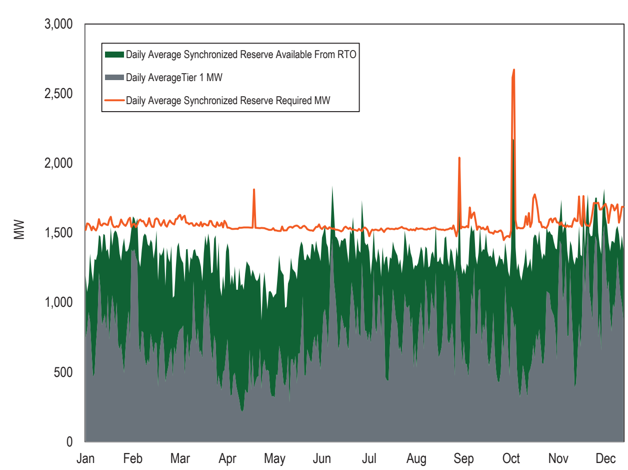
Supply and Demand

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 (gray area of Figure 10-5) as well as the synchronized reserve MW estimated to be available within the MAD Subzone from the RTO Zone (green 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: 2018



Average demand for synchronized reserve in the RTO Zone in 2018 was 1,577.8 MW, including temporary increases to the requirement.

Tier 1 Synchronized Reserve Event Response

Tier 1 synchronized reserve is awarded credits when a synchronized reserve event occurs and it responds. These synchronized reserve event response credits for tier 1 response are independent of the tier 1 estimated, independent of the synchronized reserve market clearing price, and independent of the nonsynchronized reserve market clearing price. Credits are awarded to tier 1 synchronized reserve resources equal to the increase in MW output (or decrease in MW consumption for demand resources) for each five minute interval times the five minute LMP plus $50 per MW. 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 1 minute before and 1 minute after the event is declared. Total response credited to a resource is capped at 110 percent of estimated capability.

In 2018, tier 1 synchronized reserve spinning event response credits of $1,397,244 were paid for an average response of 620 MWh of tier 1 response at an average cost per MWh of $88.53, over 18 spinning event hours (Table 10-10).

Table 10-10 Tier 1 synchronized reserve event response costs: 2017 through 2018

		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
2017	Jan	1,252	$60,319	208	19,441	$221,157	1,143.6
2017	Feb	627	$56,103	209	1,293	$15,971	1,293.2
2017	Mar	769	$56,352	385	13,389	$191,084	956.4
2017	Apr	308	$17,559	149	11,680	$114,662	730.0
2017	May	389	$20,940	406	20,242	$214,816	1,065.4
2017	Jun	612	$28,681	312	7,563	$37,542	945.4
2017	Jul	0	$0	NA	6,631	$196,128	947.2
2017	Aug	0	$0	NA	3,926	$55,108	981.5
2017	Sep	1,043	$231,178	368	21,030	$948,664	808.9
2017	Oct	0	$0	NA	6,343	$48,539	704.8
2017	Nov	0	$0	NA	24,218	$153,842	931.4
2017	Dec	0	$0	NA	1,274	$295	637.0
2017		5,000	$471,132	291	137,030	$2,197,809	928.7
2018	Jan	6,082	$1,146,858	676	39,047	$2,394,953	1,259.6
2018	Feb	0	$0	NA	0	NA	NA
2018	Mar	0	$0	NA	9,906	$176,651	990.6
2018	Apr	287	$14,969	534	2,584	$48,880	143.6
2018	May	0	$0	NA	5,565	$191,459	347.8
2018	Jun	1,422	$71,416	1,422	3,545	$20,354	590.9
2018	Jul	1,512	$76,588	519	1,763	$4,888	440.7
2018	Aug	534	$26,716	534	1,380	$15,568	460.1
2018	Sep	1,027	$53,492	513	18,256	$478,289	553.2
2018	Oct	144	$7,205	144	60,896	$1,212,173	609.0
2018	Nov	0	$0	NA	12,278	$184,777	341.1
2018	Dec	0	$0	NA	770	$4,034	192.5
2018		11,008	$1,397,244	620	155,991	$4,732,025	539.0

Paying Tier 1 the Tier 2 Price

Tier 1 synchronized reserve has zero marginal cost and the corresponding competitive price for tier 1 synchronized reserves is also zero. However, the PJM rules artificially create a marginal cost of tier 1 when the price of nonsynchronized reserve is greater than zero and tier 1 is paid the tier 2 price. The PJM market solutions do not include that marginal cost and therefore do not solve for the efficient level of tier 1, tier 2 and nonsynchronized reserve in those cases. When called to respond to a spinning event, tier 1 is compensated at the Synchronized Energy Premium Price (Table 10-12). However, the shortage pricing tariff changes (October 1, 2012) modified the pricing of tier 1 so that tier 1 synchronized reserve is paid the tier 2 synchronized reserve market clearing price whenever the nonsynchronized reserve market clearing price rises above zero. The rationale for this change was and is unclear, but it has had a significant impact on the cost of tier 1 synchronized reserves (Table 10-11). The nonsynchronized reserve market clearing price was above $0.00 in 261 hours in 2018. For those 261 hours, tier 1 synchronized reserve resources were paid a weighted average synchronized reserve market clearing price of $19.88 per MWh and earned $4,732,025 in credits.

Table 10-11 Price of tier 1 synchronized reserve attributable to a nonsynchronized reserve price above zero: 2017 through 2018

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
2017	Jan	17	$11.38	19,441	$221,157	1,143.6
2017	Feb	1	$12.35	1,293	$15,971	1,293.2
2017	Mar	14	$14.27	13,389	$191,084	956.4
2017	Apr	16	$9.82	11,680	$114,662	730.0
2017	May	19	$10.61	20,242	$214,816	1,065.3
2017	Jun	8	$4.96	7,563	$37,542	945.4
2017	Jul	7	$29.58	6,631	$196,128	947.2
2017	Aug	4	$14.04	3,926	$55,108	981.5
2017	Sep	26	$45.11	21,030	$948,664	808.9
2017	Oct	9	$7.65	6,343	$48,539	704.8
2017	Nov	26	$6.35	24,218	$153,842	931.4
2017	Dec	2	$0.26	1,274	$295	637.0
2017		149	$13.87	137,030	$2,197,809	928.7
2018	Jan	31	$61.34	39,047	$2,394,953	1,259.6
2018	Feb	0	NA	NA	NA	NA
2018	Mar	10	$17.83	9,906	$176,651	990.6
2018	Apr	18	$18.91	2,584	$48,880	143.6
2018	May	16	$34.41	5,565	$191,459	347.8
2018	Jun	6	$5.74	3,545	$20,354	590.9
2018	Jul	4	$2.77	1,763	$4,888	440.7
2018	Aug	3	$11.27	1,380	$15,568	460.1
2018	Sep	33	$26.20	18,256	$478,289	553.2
2018	Oct	100	$19.91	60,896	$1,212,173	609.0
2018	Nov	36	$15.05	12,278	$184,777	341.1
2018	Dec	4	$5.24	770	$4,034	192.5
2018		261	$19.88	155,991	$4,732,026	539.0

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 2018, 67.2 percent of the DGP adjusted market solution's estimated tier 1 MW actually responded during synchronized reserve events of 10 minutes or longer while 32.8 percent of DGP adjusted tier 1 estimated MW did not respond during spinning events. For all tier 1 units, 76.1 percent of responded with 100 percent of their T1 capability and 9.9 percent of DGP estimated T1 units did not respond at all (zero percent). The remaining 14.0 percent responded with less than their full DGP estimated tier 1 MW. 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 2018, tier 1 synchronized reserve was paid $1,397,244 for responding to synchronized reserve events. During the same time period, tier 1 synchronized reserve was paid a windfall of $4,732,025 simply because the NSRMCP was greater than $0.00 in 261 hours during 2018. Table 10-10 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.[38] 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 average of five-minute LMPs during the event, rather than hourly integrated LMP, plus $50/MW, termed the synchronized energy premium price.

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

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

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

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

Table 10-13 Tier 1 compensation as recommended by MMU

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

Tier 1 Estimate Bias

PJM's market solution software allows the dispatcher to bias the tier 2 synchronized reserve solution by forcing the software to assume a different tier 1 MW value than it actually estimates. PJM no longer allows dispatchers to use tier 1 biasing in the intermediate and real-time SCED solutions, but tier 1 biasing is used in the hour ahead reserve market solution, ASO. Biasing means manually modifying (decreasing or increasing) the tier 1 synchronized reserve estimate of the market solution. This forces the market clearing engine to clear more or less tier 2 synchronized reserve and nonsynchronized reserve to satisfy the synchronized reserve and primary reserve requirements than would have cleared under the market solution. Negative biasing is the primary form of biasing actually used although sometimes the solution is biased positively (Table 10-14).

Table 10-14 RTO zone ASO tier 1 estimate biasing: 2017 through 2018

Year	Month	Number of Hours Biased Negatively	Average Negative Bias (MW)	Number of Hours Biased Positively	Average Positive Bias (MW)
2017	Jan	332	(987.7)	4	362.5
2017	Feb	194	(719.7)	0	NA
2017	Mar	354	(760.5)	3	200.0
2017	Apr	227	(697.1)	0	NA
2017	May	301	(1,000.3)	13	207.7
2017	Jun	253	(873.5)	0	NA
2017	Jul	244	(938.1)	0	NA
2017	Aug	179	(805.3)	2	1,250.0
2017	Sep	144	(682.6)	0	NA
2017	Oct	234	(807.7)	0	NA
2017	Nov	240	(739.7)	0	NA
2017	Dec	273	(920.0)	0	NA
2017		2,975	(827.7)	22	256.7
2018	Jan	209	(851.9)	0	NA
2018	Feb	85	(558.8)	0	NA
2018	Mar	72	(477.8)	0	NA
2018	Apr	232	(510.6)	0	NA
2018	May	114	(394.1)	4	237.5
2018	Jun	95	(534.5)	3	733.3
2018	Jul	46	(1,716.3)	2	1,600.0
2018	Aug	139	(591.4)	0	NA
2018	Sep	92	(886.2)	2	325.0
2018	Oct	84	(547.6)	0	NA
2018	Nov	40	(666.3)	3	566.7
2018	Dec	20	(1,112.5)	0	NA
2018		1,228	(737.3)	14	692.5

Tier 1 biasing is not mentioned in the PJM manuals and does not appear to be defined in any public document. PJM dispatchers use tier 1 biasing to compensate for uncertainty in short-term load forecasting and uncertainty about expected generator performance, which result in uncertainty about the accuracy of the market solution's tier 1 estimate. The purpose of tier 1 estimate biasing is to modify the demand for tier 2 and therefore the market results both for tier 2 synchronized reserve and for nonsynchronized reserve. Biasing the tier 1 estimate forces the market solution to clear more or less tier 2 and thus affects the price for tier 2 reserves. 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

38 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.

1 biasing and identify the rule based reasons for each instance of biasing.

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 a condensing mode and demand resources. Tier 2 synchronized reserve resources committed for a full hour by the hour ahead market solution are defined to be inflexible resources. 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 full 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.[39]

In 2018, the Mid Atlantic Dominion (MAD) Reserve Subzone averaged 7,286.8 MW of tier 2 synchronized reserve offers, and the RTO Reserve Zone averaged 26,161.0 MW of tier 2 synchronized reserve offers (Figure 10-10).

The supply of tier 2 synchronized reserve in 2018 was sufficient to cover the ASO hourly requirement net of tier 1 in both the RTO Reserve Zone and the MAD Reserve Subzone.

The largest portion of cleared tier 2 synchronized reserve in 2018 was from CTs, 54.0 percent (Figure 10-6). Although demand resources are limited to 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 many hours demand resources make up considerably more than 33 percent of the cleared Tier 2 MW. DR MW were 24.5 percent of cleared Tier 2 Synchronized Reserve Market

39 See PJM "Manual 11: Energy & Ancillary Services Market Operations," § 4.2.1 Synchronized Reserve Market Eligibility, Rev. 101 (Jan. 9, 2019).

in 2018, combined cycle units were 10.8 percent and hydro resources were 7.5 percent.

Figure 10-6 Cleared tier 2 synchronized reserve average MW per hour by unit type, RTO Zone: 2016 through 2018

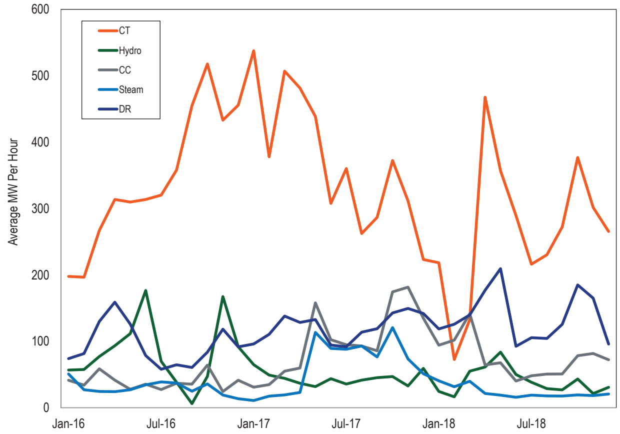
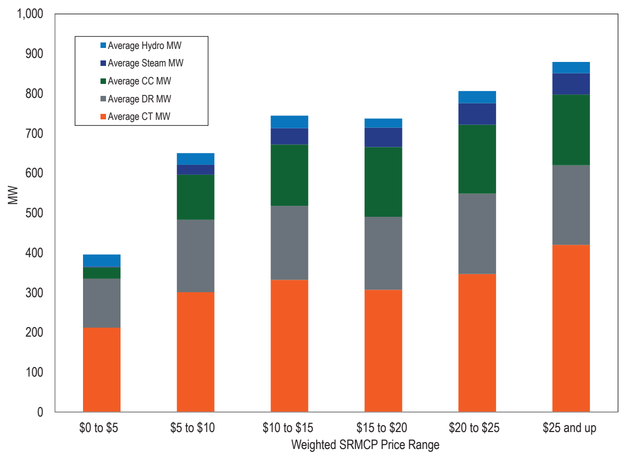


Figure 10-7 provides the average hourly cleared tier 2 MW by unit type by tier 2 clearing price range (SRMCP).

Figure 10-7 Average hourly tier 2 MW by unit type by weighted SRMCP range: January through December, 2018



Demand

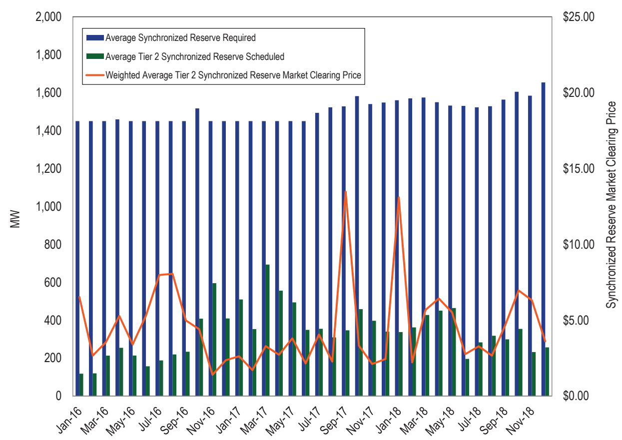
On July 12, 2017, PJM adopted a dynamic synchronized reserve requirement set equal to 100 percent of the largest contingency, determined by the hourly market solution (ASO), based on the forecasted dispatch. There are two circumstances in which PJM may alter the synchronized reserve requirement from its 100 percent of the largest contingency value. 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.[40]

In 2018, the average synchronized reserve requirement per interval in the RTO Zone was 1,577.8 MW and the average synchronized reserve requirement in the MAD Subzone was 1,564.3 MW. These averages include temporary increases to the synchronized reserve requirement.

The RTO Reserve Zone purchased an interval average of 598.4 MW of tier 2 synchronized reserves in 2018. Of this, an average of 352.4 MW cleared within the MAD Subzone.

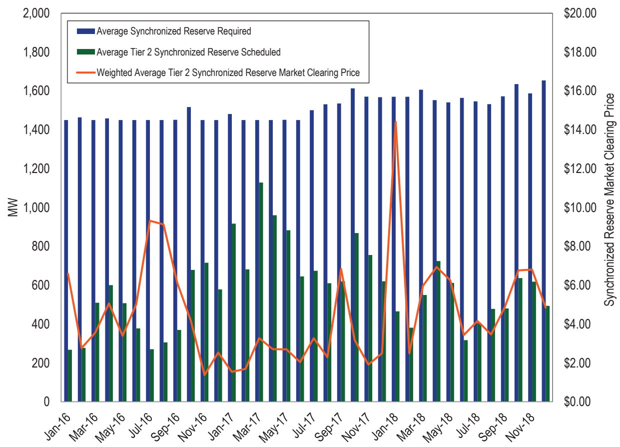
Figure 10-8 and Figure 10-9 show the average monthly synchronized reserve required and the average monthly tier 2 synchronized reserve MW scheduled (PJM scheduled plus self scheduled) from January 2016 through December 2018, for the RTO Reserve Zone and MAD Reserve Subzone. There were three intervals of shortage in 2018. There were 18 spinning events in 2018.

Figure 10-8 MAD hourly average tier 2 synchronized reserve scheduled MW: 2016 through 2018



40 PJM "Manual 11: Energy & Ancillary Services Market Operations," § 4.2.2 Synchronized Reserve Requirement Determination, Rev. 101 (Jan. 9, 2019).

Figure 10-9 RTO hourly average tier 2 synchronized reserve scheduled MW: 2016 through 2018



Market Concentration

The average HHI for tier 2 synchronized reserve cleared intervals in the Mid-Atlantic Dominion Subzone Tier 2 Synchronized Reserve Market in 2018 was 4255, which is defined as highly concentrated. In 68.4 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 2018 was 5007, which is defined as highly concentrated. In 84.0 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 2.5 percent of all tier 2 synchronized reserve in 2018. In the RTO Zone, flexible synchronized reserve assigned was 13.1 percent of all tier 2 synchronized reserve during the same period.

In 2018 22.3 percent of hours would have failed the three pivotal supplier test in the MAD Subzone in 2018 for all cleared hours of the inflexible Synchronized Reserve Market in the hour ahead market (Table 10-15) and 10.2 percent of hours would have failed the three pivotal supplier test in the RTO Zone during the same time period.

Table 10-15 Three pivotal supplier test results for the RTO Zone and MAD Subzone: 2017 through 2018

Year	Month	Mid Atlantic Dominion Reserve Subzone Pivotal Supplier Hours	RTO Reserve Zone Pivotal Supplier Hours
2017	Jan	79.3%	67.0%
2017	Feb	73.8%	57.6%
2017	Mar	72.6%	38.3%
2017	Apr	75.0%	51.0%
2017	May	70.9%	69.8%
2017	Jun	62.6%	84.9%
2017	Jul	57.3%	69.5%
2017	Aug	34.8%	71.0%
2017	Sep	53.7%	66.4%
2017	Oct	72.8%	38.5%
2017	Nov	71.2%	47.4%
2017	Dec	75.9%	45.1%
2017		66.7%	58.9%
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		22.3%	10.2%

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

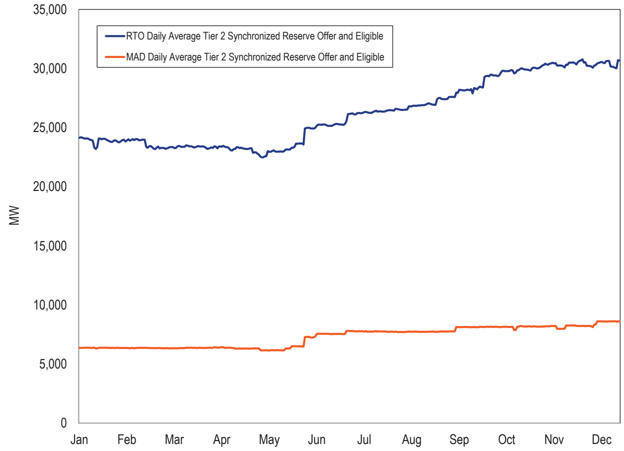
Offers

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.[41] 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.[42]

Figure 10-10 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 2018, the ratio of eligible tier 2 synchronized reserve to synchronized reserve required in the Mid-Atlantic Dominion Subzone was 4.8 averaged over all hours. For the RTO Synchronized Reserve Zone the ratio was 9.5.

PJM has a tier 2 synchronized reserve must offer requirement for all generation that is online, nonemergency, and physically able to operate with an output less than dictated by economic dispatch. Tier 2 synchronized reserve offers are made on a daily basis with hourly updates permitted. Daily offers can be changed as a result of maintenance status or physical limitations only and are required regardless of online/offline state.[43] The Tier 2 Synchronized Reserve Market is not actually 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 10-10). 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 10-10 Tier 2 synchronized reserve hourly offer and eligible volume (MW): 2018



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.[44]

Figure 10-11 shows average offer MW volume by market and unit type for the MAD Subzone and Figure 10-12 shows average offer MW volume by market and unit type for the RTO Zone.

41 See PJM "Manual 11: Energy & Ancillary Services Market Operations," § 4.2.1 Synchronized Reserve Market Eligibility Rev. 101 (Jan. 9, 2019).

42 See PJM "Manual 11: Energy & Ancillary Services Market Operations," § 4.2.1 Synchronized Reserve Market Eligibility Rev. 101 (Jan. 9, 2019).

43 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…").

44 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.

Figure 10-11 MAD average daily tier 2 synchronized reserve offer by unit type (MW): 2016 through 2018

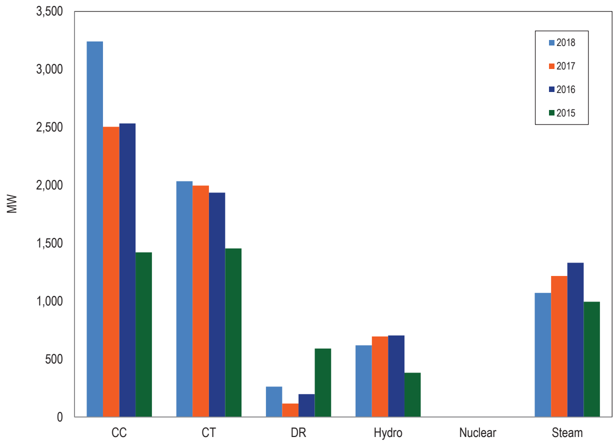
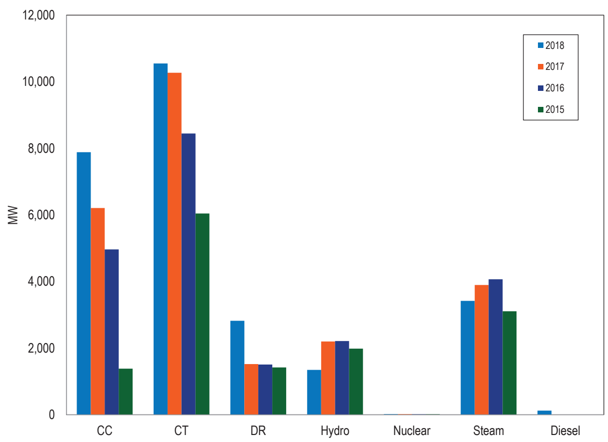


Figure 10-12 RTO Zone average daily tier 2 synchronized reserve offer by unit type (MW): January 2015 through December 2018



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 hours where total tier 1 MW synchronized reserve MW is less than the synchronized reserve requirement, PJM must clear a Tier 2 Synchronized Reserve Market for synchronized reserves.

In 2018, the Tier 2 Synchronized Reserve Market was cleared in 98.6 percent of hours. In the remaining hours and intervals there was enough tier 1 synchronized reserve or self-scheduled tier 2 reserve to cover the full requirement. For 2018 the MAD tier 2 market cleared an average of 331.5 MW at a weighted average clearing price of $5.39 compared to $3.28 in 2017 (Table 10-16).

In 2018, the Tier 2 Synchronized Reserve Market for the RTO Zone cleared an average of 513.5 MW at a weighted average price of $6.15 compared to $3.73 in 2017 (Table 10-17).

In 97.9 percent of cleared hours, the synchronized reserve market clearing price was the same for both the MAD Subzone and the RTO Zone. In the 2.1 percent of hours when the price diverged, the average clearing price was $25.60 in the MAD Subzone, and $14.00 in the RTO Zone.

Supply, performance, and demand are reflected in the price of synchronized reserve. (Figure 10-8 and Figure 10-9).

Table 10-16 MAD Subzone, average SRMCP and average scheduled, tier 1 estimated and demand response MW: 2017 through 2018

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)
2017	Jan	$2.25	356.1	981.6	96.0
2017	Feb	$1.75	233.2	1,111.6	110.5
2017	Mar	$2.87	453.3	767.4	140.5
2017	Apr	$2.80	362.4	896.9	128.4
2017	May	$3.26	376.8	1,164.6	126.2
2017	Jun	$2.12	379.6	1,373.0	91.3
2017	Jul	$3.24	353.3	1,391.9	89.4
2017	Aug	$2.05	226.9	1,438.3	110.2
2017	Sep	$11.56	339.7	1,419.2	113.1
2017	Oct	$2.98	348.1	1,364.2	138.8
2017	Nov	$2.08	245.9	1,392.1	144.3
2017	Dec	$2.38	160.0	1,411.5	139.8
2017		$3.28	319.6	1,226.0	119.0
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		$5.39	245.3	1,361.5	86.2

Table 10-17 RTO zone average SRMCP and average scheduled, tier 1 estimated and demand response MW: 2017 through 2018

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)
2017	Jan	$2.16	730.6	1,020.4	96.0
2017	Feb	$1.89	508.3	1,172.0	110.5
2017	Mar	$3.81	693.1	654.2	140.5
2017	Apr	$2.89	623.0	805.1	128.4
2017	May	$3.48	560.7	924.1	126.2
2017	Jun	$2.24	568.8	1,413.5	91.3
2017	Jul	$4.15	667.6	1,540.1	89.4
2017	Aug	$2.72	517.0	1,512.8	110.2
2017	Sep	$12.60	496.6	1,368.9	113.1
2017	Oct	$3.55	528.5	1,104.3	138.8
2017	Nov	$2.30	465.6	1,173.6	144.3
2017	Dec	$3.00	417.8	1,308.4	139.8
2017		$3.73	564.8	1,166.5	119.0
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		$6.15	392.2	1,728.7	121.3

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 one hundred percent, the more the market price reflects the full cost of tier 2 synchronized reserve. A price to cost ratio close to one hundred percent is an indicator of an efficient synchronized reserve market design.

In 2018, the price to cost (including self scheduled) ratio of the RTO Zone Tier 2 Synchronized Reserve Market averaged 53.2 percent (Table 10-18); the price to cost ratio of the MAD Subzone (Table 10-19) averaged 56.7 percent.

Table 10-18 RTO Zone tier 2 synchronized reserve MW, credits, price, and cost: 2017 through 2018

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	2017	Jan	471,027	$950,682	$2,312,698	$2.02	$6.93	29.1%
RTO Zone	2017	Feb	324,004	$551,835	$1,610,492	$1.70	$6.67	25.5%
RTO Zone	2017	Mar	539,157	$1,772,414	$2,800,782	$3.29	$8.48	38.8%
RTO Zone	2017	Apr	451,226	$1,230,490	$2,400,112	$2.73	$8.05	33.9%
RTO Zone	2017	May	421,808	$1,338,275	$1,954,082	$3.17	$7.81	40.6%
RTO Zone	2017	Jun	287,252	$611,155	$1,670,647	$2.13	$7.94	26.8%
RTO Zone	2017	Jul	320,314	$1,164,520	$2,420,822	$3.64	$11.19	32.5%
RTO Zone	2017	Aug	291,160	$667,933	$1,377,119	$2.29	$7.02	32.7%
RTO Zone	2017	Sep	300,167	$3,021,056	$2,096,255	$10.06	$17.05	59.0%
RTO Zone	2017	Oct	403,226	$1,331,871	$2,601,535	$3.30	$9.75	33.9%
RTO Zone	2017	Nov	345,630	$707,061	$1,695,179	$2.05	$6.95	29.4%
RTO Zone	2017	Dec	346,865	$868,623	$2,027,652	$2.50	$8.35	30.0%
RTO Zone	2017		4,501,834	$14,215,915	$24,967,375	$3.24	$8.85	36.6%
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	273,007	$1,258,968	$963,595	$4.61	$8.14	56.6%
RTO Zone	2018		3,684,810	$23,688,299	$20,306,909	$6.15	$11.59	53.1%

Table 10-19 MAD subzone tier 2 synchronized reserve MW, credits, price, and cost: 2017 through 2018

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	2017	Jan	242,160	$1,821,697	$2.25	$7.52	29.9%
MAD Subzone	2017	Feb	137,103	$1,354,202	$1.75	$9.88	17.7%
MAD Subzone	2017	Mar	328,192	$2,611,457	$2.87	$7.96	36.1%
MAD Subzone	2017	Apr	229,057	$1,780,751	$2.80	$7.77	36.0%
MAD Subzone	2017	May	231,704	$1,960,763	$3.26	$8.46	38.5%
MAD Subzone	2017	Jun	170,078	$1,586,215	$2.12	$9.33	22.7%
MAD Subzone	2017	Jul	193,231	$2,367,906	$3.24	$12.25	26.4%
MAD Subzone	2017	Aug	157,259	$1,269,006	$2.05	$8.07	25.4%
MAD Subzone	2017	Sep	172,568	$3,631,598	$11.56	$21.04	54.9%
MAD Subzone	2017	Oct	217,186	$2,703,322	$2.98	$12.45	23.9%
MAD Subzone	2017	Nov	157,391	$1,350,024	$2.08	$8.58	24.3%
MAD Subzone	2017	Dec	138,151	$1,296,784	$2.25	$9.39	24.0%
MAD Subzone	2017		2,374,080	$23,733,724	$3.27	$10.23	32.0%
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%

Compliance

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.[45] 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.[46] 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 2015, there were 21 spinning events of which seven were 10 minutes or longer. In 2016, there were 16 spinning events of which six were 10 minutes or longer. In 2017, there were 16 spinning events, six of which were 10 minutes or longer. In 2018 there were 18 spinning events, of which seven were 10 minutes or longer. 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 (IPI) 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

45 See *2011 State of the Market Report for PJM*, Vol. 2, Section 9, "Ancillary Services," at 250.
46 See PJM "Manual 11: Energy & Ancillary Services Market Operations," § 4.2.10 Settlements Rev. 101 (Jan. 9, 2019).

aggregate their response from over responders to offset under responders during an event.[47]

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 six 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 10-20). The analysis covered the period from the April 1, 2018, introduction of five minute pricing, 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 10-20 Tier 2 synchronized reserve market penalties: 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 event greater 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.[48] 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.

There were six synchronized reserve events of 10 minutes or longer in 2017. For those six events, 12.4 percent of all scheduled tier 2 synchronized reserve MW were not delivered and were penalized (Table 10-21). In 2018, there were seven synchronized reserve events of 10 minutes or longer. Tier 2 synchronized reserve response rate was 74.2 percent.

47 See PJM "Manual 28: Operating Agreement Accounting,"§ 6.3 Charges for Synchronized Reserve, Rev. 81 (Oct. 25, 2018).

48 See *id.* at 98.

Table 10-21 Synchronized reserve events 10 minutes or longer, tier 2 response compliance, RTO Reserve Zone: 2017 through 2018

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
Mar 23, 2017 06:48	24	926.8	549.6	742.8	559.1	183.7	59.3%	75.3%
Apr 8, 2017 11:53	10	1,222.6	827.2	879.3	828.7	50.6	67.7%	94.2%
May 8, 2017 04:18	10	1,325.6	976.3	335.1	298.5	36.6	73.6%	89.1%
Jun 8, 2017 03:39	10	974.4	726.7	575.7	522.4	53.3	74.6%	90.7%
Sep 4, 2017 20:03	15	476.3	68.1	601.0	563.8	37.2	14.3%	93.8%
Sep 21, 2017 14:15	16	305.8	217.4	1,253.9	1,037.3	216.6	71.1%	82.7%
2017 Average	14	871.9	560.9	731.3	635.0	96.3	60.1%	87.6%
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	591.2	464.6	372.5	92.1	55.6%	80.2%
Jun 30, 2018 09:46	11	2,710.1	2,086.2	71.6	56.8	14.8	77.0%	79.3%
Jul 10, 2018 15:45	12	784.3	524.9	494.6	308.8	185.8	66.9%	62.4%
Aug 12, 2018 11:06	11	1,824.5	1,390.4	274.5	229.8	44.7	76.2%	83.7%
Sep 30, 2018 11:29	11	1,430.9	976.4	231.2	216.9	14.3	68.2%	93.8%
Oct 30, 2018 06:40	11	239.7	215.9	607.7	431.5	176.2	90.1%	71.0%
2018 Average	11	1,421.4	899.3	322.4	239.1	83.3	63.3%	74.2%

History of Synchronized Reserve Events

Synchronized reserve is designed to provide relief for disturbances.[49] [50] 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 dispatchers have used synchronized reserve as a source of energy to provide relief from low ACE. There were five low ACE events in 2017, on January 12, 2017 for 8 minutes, February 13, 2017 for 7 minutes, March 23, 2017 for 24 minutes, June 20, 2017 for 9 minutes, and September 21, 2017 for 16 minutes. There was one low ACE event in 2018. PJM conducted an Apparent Cause Analysis (ACA) of the 13 minute event of July 10, 2018, without reaching a definitive cause. The ACA cited several factors including a frequency drop with an unknown cause and pseudo-tied 800MW unit trip.

The risk of using synchronized reserves for energy or any other non-disturbance 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 December 31, 2018, PJM experienced 226 synchronized reserve events (Table 10-22), approximately 2.1 events per month. During this period, synchronized reserve events had an average duration of 11.9 minutes.

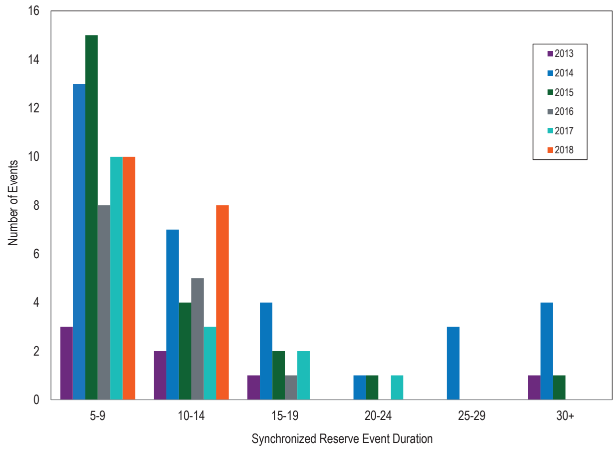
49 *2013 State of the Market Report for PJM*, Appendix F – PJM's DCS Performance, at 451–452.
50 See PJM "Manual 12: Balancing Operations," § 4.1.2 Loading Reserves, Rev. 38 (April 20, 2018).

Table 10-22 Synchronized reserve events: 2010 through 2018

Effective Time	Region	Duration (Minutes)	Effective Time	Region	Duration (Minutes)	Effective Time	Region	Duration (Minutes)	Effective Time	Region	Duration (Minutes)	Effective Time	Region	Duration (Minutes)
FEB-18-2010 13:27	Mid-Atlantic	19	JAN-11-2011 15:10	Mid-Atlantic	6	JAN-03-2012 16:51	RFC	9	JAN-22-2013 08:34	RTO	8	JAN-06-2014 22:01	RTO	68
MAR-18-2010 11:02	RFC	27	FEB-02-2011 01:21	RFC	5	JAN-06-2012 23:25	RFC	8	JAN-25-2013 15:01	RTO	19	JAN-07-2014 02:20	RTO	25
MAR-23-2010 20:14	RFC	13	FEB-08-2011 22:41	Mid-Atlantic	11	JAN-23-2012 15:02	Mid-Atlantic	8	FEB-09-2013 22:55	RTO	10	JAN-07-2014 04:18	RTO	34
APR-11-2010 13:12	RFC	9	FEB-09-2011 11:40	Mid-Atlantic	16	MAR-02-2012 19:54	RFC	9	FEB-17-2013 23:10	RTO	13	JAN-07-2014 11:27	RTO	11
APR-28-2010 15:09	Mid-Atlantic	8	FEB-13-2011 15:35	Mid-Atlantic	14	MAR-08-2012 17:04	RFC	6	APR-17-2013 01:11	RTO	11	JAN-07-2014 13:20	RTO	41
MAY-11-2010 19:57	Mid-Atlantic	9	FEB-24-2011 11:35	Mid-Atlantic	14	MAR-19-2012 10:14	RFC	10	APR-17-2013 20:01	RTO	9	JAN-10-2014 16:46	RTO	12
MAY-15-2010 03:03	RFC	6	FEB-25-2011 14:12	RFC	10	APR-16-2012 00:20	Mid-Atlantic	9	MAY-07-2013 17:33	RTO	8	JAN-21-2014 18:52	RTO	6
MAY-28-2010 04:06	Mid-Atlantic	5	MAR-30-2011 19:13	RFC	12	APR-16-2012 11:18	RFC	8	JUN-05-2013 18:54	RTO	20	JAN-22-2014 02:26	RTO	7
JUN-15-2010 00:46	RFC	34	APR-02-2011 13:13	Mid-Atlantic	11	APR-19-2012 11:54	RFC	16	JUN-08-2013 15:19	RTO	9	JAN-22-2014 22:54	RTO	8
JUN-19-2010 23:49	Mid-Atlantic	9	APR-11-2011 00:28	RFC	6	APR-20-2012 11:08	Mid-Atlantic	7	JUN-12-2013 17:35	RTO	10	JAN-25-2014 05:22	RTO	10
JUN-24-2010 00:56	RFC	15	APR-16-2011 22:51	RFC	9	JUN-20-2012 13:35	RFC	7	JUN-30-2013 01:22	RTO	10	JAN-26-2014 17:11	RTO	6
JUN-27-2010 19:33	Mid-Atlantic	15	APR-21-2011 20:02	Mid-Atlantic	6	JUN-26-2012 17:51	RFC	7	JUL-03-2013 20:40	RTO	13	JAN-31-2014 15:05	RTO	13
JUL-07-2010 15:20	RFC	8	APR-27-2011 01:22	RFC	8	JUL-23-2012 21:45	RFC	18	JUL-15-2013 18:43	RTO	29	FEB-02-2014 14:03	Dominion	8
JUL-16-2010 20:45	Mid-Atlantic	19	MAY-02-2011 00:05	Mid-Atlantic	21	AUG-03-2012 12:44	RFC	10	JUL-28-2013 14:20	RTO	10	FEB-08-2014 06:05	Dominion	18
AUG-11-2010 19:09	RFC	17	MAY-12-2011 19:39	RFC	9	SEP-08-2012 04:34	RFC	12	SEP-10-2013 19:48	RTO	68	FEB-22-2014 23:05	RTO	7
AUG-13-2010 23:19	RFC	6	MAY-26-2011 17:17	Mid-Atlantic	20	SEP-27-2012 17:19	Mid-Atlantic	7	OCT-28-2013 10:44	RTO	33	MAR-01-2014 05:18	RTO	26
AUG-16-2010 07:08	RFC	17	MAY-27-2011 12:51	RFC	6	OCT-17-2012 10:48	RTO	10	DEC-01-2013 11:17	RTO	9	MAR-05-2014 21:25	RTO	8
AUG-16-2010 19:39	Mid-Atlantic	11	MAY-29-2011 09:04	RFC	7	OCT-23-2012 22:29	RTO	19	DEC-07-2013 19:44	RTO	7	MAR-13-2014 20:39	RTO	8
SEP-15-2010 11:20	RFC	13	MAY-31-2011 16:36	RFC	27	OCT-30-2012 05:12	RTO	14				MAR-27-2014 10:37	RTO	56
SEP-22-2010 15:28	Mid-Atlantic	24	JUN-03-2011 14:23	RFC	7	NOV-25-2012 16:32	RTO	12				APR-14-2014 01:16	RTO	10
OCT-05-2010 17:20	RFC	10	JUN-06-2011 22:02	Mid-Atlantic	9	DEC-16-2012 07:01	RTO	9				APR-25-2014 17:33	RTO	6
OCT-16-2010 03:22	Mid-Atlantic	10	JUN-23-2011 23:26	RFC	8	DEC-21-2012 05:51	RTO	7				MAY-01-2014 14:18	RTO	13
OCT-16-2010 03:25	RFCNonMA	7	JUN-26-2011 22:03	Mid-Atlantic	10	DEC-21-2012 10:29	RTO	5				MAY-03-2014 17:11	RTO	13
OCT-27-2010 10:35	RFC	7	JUL-10-2011 11:20	RFC	10							MAY-14-2014 01:36	RTO	5
OCT-27-2010 12:50	Mid-Atlantic	10	JUL-28-2011 18:49	RFC	12							JUL-08-2014 03:07	RTO	9
NOV-26-2010 14:24	RFC	13	AUG-02-2011 01:08	RFC	6							JUL-25-2014 19:19	RTO	7
NOV-27-2010 11:34	RFC	8	AUG-18-2011 06:45	Mid-Atlantic	6							SEP-06-2014 13:32	RTO	18
DEC-08-2010 01:19	RFC	11	AUG-19-2011 14:49	RFC	5							SEP-20-2014 23:42	RTO	14
DEC-09-2010 20:07	RFC	5	AUG-23-2011 17:52	RFC	7							SEP-29-2014 10:08	RTO	15
DEC-14-2010 12:02	Mid-Atlantic	24	SEP-24-2011 15:48	RFC	8							OCT-20-2014 06:35	RTO	15
DEC-16-2010 18:40	Mid-Atlantic	20	SEP-27-2011 14:20	RFC	7							OCT-23-2014 11:03	RTO	27
DEC-17-2010 22:09	Mid-Atlantic	6	SEP-27-2011 16:47	RFC	9							NOV-01-2014 06:50	RTO	9
DEC-29-2010 19:01	Mid-Atlantic	15	OCT-30-2011 22:39	Mid-Atlantic	10							NOV-08-2014 02:08	RTO	8
			DEC-15-2011 14:35	Mid-Atlantic	8							NOV-22-2014 05:27	RTO	21
			DEC-21-2011 14:26	RFC	18							NOV-22-2014 08:19	RTO	10
												DEC-10-2014 18:58	RTO	8
												DEC-31-2014 21:42	RTO	12

Effective Time	Region	Duration (Minutes)	Effective Time	Region	Duration (Minutes)	Effective Time	Region	Duration (Minutes)	Effective Time	Region	Duration (Minutes)
JAN-07-2015 22:36	RTO	8	JAN-18-2016 17:58	RTO	12	JAN-08-2017 03:21	RTO	7	JAN-01-2018 02:41	RTO	7
FEB-24-2015 02:51	RTO	5	FEB-08-2016 15:05	RTO	10	JAN-09-2017 19:24	RTO	9	JAN-03-2018 03:00	RTO	13
FEB-26-2015 15:20	RTO	6	FEB-28-2016 18:29	RTO	8	JAN-10-2017 13:05	MAD	9	JAN-07-2018 14:15	RTO	9
MAR-03-2015 17:02	RTO	11	APR-14-2016 20:09	RTO	10	JAN-15-2017 20:13	RTO	8	APR-12-2018 13:28	RTO	10
MAR-16-2015 10:25	RTO	24	MAY-11-2016 15:55	RTO	6	JAN-23-2017 09:08	RTO	7	JUN-04-2018 10:22	RTO	6
MAR-17-2015 23:34	RTO	17	JUN-01-2016 09:01	RTO	5	FEB-13-2017 18:30	RTO	7	JUN-29-2018 15:21	RTO	9
MAR-23-2015 23:44	RTO	15	JUL-06-2016 00:40	RTO	5	FEB-14-2017 00:11	RTO	6	JUN-30-2018 09:46	RTO	11
APR-06-2015 14:23	RTO	8	JUL-28-2016 13:28	RTO	15	FEB-15-2017 06:37	RTO	6	JUL-04-2018 10:56	RTO	7
APR-07-2015 17:11	RTO	31	AUG-31-2016 19:29	RTO	8	MAR-23-2017 06:48	RTO	24	JUL-10-2018 15:45	RTO	13
APR-15-2015 08:14	RTO	8	SEP-09-2016 19:11	RTO	6	APR-08-2017 11:53	RTO	10	JUL-23-2018 09:02	RTO	8
APR-25-2015 03:21	RTO	9	SEP-11-2016 19:30	RTO	9	MAY-08-2017 04:18	RTO	10	JUL-23-2018 15:43	RTO	6
JUL-30-2015 14:04	RTO	10	OCT-12-2016 08:21	RTO	5	JUN-08-2017 03:39	RTO	10	JUL-24-2018 16:17	RTO	7
AUG-05-2015 19:47	RTO	7	OCT-12-2016 14:40	RTO	7	JUN-20-2017 05:38	RTO	9	AUG-12-2018 11:06	RTO	11
AUG-19-2015 16:47	RTO	9	NOV-04-2016 17:13	RTO	11	SEP-04-2017 20:18	MAD	15	SEP-13-2018 09:47	RTO	7
SEP-05-2015 01:16	RTO	7	DEC-03-2016 00:11	RTO	7	SEP-07-2017 09:16	RTO	9	SEP-14-2018 13:24	RTO	7
SEP-10-2015 10:12	RTO	8	DEC-31-2016 05:10	RTO	12	SEP-21-2017 14:15	RTO	16	SEP-26-2018 19:08	RTO	8
SEP-29-2015 00:58	Mid-Atlantic	11							SEP-30-2018 11:29	RTO	11
NOV-12-2015 16:42	RTO	8							OCT-30-2018 10:40	RTO	11
NOV-21-2015 17:17	RTO	8									
DEC-04-2015 22:41	RTO	7									
DEC-24-2015 17:42	RTO	8									

Figure 10-13 Synchronized reserve events duration distribution curve: 2013 through 2018



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

Prior to July 12, 2017, PJM specified that 2,175 MW of primary reserve must be available in the Mid-Atlantic Dominion Reserve Subzone, of which 1,450 MW must be synchronized reserve (Figure 10-2), and that 2,175 MW of primary reserve must be available in the RTO Reserve Zone of which 1,450 MW must be synchronized reserve (Figure 10-3). As of July 12, 2017, the largest contingency is calculated dynamically in every synchronized and nonsynchronized reserve market solution and the primary requirement is set equal to 150 percent of the largest expected contingency within the upcoming hour. The balance of primary reserve can be made up by the most economic combination of synchronized and nonsynchronized reserve. 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.[51]

The average hourly demand in the RTO Zone for primary reserve in 2018 was 2,267.8 MW. The average five minute interval demand in the MAD Subzone for primary reserve in 2018 was 2,247.3 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 hour ahead market solution considers the MW 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 offer price of nonsynchronized is the unit's opportunity cost of providing reserves.

51 See PJM "Manual 11: Energy and Ancillary Services Market Operations," § 4.2.2 Synchronized Reserve Requirement Determination, Rev. 101 (Jan. 9, 2019).

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 can start in 10 minutes or less, and diesels.[52] In 2018, an average of 1,968.8 MW of nonsynchronized reserve was scheduled hourly out of 3,683.2 eligible MW as part of the primary reserve requirement in the RTO Zone.

In 2018, CTs provided 78.0 percent of scheduled nonsynchronized reserve and hydro resources provided 21.5 percent. Less than one percent of cleared nonsynchronized reserve was provided by diesels.

Market Concentration

The supply of nonsynchronized reserves in the Mid-Atlantic Dominion Subzone and the RTO Zone was highly concentrated in 2018.

Table 10-23 Nonsynchronized reserve market HHIs: 2017 through 2018

Year	Month	MAD HHI	RTO HHI
2017	Jan	5538	5525
2017	Feb	5404	5402
2017	Mar	5679	5653
2017	Apr	4858	4847
2017	May	4213	4209
2017	Jun	3922	3922
2017	Jul	4106	4105
2017	Aug	4084	4084
2017	Sep	3806	3802
2017	Oct	3391	3391
2017	Nov	3125	3123
2017	Dec	2841	2841
2017		4247	4242
2018	Jan	3658	3651
2018	Feb	4063	4063
2018	Mar	4188	4188
2018	Apr	5248	5227
2018	May	3746	3706
2018	Jun	3815	3815
2018	Jul	4499	4499
2018	Aug	6310	6310
2018	Sep	4841	4804
2018	Oct	4151	4032
2018	Nov	4370	4340
2018	Dec	4675	4675
2018		4464	4443

Table 10-24 Nonsynchronized reserve market pivotal supplier test: 2017 through 2018

Year	Month	Non Synchronized Reserve Three Pivotal Supplier Hours
2017	Jan	32.2%
2017	Feb	31.1%
2017	Mar	38.1%
2017	Apr	38.1%
2017	May	52.3%
2017	Jun	60.4%
2017	Jul	55.9%
2017	Aug	57.1%
2017	Sep	70.8%
2017	Oct	82.1%
2017	Nov	57.1%
2017	Dec	92.5%
2017	Average	55.6%
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%

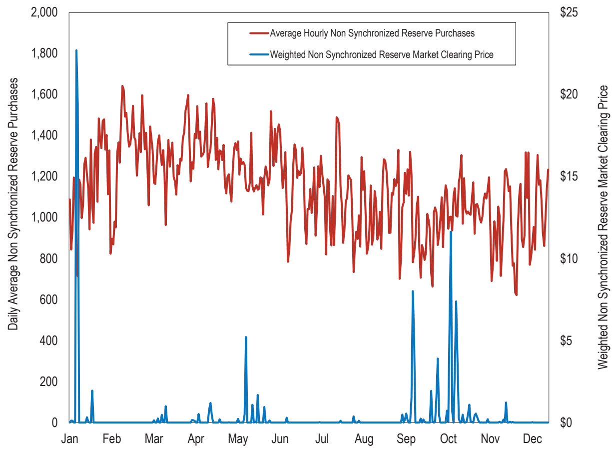
52 See PJM "Manual 11: Energy & Ancillary Services Market Operations," § 4b.2 Non-Synchronized Reserve Market Business Rules, Rev. 101 (Jan. 9, 2019).

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 10-14 shows the daily average nonsynchronized reserve market clearing price and average scheduled MW for the RTO Zone. In 2018, the average nonsynchronized market clearing price was $0.29 per MW. The hourly average nonsynchronized reserve scheduled was 1,113.3 MW. For all of 2018, the market cleared at a price greater than $0 in 220 hours. The maximum hourly clearing price was $404.60 per MW on January 7, 2018.

Figure 10-14 Daily average RTO Zone nonsynchronized reserve market clearing price and MW purchased: 2018



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 rises above the generator's cost at economic minimum, then an LOC is paid.[53]

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

In 2018, the price to cost ratio for the RTO Zone was 17.8 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 less than one percent of hours.

53 See PJM "Manual 11: Energy & Ancillary Services Market Operations," § 2.16 Minimum Capacity Emergency in Day-ahead Market, Rev. 101 (Jan. 9, 2019).

Table 10-25 RTO zone nonsynchronized reserve MW, charges, price, and cost: 2017 through 2018

Market	Year	Month	Total Nonsynchronized Reserve MW	Total Nonsynchronized Reserve Charges	Weighted Nonsynchronized Reserve Market Price	Nonsynchronized Reserve Cost	Price/Cost Ratio
RTO Zone	2017	Jan	585,294	$384,707	$0.15	$0.66	23.0%
RTO Zone	2017	Feb	599,301	$171,893	$0.00	$0.29	1.2%
RTO Zone	2017	Mar	548,021	$382,743	$0.14	$0.70	20.2%
RTO Zone	2017	Apr	653,581	$357,047	$0.13	$0.55	24.4%
RTO Zone	2017	May	796,190	$508,149	$0.16	$0.64	25.4%
RTO Zone	2017	Jun	841,672	$351,251	$0.03	$0.42	7.4%
RTO Zone	2017	Jul	745,694	$876,884	$0.13	$1.18	11.1%
RTO Zone	2017	Aug	874,602	$548,271	$0.01	$0.63	1.4%
RTO Zone	2017	Sep	867,103	$1,229,492	$0.73	$1.42	51.6%
RTO Zone	2017	Oct	929,944	$713,508	$0.02	$0.77	2.5%
RTO Zone	2017	Nov	850,863	$727,515	$0.05	$0.86	5.5%
RTO Zone	2017	Dec	936,590	$772,028	$0.00	$0.82	0.1%
RTO Zone	2017	Total	9,228,856	$7,023,487	$0.13	$0.76	17.1%
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%

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.[54]

Market Structure

Supply

DASR is offered by both generation and demand resources. 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 2018 the average available hourly DASR was 39,599.8 MW, an 8.3 percent increase from 2017. The DASR hourly MW purchased averaged 5,689.9 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.[55] The intent of this proposal is to limit cleared DASR resources to those resources actually capable of providing reserves in the real-time market. Owners of excluded resources may request an exemption from their default noneligibility.

Of the 5,689.9 MW average hourly DASR cleared in 2018, 75.3 percent was from CTs, 7.3 percent was from steam, 12.3 percent was from hydro, and 4.6 percent was CCs. Load response resources which are registered in PJM's Economic Load Response and are dispatchable by PJM are eligible to provide DASR. In 2018, four demand resources offered into the DASR Market.

Demand

Secondary reserve (30 minute reserve) requirements are determined by PJM for each reliability region. In the ReliabilityFirst (RFC) region, secondary reserve requirements are calculated based on historical under forecasted load rates and generator forced outage

54 See PJM "Manual 11: Energy & Ancillary Services Market Operations," § 10.5 Aggregation for Economic and Emergency Demand Resources, Rev. 101 (Jan. 9, 2019).

55 See PJM "Manual 11: Energy & Ancillary Services Market Operations," § 11.2.2 Day-Ahead Scheduling Reserve Market Eligibility, Rev. 101 (Jan. 9, 2019).

rates.[56] 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 will be 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.

Effective March 1, 2015, the DASR requirement can be increased by PJM dispatch under conditions of "hot weather or cold weather alert or max emergency generation alert or other escalating emergency."[57] The amount of additional DASR MW that may be required is the Adjusted Fixed Demand (AFD) determined by a Seasonal Conditional Demand (SCD) factor.[58] 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. PJM Dispatch may also schedule additional Day-Ahead Scheduling Reserves as deemed necessary for conservative operations.59 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.60 The result is substantial discretion for PJM to increase the demand for DASR under a variety of circumstances. PJM invoked adjusted fixed demand on 50 days during 2018. The 60 hours with highest DASR market clearing price were during days when adjusted fixed demand was invoked.

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

56 See PJM "Manual 13: Emergency Operations," § 2.2 Reserve Requirements, Rev. 68 (Jan. 1, 2019)

57 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>.

58 See PJM "Manual 11: Energy & Ancillary Services Market Operations," § 11.2.1 Day-Ahead Scheduling Reserve Market Requirement. Rev. 101 (Jan. 9, 2019).

59 See PJM "Manual 11: Energy & Ancillary Services Market Operations," § 11.2.1 Day-Ahead Scheduling Reserve Market Reserve Requirement, Rev. 101 (Jan. 9, 2019).

60 See PJM "Manual 13: Emergency Operations," § 3.2 Conservative Operations, Rev. 68, (Jan. 1, 2019).

Market Concentration

DASR market three pivotal supplier test results are provided in Table 10-26.

Table 10-26 DASR market three pivotal supplier test results and number of hours with DASRMCP above $0: 2017 through 2018

Year	Month	Number of Hours When DASRMCP > $0	Percent of Hours Pivotal
2017	Jan	93	16.1%
2017	Feb	49	2.0%
2017	Mar	359	2.5%
2017	Apr	402	9.5%
2017	May	250	44.0%
2017	Jun	242	37.8%
2017	Jul	341	36.8%
2017	Aug	165	8.3%
2017	Sep	179	12.8%
2017	Oct	154	0.7%
2017	Nov	92	3.2%
2017	Dec	72	17.1%
2017	Average	200	15.9%
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%

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.[61] 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 2018, 38.8 percent of generation units offered DASR at a daily price above $0.00, compared to 39.2 percent in 2017. In 2018, 15.8 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.

61 See PJM "Manual 11: Energy & Ancillary Services Market Operations," § 11.2.2 Day-Ahead Scheduling Reserve Market Eligibility, Rev. 101 (Jan. 9, 2019).

Market Performance

In 2018, the DASR Market cleared at a price above $0 in 17.8 percent of hours. The weighted average DASR price for all hours when the DASRMCP was above $0.00 was $3.49. In 2017, the weighted average DASR price for all hours when the DASRMCP was above $0.00 was $2.99. In 2018 the average cleared MW in all hours was 5,690.1 MW. The average cleared MW in all hours when the DASRMCP was above $0.00 was 6,976.2 MW. The highest DASR price was $66.04 on July 2, 2018.

The introduction of Adjusted Fixed Demand (AFD) on March 1, 2015, created a bifurcated market (Table 10-28). 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. The difference in market clearing price, MW cleared, obligation incurred, and charges to PJM load are substantial (Table 10-27).

Table 10-27 Impact of Adjusted Fixed Demand on DASR prices and demand: 2018

Metric	Year	Number Hours	Weighted Day-Ahead Scheduling Reserve Market Clearing Price (DASRMCP)	Average Hourly Total DASR MW
All Hours	Jan-Dec 2018	8,760	$0.39	5,571.2
All Hours when DASRMCP > $0	Jan-Dec 2018	1,553	$2.22	7,086.9
All Hours when AFD is used	Jan-Dec 2018	598	$4.88	9,977.9

While the new rules allow PJM dispatch 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 dispatch 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.

Table 10-28 DASR Market, regular hours vs. adjusted fixed demand hours: 2017 through 2018

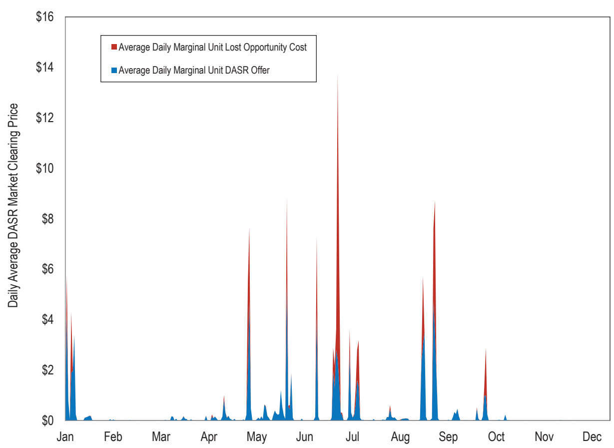
		Number of Hours DASRMCP>$0		Weighted DASRMCP		Average PJM Load MW		Hourly Average Cleared DASR MW		Average Hourly DASR Credits	
Year	Month	Normal Hour	AFD Hour	Normal Hour	AFD Hour	Normal Hour	AFD Hour	Normal Hour	AFD Hour	Normal Hour	AFD Hour
2017	Jan	93	0	$0.02		106,095		4,386		$91	
2017	Feb	49	0	$0.02		96,628		4,444		$92	
2017	Mar	359	0	$0.08		91,182		4,092		$329	
2017	Apr	402	0	$0.04		80,834		3,828		$159	
2017	May	250	48	$0.07	$18.13	85,581	98,184	4,004	10,727	$280	$194,491
2017	Jun	242	73	$0.18	$6.63	108,482	116,172	5,099	11,713	$907	$77,542
2017	Jul	341	115	$0.29	$6.41	114,832	117,568	5,288	10,669	$1,551	$68,397
2017	Aug	165	12	$0.42	$1.23	114,916	125,601	5,515	10,585	$2,318	$12,980
2017	Sep	179	22	$1.17	$40.30	105,850	104,097	5,111	11,652	$5,960	$466,893
2017	Oct	154	0	$0.33		89,402		4,404		$1,446	
2017	Nov	92	0	$0.20		91,098		4,950		$972	
2017	Dec	72	0	$0.27		110,878		5,675		$1,542	
2017		2,398	270	$0.26	$14.54	100,489	112,324	4,641	11,317	$1,298	$164,060
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

The implementation of AFD in 270 hours of 2017 and 598 hours of 2018 significantly increased the cost of DASR as a result of increases in DASR MW cleared and corresponding increases in the DASR clearing prices (Table 10-28).

Table 10-29 DASR Market all hours of DASR market clearing price greater than $0: 2017 through 2018

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 Charges
2017	Jan	93	$0.02	106,095	407,922	0	$8,426
2017	Feb	49	$0.02	96,628	217,737	0	$4,487
2017	Mar	359	$0.08	91,182	1,468,921	0	$117,995
2017	Apr	402	$0.04	80,834	1,539,010	0	$63,852
2017	May	250	$6.76	87,849	1,303,480	246,420	$8,809,449
2017	Jun	242	$3.20	110,611	1,677,956	383,822	$5,365,628
2017	Jul	341	$3.39	115,755	2,422,053	516,238	$8,216,211
2017	Aug	165	$0.53	115,693	970,853	49,896	$510,353
2017	Sep	179	$10.59	105,635	1,058,754	136,480	$11,207,356
2017	Oct	154	$0.33	89,402	678,175		$222,717
2017	Nov	92	$0.20	91,098	455,371		$89,460
2017	Dec	72	$0.27	110,878	408,569		$111,029
2017	Average	200	$2.12	100,138	1,050,733	148,095	$2,893,914
2017	Total	2,398			12,608,800	1,332,856	$34,726,963
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			45,270,434	2,312,294	$21,006,782

Figure 10-15 Daily average components of DASR clearing price ($/MW), marginal unit offer and LOC: 2018



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 (Figure 10-15). DASR prices had several severe peaks in January. PJM dispatch invoked 120 hours of Seasonal Conditional Demand, resulting in relatively high prices, during a period of cold weather from December 28, 2017, through January 7, 2018. The May 29, 2018 high price occurred during a hot weather alert and on the same day as the Twin Branch load shed event in AEP. The highest prices were $50.00 on January 8, 2018, and May 29, 2018.

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.[62] 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).

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

Regulation performance scores (0.0 to 1.0) measure the response of a regulating resource to its assigned regulation signal (RegA or RegD) every 10 seconds by measuring: delay, the time delay of the regulation response to a change in the regulation signal; correlation, the correlation between the regulating resource output and the regulation signal; and precision, the difference between the regulation response and the regulation requested.[63] Performance scores are reported on an hourly basis for each resource.

Figure 10-16 and Figure 10-17 show the average performance score by resource type and the signal followed in 2018. In these figures, the MW used are actual MW and the performance score is the hourly performance score of the regulation resource.[64] Each category (color bar) is based on the percentage of the full performance score distribution for each resource (or signal) type. As Figure 10-17 shows, 46.2 percent of RegD resources had average performance scores within the 0.91-1.00 range, and 18.2 percent of RegA resources had average performance scores within that range, in 2018. These scores are lower than the scores for both product types in 2017, where 60.1 percent of RegD resources had average performance scores within the 0.91-1.00 range, and 24.0 percent of RegA resources had average performance scores within that range.

Figure 10-16 Hourly average performance score by unit type: 2018

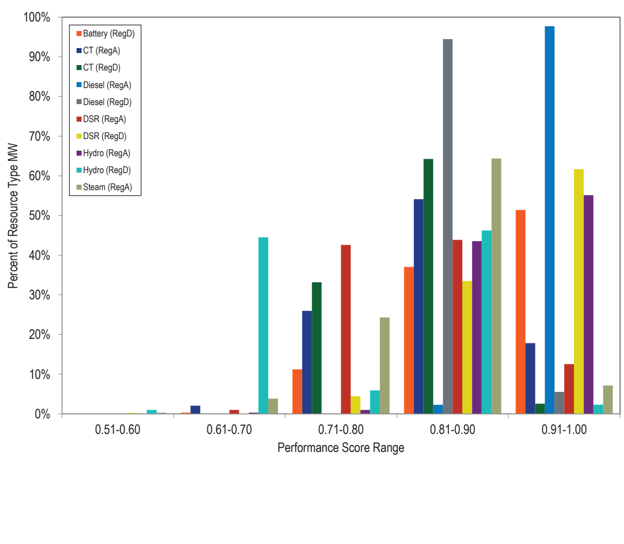
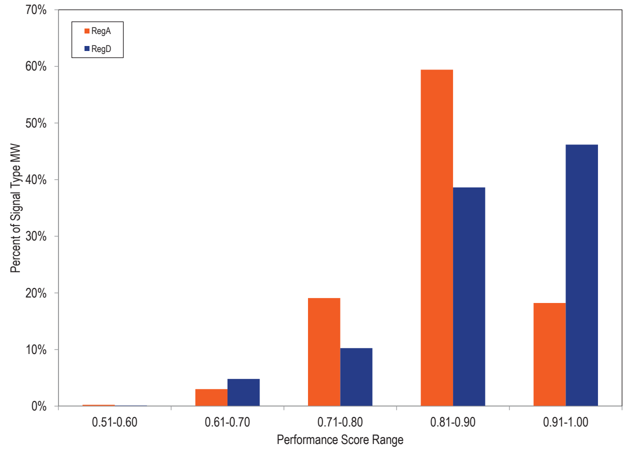


Figure 10-17 Hourly average performance score by regulation signal type: 2018



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 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.

63 PJM "Manual 12: Balancing Operations," § 4.5.6 Performance Score Calculation, Rev. 39 (Feb. 21, 2019).

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

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 in 2018.

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, Reg D 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 the 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.[65] Both PJM and the MMU have filed requests for rehearing.[66]

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.

65 162 FERC ¶ 61,295 (2018).
66 See FERC Docket No. ER18-87-002.

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 10-30). 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 10-30 Seasonal regulation requirement definitions[67]

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

Performance Scores

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

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

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

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

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

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.[68]

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.[69]

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 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.[70] 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

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

69 18 CFR § 385.211 (2017)

70 145 FERC ¶ 61,011 (2013).

and resources do not receive the same clearing price per marginal effective MW.

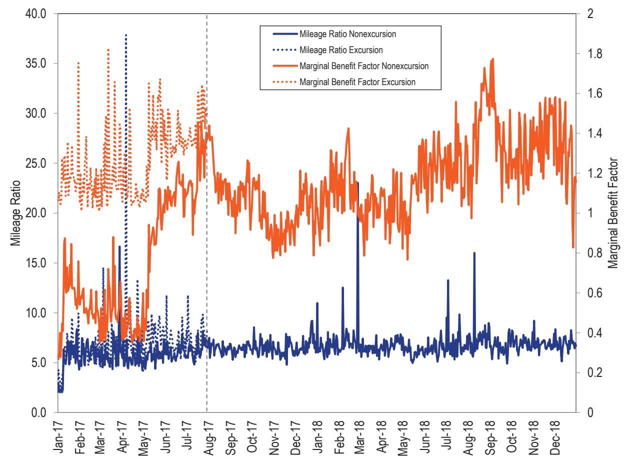
Figure 10-18 compares the daily average MBF and the mileage ratio for excursion and nonexcursion hours. Excursion hours (hours ending 7:00, 8:00, 18:00-21:00) were hours in which PJM had decided that more RegA was needed and PJM would not clear any RegD with an MBF less than 1.0.[71] Excursion hours were discontinued by PJM as of July 31, 2017. The shift in both the MBF values and the mileage ratio (Figure 10-18) resulted from the design changes implemented on January 9, 2017.

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.

The weighted average mileage ratio during nonexcursion hours increased from 6.11 in 2017, to 6.82 in 2018 (an increase of 11.6 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 10-18 Daily average MBF and mileage ratio during excursion and nonexcursion hours: 2017 through 2018[72]



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

Table 10-31 shows RegD resource payments on a performance adjusted MW basis and RegA resource payments on a performance adjusted MW basis by month, from January 1, 2017, through December 31, 2018. In 2017, RegD resources earned 78.7 percent more per performance adjusted MW than RegA resources. In 2018, RegD resources earned 32.8 percent more per performance adjusted MW than RegA resources.

71 See "PJM Manual 11: Energy & Ancillary Services Market Operations,"§ 3.2.9 Regulation Market Operations, Rev. 101 (Jan. 9, 2019).

72 Excursion hours were discontinued as of 00:00 on July 31, 2017.

Table 10-31 Average monthly price paid per performance adjusted MW of RegD and RegA: 2017 through 2018

		Settlement Payments		
Year	Month	RegD ($/Performance Adjusted MW)	RegA ($/Performance Adjusted MW)	Percent Performance Adjusted RegD/RegA Overpayment
2017	Jan	$17.07	$13.62	25.4%
	Feb	$16.58	$10.64	55.8%
	Mar	$26.76	$15.06	77.7%
	Apr	$32.60	$15.58	109.2%
	May	$28.45	$17.89	59.0%
	Jun	$28.88	$13.23	118.2%
	Jul	$28.49	$15.00	89.9%
	Aug	$32.06	$13.24	142.1%
	Sep	$37.89	$21.33	77.6%
	Oct	$32.37	$16.11	100.9%
	Nov	$26.81	$15.62	71.7%
	Dec	$36.00	$25.13	43.3%
Average		$28.73	$16.08	78.7%
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%

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 less than 1.0 in 2017 (0.96), resulting in an average overpayment of RegD resources. In 2018, the average MBF was equal to 1.2, however, RegD resources were still overpaid on average versus if they had been paid on a per effective MW basis.

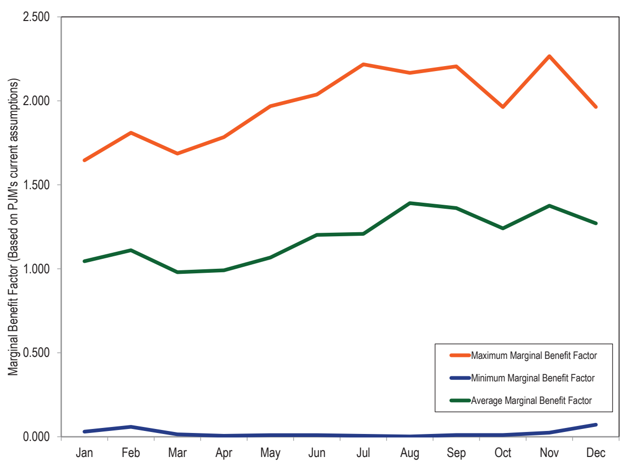
The effect of using the mileage ratio instead of the MBF to convert RegD MW into effective MW for purposes of settlement is illustrated in Table 10-32. Table 10-32 compares the monthly average payment to RegD per effective MW under the current settlement process to the monthly average payment RegD resources 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 less than one in 2017 (0.96), while the average daily mileage ratio was 6.32, resulting in RegD resources being paid $64.7 million more than they would have been if the MBF were correctly implemented. In 2018, the MBF averaged 1.2, while the average daily mileage ratio was 6.82, resulting in RegD resources being paid $20.4 million less than they would have been if the MBF were correctly implemented.

Table 10-32 Average monthly price paid per effective MW of RegD and RegA under mileage and MBF based settlement: 2017 through 2018

		RegD Settlement Payments				
Year	Month	Mileage Based RegD ($/Effective MW)	Marginal Rate of Technical Substitution Based RegD ($/Effective MW)	RegA ($/Effective MW)	Percent RegD Overpayment	Total RegD Overpayment ($)
2017	Jan	$80.44	$13.62	$13.62	490.7%	$6,674,174
	Feb	$293.97	$10.64	$10.64	2,662.3%	$23,955,220
	Mar	$80.90	$15.06	$15.06	437.2%	$5,885,287
	Apr	$79.84	$15.58	$15.58	412.4%	$5,761,398
	May	$34.79	$17.89	$17.89	94.4%	$1,985,119
	Jun	$24.18	$13.23	$13.23	82.7%	$1,481,005
	Jul	$22.16	$15.00	$15.00	47.7%	$1,021,794
	Aug	$26.53	$13.24	$13.24	100.4%	$1,874,341
	Sep	$35.67	$21.33	$21.33	67.2%	$1,719,466
	Oct	$33.29	$16.11	$16.11	106.7%	$2,119,188
	Nov	$27.43	$15.62	$15.62	75.6%	$1,367,771
	Dec	$30.24	$25.13	$25.13	20.3%	$693,153
Yearly		$62.44	$16.08	$16.08	288.3%	$64,657,186
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

Figure 10-19 shows, for 2018, the maximum, minimum and average MBF, by month, for excursion and nonexcursion hours. The average MBF in 2018 was 1.2. The average MBF in 2017 was 0.96.

Figure 10-19 Maximum, minimum, and average PJM calculated MBF by month: 2018[73]



73 Excursion hours were discontinued as of 00:00 on July 31, 2017.

Table 10-33 shows performance adjusted and effective MW that were eligible and cleared during 2017 and 2018.

Table 10-33 Performance adjusted and effective RegD MW eligible and cleared: 2017 and 2018

Performance Adjusted RegD MW			
	2017	2018	Change
Actual Eligible	316.3	272.0	(14.0%)
Effective Eligible	316.3	286.9	(9.3%)
Actual Cleared	186.6	157.9	(15.4%)
Effective Cleared	309.2	273.4	(11.6%)

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.[74]

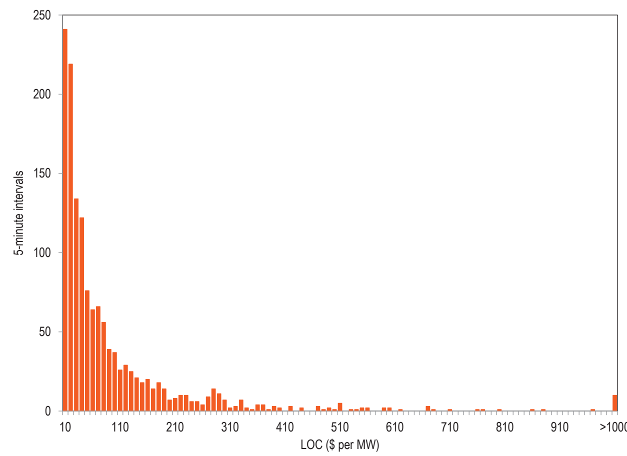
Price Spikes

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

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

In some cases the estimated LOC is very low or zero but the actual within hour LOC is a positive number. In instances where the MBF of the within hour marginal unit 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. Figure 10-20 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.

Figure 10-20 LOC distribution in each five-minute interval with a RegD marginal unit and an LOC greater than zero, in 2018



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.

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. Bit,

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

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 10-34 shows capability MW (performance adjusted), average daily offer MW (performance adjusted), average hourly eligible MW (performance adjusted and effective), and average hourly cleared MW (performance adjusted and effective) for all hours in 2018.[75] Total 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 2018, the average hourly eligible supply of regulation for nonramp hours was 1,125.5 performance adjusted MW (876.2 effective MW). This was a decrease of 10.6 performance adjusted MW (a decrease of 7.1 effective MW) from 2017, when the average hourly eligible supply of regulation was 1,136.1 performance adjusted MW (869.0 effective MW). In 2018, the average hourly eligible supply of regulation for ramp hours was 1,438.3 performance adjusted MW (1,204.1 effective MW). This was an increase of 11.1 performance adjusted MW (an increase of 20.7 effective MW) from 2017, when the average hourly eligible supply of regulation was 1,427.2 performance adjusted MW (1,183.4 effective MW).

The ratio of the average hourly eligible supply of regulation to average hourly regulation demand (performance adjusted cleared MW) for ramp hours was 1.92 in 2018. This is a decrease of 3.22 percent from 2017, when the ratio was 1.98. The ratio of the average hourly eligible supply of regulation to average hourly regulation demand (performance adjusted cleared MW) for nonramp hours was 2.33 in 2018. This is an increase of 0.10 percent from 2017, when the ratio was 2.33.

75 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.

Table 10-34 PJM regulation capability, daily offer and hourly eligible: 2018[76 77]

			By Resource Type		By Signal Type	
		All Regulation	Generating Resources	Demand Resources	RegA Following Resources	RegD Following Resources
Capability MW	Daily	11,023.5	10,991.8	31.7	10,663.9	632.5
Offered MW	Daily	5,428.1	5,406.0	22.1	5,093.4	334.7
Actual Eligible MW	Ramp	1,438.3	1,417.3	21.0	1,147.9	290.4
	Nonramp	1,125.5	1,105.9	19.6	871.8	253.7
Effective Eligible MW	Ramp	1,204.1	1,174.5	29.6	874.0	330.1
	Nonramp	876.2	851.7	24.5	632.6	243.6
Actual Cleared MW	Ramp	749.7	736.4	13.3	575.4	174.3
	Nonramp	482.9	471.1	11.8	341.4	141.5
Effective Cleared MW	Ramp	799.8	771.7	28.1	488.8	311.1
	Nonramp	526.0	502.6	23.4	290.3	235.7

Table 10-35 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 10-35 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 capability MW increased 1.1 percent from 4,583,402.4 MW in 2017 to 4,633,167.2 MW in 2018. The average proportion of regulation provided by natural gas units had the largest increase (8.1 percent), providing 40.2 percent of regulation in 2017 and 48.3 percent of regulation in 2018. Battery units had the largest decrease in average proportion of regulation provided (8.8 percent), decreasing from 30.0 percent in 2017, to 21.2 percent in 2018. The total regulation credits in 2018 were $145,483,539 up 39.6 percent from $104,478,748 in 2017.

Table 10-35 PJM regulation by source: 2017 and 2018[78]

	2017				2018			
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	22	1,376,847.1	30.0%	$38,907,116	23	981,768.0	21.2%	$32,612,688
Coal	42	392,183.0	8.6%	$9,971,617	37	410,773.8	8.9%	$18,544,611
Hydro	27	907,927.5	19.8%	$18,490,838	28	904,072.7	19.5%	$29,979,158
Natural Gas	156	1,842,498.1	40.2%	$35,266,796	168	2,237,299.1	48.3%	$61,286,347
DR	29	63,947	1.4%	$1,842,380	30	99,254	2.1%	$3,060,736
Total	276	4,583,402.4	100.0%	$104,478,748	286	4,633,167.2	100.0%	$145,483,539

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 10-36).

Table 10-36 Active battery storage projects in the PJM queue system by submitted year: 2012 to 2018

Year	Number of Storage Projects	Total Capacity (MW)
2012	1	4.5
2013	0	0.0
2014	2	30.0
2015	29	106.1
2016	3	41.2
2017	3	2.5
2018	33	1,011.4
Total	71	1,195.7

76 Average Daily Offer MW excludes units that have offers but are unavailable for the day.

77 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.

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

The supply of regulation can be affected by regulating units retiring from service. If all units that are requesting retirement through the end of 2018 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 10-30).

Table 10-37 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 483.0 hourly average performance adjusted actual MW in 2018. This is a decrease of 5.1 performance adjusted actual MW from 2017, when the average hourly total regulation cleared performance adjusted actual MW for nonramp hours were 488.1 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 749.3 hourly average performance adjusted actual MW in 2018. This is an increase of 29.1 performance adjusted actual MW from 2017, where the average hourly regulation cleared MW for ramp hours were 720.2 performance adjusted actual MW.

Table 10-37 Required regulation and ratio of supply to requirement: 2017 and 2018[79]

		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	2017	2018	2017	2018	2017	2018	2017	2018
Ramp	Jan	690.8	756.8	766.8	800.0	2.10	1.88	1.48	1.49
	Feb	705.8	738.7	800.1	799.9	2.11	1.90	1.52	1.48
	Mar	714.7	742.9	800.1	800.0	1.96	1.86	1.41	1.43
	Apr	730.6	747.4	800.0	799.9	1.86	1.76	1.41	1.39
	May	723.6	747.2	800.0	800.1	1.88	1.76	1.44	1.42
	Jun	719.9	746.4	800.0	800.0	1.98	1.88	1.49	1.51
	Jul	727.6	756.2	799.9	800.0	2.00	1.91	1.52	1.54
	Aug	727.8	760.4	800.3	800.1	1.97	1.94	1.50	1.53
	Sep	728.3	754.0	799.9	797.3	1.90	1.98	1.46	1.57
	Oct	716.8	752.0	800.0	800.0	2.09	1.92	1.59	1.49
	Nov	713.6	747.3	800.1	800.1	1.99	2.13	1.50	1.63
	Dec	742.6	742.3	799.9	800.1	1.91	2.08	1.48	1.55
Nonramp	Jan	503.6	497.6	525.1	525.1	2.45	2.27	1.65	1.71
	Feb	508.3	482.0	525.0	525.2	2.47	2.37	1.75	1.70
	Mar	499.9	486.6	525.0	525.2	2.22	2.35	1.52	1.67
	Apr	519.0	488.1	525.0	525.0	2.20	2.03	1.60	1.47
	May	479.7	481.5	525.1	524.9	2.26	2.13	1.59	1.55
	Jun	471.9	482.7	525.1	524.9	2.31	2.36	1.63	1.68
	Jul	484.9	488.8	541.0	525.0	2.32	2.24	1.66	1.63
	Aug	481.8	483.5	535.2	525.1	2.41	2.32	1.71	1.65
	Sep	475.8	490.5	526.4	535.1	2.26	2.33	1.62	1.66
	Oct	470.5	477.2	525.2	525.1	2.45	2.30	1.74	1.60
	Nov	472.8	471.1	525.1	525.1	2.34	2.61	1.67	1.83
	Dec	489.5	466.5	525.1	525.1	2.37	2.74	1.71	1.89

Market Concentration

In 2018, the effective MW weighted average HHI of RegA resources was 2419 which is highly concentrated and the weighted average HHI of RegD resources was 1546 which is also highly concentrated.[80] The weighted average HHI of all resources was 1125, which is moderately concentrated. The HHI of RegA resources and the HHI of RegD resources are higher than the HHI for all resources because different owners have large market shares in the RegA and RegD markets.

Table 10-38 includes a monthly summary of three pivotal supplier (TPS) results. In 2018, 81.7 percent of hours had three or fewer pivotal suppliers. The MMU concludes that the PJM Regulation Market in 2018 was characterized by structural market power.

Table 10-38 Regulation market monthly three pivotal supplier results: 2017 through 2018

	Percent of Hours Pivotal		
Month	2016	2017	2018
Jan	93.9%	90.6%	88.7%
Feb	90.9%	93.1%	77.5%
Mar	87.8%	92.7%	83.9%
Apr	93.5%	92.9%	90.3%
May	94.0%	88.7%	87.8%
Jun	89.3%	89.2%	79.9%
Jul	92.2%	91.0%	79.4%
Aug	93.7%	88.0%	79.6%
Sep	94.0%	82.6%	78.6%
Oct	90.6%	68.1%	82.1%
Nov	96.2%	72.5%	78.2%
Dec	90.4%	79.3%	74.2%
Average	92.2%	85.7%	81.7%

79 The regulation requirement for January 2017 includes eight days of 700 effective MW and 23 days of 800 effective MW.

80 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.[81] 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.[82]

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.[83]

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.[84]

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 10-40).[85] Figure 10-21 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.[86] Self scheduled regulation comprised an average of 33.6 percent during ramp hours and 45.6 percent during nonramp hours in 2018.

Figure 10-21 Off peak, on peak, nonramp, and ramp regulation levels: 2017 through 2018[87]

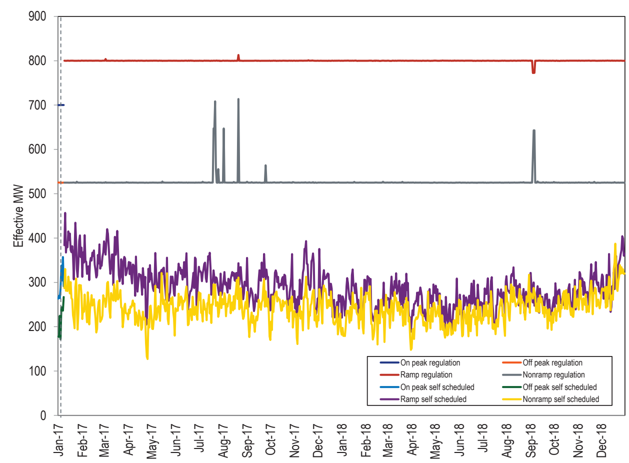


Table 10-39 shows the role of RegD resources in the regulation market. RegD resources are both a growing proportion of the market (10.9 percent of the total effective MW at the start of the performance based regulation market design in October 2012 and 40.5 percent of the total effective MW in December 2018) and a growing proportion of resources that self schedule (10.1 percent of all self scheduled MW in October 2012

81 See "PJM Manual 11: Energy & Ancillary Services Market Operations," § 3.2.1 Regulation Market Eligibility, Rev. 101 (Jan. 9, 2019).

82 Id. at 3.2.2, at p 62.

83 See "PJM Manual 15: Cost Development Guidelines," § 7.8 Regulation Cost, Rev. 29 (May 15, 2017).

84 See "PJM Manual 11: Energy & Ancillary Services Market Operations," § 3.2.1 Regulation Market Eligibility, Rev. 101 (Jan.9, 2019).

85 See "PJM Manual 28: Operating Agreement Accounting," § 4.1Regulation Accounting Overview, Rev. 81 (Oct. 25, 2018).

86 See "PJM Manual 11: Energy & Ancillary Services Market Operations," § 3.2.1 Regulation Market Eligibility, Rev. 101 (Jan 9, 2019).

87 The MW increases during the nonramp hours of 2017 and 2018 were a result of PJM operations treating those hours as ramp hours.

and 25.5 percent of all self scheduled MW in December 2018). The increase in the 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 (Table 10-39). The decrease in the RegD share of total effective MW for 2017 and 2018 were a result of a decrease in the amount of eligible MW of RegD (Table 10-33) in response to the changes to the regulation market on January 9, 2017.

Table 10-39 RegD self scheduled regulation by month: October 2012 through 2018

Year	Month	RegD Self Scheduled Effective MW	RegD Effective MW	Total Self Scheduled Effective MW	Total Effective MW	Percent of Total Self Scheduled	RegD Percent of Total Self Scheduled	RegD Percent of Total Effective MW
2012	Oct	66.3	71.8	264.7	658.1	40.2%	10.1%	10.9%
2012	Nov	74.4	88.3	196.5	716.5	27.4%	10.4%	12.3%
2012	Dec	82.5	88.8	188.8	701.1	26.9%	11.8%	12.7%
2013	Jan	35.7	82.5	133.6	720.0	18.6%	5.0%	11.5%
2013	Feb	84.8	90.2	212.2	724.3	29.3%	11.7%	12.5%
2013	Mar	80.1	119.3	279.8	680.7	41.1%	11.8%	17.5%
2013	Apr	82.3	106.9	266.0	594.1	44.8%	13.8%	18.0%
2013	May	74.0	109.0	268.2	616.2	43.5%	12.0%	17.7%
2013	Jun	79.6	122.7	334.9	730.6	45.8%	10.9%	16.8%
2013	Jul	77.6	120.4	303.6	822.9	36.9%	9.4%	14.6%
2013	Aug	83.6	127.6	366.0	756.8	48.4%	11.0%	16.9%
2013	Sep	112.2	152.1	381.6	669.9	57.0%	16.7%	22.7%
2013	Oct	120.2	163.7	349.6	613.3	57.0%	19.6%	26.7%
2013	Nov	133.9	175.7	396.5	663.3	59.8%	20.2%	26.5%
2013	Dec	136.5	180.7	313.6	663.5	47.3%	20.6%	27.2%
2013 Average		91.7	129.2	300.5	688.0	44.1%	13.6%	19.0%
2014	Jan	132.9	193.5	261.1	663.6	39.3%	20.0%	29.2%
2014	Feb	134.3	193.4	289.0	663.6	43.5%	20.2%	29.1%
2014	Mar	131.8	193.8	287.2	663.8	43.3%	19.9%	29.2%
2014	Apr	126.8	212.4	270.8	663.7	40.8%	19.1%	32.0%
2014	May	121.7	248.5	265.6	663.6	40.0%	18.3%	37.4%
2014	Jun	123.3	231.0	365.5	663.9	55.0%	18.6%	34.8%
2014	Jul	126.4	235.5	352.7	663.5	53.2%	19.0%	35.5%
2014	Aug	117.6	229.8	368.2	663.6	55.5%	17.7%	34.6%
2014	Sep	121.0	242.6	393.8	663.6	59.3%	18.2%	36.6%
2014	Oct	116.1	255.4	352.7	663.6	53.2%	17.5%	38.5%
2014	Nov	113.5	235.1	347.5	664.2	52.3%	17.1%	35.4%
2014	Dec	116.7	254.3	353.0	663.6	53.2%	17.6%	38.3%
2014 Average		123.5	227.1	325.6	663.7	49.1%	18.6%	34.2%
2015	Jan	116.4	250.1	304.8	663.7	45.9%	17.5%	37.7%
2015	Feb	111.3	245.8	242.6	663.5	36.6%	16.8%	37.0%
2015	Mar	113.8	255.2	229.9	663.8	34.6%	17.1%	38.5%
2015	Apr	110.1	248.2	283.7	663.7	42.7%	16.6%	37.4%
2015	May	121.8	265.1	266.7	663.6	40.2%	18.4%	39.9%
2015	Jun	158.9	283.1	321.2	663.7	48.4%	23.9%	42.6%
2015	Jul	161.4	278.3	314.0	663.8	47.3%	24.3%	41.9%
2015	Aug	159.5	276.0	300.7	663.6	45.3%	24.0%	41.6%
2015	Sep	155.4	289.2	286.0	663.5	43.1%	23.4%	43.6%
2015	Oct	147.1	299.0	292.8	663.4	44.1%	22.2%	45.1%
2015	Nov	164.9	302.1	298.1	664.2	44.9%	24.8%	45.5%
2015	Dec	144.6	317.2	260.7	663.9	39.3%	21.8%	47.8%
2015 Average		138.8	275.8	283.4	663.7	42.7%	20.9%	41.6%
2016	Jan	187.7	335.9	295.3	663.8	44.5%	28.3%	50.6%
2016	Feb	179.9	339.0	274.6	663.6	41.4%	27.1%	51.1%
2016	Mar	182.6	340.8	280.1	663.7	42.2%	27.5%	51.3%
2016	Apr	182.2	339.5	287.0	663.5	43.3%	27.5%	51.2%
2016	May	183.9	341.1	301.5	663.5	45.4%	27.7%	51.4%
2016	Jun	178.8	340.5	302.4	663.6	45.6%	26.9%	51.3%
2016	Jul	165.2	337.5	273.3	663.5	41.2%	24.9%	50.9%
2016	Aug	165.8	338.5	283.2	663.5	42.7%	25.0%	51.0%
2016	Sep	160.9	341.4	279.9	663.6	42.2%	24.2%	51.4%
2016	Oct	168.6	340.0	283.0	663.5	42.6%	25.4%	51.2%
2016	Nov	156.2	338.0	259.8	664.3	39.1%	23.5%	50.9%
2016	Dec	162.2	342.7	274.7	663.6	41.4%	24.4%	51.6%
2016 Average		172.8	339.6	282.9	663.7	42.6%	26.0%	51.2%

Table 10-39 RegD self scheduled regulation by month: October 2012 through 2018 (continued)

Year	Month	RegD Self Scheduled Effective MW	RegD Effective MW	Total Self Scheduled Effective MW	Total Effective MW	Percent of Total Self Scheduled	RegD Percent of Total Self Scheduled	RegD Percent of Total Effective MW
2017	Jan	187.1	334.9	318.0	673.9	47.2%	27.8%	49.7%
2017	Feb	192.7	337.8	296.6	674.2	44.0%	28.6%	50.1%
2017	Mar	172.2	315.3	297.5	638.5	46.6%	27.0%	49.4%
2017	Apr	159.9	306.4	255.0	639.6	39.9%	25.0%	47.9%
2017	May	167.6	297.0	265.7	639.7	41.5%	26.2%	46.4%
2017	Jun	178.6	315.6	284.3	696.9	40.8%	25.6%	45.3%
2017	Jul	171.9	310.3	290.0	703.1	41.3%	24.5%	44.1%
2017	Aug	176.7	314.0	286.3	700.9	40.8%	25.2%	44.8%
2017	Sep	156.9	297.8	259.0	640.4	40.4%	24.5%	46.5%
2017	Oct	158.6	295.3	263.7	639.7	41.2%	24.8%	46.2%
2017	Nov	158.6	298.1	261.7	640.4	40.9%	24.8%	46.5%
2017	Dec	147.7	290.8	260.6	674.0	38.7%	21.9%	43.1%
2017 Average		164.1	286.2	269.6	663.4	40.6%	8.2%	45.7%
2018	Jan	130.6	274.3	247.4	673.8	36.7%	19.4%	40.7%
2018	Feb	131.1	276.6	245.5	674.0	36.4%	19.5%	41.0%
2018	Mar	126.6	270.9	249.4	639.8	39.0%	19.8%	42.3%
2018	Apr	124.8	266.5	232.3	639.6	36.3%	19.5%	41.7%
2018	May	124.7	275.7	223.0	639.6	34.9%	19.5%	43.1%
2018	Jun	136.0	298.4	241.5	696.8	34.7%	19.5%	42.8%
2018	Jul	138.5	294.6	248.3	696.9	35.6%	19.9%	42.3%
2018	Aug	159.6	274.3	271.6	697.0	39.0%	22.9%	39.4%
2018	Sep	150.1	256.7	251.4	644.3	39.0%	23.3%	39.8%
2018	Oct	148.0	266.6	256.6	639.6	40.1%	23.1%	41.7%
2018	Nov	144.0	252.9	274.8	640.4	42.9%	22.5%	39.5%
2018	Dec	172.0	273.0	308.5	674.0	45.8%	25.5%	40.5%
2018 Average		140.5	263.8	254.2	663.0	38.4%	20.8%	41.2%

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 2018, 60.4 percent was purchased in the PJM market, 34.2 percent was self scheduled, and 5.3 percent was purchased bilaterally (Table 10-40). Table 10-41 shows the total regulation by source including spot market regulation, self scheduled regulation, and bilateral regulation for each year from 2012 to 2018. Table 10-40 and Table 10-41 are based on settled (purchased) MW.

Table 10-40 Regulation sources: spot market, self scheduled, bilateral purchases: 2017 through 2018

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)
2017	Jan	181,386.7	45.8%	188,924.6	47.7%	25,490.5	6.4%	395,801.8
2017	Feb	179,488.3	50.4%	154,308.8	43.3%	22,371.0	6.3%	356,168.1
2017	Mar	174,026.3	46.3%	177,638.3	47.3%	23,963.0	6.4%	375,627.5
2017	Apr	206,895.4	55.7%	145,424.6	39.1%	19,207.5	5.2%	371,527.5
2017	May	212,510.8	57.8%	139,361.6	37.9%	15,967.5	4.3%	367,839.9
2017	Jun	221,942.4	57.5%	142,537.9	36.9%	21,535.0	5.6%	386,015.3
2017	Jul	227,034.0	55.8%	152,610.9	37.5%	27,183.5	6.7%	406,828.4
2017	Aug	238,692.9	59.2%	141,756.7	35.1%	22,844.5	5.7%	403,294.0
2017	Sep	206,361.1	58.1%	130,432.8	36.7%	18,197.0	5.1%	354,990.9
2017	Oct	213,228.1	58.3%	136,134.9	37.2%	16,631.0	4.5%	365,994.1
2017	Nov	201,998.5	57.5%	132,863.4	37.8%	16,257.5	4.6%	351,119.3
2017	Dec	233,931.8	59.1%	141,051.3	35.7%	20,536.5	5.2%	395,519.6
Total		2,497,496.2	55.1%	1,783,045.7	39.4%	250,184.5	5.5%	4,530,726.5
2018	Jan	241,090.6	60.6%	134,251.7	33.7%	22,447.0	5.6%	397,789.2
2018	Feb	221,617.9	61.9%	120,581.1	33.7%	15,846.5	4.4%	358,045.5
2018	Mar	213,227.4	57.0%	141,161.2	37.7%	19,749.0	5.3%	374,137.6
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	220,820.1	59.8%	129,259.5	35.0%	19,042.5	5.2%	369,122.0
2018	Nov	196,182.7	54.8%	136,240.8	38.0%	25,716.0	7.2%	358,139.5
2018	Dec	213,255.5	54.6%	157,304.7	40.3%	20,237.5	5.2%	390,797.7
Total		2,752,717.6	60.4%	1,558,345.7	34.2%	243,589.5	5.3%	4,554,652.8

Table 10-41 Regulation sources: 2012 through 2018

Year	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	6,149,110.0	78.6%	1,484,446.2	19.0%	193,408.0	2.5%	7,826,964.2
2013	3,088,963.1	57.7%	2,064,156.7	38.5%	204,260.5	3.8%	5,357,380.3
2014	2,327,322.4	49.3%	2,161,996.5	45.8%	231,218.0	4.9%	4,720,536.9
2015	2,546,688.3	54.4%	1,888,040.0	40.3%	250,386.1	5.3%	4,685,114.3
2016	2,260,701.6	48.6%	2,104,775.1	45.2%	287,809.5	6.2%	4,653,286.2
2017	2,497,496.2	55.1%	1,783,045.7	39.4%	250,184.5	5.5%	4,530,726.5
2018	2,752,717.6	60.4%	1,558,345.7	34.2%	243,589.5	5.3%	4,554,652.8

In 2018, DR provided an average of 13.3 MW of regulation per hour during ramp hours (8.5 MW of regulation per hour during ramp hours in 2017), and an average of 11.8 MW of regulation per hour during nonramp hours (7.5 MW of regulation per hour during off peak hours in 2017). Generating units supplied an average of 736.4 MW of regulation per hour during ramp hours in 2018 (711.5 MW of regulation per hour during ramp hours in 2017), and an average of 471.1 MW per hour during nonramp hours in 2018 (480.4 MW of regulation per hour during nonramp hours in 2017).

Market Performance

Price

Table 10-45 shows the regulation price and regulation cost per MW for each year from 2009 through 2018. The weighted average RMCP for 2018 was $25.33 per MW. This is an increase of $8.55 per MW, or 50.9 percent, from the weighted average RMCP of $16.78 per MW in 2017. This increase in the regulation clearing price was the result of an increase in energy prices in 2018 and the related increase in the opportunity cost component of RMCP. The decrease in self supply and $0.00 offers from RegD resources since 2016 also contributed to higher prices.

Figure 10-22 shows the daily weighted average regulation market clearing price and the opportunity cost component for the PJM Regulation Market on a performance adjusted MW basis. This data is based on actual five minute interval operational data. The increase in January was the result of increases in energy prices and the corresponding increase in the opportunity cost component of the RMCP.

Figure 10-22 illustrates that the opportunity cost (blue line) is the largest component of the clearing price.

Figure 10-22 Regulation market-clearing price, opportunity cost and offer price components (Dollars per MW): 2018

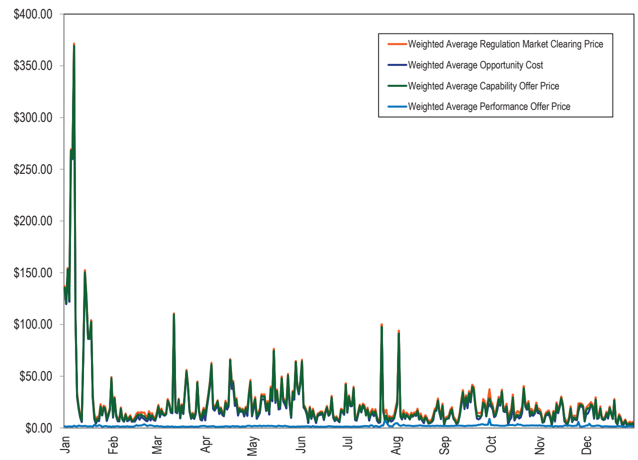


Table 10-42 shows the capability and performance components of the monthly average regulation prices. These components differ from the components of the marginal unit's offers in Figure 10-22 because the performance component of the settlement price for each hour is determined from the average of the highest performance offers in each five minute interval, calculated independent of the marginal unit's offers in those intervals.

Table 10-42 PJM regulation market monthly component of price (Dollars per MW): 2018

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	$79.12	$1.72	$80.84
Feb	$10.91	$1.90	$12.80
Mar	$22.36	$1.36	$23.73
Apr	$26.16	$1.54	$27.70
May	$29.09	$1.75	$30.84
Jun	$17.26	$1.38	$18.64
Jul	$17.40	$2.02	$19.42
Aug	$14.92	$2.31	$17.22
Sep	$18.34	$2.58	$20.92
Oct	$18.27	$2.54	$20.81
Nov	$13.24	$2.05	$15.28
Dec	$11.61	$1.78	$13.39
Average	$23.22	$1.91	$25.13

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 10-43. Total scheduled regulation is based on settled performance adjusted MW. The total of all regulation charges for 2018 was $145.5 million, compared to $104.4 million for 2017.

Table 10-43 Total regulation charges: 2017 through 2018

Year	Month	Scheduled Regulation (MW)	Total Regulation Charges ($)	Weighted Average Regulation Market Price ($/MW)	Cost of Regulation ($/MW)	Price as Percent of Cost
2017	Jan	395,801.8	$6,867,859	$14.08	$17.35	81.2%
2017	Feb	356,168.1	$5,351,147	$11.12	$15.02	74.0%
2017	Mar	375,627.5	$8,604,989	$16.32	$22.91	71.2%
2017	Apr	371,527.5	$9,057,296	$16.21	$24.38	66.5%
2017	May	367,839.9	$8,949,242	$18.85	$24.33	77.5%
2017	Jun	386,015.3	$7,729,571	$13.85	$20.02	69.1%
2017	Jul	406,828.4	$8,698,583	$15.66	$21.38	73.3%
2017	Aug	403,294.0	$8,396,208	$13.70	$20.82	65.8%
2017	Sep	354,990.9	$10,511,205	$21.98	$29.61	74.2%
2017	Oct	365,994.1	$8,807,785	$16.96	$24.07	70.5%
2017	Nov	351,119.3	$7,994,687	$16.65	$22.77	73.1%
2017	Dec	395,432.9	$13,406,934	$26.06	$33.90	76.9%
Yearly		4,530,745.1	$104,386,359	$16.78	$23.04	72.8%
2018	Jan	397,789.2	$39,129,936	$80.83	$98.37	82.2%
2018	Feb	358,045.5	$6,260,199	$12.81	$17.48	73.2%
2018	Mar	374,137.6	$10,735,239	$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	369,122.0	$10,333,629	$20.81	$28.00	74.3%
2018	Nov	358,139.5	$7,528,217	$15.28	$21.02	72.7%
2018	Dec	390,797.7	$7,118,344	$13.39	$18.21	73.5%
Yearly		4,554,652.8	$145,465,939	$25.33	$31.94	79.3%

The capability, performance, and opportunity cost components of the cost of regulation are shown in Table 10-44. Total scheduled regulation is based on settled performance adjusted MW. In 2018, the average total cost of regulation was $31.94 per MW, 38.62 percent higher than $23.04 in 2017. In 2018, the monthly average capability component cost of regulation was $24.22, 68.62 percent higher than $14.36 in 2017. In 2018, the monthly average performance component cost of regulation was $3.63, 46.15 percent lower than $6.75 in 2017.

Table 10-44 Components of regulation cost: 2017 through 2018

Year	Month	Scheduled Regulation (MW)	Cost of Regulation Capability ($/MW)	Cost of Regulation Performance ($/MW)	Opportunity Cost ($/MW)	Total Cost ($/MW)
2017	Jan	395,801.8	$13.19	$2.43	$1.73	$17.35
	Feb	356,168.1	$9.91	$3.68	$1.43	$15.02
	Mar	375,627.5	$13.93	$6.99	$1.98	$22.91
	Apr	371,527.5	$12.94	$9.78	$1.66	$24.38
	May	367,839.9	$16.77	$5.78	$1.78	$24.33
	Jun	386,015.3	$10.81	$7.95	$1.26	$20.02
	Jul	406,828.4	$13.19	$6.37	$1.82	$21.38
	Aug	403,294.0	$10.10	$9.34	$1.38	$20.82
	Sep	354,990.9	$18.83	$8.82	$1.96	$29.61
	Oct	365,994.1	$13.88	$8.51	$1.67	$24.07
	Nov	351,138.0	$14.55	$6.12	$2.09	$22.77
	Dec	395,519.6	$24.35	$5.29	$4.29	$33.92
Yearly		4,530,745.1	$14.36	$6.75	$1.93	$23.04
2018	Jan	397,789.2	$80.32	$3.76	$14.29	$98.37
	Feb	358,045.5	$11.17	$4.47	$1.84	$17.48
	Mar	374,137.6	$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	369,122.0	$19.20	$4.99	$3.81	$28.00
	Nov	358,139.5	$14.20	$3.36	$3.46	$21.02
	Dec	390,797.7	$12.31	$3.29	$2.61	$18.21
Yearly		4,554,652.8	$24.22	$3.63	$4.08	$31.94

Table 10-45 provides a comparison of the average price and cost for PJM regulation. The ratio of regulation market price to the cost of regulation in 2018 was 79.3 percent, an 8.9 percent increase from 72.8 percent in 2017.

Table 10-45 Comparison of average price and cost for PJM regulation: 2009 through 2018

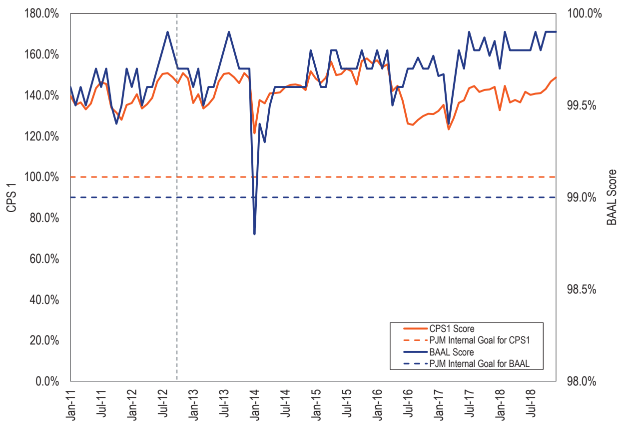
Year	Weighted Regulation Market Price	Weighted Regulation Market Cost	Regulation Price as Percent Cost
2009	$23.00	$30.68	75.0%
2010	$18.00	$32.86	54.8%
2011	$16.49	$29.72	55.5%
2012	$19.02	$25.32	75.1%
2013	$30.85	$35.79	86.2%
2014	$44.49	$53.82	82.7%
2015	$31.92	$38.36	83.2%
2016	$15.73	$18.13	86.7%
2017	$16.78	$23.04	72.8%
2018	$25.33	$31.94	79.3%

Performance Standards

PJM's performance as measured by CPS1 and BAAL standards is shown in Figure 10-23 for every month from January 2011 through December 2018 with the dashed vertical line marking the date (October 1, 2012) of the implementation of the Performance Based Regulation Market design.[88] 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.

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

Figure 10-23 PJM monthly CPS1 and BAAL performance: 2011 through 2018



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.[89] [90] 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.

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

89 See PJM. "RTO-Wide Five-Year Selection Process Request for Proposal for Black Start Service," (July 1, 2013).

90 RFPs issued can be found on the PJM website. See PJM. <http://www.pjm.com/markets-and-operations/ancillary-services.aspx>.

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.[91]

In 2018, total black start charges were $64.747 million, a decrease of $4.769 million (-6.9 percent) from the same period in 2017. Operating reserve charges for black start service increased from $0.257 million in 2017 to $0.303 million in 2018. Table 10-46 shows total revenue requirement charges from 2010 through 2018. 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.

Table 10-46 Black start revenue requirement charges: 2010 through 2018

Year	Revenue Requirement Charges	Operating Reserve Charges	Total
2010	$11,490,379	$0	$11,490,379
2011	$13,695,331	$0	$13,695,331
2012	$18,749,617	$8,384,651	$27,134,269
2013	$20,874,535	$86,701,561	$107,576,097
2014	$26,945,112	$32,906,733	$59,851,845
2015	$56,425,648	$5,175,644	$61,601,292
2016	$69,376,257	$279,017	$69,655,275
2017	$69,258,169	$257,174	$69,515,342
2018	$64,443,593	$303,184	$64,746,777

Black start zonal charges in 2018 ranged from $0.07 per MW-day in the DLCO Zone (total charges were $72,167) to $4.26 per MW-day in the PENELEC Zone (total charges were $4,496,206). For each zone, Table 10-47 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 $1.12 per MW day of reserve capacity during 2018.

Table 10-47 Black start zonal charges for network transmission use: 2017 and 2018[92]

	2017						2018					
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	$2,689,333	$9,974	$2,699,307	2,673	365	$2.77	$2,715,114	$14,518	$2,729,632	2,541	365	$2.94
AEP	$17,515,655	$38,221	$17,553,876	22,474	365	$2.14	$17,460,948	$40,684	$17,501,632	21,647	365	$2.22
APS	$3,863,022	$1,394	$3,864,416	8,717	365	$1.21	$3,909,172	$3,945	$3,913,116	8,755	365	$1.22
ATSI	$3,025,757	$0	$3,025,757	12,752	365	$0.65	$3,064,308	$934	$3,065,242	12,052	365	$0.70
BGE	$4,180,070	$3,310	$4,183,379	6,601	365	$1.74	$1,050,713	$3,371	$1,054,084	6,448	365	$0.45
ComEd	$4,889,894	$21,923	$4,911,817	21,175	365	$0.64	$4,516,877	$15,937	$4,532,813	20,351	365	$0.61
DAY	$255,338	$9,966	$265,304	3,342	365	$0.22	$230,458	$2,330	$232,789	3,225	365	$0.20
DEOK	$1,043,068	$3,622	$1,046,690	5,308	365	$0.54	$749,240	$1,959	$751,198	5,036	365	$0.41
DLCO	$51,114	$12,906	$64,020	2,797	365	$0.06	$48,258	$23,909	$72,167	2,682	365	$0.07
Dominion	$4,297,174	$33,766	$4,330,940	19,538	365	$0.61	$3,931,631	$23,354	$3,954,985	19,661	365	$0.55
DPL	$2,280,454	$7,735	$2,288,189	4,127	365	$1.52	$2,246,697	$9,602	$2,256,299	3,813	365	$1.62
EKPC	$414,454	$0	$414,454	2,878	365	$0.39	$369,857	$844	$370,702	2,860	365	$0.36
JCPL	$6,821,817	$9,358	$6,831,175	5,955	365	$3.14	$6,814,859	$9,035	$6,823,894	5,721	365	$3.27
Met-Ed	$607,876	$65,332	$673,209	2,947	365	$0.63	$566,537	$107,889	$674,426	2,897	365	$0.64
PECO	$1,643,443	$1,777	$1,645,220	8,364	365	$0.54	$1,509,876	$2,460	$1,512,336	8,141	365	$0.51
PENELEC	$4,543,929	$1,623	$4,545,552	2,909	365	$4.28	$4,492,887	$3,319	$4,496,206	2,890	365	$4.26
Pepco	$2,521,020	$16,114	$2,537,133	6,584	365	$1.06	$2,505,653	$17,171	$2,522,824	6,097	365	$1.13
PPL	$1,211,901	$5,547	$1,217,448	7,025	365	$0.47	$1,180,925	$7,873	$1,188,798	7,401	365	$0.44
PSEG	$4,180,537	$2,805	$4,183,342	9,800	365	$1.17	$4,202,903	$861	$4,203,765	9,567	365	$1.20
RECO	$0	$0	$0	NA	365	NA	$0	$0	$0	NA	365	NA
(Imp/Exp/Wheels)	$3,222,313	$11,802	$3,234,114	7,617	365	$1.16	$2,876,681	$13,188	$2,889,869	7,121	365	$1.11
Total	$69,258,169	$257,174	$69,515,342	163,583		$1.16	$64,443,593	$303,184	$64,746,777	158,906		$1.12

91 OATT Schedule 6A (paras. 25, 26 and 27 outline how charges are to be applied).
92 Peak load for each zone is used to calculate the black start rate per MW day.

Table 10-48 provides a revenue requirement estimate by zone for the 2018/2019, 2019/2020 and 2020/2021 delivery years.[93] 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.

Table 10-48 Black start zonal revenue requirement estimate: 2018/2019 through 2020/2021 delivery years

Zone	2018 / 2019 Revenue Requirement	2019 / 2020 Revenue Requirement	2020 / 2021 Revenue Requirement
AECO	$2,900,000	$2,800,000	$2,700,000
AEP	$18,200,000	$18,800,000	$21,550,000
APS	$4,150,000	$4,150,000	$5,550,000
ATSI	$4,150,000	$5,850,000	$5,850,000
BGE	$450,000	$350,000	$50,000
ComEd	$4,450,000	$5,650,000	$10,100,000
DAY	$250,000	$250,000	$250,000
DEOK	$500,000	$400,000	$400,000
DLCO	$50,000	$50,000	$50,000
Dominion	$3,750,000	$4,300,000	$5,700,000
DPL	$2,400,000	$2,350,000	$2,350,000
EKPC	$350,000	$350,000	$350,000
JCPL	$7,150,000	$7,100,000	$750,000
Met-Ed	$550,000	$500,000	$450,000
OVEC	$0	$0	$0
PECO	$1,450,000	$1,450,000	$1,450,000
PENELEC	$4,650,000	$4,600,000	$4,600,000
Pepco	$2,600,000	$2,600,000	$700,000
PPL	$1,250,000	$1,750,000	$4,400,000
PSEG	$4,400,000	$4,400,000	$1,850,000
RECO	$0	$0	$0
Total	$63,650,000	$67,700,000	$69,100,000

NERC – CIP

Currently, no black start units have requested new or additional black start NERC – CIP Capital Costs.[94]

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 10-24 illustrates that the size of the oil tank does not change with the addition of the black start unit. Figure 10-25 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.

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

94 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 10-24 Oil tank MTSL not changed from addition of black start generator

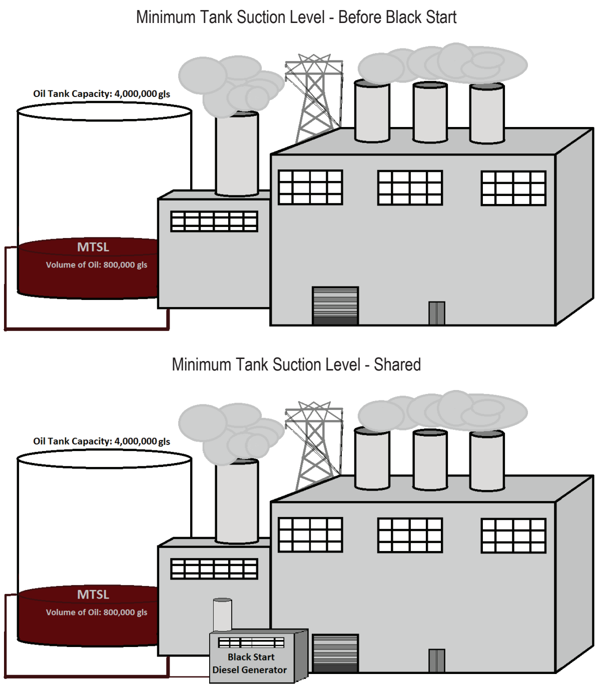
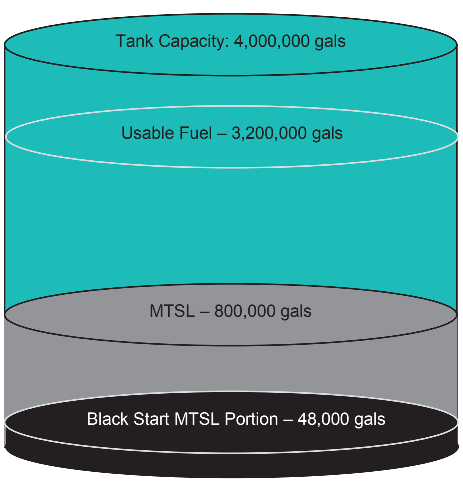


Figure 10-25 Oil tank black start MTSL portion



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.[95]

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.

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).[96] 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.[97] 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.[98]

In 2016, the FERC began to reexamine its policies on reactive compensation.[99] 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.[100]

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

96 OATT Schedule 2.

97 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).

98 OATT Schedule 2.

99 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).

100 See 88 FERC ¶ 61,141 (1999).

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.[101] 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.[102] The Commission has recently extended the interconnection service requirement to have reactive capability to wind and solar units, which previously had been exempt.[103] 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.

PJM requires a power factor of at least 0.95 leading to 0.90 lagging for synchronous units and at least 0.95 leading to 0.95 lagging for nonsynchronous units.[104] The regulations specify a minimum power factor range of 0.95 leading and 0.95 lagging power factor unless the market operators' rules specify otherwise.[105]

There are two ways to address the cost of reactive in the PJM market design.

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 is not part of net CONE.[106] 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. In fact, the revenue offset is defined as a fixed number in the PJM tariff and does not correctly reflect the current revenue requirement of a new unit.

An alternative approach to the current treatment of reactive costs in the capacity market would be to include the gross costs of the entire plant including any reactive costs in the gross Cost of New Entry (CONE) but to calculate net CONE without a reactive revenue offset for reactive service capability rates. The result of this approach would be that the cost of reactive is part of net CONE. This is logically consistent with the elimination of the separate collection of reactive costs through a cost of service rate in that there is no double counting if done accurately. Under this approach there would be no separate collection of reactive capability costs.

PJM currently uses the first approach. There is no reason that PJM could not easily implement the second approach.

The second approach is preferable. The second approach relies on competitive markets to provide incentives to provide energy, both real and reactive, at the lowest

101 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.").

102 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).

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

104 See OATT Attachment O Appendix 2 § 4.7.

105 See LGIA Article 9.6.1 ("Interconnection Customer shall design the Large Generating Facility to maintain a composite power delivery at continuous rated power output at the Point of Interconnection at a power factor within the range of 0.95 leading to 0.95 lagging, unless Transmission Provider has established different requirements that apply to all generators in the Control Area on a comparable basis.").

106 See OATT Attachment DD § 5.10(a)(iv).

possible cost. The second approach provides a consistent and nondiscriminatory approach to compensation, avoiding reliance on a large number of costly and sporadic ratemaking proceedings. The second approach does not require the use of arbitrary, approximate and generally inaccurate allocators to determine the cost of providing reactive. The second approach does not require the use of estimated, average and inaccurate net reactive revenue offsets to calculate Net CONE. It is critical in the PJM Capacity Market that Net CONE be as accurate as possible. Only the second approach assures this.

Units are compensated for reactive capability costs under the second approach. But the compensation is based on the outcome of a competitive capacity market rather than based on current or historical cost of service filings for units or fleets of units.

The first approach, although internally logically consistent, relies on unnecessary and inaccurate approximations. The reactive allocator is such an approximation. The reactive revenue offset is an inaccurate estimate based on historical data from reactive revenue requirement filings. The reactive revenues used in the net CONE calculation are based on an average of reactive filings over the three years from 2005 through 2007 and therefore do not reflect even the allocated reactive costs and revenues for a new unit, as would be required to be consistent with the CONE logic.[107] To the extent that the reactive portion of the Net Energy and Ancillary Services Offset is inaccurate, the net CONE is inaccurate.

The reactive revenue offset is set equal to $ 2,199/MW-year in the OATT.[108] This figure 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 Net Cost of New Entry is a key parameter in the PJM Capacity Market as it affects the location of the VRR or demand curve and thus has a direct impact on capacity market prices.[109]

If revenues for reactive capacity were removed from the Net Energy and Ancillary Services Revenue Offset, then the fixed costs for investment in reactive capability would be recoverable through the capacity market. By employing a simple and direct approach using CONE with no offset, the rules for cost of service compensation included in Schedule 2 could be eliminated and the requirement for cost of service filings would be eliminated.

As a result of the nature of reactive filings, it is not possible to identify the reactive capability revenues for all individual units that receive reactive capability revenues. As a result, the offer caps in the capacity market are not as accurate as they should be.

Relying on capacity markets instead of cost of service allocations would enhance competition and efficient pricing.

Actual experience with the cost of service approach suggests that customers would be better off under a competition based approach. The Commission's recent investigations into particular rates raises questions about the accuracy and basis of rates currently charged for reactive capability.

Cost of service ratemaking creates unnecessary monitoring difficulties. Because service providers do not have to file rates periodically, suppliers have no incentive to adjust reactive capability rates except when they increase. Suppliers have direct access to information about the costs for their own units. The Commission and other parties do not have such access. When rates are established on a fleet basis or result from a black box settlement, the ability of parties to review and challenge rates is further reduced.

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

107 OATT Attachment DD § 5.10(a)(v)(A) ("The Office of the Interconnection shall determine the Net Energy and Ancillary Services Revenue Offset each year for the PJM Region as (A) the annual average of the revenues that would have been received by the Reference Resource from the PJM energy markets during a period of three consecutive calendar years preceding the time of the determination, based on (1) the heat rate and other characteristics of such Reference Resource; (2) fuel prices reported during such period at an appropriate pricing point for the PJM Region with a fuel transmission adder appropriate for such region, as set forth in the PJM Manuals, assumed variable operation and maintenance expenses for such resource of $6.47 per MWh, and actual PJM hourly average Locational Marginal Prices recorded in the PJM Region during such period; and (3) an assumption that the Reference Resource would be dispatched for both the Day-Ahead and Real-Time Energy Markets on a Peak-Hour Dispatch basis; plus (B) ancillary service revenues of $2,199 per MW-year.").

108 *Id.*

109 *Id.*

organized markets.[110] 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

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 is measured in tests performed by PJM or demonstrated in market data showing actual reactive output and based on capability levels that are useful to PJM system operators to maintain system stability. 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.[111]

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. Tests are essential to "evaluate and analyze" proposed reactive revenue requirements.[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.

110 See FERC Docket No. AD16-17-000.

111 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.

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.

There is no reason to use the nameplate MVAR rating to develop a reactive allocation and there is no basis in the AEP method for reliance on the nameplate MVAR rating. Nameplate reactive power ratings are generally higher than the actual ratings as defined by the PJM mandated tests of capability because nameplate power ratings are generally calculated using leading and lagging power factors that are lower than are achievable when installed in a specific plant interconnected to a specific transmission network. Although this issue is characterized as degradation, the difference between pre installation nameplate ratings and post installation tested capability exists even when units are new. Testing reveals whether the tested capability changes. Reliance on tested results would address both the issue of degradation and the issue of theoretical versus actual MVAR ratings.

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 estimated capability costs also include estimated heating losses relative to MVAR output.[118] Heating losses are variable costs and not fixed costs and should not be included in the definition of reactive capability costs.[119] Heating losses can be accurately calculated for each hour of operation if each unit had an accurate, recent D-curve test. Heating losses are variable costs and should not be included in the cost of reactive capability. The production of reactive power slightly reduces the MWh output of the generator as the generator follows its D-curve. The value of this heating loss component is generally estimated based on estimated operation and associated estimated losses and estimated market

117 *See supra* footnote 27.

118 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).

119 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.

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.

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 proportionally to their zone and nonzone peak transmission use and point to point transmission reservations.

Cost of service rates are established under Schedule 2 of the OATT and may cover rates for single units or a fleet of units.[120] 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.[121] 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.[122] Fleet rates should be eliminated. Compensation should be based on unit specific costs. Fleet rates make it almost impossible to monitor whether compensation for reactive capability is based on actual unit specific performance and costs.

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.[123] 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 this issue through participation in proceedings at FERC concerning reactive capability rates for PJM units.[124]

Reactive Costs

In 2018, total reactive charges were $342.0 million, a 3.1 percent increase from the $331.7 million for 2017. Reactive capability revenue requirement charges increased from $311.3 million in 2017 to $328.8 million in 2018 and reactive service charges decreased from $20.4 million in 2017 to $13.1 million in 2018.[125] All $13.1 million in 2018 were paid for reactive service provided by 25 units in 283 hours in specific locations.

Table 10-49 shows reactive service charges in 2017 and 2018, reactive capability revenue requirement 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 revenue requirement charges show charges to each zone for reactive capability.

120 See, e.g., OATT Schedule 2; 114 FERC ¶ 61,318 (2006).
121 See 149 FERC ¶ 61,132 (2014); 151 FERC ¶ 61,224 (2015); OATT Schedule 2.
122 *Id.*
123 See OATT Attachment DD §§ 6.4, 6.8(d).
124 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.
125 See *2018 State of the Market Report for PJM*, Section 4, "Energy Uplift."

Table 10-49 Reactive zonal charges for network transmission use: 2017 and 2018

	2017			2018		
Zone	Reactive Service Charges	Reactive Capability Revenue Requirement Charges	Total Charges	Reactive Service Charges	Reactive Capability Revenue Requirement Charges	Total Charges
AECO	$8,686	$4,247,222	$4,255,908	$145	$4,713,244	$4,713,390
AEP	$178,314	$39,234,081	$39,412,395	$775,231	$43,933,120	$44,708,351
APS	$135,676	$16,800,854	$16,936,530	$0	$16,229,147	$16,229,147
ATSI	$77,078	$21,342,021	$21,419,099	$0	$21,913,045	$21,913,045
BGE	$1,694,486	$8,205,331	$9,899,817	$30,956	$8,046,036	$8,076,993
ComEd	$13,242,447	$30,855,459	$44,097,906	$11,335,202	$39,133,222	$50,468,424
DAY	$15,845	$5,628,799	$5,644,643	$0	$4,557,604	$4,557,604
DEOK	$25,386	$8,057,110	$8,082,496	$0	$8,502,164	$8,502,164
Dominion	$120,722	$34,512,902	$34,633,624	$46,914	$38,115,437	$38,162,351
DPL	$1,308,524	$11,512,490	$12,821,014	$257,310	$11,525,471	$11,782,781
DLCO	$12,737	$779,263	$792,000	$0	$780,579	$780,579
EKPC	$20,528	$2,185,849	$2,206,377	$198,562	$2,189,542	$2,388,104
JCPL	$19,441	$8,973,314	$8,992,755	$0	$8,974,083	$8,974,083
Met-Ed	$68,170	$5,198,247	$5,266,417	$0	$4,831,397	$4,831,397
PECO	$103,510	$22,285,794	$22,389,303	$0	$23,244,991	$23,244,991
PENELEC	$1,675,853	$11,645,044	$13,320,897	$403,889	$11,993,445	$12,397,334
Pepco	$1,595,597	$8,301,363	$9,896,960	$0	$9,914,160	$9,914,160
PPL	$37,886	$24,416,798	$24,454,684	$90,643	$26,158,789	$26,249,432
PSEG	$37,255	$27,659,023	$27,696,277	$0	$28,164,482	$28,164,482
RECO	$1,239	$0	$1,239	$0	$0	$0
(Imp/Exp/Wheels)	$0	$19,435,328	$19,435,328	$0	$15,909,575	$15,909,575
Total	$20,379,379	$311,276,291	$331,655,670	$13,138,854	$328,829,532	$341,968,385

Frequency Response

On February 15, 2018, the Commission issued Order No. 842, which modified the pro forma large and small generator interconnection agreements and procedures to require newly interconnecting generating facilities, both synchronous and nonsynchronous, to include equipment for primary frequency response capability as a condition to receive interconnection service.[126] 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.[127]

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 additional cost to install the necessary equipment is minimal, and the current PJM market design provides compensation for all capacity costs, including these, in the capacity market. 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.

126 157 FERC ¶ 61,122 (2016).
127 See 164 FERC ¶ 61,224 (2018).

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. 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.