Ancillary Service Markets

The United States Federal Energy Regulatory Commission (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 the 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 Market Monitoring Unit (MMU) analyzed measures of market structure, conduct and performance for the PJM Synchronized Reserve Market, the PJM DASR Market, and the PJM Regulation Market for the first three months of 2017.

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 6.9 percent of all cleared hours in the first three months of 2017.
- 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 set the clearing price in 496 hours (22.8 percent).
- Market design was evaluated as mixed because the DASR product does not include performance obligations, and the three pivotal supplier test and appropriate market power mitigation should be added to the market to ensure that market power cannot be exercised at times of system stress.

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

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

- The regulation market structure was evaluated as not competitive for the first three months of 2017 because the PJM Regulation Market failed the three pivotal supplier (TPS) test in 92.1 percent of the hours in the first three months of 2017.
- Participant behavior in the PJM Regulation Market was evaluated as competitive for the first three months of 2017 because market power mitigation requires competitive offers when the three pivotal supplier test is failed and there was no evidence of generation owners engaging in noncompetitive behavior.
- Market performance was evaluated as competitive, despite significant issues with the market design.
- Market design was evaluated as flawed. The market design has failed to correctly incorporate a consistent implementation of the marginal benefit factor in optimization, pricing and settlement. The market results continue to include the incorrect definition of opportunity cost. The result is significantly flawed market signals to existing and prospective suppliers of regulation.

Overview

Primary Reserve

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

Market Structure

- **Supply.** Primary reserve is satisfied by both synchronized reserve (generation or demand response currently synchronized to the grid and available within 10 minutes), and nonsynchronized reserve (generation currently off-line but available to start and provide energy within 10 minutes).
- **Demand.** The PJM primary reserve requirement is 150 percent of the largest contingency. The primary reserve requirement in the RTO Zone was raised on January 8, 2015, to 2,175 MW of which at least 1,700 MW must be available within the Mid-Atlantic Dominion (MAD) Subzone. Adjustments to the primary reserve requirement can occur when grid maintenance or outages change the largest contingency. The hourly average primary reserve requirement in the RTO Zone in the first three months of 2017 was 2,191.2 MW. The primary reserve requirement in the MAD Subzone was 1,700 MW for all hours.

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 part of primary reserve and 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 reserve. The market solution estimates tier 1 synchronized reserve as available 10-minute ramp from the energy dispatch. In the first three months of 2017, there was an average hourly supply of 1,252.2 MW of tier 1 for the RTO Synchronized Reserve Zone, and an average hourly supply of 1,059.4 MW of tier 1 in the Mid-Atlantic Dominion Subzone.
- **Demand.** The default hourly required synchronized reserve requirement is 1,450 MW in the RTO Reserve Zone and 1,450 MW for the Mid-Atlantic Dominion Reserve 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, rather than hourly

3 See PJM. "Manual 10: Pre-Scheduling Operations," Revision. 34 (July 1, 2016), p. 24.

integrated LMP, plus $50/MW. This is the Synchronized Energy Premium Price. The synchronized reserve event response credits for tier 1 response are independent of the tier 2 synchronized reserve market clearing price and independent of the nonsynchronized reserve market clearing price.

Of the Degree of Generator Performance (DGP) adjusted tier 1 synchronized reserve MW estimated at market clearing, 59.3 percent actually responded during the one synchronized reserve event with duration of 10 minutes or longer in the first three months of 2017.

- **Issues.** The competitive offer for tier 1 synchronized reserves is zero, as there is no incremental cost associated with the ability to ramp up from the current economic dispatch point and the appropriate payment for responding to an event is the five-minute LMP plus $50 per MWh. A tariff change included in the shortage pricing tariff changes (October 1, 2012) added the requirement to pay tier 1 synchronized reserve the tier 2 synchronized reserve market clearing price whenever the non-synchronized 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, 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, and $428,212 in the first three months of 2017.

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 incur costs to be synchronized, that have an obligation to respond with corresponding penalties, 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 conducts 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 the first three months of 2017, the supply of offered and eligible synchronized reserve was 23,563.7 MW in the RTO Zone of which 6,779.8 MW (including 1,514.4 MW of DSR) was available to the MAD Subzone.
- **Demand.** The default hourly required synchronized reserve requirement was 1,450 MW in the RTO Reserve Zone and 1,450 MW for the Mid-Atlantic Dominion Reserve Subzone. The requirement can be met with tier 1 or tier 2 synchronized reserves. After subtracting the tier 1 synchronized reserve estimate from the default requirement, the hourly average required tier 2 synchronized reserve was 412.8 MW in the MAD Subzone and 616.4 MW in the RTO.
- **Market Concentration.** In the first three months of 2017, the weighted average HHI for tier 2 synchronized reserve in the Mid-Atlantic Dominion Subzone was 5689 which is classified as highly concentrated. The MMU calculates that 92.2 percent of hours would have failed a three pivotal supplier test in the Mid-Atlantic Dominion Subzone.

  In the first three months of 2017, the weighted average HHI for cleared tier 2 synchronized reserve in the RTO Synchronized Reserve Zone was 4672 which is classified as highly concentrated. The MMU calculates that 61.2 percent of hours would have failed a three pivotal supplier test in the RTO Synchronized Reserve Zone.

  The MMU concludes from these results that both the Mid-Atlantic Dominion Subzone Tier 2 Synchronized Reserve Market and the RTO Synchronized Reserve Zone Market were characterized by structural market power in the first three months of 2017.

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. 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.

There has been less than complete compliance with the tier 2 synchronized reserve must offer requirement.

Market Performance

- **Price.** The weighted average price for tier 2 synchronized reserve for all cleared hours in the Mid-Atlantic Dominion (MAD) Subzone was $2.22 per MW in the first three months of 2017, a decrease of $2.77, from the first three months of 2016.

  The weighted average price for tier 2 synchronized reserve for all cleared hours in the RTO Synchronized Reserve Zone was $2.32 per MW in the first three months of 2017, a decrease of $2.34, from the first three months of 2016.

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. The market 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.

Market Structure

- **Supply.** In the first three months of 2017, the supply of eligible nonsynchronized reserve was 2,244.9 MW in the RTO Zone and 1,847.2 MW in MAD Subzone.
- **Demand.** Demand for nonsynchronized reserve is the remaining primary reserve requirement after tier 1 synchronized reserve is estimated and tier 2 synchronized reserve is scheduled.[4] In the RTO Zone, the market cleared an hourly average of 676.2 MW of nonsynchronized reserve in the first three months of 2017. The MAD Subzone cleared an average of 379.4 MW in the first three months of 2017.
- **Market Concentration.** In the first three months of 2017, the weighted average HHI for cleared nonsynchronized reserve in the MAD Subzone was 4107 which is classified as highly concentrated. In the RTO Zone the weighted average HHI was 4098, which is also highly concentrated. The MMU calculates that 33.8 percent of hours would have failed a three pivotal supplier test in the MAD Subzone and zero percent of hours would have failed a three pivotal supplier test in the RTO Zone.

Market Conduct

- **Offers.** No offers are made for nonsynchronized reserve by resource owners. 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 cleared hours (284 hours) in the RTO Reserve Zone was $0.10 per MW in the first three months of 2017 and in 98.4 percent of hours the market clearing price was $0.00. The MAD Subzone cleared separately from the RTO Zone in 34 hours in the first three months of 2017, with a weighted average price of $0.10.

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

4 See PJM. "Manual 11: Energy & Ancillary Services Market Operations," Revision 82 (July 1, 2016), p. 81. "Because Synchronized Reserve may be utilized to meet the Primary Reserve requirement, there is no explicit requirement for non-synchronized reserves. "

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.[5] The Day-Ahead Scheduling Reserves 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.[6]

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 thirty minute energy ramp rate or the economic maximum MW minus the day-ahead dispatch point for all online units. In the first three months of 2017, the average available hourly DASR was 37,058 MW.
- **Demand.** The DASR requirement for 2017 is 5.52 percent of peak load forecast, down from 5.70 percent in 2016. The average DASR MW purchased was 3,916.3 MW per hour in the first three months of 2017.
- **Concentration.** In the first three months of 2017, the DASR Market failed the three pivotal supplier test in 6.9 percent of hours.

Market Conduct

- **Withholding.** Economic withholding remains an issue in the DASR Market. The direct marginal cost of providing DASR is zero. PJM calculates the opportunity cost for each resource. All offers by resource owners greater than zero constitute economic withholding. In the first three months of 2017, a daily average of 39.3 percent of units offered above $0.00. A daily average of 14.2 percent of units offered above $5.
- **DR.** Demand resources are eligible to participate in the DASR Market. Some demand resources have entered offers for DASR. No demand resources cleared the DASR market in the first three months of 2017.

5 See PJM. "Glossary," <http://www.pjm.com/Glossary.aspx>.
6 See PJM, "Manual 11: Energy & Ancillary Services Market Operations," Revision 85 (November 1, 2016), p. 166 §11.1.

Market Performance

- **Price.** In the first three months of 2017, the weighted average DASR price for all hours when the DASRMCP was above $0.00 was $0.06, a decrease of $1.55 per MW from 2016.

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 lost 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 very fast ramp rates. In the Regulation Market RegD MW are converted to marginal effective MW using a marginal rate of substitution (MRTS), called a marginal benefit function (MBF). Correctly implemented, the MBF would define and be used as the marginal rate of technical substitution (MRTS) between RegA and RegD, holding the level of regulation service constant. The current market design is critically flawed as it has not properly implemented the MBF as an MRTS between RegA and RegD resource MW and the MBF has not been consistently applied in the optimization, clearing and settlement of the Regulation Market.

Market Structure

- **Supply.** In the first three months of 2017, the average hourly eligible supply of regulation for nonramp hours was 1,187.5 actual MW (852.4 effective MW). This was an increase of 4.2 actual MW (32.0 effective MW) from the first three months of 2016, when the average hourly eligible supply of regulation was 1,183.3 actual MW (820.4 effective MW). In the first three months of 2017, the average hourly eligible supply of regulation for ramp hours was 1,449.4 actual MW (1,158.4 effective MW). This was an increase of 236.9 actual MW (199.5 effective MW) from the first three months of 2016, when the average hourly eligible supply of regulation was 1,212.4 actual MW (958.9 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.[7]

- **Supply and Demand.** The nonramp regulation requirement of 525.0 effective MW was provided by a combination of RegA and RegD resources equal to 503.4 hourly average actual MW in the first three months of 2017. This is a decrease of 36.6 actual MW from the first three months of 2016, when the average hourly total regulation cleared MW for nonramp hours were 540.1 actual MW. The ramp regulation requirement of 700.0 effective MW prior to January 9, 2017, and 800.0 effective MW after January 9, 2017, was provided by a combination of RegA and RegD resources equal to 702.1 hourly average actual MW in the first three months of 2017. This is an increase of 48.5 actual MW from the first three months of 2016, where the average hourly regulation cleared MW for ramp hours were 653.6 actual MW.

  The ratio of the average hourly eligible supply of regulation to average hourly regulation demand for ramp hours was 2.06 in the first three months of 2017. This is an increase of 11.3 percent from the first three months of 2016, when the ratio was 1.85. The ratio of the average hourly eligible supply of regulation to average hourly regulation demand required for nonramp hours was 2.36 in the first three months of 2017. This is an increase of 7.7 percent from the first three months of 2016, when the ratio was 2.19.

- **Market Concentration.** In the first three months of 2017, the three pivotal supplier test was failed in 92.1 percent of hours. In the first three months of 2017, the weighted average HHI of RegA resources was 2860, which is highly concentrated and the weighted average HHI of RegD resources was 1642, which is highly concentrated. The weighted average HHI of all resources was 1155 which is moderately concentrated.

Market Conduct

- **Offers.** Daily regulation offer prices are submitted for each unit by the unit owner. Owners are required to submit a cost-based offer and may submit a price-based offer. Offers include both a capability offer and a performance offer. Owners must specify which signal type the unit will be following, RegA or RegD.[8] In the first three months of 2017, there were 147 resources following the RegA signal and 44 resources following the RegD signal.

Market Performance

- **Price and Cost.** The weighted average clearing price for regulation was \$13.87 per effective MW of regulation in the first three months of 2017, a decrease of \$1.68 per MW, or 10.8 percent, from of the first three months of 2016. The cost of regulation in the first three months of 2017 was \$18.40 per effective MW of regulation, an increase of \$0.48 per MW, or 2.7 percent, from the first three months of 2016. The decrease in regulation price in the first three months of 2017 resulted primarily from reductions in the LOC component of the regulation clearing prices due to low energy prices in the first three months of 2017 compared to the first three months of 2016.

- **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, pricing, 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 one, RegD resources are generally (depending on the mileage ratio) underpaid on a per effective MW basis. When the MBF

7 On peak and off peak hours are now designated as ramp and nonramp hours. The definitions change by season. See "Regulation requirement definition," <http://www.pjm.com/~/media/markets-ops/ancillary/regulation-requirement-definition.ashx>

8 See the *2016 State of the Market Report for PJM*, Volume II, Appendix F "Ancillary Services Markets."

is less than one, RegD resources are generally overpaid on a per effective MW basis. Currently, the MBF is less than one, resulting in persistent overpayment of RegD resources that creates an artificial incentive for inefficient entry of RegD resources. The MBF averaged less than one in each of the first three months of 2017, resulting in RegD resources being paid an average of 1,016.4 percent more than they should have in the first three months of 2017. In the first three months of 2016, the MRTS averaged was also less than one, resulting in RegD resources being paid an average of 222.4 percent more than they should have been.

- **Marginal Benefit Factor Function.** The marginal benefit factor (MBF) is intended to measure the substitutability of RegD resources for RegA resources. The marginal benefit factor function is currently incorrectly defined and applied in the PJM market clearing and incorrectly describes the operational relationship between RegA and RegD regulation resources. 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 began to degrade the ability of PJM to control ACE in some hours while at the same time increasing the cost of regulation.
- **Interim changes to the MBF function.** On December 14, 2015, PJM changed the MBF curve in an attempt to reduce the over procurement of RegD. The modification to the marginal benefit curve did not correct the identified issues.
- **Changes to the Regulation Market.** Changes were approved by the Regulation Market Issues Senior Task Force (RMISTF), which went into effect on January 9, 2017. These include changing the definition of off-peak and on-peak hours (now called nonramp and ramp hours) based on the season, increasing the effective MW requirement during ramp hours from 700 MW to 800 MW, 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 conditional neutrality requirement.

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).[9]

In the first three months of 2017, total black start charges were $17.1 million with $17.0 million in revenue requirement charges and $.057 million in 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. 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 for first three months of 2017 ranged from $0.05 per MW-day in the DLCO Zone (total charges were $12,507) to $4.30 per MW-day in the PENELEC Zone (total charges were $1,127,246).

Reactive

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

9 OATT Schedule 1 § 1.3BB.

reactive service. In the first three months of 2017, total reactive charges were $86.4 million, a 17.6 percent increase from $73.4 million in 2016. Reactive capability revenue requirement charges increased from $73.2 million in 2016 to $80.5 million and reactive service charges increased from $0.3 million to $5.9 million in 2017. Total charges in 2017 ranged from $636 in the RECO Zone to $9.7 million in the AEP Zone.

Ancillary Services Costs per MWh of Load: January through March, 1999 through 2017

Table 10-4 shows PJM ancillary services costs for January through March, 1999 through 2017, per MWh of load. The rates are calculated as the total charges for the specified ancillary service divided by the total PJM real-time load in MWh. The scheduling, system control, and dispatch category of costs is comprised of PJM scheduling, PJM system control and PJM dispatch; owner scheduling, owner system control and owner dispatch; other supporting facilities; black start services; direct assignment facilities; and Reliability*First* Corporation charges. The cost per MWh of load in Table 10-4 is a different metric than the cost of each ancillary service per MW of that service. The cost per MWh of load includes the effects both of price changes per MW of the ancillary service and changes in total load.

Table 10-4 History of ancillary services costs per MWh of Load: January through March, 1999 through 2017[10]

Year (Jan-Mar)	Regulation	Scheduling, Dispatch and System Control	Reactive	Synchronized Reserve	Total
1999	$0.04	$0.23	$0.25	$0.00	$0.52
2000	$0.21	$0.38	$0.37	$0.00	$0.96
2001	$0.49	$0.64	$0.22	$0.00	$1.35
2002	$0.24	$0.67	$0.16	$0.00	$1.07
2003	$0.65	$1.01	$0.22	$0.11	$1.99
2004	$0.54	$1.06	$0.26	$0.17	$2.03
2005	$0.47	$0.80	$0.25	$0.07	$1.59
2006	$0.48	$0.70	$0.28	$0.09	$1.55
2007	$0.58	$0.72	$0.25	$0.11	$1.66
2008	$0.59	$0.73	$0.30	$0.07	$1.69
2009	$0.38	$0.35	$0.34	$0.03	$1.10
2010	$0.34	$0.36	$0.35	$0.05	$1.10
2011	$0.27	$0.30	$0.38	$0.12	$1.07
2012	$0.18	$0.41	$0.48	$0.03	$1.10
2013	$0.28	$0.41	$0.63	$0.04	$1.36
2014	$0.63	$0.38	$0.37	$0.29	$1.67
2015	$0.32	$0.41	$0.36	$0.18	$1.26
2016	$0.11	$0.42	$0.38	$0.04	$0.95
2017	$0.11	$0.46	$0.46	$0.06	$1.09

Recommendations

- The MMU recommends that the Regulation Market be modified to incorporate a consistent application of the marginal benefit factor throughout the optimization, assignment and settlement process. (Priority: High. First reported 2012. Status: Not adopted.)
- The MMU recommends that all data necessary to perform the Regulation Market three pivotal supplier test be saved so that the test can be replicated. (Priority: Medium. First reported 2016. Status: Not adopted.)
- The MMU recommends that 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, to prevent gaming. (Priority: Medium. First reported 2016. Status: Not adopted.)

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

- The MMU recommends that the lost opportunity cost in the ancillary services markets be calculated using the schedule on which the unit was scheduled to run in the energy market. (Priority: High. First reported 2010. Status: Not adopted.)
- The MMU recommends that the rule requiring the payment of the tier 2 synchronized reserve price to tier 1 synchronized reserve resources when the nonsynchronized reserve price is above zero be eliminated immediately and that 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. 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: Not 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 PJM modify the DASR Market to ensure that all resources cleared incur a real-time performance obligation. (Priority: Low. First reported 2013. Modified 2017. Status: Not adopted.)
- The MMU recommends that the three pivotal supplier test and market power mitigation be incorporated in the DASR Market. (Priority: Low. First reported 2009. Status: Not adopted.)
- The MMU recommends that a reason code be attached to every hour in which PJM market operations adds additional DASR MW. (Priority: Medium. First reported 2015. Status: Not adopted.)
- The MMU recommends that separate 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 a number of market design changes to improve the performance of the Regulation Market, including use of a single five minute clearing price based on actual LMP and actual LOC, modifications to the LOC calculation, a software change to save some data elements necessary for verifying market outcomes, and further documentation of the implementation of the market design. (Priority: Medium. First reported 2010. Status: Partially adopted in 2012.)
- The MMU recommends that PJM revise the current confidentiality rules in order to specifically allow a more transparent disclosure of information regarding black start resources and their associated payments in PJM. (Priority: Low. First reported 2013. Status: Partially adopted, 2014.)
- The MMU recommends that the single clearing price for synchronized reserves be determined based on the actual five minute LMP and actual LOC and not the forecast LMP. (Priority: Low. First reported 2010. Status: Adopted.)
- The MMU recommends that no payments be made to tier 1 resources if they are deselected in the PJM market solution. The MMU also recommends that documentation of the Tier 1 synchronized reserve deselection process be published. (Priority: High. First reported 2014. Status: Adopted 2014.)

Conclusion

The design of the PJM Regulation Market is significantly flawed. The market design has failed to correctly incorporate the marginal benefit factor, or marginal rate of technical substitution, in optimization, pricing and settlement. The market design uses the marginal benefit factor in the optimization (incorrectly) and pricing (correctly), but a mileage ratio instead of the marginal benefit factor in settlement. This failure to correctly and consistently incorporate marginal benefit factor 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 have led to the MMU's conclusion that the regulation market design is flawed. PJM and the MMU have developed a joint proposal to correct these issues.

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, compliance with calls to respond to actual synchronized reserve events remains less than 100 percent. For the six 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 one spinning event of 10 minutes or longer in 2017, the response was 75.3 percent of scheduled tier 2 MW.

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. Such 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 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, and $0.4 million in the first three months of 2017.

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. 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-002-1, Disturbance Control Performance, requires PJM to carry sufficient contingency reserve to recover from a sudden loss of load (disturbance) within 15 minutes. The NERC requirement is 100 percent compliance and must be reported quarterly. PJM implements this contingency reserve requirement using primary reserves.[11] 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

Supply

In the first three months of 2017, PJM's primary reserve requirement was 2,175 MW for the RTO Zone, and 1,700 MW for the MAD Subzone.[12] It is satisfied by tier 1 synchronized reserves, tier 2 synchronized reserves and non-synchronized reserves, subject to the requirement that synchronized reserves equal 100 percent of the largest contingency. The synchronized reserve requirement is 1,450 MW in both the Mid-Atlantic Dominion Subzone, and the RTO Zone. After the synchronized reserve requirement is satisfied, the

11 See PJM, "Manual 10: Pre-Scheduling Operations," revision 35, January 1, 2017, p. 24, 25

12 In this State of the Market Report, scheduled MW and average clearing prices are calculated differently for the RTO Zone than in prior reports. Formerly data were reported for three geographic structures for primary reserve and its component synchronized and non-synchronized reserve. Those three structures were, Full RTO Zone, Mid-Atlantic Dominion Subzone, and the RTO Zone excluding the Mid-Atlantic Subzone. In this report the term RTO Zone is the Full RTO Zone.

remainder of primary reserves can come from the least expensive combination of synchronized and nonsynchronized reserves.

Estimated tier 1 is credited against PJM's primary reserve requirement. In the MAD Subzone an average of 953.5 MW of tier 1 was identified by the ASO market solution as available hour ahead (Table 10-6).[13] Of this, an average of 947.4 MW of tier 1 was actually used by the market solution in satisfying the synchronized reserve requirement. This tier 1 reduced the amount of tier 2 and nonsynchronized reserve needed to fill the synchronized reserve and primary reserve requirements. Tier 1 synchronized reserve fully satisfied the MAD Subzone synchronized reserve requirement in 2.1 percent of hours in the first three months of 2017. In the RTO Zone, an average of 948.4 MW of tier 1 was available (Table 10-6). Tier 1 synchronized reserve fully satisfied the RTO Zone synchronized reserve requirement in 26.3 percent of all hours.

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). Offer MW and other non-cost offer parameters can be changed during the operating day. Owners are permitted to make resources unavailable for synchronized reserve daily or hourly but only if they are physically unavailable. Certain unit types including nuclear, wind, solar, landfill gas and batteries, are expected to have zero MW tier 2 synchronized reserve offer quantities.[14]

After tier 1 is estimated, the remainder of the synchronized reserve requirement is met by tier 2. In the RTO Zone there were 23,563.7 MW of tier 2 synchronized reserve offered daily. Of this, 6,779.8 MW were located in the MAD Subzone (Figure 10-12) and available to meet the average tier 2 hourly demand of 524.2 MW (Table 10-5).

In the MAD Subzone, there was an average of 2,052.3 MW of eligible nonsynchronized reserve supply available to meet the average hourly demand of 379.3 MW (Table 10-6). In the RTO Zone, an hourly average of 2,255.3 MW supply was available to meet the average hourly demand of 396.1 MW (Table 10-5).

Demand

PJM requires that 150 percent of the largest contingency on the system be maintained as primary reserve. Adjustments to this value can occur when grid maintenance or outages change the largest contingency or in cases of hot weather alerts or cold weather alerts.

On January 10, 2017, the default primary reserve requirement in the RTO Reserve Zone was raised from 2,175 MW to 3,300 MW for 32 hours. The hourly average RTO primary reserve requirement in the first three months of 2017 was 2,191.2 MW. In the MAD Subzone, the primary reserve requirement remained at 1,700 MW for all hours for the first three months of 2017.

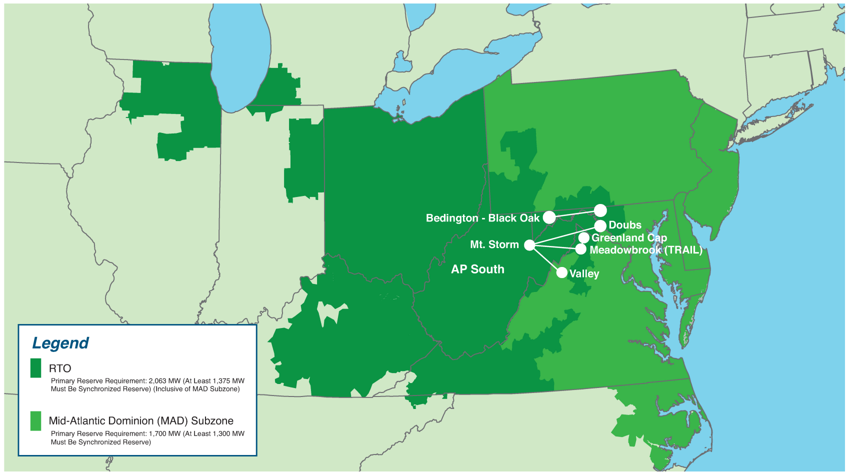
Transmission constraints limit the deliverability of reserves within the RTO, requiring the definition of the Mid-Atlantic Dominion (MAD) Subzone.[15] Of the 2,175 MW RTO primary reserve requirement, 1,700 MW (Table 10-15) must be deliverable to the MAD Subzone (Figure 10-1).

13 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.

14 See PJM, "Manual 11: Energy & Ancillary Services Market Operations," Revision 85 (November 1, 2016), p. 84.

15 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," Revision 84 (August 251, 2016), p. 87.

Figure 10-1 PJM RTO Zone and MAD Subzone geography: 2017



The Mid-Atlantic Dominion Reserve (MAD) Subzone is generally defined dynamically by the most limiting constraint separating MAD from the PJM RTO Reserve Zone. However, PJM can override the dynamic determination of the most limiting constraint that defines the MAD Subzone market. From October 10, 2016 through January 16, 2017, the most limiting constraint had been fixed by PJM as the AP South transfer interface.

PJM requires that synchronized reserves equal at least 100 percent of the largest contingency. This means that 1,450 MW of the primary reserve requirement must be synchronized reserve for both RTO Reserve Zone and the Mid Atlantic Dominion Reserve Subzone.

Table 10-5 Average monthly reserves used to satisfy the primary reserve requirement, MAD Subzone: January 1, 2016 through March 31, 2017

Year	Month	Tier 1 Total MW	Tier 2 Synchronized Reserve MW	Non-Synchronized Reserve MW	Total Primary Reserve MW
2016	Jan	1,263.5	228.5	295.9	1,787.9
2016	Feb	1,230.1	241.5	302.2	1,773.8
2016	Mar	993.3	485.7	265.7	1,744.7
2016	Apr	912.4	565.0	289.2	1,766.5
2016	May	956.5	511.3	292.2	1,760.0
2016	Jun	1,116.9	348.4	368.7	1,834.0
2016	Jul	1,254.7	208.8	621.3	2,084.7
2016	Aug	1,228.4	239.7	669.1	2,137.2
2016	Sep	1,170.6	293.0	603.7	2,067.2
2016	Oct	1,086.1	481.3	508.7	2,076.2
2016	Nov	774.8	687.8	360.4	1,822.9
2016	Dec	995.0	479.6	520.7	1,995.3
2016		1,081.8	397.5	424.8	1,904.2
2017	Jan	981.6	508.5	361.1	1,851.2
2017	Feb	1,111.6	355.5	377.7	1,844.9
2017	Mar	767.4	693.3	399.3	1,860.0
2017		953.5	519.1	379.4	1,852.0

Table 10-6 Average monthly reserves used to satisfy the primary reserve requirement, RTO Zone: January 1, 2016 through March 31, 2017

Year	Month	Tier 1 Total MW	Tier 2 Synchronized Reserve MW	Non-Synchronized Reserve MW	Total Primary Reserve MW
2016	Jan	1,659.4	374.5	319.1	2,353.0
2016	Feb	1,564.1	411.4	329.4	2,304.9
2016	Mar	1,089.1	818.1	300.0	2,207.2
2016	Apr	1,011.7	878.3	318.0	2,207.9
2016	May	1,160.9	722.6	349.5	2,233.0
2016	Jun	1,546.0	497.1	384.2	2,427.3
2016	Jul	1,663.8	360.1	634.0	2,657.9
2016	Aug	1,605.6	419.0	682.4	2,707.0
2016	Sep	1,290.4	578.6	617.5	2,486.5
2016	Oct	802.7	982.4	524.0	2,309.1
2016	Nov	810.8	1,014.1	375.4	2,200.4
2016	Dec	953.1	807.3	533.0	2,293.4
2016		1,263.1	655.3	447.2	2,365.6
2017	Jan	1,020.4	915.5	372.3	2,308.2
2017	Feb	1,172.0	686.0	395.1	2,253.2
2017	Mar	654.2	1,128.9	420.9	2,204.0
2017		948.9	910.1	396.1	2,255.1

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).

The ASO jointly optimizes energy, synchronized reserves, and nonsynchronized reserves based on forecast system conditions to determine the most economic set of reserve resources to commit for the upcoming operating hour (before the hour commitments). 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 tier 2 resources (flexibly or inflexibly) if needed.

Figure 10-2 illustrates how the ASO satisfies the primary reserve requirement (orange line) for the Mid-Atlantic Dominion Subzone. For the Mid-Atlantic Dominion Reserve Zone primary reserve solution the ASO must first satisfy the synchronized reserve requirement (yellow line) which is generally 1,450 MW in the MAD Subzone. Since the market solution considers tier 1 synchronized reserve to be zero cost, the ASO first estimates how much tier 1 synchronized reserve (green area) is available. If there are 1,450 MW of tier 1 available, then ASO jointly optimizes synchronized reserve and nonsynchronized reserve to assign the remaining primary reserve up to 1,700 MW. If there are not 1,450 MW of tier 1 then the remaining synchronized reserve requirement up to 1,450 MW is filled with tier 2 synchronized reserve (dark blue area). After 1,450 MW of synchronized reserve are assigned, the remaining 250 MW of 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 between 1,450 MW and 1,700 MW is filled by nonsynchronized reserve.

Figure 10-2 Mid-Atlantic Dominion Subzone primary reserve MW by source (Daily Averages): January through March, 2017

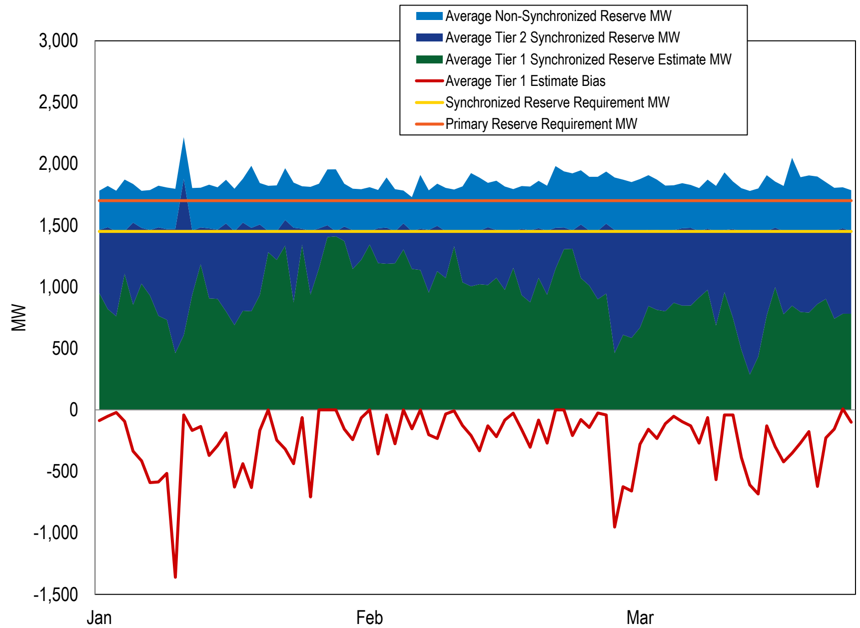
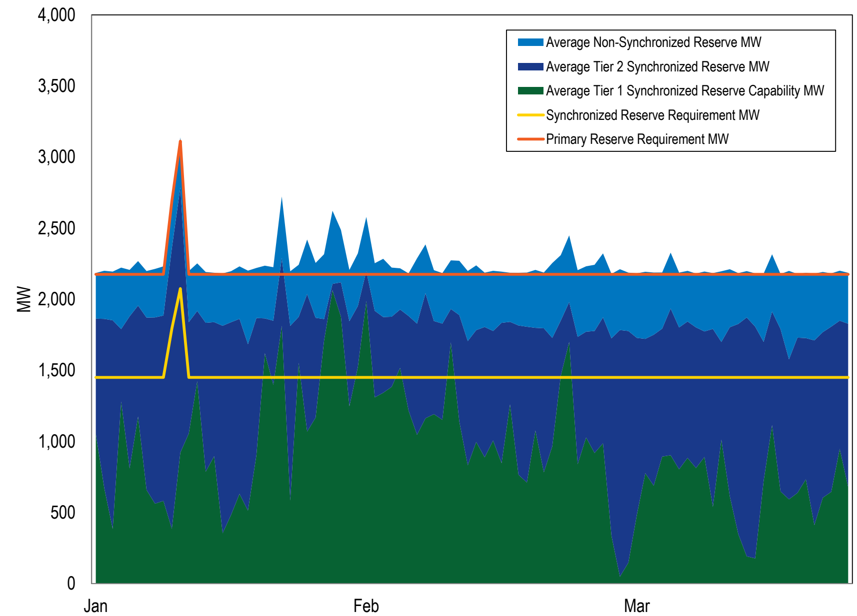


Figure 10-3 RTO Reserve Zone primary reserve MW by source (Daily Averages): January through March, 2017



The solution method is similar for the RTO Reserve Zone (Figure 10-3) except that the required primary reserve MW is 2,175 MW.[16] Figure 10-3 shows how the hour ahead ASO satisfies the primary reserve requirement for the RTO Zone.

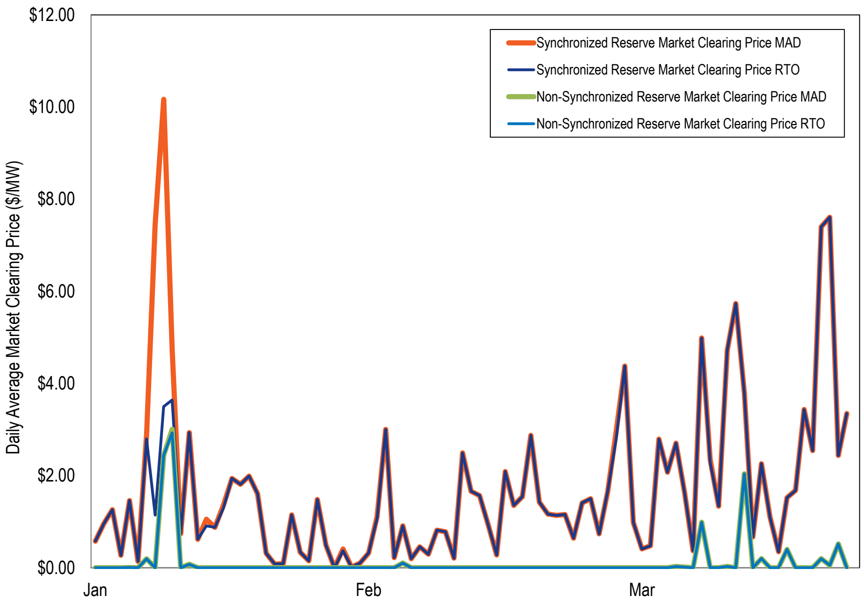
Figure 10-2 and Figure 10-3 show that tier 1 synchronized reserve remains the major contributor to satisfying the synchronized reserve requirements both in the RTO Zone and the Mid-Atlantic Dominion (MAD) Subzone.

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

Price and Cost

Figure 10-4 shows daily average synchronized and nonsynchronized market clearing prices in the first three months of 2017.

Figure 10-4 Daily weighted average market clearing prices ($/MW) for synchronized reserve and nonsynchronized reserve: January through March, 2017



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-002-1 primary reserve requirement is calculated by combining the three components (Table 10-7). Under most market conditions, most primary reserve identified by the hour ahead market solution is provided at no incremental cost from nonsynchronized reserve and tier 1 synchronized reserve. The "Cost per MW" column is the total credits divided by the total MW of reserves. The "All-In Cost" column is the total credits paid divided by the load, or the total cost per MWh of energy to satisfy the primary reserve requirement.

On a combined basis, the price cost ratio for primary reserve is low at 44 percent due to the current inappropriately incurred cost of Estimated Tier 1 Synchronized Reserve. While Tier 1 has no actual incremental cost and has no clearing price, estimated Tier 1 is paid the Tier 2 clearing price in any hour where non-synchronized reserves clears at a non zero price. Table 10-7 shows that the cost per MW of Tier 1 reserves is $5.13 dollars and 59.1 percent greater than the cost of tier 2 reserves entirely as a result of paying tier 1 reserves when the price of nonsynchronized reserves is greater than zero.

Table 10-7 MW credited, price, cost, and all-in price for primary reserve and its component products, RTO Reserve Zone: January through March, 2017

Product	MW Share of Primary Reserve Requirement	MW	Credits Paid	Price Per MW Reserve	Cost Per MW Reserve	All-In Cost
Tier 1 Synchronized Reserve Response	NA	2,632	$171,452	NA	$65.14	$0.00
Tier 1 Synchronized Reserve Estimated	1.1%	34,124	$428,212	$0.00	$12.55	$0.00
Tier 2 Synchronized Reserve Scheduled	43.0%	1,339,352	$9,762,807	$2.33	$7.29	$0.05
Non Synchronized Reserve Scheduled	55.8%	1,738,897	$958,311	$0.10	$0.55	$0.01
Primary Reserve (total of above)	100.0%	3,115,005	$11,320,782	$1.06	$3.63	$0.06

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 measured as the lower of the available 10 minute ramp and the difference between the economic dispatch point and the economic maximum output. Tier 1 resources are identified by the market solution. The sum of their 10 minute availability equals available tier 1 synchronized reserve (green area of Figure 10-2 and Figure 10-3). Tier 1 synchronized reserve is the first element of primary reserve identified by the market software and is available at zero incremental cost unless called to respond to a synchronized reserve event or unless 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 as defined below.

There have been issues with the tier 1 estimate, and the process for estimating tier 1 synchronized reserve has been refined. Beginning 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.[17] 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 overriding submitted synchronized reserve ramp rate, adjusted by its DGP percent. 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.[18] Total estimated tier 1 MW also reflect any tier 1 bias added by PJM operators.

In the first three months of 2017, PJM estimated tier 1 MW for an average of 135 units as part of the market solution each hour. The average tier 1 synchronized reserve DGP was 88.5 percent for those 135 units.

The supply of tier 1 synchronized reserve available to the market solution is further adjusted by eliminating tier 1 MW from units that cannot reliably provide synchronized reserve. These units are identified as nuclear, wind, solar, energy storage, and hydro units.[19] 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.

In the first three months of 2017, in the RTO Reserve Zone, the average hourly estimated tier 1 synchronized reserve was 948.9 MW (Table 10-8). In 26.3 percent of hours, 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.

In the first three months of 2017, in the MAD Reserve Subzone, the average hour ahead estimated tier 1 synchronized reserve was 544.4 MW in MAD and 516.0 MW in the RTO (Table 10-8). In 2.1 percent of hours, the estimated tier 1 synchronized reserve available in MAD was greater than the subzone requirement for synchronized reserve and no Tier 2 Synchronized Reserve Market was needed.

17 See PJM. "Manual 11: Energy & Ancillary Services Market Operations," Revision 85 (November 1, 2016), p. 85.
18 PJM. Ancillary Services, "Communication of Synchronized Reserve Quantities to Resource Owners," <http://www.pjm.com/~/media/markets-ops/ancillary/communication-of-synchronized-reserve-quantities-to-resource-owners.ashx> (May 6, 2015).
19 See PJM. "Manual 11: Energy & Ancillary Services Market Operations," Revision 85 (November 1, 2016), p. 83.

Table 10-8 Monthly average market solution Tier 1 Synchronized Reserve (MW) identified hourly: January 1, 2016 through March 31, 2017

Year	Month	Average Hourly Tier 1 Local To MAD	Tier 1 Synchronized Reserve From RTO Zone	Average Hourly Tier 1 Used in MAD	Average Hourly Tier 1 Used in RTO Zone
2016	Jan	586.1	659.3	1,245.4	1,659.4
2016	Feb	609.3	635.9	1,245.2	1,564.1
2016	Mar	402.4	660.7	1,063.0	1,089.1
2016	Apr	341.7	620.2	961.9	1,011.7
2016	May	408.2	613.9	1,022.1	1,160.9
2016	Jun	638.4	504.0	1,142.5	1,546.0
2016	Jul	756.7	513.5	1,270.2	1,663.8
2016	Aug	750.5	495.2	1,245.7	1,605.6
2016	Sep	658.9	566.8	1,225.7	1,290.4
2016	Oct	393.6	723.9	1,117.5	802.7
2016	Nov	385.2	478.6	863.8	810.8
2016	Dec	660.4	419.8	1,080.2	953.1
2016		549.3	574.3	1,123.6	1,263.1
2017	Jan	592.0	498.8	1,090.8	1,316.9
2017	Feb	577.0	602.1	1,179.1	1,395.3
2017	Mar	464.1	455.8	919.9	1,057.8
2017		544.4	518.9	1,063.3	1,256.7

Demand

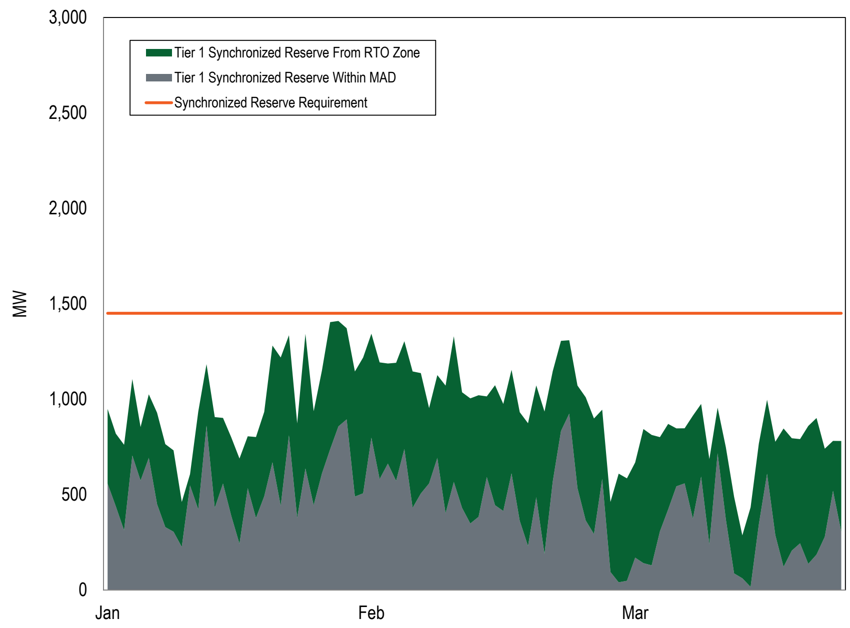
There is no required amount of tier 1 synchronized reserve. The tier 1 synchronized reserve for each online resource is estimated from its synchronized reserve ramp rate as part of each market solution. Given estimated tier 1, the market software (ASO) determines the demand for tier 2 and nonsynchronized reserve under the assumption that the estimated tier 1 will be available if needed. 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 minimize the total cost of primary reserves.

Supply and Demand

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. To improve its tier 1 estimates, PJM deselects certain resources from the tier 1 estimate. Tier 1 deselection is based on unit type.

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). It then adds the tier 1 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: January through March, 2017



Average demand for synchronized reserve in the RTO Zone in the first three months of 2017 was 1,460.8 MW. There was a temporary increase in the hourly synchronized reserve requirement to 2,200 MW on January 10 and 11, 2017.

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.

In the first three months of 2017, tier 1 synchronized reserve synchronized reserve event response credits of $171,452 were paid for 2,632.2 MWh of tier 1 response at an average cost per MWh of $65.14, for 11 spinning event hours (Table 10-9).

Table 10-9 Tier 1 synchronized reserve event response costs: January 1, 2016 through March 31, 2017

Year	Month	Total Synchronized Reserve Event Response Hour Count	Total Credited Tier 1 Synchronized Reserve Event Response MWh	Total Tier 1 Synchronized Reserve Event Response Credits	Tier 1 Synchronized Reserve Event Response Cost Per MWh	Average Tier 1 MWh Response
2016	Jan	2	731.1	$70,330	$96.24	365.4
2016	Feb	2	675.0	$40,622	$60.18	337.5
2016	Mar	0	0.0	$0	$0.00	0.0
2016	Apr	1	339.0	$66,199	$195.27	339.0
2016	May	2	113.4	$9,790	$86.35	56.7
2016	Jun	1	206.9	$11,129	$53.78	206.9
2016	Jul	3	714.3	$58,114	$81.36	357.1
2016	Aug	1	334.5	$13,026	$38.95	334.5
2016	Sep	2	452.4	$34,824	$76.97	226.2
2016	Oct	2	281.1	$24,130	$85.85	140.5
2016	Nov	1	204.3	$10,910	$53.41	204.3
2016	Dec	1	256.8	$14,766	$57.50	256.8
2016		18	4,308.8	$353,840	$76.57	235.4
2017	Jan	6	1,250.2	$60,447	$48.35	208.4
2017	Feb	3	624.1	$55,705	$89.26	208.0
2017	Mar	2	757.9	$55,300	$72.96	379.0
2017		11	2,632.2	$171,452	$65.14	265.1

Paying Tier 1 the Tier 2 Price

The market solutions treat tier 1 synchronized reserve as having zero marginal cost. The price for tier 1 synchronized reserves is zero as there is no marginal cost associated with having the ability to ramp up from the current economic dispatch point. 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. But 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. The nonsynchronized reserve market clearing price was above $0.00 in 32 hours from the first three months of 2017. For those 32 hours, tier 1 synchronized reserve resources were paid a weighted average synchronized reserve market clearing price of $12.62 per MW and earned $428,213 in credits. In 2016, PJM paid $4,948,084 in credits for tier 1 estimated during the 297 hours when the nonsynchronized reserve market clearing price was above $0.

Table 10-10 Weighted price of tier 1 synchronized reserve attributable to a nonsynchronized reserve price above zero: January 1, 2016 through March 31, 2017

Year	Month	Total Hours When NSRMCP>$0	Weighted Average SRMCP for Hours When NSRMCP>$0	Total Tier 1 MW Credited for Hours When NSRMCP>$0	Total Tier 1 Credits Paid When NSRMCP>$0	Average Tier 1 MW Paid
2016	Jan	41	$14.18	56,841	$806,038	1,624.0
2016	Feb	16	$9.42	24,752	$233,208	1,768.0
2016	Mar	73	$6.57	105,142	$690,294	1,440.3
2016	Apr	40	$28.83	38,662	$1,114,670	1,137.1
2016	May	22	$9.01	27,027	$243,515	1,228.5
2016	Jun	9	$15.24	11,630	$177,275	1,453.8
2016	Jul	10	$21.38	13,975	$298,736	1,397.5
2016	Aug	14	$32.45	19,649	$637,554	1,403.6
2016	Sep	9	$26.22	11,247	$294,857	1,249.7
2016	Oct	50	$12.12	33,761	$409,208	675.2
2016	Nov	12	$3.04	13,867	$42,216	1,155.6
2016	Dec	1	$0.58	888	$515	888.2
2016		297	$13.84	357,442	$4,948,084	1,285.1
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		32	$12.67	34,124	$428,212	1,131.1

The additional payments to tier 1 synchronized reserves under the shortage pricing rule can be considered 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 as all estimated tier 1 receives the payment regardless of whether they provided any response during any spinning event. Tier 1 resources are not obligated to respond to synchronized reserve events. In the first three months of 2017, 59.3 percent of the DGP adjusted market solution's estimated tier 1 resources MW actually responded during synchronized reserve events of greater than 10 minutes. Thus, 40.7 percent of DGP adjusted tier 1 estimated MW did not respond during spinning events. 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. Tier 2 synchronized reserve resources are paid the market clearing price for tier 2 because they stand ready to respond and incur costs to do so, have an obligation to perform and pay penalties for nonperformance.

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

In the first three months of 2017, tier 1 synchronized reserve was paid $171,452 for responding to synchronized reserve events. During the same time period tier 1 synchronized reserve was paid a windfall of $428,212 simply because the NSRMCP was greater than $0.00 in 32 hours (Table 10-11).

Table 10-11 Excess payments for tier 1 synchronized reserve: January 1, 2016 through March 31, 2017

		Synchronized Reserve Events			Hours When NSRMCP>$0		
Year	Month	Total MWh	Total Credits	Average MWh Per Event	Total MW	Total Credits	Average MW Per Hour
2016	Jan	754	$70,330	366	56,841	$806,038	1,624.0
2016	Feb	675	$40,622	338	24,752	$233,208	1,768.0
2016	Mar	0	$0	0	105,142	$690,294	1,440.3
2016	Apr	339	$66,199	339	38,662	$1,114,670	1,137.1
2016	May	113	$9,790	57	27,028	$243,515	1,228.5
2016	Jun	207	$11,129	207	11,630	$177,275	1,453.8
2016	Jul	714	$58,114	238	13,975	$298,736	1,397.5
2016	Aug	334	$13,026	334	19,650	$637,554	1,403.6
2016	Sep	452	$34,824	226	11,247	$294,857	1,249.7
2016	Oct	141	$24,130	141	33,761	$409,208	675.2
2016	Nov	204	$10,910	204	13,867	$42,216	1,155.6
2016	Dec	695	$43,512	347	888	$515	888.2
2016		4,629	$382,585	233	357,442	$4,948,084	1,285.1
2017	Jan	1,250	$60,447	250	19,441	$221,157	1,143.6
2017	Feb	624	$55,705	208	1,293	$15,971	1,293.2
2017	Mar	758	$55,300	379	13,389	$191,084	956.4
2017		2,632	$171,452	279	34,124	$428,212	1,131.1

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.[20] 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.

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

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

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

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		
Hourly Parameters	No Synchronized Reserve Event	Synchronized Reserve Event
NSRMCP=$0	T1 credits = $0	T1 credits = Synchronized Energy Premium Price * actual response MWh
NSRMCP>$0	T1 credits = $0	T1 credits = Synchronized Energy Premium Price * actual response MWh

Tier 1 Estimate Bias

PJM's market solution software allows the dispatcher to bias the synchronized reserve solution by forcing the software to assume a different tier 1 MW value than it 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.

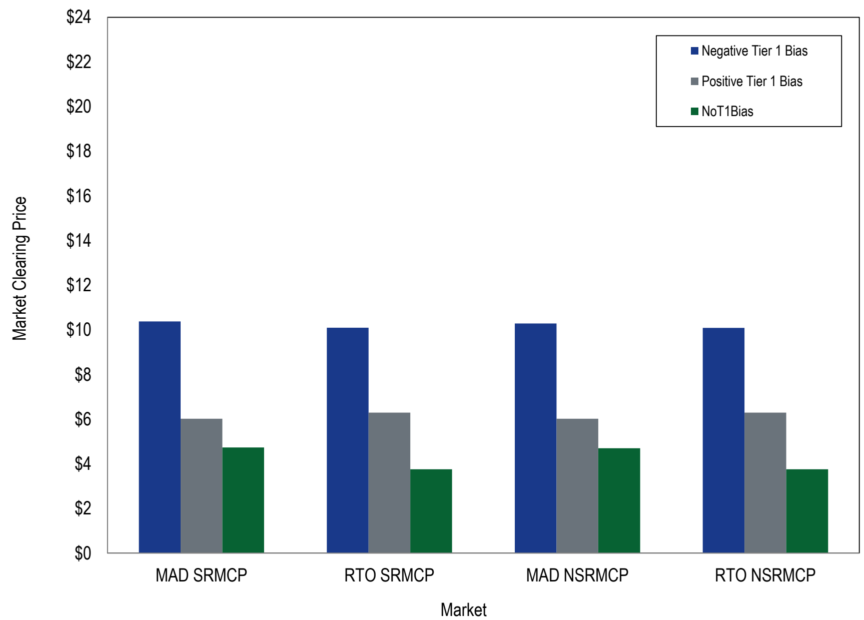
PJM uses tier 1 estimate biasing in the MAD Subzone and in the full RTO Zone of the ASO market solution (Table 10-14).

Table 10-14 RTO Zone ASO tier 1 estimate biasing: January 1, 2016 through March 31, 2017

Year	Month	Number of Hours Biased Negatively	Average Negative Bias (MW)	Number of Hours Biased Positively	Average Positive Bias (MW)
2016	Jan	21	(682.7)	64	1,104.7
2016	Feb	27	(484.3)	12	762.5
2016	Mar	1	(400.0)	28	732.1
2016	Apr	31	(303.2)	22	502.1
2016	May	19	(452.4)	21	335.7
2016	Jun	46	(502.1)	3	500.0
2016	Jul	53	(532.1)	1	250.0
2016	Aug	134	(687.1)	1	1,000.0
2016	Sep	105	(864.7)	0	NA
2016	Oct	77	(729.9)	0	NA
2016	Nov	139	(877.0)	1	100.0
2016	Dec	262	(1,420.4)	0	NA
2016		915	(661.3)	153	648.4
2017	Jan	332	(987.7)	4	362.5
2017	Feb	194	(719.7)	0	NA
2017	Mar	354	(760.5)	3	200.0
2017		880	(822.6)	7	281.3

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. Figure 6 compares the average tier 2 and nonsynchronized reserve clearing price for the RTO Zone and MAD Subzone markets, whenever the price is above $0 for all hours when tier 1 is biased negatively and all hours when tier 1 is biased positively.

Figure 10-6 Impact of tier 1 bias on clearing prices for synchronized and nonsynchronized reserve in both the RTO Zone and MAD Subzone: January through March, 2017



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.

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 sixty 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 SRMCP.

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. Tier 2 synchronized reserve resources may also be inflexible because of asserted physical limitations. Such resources include synchronous condensers operating solely for the purpose of providing synchronized reserves and demand resources.

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 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. 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.[21]

In the first three months of 2017, the Mid Atlantic Dominion (MAD) Reserve Subzone averaged 6,779.8 MW of tier 2 synchronized reserve offers, and the RTO Reserve Zone averaged 23,563.7 MW of synchronized reserve offers (Figure 10-12).

The supply of tier 2 synchronized reserve in the first three months of 2017 was sufficient to cover the 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 2017 was from CTs, 68.1 percent (Figure 10-7). 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. The DR MW share of the total cleared Tier 2 Synchronized Reserve Market was 8.8 percent in 2016.[22] The DR MW share of the total cleared Tier 2 Synchronized Reserve Market in the first three months of 2017 was 20.5 percent.

21 See PJM. "Manual 11: Energy & Ancillary Services Market Operations," Revision 84 (August 25, 2016), p. 85.
22 The cap on demand response participation is defined in MW terms. There is no cap on the proportion of cleared demand response consistent with the MW cap.

Figure 10-7 Cleared tier 2 synchronized reserve average hourly MW per hour by unit type, RTO Zone: January 1, 2016 through March 31, 2017

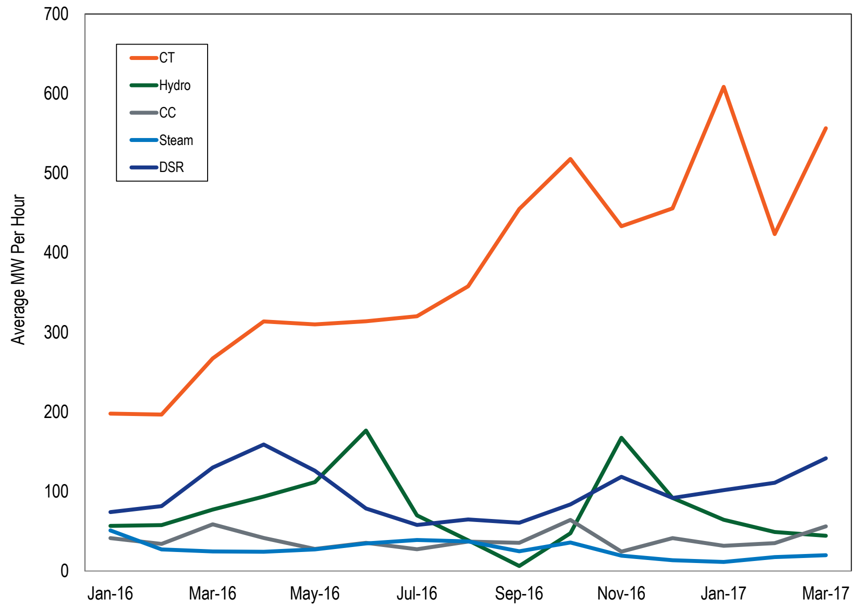
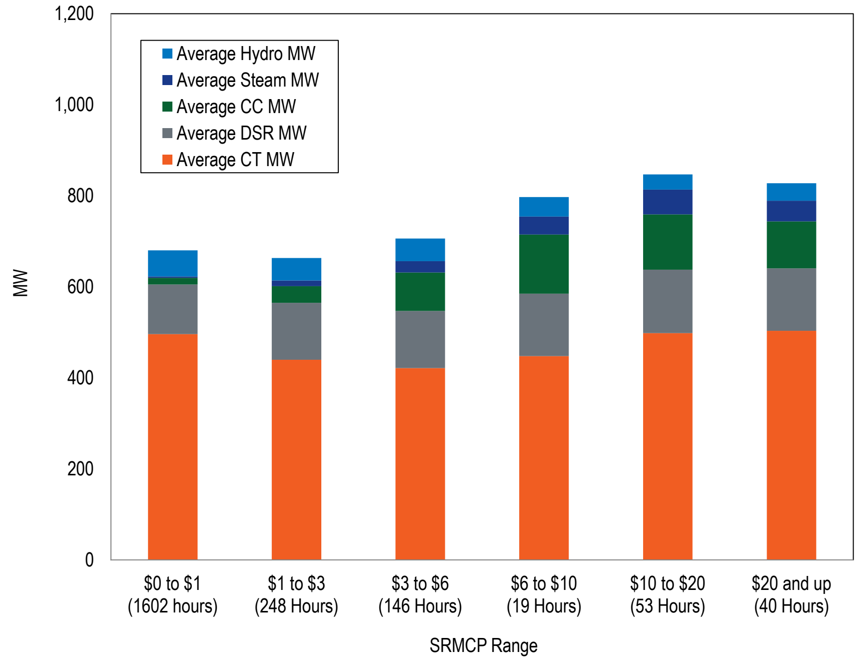


Figure 10-8 provides the average hourly cleared tier 2 MW by unit type by tier 2 clearing price range (SRMCP).

Figure 10-8 Average hourly tier 2 MW by unit type by SRMCP range: January through March, 2017



Demand

The default synchronized reserve requirement is set at 1,450 MW in both the Mid-Atlantic Dominion Subzone and the RTO Zone (Table 10-15). There are two circumstances in which PJM may alter the synchronized reserve requirement from its default value. When PJM operators anticipate periods of heavy 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 escalating 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.[23]

23 PJM. "Manual 11: Energy & Ancillary Services Market Operations," Revision 85 (November 1, 2016) pp. 88.

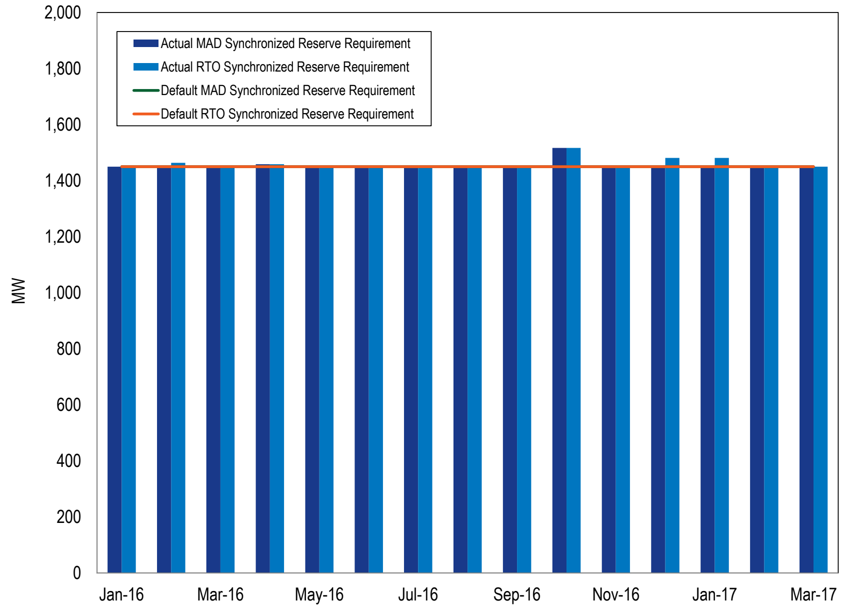
The synchronized reserve requirement was temporarily increased for the RTO Zone on January 10 and January 11, 2017, for a 31 hour period to 2,200 MW.

Table 10-15 Default Tier 2 Synchronized Reserve Markets required MW, RTO Zone and Mid-Atlantic Dominion Subzone

Mid-Atlantic Dominion Subzone			RTO Synchronized Reserve Zone		
From Date	To Date	Required MW	From Date	To Date	Required MW
May 10, 2008	May 8, 2010	1,150	May 10, 2008	Jan 1, 2009	1,305
May 8, 2010	Jul 13, 2010	1,200	Jan 1, 2009	Mar 15, 2010	1,320
July 13, 2010	Jan 1, 2015	1,300	Mar 15, 2010	Nov 12, 2012	1,350
Jan 1, 2015	Jan 8, 2015	1,342	Nov 12, 2012	Jan 8, 2015	1,375
Jan 8, 2015		1,450	Jan 8, 2015		1,450

PJM may also change the synchronized reserve requirement from its default value when grid maintenance or outages change the largest contingency. Figure 10-9 shows monthly average actual synchronized reserve requirements and the default synchronized reserve requirements..

Figure 10-9 Monthly average actual vs default synchronized reserve requirements, RTO Zone and MAD Subzone: January 2016 through March 2017



The RTO Reserve Zone cleared an hourly average of 616.4 MW of tier 2 synchronized reserves the first three months of 2017. Of this, an average of 113.6 MW cleared within the RTO exclusive of MAD and 502.8 MW cleared in the MAD Subzone.

Figure 10-10 and Figure 10-11 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 March 2017, for the RTO Reserve Zone and MAD Reserve Subzone.

Figure 10-10 MAD monthly average tier 2 synchronized reserve scheduled MW: January 1, 2016 through March 31, 2017

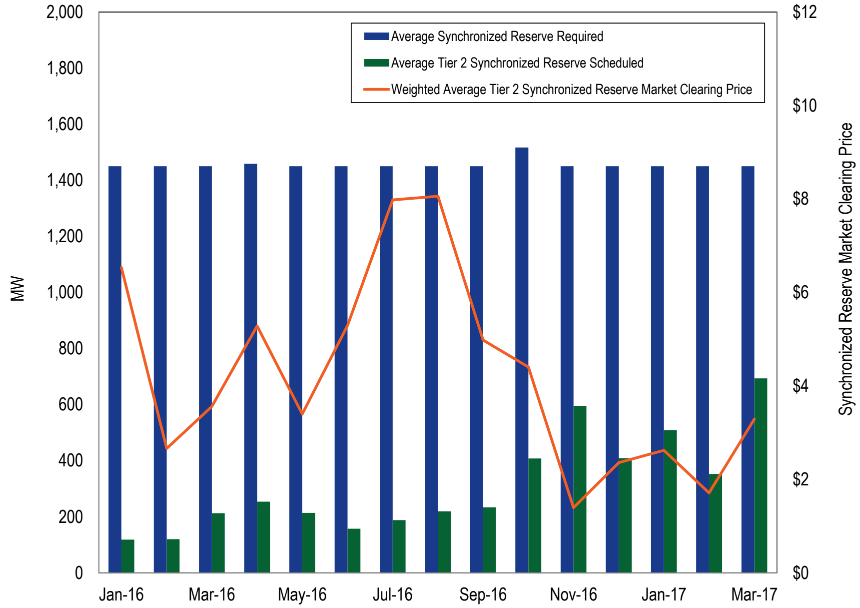
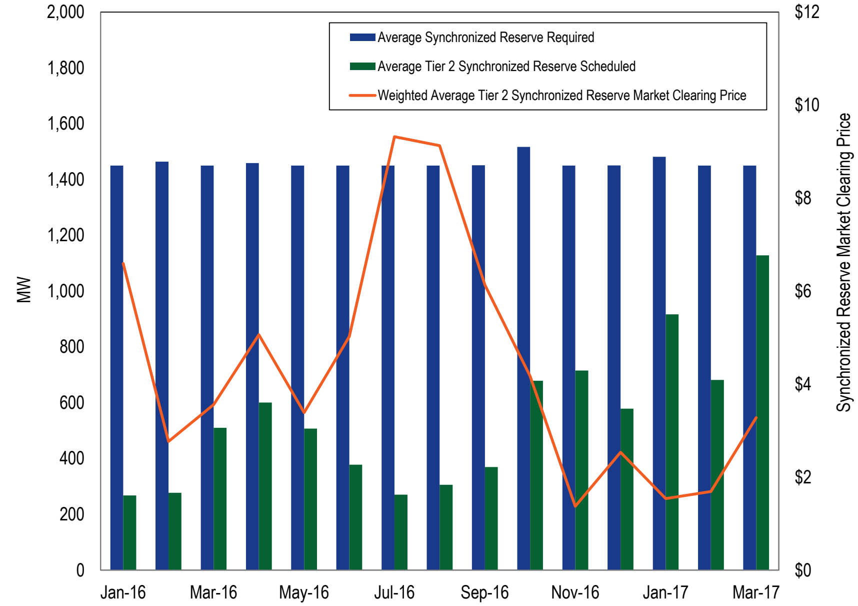


Figure 10-11 RTO monthly average tier 2 synchronized reserve scheduled MW: January 1, 2016 through March 31, 2017



Market Concentration

The HHI for tier 2 synchronized reserve for cleared hours in the Mid-Atlantic Dominion Subzone Tier 2 Synchronized Reserve Market in the first three months of 2017 was 5689, which is defined as highly concentrated. The largest hourly market share was 100 percent and 95.0 percent of all cleared hours had a maximum market share greater than or equal to 40 percent.

The HHI for tier 2 synchronized reserve for cleared hours of the RTO Zone Tier 2 Synchronized Reserve Market in the first three months of 2017 was 7321, which is defined as highly concentrated. The largest hourly market share was 100 percent and 81.3 percent of cleared hours had a maximum market share greater than or equal to 40 percent.

In the MAD Subzone, flexible synchronized reserve was 8.5 percent of all tier 2 synchronized reserve in the first three months of 2017. In the RTO Zone, flexible synchronized reserve assigned was 11.2 percent of all tier 2 synchronized reserve during the same period.

The MMU calculates that 92.2 percent of hours would have failed the three pivotal supplier test in the MAD Subzone in the first three months of 2017 for the inflexible Synchronized Reserve Market (excluding self-scheduled synchronized reserve) in the hour ahead market (Table 10-16) and 61.2 percent of hours would have failed a three pivotal supplier test in the RTO Zone during the same time period.

Table 10-16 Three pivotal supplier test results for the RTO Zone and MAD Subzone: January 1, 2016 through March 31, 2017

Year	Month	Mid Atlantic Dominion Reserve Subzone Pivotal Supplier Hours	RTO Reserve Zone Pivotal Supplier Hours
2016	Jan	82.7%	43.1%
2016	Feb	72.0%	39.6%
2016	Mar	93.4%	59.1%
2016	Apr	97.9%	55.6%
2016	May	94.2%	31.3%
2016	Jun	90.4%	27.4%
2016	Jul	79.4%	14.2%
2016	Aug	75.9%	14.4%
2016	Sep	84.3%	41.9%
2016	Oct	87.9%	80.9%
2016	Nov	96.0%	65.9%
2016	Dec	92.3%	69.8%
2016		87.2%	45.3%
2017	Jan	93.5%	73.5%
2017	Feb	88.4%	62.3%
2017	Mar	94.6%	48.0%
2017		92.2%	61.2%

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 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, spin as a condenser status, and condense available status. The synchronized reserve offer price made by the unit owner is subject to an offer cap of marginal cost plus $7.50 per MW. 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. Defined resources are not required to offer tier 2 because they cannot reliably provide synchronized reserve: nuclear, wind, solar, batteries and landfill gas.[24]

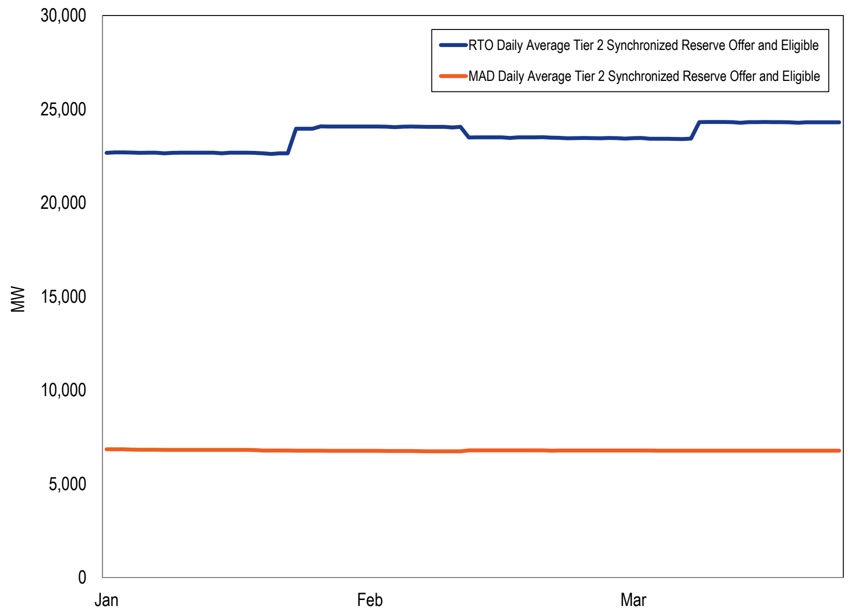
Figure 10-12 shows the daily average of hourly offered tier 2 synchronized reserve MW for both the RTO Synchronized Reserve Zone and the Mid-Atlantic Dominion Synchronized Reserve Subzone. In the first three months of 2017, the ratio of online and eligible tier 2 synchronized reserve to synchronized reserve required in the Mid-Atlantic Dominion Subzone was 4.96 averaged over all hours. For the RTO Synchronized Reserve Zone the ratio was 5.74.

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

24 See PJM "Manual 11: Energy & Ancillary Services Market Operations," Revision 85 (November 1, 2016) p. 86.

required regardless of online/offline state.[25] 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 10-12). 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. This means that while compliance with the must offer requirement can be done daily it is not possible to verify compliance with the tier 2 must offer requirement on an hourly basis.

Figure 10-12 Tier 2 synchronized reserve hourly offer and eligible volume (MW), averaged daily: January through March, 2017



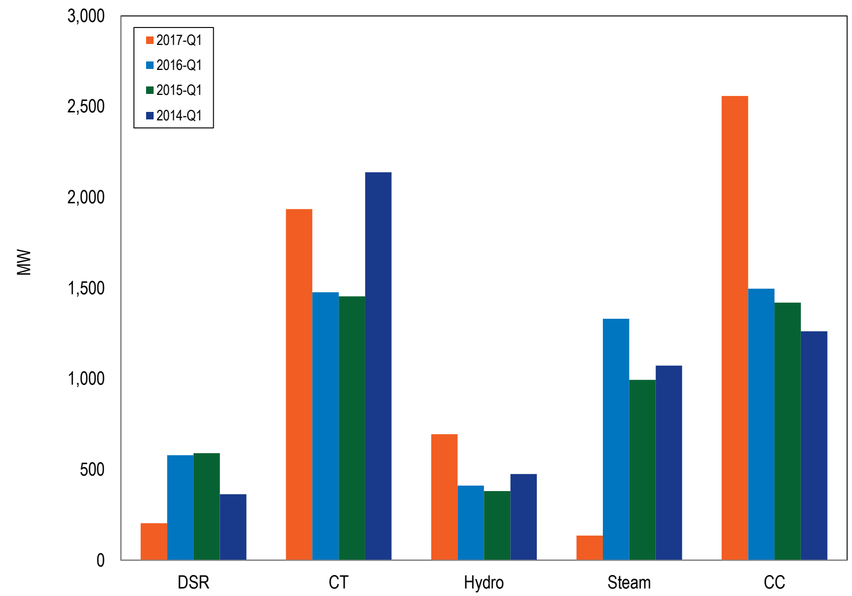
25 See PJM. "Manual 11: Energy & Ancillary Services Market Operations," Revision 85 (November 1, 2016) p. 85, "Regardless of online/offline state, all non-emergency generation capacity resources must submit a daily offer for Tier 2 Synchronized Reserve in eMKT..."

Of all nonemergency resources capable of reliably producing synchronized reserve and therefore obligated to offer, an average of 4.2 percent of units capable of providing tier 2 synchronized reserve did not enter a daily tier 2 synchronized reserve offer for the first three months of 2017.

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.[26]

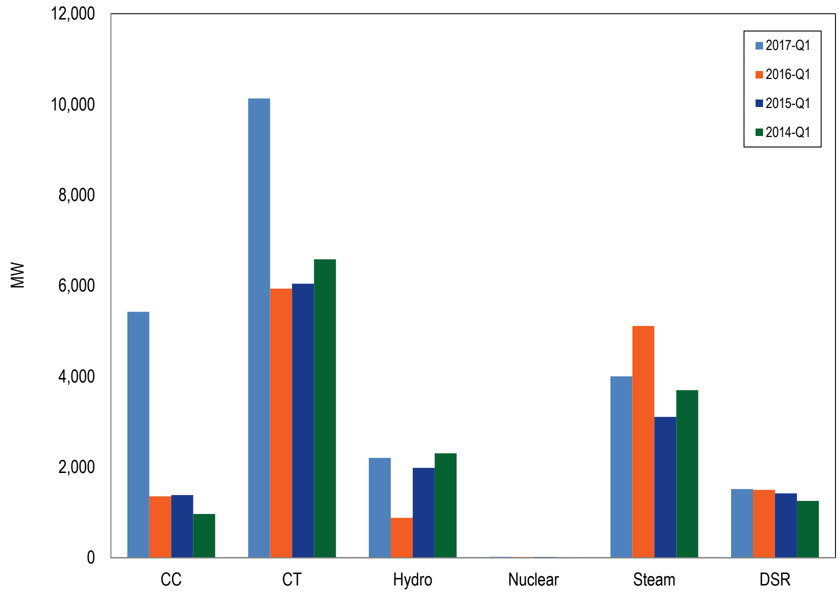
Figure 10-13 shows average offer MW volume by market and unit type for the MAD Subzone and Figure 10-14 shows average offer MW volume by market and unit type for the RTO Zone.

Figure 10-13 MAD average daily tier 2 synchronized reserve offer by unit type (MW): January through March, 2014 through 2017



26 PJM has indicated that it will initiate a new procedure in the second quarter of 2017 to enforce compliance with the tier 2 must-offer requirement.

Figure 10-14 RTO Zone average daily tier 2 synchronized reserve offer by unit type (MW): January through March, 2014 through 2017



Market Performance

Price

The price of tier 2 synchronized reserve is calculated in real time every five minutes and averaged each hour 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 market for synchronized reserves.

In the first three months of 2017, a tier 2 synchronized reserve market was cleared for the MAD Subzone in 97.9 percent of all hours. In 2.1 percent of hours there was enough tier 1 synchronized reserve to cover the full requirement. The MAD tier 2 market cleared an average of 379.3 MW at a weighted average clearing price of $2.22 compared to $4.99 in the first three months of 2016.

In the first three months of 2017, the Tier 2 Synchronized Reserve Market for the RTO Zone cleared an average of 396.1 MW at a weighted average price of $2.32 compared to $4.96 in the first three months of 2016.

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 $10.53 in the MAD Subzone, and $8.03 in the RTO Zone.

Supply, performance, and demand are reflected in the price of synchronized reserve. (Figure 10-10 and Figure 10-11).

Table 10-17 Mid-Atlantic Dominion subzone, weighted average SRMCP and average scheduled, tier 1 estimated and demand response MW: January 1, 2016 through March 31, 2017

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)
2016	Jan	$4.70	206.1	586.1	62.2
2016	Feb	$1.99	205.3	609.3	63.1
2016	Mar	$3.07	386.8	402.4	97.8
2016	Apr	$4.62	500.9	341.7	125.7
2016	May	$2.88	432.0	408.2	96.6
2016	Jun	$4.34	311.7	638.4	67.1
2016	Jul	$7.98	188.0	756.7	46.8
2016	Aug	$8.06	219.2	750.5	50.5
2016	Sep	$4.66	230.6	658.9	43.6
2016	Oct	$4.00	407.9	393.6	58.8
2016	Nov	$1.28	595.1	385.2	92.8
2016	Dec	$2.21	408.7	500.5	69.5
2016		$4.15	341.0	539.2	72.9
2017	Jan	$2.18	400.7	592.0	75.3
2017	Feb	$1.60	288.8	577.0	84.8
2017	Mar	$2.88	549.3	464.1	108.4
2017		$2.22	412.9	544.4	89.5

Table 10-18 RTO zone weighted average SRMCP and average scheduled, tier 1 estimated and demand response MW: January 1, 2016 through March 31, 2017

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)
2016	Jan	$6.64	269.5	1,659.4	74.3
2016	Feb	$2.76	277.9	1,564.1	81.5
2016	Mar	$3.56	510.2	1,089.1	130.0
2016	Apr	$5.06	602.2	1,011.7	159.3
2016	May	$3.39	508.3	1,160.9	125.8
2016	Jun	$5.03	378.3	1,546.0	78.4
2016	Jul	$9.32	270.5	1,663.8	59.6
2016	Aug	$9.13	306.0	1,605.6	64.5
2016	Sep	$5.62	364.6	1,290.4	60.7
2016	Oct	$4.17	678.9	802.7	83.5
2016	Nov	$1.37	715.6	810.8	117.7
2016	Dec	$2.54	578.6	953.1	92.5
2016		$4.88	455.1	1,399.0	94.0
2017	Jan	$2.00	639.2	592.0	100.9
2017	Feb	$1.70	483.5	577.0	110.6
2017	Mar	$3.28	728.2	464.1	140.7
2017		$2.33	617.0	544.4	117.4

Cost

As a result of changing grid conditions, load forecasts, and unexpected generator performance, prices do not always cover the full cost including the final LOC for each resource. Because price formation occurs within the hour (on a five minute basis integrated over the hour) but the 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 the first three months of 2017, the price to cost (including self-scheduled) ratio of the RTO Zone Tier 2 Synchronized Reserve Market averaged 32.5 percent (Table 10-19); the price to cost ratio of the MAD Subzone averaged 32.0 percent.

Table 10-19 RTO Zone, Mid-Atlantic Subzone tier 2 synchronized reserve MW, credits, weighted price, and cost (including self-scheduled): January 1 through March 31, 2017

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	297,672	$1,926,899	$2.18	$6.47	33.7%
MAD Subzone	2017	Feb	194,076	$1,423,859	$1.60	$7.34	21.8%
MAD Subzone	2017	Mar	406,593	$2,846,983	$2.88	$7.00	41.2%
MAD Subzone	2017		898,341	$6,197,742	$2.22	$6.94	32.0%
RTO Zone	2017	Jan	475,031	$3,201,712	$2.00	$6.74	29.7%
RTO Zone	2017	Feb	324,910	$2,082,841	$1.70	$6.41	26.5%
RTO Zone	2017	Mar	539,411	$4,478,254	$3.28	$8.30	39.5%
RTO Zone	2017		1,339,352	$9,762,807	$2.33	$7.15	32.5%

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.[27] 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.[28] Tier 2 resources are obligated to sustain their final output for the

27 See the *2011 State of the Market Report for PJM*, Volume II, Section 9, "Ancillary Services" at pg. 250.
28 See PJM "Manual 11: Energy & Ancillary Services Market Operations," Revision 84 (August 25, 2016) § 4.2.11 Verification, p. 97.

shorter of the length of the event or 30 minutes. Penalties can be assessed for failure of a scheduled tier 2 resource to perform during any synchronized reserve event lasting 10 minutes or longer.

The MMU has reported the wide range of synchronized reserve event response levels and recommended that PJM take action to increase compliance rates. 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 the first three months of 2017 there have been nine spinning events only one of which was longer 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.[29] Tier 2 resource owners are paid for being available and responding 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.

A tier 2 resource is penalized for the amount of MW it falls short of its offer for the entire hour, not just for the portion of the hour covered by the synchronized reserve event.[30] The penalty period extends for the average number of days between spinning events. For the first three months of 2017, PJM used the average number of days between spinning events from November 2015 through October 2016 which is 13 days.[31] 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.

There was only one synchronized reserve event of 10 minutes or longer that occurred in the first three months of 2017. In that event from March 23, 2017, 24.7 percent of all scheduled tier 2 synchronized reserve MW were not delivered and were penalized (Table 10-20).

29 See PJM "Manual 11: Energy & Ancillary Services Market Operations," Revision 85 (November 1, 2016) § 4.2.12 Non Performance, p. 98.
30 See PJM. "Manual 28: Operating Agreement Accounting," Revision 75 (November 18, 2016) p. 47. *See also* "See PJM "Manual 11: Energy & Ancillary Services Market Operations," Revision 85 (November 1, 2016) § 4.2.12 Non-Performance, p. 99.
31 "2016 Third Quarter Synchronized Reserve Performance & 2017 Synchronized Reserve Penalty Days," presentation to the Operating Committee, December 13, 2016. <http://www.pjm.com/~/media/committees-groups/committees/oc/20161213/20161213-item-16-2016-third-quarter-synchronized-reserve-performance-with-2017-penalty-days.ashx>

Table 10-20 Synchronized reserve events 10 minutes or longer, tier 2 response compliance, RTO Reserve Zone: January 1 through March 31, 2017

Spin Event (Day, Time)	Duration (Minutes)	Tier 1 Estimate (MW Adj by DGP)	Tier 1 Resp (MW)	Tier 2 Scheduled (MW)	Tier 2 Response (MW)	Tier 2 Penalty (MW)	Tier 1 Response Pct	Tier 2 Response Pct
Mar 23, 2017 06:48	24	926.8	549.6	742.8	559.1	183.7	59.3%	75.3%

History of Synchronized Reserve Events

Synchronized reserve is designed to provide relief for disturbances.[32 33] A disturbance is defined as loss of generation and/or transmission resources. 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 three low ACE events in the first three months of 2017, on January 12, 2017 for 8 minutes, February 13, 2017 for 7 minutes, and on March 23, 2017 for 24 minutes.

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 thirty minutes. When the need is for reserve extending past thirty 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 March 31, 2017, PJM experienced 193 synchronized reserve events (Table 10-21), approximately 2.2 events per month. During this period, synchronized reserve events had an average duration of 12.2 minutes.

32 2013 State of the Market Report for PJM, Appendix F – PJM's DCS Performance, pp 451-452.
33 See PJM. "Manual 12: Balancing Operations," Revision 34 (April 28, 2016) § 4.1.2 Loading Reserves pp. 36.

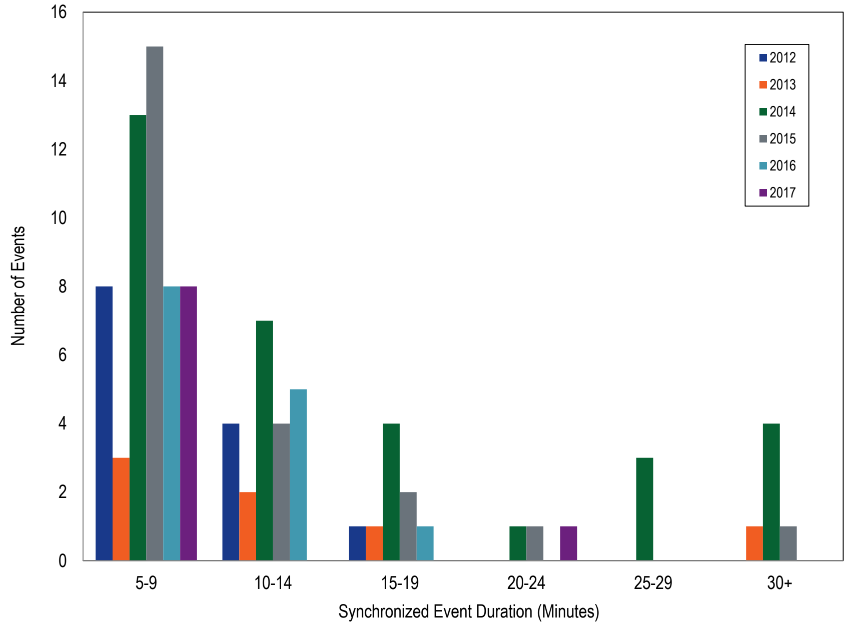
Table 10-21 Synchronized reserve events: January 1, 2010 through March 31, 2017

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
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
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
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
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
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
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
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
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
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
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
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
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
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
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
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
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
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
SEP-15-2010 11:20	RFC	13	MAY-31-2011 16:36	RFC	27	OCT-30-2012 05:12	RTO	14			
SEP-22-2010 15:28	Mid-Atlantic	24	JUN-03-2011 14:23	RFC	7	NOV-25-2012 16:32	RTO	12			
OCT-05-2010 17:20	RFC	10	JUN-06-2011 22:02	Mid-Atlantic	9	DEC-16-2012 07:01	RTO	9			
OCT-16-2010 03:22	Mid-Atlantic	10	JUN-23-2011 23:26	RFC	8	DEC-21-2012 05:51	RTO	7			
OCT-16-2010 03:25	RFCNonMA	7	JUN-26-2011 22:03	Mid-Atlantic	10	DEC-21-2012 10:29	RTO	5			
OCT-27-2010 10:35	RFC	7	JUL-10-2011 11:20	RFC	10						
OCT-27-2010 12:50	Mid-Atlantic	10	JUL-28-2011 18:49	RFC	12						
NOV-26-2010 14:24	RFC	13	AUG-02-2011 01:08	RFC	6						
NOV-27-2010 11:34	RFC	8	AUG-18-2011 06:45	Mid-Atlantic	6						
DEC-08-2010 01:19	RFC	11	AUG-19-2011 14:49	RFC	5						
DEC-09-2010 20:07	RFC	5	AUG-23-2011 17:52	RFC	7						
DEC-14-2010 12:02	Mid-Atlantic	24	SEP-24-2011 15:48	RFC	8						
DEC-16-2010 18:40	Mid-Atlantic	20	SEP-27-2011 14:20	RFC	7						
DEC-17-2010 22:09	Mid-Atlantic	6	SEP-27-2011 16:47	RFC	9						
DEC-29-2010 19:01	Mid-Atlantic	15	OCT-30-2011 22:39	Mid-Atlantic	10						
			DEC-15-2011 14:35	Mid-Atlantic	8						
			DEC-21-2011 14:26	RFC	18						

Table 10-21 Synchronized reserve events: January 1, 2010 through March 31 2017 (continued)

Effective Time	Region	Duration (Minutes)	Effective Time	Region	Duration (Minutes)	Effective Time	Region	Duration (Minutes)	Effective Time	Region	Duration (Minutes)
JAN-06-2014 22:01	RTO	68	JAN-07-2015 22:36	RTO	8	JAN-18-2016 17:58	RTO	12	Jan-08-2017 03:21	RTO	7
JAN-07-2014 02:20	RTO	25	FEB-24-2015 02:51	RTO	5	FEB-08-2016 15:05	RTO	10	Jan-09-2017 19:24	RTO	9
JAN-07-2014 04:18	RTO	34	FEB-26-2015 15:20	RTO	6	FEB-28-2016 18:29	RTO	8	Jan-10-2017 13:05	MAD	9
JAN-07-2014 11:27	RTO	11	MAR-03-2015 17:02	RTO	11	APR-14-2016 20:09	RTO	10	Jan-15-2017 20:13	RTO	8
JAN-07-2014 13:20	RTO	41	MAR-16-2015 10:25	RTO	24	MAY-11-2016 15:55	RTO	6	Jan-23-2017 09:08	RTO	7
JAN-10-2014 16:46	RTO	12	MAR-17-2015 23:34	RTO	17	JUN-01-2016 09:01	RTO	5	Feb-13-2017 18:30	RTO	7
JAN-21-2014 18:52	RTO	6	MAR-23-2015 23:44	RTO	15	JUL-06-2016 00:40	RTO	5	Feb-14-2017 00:11	RTO	6
JAN-22-2014 02:26	RTO	7	APR-06-2015 14:23	RTO	8	JUL-28-2016 13:28	RTO	15	Feb-15-2017 06:37	RTO	6
JAN-22-2014 22:54	RTO	8	APR-07-2015 17:11	RTO	31	AUG-31-2016 19:29	RTO	8	Mar-23-2017 06:48	RTO	24
JAN-25-2014 05:22	RTO	10	APR-15-2015 08:14	RTO	8	SEP-09-2016 19:11	RTO	6			
JAN-26-2014 17:11	RTO	6	APR-25-2015 03:21	RTO	9	SEP-11-2016 19:30	RTO	9			
JAN-31-2014 15:05	RTO	13	JUL-30-2015 14:04	RTO	10	OCT-12-2016 08:21	RTO	5			
FEB-02-2014 14:03	Dominion	8	AUG-05-2015 19:47	RTO	7	OCT-12-2016 14:40	RTO	7			
FEB-08-2014 06:05	Dominion	18	AUG-19-2015 16:47	RTO	9	NOV-04-2016 17:13	RTO	11			
FEB-22-2014 23:05	RTO	7	SEP-05-2015 01:16	RTO	7	DEC-03-2016 00:11	RTO	7			
MAR-01-2014 05:18	RTO	26	SEP-10-2015 10:12	RTO	8	DEC-31-2016 05:10	RTO	12			
MAR-05-2014 21:25	RTO	8	SEP-29-2015 00:58	Mid-Atlantic	11						
MAR-13-2014 20:39	RTO	8	NOV-12-2015 16:42	RTO	8						
MAR-27-2014 10:37	RTO	56	NOV-21-2015 17:17	RTO	8						
APR-14-2014 01:16	RTO	10	DEC-04-2015 22:41	RTO	7						
APR-25-2014 17:33	RTO	6	DEC-24-2015 17:42	RTO	8						
MAY-01-2014 14:18	RTO	13									
MAY-03-2014 17:11	RTO	13									
MAY-14-2014 01:36	RTO	5									
JUL-08-2014 03:07	RTO	9									
JUL-25-2014 19:19	RTO	7									
SEP-06-2014 13:32	RTO	18									
SEP-20-2014 23:42	RTO	14									
SEP-29-2014 10:08	RTO	15									
OCT-20-2014 06:35	RTO	15									
OCT-23-2014 11:03	RTO	27									
NOV-01-2014 06:50	RTO	9									
NOV-08-2014 02:08	RTO	8									
NOV-22-2014 05:27	RTO	21									
NOV-22-2014 08:19	RTO	10									
DEC-10-2014 18:58	RTO	8									
DEC-31-2014 21:42	RTO	12									

Figure 10-15 Synchronized reserve events duration distribution curve: January through March, 2012 through 2017



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. 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 always less than or equal to the synchronized reserve market clearing price. In most hours, the nonsynchronized reserve clearing price is zero.

Market Structure

Demand

PJM specifies that 1,700 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). The balance of primary reserve can be made up by the most economic combination of synchronized and nonsynchronized reserve. PJM market operations increased the required amount of primary reserve from 2,175 MW to 3,300 MW on January 10 and January 11, 2017, for a 32 hour period.

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 non-synchronized 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 times10 minutes minus the startup and notification time. The offer price of nonsynchronized is the unit's opportunity cost of providing reserves.

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

Resources that generally qualify as nonsynchronized reserve include run of river hydro, pumped hydro, combustion turbines, combined cycles and diesels.[34] In the first three months of 2017, an average of 379.4 MW of nonsynchronized reserve was scheduled hourly out of 1,847.2 eligible MW as part of the primary reserve requirement in the Mid-Atlantic Dominion Subzone. In the first three months of 2017, an average of 676.2 MW of nonsynchronized reserve was scheduled hourly out of 2,244.9 MW eligible MW in the RTO Zone.

In the first three months of 2017, CTs provided 35.6 percent of scheduled nonsynchronized reserve and hydro provided 63.9 percent. The remaining 0.5 percent of cleared nonsynchronized reserve was provided by diesel resources.

Market Concentration

The supply of nonsynchronized reserves in the Mid-Atlantic Dominion Subzone and the RTO Zone was highly concentrated in the first three months of 2017.

Table 10-22 Nonsynchronized reserve market HHIs: January 1 through March 31, 2017

Year	Month	MAD HHI	RTO HHI
2017	Jan	3968	3966
2017	Feb	3995	3986
2017	Mar	4359	4343
2017	Average	4107	4098

Table 10-23 Nonsynchronized reserve market pivotal supply test: January 1 through March 31, 2017

Year	Month	MAD Three Pivotal Supplier Hours	RTO Three Pivotal Supplier Hours
2017	Jan	32.2%	0.0%
2017	Feb	31.1%	0.0%
2017	Mar	38.1%	0.0%
2017	Average	33.8%	0.0%

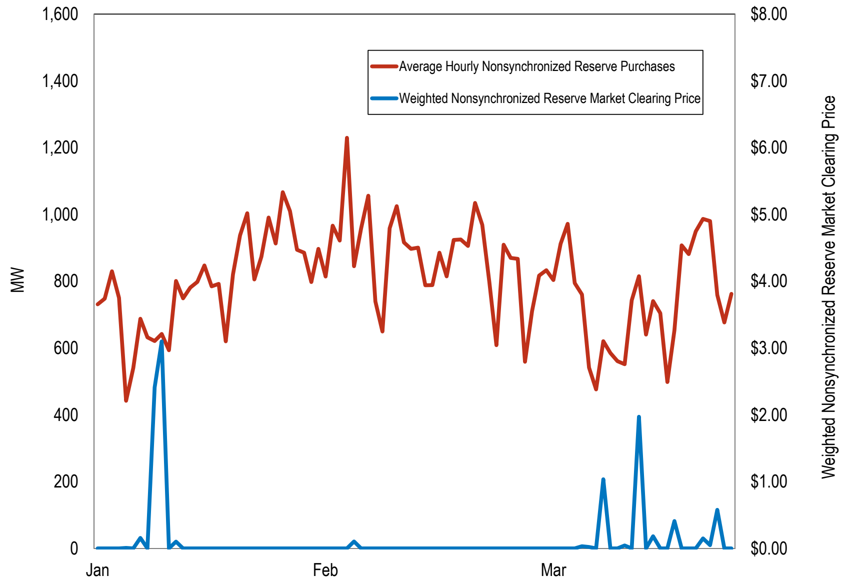
Price

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

Figure 10-16 shows the daily average nonsynchronized reserve market clearing price and average scheduled MW for the RTO Zone. In the MAD Subzone and the RTO Zone in the first three months of 2017, the average nonsynchronized market clearing price was $0.11 per MW. The hourly average nonsynchronized reserve assigned was 805.0 MW. The market cleared at a price greater than $0 in 34 hours. The maximum hourly clearing price was $27.53 per MW on March 18, 2017.

34 See PJM. "Manual 11: Energy & Ancillary Services Market Operations," Revision 84 (August 25, 2016), p. 101.

Figure 10-16 Daily average RTO Zone nonsynchronized reserve market clearing price and MW purchased: January 1 through March 31, 2017



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.[35]

The full cost of nonsynchronized reserve including payments for the clearing price and uplift costs is calculated and compared to the price (Table 10-24). The closer the price to cost ratio comes to one, the more the market price reflects the full cost of non-synchronized reserve.

In the first three months of 2017, the price to cost ratio in both the RTO Zone Nonsynchronized Reserve Market averaged 18.1 percent; and the price to cost ratio of the MAD Subzone averaged 20.5 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 only 1.6 percent of hours.

The costs of nonsynchronized reserves could be minimized if PJM could flexibly substitute lower LOC units for higher LOC units in real time as system conditions changed. Under current rules, PJM is required to keep committed a unit for which the LOC increases within the hour even if lower LOC units are available as substitutes.

Table 10-24 RTO zone, MAD subzone nonsynchronized reserve MW, charges, price, and cost: January 1 through March 31, 2017

Market	Year	Month	Total Non-synchronized Reserve MW	Total Non-synchronized Reserve Charges	Weighted Non-synchronized Reserve Market Price	Non-synchronized Reserve Cost	Price/Cost Ratio
RTO Zone Full	2017	Jan	585,413	$386,166	$0.15	$0.66	22.9%
RTO Zone Full	2017	Feb	599,911	$180,670	$0.00	$0.30	1.2%
RTO Zone Full	2017	Mar	553,573	$391,475	$0.15	$0.71	20.5%
RTO Zone Full	2017	Total	1,738,897	$958,311	$0.10	$0.55	18.1%
MAD	2017	Jan	584,751	$329,190	$0.15	$0.56	26.3%
MAD	2017	Feb	599,851	$178,880	$0.00	$0.30	1.2%
MAD	2017	Mar	552,418	$331,164	$0.15	$0.60	24.3%
MAD	2017	Total	1,737,020	$839,234	$0.10	$0.48	20.5%

35 See PJM. "Manual 11: Energy & Ancillary Services Market Operations," Revision 85 (November 1, 2016), p. 103.

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.[36] The Day-Ahead Scheduling Reserves 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.[37]

Market Structure

Supply

DASR is offered by both generation and demand resources. DASR offers consist of price only. 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 thirty minutes, or the economic maximum MW minus the day-ahead dispatch point. For offline resources capable of being online in thirty minutes, the DASR quantity is the economic maximum. In the first three months of 2017, the average available hourly DASR was 37,058 MW, a 6.6 percent increase from 2016. The DASR hourly MW purchased averaged 5,323.3 MW, a small decrease from 5,645.4 MW the first three months of 2016.

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.[38] 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 non-eligibility.

36 See PJM. "Glossary."<http://www.pjm.com/Glossary.aspx>.
37 See PJM. "Manual 11: Energy & Ancillary Services Market Operations," Revision 85 (November 1, 2016), p. 166 §11.1.
38 See PJM. "Manual 11: Energy & Ancillary Services Market Operations," Revision 85 (November 1, 2016), p. 169 §11.2.3 Day-Ahead Scheduling Reserve Market Rules.

On December 14, 2015, PJM announced a plan to recover DASR credits awarded to owners for units that clear the day-ahead scheduled reserve market but become unavailable through forced outage in real time.[39] The recovery was for hours cleared from April 2015 through March 2016. This recovery is completed for a total of $404K.

All generation resources are required to offer a price for DASR.[40] Of the 5,323.3 MW average hourly DASR cleared in the first three months of 2017, 67.1 percent was from CTs, 6.3 percent was from steam, 19.6 percent was from hydro, and 6.2 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 the first three months of 2017, seven demand resources offered into the DASR Market.

Demand

Secondary reserve (30-minute reserve) requirements are determined by PJM for each reliability region. In the Reliability*First* (RFC) region, secondary reserve requirements are calculated based on historical under-forecasted load rates and generator forced outage rates.[41] 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. For 2017, the DASR requirement is set to 5.52 percent of daily peak load forecast. This is down from 5.70 for 2016. 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."[42] The amount of additional DASR MW that may be required is the Adjusted Fixed Demand (AFD) determined by a Seasonal Conditional Demand (SCD) factor.[43] The SCD

39 See PJM Market Settlements Subcommittee Meeting, December 14, 2015, "Item 01 – CT LOC Reconciliation," <http://www.pjm.com/~/media/committees-groups/subcommittees/mss/20151214/20151214-item-01-ct-loc-reconciliation.ashx>
40 See PJM Manual 11: Energy & Ancillary Services Market Operations," Revision 82 (July 1, 2016), p. 144 §11.2.3 Day-Ahead Scheduling Reserve Market Rules.
41 See PJM. "Manual 13: Emergency Operations," Revision 61 (January 1, 2017), p. 12.
42 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>.
43 See PJM. "See PJM "Manual 11: Energy & Ancillary Services Market Operations," Revision 85 (November 11, 2016) p. 166 at 11.2.1 Day-Ahead Scheduling Reserve Market Requirement.

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 2015 through October 2016, the SCD values are 3.45 percent for winter and 2.88 percent for summer. PJM Dispatch may also schedule additional Day-Ahead Scheduling Reserves as deemed necessary for conservative operations.[44] 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.[45] The result is substantial discretion for PJM to increase the demand for DASR under a variety of circumstances. PJM did not invoked adjusted fixed demand in the first three months of 2017.

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

The MMU recommends that PJM make a change to the DASR market so that any resource that clears the DASR market incurs a real-time obligation to be available for secondary reserve.

Market Concentration

DASR market three pivotal test results are provided in Table 10-25.

44 See PJM "See PJM "Manual 11: Energy & Ancillary Services Market Operations," Revision 85 (November 1, 2016) p. 167 at 11.2.1 Day-Ahead Scheduling Reserve Market Requirement.

45 See PJM, "Manual 13: Emergency Operations" Revision 61, (January 1e 2017), p. 53 at 3.2 Conservative Operations

Table 10-25 DASR market three pivotal supplier test results and number of hours with DASRMCP above $0: January 1, 2016 through March 31, 2017

Year	Month	Number of Hours When DASRMCP > $0	Percent of Hours Pivotal
2016	Jan	326	0.3%
2016	Feb	235	0.4%
2016	Mar	369	1.9%
2016	Apr	392	0.0%
2016	May	259	4.2%
2016	Jun	193	6.2%
2016	Jul	474	38.0%
2016	Aug	402	42.8%
2016	Sep	383	45.7%
2016	Oct	373	35.1%
2016	Nov	351	20.8%
2016	Dec	209	23.9%
2016	Average	331	18.3%
2017	Jan	93	16.1%
2017	Feb	49	2.0%
2017	Mar	359	2.5%
2017	Average	167	6.9%

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.[46] Units that do not offer have their offers set to $0.00 per MW.

Economic withholding remains an issue in the DASR Market. The marginal cost of providing DASR is zero. All offers greater than zero constitute economic withholding. In the first three months of 2017, 39.3 percent of generation units offered DASR at a daily price above $0.00. This compares to 36.2 percent in 2016. In the first three months of 2017, 14.2 percent of daily offers were above $5.00 per MW.

Market Performance

In the first three months of 2017 the DASR market cleared at a price above $0 in 501 hours. In the first three months of 2017, the weighted average DASR

46 See PJM "Manual 11: Energy & Ancillary Services Market Operations," Revision 85 (November 1, 2016), p. 168.

price for all hours when the DASRMCP was above $0.00 was $0.06. In 2016, the weighted average DASR price for all hours when the DASRMCP was above $0.00 was $1.61. The average cleared MW in all hours was 3,916.3 MW. The average cleared MW in all hours when the DASRMCP was above $0.00 was 4,180.8 MW. The highest DASR price was $3.00 on Mar 23, 2017.

The introduction of Adjusted Fixed Demand (AFD) on March 1, 2015, created a bifurcated market (Table 10-26). 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. The difference in market clearing price, MW cleared, obligation incurred, and charges to PJM load are substantial. During the 522 hours when AFD was in effect, the weighted average DASR price was $9.30 compared to $2.69 for hours when DASRMCP was greater than $0.00 and PJM dispatch did not augment the requirement. PJM did not invoke adjusted fixed demand in 2017, and this has resulted in lower demand and lower prices.

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 10-26 DASR Market, regular hours vs. adjusted fixed demand hours: January 1, 2016 through March 31, 2017

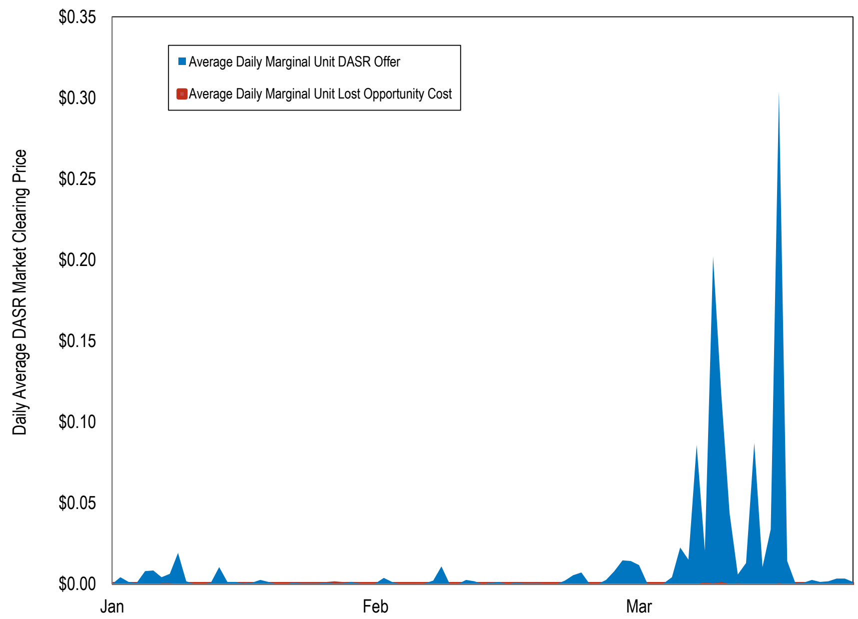
		Number of Hours DASRMCP>$0		Weighted DASRMCP		Average PJM Load MW		Hourly Average Cleared DASR MW		Average Hourly DASR Credits	
Year	Month	Normal Hour	AFD Hour	Normal Hour	AFD Hour	Normal Hour	AFD Hour	Normal Hour	AFD Hour	Normal Hour	AFD Hour
2016	Jan	326		$0.15		103,263		4,723		$720	
2016	Feb	212	24	$0.05	$3.10	102,040	107,852	4,640	6,830	$249	$21,167
2016	Mar	369		$0.04		83,994		4,175		$175	
2016	Apr	393		$0.26		80,925		4,083		$1,060	
2016	May	259		$0.43		89,181		4,228		$1,839	
2016	Jun	191		$0.53		111,102		5,377		$2,892	
2016	Jul	188	288	$0.71	$8.23	117,686	112,587	5,794	10,226	$4,117	$84,195
2016	Aug	247	143	$0.76	$10.82	122,187	113,823	6,076	11,150	$4,639	$120,663
2016	Sep	316	67	$1.11	$11.53	100,198	110,940	5,231	12,163	$5,792	$138,972
2016	Oct	373	0	$0.58	$0.00	82,824	0	4,265		$2,494	
2016	Nov	350	0	$0.10	$0.00	84,561	0	4,095		$420	
2016	Dec	210	0	$0.04	$0.00	102,293	0	4,444		$169	
2016		286	75	$0.40	$4.81	98,355	63,600	4,761	10,092	$2,047	$91,249
2017	Jan	93		$0.02		106,095		4,386		$91	
2017	Feb	49		$0.02		96,628		4,444		$92	
2017	Mar	359		$0.08		91,182		4,092		$330	
2017		167		$0.04		97,968		4,307		$171	

The implementation of AFD in 367 hours of 2015 and 528 hours of 2016 significantly increased the cost of DASR as a result of increases in DASR MW cleared and corresponding increases in the DASR clearing prices (Table 10-27).

Table 10-27 DASR Market all hours of DASR market clearing price greater than $0: January 1, 2016 through March 31, 2017

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
2016	Jan	326	$0.15	103,263	1,539,783	0	$234,679
2016	Feb	212	$0.49	102,631	1,147,608	72,197	$560,692
2016	Mar	369	$0.04	83,994	1,540,415	0	$64,728
2016	Apr	393	$0.26	80,925	1,604,693	0	$416,418
2016	May	259	$0.43	89,181	1,094,991	0	$476,305
2016	Jun	191	$0.54	111,102	1,027,053	0	$552,455
2016	Jul	476	$6.20	114,601	4,034,436	1,161,661	$25,022,218
2016	Aug	390	$5.94	119,563	3,095,240	742,332	$18,400,638
2016	Sep	383	$4.51	102,077	2,467,814	409,330	$11,141,362
2016	Oct	373	$0.58	82,824	1,591,016	0	$930,355
2016	Nov	350	$0.10	84,561	1,433,267	0	$147,023
2016	Dec	210	$0.04	102,292	933,225	0	$33,582
2016	Average	328	$1.61	98,085	1,792,462	198,793	$4,831,704
2016	Total	3932			21,509,542	2,385,520	$57,980,453
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	$118,345
2017	Average	167	$0.04	97,968	698,193	0	$43,752
2017	Total	501			2,094,580	0	$131,257

Figure 10-17 Daily average components of DASR clearing price ($/MW), marginal unit offer and LOC: January 1 through March 31, 2017



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 10-17). DASR prices increase at peak loads as a result of high LOCs. For the first three months of 2017, DASR prices were low to moderate and included LOC in only 43 hours of the 501 hours when DASRMCP was above $0. The first three months of 2017 showed the same pattern as the first three months of 2016 with low prices and therefore little LOC.

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. Significant technical and structural changes were made to the PJM Regulation Market in 2012.[47]

Market Design

The objective of PJM's regulation market design is to minimize the cost to provide regulation using two resource types, RegA and RegD, in a single market. The RegA signal is designed for energy unlimited resources (for example, thermal and/or hydro resources) with physically constrained ramp ability. The RegD signal is designed for energy limited resources with very fast ramp rates. Some resource types (such as some Combustion Turbines) can qualify as both RegA and RegD.

Regulation was historically provided by resources following the RegA signal. Since regulation service could be provided solely with RegA following resources, performance adjusted RegA MW are used as the common unit of measure, called effective MW, of regulation service provided in the PJM Regulation Market. The regulation requirement (the amount of regulation MW needed to control for ACE) is defined in terms of the total effective MW required to provide an expected amount of area control error (ACE) control.

In concept, the Regulation Market solution starts with an assumption of the effective regulation requirement being met entirely with performance adjusted RegA MW. When solving for the least cost combination of RegA and RegD MW to meet the effective regulation requirement, the Regulation Market will substitute RegD MW for RegA MW so long as it is economic (reduces total cost while maintaining a fixed level of control) to do so. The Regulation Market functions by converting performance adjusted RegD MW into their marginal effective MW equivalent using a marginal rate of substitution called a marginal benefit function (MBF). The MBF is used to convert incremental additions of RegD MW into incremental effective MW. Correctly implemented, the total effective MW for a given amount of RegD MW are determined by the area under the MBF curve (the sum of the incremental effective MW contributions). This conversion into a common unit of measure allows a direct comparison of RegA and RegD offers. The MBF reflects the fact that each additional MW of RegD has a progressively smaller value defined as incremental effective MW. Total regulation provided by a given combination of RegA and RegD is defined in terms of total effective MW. In a correctly implemented market structure, all resources, either RegA or RegD, would be paid the same price per marginal effective MW provided.

To meet the objective of minimizing cost, the marginal benefit factor (MBF) function describing the engineering substitutability between RegA and RegD must be correctly defined and consistently applied throughout the market design, from optimization to settlement. Correctly implemented, the MBF would define and be used as the marginal rate of technical substitution (MRTS) between RegA and RegD, holding regulation service constant. Consistently applying the MBF from optimization to settlement is the only way to ensure that the engineering relationship is reflected in the relative value of RegA and RegD resources in the market price signals. That is not the case in PJM's current regulation market design. The MBF function is not correctly defined as the MRTS between RegA and RegD and it is not consistently applied throughout the market design, from optimization to settlement.

The result has been that the PJM Regulation Market has over procured RegD relative to RegA in most hours and has provided a consistently inefficient market signal to participants regarding the value of RegD to the market in every hour. 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 MBF related issues with the Regulation Market have been raised in the PJM stakeholder process. In 2015, PJM stakeholders approved an interim, partial

47 See the *2012 State of the Market Report for PJM*, Volume II, Section 9, "Ancillary Services," p. 271.

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 the optimization 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 approved by the Regulation Market Issues Senior Task Force (RMISTF) in 2016, with an implementation date of January 9, 2017, that introduced new signal designs and regulation requirements intended to improve system performance. These modifications include 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. Previously, off-peak hours were from 00:00 to 04:59, and on-peak hours were between 05:00 and 23:59 every day. With the changes that went into effect on January 9, 2017, off-peak and on-peak hours are now called nonramp and ramp, and have new timeframes that are based on the season. In addition to different timeframes, the regulation requirement for ramp hours has been increased from 700 MW to 800 MW (See Table 10-28). Like the interim solution implemented in December 4, 2015, the latest market changes still do not address the fundamental issues in the optimization or the lack of consistency in the application of the MBF. The MMU and PJM are pursuing a comprehensive solution through the Regulation Market Issues Senior Task Force ("RMISTF").

Table 10-28 Seasonal Regulation Requirement Definitions[48]

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

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

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.

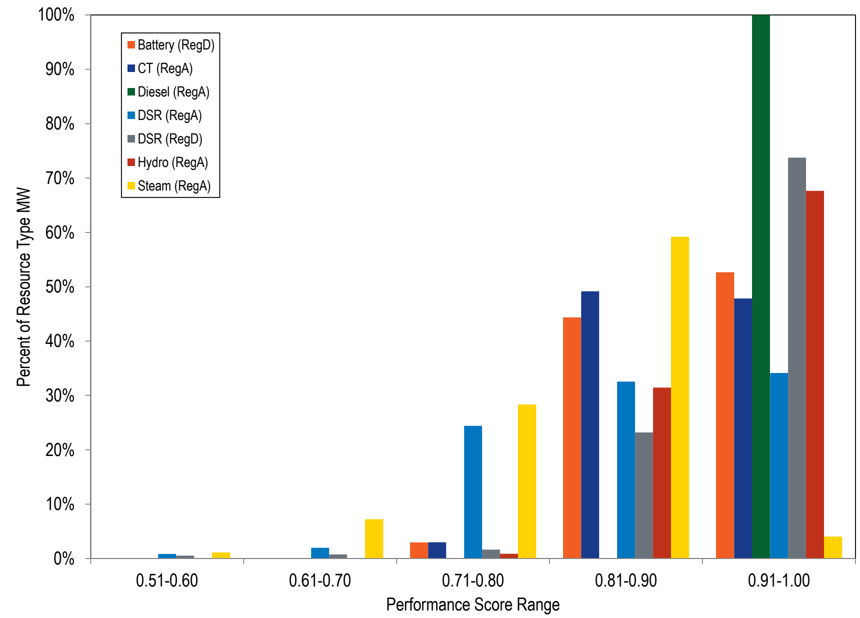
The regulation market includes resources following two signals: RegA and RegD. Resources responding to either signal help control ACE (area control error). RegA is PJM's slow-oscillation regulation signal and is designed for resources with the ability to sustain energy output for long periods of time, 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 and performance score translate a RegD resource's capability (actual) MW into marginal effective MW and offers into $/effective MW.

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

Regulation 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.[49]

Figure 10-18 and Figure 10-19 show the average performance score by resource type and the signal followed for the first three months of 2017. In these figures, the MW used are actual MW and the performance score is the hourly performance score of the regulation resource.[50] Each category (color bar) is based on the percentage of the full performance score distribution for each resource (or signal) type. As Figure 10-19 shows, 53.4 percent of RegD resources had average performance scores within the 0.91-1.00 range, and 23.6 percent of RegA resources had average performance scores within that range.

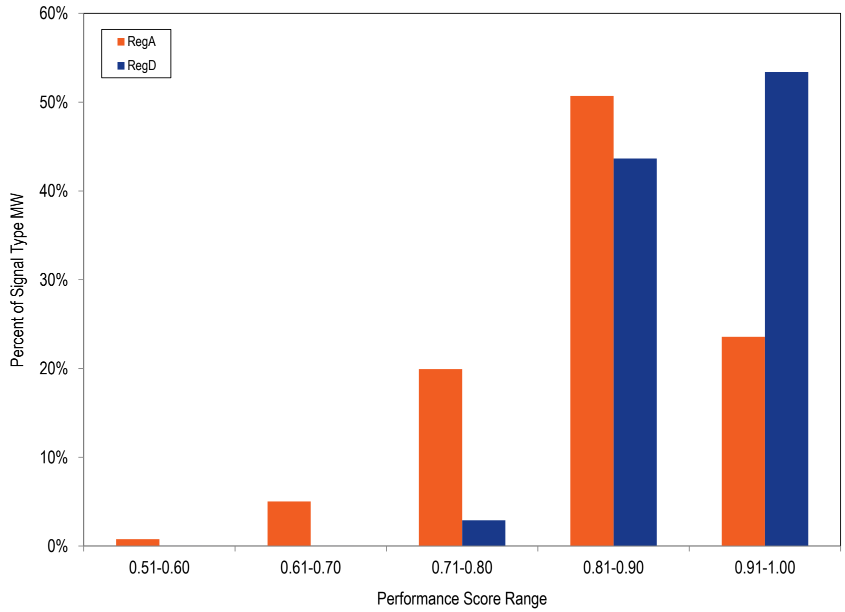
Figure 10-18 Hourly average performance score by unit type: January 1 through March 31, 2017



49 PJM "Manual 12: Balancing Operations," Rev. 36 (February 1, 2017) at 4.5.6, p 54.

50 Except where explicitly referred to as effective MW or effective regulation MW, MW means actual MW unadjusted for either marginal benefit factor or performance factor.

Figure 10-19 Hourly average performance score by regulation signal type: January 1 through March 31, 2017



PJM creates an individual resource's regulation signal by comparing the individual resource's TREG signal to the resource's MW output (or, for DR, load) to calculate the performance score based on delay, correlation, and precision. Performance scores are calculated using data every 10 seconds, but are reported on an hourly basis for each individual regulating resource.

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. The optimization of RegA and RegD assignments is dependent on the conversion of RegA and RegD MW into a common unit of measure (effective MW). The marginal benefit factor (MBF) is the marginal measure of substitutability of RegD resources for RegA resources in satisfying the regulation requirement at any combination of RegA and RegD MW that can be used to meet the regulation requirement.

The MBF, as the marginal rate of technical substitution between RegA and RegD resource MW for a given regulation requirement, defines specific combinations of RegA and RegD MW needed to meet specific regulation performance levels, defined as the amount of regulation that would be provided by a specified amount of RegA MW alone (which is the total effective MW requirement defined in terms of MW of RegA). The use of the MBF in the optimization should result in the selection of the least cost combination/ratio of RegA and RegD MW that achieves this level of specified regulation service when the prices of RegA and RegD are known. PJM's optimization engine has not properly implemented the MBF so that the market clearing combination of RegA and RegD MW is consistent with the combinations defined by the MBF curve.

At any valid combination of RegA and RegD, regulation offers are converted to dollars per effective MW by dividing the RegD offer by the corresponding MRTS associated with that combination of RegA and RegD. The marginal contribution of a RegD MW to total effective MW at a valid RegA/RegD combination 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 marginal benefit factor of 0.5 and a performance score of 100 percent, would be calculated as offering 0.5 effective MW (0.5 marginal benefit factor 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).

PJM's market design does not correctly calculate total effective RegD MW. Under PJM's method, cleared RegD MW are converted to total effective MW by multiplying each resource's offered MW by the product of the resource specific marginal benefit factor and performance score. This resource specific block assignment approach undercounts total effective MW because the method fails to count part of the area under the MBF curve. Total effective RegD MW are correctly calculated as the area under the MBF curve.

Market Design Issues

Marginal Benefit Factor Not Reflected Consistently or Correctly in Market

The marginal benefit factor function is incorrectly defined and improperly implemented in the current PJM Regulation Market. The market results do not represent the least cost solution that is consistent with a specific level of regulation service.

Properly defined, the marginal benefit factor is the marginal rate of technical substitution between RegA and RegD MW at specific combinations of RegA and RegD that can be used to provide a defined level of regulation service. The specific combinations of RegA and RegD that can be used to provide a defined level of regulation service are feasible combinations of RegA and RegD. 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 marginal benefit factor 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.

The marginal benefit factor 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 adhered to a FERC order that required the marginal benefit factor be fixed at 1.0 for settlement calculations only. On October 2, 2013, the FERC directed PJM to eliminate the use of the marginal benefit factor 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.[51]

The result of the FERC directive is that the marginal benefit factor is used in the optimization (currently using the incorrect PJM MBF) to determine the relative value of additional MW of RegD, but the marginal benefit factor is not used in the settlement for RegD.

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 twelve 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.

If the marginal benefit factor were consistently applied in the optimization, clearing, pricing and settlement, every resource would receive the same clearing price per marginal effective MW provided to the system. Because the marginal benefit factor is not consistently applied in the optimization, clearing, pricing and settlement, resources do not receive the same clearing price per marginal effective MW provided to the system.

While prices are set on the basis of dollars per effective MW, only RegA resources receive payments (credits) that are consistent with this price per effective MW (RMCP).[52] RegA resources are paid the RMCCP per effective MW plus the RMPCP per effective MW. RegD resources do not receive payments consistent with this price per effective MW. RegD resources are paid the RMCCP per performance adjusted MW (not per effective MW) plus the RMPCP times the mileage ratio per performance adjusted MW (not per effective MW).[53] As a result the current market design does not send the correct price signal to the RegD resources.

51 145 FERC ¶ 61,011 (2013).

52 This is due to the fact that RegA resources performance adjusted MW are their effective MW as the MRTS of RegA resources is always equal to one, as effective MW are defined in terms of RegA performance adjusted MW.

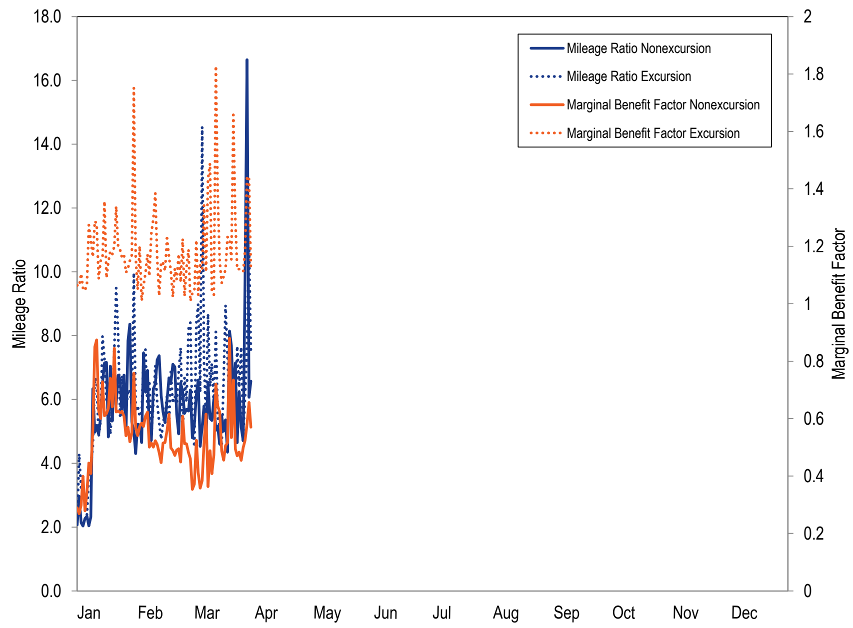
53 Performance adjusted RegD MW are converted to effective MW by multiplying the performance adjusted MW by the market clearing MRTS.

Figure 10-20 compares the daily average marginal benefit factor and the mileage ratio for excursion and nonexcursion hours. Excursion hours (hours ending 7:00, 8:00, 18:00-21:00) are hours in which PJM has decided that more RegA is needed and has therefore limited the minimum marginal benefit factor that can be assigned to RegD MW to 1.0.[54] Once this limit is reached, the remaining regulation requirement satisfied with RegA MW. The shift in values seen in Figure 10-20 is due to the implementation of the new ramp/nonramp timeframes and the new regulation requirement of 800 MW for ramp hours, on January 9, 2017.

The high mileage ratios on March 6, 2017, and March 29, 2017, were a result of the mechanics of the mileage ratio calculation. The extreme mileage ratios result when the RegA signal is fixed to control ACE and the RegD signal is not. The result of a fixed RegA signal is that RegA mileage is very small and therefore the mileage ratio of RegD/RegA is very large.

This result demonstrates why it is not appropriate to use the mileage ratio, rather than the marginal benefit factor, to measure the relative value of RegA and RegD resources. In these events RegA resources are providing ACE control (regulation service) despite not changing MW output (no mileage), while the change in MW output from RegD resources (positive mileage) is alternating between helping and hurting ACE control.

Figure 10-20 Daily average marginal benefit factor and mileage ratio during excursion and nonexcursion hours: January 1 through March 31, 2017



The current settlement process does not result in RegA and RegD resources being 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 one, RegD resources are generally (depending on the mileage ratio) underpaid on a per effective MW basis. When the marginal benefit factor is less than one, RegD resources are generally overpaid on a per effective MW basis. Currently, the marginal benefit factor is generally less than one, resulting in persistent overpayment of RegD resources.

The effect of using the mileage ratio instead of the marginal benefit factor to convert RegD MW into effective MW for purposes of settlement is illustrated

54 See PJM. "Manual 11: Energy & Ancillary Services Market Operations," Rev. 86 (February 1, 2017) at 3.2.7, p 70.

in Table 10-29. Table 10-29 provides the monthly average payment by RegD per effective MW realized under the current, incorrect mileage ratio based settlement process and compares it to the dollar per effective MW that is being paid to RegA MW and should be paid to RegD MW based on the MRTS based settlement process for each of the first three months in 2016 and 2017. As a result of the relative amount of RegD being procured, as well as the changes to the MRTS slope that went into effect on December 14, 2015, the MRTS averaged less than one in each month of 2016, resulting in RegD resources being paid $4.29 million (222.4 percent) more than they should have in the first three months of 2016. In 2017, the MRTS also averaged less than one, resulting in RegD resources being paid $4.10 million (1,016.4 percent) more than they should have been.

Table 10-29 Average monthly price paid per effective MW of RegD and RegA under mileage and MRTS based settlement: January 1 through March 31, 2016 through 2017

		RegD Settlement Payments				
	Month	Mileage Based ($/Effective RegD MW)	Marginal Rate of Technical Substitution Based ($/Effective RegD MW)	RegA ($/ Effective MW)	RegD Under/ Over Payment ($)	Percent RegD Under/Over Payment
2016	Jan	$30.61	$15.60	$15.60	$1,319,364	96.2%
	Feb	$43.33	$17.56	$17.56	$1,591,651	146.8%
	Mar	$70.02	$13.21	$13.21	$1,375,711	430.1%
Average		$49.68	$15.41	$15.41	$4,286,727	222.4%
2017	Jan	$80.44	$13.62	$13.62	$956,485	490.7%
	Feb	$293.97	$10.64	$10.64	$1,161,959	2,662.3%
	Mar	$80.90	$15.06	$15.06	$1,977,295	437.2%
Average		$147.18	$13.18	$13.18	$4,095,739	1,016.4%

Figure 10-21 shows, for the first three months of 2017, the maximum, minimum and average marginal benefit factor, based on PJM's incorrect marginal benefit factor curve, by month, for excursion and nonexcursion hours. The average MBF during excursion hours in the first three months of 2017 was 1.18, and the average MBF during nonexcursion hours in the first three months of 2017 was 0.48. The average MBF during excursion hours in the first three months of 2016 was 1.15, and the average MBF during nonexcursion hours in the first three months of 2016 was 0.38. The marginal benefit factor (MBF) levels were a result of changes in the marginal benefit factor curve made effective on December 14, 2015, which reduced the relative value of RegD MW in the optimization in all hours. The slope of the benefit factor curve was changed to alter where it intercepts the x-axis, defined in terms of RegD MW as a percent of the regulation requirement, to 40 percent instead of 62 percent. PJM also capped the procurement of RegD MW during excursion hours at the point where the MBF on the curve is equal to 1.0.

Figure 10-21 Maximum, minimum, and average PJM calculated marginal benefit factor by month for excursion and nonexcursion hours: January 1 through March 31, 2017

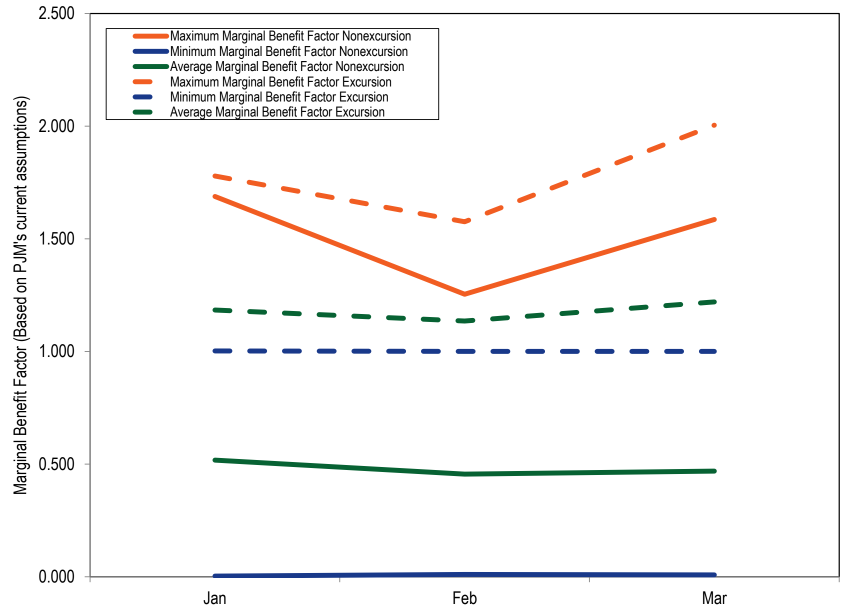
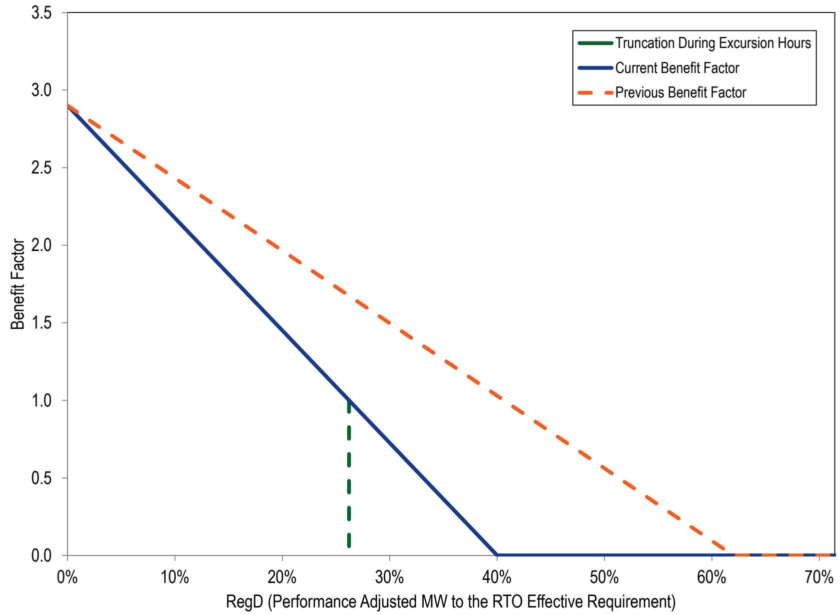


Figure 10-22 shows the marginal benefit factor curve (as incorrectly defined by PJM) before and after the December 14, 2015, modification. The modification to the marginal benefit factor curve reduced the amount of RegD procured, but did not correct for identified issues with the optimization engine.

Correcting the issues with the optimization engine would require correctly defining and using the marginal benefit factor curve, rather than continuing to incorrectly define the MBF as RegD MW cleared as a percentage of the effective MW target.

Figure 10-22 Marginal benefit factor curve before and after December 14, 2015, revisions by PJM



The MMU recommends that the Regulation Market be modified to incorporate a consistent and correct application of the marginal benefit factor throughout the optimization, assignment and settlement process.[55]

Incorrect MBF and Inconsistent Application of MBF in Optimization Causing Incorrect Proportion of RegD MW to Be Purchased

The current PJM MBF incorrectly defines the contribution of RegD MW as a percent of the regulation requirement rather than using the correct MBF, defined as the marginal rate of technical substitution between RegA and RegD.

As a result, the market clearing engine is not correctly maintaining the shares of RegA and RegD that are the basis of the MBF function. The MBF, as the marginal rate of technical substitution between RegA and RegD resource MW for a given regulation requirement, defines specific combinations/ratios of RegA and RegD MW that are needed to meet specified regulation performance goals. Properly implemented, the use of the MBF should result in the selection of the least cost combination of RegA and RegD MW.

Instead, the current market clearing engine uses the incorrect MBF function to adjust RegD offers (both MW and price) for purposes of rank ordering RegA and RegD resources in the supply stack and then clears RegA and RegD resources in price order until the calculated effective MW target is reached. In other words, PJM's market clearing engine rank orders resources by prices and then clears them as a single supply stack at the point of intersection of cumulative effective supply and the regulation requirement. Self scheduling or pricing at zero causes RegD resources to appear at the bottom of the supply stack, forcing the clearing engine to take the RegD MW so long as the MBF is greater than zero. This market clearing is done without confirming that the resulting combinations of RegA and RegD are feasible and can meet the defined demand for regulation. This guarantees that an increasing proportion of RegD MW in the market incorrectly appears as a cheap feasible source of incremental effective regulation MW regardless of whether there is sufficient RegA MW clearing the market to support this market solution

The market design, combined with an increasing proportion of RegD offering at an effective price of zero, is that the market clears too much RegD relative to RegA MW.

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

This is illustrated in Table 10-30, for both the MBF curve used prior to December 14, 2015, and the current MBF curve. In Table 10-30, the contribution to the total regulation requirement of 700 MW for an on peak hour is given on both a performance adjusted actual RegD MW and effective RegD MW basis. For example, if the market cleared 280 MW of performance adjusted RegD (40 percent of the 700 performance adjusted MW needed) at a price of zero, the market clearing engine would determine it would need 149.9 MW of RegA to meet the 700 MW requirement using the previous MBF curve, and would need 294.0 MW using the current MBF curve. The resulting proportion of RegD to total regulation cleared would be 65 percent and 49 percent for the previous and current MBF curves, rather than the 40 percent that was assumed by the MBF function. Although there is a smaller difference between the proportion of RegD cleared under the current MBF curve and the correct amount, as compared to that of the previous MBF curve, the error still persists and is not eliminated by simply adjusting the curve. A full correction requires that the proportions assumed in the curve are maintained through the market clearing process.

Table 10-30 MBF assumed RegD proportions versus market solution realized RegD proportions[56]

RegD Percent of 700 MW	RegD MW (Performance Adjusted)	MBF (Previous)	MBF (Current)	Effective MW from RegD MW (Previous)	Effective MW from RegD MW (Current)	Residual A (700 MW Target, Previous)	Residual A (700 MW Target, Current)	RegD/ (RegA+RegD, Previous)	RegD/ (RegA+RegD, Current)
5%	35	2.67	2.54	97.41	95.16	602.59	604.84	5%	5%
10%	70	2.43	2.18	186.63	177.63	513.37	522.38	12%	12%
15%	105	2.20	1.81	267.67	247.41	432.33	452.59	20%	19%
20%	140	1.96	1.45	340.52	304.50	359.48	395.50	28%	26%
25%	175	1.73	1.09	405.18	348.91	294.82	351.09	37%	33%
30%	210	1.50	0.73	461.66	380.63	238.34	319.38	47%	40%
35%	245	1.26	0.36	509.96	399.66	190.04	300.34	56%	45%
40%	280	1.03	0.00	550.06	406.00	149.94	294.00	65%	49%
45%	315	0.80		581.99		118.01		73%	
50%	350	0.56		605.73		94.27		79%	
55%	385	0.33		621.28		78.72		83%	
60%	420	0.09		628.65		71.35		85%	

56 This example assumes that the calculation of effective MW from RegD was calculated correctly as the area under the MBF curve.

The Effective MW of Regulation Purchased Are Understated

In 2015, the MMU determined that the regulation market optimization/market solution was understating the amount of effective MW provided by RegD. Rather than correctly calculating the total effective MW contribution of RegD MW based on the area under the marginal benefit factor curve, the regulation market optimization assigns the MBF associated with the last MW of a cleared unit to every MW of that unit (unit block). PJM calculates the total effective MW of a unit as the simple product of the MW and the MBF, rather than the area under the MBF. The result is that 100 MW of RegD (performance adjusted) provided by a single resource (one 100 MW unit) will appear to provide fewer total effective MW than 100 MW (performance adjusted) provided by two separate 50 MW units although they provide exactly the same total effective MW.

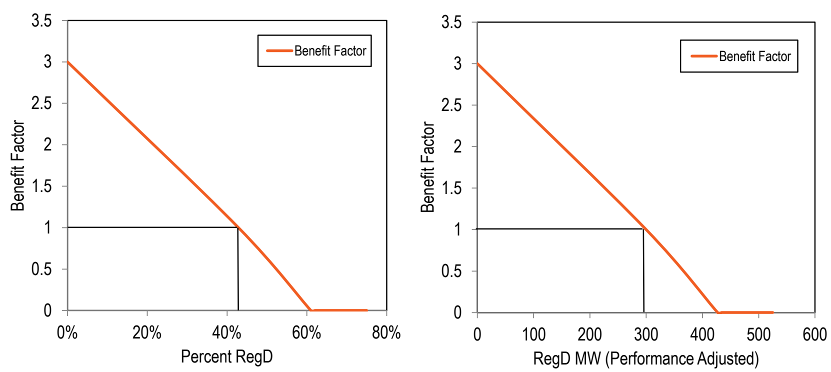
In addition, the MMU determined that the regulation market optimization/market solution treats all RegD resources with the same effective price as a single resource (price block) for purposes of assigning a benefit factor and calculating total effective MW. This means that all of the MW associated with multiple units with the same effective price (for example a price of zero) were assigned the MBF of the last MW of the last unit of that block of resources with the same effective price. PJM then calculates the total effective MW as the simple product of the MW and the MBF, rather than the area under the MBF curve. This resulted in understating total effective MW from RegD resources cleared at an effective price of zero or self-scheduled.

The identified total effective MW measurement issue was not fully addressed by the modification that was put into effect on December 14,

2015. The modification rank orders self-scheduled units and assigns the MBF of the last MW of each of these units to all MW of that unit. The result is to break up the RegD MW in the zero price or self-scheduled block into unit specific blocks of MW that are each assigned a unit specific benefit factor. The resulting unit block effective MW calculation for all units better approximates the area under the marginal benefit factor curve for those price block MW. A full correction of the effective MW calculation requires the use of the area under the curve.

An example illustrates the issue. Figure 10-23 shows the same marginal benefit factor curve, in terms of RegD percent (left diagram) and RegD MW (right diagram) in a scenario where 700 MW of effective MW are needed and the market clears 300 MW of RegD (actual MW), all priced at $0.00, and 400 MW of RegA. Figure 10-23 shows that the 300 MW of cleared RegD are 42.9 percent of total cleared actual MW and that the marginal benefit factor is 1.0.

Figure 10-23 Example marginal benefit line in percent RegD and RegD MW terms



Using PJM's price block/unit block method for the calculation of effective MW from RegD resources, all RegD resources are assigned the lowest marginal benefit factor associated with the last RegD MW purchased. In this example, all 300 MW have an MBF of 1.0. PJM calculates total effective MW from RegD resources to be 300 (300MW x 1.0 = 300 effective MW).

In Figure 10-24, PJM's price block/unit block calculation of total effective MW from RegD is represented by the area of the blue rectangle which is 400 effective MW.

PJM's unit block method is flawed. By assigning a single benefit value to every MW, the unit block method undervalues the amount of effective MW provided by RegD MW. This means that the amount of RegD and RegA cleared is not consistent with the combinations of RegD and RegA that will provide the target level of regulation service. This is because the marginal benefit curve represents a marginal rate of substitution between RegD and RegA MW, and the area under the curve, at any RegD amount, represents the total effective MW supplied by RegD at that point. In fact, RegD is providing effective MW equal to area defined by the green triangle and the blue rectangle in Figure 10-24. This corresponds to 600 effective MW being supplied by RegD resources, not 300 effective MW. This means that the actual total effective MW cleared in the market solution is 300 more effective MW than needed to meet the regulation requirement.

Figure 10-24 Illustration of correct method for calculating effective MW

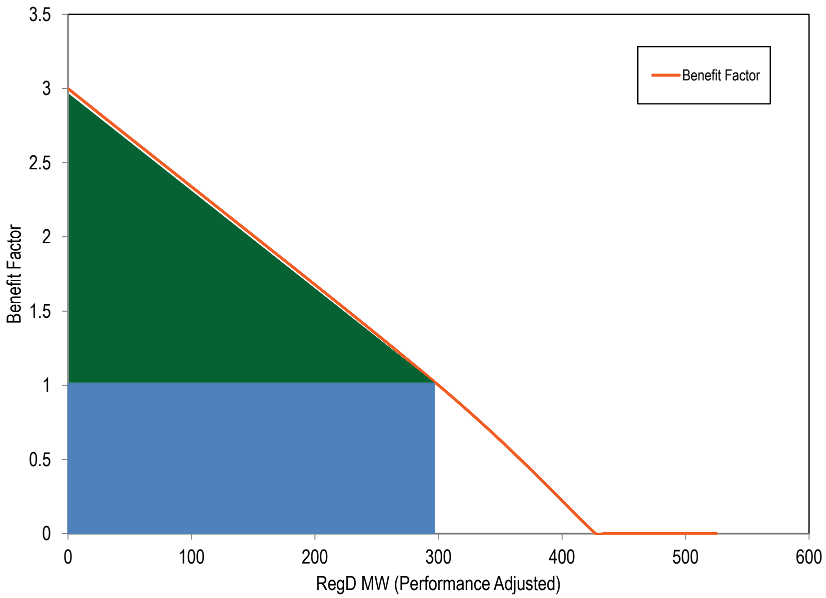


Figure 10-25 illustrates PJM's December 14, 2015, correction of the price block issue for RegD resources that clear with an effective price of zero. In this example, the PJM market clears two self-scheduled resources, one with 100 MW and one with 83 MW, for a total of 183 MW and a market MBF of 1.0. Prior to the correction, all 183 MW of RegD would have been assigned the MBF of 1.0.

After December 14, 2015, zero price offer and self scheduled resources are rank ordered by performance score and assigned unit specific MBF based on the MBF associated with the last MW of each unit that cleared. Using this approach, assuming the 83 MW resource was ranked higher than the 100 MW resource, the 83 MW resource would be assigned a unit specific benefit factor of 2.0 (see figure) and the 100 MW resource would be assigned a unit specific marginal benefit factor of 1.0 (see figure).

This correction did not address the unit block issue. PJM still calculates effective MW as the simple product of the MW and the MBF, rather than the area under the MBF curve for cleared MW, which results in an effective MW total of 269.9 MW, due to 169.9 effective MW being attributed to the 83 MW resource (83 MW times 2.0 BF) and 100 effective MW being attributed to the 100 MW resource (100 MW times 1.0 BF). Using the area under the curve approach would correctly result in a total effective MW total of 356.9 MW being attributed to the 183 MW cleared in the market, not the 266 total effective MW of the corrected method.

Figure 10-25 Example of pre and post December 14, 2015, total effective MW calculations for RegD MW offered at $0.00 or as self supply

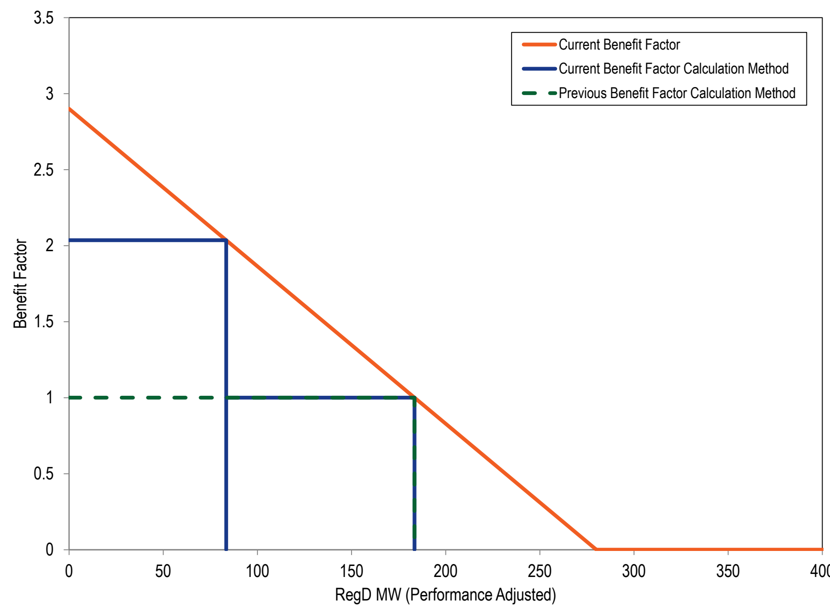
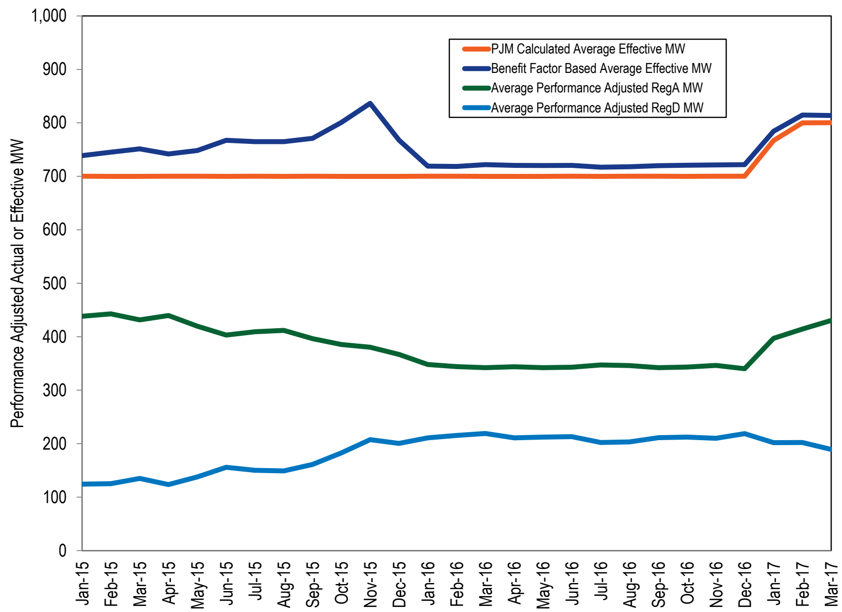


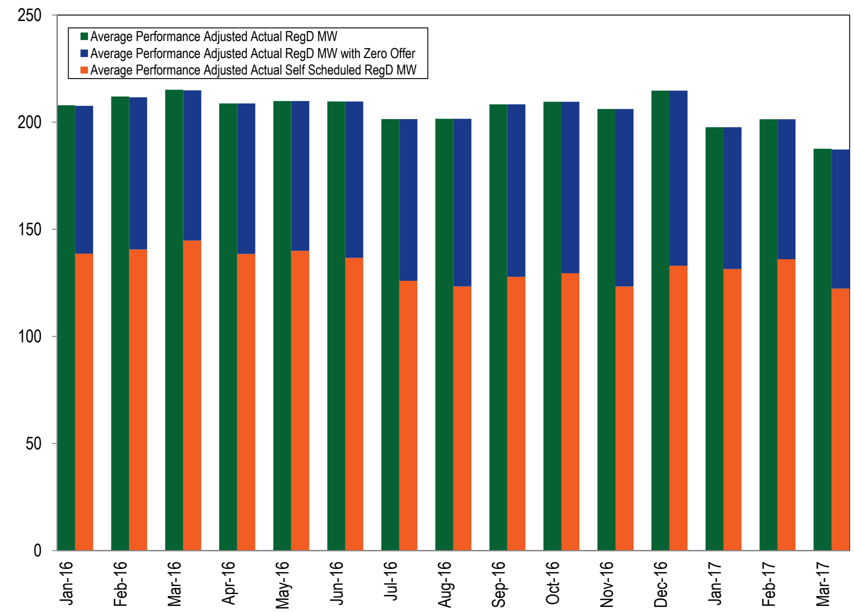
Figure 10-26 shows the average monthly peak total effective MW as calculated by PJM's incorrect effective MW accounting method(s) and as calculated by a correctly applied marginal benefit factor for the January 1, 2015, through March 31, 2016, period. The figure also shows the monthly average performance adjusted RegA MW and RegD MW cleared in the Regulation Market for the period. Figure 10-26 shows that PJM had been clearing an increasing surplus of total effective MW prior to December of 2015. The implementation of the 800 effective MW regulation requirement for ramp hours has increased the average amount of RegA, because the majority of the additional MW being procured are from RegA.

Figure 10-26 Average monthly ramp total effective MW: PJM market calculated versus benefit factor based: January 1, 2015 through March 31, 2017



The excess procurement of RegD combined with the overpayment of RegD has resulted in an increase in the level of $0.00 offers from RegD resources. RegD MW providers are ensured that $0.00 offers will be cleared and will be paid a price determined by the offers of RegA resources. Figure 10-27 shows, by month, the proportion of cleared RegD MW with an effective price of $0.00. The figure shows that all RegD MW clearing the market in the period between January 1, 2016, and December 31, 2016, had an effective offer of $0.00. The level of RegD clearing the market leveled off beginning in January 2016 because the market cleared the maximum allowed RegD actual MW.

Figure 10-27 Average cleared RegD MW and average cleared RegD with an effective price of $0.00 by month: January 1, 2016 through March 31, 2017



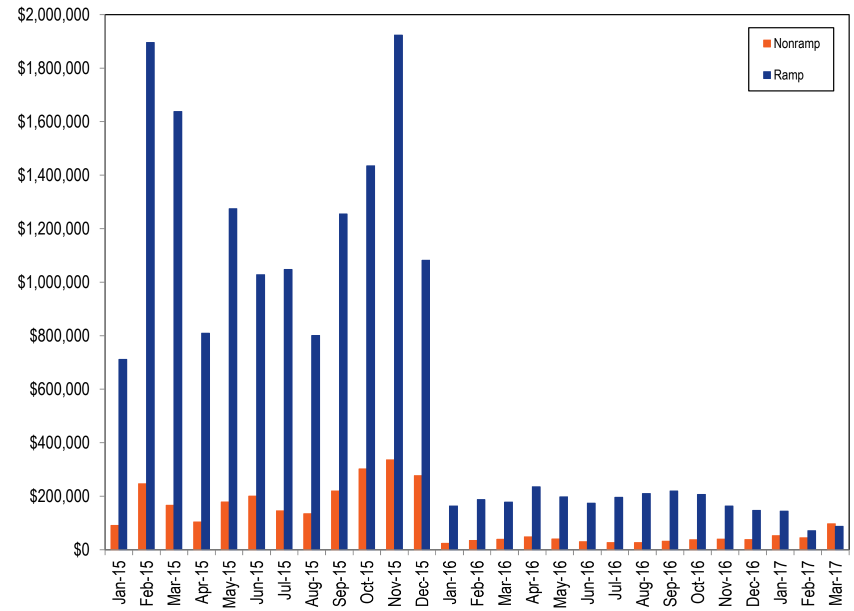
The Cost of Purchasing Too Many Regulation MW Due to Incorrect Effective MW Calculation Approach

Figure 10-28 shows the estimated cost of the excess effective MW cleared by month, peak and off peak, from January 1, 2015, through March 31, 2017, caused by PJM's incorrect approach(s) to calculating effective MW from RegD resources. To determine this excess cost, the total effective MW of RegD are calculated using the full area under the incorrect PJM marginal benefit factor curve, and the difference between that value and the one used by PJM is multiplied by the price in each hour. The calculation of excess cost shown in

Figure 10-28 that is caused by purchasing too much RegD is conservatively underestimated because it does not incorporate how the market clearing price and settlement would have been affected by replacing the current optimization and settlement process with a correct and consistent utilization of the MBF. Specifically, the calculation only reflects differences in RegA and RegD proportions due to incorrect versus correct application of the MBF in the clearing engine, holding the actual market price and the mileage ratio based settlement constant.

In the first three months of 2017, the estimated total cost of excess effective RegD MW during on peak and off peak hours was $0.30 million and $0.19 million. In the first three months of 2016, the estimated total cost of excess RegD MW during on peak and off peak hours was $0.53 million and $0.10 million. The implementation of the partial solution to the effective MW calculation and the changes in the marginal benefit factor curve in December of 2015 reduced, but did not eliminate, the excess effective MW clearing in the Regulation Market.

Figure 10-28 Cost of excess effective MW cleared by month, peak and off peak: January 1, 2015 through March 31, 2017



Market Structure

Supply

Table 10-31 shows capability MW (actual), average daily offer MW (actual), average hourly eligible MW (actual and effective), and average hourly cleared MW (actual and effective) for all hours in the first three months of 2017. Total Effective MW are adjusted by the historic 100-hour moving average performance score and resource-specific benefit factor.[57] A resource must be either generation or demand. A resource can choose to follow both signals. 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 categorized as available for the day. Eligible MW are calculated

57 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 and future analysis will show the effect of this correction.

from the hourly offers from both units with daily offers and units that are categorized as unavailable for the day, but still offer MW into some hours. Additionally, units with daily offers are permitted to offer above or below their daily offer from hour to hour. Because of these hourly MW adjustments to MW offers beyond what was offered on a daily basis, the average hourly Eligible MW can be higher than the Offered MW. In the first three months of 2017, the average hourly eligible supply of regulation for nonramp hours was 1,187.5 actual MW (852.4 effective MW). This was an increase of 4.2 actual MW (32.0 effective MW) from the first three months of 2016, when the average hourly eligible supply of regulation was 1,183.3 actual MW (820.4 effective MW). In the first three months of 2017, the average hourly eligible supply of regulation for ramp hours was 1,449.4 actual MW (1,158.4 effective MW). This was an increase of 236.9 actual MW (199.5 effective MW) from the first three months of 2016, when the average hourly eligible supply of regulation was 1,212.4 actual MW (958.9 effective MW).

Table 10-31 PJM regulation capability, daily offer and hourly eligible: January through March, 2017[58 59]

			By Resource Type		By Signal Type	
		All Regulation	Generating Resources	Demand Resources	RegA Following Resources	RegD Following Resources
Capability MW	Daily	10,042.5	10,017.8	24.7	9,705.3	656.3
Offered MW	Daily	7,024.6	7,009.7	14.9	6,648.6	375.9
Actual Eligible MW	Ramp	1,449.4	1,431.5	17.9	1,077.1	372.2
	Nonramp	1,187.5	1,170.9	16.6	815.8	371.7
Effective Eligible MW	Ramp	1,158.4	1,138.4	20.0	780.0	378.5
	Nonramp	852.4	836.1	16.3	571.8	280.6
Actual Cleared MW	Ramp	702.1	692.2	10.0	484.0	218.2
	Nonramp	503.4	494.6	8.8	289.9	213.5
Effective Cleared MW	Ramp	786.6	768.2	18.4	411.6	374.9
	Nonramp	525.0	509.8	15.2	246.2	278.8

Table 10-32 provides the scheduled regulation in MW by source, the total scheduled regulation in MW provided by all resources (including DR), and the percent of scheduled regulation provided by each fuel type. In Table 10-32 the MW have been adjusted by the actual within hour performance score since this adjustment forms the basis of payment for units providing regulation. Total regulation performance adjusted capability MW increased from 1,268,830.1 MW in the first three months of 2016 to 1,457,098.0 MW in the first three months of 2017. The average proportion of regulation provided by battery units had the largest increase, providing 43.7 percent of regulation in the first three months of 2016 and 48.0 percent of regulation in the first three months of 2017. Hydro units had the largest decrease in average proportion of regulation provided, decreasing from 20.7 percent in the first three months of 2016, to 15.6 percent in the first three months of 2017. The total regulation credits in the first three months of 2017 were $20,752,915 down 3.0 percent from $21,386,126 in the first three months of 2016.

Table 10-32 PJM regulation by source: January through March, 2016 and 2017[60]

	2016 (Jan-Mar)				2017 (Jan-Mar)			
Source	Number of Units	Adjusted Settled Regulation (MW)	Percent of Scheduled Regulation	Total Regulation Credits	Number of Units	Adjusted Settled Regulation (MW)	Percent of Scheduled Regulation	Total Regulation Credits
Battery	21	554,571.3	43.7%	$8,400,232	21	700,004.1	48.0%	$7,964,751
Coal	49	97,990.0	7.7%	$2,123,964	39	77,435.9	5.3%	$1,673,859
Hydro	39	263,246.6	20.7%	$5,033,328	24	227,201.8	15.6%	$4,140,938
Natural Gas	152	342,839.8	27.0%	$5,668,338	88	421,126.7	28.9%	$6,610,197
DR	35	10,182.4	0.8%	$160,263	20	31,329.6	2.2%	$363,170
Total	296	1,268,830.1	100.0%	$21,386,126	192	1,457,098.0	100.0%	$20,752,915

Significant flaws in the regulation market design have led to a significant 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 10-33).

58 Average Daily Offer MW excludes units that have offers but are unavailable for the day.
59 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.

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

Table 10-33 Active battery storage projects in the PJM queue system by submitted year: 2012 to 2017

Year	Number of Storage Projects	Total Capacity (MW)
2012	2	8.5
2013	0	0.0
2014	8	132.0
2015	38	280.1
2016	15	191.3
2017	1	9.0
Total	64	620.9

The supply of regulation can be affected by regulating units retiring from service. If all units that are requesting retirement through the end of 2017 retire, the supply of regulation in PJM will be reduced by less than one percent.

Although the marginal benefit factor for RegA resources is 1.0, the effective MW of RegA resources were lower than the offered MW in the first three months of 2017, because the average performance score was less than 1.00. For the first three months of 2017, the MW weighted average RegA performance score was 0.85 and there were 147 resources following the RegA signal.

For RegD resources, the total effective MW vary from actual MW because the marginal benefit factor for RegD resources can range from 2.9 to 0.0. In the first three months of 2017, the marginal benefit factor, based on PJM's current assumed marginal benefit factor curve, for cleared RegD resources ranged from 0.003 to 1.688 with an average over all nonexcursion hours of 0.481 and from 1.000 to 2.004 with an average over all excursion hours of 1.181. In the first three months of 2017, the MW weighted average RegD resource performance score was 0.91 and there were 44 resources following the RegD signal.

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 (formerly known as on-peak) hours (See Table 10-28).

Table 10-34 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. For January, the average ramp regulation requirement is a combination of the old peak hours and 700 effective MW requirement before January 9, and the new ramp hours and 800 effective MW requirement for the rest of the month.

Table 10-34 PJM Regulation Market required MW and ratio of eligible supply to requirement for ramp and nonramp hours: January through March, 2016 through 2017[61]

		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	2016	2017	2016	2017	2016	2017	2016	2017
Ramp	Jan	657.5	690.8	700.1	766.8	1.83	2.10	1.34	1.48
	Feb	663.6	705.8	700.1	800.1	1.84	2.11	1.38	1.52
	Mar	640.6	714.7	700.0	800.1	1.90	1.96	1.39	1.41
Nonramp	Jan	553.8	503.6	525.0	525.1	2.15	2.45	1.56	1.65
	Feb	550.0	508.3	525.6	525.0	2.17	2.47	1.56	1.75
	Mar	517.0	499.9	525.0	525.0	2.25	2.22	1.57	1.52

Market Concentration

In the first three months of 2017, the effective MW weighted average HHI of RegA resources was 2860 which is highly concentrated and the weighted average HHI of RegD resources was 1642 which is also highly concentrated.[62] The weighted average HHI of all resources was 1155, 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 10-35 includes a monthly summary of three pivotal supplier (TPS) results. In the first three months of 2017, 92.1 percent of hours had three or fewer pivotal suppliers. The MMU concludes that the PJM Regulation Market in the first three months of 2017 was characterized by structural market power. The TPS values are provided by PJM. The TPS results cannot be verified by the MMU or PJM because PJM does not save the necessary data. The MMU recommends that PJM save this data and make it available so that the TPS test calculations can be replicated by both PJM and the MMU. PJM has agreed that the lack of information is an issue but does not have a specific plan or timeline to resolve the issue.

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

62 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.

Table 10-35 Regulation market monthly three pivotal supplier results: January 1, 2015 through March 31, 2017

	Percent of Hours Pivotal		
Month	2015	2016	2017
Jan	97.8%	93.9%	90.6%
Feb	96.3%	90.9%	93.1%
Mar	97.3%	87.8%	92.7%
Apr	98.1%	93.5%	
May	99.3%	94.0%	
Jun	98.6%	89.3%	
Jul	98.8%	92.2%	
Aug	97.7%	93.7%	
Sep	97.1%	94.0%	
Oct	96.1%	90.6%	
Nov	99.2%	96.2%	
Dec	97.2%	90.4%	
Average	97.8%	92.2%	92.1%

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.[63] When offering into the regulation market, regulating resources must submit a cost offer and may submit a price offer (capped at $100/MW) by 2:15 pm the day before the operating day.[64]

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 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 adder. The performance component for cost offers is not to exceed the increased costs (increased VOM and increased fuel costs) resulting from moving the unit up and down to provide regulation.

63 See PJM. "Manual 11: Energy & Ancillary Services Market Operations," Rev. 86 (February 1, 2017) at 3.2.1, p 65.

64 See PJM. "Manual 11: Energy & Ancillary Services Market Operations," Rev. 86 (February 1, 2017) at 3.2.6, p 70.

Batteries and flywheels have zero cost for lower efficiency from providing regulation instead of energy, as they are not net energy producers. On April 1, 2015, PJM added 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.[65]

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.[66]

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 10-37).[67] Figure 10-29 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.[68] Self scheduled regulation comprised an average of 44.6 percent during ramp hours and 47.9 percent during nonramp hours in the first three months of 2017.

Figure 10-29 Off peak, on peak, nonramp, and ramp regulation levels: January 1, 2016 through March 31, 2017

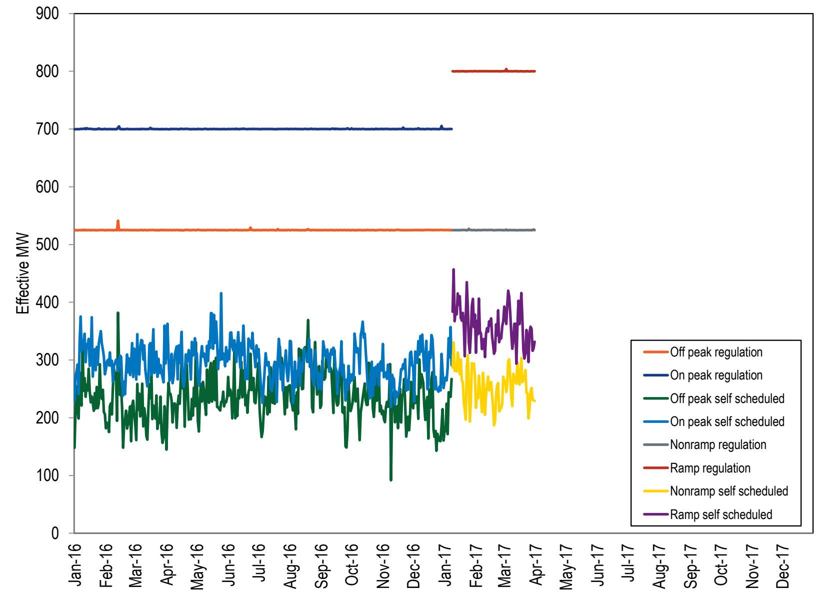


Table 10-36 shows the role of RegD resources in the regulation market. RegD resources are both a growing proportion of the market (10.9 percent of the total effective MW at the start of the performance based regulation market design in October 2012 and 49.4 percent of the total effective MW in March 2017) and a growing proportion of resources that self schedule (10.1 percent of all self scheduled MW in October 2012 and 27.0 percent of all self scheduled MW in March 2017). The increase in the share of RegD making up the total effective MW for 2016 (starting with the changes made to the MBF curve in December 2015), were due to the use of the unit block method of calculating the MBF over the previous price block method (See Figure 10-25). The decrease in the RegD share of total effective MW for the first three months of 2017 was due to the increased regulation requirement (from 700 effective MW to 800 effective MW during ramp hours), which resulted in more RegA clearing MW.

65 See PJM. "Manual 15: Cost Development Guidelines," Rev. 28 (October 18, 2016) at 11.8, p 65.
66 See PJM. "Manual 11: Energy & Ancillary Services Market Operations," Rev. 86 (February 1, 2017) at 3.2.2, p 68.
67 See PJM. "Manual 28: Operating Agreement Accounting," Rev. 75 (November 18 1, 2016) at 4.1, p 22.
68 See PJM. "Manual 11: Energy & Ancillary Services Market Operations," Rev. 86 (February 1, 2017) at 3.2.9, p 79.

Table 10-36 RegD self-scheduled regulation by month: October 31, 2012 through March 31, 2017

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%

Table 10-36 RegD self-scheduled regulation by month: October 31, 2012 through March 31, 2017 (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
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%
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%
YTD		184.0	329.3	304.0	662.2	45.9%	27.8%	49.7%

Increased self-scheduled regulation lowers the requirement for cleared regulation, resulting in fewer MW cleared in the market and lower clearing prices. Of the LSEs' obligation to provide regulation in the first three months of 2017, 47.4 percent was purchased in the PJM market, 46.2 percent was self-scheduled, and 6.4 percent was purchased bilaterally (Table 10-37). Table 10-38 shows the total regulation by source including spot market regulation, self scheduled regulation, and bilateral regulation for the first three months of each year from 2012 to 2017. Table 10-37 and Table 10-38 are based on settled (purchased) actual MW.

Table 10-37 Regulation sources: spot market, self-scheduled, bilateral purchases: January 1, 2016 through March 31, 2017

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)
2016	Jan	197,085.6	47.8%	193,843.1	47.0%	21,671.0	5.3%	412,599.7
2016	Feb	190,668.7	49.7%	173,704.0	45.2%	19,546.0	5.1%	383,918.8
2016	Mar	196,173.9	49.4%	178,691.7	45.0%	22,017.0	5.5%	396,882.6
2016	Apr	192,872.3	50.1%	173,923.2	45.2%	18,058.0	4.7%	384,853.5
2016	May	185,673.4	47.4%	185,434.2	47.4%	20,221.0	5.2%	391,328.7
2016	Jun	177,041.1	46.7%	180,936.5	47.7%	21,295.5	5.6%	379,273.1
2016	Jul	176,073.5	45.6%	168,116.9	43.5%	42,233.0	10.9%	386,423.4
2016	Aug	187,641.6	48.6%	172,116.0	44.6%	26,299.5	6.8%	386,057.1
2016	Sep	169,565.3	45.0%	171,466.0	45.5%	35,462.5	9.4%	376,493.8
2016	Oct	190,611.4	49.0%	174,555.6	44.8%	24,074.0	6.2%	389,241.0
2016	Nov	206,016.3	55.0%	155,359.8	41.5%	13,289.5	3.5%	374,665.6
2016	Dec	190,565.5	48.8%	176,628.1	45.2%	23,642.5	6.0%	390,836.1
Total		2,259,988.6	48.6%	2,104,775.1	45.2%	287,809.5	6.2%	4,652,573.2
2017	Jan	181,234.1	45.8%	188,924.6	47.8%	25,490.5	6.4%	395,649.2
2017	Feb	179,287.3	50.4%	154,308.8	43.3%	22,371.0	6.3%	355,967.1
2017	Mar	173,565.1	46.3%	177,638.3	47.3%	23,963.0	6.4%	375,166.4
YTD		534,086.5	47.4%	520,871.7	46.2%	71,824.5	6.4%	1,126,782.7

Table 10-38 Regulation sources by year: 2012 through 2017, January through March

Year (Jan-Mar)	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	1,510,190.1	73.4%	485,672.8	23.6%	61,563.0	3.0%	2,057,425.9
2013	1,026,962.9	73.0%	342,003.1	24.3%	38,538.5	2.7%	1,407,504.5
2014	724,996.3	61.1%	404,832.1	34.1%	56,853.5	4.8%	1,186,681.9
2015	670,281.4	58.5%	411,928.8	36.0%	63,367.6	5.5%	1,145,577.7
2016	583,928.2	48.9%	546,238.8	45.8%	63,234.0	5.3%	1,193,401.0
2017	534,086.5	47.4%	520,871.7	46.2%	71,824.5	6.4%	1,126,782.7

In the first three months of 2017, DR provided an average of 10.0 MW of regulation per hour during ramp hours (4.3 MW of regulation per hour during ramp hours in the first three months of 2016), and an average of 8.8 MW of regulation per hour during nonramp hours (2.9 MW of regulation per hour during off peak hours in the first three months of 2016). Generating units supplied an average of 692.2 MW of regulation per hour during ramp hours (649.4 MW of regulation per hour during ramp hours in the first three months of 2016), and an average of 494.6 MW per hour during nonramp hours (537.2 MW of regulation per hour during nonramp hours in the first three months of 2016).

Market Performance

Price

After regulation performance was implemented on October 1, 2012, both regulation price and regulation cost per MW were higher than they were prior to October 1, 2012, for each year until 2016 (Table 10-42). In the first three months of 2017, the price and cost of regulation continued to be lower than the price and cost of regulation for the first three months in the years prior to 2016. The weighted average RMCP for the first three months of 2017 was $13.87 per effective MW. This is a 10.8 percent decrease from the weighted average RMCP of $15.55 per MW in the first three months of 2016. The decrease in the regulation clearing price was the result of a reduction in energy prices and the related reduction in the LOC component of RMCP. The increase in self supply and $0.00 offers from RegD resources since 2016 also contributed to lower prices.

In September 2016, an issue was identified concerning the real time clearing price for five minute intervals in the regulation market. Regulation units available to set price in a given five minute interval are based on the latest five minute RT-SCED 15 minute look ahead scheduling and assignment of regulation resources. This means that at the end of an hour, pricing in five minute intervals starting at 00:45, 00:50, and 00:55 is based on RT-SCED scheduling information (regulation assignments) from 01:00, 01:05, and 01:10 of the following hour. In cases where units provided regulation in an hour, but are not assigned to provide regulation in the following hour, these deassigned units appeared as unavailable for purposes of determining price in the last three, five minute intervals of their assigned regulation hour (00:45, 00:50, and 00:55). The pricing algorithm instead used the list of resources assigned to regulation for the next hour to set the price in intervals 00:45, 00:50, and 00:55 of the current hour. The result was that the prices did not accurately reflect the units actually running in intervals 00:45, 00:50, and 00:55. In November 2016, PJM corrected this problem by forcing the pricing algorithm to use the regulation availability status of the current hour to determine which units are eligible to set the regulation price for the current hour.

Figure 10-30 shows the daily weighted average regulation market clearing price and the opportunity cost component for the marginal units in the PJM Regulation Market on an actual regulation capability MW basis. This data is based on actual five minute interval operational data. As Figure 10-30 illustrates, the LOC component (blue line) is the dominant component of the clearing price.

Figure 10-30 PJM regulation market daily weighted average market-clearing price, marginal unit opportunity cost and offer price (Dollars per MW): January through March, 2017

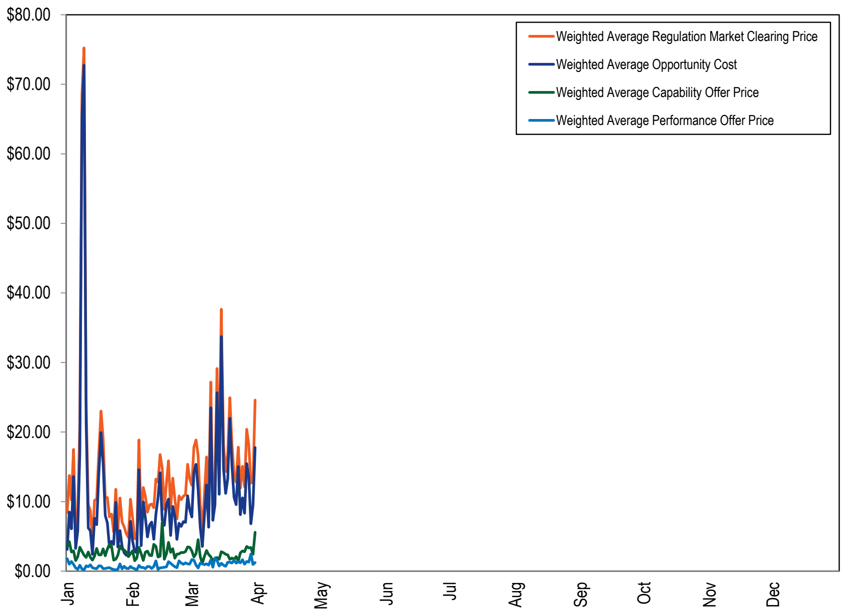


Table 10-39 shows the components of the monthly average regulation prices. NA is the unexplained portion of the total weighted average market price.

Table 10-39 PJM regulation market monthly weighted average market-clearing price, marginal unit opportunity cost and offer price from five minute market solution data (Dollars per MW): January through March, 2017

Month	Weighted Average Regulation Marginal Unit LOC ($/Actual MW)	Weighted Average Regulation Marginal Unit Capability Offer ($/Actual MW)	Weighted Average Regulation Marginal Unit Performance Offer ($/Actual MW)	Weighted Average Regulation Market Clearing Price ($/ Actual MW)	NA	Weighted Average Regulation Market Price from Settlements ($/Actual MW)
Jan	$11.77	$2.68	$0.59	$15.04	$0.98	$14.06
Feb	$7.49	$2.84	$0.75	$11.08	($0.05)	$11.12
Mar	$12.81	$2.50	$1.21	$16.52	$0.23	$16.29
Average	$10.69	$2.67	$0.85	$14.21	$0.39	$13.82

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 10-40. Total scheduled regulation is based on settled (actual) MW. The total of all regulation charges for the first three months of 2017 was $20.7 million, compared to $21.4 million for the first three months of 2016.

Table 10-40 Total regulation charges: January 1, 2016 through March 31, 2017[69]

Year	Month	Scheduled Regulation (MW)	Total Regulation Charges ($)	Weighted Average Regulation Market Price ($/MW)	Cost of Regulation ($/MW)	Price as Percent of Cost
2016	Jan	412,310.8	$7,589,231	$15.65	$18.41	85.0%
2016	Feb	383,646.6	$7,677,113	$17.63	$20.01	88.1%
2016	Mar	396,604.0	$6,107,773	$13.43	$15.40	87.2%
2016	Apr	384,591.8	$8,367,326	$19.07	$21.76	87.7%
2016	May	391,135.2	$7,217,226	$15.67	$18.45	84.9%
2016	Jun	379,014.9	$5,993,073	$14.03	$15.81	88.7%
2016	Jul	386,146.2	$7,954,280	$17.86	$20.60	86.7%
2016	Aug	385,843.5	$7,703,653	$17.59	$19.97	88.1%
2016	Sep	376,321.1	$7,780,425	$17.91	$20.67	86.6%
2016	Oct	389,139.0	$7,018,089	$15.68	$18.03	87.0%
2016	Nov	374,665.6	$5,777,367	$13.12	$15.42	85.1%
2016	Dec	390,836.1	$5,113,222	$11.15	$13.08	85.2%
2016 Annual		4,650,254.7	$84,298,779	$15.73	$18.13	86.7%
2017	Jan	395,649.2	$6,824,379	$14.06	$17.25	81.5%
2017	Feb	355,967.1	$5,327,528	$11.12	$14.97	74.3%
2017	Mar	375,166.4	$8,581,366	$16.29	$22.87	71.2%
YTD		1,126,782.7	$20,733,273	$13.82	$18.36	75.7%

69 Weighted average market clearing prices presented here are taken from PJM settlements data, and differ from the values reported in Table 10-11, which are from five minute interval operational data. The MMU is investigating the cause of the discrepancies with PJM.

The capability, performance, and opportunity cost components of the cost of regulation are shown in Table 10-41. Total scheduled regulation is based on settled actual MW. In the first three months of 2017, the monthly average total cost of regulation was $18.36, 2.4 percent higher than $17.94 in the first three months of 2016. In the first three months of 2017, the monthly average capability component cost of regulation was $12.33, 13.0 percent lower than $14.17 in the first three months of 2016. In the first three months of 2017, the monthly average performance component cost of regulation was $4.37, 92.0 percent higher than $2.28 in the first three months of 2016.

Table 10-41 Components of regulation cost, January through March, 2016 through 2017

Year	Month	Scheduled Regulation (MW)	Cost of Regulation Capability ($/MW)	Cost of Regulation Performance ($/MW)	Opportunity Cost ($/MW)	Total Cost ($/MW)
2016	Jan	412,310.8	$14.49	$1.97	$1.95	$18.41
	Feb	383,646.6	$16.00	$2.61	$1.40	$20.01
	Mar	396,604.0	$12.01	$2.25	$1.14	$15.40
	YTD	1,192,561.4	$14.17	$2.28	$1.50	$17.94
2017	Jan	395,649.2	$13.17	$2.43	$1.65	$17.25
	Feb	355,967.1	$9.91	$3.69	$1.37	$14.97
	Mar	375,166.4	$13.91	$7.00	$1.97	$22.87
	YTD	1,126,782.7	$12.33	$4.37	$1.66	$18.36

Table 10-42 provides a comparison of the average price and cost for PJM regulation. The ratio of regulation market price to the actual cost of regulation in the first three months of 2017 was 75.4 percent, a 13.1 percent decrease from 86.8 percent in the first three months of 2016.

Table 10-42 Comparison of average price and cost for PJM regulation: January through March, 2009 through 2017

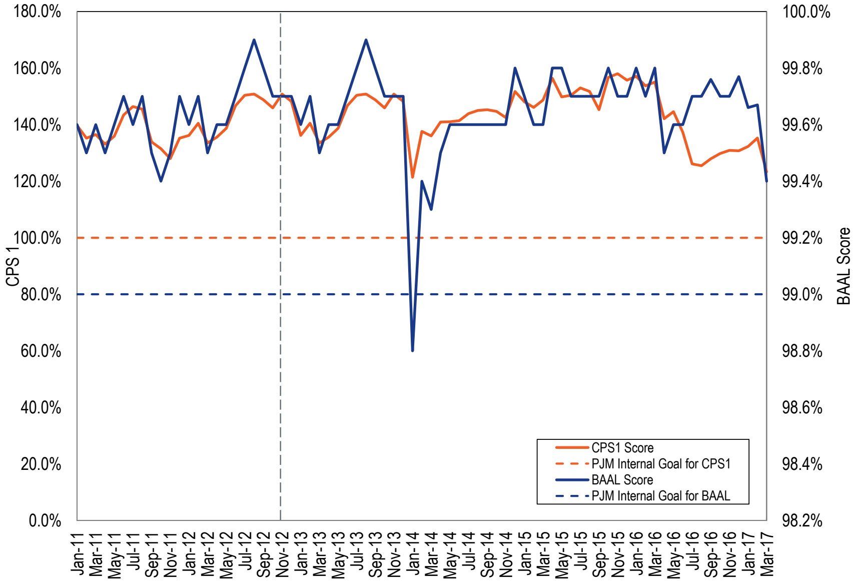
Year (Jan-Mar)	Weighted Regulation Market Price	Weighted Regulation Market Cost	Regulation Price as Percent Cost
2009	$22.25	$34.06	65.3%
2010	$17.97	$31.24	57.5%
2011	$11.52	$25.03	46.0%
2012	$12.62	$16.75	75.3%
2013	$33.91	$39.36	86.2%
2014	$92.97	$112.30	82.8%
2015	$47.91	$58.23	82.3%
2016	$15.55	$17.92	86.8%
2017	$13.87	$18.40	75.4%

Performance Standards

PJM's performance as measured by CPS1 and BAAL standards is shown in Figure 10-31 for every month from January 2011 through December 2016 with the dashed vertical line marking the date (October 1, 2012) of the implementation of the Performance Based Regulation Market design.[70] 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.

70 See the *2016 State of the Market Report for PJM*, Appendix F: Ancillary Services.

Figure 10-31 PJM monthly CPS1 and BAAL performance: January 1, 2011 through March 31, 2017



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.[71] [72] PJM set a September 30, 2013, deadline for resources submitting proposals and requested that resources be able to provide black start by April 1, 2015. PJM identified zones with black start shortages, prioritized its selection process accordingly, and began awarding proposals on January 14, 2014. PJM and the MMU coordinated closely during the selection process.

PJM issued two incremental 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.

Black start payments are nontransparent payments made to units by load to maintain adequate reliability to restart the system in case of a blackout. Current rules appear to prevent publishing detailed data regarding these black start resources, hindering transparency and competitive replacement RFPs. The MMU recommends that the current confidentiality rules be revised to allow disclosure of information regarding black start resources and their associated payments. In 2014, zonal reporting of black start payments was implemented, partially fulfilling the recommendation.

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

Total black start charges are the sum of black start revenue requirement charges and black start operating reserve charges. Black start revenue requirements for black start units consist of fixed black start service costs, variable black start service costs, training costs, fuel storage costs, and an incentive factor. Section 18 of Schedule 6A of the OATT specifies how to calculate each component of the revenue requirement formula. Black start resources can choose to recover fixed costs under a formula rate based on zonal Net CONE and unit ICAP rating, a cost recovery rate based on incremental black start NERC-CIP compliance capital costs, or a cost recovery rate based on incremental black start equipment capital costs. Black start operating reserve charges are paid to units scheduled in the Day-Ahead Energy Market or committed in real time to provide black start service under the automatic load rejection (ALR) option or for black start testing. Total black start charges are allocated monthly to PJM customers proportionally to their zone and nonzone peak transmission use and point to point transmission reservations.[73]

In the first three months of 2017, total black start charges were $17.0 million, an increase of $0.3 million (1.8 percent) from the same period of 2016. Operating reserve charges for black start service increased from $0.057 million in 2016 to $0.058 million in 2017. Table 10-43 shows total revenue requirement charges from 2010 through 2017. (Prior to December 2012, PJM did not define a black start operating reserve category. As a result of the changes in the black start operating reserve category, 2013 was the first full year in which operating reserves charges were allocated to black start, resulting in the increase in operating reserves charges. Starting in 2014, the ALR black start units began to be replaced with new black start units, resulting in a decline in operating reserve charges. Prior to December 2012, operating reserve charges resulting from units providing black start service were allocated as operating reserve charges for reliability in the western region.)

Table 10-43 Black start revenue requirement charges: 2010 through 2017

Year Jan-Mar	Revenue Requirement Charges	Operating Reserves Charges	Total
2010	$2,673,689	$0	$2,673,689
2011	$2,793,709	$0	$2,793,709
2012	$3,864,301	$0	$3,864,301
2013	$5,412,855	$22,210,646	$27,623,501
2014	$5,104,104	$7,561,533	$12,665,637
2015	$10,276,712	$4,699,965	$14,976,676
2016	$16,677,315	$57,082	$16,734,396
2017	$16,977,182	$57,772	$17,034,954

Black start zonal charges in the first three months of 2017 ranged from $0.05 per MW-day in the DLCO Zone (total charges were $12,507) to $4.30 per MW-day in the PENELEC Zone (total charges were $1,127,246). For each zone, Table 10-44 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 $0.0414 per MW of reserve capacity during the first three months of 2017.

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

Table 10-44 Black start zonal charges for network transmission use: January through March, 2016 and 2017

	Jan-Mar 2016					Jan-Mar 2017				
Zone	Revenue Requirement Charges	Operating Reserve Charges	Total Charges	Peak Load (MW-day)	Black Start Rate ($/MW-day)	Revenue Requirement Charges	Operating Reserve Charges	Total Charges	Peak Load (MW-day)	Black Start Rate ($/MW-day)
AECO	$498,192	$6,210	$504,402	232,305	$2.17	$625,055	$0	$625,055	240,606	$2.60
AEP	$3,700,273	$20,455	$3,720,728	2,249,984	$1.65	$3,648,502	$1,006	$3,649,508	2,022,813	$1.80
AP	$1,046,187	$0	$1,046,187	873,018	$1.20	$966,701	$0	$966,701	784,548	$1.23
ATSI	$753,343	$0	$753,343	1,124,432	$0.67	$756,392	$0	$756,392	1,147,698	$0.66
BGE	$2,024,438	$0	$2,024,438	610,783	$3.31	$1,612,788	$0	$1,612,788	594,081	$2.71
ComEd	$1,216,614	$12,558	$1,229,172	1,834,769	$0.67	$1,211,762	$9,119	$1,220,881	1,905,714	$0.64
DAY	$59,439	$8,784	$68,223	298,553	$0.23	$56,824	$9,966	$66,789	300,591	$0.22
DEOK	$292,248	$0	$292,248	466,193	$0.63	$260,610	$0	$260,610	477,729	$0.55
Dominion	$738,170	$4,361	$742,531	1,970,232	$0.38	$1,077,751	$28,576	$1,106,327	1,758,429	$0.63
DPL	$260,192	$1,206	$261,398	374,374	$0.70	$572,710	$0	$572,710	371,412	$1.54
DLCO	$12,883	$0	$12,883	255,164	$0.05	$12,507	$0	$12,507	251,685	$0.05
EKPC	$71,452	$0	$71,452	317,617	$0.22	$102,456	$0	$102,456	259,002	$0.40
JCPL	$1,724,360	$0	$1,724,360	529,447	$3.26	$1,703,417	$0	$1,703,417	535,932	$3.18
Met-Ed	$145,886	$0	$145,886	254,654	$0.57	$149,649	$5,504	$155,153	265,266	$0.58
PECO	$407,647	$620	$408,267	736,590	$0.55	$388,222	$1,047	$389,269	752,751	$0.52
PENELEC	$1,196,171	$0	$1,196,171	275,211	$4.35	$1,127,246	$0	$1,127,246	261,846	$4.30
Pepco	$641,618	$0	$641,618	570,361	$1.12	$628,995	$0	$628,995	592,524	$1.06
PPL	$249,314	$0	$249,314	732,996	$0.34	$299,455	$0	$299,455	632,223	$0.47
PSEG	$1,065,246	$1,067	$1,066,314	873,136	$1.22	$1,044,699	$0	$1,044,699	882,027	$1.18
RECO	$0	$0	$0	NA	NA	$0	$0	$0	NA	NA
(Imp/Exp/Wheels)	$573,640	$1,821	$575,461	519,320	$1.11	$731,442	$2,554	$733,996	633,529	$1.16
Total	$16,677,315	$57,082	$16,734,396	15,099,139	$1.11	$16,977,182	$57,772	$17,034,954	14,670,406	$1.16

Table 10-45 provides a revenue requirement estimate by zone for the 2016/2017, 2017/2018 and 2018/2019 delivery years.[74] 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, and owner provided cost estimates of incoming black start units, at the time of publication and may change significantly.

74 The Market Monitoring Unit was requested to provide estimated black start revenue requirements in the System Restoration Strategy Task Force group.

NERC – CIP

Currently, no black start units have requested new or additional black start NERC – CIP Capital Costs.[75]

Table 10-45 Black start zonal revenue requirement estimate: 2016/2017 through 2018/2019 delivery years

Zone	2016 / 2017 Revenue Requirement	2017 / 2018 Revenue Requirement	2018 / 2019 Revenue Requirement
AECO	$2,850,000	$2,850,000	$2,800,000
AEP	$19,150,000	$19,200,000	$18,950,000
AP	$4,150,000	$4,150,000	$4,150,000
ATSI	$3,100,000	$3,100,000	$3,100,000
BGE	$8,400,000	$3,650,000	$3,550,000
ComEd	$5,100,000	$5,200,000	$4,750,000
DAY	$250,000	$300,000	$250,000
DEOK	$1,250,000	$1,250,000	$1,200,000
DLCO	$100,000	$100,000	$2,750,000
Dominion	$5,400,000	$5,400,000	$5,400,000
DPL	$2,600,000	$2,600,000	$2,500,000
EKPC	$450,000	$450,000	$300,000
JCPL	$7,200,000	$7,200,000	$7,150,000
Met-Ed	$700,000	$750,000	$600,000
PECO	$1,750,000	$1,900,000	$1,550,000
PENELEC	$4,700,000	$4,750,000	$4,500,000
Pepco	$2,700,000	$2,700,000	$2,650,000
PPL	$800,000	$800,000	$750,000
PSEG	$4,450,000	$4,500,000	$4,450,000
RECO	$0	$0	$0
Total	$75,100,000	$70,850,000	$71,350,000

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 by FERC per Schedule 2 of the OATT. Generators may obtain FERC approval to recover a share of units' fixed costs by calculating a reactive revenue requirement, the reactive capability rate, and to collect such rates from PJM transmission customers.[76]

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).[77] While a fixed requirement for reactive power is not established, reactive power helps maintain appropriate voltages on the transmission system.

Total reactive capability charges are the sum of FERC approved reactive supply revenue requirements which are posted monthly on the PJM website.[78] Zonal reactive supply revenue requirement charges are allocated monthly to PJM customers proportionally to their zone and nonzone peak transmission use and point to point transmission reservations.[79]

In 2016, the FERC began to reexamine its policies on reactive compensation.[80] 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.[81] 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

75 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.

76 See also PJM, Manual 27 (Open Access Transmission Tariff Accounting), Rev. 86, (January 26, 2017) at 3.
77 OATT Schedule 2.
78 See PJM. Markets & Operations: Billing, Settlements & Credit <http://www.pjm.com/~/media/markets-ops/settlements/reactive-revenue-requirements-table-may-2016.ashx> (June 8, 2016).
79 OATT Schedule 2.
80 *See, e.g., 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).
81 See 88 FERC ¶ 61,141 (July 30, 1999).

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.[82] There is no support for the assertion 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 support for the assertion 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.[83]

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.[84] 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.[85] The Commission has recently extended the interconnection service requirement to have reactive capability to wind and solar units, which previously had been exempt.[86] 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.

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

82 *See Reactive Power Requirements for Non-Synchronous Generation*, Order No. 827, 155 FERC ¶ 61,277 at 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.").

83 *See* 18 CFR § 35.28(f)(1); *Standardization of Generator Interconnection Agreements and Procedures*, 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); *Standardization of Small Generator Interconnection Agreements and Procedures*, 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).

84 *See* OATT Attachment O Appendix 2 § 4.7.

85 *See, e.g., id.* 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.").

86 *Reactive Power Requirements for Non-Synchronous Generation*, Order No. 827, 155 FERC ¶ 61,277 (2016); see also PJM Interconnection, L.L.C., 151 FERC ¶ 61,097 at P 28 (2015).

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.[87] 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.

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 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.

87 *See* OATT Attachment DD § 5.10(a)(iv).

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.[88] 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.[89] 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.[90]

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 organized markets.[91] 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.

88 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.").

89 *Id.*

90 *Id.*

91 See FERC Docket No. AD16-17.

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. The FERC recently has initiated a number of investigations into the basis for reactive rates, and the MMU has intervened in and is participating in those proceedings.[92]

Under the *AEP* method, units must establish their MVAR rating based on "the capability of the generators to produce VArs."[93] Typically this has meant reliance on manufacturers' specified nameplate power factor.[94] More recently, the Commission has, in the *Wabash* Orders, required that "reactive power revenue requirement filings must include reactive power test reports."[95] 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.[96]

The Commission has identified a significant issue. Tests are essential to "evaluate and analyze" proposed reactive revenue requirements.[97] 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.

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 will reveal whether the tested capability degrades further. Reliance on tested results would address both the issue of degradation and the issue of theoretical versus actual MVAR ratings.

The logic of the *Wabash* orders should be extended to exclude manufacturers' nameplate MVAR ratings and the corresponding theoretical power factors. Nameplate MVAR ratings should not be relied upon to define the allocator used to calculate the costs of reactive capability. Current performance and testing show significant disparities between nameplate MVAR output and actual output. This is significant regardless of whether the cause is degradation of power factors or simply the difference between theoretical and tested power factors.[98] PJM determined in 1999 that nameplate MVAR and power factor ratings do not reflect the value to the system operator of a units' reactive output after it is interconnected at a specific location.[99] Only operator evaluation of reactive capability can provide a meaningful measure of reactive capability.

The information for MVAR ratings should come from data on the MVAR output provided. System operators can evaluate the usefulness and value of reactive capacity based on the actual availability and use of such capability.

Data from periodic testing for reactive capability is another approach to measuring MVAR output. Testing at relatively long intervals is not likely to be as accurate as actual market operations data, but it is more reliable than an untested and dated manufacturers' nameplate rating.

92 *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.

93 *AEP mimeo* at 31.

94 *See, e.g.*, *id.*

95 154 FERC ¶ 61,246 at P 28 (2016); see also 154 FERC ¶ 61,246 at P 29 (*Wabash* Orders).

96 *See, e.g.*, *Talen Energy Marketing, LLC*, 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.").

97 154 FERC ¶ 61,246 at P 28 (2016); see also 154 FERC ¶ 61,246 at P 29.

98 In response to a 1999 low voltage event, PJM performed a root cause analysis. The analysis concluded that "PJM narrowly avoided a voltage collapse" and that "if PJM had realized that the MVAR reserves that the EMS indicated were available were not realistic, other action could have been take [sic] to stabilize the system." PJM State & Member Training Dept., Slides, Reactive Reserves and Generator D-Curves at 13 (included as an Attachment), which can be accessed at: *<http://www.pjm.com/~/media/training/nerc-certifications/gen-exam-materials/gof/20160104-reactive-reserves-and-d-curve.ashx>*.

99 *Id.*, including Attachment.

The estimated capability costs also include estimated heating losses relative to MVAR output.[100] Heating losses are variable costs and not fixed costs and should not be included in the definition of reactive capability costs.[101] Heating losses can be accurately calculated for each hour of operation if each unit had an accurate, recent D-curve test.

Heating losses are variable costs and should not be included in the cost of reactive capability. The production of reactive power slightly reduces the MWh output of the generator as the generator follows its D-curve. The value of this heating loss component is generally estimated based on estimated operation and associated estimated losses and estimated market prices, treated as a fixed cost, and included in the cost of reactive capability. Losses are minimal and occur during normal operations and should not be treated as a fixed cost. Losses can be better and more accurately accounted for as a variable cost based on actual unit operations and market conditions.

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.[102] 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.[103] 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.[104] 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. Rates that do not accurately reflect the cost of the service provided are not just and reasonable.

Reactive capability rates 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.[105] 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 the FERC concerning reactive capability rates for PJM units.

Reactive Costs

In the first three months of 2017, total reactive charges were $86.4 million, a 17.6 percent increase from the 2016 level of $73.4 million.[106] Reactive service charges increased in the first three months of 2017 to $5.9 million from $251 thousand in the first three months of 2016. All $5.9 million in 2017 were paid for reactive service provided by 18 units in 97 hours. The reason for the increase in reactive service charges from the first three months in 2016 to 2017 is primarily due to the need to control regional voltages resulting from outages and locational seasonal light loads.

100 *See, e.g., id.* at P 10 n12 citing *PPL Energy Plus, LLC*, Letter Order, Docket No. ER08-1462-000 (Sept. 24, 2008); *Dynegy Midwest Generation, Inc.*, 125 FERC ¶ 61,280, at P 35 (2008).

101 *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.

102 *See, e.g.*, OATT Schedule 2; *Virginia Electric and Power Company*; 114 FERC ¶ 61,318 (2006).

103 *See PJM Interconnection, L.L.C.*, 149 FERC ¶ 61,132 (2014); 151 FERC ¶ 61,224 (2015); OATT Schedule 2.

104 *Id.*

105 See OATT Attachment DD §§ 6.4, 6.8(d).

106 See the *2015 State of the Market Report for PJM*, Volume II, Section 4, "Energy Uplift."

Table 10-46 shows reactive service charges in 2016 and 2017, reactive capability revenue requirement charges and total charges.

Table 10-46 Reactive zonal charges for network transmission use: January through March, 2016 and 2017

	Jan-Mar 2016			Jan-Mar 2017		
Zone	Reactive Service Charges	Reactive Capability Revenue Requirement Charges	Total Charges	Reactive Service Charges	Reactive Capability Revenue Requirement Charges	Total Charges
AECO	$0	$1,360,729	$1,360,729	$4,392	$1,542,545	$1,546,936
AEP	$14,106	$9,191,375	$9,205,481	$102,082	$9,551,200	$9,653,281
AP	$0	$4,205,441	$4,205,441	$24,854	$4,194,868	$4,219,722
ATSI	$0	$5,547,337	$5,547,337	$32,667	$5,565,868	$5,598,535
BGE	$0	$1,927,384	$1,927,384	$1,681,755	$1,936,287	$3,618,042
ComEd	$1,091	$6,420,094	$6,421,185	$1,184,616	$7,885,880	$9,070,496
DAY	$0	$2,141,598	$2,141,598	$8,407	$1,901,104	$1,909,511
DEOK	$0	$1,431,077	$1,431,077	$12,641	$1,631,892	$1,644,534
Dominion	$0	$7,528,684	$7,528,684	$48,153	$7,457,061	$7,505,214
DPL	$224,934	$3,243,447	$3,468,381	$72,136	$3,123,980	$3,196,116
DLCO	$0	$0	$0	$6,479	$0	$6,479
EKPC	$0	$543,758	$543,758	$6,384	$538,585	$544,969
JCPL	$0	$2,260,113	$2,260,113	$10,251	$2,088,950	$2,099,201
Met-Ed	$0	$1,950,686	$1,950,686	$15,597	$1,791,128	$1,806,725
PECO	$0	$4,477,340	$4,477,340	$19,130	$4,406,222	$4,425,352
PENELEC	$10,366	$1,853,304	$1,863,670	$1,018,417	$2,610,963	$3,629,380
Pepco	$0	$1,338,510	$1,338,510	$1,582,888	$2,053,524	$3,636,412
PPL	$0	$4,786,381	$4,786,381	$21,901	$8,121,164	$8,143,065
PSEG	$0	$9,056,964	$9,056,964	$19,574	$9,081,874	$9,101,447
RECO	$0	$0	$0	$636	$0	$636
(Imp/Exp/Wheels)	$0	$3,919,825	$3,919,825	$0	$5,038,621	$5,038,621
Total	$250,496	$73,184,046	$73,434,542	$5,872,960	$80,521,715	$86,394,674