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 incentive rates or cost.

The Market Monitoring Unit (MMU) analyzed measures of market structure, conduct and performance for the PJM Regulation Market, the two regional Synchronized Reserve and Non-Synchronized Reserve Markets, and the PJM DASR Market for the first three months of 2014.

Table 10-1 The Regulation Market results were competitive

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

- Market structure was evaluated as not competitive for the year because the Regulation Market had one or more pivotal suppliers which failed PJM's three pivotal supplier (TPS) test in 97 percent of the hours in the first three months of 2014.
- Participant behavior in the Regulation Market was evaluated as competitive for the first three months of 2014 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 anti-competitive behavior.
- Market performance was evaluated as competitive, after the introduction of the new market design, despite significant issues with the market design.
- Market design was evaluated as flawed. While the design of the Regulation Market was significantly improved with changes introduced October 1, 2012, a number of issues remain. The market results continue to include the incorrect definition of opportunity cost. Further, the market design has failed to correctly incorporate a consistent implementation of the marginal benefit factor in optimization, pricing and settlement.

Table 10-2 The Synchronized Reserve Markets results were competitive

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

- The 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 the 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 non-synchronized reserve market clears with a non-zero price.

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

Table 10-3 The Day-Ahead Scheduling Reserve Market results were competitive

Market Element	Evaluation	Market Design
Market Structure	Competitive	
Participant Behavior	Mixed	
Market Performance	Competitive	Mixed

- The Day-Ahead Scheduling Reserve Market structure was evaluated as competitive because market participants did not fail the three pivotal supplier test.
- Participant behavior was evaluated as mixed because while most offers appeared consistent with marginal costs, 12 percent of offers reflected economic withholding.
- Market performance was evaluated as competitive because there were adequate offers at reasonable levels in every hour to satisfy the requirement and the clearing price reflected those offers.
- Market design was evaluated as mixed because while the market is functioning effectively to provide DASR, the three pivotal supplier test, and cost-based offer capping when the test is failed, should be added to the market to ensure that market power cannot be exercised at times of system stress.

Overview

Regulation Market

The PJM Regulation Market is a single market for the RTO. Regulation is provided by demand response and generation resources that must qualify to follow a regulation signal (RegA or RegD). PJM jointly optimizes regulation with synchronized reserve and energy to provide all three of these services at least cost. The PJM Regulation Market design includes three clearing price components (capability, performance, and lost opportunity cost), the rate of substitution between RegA and RegD resources (marginal benefit factor) and a measure of the quality of response (performance score) by a regulation resource to a regulation signal. The marginal benefit factor and performance score translate a resource's capability (actual) MW into effective MW.

Market Structure

- **Supply.** In the first three months of 2014, the average hourly eligible supply of regulation was 1,378 actual MW (1,016 effective MW). This is a decrease of 110 actual MW (169 effective MW) from the first three months of 2013 when the average hourly eligible supply of regulation was 1,488 actual MW (1,185 effective MW).
- **Demand.** The average hourly regulation demand was 685 actual MW (664 effective MW) in the first three months of 2014. This is a 152 actual MW (45 effective MW) decrease in the average hourly regulation demand of 837 actual MW (708 effective MW) in the same period of the first three months of 2013.
- **Supply and Demand.** The ratio of offered and eligible regulation to regulation required averaged 2.01. This is a 13.4 percent increase over the first three months of 2013 when the ratio was 1.77.
- **Market Concentration.** In the first three months of 2014, the PJM Regulation Market had a weighted average Herfindahl-Hirschman Index (HHI) of 1972 which is classified as highly concentrated. In the first three months of 2014, the three pivotal supplier test was failed in 97 percent of hours.

Market Conduct

- **Offers.** Daily regulation offer prices are submitted for each unit by the unit owner. Owners are required to submit a cost offer along with cost parameters to verify the offer, and may optionally submit a price 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.[3] As of March 31, 2014, there were 261 resources following the RegA signal and 38 resources following the RegD signal.

3 See the *2012 State of the Market Report for PJM*, Volume II, Appendix F "Ancillary Services Markets."

Market Performance

- **Price and Cost.** The weighted average clearing price for regulation was $91.94 per MW of regulation in the first three months of 2014, an increase of $58.24 per MW of regulation, or 172.8 percent, from the first three months of 2013. The cost of regulation in the first three months of 2014 was $111.02 per MW of regulation, a $72.28 per MW of regulation, or 186.6 percent, increase from the first three months of 2013.
- **RMCP Credits.** RegD resources continue to be underpaid relative to RegA resources due to an inconsistent application of the marginal benefit factor in the optimization, assignment, pricing, and settlement processes. In the first three months of 2014, RegA resources received RMCP credits per effective MW on average 2.1 times higher than RegD resources. If the Regulation Market were functioning correctly, RegD and RegA resources would be paid equally per effective MW.

Synchronized Reserve Market

Synchronized reserve is a component of primary reserve. The Tier 2 Synchronized Reserve market includes the PJM RTO Reserve Zone and a subzone, the Mid-Atlantic Dominion Reserve Subzone (MAD). The MAD subzone is designed to ensure that transmission constraints will not prevent adequate synchronized reserves from being available in MAD when called. PJM has the right to define new zones or subzones "as needed for system reliability."[4]

Market Structure

- **Supply.** In the first three months of 2014, the supply of offered and eligible synchronized reserve was sufficient to cover the requirement in both the RTO Reserve Zone and the Mid-Atlantic Dominion Reserve Subzone, except for two hours on January 6, 2014, and eight hours on January 7, 2014.
- **Demand.** The synchronized reserve requirement for the RTO Synchronized Reserve Zone remained at 1,375 MW where it was set in November 2012. The synchronized reserve requirement for the Mid-Atlantic Dominion Reserve Subzone remained at 1,300 MW where it was set in July 2010.
- **Supply and Demand.** All on-line generation resources are required to offer synchronized reserve. In the first three months of 2014, the ratio of on-line tier 2 offered synchronized reserve to synchronized reserve required in the Mid-Atlantic Dominion Subzone was 3.02 averaged over all hours. The highest offered to required ratio was 3.99 on January 31 and the lowest was 1.77 on March 31. For the RTO Synchronized Reserve Zone the ratio was 8.85. The highest offered to required ratio was 10.46 on January 1 and the lowest was 6.62 on March 27.
- **Market Concentration.** In the first three months of 2014, the weighted average HHI for cleared inflexible tier 2 synchronized reserve in the Mid-Atlantic Dominion Subzone was 4236 which is classified as highly concentrated. The HHI for flexible synchronized reserve cleared during real-time market solutions (which was only 14.0 percent of all tier 2 synchronized reserve) was 8743. In the first three months of 2014, 56 percent of hours had a maximum market share greater than 40 percent. The MMU calculates that during the first three months of 2014, 57.9 percent of hours would have failed a three pivotal supplier test in the Mid-Atlantic Dominion Subzone if PJM had such a test and 37.7 percent of hours would have failed a three pivotal supplier test in the RTO Synchronized Reserve Zone if PJM had such a test.

  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 in the first three months of 2014 were characterized by structural market power.

Market Conduct

- **Offers.** 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.

4 See PJM. "Manual 11, Energy and Ancillary Services Market Operations," Revision 64 (January 6, 2014), p. 66.

Market Performance

- **Price.** The cleared synchronized reserve weighted average price for Tier 2 synchronized reserve in the Mid-Atlantic Dominion (MAD) Subzone was $26.46 per MW in the first three months of 2014, a $19.11 increase from the first three months of 2013. The cost of tier 2 synchronized reserves per MW in MAD in the first three months of 2014 was $33.48, a $20.90 increase the cost of synchronized reserve in the first three months of 2013. For the MAD Subzone the market clearing price was 79 percent of the synchronized reserve cost per MW in the first three months of 2014, an increase from the 60 percent in the first three months of 2013.

  The cleared synchronized reserve weighted average price for tier 2 synchronized reserve in the RTO Synchronized Reserve Zone was $50.90 per MW in the first three months of 2014. The cost for tier 2 synchronized reserve in RTO Synchronized Reserve Zone was $100.53. For the RTO Synchronized Reserve Zone the market clearing price was 50.6 percent of the synchronized reserve cost per MW in the first three months of 2014.

- **Supply and Demand.** A synchronized reserve shortage occurs when the combination of tier 1 and tier 2 synchronized reserve supply is not adequate to meet the synchronized reserve requirement. The synchronized reserve requirement did not change for either the RTO Reserve Zone or the Mid-Atlantic Dominion Subzone during the first three months of 2014. There were four hours of synchronized reserve shortage in the first three months of 2014 on January 7, 2014. The shortage was in both the RTO Zone and the MAD subzone.

Non-Synchronized Reserve Market

Non-synchronized reserve is a component of primary reserve and shares its market definitions including the RTO Reserve Zone and the Mid-Atlantic Dominion Reserve subzone (MAD). After the hour ahead market solution satisfies the requirement for synchronized reserve the remainder of the primary reserve requirement is satisfied with non-synchronized reserve. Non-synchronized reserve is non-emergency energy resources not currently synchronized to the grid that can provide energy within ten minutes at the direction of PJM dispatch.

Market Structure

- **Supply.** With the exception of two hours on January 6, 2014, and eight hours on January 7, 2014, the supply of offered and eligible tier 2 synchronized reserve for the period spanning January 1, 2014 through March 31, 2014 was sufficient to cover the requirement in both the RTO Reserve Zone and the Mid-Atlantic Dominion Reserve Subzone.
- **Demand.** In the RTO Zone the market cleared an hourly average of 37.8 MW of non-synchronized reserve of which 86.9 percent of cleared non-synchronized reserve was at a price of $0. In the MAD subzone, the market cleared an hourly average of 560 MW of non-synchronized reserve of which 92.7 percent was at a price of $0.
- **Supply and Demand.** The requirement for primary reserve is 1.5 times the largest contingency. There is no specific requirement for non-synchronized reserve. In the RTO Reserve Zone the primary reserve requirement is 2,063 MW. Of that 2,063 MW 1,375 MW must be synchronized to the grid. All or any portion of the remaining 688 MW is a jointly optimized solution of tier 2 synchronized reserve, tier 1 synchronized reserve, and non-synchronized reserve. In the MAD subzone the primary reserve requirement is 1,700 MW of which 1,300 MW must be synchronized to the grid. All or any portion of the remaining 400 MW can be non-synchronized reserve.

Market Conduct

- **Offers.** No offers are made for non-synchronized reserve. Non-emergency generation resources that are available to provide energy and can start in 10 minutes or less are considered available for Non-Synchronized Reserves by the market solution software.

Market Performance

- **Price.** Prices are a function of the opportunity costs of any resources taken for non-synchronized reserves. The cleared non-synchronized reserve weighted average price in the RTO Reserve Zone was $2.02 per MW for the first three months of 2014. The cleared non-synchronized reserve weighted average price in the Mid-Atlantic Dominion (MAD) Subzone was $4.56 per MW.

Day-Ahead Scheduling Reserve (DASR)

The purpose of the DASR Market is to satisfy secondary supplemental (30-minute) reserve requirements with a market-based mechanism that allows generation resources to offer their reserve energy at a price and compensates cleared supply at a single market clearing price. The DASR 30-minute reserve requirements are determined for each reliability region.[5]

Market Structure

- **Concentration.** The MMU calculates that in the first three months of 2014, zero hours in the DASR market would have failed the three pivotal supplier test.
- **Supply.** The DASR market is a must offer market. Any resources that do not make an offer have their offer set to $0 per MW. Eligible DASR resources consist of all resources that can provide reserve capability that can be fully converted into energy within 30 minutes as requested by PJM dispatchers.
- **Demand.** The DASR requirement in 2014 is 6.27 percent of peak load forecast, down from 6.91 percent in 2013.

Market Conduct

- **Withholding.** Economic withholding remains an issue in the DASR Market. The direct marginal cost of providing DASR is zero. All offers greater than zero constitute economic withholding. On March 31, 2014, 56.4 percent of resources offered at $0, 65.9 percent of resources offered at $0.05 or less, 74.4 percent of resources offered at less than $1.00, and 11.5 percent resources offered at above $5 per MW.
- **DR.** Demand resources are eligible to participate in the DASR Market, but no demand resource cleared the DASR Market in the first three months of 2014.

Market Performance

- **Price.** The DASR market clearing price in the first three months of 2014 was $0.06 per MW. This is a 100 percent increase from the first three months of 2013 which had a weighted price of $0.03 per MW.

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.[6]

In the first three months of 2014, total black start charges were $12.7 million with $5.1 million in revenue requirement charges and $7.6 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 for scheduling in the Day-Ahead Energy Market or committing in real time units that provide black start service. Black start zonal charges in the first three months of 2014 ranged from $0.02 per MW-day in the ATSI Zone (total charges were $28,280) to $3.50 per MW-day in the AEP Zone (total charges were $7,202,857).

Reactive

Reactive service, reactive supply and voltage control from generation or other sources service, is provided by generation and other sources of reactive power (measured in VAR). Reactive power helps maintain appropriate voltages on

5 See PJM. "Manual 13: Emergency Operations," Revision 53, (June 1, 2013); pp 11-12.

6 OATT Schedule 1 § 1.3BB.

the transmission system and is essential to the flow of real power (measured in MW).

In the first three months of 2014, total reactive service charges were $77.7 million with $70.2 million in revenue requirement charges and $7.5 million in operating reserve charges. Reactive service revenue requirements are based on FERC-approved filings. Reactive service operating reserve charges are paid for scheduling in the Day-Ahead Energy Market and committing in real time units that provide reactive service. Total charges in the first three months of 2014 ranged from $487 in the RECO Zone to $10.1 million in the AEP Zone.

Ancillary Services Costs per MWh of Load: January through March, 2003 through 2014

Table 10-4 shows PJM ancillary services costs for the first three months of years 2003 through 2014, on a per MWh of load basis. The rates are calculated as the total charges for the specified ancillary service divided by the total real time load in MWh for the first three months of 2014 (212.3 million 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. Supplementary operating reserve includes day-ahead operating reserve; balancing operating reserve; and synchronous condensing. The cost per MWh of load in Table 10-4 is a different metric than the cost of each ancillary in 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 also changes in the volume of each ancillary service purchased. As an example, the Regulation Market clearing price increased 172.8 percent (from $33.70 to $91.94 per MW of regulation capability), the cost of regulation per MWh of real time load increased only 125.0 percent (from $0.28 to $0.63 per MWh of real time load).

Table 10-4 History of ancillary services costs per MWh of Load: January through March, 2003 through 2014

Year (Jan-Mar)	Regulation	Scheduling, Dispatch, and System Control	Reactive	Synchronized Reserve	Supplementary Operating Reserve	Total
2003	$0.65	$0.59	$0.22	$0.00	$0.98	$2.43
2004	$0.53	$0.63	$0.26	$0.17	$0.89	$2.48
2005	$0.46	$0.51	$0.25	$0.07	$0.57	$1.86
2006	$0.48	$0.46	$0.28	$0.09	$0.32	$1.62
2007	$0.58	$0.46	$0.30	$0.11	$0.50	$1.95
2008	$0.59	$0.47	$0.29	$0.07	$0.52	$1.94
2009	$0.37	$0.37	$0.34	$0.16	$0.56	$1.80
2010	$0.34	$0.38	$0.35	$0.05	$0.68	$1.80
2011	$0.27	$0.33	$0.39	$0.12	$0.84	$1.95
2012	$0.18	$0.41	$0.49	$0.03	$0.53	$1.64
2013	$0.28	$0.41	$0.63	$0.04	$0.94	$2.30
2014	$0.63	$0.38	$0.37	$0.56	$3.55	$5.49

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.
- The MMU recommends that the rule requiring the payment of tier 1 synchronized reserve resources when the non-synchronized reserve price is above zero be eliminated immediately.
- The MMU recommends that the tier 2 synchronized reserve must-offer provision of scarcity pricing be enforced.
- The MMU recommends that PJM be more explicit about why tier 1 biasing is used in the optimized solution to the Tier 2 Synchronized Reserve Market. The MMU recommends that PJM define rules for calculating available tier 1 MW and for the use of biasing during any phase of the market solution and then identify the relevant rule for each instance of biasing.
- The MMU recommends that PJM determine why secondary reserve was either unavailable or not dispatched on September 10, 2013, January 6, 2014, and January 7, 2014, and that PJM consider replacing the DASR

Market with a real time secondary reserve product that is available and dispatchable in real time.

- The MMU recommends 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.
- The MMU recommends that the three pivotal supplier test be incorporated in the DASR Market.

Conclusion

While the design of the Regulation Market was significantly improved with changes introduced October 1, 2012, a number of issues remain. The market results continue to include the incorrect definition of opportunity cost. Further, the market design has failed to correctly incorporate a consistent implementation of the marginal benefit factor in optimization, pricing and settlement. Instead, the market design makes use of the marginal benefit factor in the optimization and pricing, but a mileage ratio multiplier in settlement. This failure to correctly incorporate marginal benefit factor into the current Regulation Market design is causing effective MW provided by RegD resources to be underpaid per effective MW. These issues have led to the MMU's conclusion that the Regulation Market design, as currently implemented, is flawed.

The structure of each 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 service 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. Compliance with calls to respond to actual spinning events has been an issue. Compliance with the synchronized reserve must-offer requirement has also been an issue.

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 new Regulation Market results were competitive. The MMU concludes that the Synchronized Reserve Market results were competitive. The MMU concludes that the DASR Market results were competitive.

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 market. Significant technical and structural changes were made to the Regulation Market in 2012.[7]

Market Design

The regulation market includes resources following two signals: RegA and RegD. Resources responding to either signal help control ACE. 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, but with limited ramp rates. RegD is PJM's fast-oscillation regulation signal and is designed for resources with the ability to quickly adjust energy output, but with limited ability to sustain energy output for long periods of time. Resources must qualify to follow the RegA and RegD signals. Resources must qualify for one signal or both signals, but will be assigned by the market clearing engine to follow only one signal within a given market hour. The PJM Regulation Market design includes three clearing price components (capability, performance,

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

and lost opportunity cost), the rate of substitution between RegA and RegD resources (marginal benefit factor) and a measure of the quality of response (performance score) by a regulation resource to a regulation signal.

Regulation performance scores (0.0 to 1.0) measure the response of a regulating resource to its chosen regulation signal (RegA or RegD) every ten 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.[8]

While resources following RegA and RegD can both provide regulation service in PJM's regulation market, PJM's joint optimization is designed 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 resources into a common unit of measure via a marginal benefit factor (MBF). The marginal benefit factor is a measure of the substitutability of RegD resources for RegA resources in satisfying the regulation requirement. The marginal benefit factor and the performance score of the resource are used to convert RegA and RegD resource regulation capability MW into comparable units, termed effective MW. Resource-specific marginal benefit factors are defined for each resource separately while the market marginal benefit factor is the marginal benefit factor of the last RegD resource cleared in the market. Effective MW, supplied from RegA or RegD resources, are defined in terms of RegA MW. Except where expressly referred to as effective MW or effective regulation MW, MW means regulation capability MW unadjusted for either marginal benefit factor or performance factor.

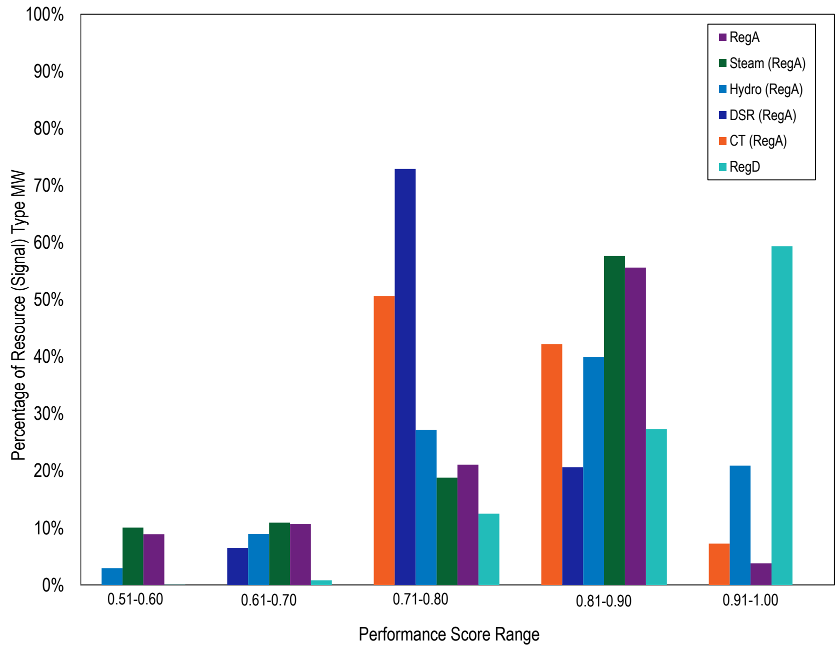
PJM posts clearing prices for the Regulation Market (RMCCP, RMPCP and RMCP) in what are termed to be dollars per unadjusted regulation capability MW. The Regulation Market clearing price (RMCP) for the hour is the simple average of the twelve five-minute RMCPs within the hour. The five-minute RMCP is the sum of the performance clearing price (RMPCP) and the capability clearing price (RMCCP). The performance clearing price ($/MW) is equal to the most expensive performance offer cleared for the hour. The capability clearing price ($/MW) is equal to the difference between the RMCP for the hour and the RMPCP for the hour.

Resources are paid by RMCP credits (the sum of RMCCP credits and RMPCP credits) and lost opportunity cost credits. RMCCP credits are calculated as MW of regulation capability times performance score times RMCCP. RMPCP credits are calculated as MW of regulation capability times performance score times RegD to RegA mileage ratio times RMPCP. RMCP credits are calculated as RMCCP credits plus RMPCP 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.

Figure 10-1 shows the average performance score by resource type and signal followed for the first three months of 2014. In this figure, the MW used are unadjusted regulation capability MW and the performance score is the actual within hour (as opposed to the historic 100-hour moving average) performance score of the regulation resource. Each category (color bar) adds up to 100 percent so that the full performance score distribution for each resource (or signal) type is shown. Resources following the RegD signal tend to follow the RegD signal more closely than resources following the RegA signal follow the RegA signal. That is, RegD resources tend to have higher performance scores. As the figure shows, 59.4 percent of RegD resources have average performance scores within the 0.91-1.00 range, whereas only 3.8 percent of RegA resources have average performance scores within that range.

8 PJM "Manual 12: Balancing Operations" Rev. 27 (December 20, 2012); 4.5.6, p 52.

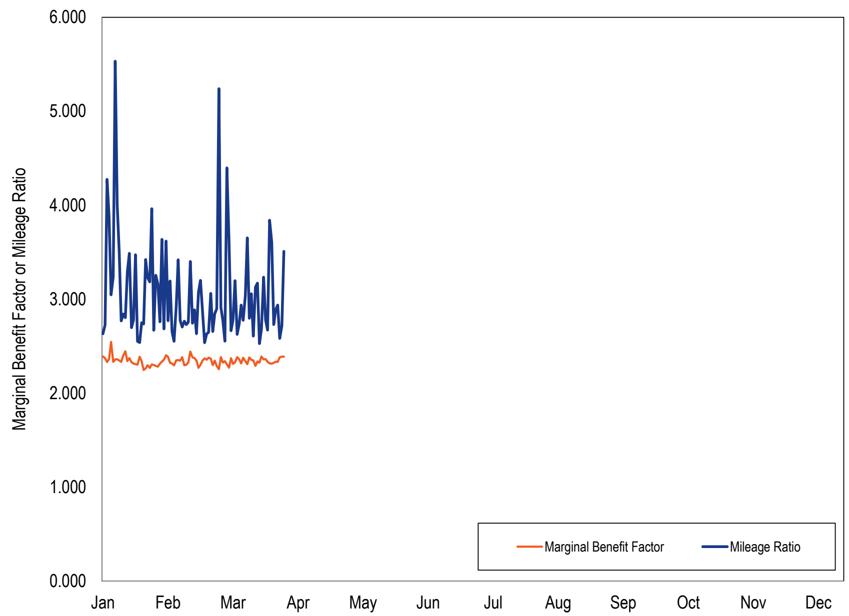
Figure 10-1 Hourly average performance score by unit type and regulation signal type: 2013



From October 1, 2012, through October 31, 2013, PJM adhered to a FERC order that required the marginal benefit factor be fixed at one for settlement calculations only. As Figure 10-2 shows that the true marginal benefit factor, as used in the optimization and commitment process for regulation in the first three months of 2014, was always higher than one. This caused resources following the RegD signal to be underpaid. Resources following the RegD signal should have been paid the true market marginal benefit factor times the amount that they were actually paid. The market marginal benefit factor should have been applied to the capability and the performance payments of RegD resources.

On October 2, 2013, FERC directed PJM to eliminate the use of the marginal benefit factor completely from settlement calculations of the capability and performance credits and replace it with RegD to RegA mileage ratio in the performance credit paid to RegD resources, effective November 1, 2013, and retroactively to October 1, 2012.[9] As Figure 10-2 demonstrates, the RegD to RegA mileage ratio is generally higher than the actual marginal benefit factor and much more variable. In this figure the mileage ratio is the actual hourly mileage ratio, calculated as the mileage provided by RegD resources divided by the mileage provided by RegA resources. The mileage multiplier has not brought total payment of RegD resources in line with RegA resources on a dollar per effective MW basis. This is, in part, due to the fact that the performance related price per MW of capability, which is the only part multiplied by the mileage ratio, is a relatively small portion of the total price per MW of capability.

Figure 10-2 Daily average marginal benefit factor and mileage ratio: January through March 2014



9 145 FERC ¶ 61,011 (2013).

Market Structure

Supply

Table 10-5 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 January through March 2014. In this table, actual MW are unadjusted regulation capability MW and effective MW are adjusted by the historic 100-hour moving average performance score and resource-specific benefit factor. A resource must be either generation or demand. But a resource can (and several resources currently do) choose to follow both signals. For that reason the sum of each signal type's capability can exceed the full regulation capability.

Table 10-5 PJM regulation capability, daily offer[10] and hourly eligible: January through March 2014[11]

		By Resource Type		By Signal Type	
Metric	All Regulation	Generating Resources	Demand Resources	RegA Following Resources	RegD Following Resources
Capability MW	8,179.8	8,170.5	9.3	8,130.2	303.3
Offered MW	5,993.1	5,984.0	9.0	5,801.1	192.0
Actual Eligible MW	1,377.8	1,370.7	7.1	1,232.7	145.0
Effective Eligible MW	1,016.1	1,006.2	9.9	817.8	198.2
Actual Cleared MW	684.8	681.0	3.8	598.0	86.8
Effective Cleared MW	663.6	655.5	8.1	470.0	193.6

While total regulation capability MW provided by coal units declined from 189,372 MW in the first three months of 2013 to 173,842 MW in the first three months of 2014, the proportion of regulation provided by coal increased slightly, from 16.5 percent of regulation in the first three months of 2013 to 17.1 percent of regulation in the first three months of 2014. This was a result of PJM's reducing the regulation requirement for January through March 2014 compared to the regulation requirement for January through March, 2013. Coal unit revenues in the first three months of 2014 were 2.5 times the revenues in the first three months of 2013 ($27.3 million in the first three months of 2014, versus $10.9 million in the first three months of 2013). The increase was a result of the high regulation market clearing prices and out of market opportunity cost credits in January. Table 10-6 provides monthly data on the number of coal units providing regulation, the scheduled regulation in MW provided by coal units, the total scheduled regulation in MW provided by all resources, the percent of scheduled regulation provided by coal units, and the total credits received by coal units. In Table 10-6, the MW have been adjusted by the actual within-hour performance score since this adjustment forms the basis of payment for coal units providing regulation.

Table 10-6 PJM regulation provided by coal units

Year	Period	Number of Coal Units Providing Regulation	Adjusted Settled Regulation from Coal Units (MW)	Adjusted Settled Regulation from All Resources (MW)	Percent of Scheduled Regulation from Coal Units	Total Coal Unit Regulation Credits
2013	Jan	117	80,766	401,101	20.1%	$5,376,060
2013	Feb	101	64,164	365,249	17.6%	$3,071,878
2013	Mar	96	44,443	372,154	11.9%	$2,473,951
2013	Jan-Mar Average	105	63,124	379,502	16.5%	$3,640,630
2014	Jan	109	70,441	360,513	19.5%	$15,780,551
2014	Feb	102	51,033	309,976	16.5%	$4,690,694
2014	Mar	101	52,368	341,089	15.4%	$6,860,625
2014	Jan-Mar Average	104	57,947	337,193	17.1%	$9,110,623

The supply of regulation can be affected by regulating units retiring from service. Table 10-7 shows what the impact on the Regulation Market would be if all units retire that are requesting retirement through the end of 2015. These retirements should not substantially impact the supply of regulation capability in PJM. The MW in Table 10-7 have been adjusted by the actual within-hour performance score.

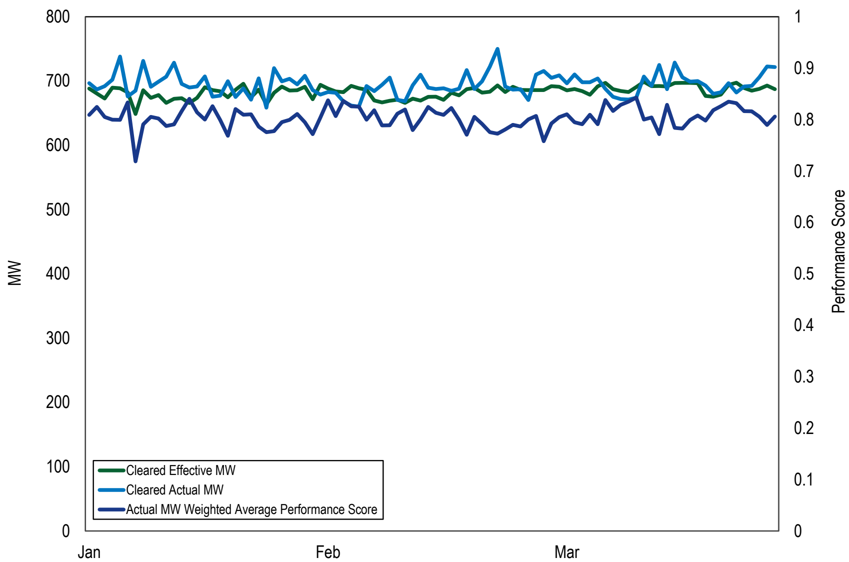
10 Average Daily Offer MW excludes units that have offers but are unavailable for the day.
11 Total offer capability is defined as the sum of the maximum daily offer volume for each offering unit during the period, without regard to the actual availability of the resource or to the day on which the maximum was offered.

Table 10-7 Impact on PJM Regulation Market of currently regulating units scheduled to retire through 2015

Current Regulation Units, January through March 2014	Adjusted Settled MW, January through March 2014	Units Scheduled To Retire Through 2015	Adjusted Settled MW of Units Scheduled To Retire Through 2015	Percent Of Regulation MW To Retire Through 2015
267	1,011,578	28	11,457	1.13%

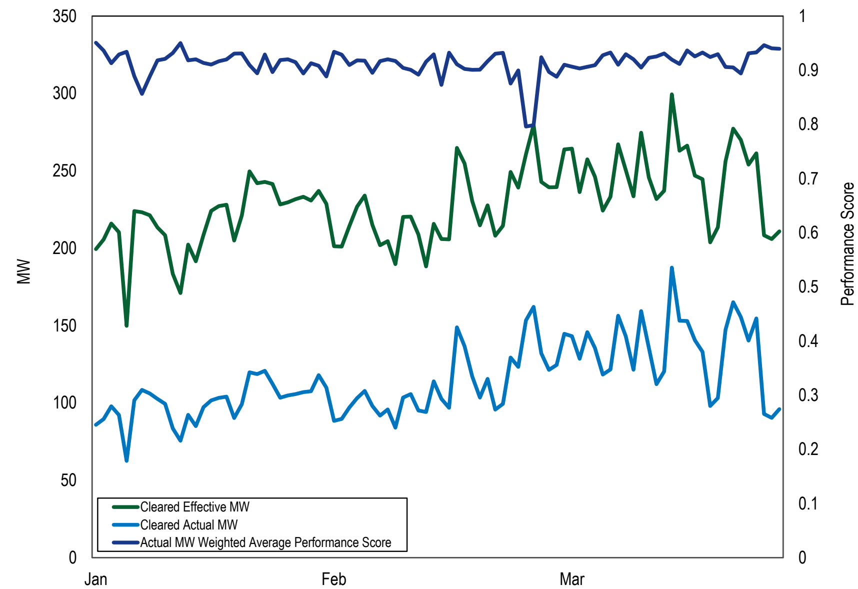
Although the marginal benefit factor for slow (RegA) resources is 1.0, the effective MW of RegA following resources was lower than the offered MW in the first three months of 2014 because the average performance score was less than 1.00 (Figure 10-3). For the first three months of 2014, the MW-weighted average RegA performance score was 0.79 and as of March 31, 2014, there were 261 resources following the RegA signal.

Figure 10-3 Daily average actual cleared MW of regulation, effective cleared MW of regulation, and average performance score; all cleared regulation: January through March 2014



In Figure 10-3 and Figure 10-4, actual MW are unadjusted for either performance score or benefit factor and effective MW are adjusted for the historic 100-hour moving average performance score and the resource-specific benefit factor.

Figure 10-4 RegD: Daily average actual cleared MW of regulation, effective cleared MW of regulation, and average performance score; RegD units: January through March 2014



For RegD resources, the effective MW are higher than the actual MW because their marginal benefit factor at current participation levels is significantly greater than 1.0. In the first three months of 2014, the marginal benefit factor for cleared RegD following resources ranged from 1.613 to 2.672 with an average over all hours of 2.340. For the first three months of 2014, the MW-weighted average RegD resource performance score was 0.92 and as of March 31, 2014, there were 38 resources following the RegD signal.

The cost of each unit is calculated using its offer price, lost opportunity cost, capability MW, and the miles to MW ratio of the signal type offered, modified by resource marginal benefit factor and historic performance score. (The miles to MW ratio of the signal type offered is the historic 30-day moving average of requested mileage for that signal type per unadjusted regulation capability MW.)

As of October 1, 2012, a regulation resource's total offer is equal to the sum of its capability offer ($/MW) and performance offer ($/MW) and its estimated lost opportunity cost ($/MW). As of October 1, 2012, the within hour five minute clearing price for regulation is determined by the total offer, including the actual opportunity cost and any applicable benefit factor, of the most expensive cleared regulation resource in each interval.

Since the implementation of regulation performance on October 1, 2012, both regulation price and regulation cost per MW are higher than they were prior to October 1, 2012, (Table 10-14). Throughout the first three months of 2014, the price and cost of regulation have remained high relative to prior years. The weighted average regulation price for the first three months of 2014 was $91.94/MW. The regulation cost for the first three months of 2014 was $111.02/MW. The ratio of price to cost is lower (83 percent) than in the same period in 2013 (87 percent) due to the extreme market conditions in January that resulted in increased out of market payments based on lost opportunity costs.

Demand

The demand for regulation does not change with price. The regulation requirement is set by PJM in accordance with NERC control standards, based on reliability objectives. 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 1, 2013, it was reduced to 700 effective MW during peak hours and 525 effective MW during off peak hours.

Table 10-8 shows the average hourly required regulation by month and its relationship to the supply of regulation for both actual (unadjusted) and effective MW.

Table 10-8 PJM Regulation Market required MW and ratio of eligible supply to requirement: January through March, 2013 and 2014

Month	Average Required Regulation (MW), 2013	Average Required Regulation (MW), 2014	Average Required Regulation (Effective MW), 2013	Average Required Regulation (Effective MW), 2014	Ratio of Supply MW to MW Requirement, 2013	Ratio of Supply MW to MW Requirement, 2014	Ratio of Supply Effective MW to Effective MW Requirement, 2013	Ratio of Supply Effective MW to Effective MW Requirement, 2014
Jan	862	690	720	663	1.80	2.05	1.72	1.60
Feb	875	681	724	664	1.85	2.00	1.73	1.51
Mar	774	683	681	664	1.67	1.99	1.56	1.48

PJM's performance as measured by CPS and BAAL standards has not declined as a result of the lower regulation requirement.[12]

12 See the *2013 State of the Market Report for PJM*, Appendix F: Ancillary Services.

Market Concentration

Table 10-9 shows Herfindahl-Hirschman Index (HHI) results for the first three months of 2013 and the first three months of 2014, based on market shares of effective MW, defined as regulation capability MW adjusted by performance score and resource-specific benefit factor, consistent with the metrics used to clear the regulation market. The average HHI of 1972 is classified as highly concentrated, but is lower than the HHI for the same period in the first three months of 2013 of 2003. For the first three months of 2014, the weighted-average HHI of RegD resources was 3901 (highly concentrated).

Table 10-9 PJM cleared regulation HHI: January through March 2013 and 2014

Period	Minimum HHI	Weighted Average HHI	Maximum HHI
2013 (Jan-Mar)	957	2003	3996
2014 (Jan-Mar)	977	1972	3813

Figure 10-5 compares the frequency distribution of HHI for the first three months of 2014 with the first three months of 2013.

Figure 10-5 PJM Regulation Market HHI distribution: January through March 2013 and 2014

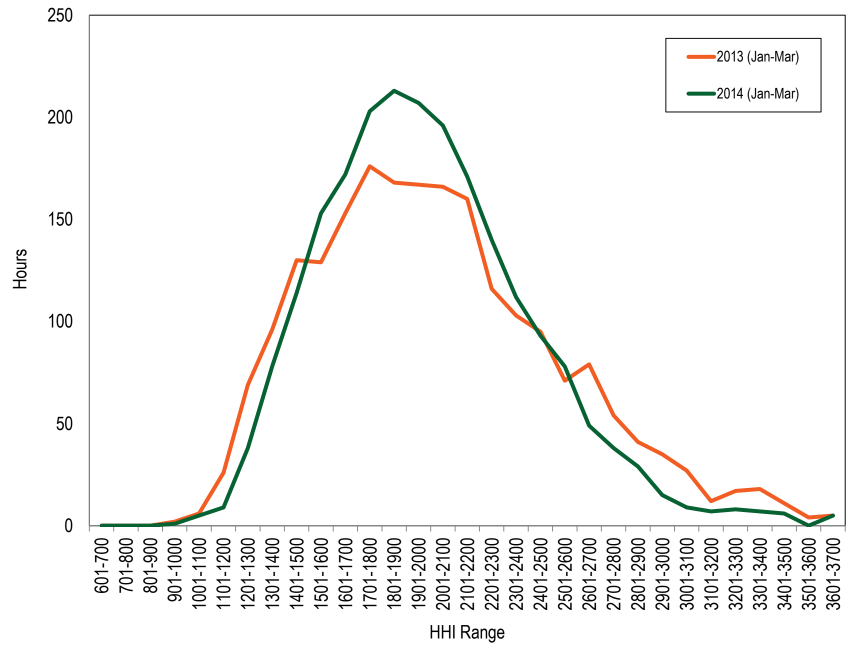


Table 10-10 includes a monthly summary of three pivotal supplier results. In the first three months of 2014, 97 percent of hours had one or more pivotal suppliers which failed PJM's three pivotal supplier test. The impact of offer capping in the regulation market is limited because of the role of LOC in price formation (Figure 10-7).

The MMU concludes from these results that the PJM Regulation Market in the first three months of 2014 was characterized by structural market power in 97 percent of hours.

Table 10-10 Regulation market monthly three pivotal supplier results: January through March 2012 through 2014

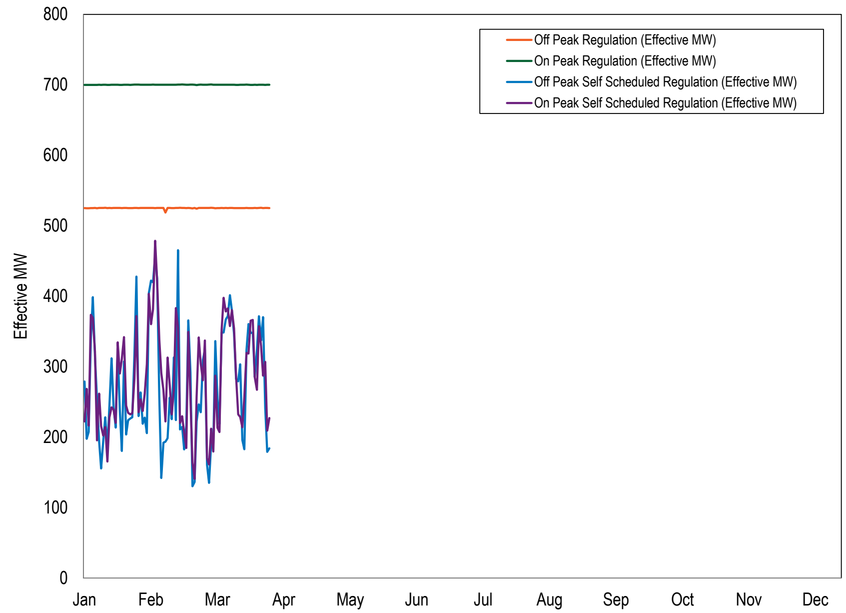
	2012	2013	2014
Month	Percent of Hours Pivotal	Percent of Hours Pivotal	Percent of Hours Pivotal
Jan	71%	83%	97%
Feb	67%	82%	99%
Mar	64%	97%	95%
Average	67%	88%	97%

Market Conduct

Offers

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 10-11).[13] Figure 10-6 compares average hourly regulation and self scheduled regulation during on peak and off peak hours on an effective MW basis. Self scheduled regulation during on peak and off peak hours varies from hour to hour and comprises a large portion of total effective regulation per hour (on average 40.1 percent during on peak and 51.7 percent during off peak hours in the first three months of 2014).

Figure 10-6 Off peak and on peak regulation levels: January through March 2014



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 2014, 61.0 percent was purchased in the PJM market, 34.2 percent was self-scheduled, and 4.8 percent was purchased bilaterally (Table 10-11) From 2010 through the first three months of 2014, Table 10-12 shows the total regulation by market regulation, self-scheduled regulation, and bilateral regulation. These tables are based on settled (purchased) MW, but are not adjusted for either performance score or benefit factor to maintain consistency with January through March in years 2010 through 2012 when these constructs were not part of the Regulation Market.

13 See PJM. "Manual 28: Operating Agreement Accounting," Revision 60, (June 1, 2013); para 4.1, pp 15.

Table 10-11 Regulation sources: spot market, self-scheduled, bilateral purchases: January through March 2013 and 2014

Year	Month	Spot Market Regulation (MW)	Spot Market Percent of Total	Self-Scheduled Regulation (MW)	Self-Scheduled Percent of Total	Bilateral Regulation (MW)	Bilateral Percent of Total	Total Regulation (MW)	RegA Regulation (MW)	RegA Percent of Total	RegD Regulation (MW)	RegD Percent of Total
2013	Jan	413,304	83.6%	72,880	14.7%	8,070	1.6%	494,253	486,959	98.5%	7,294	1.5%
2013	Feb	338,990	74.7%	102,005	22.5%	12,808	2.8%	453,803	444,689	98.0%	9,113	2.0%
2013	Mar	275,880	60.0%	165,987	36.1%	17,554	3.8%	459,421	441,000	96.0%	18,421	4.0%
2014	Jan	259,686	63.7%	125,234	30.7%	22,737	5.6%	407,656	381,313	93.5%	26,343	6.5%
2014	Feb	217,755	59.4%	132,385	36.1%	16,530	4.5%	366,670	342,929	93.5%	23,741	6.5%
2014	Mar	245,981	59.8%	148,162	36.0%	17,524	4.3%	411,667	384,304	93.4%	27,363	6.6%

Table 10-12 Regulation sources by year: January through March, 2010 through 2014

Year (Jan-Mar)	Spot Market Regulation (MW)	Spot Market Percent of Total	Self-Scheduled Regulation (MW)	Self-Scheduled Percent of Total	Bilateral Regulation (MW)	Bilateral Percent of Total	Total Regulation (MW)
2010	1,615,233	83.8%	271,709	14.1%	41,288	2.1%	1,928,230
2011	1,503,065	78.9%	338,972	17.8%	62,330	3.3%	1,904,367
2012	1,512,255	73.5%	484,971	23.6%	61,400	3.0%	2,058,626
2013	1,028,173	73.1%	340,872	24.2%	38,432	2.7%	1,407,477
2014	723,422	61.0%	405,781	34.2%	56,790	4.8%	1,185,993

In the first three months of 2014, DR provided an average of 3.83 MW of regulation per hour. Generating units supplied an average of 684.39 MW of regulation per hour.

Market Performance

Price

The weighted average RMCP for the first three months of 2014 was $91.94 per MW. This is the average price per unadjusted capability MW. This is a 172.8 percent increase from the weighted average RMCP of $33.70/MW in first three months of 2013. Figure 10-7 shows the daily average Regulation Market clearing price and the opportunity cost component for the marginal units in the PJM Regulation Market on an unadjusted regulation capability MW basis.

Figure 10-7 PJM Regulation Market daily weighted average market-clearing price, marginal unit opportunity cost and offer price (Dollars per MW): 2014

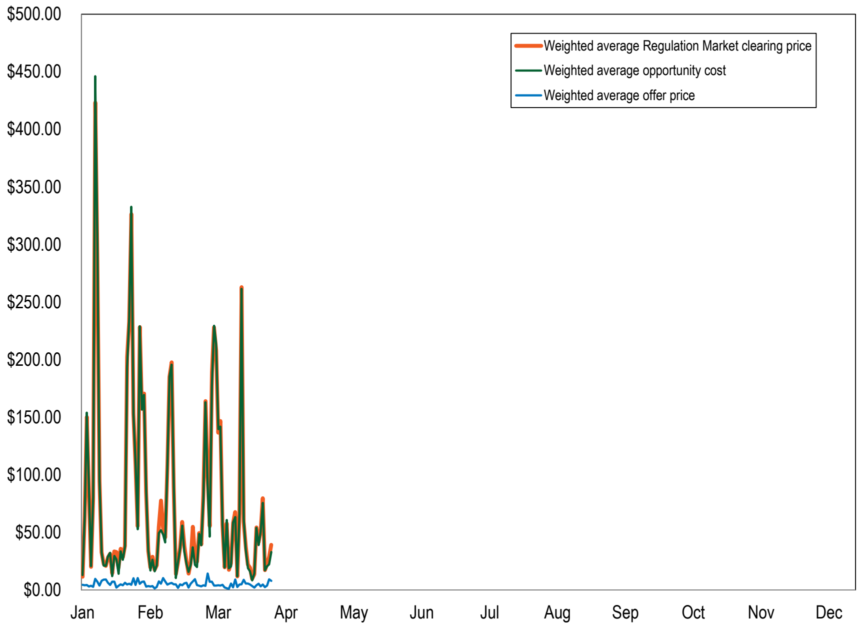


Table 10-13 shows monthly average regulation market clearing price, average marginal unit offer price, and average marginal unit LOC on an unadjusted capability MW basis.

Table 10-13 PJM Regulation Market monthly weighted average market-clearing price, marginal unit opportunity cost and offer price (Dollars per MW): 2014

Month	Weighted Average Regulation Market Clearing Price	Weighted Average Regulation Marginal Unit Offer	Weighted Average Regulation Marginal Unit LOC
Jan	$132.49	$5.44	$101.27
Feb	$62.61	$4.72	$60.76
Mar	$80.73	$4.79	$71.35

Total scheduled regulation MW, total regulation charges, regulation price and regulation cost are shown in Table 10-14. Total scheduled regulation is based on settled (unadjusted capability) MW.

Table 10-14 Total regulation charges: January through March, 2013 and 2014

Year	Month	Scheduled Regulation (MW)	Total Regulation Charges ($/MW)	Weighted Average Regulation Market Price ($/MW)	Cost of Regulation ($/MW)	Price as Percentage of Cost
2013	Jan	494,253	$22,870,690	$39.94	$46.27	86%
2013	Feb	453,803	$15,273,604	$29.51	$33.66	88%
2013	Mar	459,421	$16,678,410	$31.64	$36.30	87%
2014	Jan	407,656	$65,714,049	$132.49	$161.20	82%
2014	Feb	366,670	$27,293,638	$62.61	$74.44	84%
2014	Mar	411,667	$40,104,102	$80.73	$97.42	83%

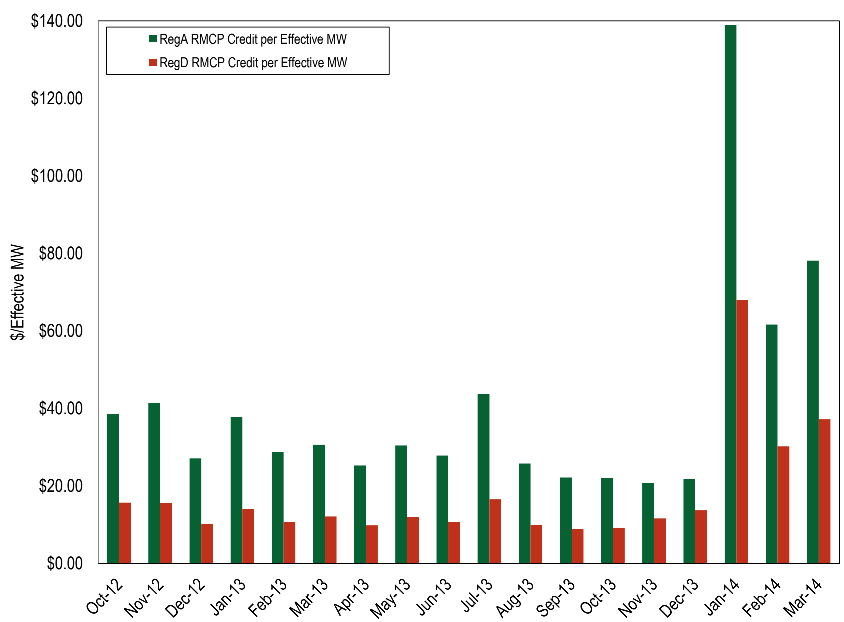
The capability, performance, and opportunity cost components of the cost of regulation are shown in Table 10-15. Total scheduled regulation is based on settled (unadjusted capability) MW.

Table 10-15 Components of regulation cost: 2014

Month	Scheduled Regulation (MW)	Cost of Regulation Capability ($/MW)	Cost of Regulation Performance ($/MW)	Opportunity Cost ($/MW)	Total Cost ($/MW)
Jan	407,656	$124.57	$11.60	$25.03	$161.20
Feb	366,670	$57.80	$6.41	$10.23	$74.44
Mar	411,667	$76.75	$5.71	$14.96	$97.42

A comparison of monthly average RMCP credits per Effective MW earned by RegA and RegD resources from October 1, 2012, (the implementation date of the performance-based Regulation Market) through the first three months of 2014 is shown in Figure 10-8. On November 1, 2013, PJM removed the marginal benefit factor from all settlement calculations. In its place, PJM inserted the mileage ratio for the performance credit only. In Figure 10-8, the RegA RMCP Credit per effective MW is, on average, 2.6 times higher than the RegD RMCP Credit per effective MW from October 2012 through October 2013. However, since November 1, 2013, the RegA RMCP Credit per effective MW is only, on average, 1.9 times higher than the RegD RMCP Credit per effective MW. Were the marginal benefit factor correctly applied to settlements, the average RegD RMCP Credit per effective MW would be higher and equal to the RegA RMCP Credit per effective MW.

Figure 10-8 Comparison of monthly average RegA and RegD RMCP Credits per Effective MW: October 2012 through March 2014[14]



14 These values are credits before PJM makes its retroactive adjustments to RMCP credits.

Table 10-16 provides a comparison of the average price and cost for PJM Regulation. The difference between the Regulation Market price and the actual cost of regulation was more in the first three months of 2014 than it was in the first three months of 2013. This is a result of extreme market conditions in January.

Table 10-16 Comparison of average price and cost for PJM Regulation, January through March, 2008 through 2014

Month	Scheduled Regulation (MW)	Cost of Regulation Capability ($/MW)	Cost of Regulation Performance ($/MW)	Opportunity Cost ($/MW)	Total Cost ($/MW)
Jan	407,656	$124.57	$11.60	$25.03	$161.20
Feb	366,670	$57.80	$6.41	$10.23	$74.44
Mar	411,667	$76.75	$5.71	$14.96	$97.42

Primary Reserve

Reserves are sources of energy that can be made available within a defined time for the purpose of correcting an imbalance between supply and demand. Primary reserve is ten minute reserve which can be sustained for up to thirty minutes to correct a disturbance.[15,16]

PJM uses synchronized and non-synchronized reserve, both of which are available within ten minutes, to provide primary reserve. Synchronized reserve is on line and synchronized to the grid. Non-synchronized reserve may be provided by any unit not synchronized to the grid but capable of providing energy within ten minutes.

Requirements

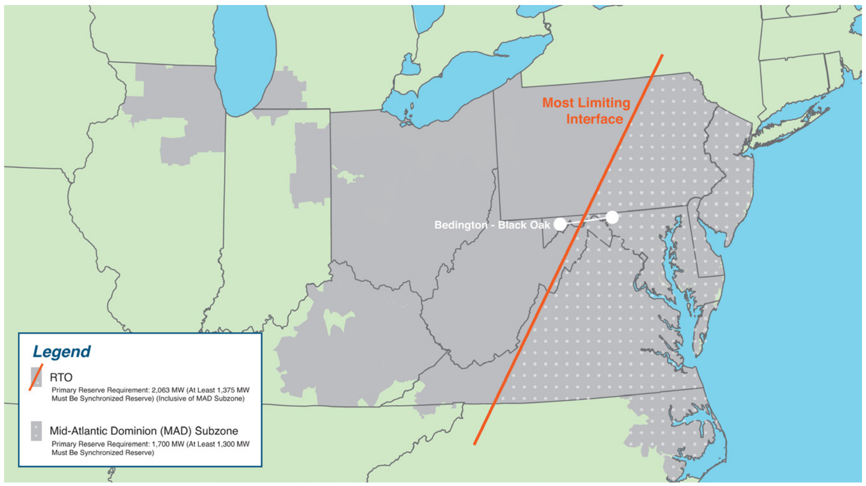
For the RTO Reserve Zone the primary reserve requirement is 150 percent of the largest contingency in the PJM footprint, currently 2,063 MW. Changes to this requirement can occur when grid maintenance or outages change the largest contingency. The actual hourly average RTO primary reserve requirement was 2,066 MW in January through March 2014 (Table 10-18).

15 NERC uses the term contingency reserves, which are reserves available within 15 minutes and that may be on line or off line. PJM criteria require response within 10 minutes. PJM meets the NERC requirements through primary reserves.

16 NERC defines reporting and response requirements for disturbance events in "NERC Performance Standard BAL-002-0, Disturbance Control Performance" and PJM defines its corresponding obligations in Manual M-12. See PJM. "Manual 12. Balancing Operations" Revision 30. Attachment D. "Disturbance Control Performance/Standard" (December 1, 2013), p. 85.

Transmission constraints limit the deliverability of reserves within the RTO, requiring the definition of the Mid-Atlantic Dominion (MAD) Subzone. Of the 2,063 MW RTO primary reserve requirement, 1,700 MW must be deliverable to the Mid-Atlantic Dominion Subzone (Figure 10-9). The actual hourly average MAD primary reserve requirement was 1,704 MW in January through March, 2014 (Table 10-18).

Figure 10-9 PJM RTO geography and primary reserve requirement: January through June 2013



Of the 2,063 MW RTO primary reserve requirement, PJM requires that at least 1,375 MW be synchronized to the grid. The synchronized reserve requirement is 100 percent of the largest contingency. Of the 1,375 MW of synchronized reserve requirement for the RTO, 1,300 MW must be deliverable to the Mid-Atlantic Dominion Subzone.

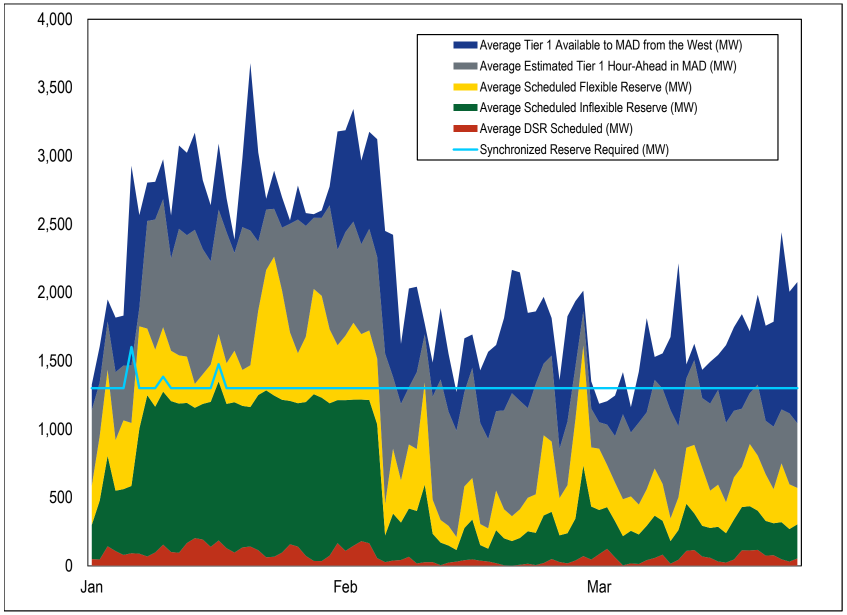
The Mid-Atlantic Dominion Reserve Subzone is defined dynamically by the most limiting constraint real time.[17] In 78.1 percent of hours in January through March 2014, that constraint was the Bedington – Black Oak transfer interface constraint (Figure 10-9).

Synchronized and non-synchronized reserve is identified, priced, and assigned by PJM's market solution software. The market solution software consists of three distinct modules: the Ancillary Services Optimizer (ASO), 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, non-synchronized reserves, and regulation based on forecast system conditions to determine an economic set of inflexible 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 is used to estimate available tier 1 synchronized reserve and to provide a near real time load forecast and ancillary services solutions. RT-SCED runs at five minute intervals and jointly optimizes energy and reserves given inflexible unit commitment. The RT-SCED estimates the available tier 1, provides a real time ancillary services solution and can commit additional within-hour flexible tier 2 resources.

The components of the Mid-Atlantic Dominion Primary Reserve Zone primary reserve solution in order of increasing cost are: tier 1 synchronized reserve available within the Mid-Atlantic Dominion Primary Reserve Zone; tier 1 synchronized reserve available across the most limiting constraint; tier 2 before the hour commitments of inflexible demand response; tier 2 before the hour commitments of inflexible generation; and tier 2 within hour commitments of flexible generation. Figure 10-10 shows daily average Mid-Atlantic Dominion Subzone primary reserves MW by source for the January 1, 2014, through March 31, 2014 period. Figure 10-10 shows tier 1 synchronized reserve remains the major contributor to satisfying the synchronized reserve requirements in the Mid-Atlantic Dominion (MAD) subzone.

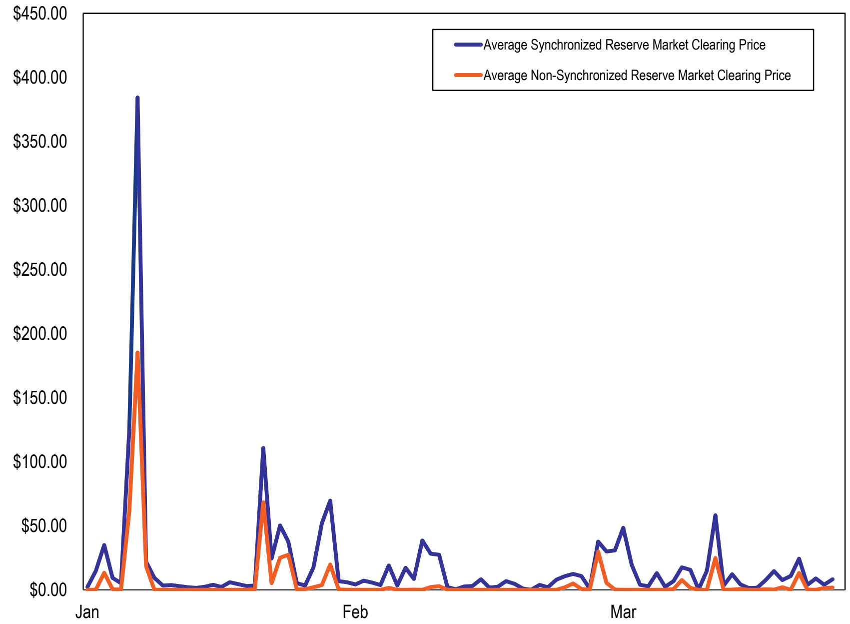
17 Additional subzones may be defined by PJM to meet system reliability needs. PJM will notify stakeholders in such an event. See PJM, "Manual 11, Energy and Ancillary Services Market Operations," Revision 62 (January 6, 2014), p. 66.

Figure 10-10 Mid-Atlantic Dominion Subzone primary reserve MW by source (Daily Averages): January through March 2014



In January 2014, cold weather resulted in high loads which, combined with unit outages, contributed to volatility and high prices in the primary reserve (synchronized and non-synchronized) markets. Figure 10-11 shows Mid-Atlantic Dominion Subzone daily average synchronized and non-synchronized market clearing prices from January 1, 2014, through March 31, 2014.

Figure 10-11 Mid-Atlantic Dominion Subzone daily average market clearing price: January through March 2014



PJM experienced primary and synchronized reserve shortage events on January 6 and 7 of 2014.

On January 6, in response to a reserve shortage, PJM issued a Voltage Reduction Warning, followed shortly by a Voltage Reduction Action in hours 19 and 20. PJM issued RTO-wide Voltage Reduction Warnings on January 6, 7, and 30 for synchronized reserve shortages.

On January 7, PJM issued a Primary Reserve Warning indicating that the supply of primary reserve dropped below the required level. On January 7, PJM's RTO Zone experienced synchronized reserve shortages in hours 7 through 11 and Primary Reserve shortfalls in hours 7 through 12, 17 and

18. On January 7, 2014, PJM's MAD Zone experienced synchronized reserve shortages and primary reserve shortages in hours 7 through 12, 17 and 18.

The synchronized reserve and primary reserve shortfalls triggered Shortage Pricing in hours 7 through 12, 17 and 18.

Synchronized Reserve Market

PJM operates a Synchronized Reserve Market in the RTO Synchronized Reserve Zone. Synchronized reserve is energy or demand reduction synchronized to the grid and capable of increasing output or decreasing load within ten minutes. Synchronized reserve is of two distinct types, tier 1 and tier 2. Tier 1 synchronized reserve is provided by any resource that is on-line, following economic dispatch, and capable of increasing its output within ten minutes following a call for a synchronized reserve event (often called spinning event). Tier 1 resources are not required to respond to a synchronized reserve event. Market solutions provided by the ASO, IT-SCED and RT-SCED estimate the amount of tier 1 synchronized reserve available from the current energy price based economic dispatch and subtract that amount from the synchronized reserve requirement to determine how much tier 2 synchronized reserve is needed. Tier 2 synchronized reserve is provided by on-line resources, either synchronized to the grid but not producing energy, or dispatched to provide synchronized reserve at an operating point that deviates from their energy price based economic dispatch. Tier 2 synchronized reserves commitments guarantee that the Tier 2 MW will be available in the event of a synchronized reserve event. Tier 2 resources are required to provide their reserve MW within ten minutes of a synchronized reserve event.

The Synchronized Reserve Market clears Tier 2 synchronized reserve to satisfy the synchronized reserve portion of the primary reserve requirement (2,063 MW, of which 1,375 MW must be synchronized reserve) minus the Tier 1 MW available. Both Tier 1 and Tier 2 consist of units synchronized to the grid.

A market also exists for the Mid-Atlantic Dominion subzone (MAD) to satisfy a constraint that of the 1,375 MW of synchronized reserve in the RTO at least 1,300 MW must be deliverable to the Mid-Atlantic Subzone.

Tier 2 synchronized reserves can be provide by flexible or inflexible resources. The flexibility or inflexibility of a resource is a function of the resource's operating parameters. Inflexible online resources, such as demand response (DR) or large steam units, are scheduled to provide Tier 2 synchronized reserves 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). Flexible on line resources, such as hydro resources or combustion turbines (CTs), can be assigned to Tier 2 within the operating hour as system requirements warrant.

Market Structure

Supply

With the exception of several hours on January 6 and 7, the supply of offered and eligible tier 2 synchronized reserve for January, February and March was sufficient to cover the requirement in both the RTO Reserve Zone and the Mid-Atlantic Dominion Reserve Subzone. On January 6, hours 19 and 20, an RTO-wide Shortage Pricing event was triggered by a Voltage Reduction Action implemented in response to RTO-wide synchronized reserve levels falling below 1,375 MW synchronized reserve requirement. On January 7 deficient synchronized reserves in the RTO Reserve Zone caused Shortage Pricing in hours 7 through 11. On January 7 deficient synchronized reserves in the Mid-Atlantic Dominion Reserve Subzone caused Shortage Pricing in hours 7 through 12, 17 and 18.

Synchronized reserve is designed to provide relief for disturbances.[18] PJM dispatchers can use synchronized reserve as a source of energy to provide relief from low ACE. Such an event occurred on January 6, 2014. Three extended (68, 25, and 34 minutes) spinning events were declared during afternoon and evening hours of January 6 for low ACE.

If PJM issues a primary reserve warning, voltage reduction warning, or manual load dump warning, all off line non-emergency generation capacity resources

18 *2013 State of the Market Report for PJM*, Appendix F – PJM's DCS Performance, pp 451-452.

available to provide energy must submit an offer for tier 2 synchronized reserve.[19] This rule is intended to increase the accuracy of estimates of available primary reserve.

The Tier 2 Synchronized Reserve Market for the MAD subzone cleared an hourly average 414.6 MW with a weighted average SRMCP of $26.46 in the first three months of 2014. This is an increase of $19.11 over the weighted average SRMCP of $7.35 for the first three months of 2013. The DR MW share of the total cleared MAD subzone Tier 2 Synchronized Reserve Market was 18.3 percent in the first three months of 2014.[20] This is a reduction of 30.7 percent from the DR MW share of 49 percent of all cleared MAD tier 2 synchronized reserve from the same period in 2013.

The Tier 2 Synchronized Reserve Market for the RTO Zone cleared in 56.9 percent of hours averaging 160.2 MW with a weighted average SRMCP of $50.90 for the first three months of 2014. This is an increase from the first three months of 2013 in which the Tier 2 Synchronized Reserve Market for the RTO Zone cleared in only eight hours. The increase is a result of a change in PJM's method for estimating available tier 1 MW which was effective October 1, 2013.

Between October 1, 2013 and December 31, 2013, PJM implemented several changes in the way tier 1 available MW is estimated.[21] The effect of these changes in both the RTO zone and MAD subzone was to reduce the estimates of tier 1 and to increase the amount of tier 2 MW cleared. The changes included involved capping the tier 1 estimate at the lesser of a generator's economic maximum or its spinning maximum value (spinning maximum is a parameter defined as the maximum output a unit can attain within ten minutes). In addition, hydro units were excluded from tier 1 estimates because most hydro units do not respond to Spin Events as they operate on a schedule and have limitations based on water availability and time of day. In addition, combined cycle units are excluded from tier 1 estimates because combined cycles often require additional equipment or operator intervention to respond to spinning events. In addition, units that are assigned provide regulation and units that are backed down for constraint control are excluded from tier 1 estimates. The goal was a more realistic estimated tier 1 reserve.

Demand

The default hourly required synchronized reserve requirement is 1,375 MW and the requirement for the MAD subzone is 1,300 MW, Table 10-17.[22]

Table 10-17 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	Dec 31, 2012	1,300	Mar 15, 2010	Nov 12, 2012	1,350
			Nov 12, 2012		1,375

Exceptions to the requirement can occur when grid maintenance or outages change the largest contingency. Exceptions in the first three months of 2014 are listed in Table 10-18.

19 See PJM. "Manual 11: Energy and Ancillary Services Market Operations" Revision 64, (January 6, 2014), p. 63.
20 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.
21 PJM Operating Committee Meeting, November 5, 2013, <http://www.pjm.com/~/media/committees-groups/committees/oc/20131105/20131105-item-10-oc-tier-1-changes.ashx>.
22 NERC defines reporting and response requirements for disturbance events in "NERC Performance Standard BAL-002-0, Disturbance Control Performance" and PJM defines its corresponding obligations in Manual M-12. See PJM. "Manual 12: Balancing Operations" Revision 30, Attachment D, "Disturbance Control Performance/Standard" (December 1, 2013), p. 85.

Table 10-18 Exceptions to RTO Zone and MAD Subzone Synchronized Reserve requirement: January through March 2014

Time Period	MAD Temporary Synchronized Reserve Requirement (MW), Normally 1,300 MW	RTO Temporary Synchronized Reserve Requirement (MW), Normally 1,375 MW
Jan 6 mkt hour 19	2,025	2,093
Jan 6 mkt hour 20	7,824	7,843
Jan 10 mkt hour 5	1,341	1,409
Jan 10 mkt hours 6-9	1,786	1,786
Jan 10 mkt hour 10	1,341	1,409
Jan 17 mkt hour 6	1,381	1,444
Jan 17 mkt hours 7-14	1,786	1,786
Jan 17 mkt hour 15	1,543	1,581
Mar 17 mkt hour 17		1,394
Mar 17 mkt hours 18-23		1,600
Mar 18 mkt hour 0		1,394
Mar 18 mkt hour 4		1,394
Mar 18 mkt hours 5-22		1,600
Mar 18 mkt hour 23		1,581
Mar 19 mkt hour 5		1,581
Mar 19 mkt hour 6-14		1,600
Mar 19 mkt hour 15		1,563

The market demand for tier 2 synchronized reserve in the Mid-Atlantic Dominion subzone is determined by subtracting the amount of forecast tier 1 synchronized reserve (+/- the tier 1 estimate bias when applicable) available in the subzone including the amount of tier 1 available from the RTO Zone, from the subzone's requirement each five-minute period. Market demand is also reduced by subtracting the amount of self-scheduled tier 2 resources.

Figure 10-12 shows the average monthly synchronized reserve required and the average monthly Tier 2 synchronized reserve MW scheduled in the first three months of 2014, for the Mid-Atlantic Dominion Reserve Market. The month of January 2014 was unusual in that much more tier 2 synchronized reserve was cleared than prior years. As a result of the extreme weather and reserve shortages on the cold weather days, which reduced the tier 1 available, the dispatchers biased the tier 1 estimate down.

Supply and Demand

The change to the estimates of tier 1 made in the last three months of 2013 had a significant impact on the frequency of clearing an RTO Synchronized Reserve Market. In the RTO Synchronized Reserve Zone 56.9 percent of hours cleared a Tier 2 Synchronized Reserve Market in the first three months of 2014 averaging 160.2 MW. An RTO Tier 2 Synchronized Reserve Zone Market was cleared in less than one percent of hours from January through March, 2013.

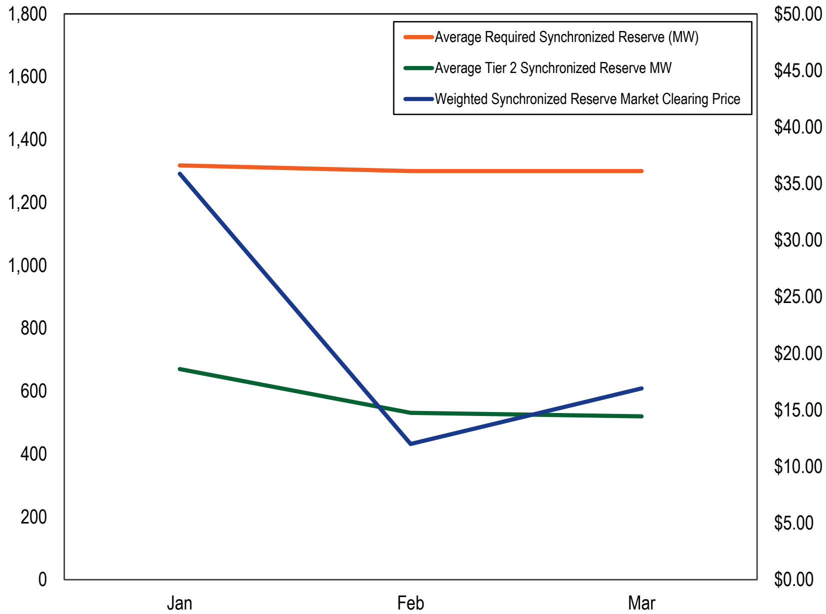
In the Mid-Atlantic Dominion Subzone, 99.8 percent of hours cleared a Tier 2 Synchronized Reserve Market in the first three months of 2014 averaging 153.8 MW. This is a slight increase from the average of 146.7 MW cleared in the first three months of 2013.

In the first three months of 2014, the weighted average Tier 2 Synchronized Reserve Market Clearing Price in the RTO Zone for all cleared hours was $50.90. In the first three months of 2013 the weighted average Synchronized Reserve Market Clearing Price in the RTO Zone (only cleared eight hours) was $0.64. In the first three months of 2014, the weighted average Tier 2 synchronized reserve market clearing price in the MAD subzone for all cleared hours was $26.46. In the first three months of 2013 the weighted average Synchronized Reserve Market Clearing Price in the MAD subzone was $7.35.

Shortage pricing for synchronized reserve was triggered on January 6 and 7. On January 6, hours 19 and 20, an RTO-wide Shortage Pricing event was triggered by a Voltage Reduction Action implemented in response to RTO-wide synchronized reserve levels falling below 1,375 MW synchronized reserve requirement. On January 7 deficient synchronized reserves in the RTO Reserve Zone caused Shortage Pricing in hours 7 through 11. On January 7 deficient synchronized reserves in the Mid-Atlantic Dominion Reserve Subzone caused Shortage Pricing in hours 7 through 12, 17 and 18.

Both the RTO Zone and the MAD subzone experienced a primary reserve shortage and resulting Shortage Pricing event on January 6 in hour 19 and 20 and on January 7 in hours 7 through 12, 17 and 18.

Figure 10-12 Mid-Atlantic Dominion Reserve Subzone Monthly average synchronized reserve required vs. tier 2 synchronized reserve scheduled MW: January through March 2014



Market Concentration

The HHI for settled tier 2 synchronized reserve during cleared hours of the Mid-Atlantic Dominion subzone Tier 2 Synchronized Reserve Market for the first three months of 2014 was 4236, which is defined as highly concentrated. The HHI for the first three months of 2013 for the Mid-Atlantic Subzone Tier 2 Synchronized Reserve Market was 2638, which is also defined as highly concentrated. The largest hourly market share was 100 percent and 56 percent of all hours had a maximum market share greater than or equal to 40 percent, higher than the 35 percent for the first three months of 2013. Most Tier 2 synchronized reserve is provided by inflexible scheduled resources.[23] Flexible synchronized reserve assigned was 14.0 percent of all tier 2 synchronized reserve in the MAD subzone in the first three months of 2014. Flexible synchronized reserve assigned was 24.5 percent of all tier 2 synchronized reserve in the RTO zone in the first three months of 2014. The hourly average HHI in the first three months of 2014 in the MAD subzone was 8743 for flexible resources assigned during the hour. The hourly average HHI in the first three months of 2014 in the RTO zone was 9078 for flexible resources assigned during the hour.

The MMU calculates that 57.9 percent of hours failed the three pivotal supplier test in the MAD subzone in the first three months of 2014 for the inflexible synchronized reserve market (excluding self-scheduled synchronized reserve) in the hour ahead market (Table 10-19) and 37.7 percent of hours would have failed a three pivotal supplier test in the RTO zone in the first three months of 2014.

Table 10-19 Three Pivotal Supplier Test Results for the RTO Zone and MAD Subzone: January through March, 2014

Year	Month	MAD Subzone Percent of Hours Pivotal	RTO Zone Percent of Hours Pivotal
2014	Jan	91.2%	74.0%
2014	Feb	46.1%	22.0%
2014	Mar	36.4%	17.0%
2014	Average	57.9%	37.7%

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

23 See the *2013 State of the Market Report for PJM*, Volume II, Appendix F, Ancillary Service Markets, Synchronized Reserve Market Clearing. With shortage pricing, PJM divided synchronized reserve into flexible and inflexible. A synchronized reserve resource can be either flexible or inflexible, but not both. Inflexible resources must be dispatched, which means incurring lost opportunity costs and/or startup and fuel costs associated with their synchronized reserve dispatch point. Flexible units can respond more quickly to a spinning event and need not be moved from their economic dispatch at the time the ASO or IT-SCED runs.

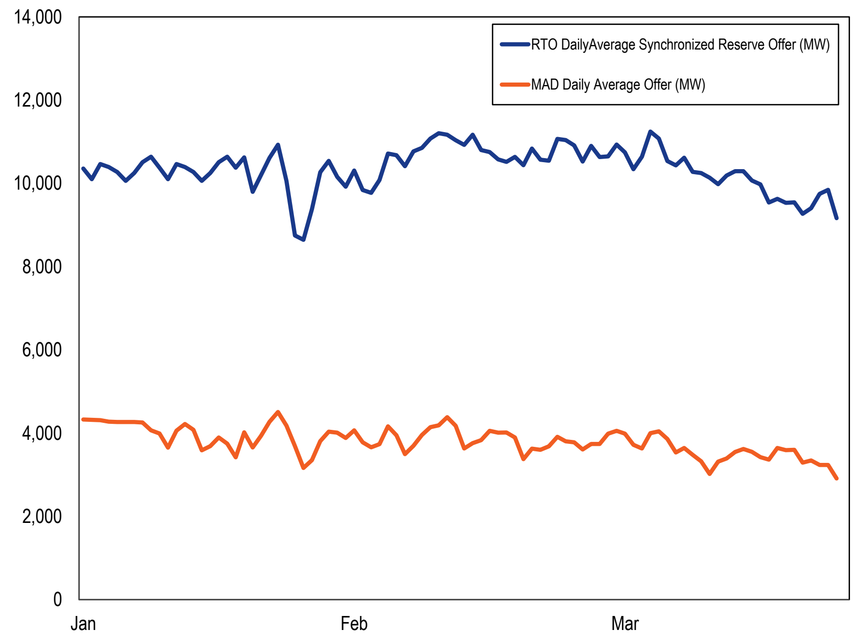
Market Behavior

Offers

Daily cost based offer prices are submitted for each unit by the unit owner. For generators the offer price must include tier 1 synchronized reserve ramp rate, a tier 1 synchronized reserve maximum, synchronized reserve availability, synchronized reserve offer quantity (MW), tier 2 synchronized reserve offer price, energy use for tier 2 condensing resources (MW), condense to gen cost, shutdown costs, condense startup cost, condense hourly cost, condense notification time, and spin as a condenser. The synchronized reserve offer price made by the unit owner is subject to an offer cap of marginal cost plus $7.50 per MW, plus lost opportunity cost. All suppliers are paid the higher of the market clearing price or their offer plus their unit specific opportunity cost. The offer includes the synchronized reserve offer quantity (MW). The offer quantity is limited to the economic maximum or less if a spin maximum value less than economic maximum is supplied. 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 ten minutes. Figure 10-13 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 2014, the ratio of on-line tier 2 synchronized reserve to synchronized reserve required in the Mid-Atlantic Dominion Subzone was 3.02 averaged over all hours. The highest offered to required ratio was 3.99 on January 31 and the lowest was 1.77 on March 31. For the RTO Synchronized Reserve Zone the ratio was 8.85. The highest offered to required ratio was 10.46 on January 1 and the lowest was 6.62 on March 27.

After October 1, 2012, PJM adopted a new rule creating a must offer requirement for synchronized reserve for all generation that is online, non-emergency, and available to produce energy. Compliance with this rule has improved in the first three months of 2014, but remains incomplete. As of March 31, 2014, 24.0 percent of eligible resources do not comply with this requirement.

Figure 10-13 Tier 2 synchronized reserve daily average offer volume (MW): January through March 2014



Synchronized reserve is offered by steam, CT, CC, hydroelectric and DR resources. Figure 10-14 shows average offer MW volume by market and unit type for the MAD subzone and Figure 10-15 shows average offer MW volume by market and unit type for the RTO Zone.

Figure 10-14 Mid-Atlantic Dominion Subzone average daily tier 2 synchronized reserve offer by unit type (MW): January through March 2012 – 2014

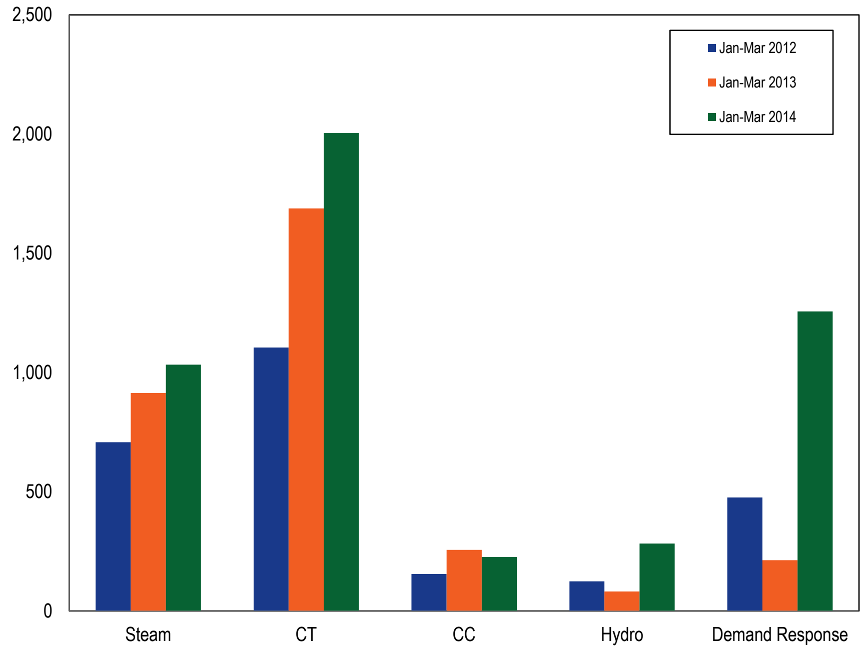
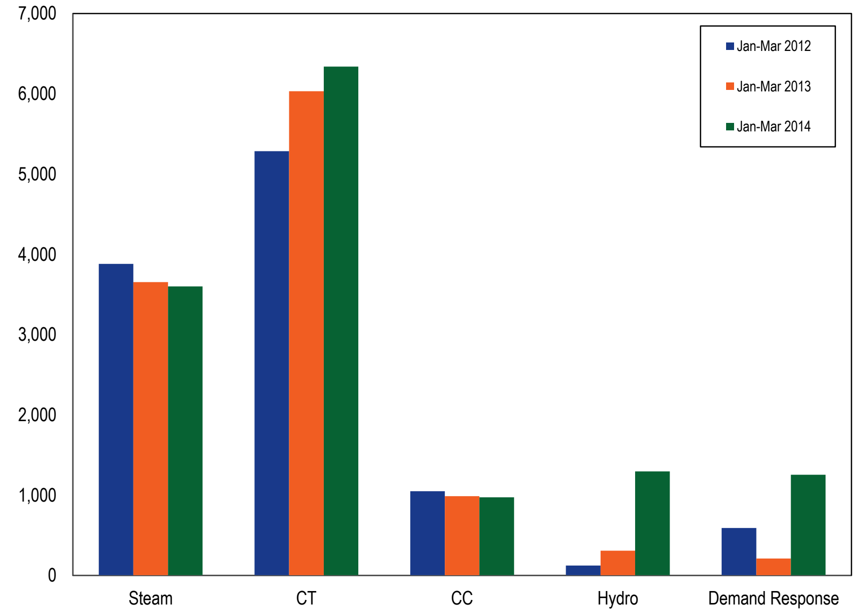


Figure 10-15 RTO Zone average daily tier 2 synchronized reserve offer by unit type (MW): January through March 2012 – 2014



Demand Resources

Demand resources remain a significant part of market scheduled synchronized reserve although their share of total cleared synchronized reserve declined significantly as the amount of tier 2 has increased. In the first three months of 2014, DR was 17.7 percent of all cleared Tier 2 synchronized reserves, compared to 51.7 percent for the first three months of 2013.

Market Performance

Price

Table 10-20 shows all tier 2 credits including LOC credits, all tier 1 credits including credits paid to tier 1 resources when the Non Synchronized Reserve Market Clearing Price is above $0, all tier 2 MW including MW scheduled by PJM, self scheduled, and added by either the intermediate or short term market solution software for the Mid-Atlantic Dominion subzone.

Table 10-20 RTO Zone, Mid-Atlantic Dominion Subzone, and Full RTO credits, and MWs: January through March 2014

Synchronized Reserve Market	Year	Month	Tier 2 Synchronized Reserve Credits	Tier 1 Synchronized Reserve Credits	Tier 2 Synchronized Reserve Cleared MW	Tier 2 Synchronized Reserve Added By SCED MW	Self Scheduled Tier 2 Synchronized Reserve MW	Total Tier 2 Synchronized Reserve MW
RTO Zone w/o MAD Subzone	2014	Jan	$6,099,636	$21,685,392	16,629	3,557	0	20,185
RTO Zone w/o MAD Subzone	2014	Feb	$1,503,069	$850,597	19,456	4,647	0	24,103
RTO Zone w/o MAD Subzone	2014	Mar	$1,694,304	$2,887,014	33,646	14,551	0	48,196
MAD Subzone	2014	Jan	$19,392,761	$44,252,473	253,282	35,604	147,561	436,448
MAD Subzone	2014	Feb	$4,695,064	$1,759,180	118,287	28,536	124,119	270,942
MAD Subzone	2014	Mar	$10,298,554	$7,985,276	119,112	79,383	121,659	320,154
All RTO	2014	Jan	$25,492,397	$65,937,864	269,911	39,161	147,561	456,633
All RTO	2014	Feb	$6,198,133	$2,609,777	137,743	33,183	124,119	295,045
All RTO	2014	Mar	$11,994,837	$10,872,290	152,757	93,934	121,659	368,350

Table 10-21 RTO Zone, Mid-Atlantic Dominion Subzone, and Full RTO Weighted SRMCP, Tier 2 Cost, and Synchronized Reserve Cost

Synchronized Reserve Market	Year	Month	Weighted Synchronized Reserve Market Clearing Price ($/MW)	Tier 2 Cost ($/MW)	Synchronized Reserve (Tier 1 plus Tier 2) Cost ($/MW)
RTO Zone w/o MAD Subzone	2014	Jan	$145.25	$302.18	$1,376.48
RTO Zone w/o MAD Subzone	2014	Feb	$31.95	$62.36	$97.65
RTO Zone w/o MAD Subzone	2014	Mar	$20.86	$35.15	$95.06
MAD Subzone	2014	Jan	$40.02	$44.43	$145.83
MAD Subzone	2014	Feb	$12.65	$17.33	$23.82
MAD Subzone	2014	Mar	$19.66	$32.21	$57.21
All RTO	2014	Jan	$44.67	$55.83	$200.23
All RTO	2014	Feb	$14.23	$21.01	$29.85
All RTO	2014	Mar	$19.81	$32.59	$62.18

The Tier 1 synchronized reserve compensation rules included in PJM's shortage pricing filing resulted in a substantial increase in payments for the same service. Under the rule change, Tier 1 is paid more when the non-synchronized reserve price rises above zero. PJM's shortage pricing rules require that tier 1 synchronized reserve be paid the tier 2 synchronized reserve clearing price when the non-synchronized reserve clearing price is above $0. This rule significantly increases the cost of tier 1 synchronized reserves with no operational or economic reason to do so. PJM is not reserving any tier 1, but simply paying substantially more for the same product without any additional performance requirements. The impact of the change to the way tier 1 estimate is calculated had a significant effect on the tier 2 market. The significance of this rule can be seen in Table 10-20.

The MAD subzone cleared a tier 2 synchronized reserve market in 99.4 percent of hours in the first three months of 2014 compared to 38 percent of hours in January through March, 2013. The RTO Zone cleared a tier 2 synchronized reserve market in 56.9 percent of hours in January through March of 2014 compared to less than one percent of hours in January through March, 2013.

For the first three months of 2014, the weighted average price for tier 2 synchronized reserve in the Mid-Atlantic Dominion subzone was $26.46 while the cost of tier 2 synchronized reserve was $33.48. The price for synchronized reserve in the first three months of 2013 was $7.35 while the cost was $12.58.

For the first three months of 2014 (Table 10-21), the weighted average price for tier 2 synchronized reserve in the RTO reserve zone (exclusive of the MAD subzone) was $50.90 while the cost of tier 2 synchronized reserve was $100.53.

Although the market is separated into a zone and subzone with different requirements and often different clearing prices, it is useful to look at the weighted price and cost of the PJM RTO in its entirety. For the RTO and MAD together, the weighted average SRMCP was $44.67 for the first three months of 2014, the tier 2 cost was $28.48 and the cost of tier 2 synchronized reserve was $39.02.

There is no market for tier 1 synchronized reserve so there is no clearing price for it but it is paid when it performs. With shortage pricing tier 1 is paid the tier 2 SRMCP whenever the non-synchronized reserve clearing price is greater than $0. By adding the total credits paid to tier 1 resources into the existing weighted calculation of tier 2 cost, the overall cost for synchronized reserve in the MAD subzone is $86.07 per MW. The overall cost of synchronized reserve in the RTO excluding the MAD subzone is $375.41 per MW. The overall cost of synchronized reserve across the entire RTO zone is $109.98 per MW.

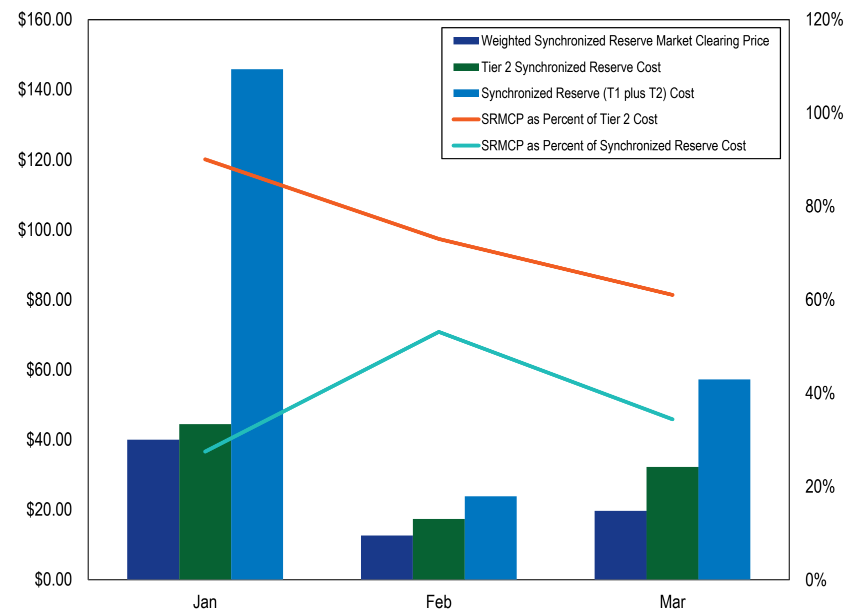
In the first three months of 2014, the non synchronized reserve market cleared above $0 in eleven percent of hours, almost all of them in January during the cold days of January 6, 7, 8, 22, 23, 24, and 25. In January 2014 PJM paid almost $66M for tier 1 synchronized reserve, only 22 percent of which was paid for tier 1 response to a spinning event. In fifteen hours during the first three months of 2014, PJM paid more than $1M each hour for tier 1 synchronized reserve (all of them on January 7, an extreme cold day) with the highest being $2.6M in hour 16. In four additional hours (on January 23, January 30, and March 4) tier 1 synchronized reserve cost over $900,000. The tier 1 payments during January 2014 were extreme because a shortage of reserve during the cold days necessitated the clearing of a non-synchronized reserve market. But even in the more normal months of February and March, tier 1 payments, when added to the cost of tier 2 made synchronized reserve significantly more expensive than it would be without the shortage pricing rule (Table 10-17). And for this additional expense PJM gets no additional response. This is a windfall payment to Tier 1 reserves.

The MMU recommends that the rule requiring the payment of tier 1 synchronized reserve resources when the non-synchronized reserve price is above zero be eliminated immediately.

Price and Cost

A price to cost ratio close to 1.0 is an indicator of an efficient synchronized reserve market design. In the Mid-Atlantic Dominion Subzone tier 2 Synchronized Reserve Market for the first three months of 2014, the price of tier 2 synchronized reserves was 79 percent of the cost. In the first three months of 2013, the tier 2 price to cost ratio was 60 percent. The highest (best) ratio occurred in the high price / high cost month of January (Figure 10-16). The price of tier 2 synchronized reserves against the full cost of synchronized reserve however (tier 1 plus tier 2) was lowest (worst) in January. For the first three months of 2014 the price of tier 2 synchronized reserve was only 38 percent of the cost of all synchronized reserve.

Figure 10-16 Comparison of Mid-Atlantic Dominion Subzone synchronized reserve weighted average clearing price and cost (Dollars per MW): January through March 2014



Tier 1 Estimate Bias

The ASO, IT-SCED and RT-SCED market clearing engines can each have its own tier 1 estimate biased. Biasing means modifying (increasing or decreasing) the demand for tier 1 synchronized reserve from the default level defined by the tariff. Negative tier 1 estimate biasing refers to the manual subtraction from the Tier 1 estimate that the market clearing engines uses to determine how much tier 2 MW to schedule. A negative bias reduces the amount of tier 1 estimated to be available and therefore increases the amount of tier 2 which must be purchased. When the hour ahead market solution (using the ASO) has its tier 1 estimate biased negatively, it forces the hour ahead market solution to include more inflexible synchronized reserve resources reducing the flexibility of the market software to reallocate an on-line resource from reserves to energy. When the IT-SCED is biased negatively it induces the within-hour market solution to move flexible resources into reserve from energy. Tier 1 estimate biasing can be used by PJM dispatchers to compensate for uncertainty in short term load forecasting, generator performance, or uncertainty in the accuracy of the tier 1 estimate of the market solution.

PJM used tier 1 estimate biasing in both the MAD and RTO synchronized reserve hour ahead market solutions during the first three months of 2014. In the MAD subzone the tier 1 estimate in the hour ahead solution was biased in 93 hours (4.3 percent) during the first three months of 2013. In the MAD subzone the tier 1 estimate in the hour ahead solution was biased in 599 hours (27.7 percent) during the first three months of 2013. In seven hours tier 1 was biased positively and in 86 hours the tier 1 bias was negative.

PJM used tier 1 estimate biasing in 328 real time market solution 5 minute periods 1.2 percent of all real time market solutions in the MAD subzone. All 328 periods were in the cold days of January 7, and 8.

The MMU recommends that PJM be more explicit about why tier 1 biasing is used. The MMU recommends that PJM define rules for calculating available tier 1 MW and for the use of biasing during any phase of the market solution and then identify the relevant rule for biasing.

Compliance

Synchronized reserve non-compliance has two components: failure to deliver scheduled tier 2 Synchronized Reserve MW during spinning events; and failure of non-emergency, generation resources capable of providing energy to provide a daily synchronized reserve offer.

The MMU has identified and quantified the failure of scheduled tier 2 synchronized reserve resources to deliver during spinning events since 2011.[24] When synchronized reserve resources clear the Tier 2 Synchronized Reserve Market they are obligated to provide their full cleared Tier 2 MW in a spinning event. The MMU has reported a wide range of spinning event response levels and recommended PJM take action to increase compliance rates. An enhanced penalty structure became effective January 1, 2014. Penalties can be assessed for any spinning event greater than 10 minutes during which flexible or inflexible synchronized reserve was scheduled either by the resource owner or by PJM. In the first three months of 2014, nine spinning events occurred in the Mid Atlantic subzone that met these criteria.

24 See the *2011 State of the Market Report for PJM*, Volume II, Section 9, "Ancillary Services" at pg. 250.

Table 10-22 Synchronized reserve events greater than 10 minutes, Mid-Atlantic Dominion Tier 2 Response Compliance January through March 2014

2014 Qualifying Spinning Events (DD-MON-YYYY HR)	Event Duration (minutes)	MAD Synchronized Reserve Market Clearing Price	Tier 2 Plus DR Cleared MW	Tier 2 Plus DR Added MW	Percent of Tier 2 Penalized for Non Compliance	Percent of DR Penalized for Non Compliance	Overall Percent of Synchronized Reserve Penalized for Non Compliance
06-JAN-2014 22	68	$388.20	$454.00	$0.00	26%	77%	39%
07-JAN-2014 02	25	$97.52	$539.00	$0.00	60%	79%	64%
07-JAN-2014 04	34	$193.16	$823.00	$0.00	89%	90%	89%
07-JAN-2014 11	11	$635.15	484	39	67%	11%	54%
07-JAN-2014 13	41	$800.00	$328.00	$0.00	94%	17%	64%
10-JAN-2014 16	12	$4.79	$396.00	$0.00	2%	7%	4%
31-JAN-2014 15	13	$52.74	$382.00	$53.00	14%	21%	15%
01-MAR-2014 05	26	$26.33	36	0	0%	5%	1%
27-MAR-2014 10	56	$117.37	$249.00	$309.00	43%	28%	39%

For the nine qualifying spinning events that occurred in the first three months of 2014, 50.2 percent of all scheduled synchronized reserve MW were not delivered and were penalized.

The new penalty structure will increase the number of consecutive days that an underperforming resource is penalized from three days to the lesser of the average number of days between spinning events (recalculated annually) or the numbers of days since the resource was last penalized. The average number of days between spinning events calculated for 2014 is 15 days. In addition, a resource will be 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 spinning event.[25] Resource owners are permitted to aggregate the response of multiple units to offset an underresponse from one unit with an overresponse from a different unit for the purpose of reducing an underresponse penalty.

A second compliance issue is the failure to comply with the must offer requirement. The shortage pricing rules include a must offer requirement for Tier 2 synchronized for most generators under normal conditions, and an expanded set of generators under defined conditions related to peak load. For all hours, all on-line, non-emergency, generating resources that are providing energy and are capable of providing synchronized reserve are deemed available for Tier 1 and Tier 2 synchronized reserve and they must have a tier 2 offer and be available for reserve. When PJM issues a primary reserve warning, voltage reduction warning, or manual load dump warning, all other non-emergency, off-line available generation capacity resources must have a tier 2 offer and be available for reserve. As of March 31, 2014, the MMU estimates that 24.0 percent of eligible energy resources are not in compliance with the synchronized reserve must-offer requirement.

PJM is to monitor every generator subject to the must-offer requirement to ensure that it has submitted a tier 2 synchronized reserve offer greater than or equal to ninety percent of its ramp rate time 10 minutes. If the offer is less than that rate, PJM will contact the generation owner.[26]

History of Spinning Events

Spinning events (Table 10-23) are usually caused by a sudden generation outage or transmission disruption (disturbance) requiring PJM to load synchronized reserve.[27] PJM also calls spinning events for non-disturbance events, which it characterizes as low ACE. The reserve remains loaded until system balance is recovered. From 2011 through the first three months of 2014, PJM experienced 95 spinning events, between two and three events per month. Spinning events had an average length of 13.2 minutes.

25 See PJM "M-28 Operating Agreement Accounting," Rev. 63, December 19, 2013, p. 43. See also PJM "Energy & Ancillary Services Market Operations," rev. 65, January 21, 2014, pg. 74.

26 See PJM, "Manual 11, Energy & Ancillary Services Market Operations," Rev. 65, January 21, 2014 Section 4, p. 63.

27 See PJM, "Manual 12, Balancing Operations," Revision 30 (December 1, 2013), pp. 36-37.

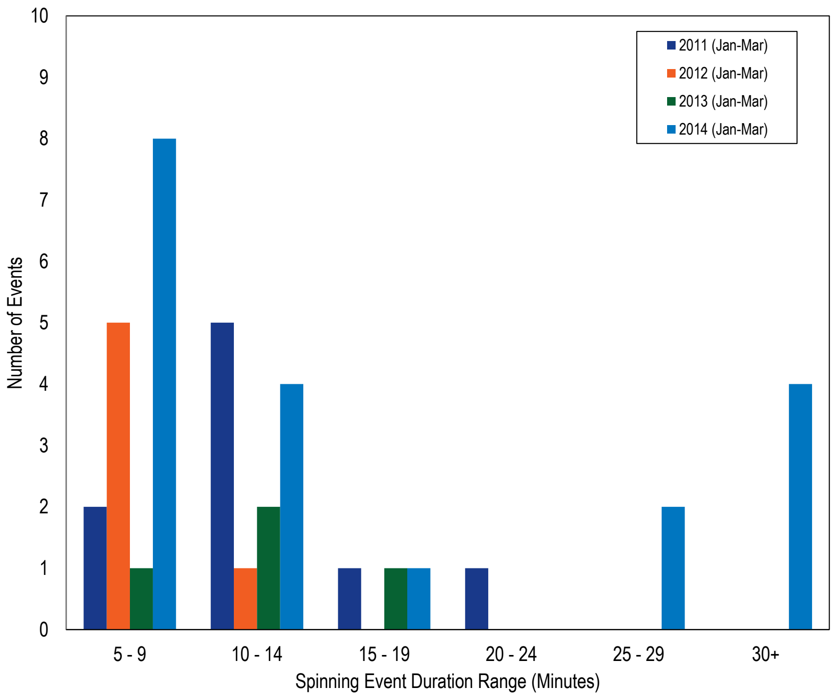
Table 10-23 Spinning events: 2011 through 2014

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

Of the nineteen distinct spinning events in the first three months of 2014, ten were caused by unit trips and two were listed by PJM dispatch as being caused by Low ACE, in which synchronized reserve is being used as energy to maintain power balance.

The danger of using synchronized reserves for energy is that it reduces the amount of synchronized reserve available for a disturbance. This is always a judgment call by PJM Dispatch whose primary focus must be grid reliability. The spinning event of January 6, 2014 (caused by a unit trip) was 68 minutes which is as long as the September 10 due to low ACE. Compliance by tier 2 synchronized reserve to the 68 minute spinning event of January 6 was very poor (Table 10-22) at 39 percent.

Figure 10-17 Spinning events duration distribution curve, January through March 2011 through 2014



Non-Synchronized Reserve Market

Non-synchronized reserve is reserve MW available within ten minutes but not synchronized to the grid. There is no defined, hourly requirement for non-synchronized reserves. It is available to meet the primary reserve requirement subject to conditions. Generation resources that have designated their entire output as emergency will not be considered eligible to provide non-synchronized reserves. Generation resources that are not available to provide energy will not be considered eligible to provide non-synchronized reserves.

PJM specifies that 1,700 MW of 10-minute primary reserve must be available in the Mid-Atlantic Dominion Reserve Sub Zone of which 1,300 MW must be synchronized reserve, and that 2,063 MW of 10-minute primary reserve must be available in the RTO Reserve Zone of which 1,375 MW must be synchronized reserve. The balance of primary reserve can be made up by the most economic combination of synchronized and non-synchronized reserve. Examples of equipment that generally qualify as non-synchronized reserve in this category are run of river hydro, pumped hydro, combustion turbines, combined cycles and diesels.[28]

In the MAD subzone hour ahead market solution the first 1,300 MW of the 1,700 MW primary reserve requirement must be satisfied by a jointly optimized mixture of tier 1 and tier 2 synchronized reserve. The next 400 MW of primary reserve is a jointly optimized solution of tier 1 and tier 2 synchronized reserve and non-synchronized reserve. Prices are determined during the operating hour. Sometimes a non-synchronized reserve resource becomes economic during the hour. In that case a non-synchronized reserve clearing price is established consisting of the lost opportunity cost. CTs provided 70.2 percent and hydro 26.7 percent of cleared non-synchronized reserve MW in the first three months of 2014. The remaining cleared non-synchronized reserve was provided by diesel and landfill resources.

Startup time for non-synchronized reserve resources is not subject to testing. There is no non-synchronized reserve offer MW or offer price. Prices are determined solely by the lost opportunity cost created by any deviation from economic merit order required to maintain the non-synchronized reserve commitment. Since non-synchronized 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 non-synchronized reserve clearing price is zero.

Figure 10-18 shows the daily average hour ahead non-synchronized reserve market clearing price and average scheduled MW for the MAD subzone. The

28 See PJM. "Manual 11, Energy & Ancillary Services Market Operations" Revision 64 (January 6, 2014), p. 77.

MAD subzone non-synchronized reserve market had a clearing price greater than zero in 237 (10.5 percent) hours in the first three months of 2014, at an average price of $52.78 per MW. The weighted non-synchronized reserve market clearing price for all hours in the MAD subzone, including cleared hours when the price was zero, was $4.56 per MW. The maximum clearing price was the shortage pricing non-synchronized reserve maximum of $400 per MW for four consecutive hours on January 7, 2014.

Figure 10-19 shows the daily average hour ahead non-synchronized reserve market clearing price and average scheduled MW for the RTO Zone cleared in 128 (5.9 percent) hours in the first three months of 2014 at an average price of $53.14. The weighted non-synchronized reserve market clearing price for all hours in the RTO Zone was $2.02. The maximum clearing price was the shortage pricing non-synchronized reserve maximum of $400 for four consecutive hours on January 7, 2014.

Figure 10-18 Daily average MAD Subzone Non-Synchronized Reserve Market clearing price and MW purchased: January through March 2014

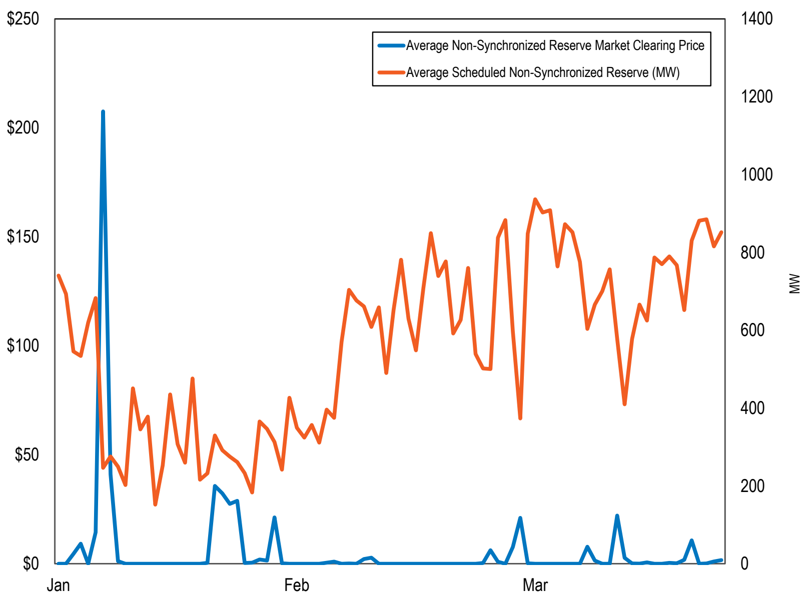
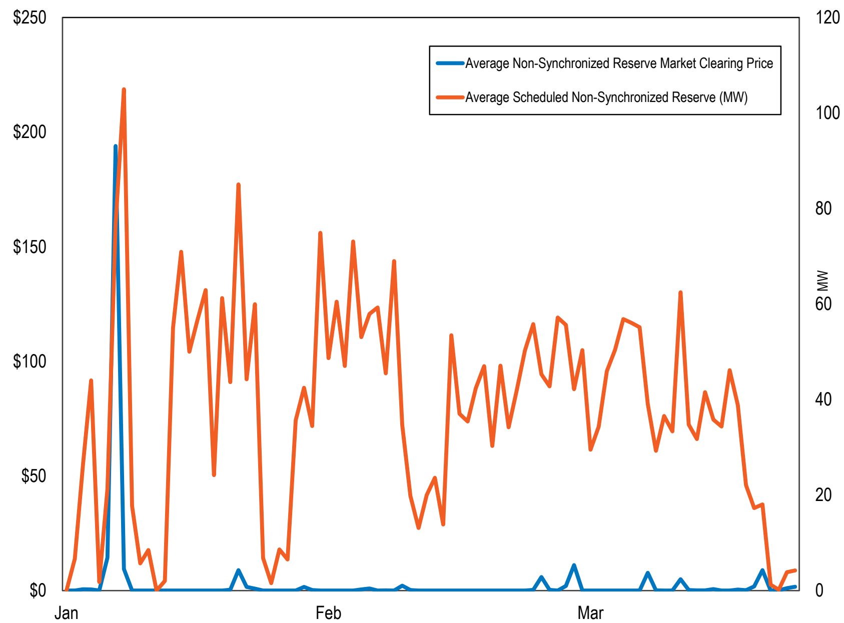


Figure 10-19 Daily average RTO Zone Non-Synchronized Reserve Market clearing price and MW purchased: January through March 2014



Day-Ahead Scheduling Reserve (DASR)

The Day-Ahead Scheduling Reserve Market is a market based mechanism for the procurement of supplemental, 30-minute reserves.[29] Thirty minute reserves are secondary reserves.[30]

The DASR 30-minute reserve requirements are determined by PJM for each reliability region.[31] In the Reliability*First* (RFC) region secondary reserve requirements are calculated based on historical under-forecasted load rates and generator forced outage rates.[32] The RFC and Dominion secondary reserve requirements are added together to form a single RTO DASR requirement defined as a percentage of the daily peak load forecast. The DASR requirement

29 PJM uses the terms "supplemental operating reserves" and "scheduling operating reserves" interchangeably.
30 See PJM. "Manual 35, Definitions and Acronyms," Revision 35, (April 11, 2014), p. 89.
31 See PJM. "Manual 13, Emergency Requirements," Revision 55 (January 1, 2014), p. 11.
32 See PJM. "Manual 10, Pre-Scheduling Operations," Revision 29 (November 1, 2013), pp. 19-20.

is procured via the DASR Market. The requirement is applicable for all hours of the operating day. If the DASR Market does not result in procuring adequate scheduling reserves, PJM is required to schedule additional operating reserves.

Market Structure

In the first three months of 2014, the required DASR was 6.27 percent of peak load forecast, down from 6.91 percent in 2013.[33] The DASR requirement is a sum of the load forecast error and the forced outage rate. The load forecast error is a three year average of underforecast errors. The load forecast error decreased from 2.13 percent in 2013 to 2.11 percent in 2014. The forced outrage rate is based on a three year rolling average of outages that occur between 18:00 on the scheduling day (day-ahead) and 20:00 of the operating day. The forced outage rate decreased from 4.66 percent in 2013 to 4.16 percent in 2014. The DASR MW purchased averaged 6,805 MW per hour for the first three months of 2014, a slight decrease from 6,841 MW per hour in the first three months of 2013.

In the first three months of 2014, no hours failed the three pivotal supplier test in the DASR Market. No hours failed the three pivotal supplier test in the first three months of 2013.

All generation resources are required to offer DASR.[34] Load response resources which are registered in PJM's Economic Load Response and are dispatchable by PJM are eligible to provide DASR. No demand resources offered in the DASR market in the first three months of 2014. The amount of DASR available is the lesser of the energy ramp rate times thirty minutes, or the emergency maximum minus the day-ahead dispatch point. For off-line resources capable of being online in thirty minutes, the DASR quantity is emergency maximum.

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

Economic withholding remains an issue in the DASR Market. The direct marginal cost of providing DASR is zero. All offers greater than zero constitute economic withholding. On March 31, 2014, 56.4 percent of resources offered at $0, 65.9 percent of resources offered at $0.05 or less, 74.4 percent of resources offered at less than $1.00. 11.5 percent resources offered DASR at levels above $5 per MW.

Market Performance

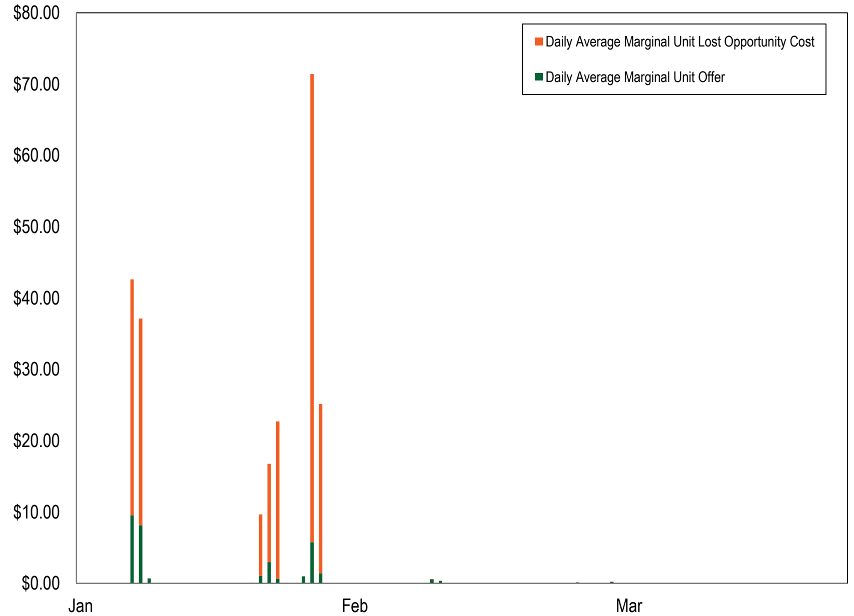
For 84.0 percent of hours in the first three months of 2014, DASR cleared at a price of $0.00 (Figure 10-20). For the first three months of 2014, the weighted average DASR price was $0.06. The highest DASR price was $534.66 on January 8, 2014. DASR prices are calculated as the sum of the offer price plus the opportunity cost. For most hours the price is comprised entirely of the offer price. When the DASR clearing price is greater than $0.00, 78 percent of the time the price consists solely of the offer price.

33 See the *2012 State of the Market Report for PJM*, Volume II, Section 9, "Ancillary Services" at Day Ahead Scheduling Reserve (DASR).
34 See PJM "Manual 11" Revision 64, (January 6, 2014) p. 138 at Day-ahead Scheduling Reserves Market Rules.
35 See PJM. "Manual 11, Emergency and Ancillary Services Operations," Revision 63 (January 6, 2014), p. 143.

Table 10-24 PJM Day-Ahead Scheduling Reserve Market MW and clearing prices: January 2012 Through March 2014

Year	Month	Average Required Hourly DASR (MW)	Minimum Clearing Price	Maximum Clearing Price	Weighted Average Clearing Price	Total DASR MW Purchased	Total DASR Credits
2012	Jan	6,944	$0.00	$0.02	$0.00	5,166,216	$604
2012	Feb	6,777	$0.00	$0.02	$0.00	4,716,710	$2,037
2012	Mar	6,180	$0.00	$0.05	$0.00	4,591,937	$5,031
2012	Apr	5,854	$0.00	$0.10	$0.00	4,214,993	$5,572
2012	May	6,491	$0.00	$5.00	$0.05	4,829,220	$226,881
2012	Jun	7,454	$0.00	$156.29	$2.39	5,366,935	$11,422,377
2012	Jul	8,811	$0.00	$155.15	$3.69	6,520,522	$20,723,970
2012	Aug	8,007	$0.00	$55.55	$0.51	5,956,318	$2,601,271
2012	Sep	6,656	$0.00	$7.80	$0.12	4,805,769	$540,586
2012	Oct	6,022	$0.00	$0.04	$0.00	4,454,997	$5,878
2012	Nov	6,371	$0.00	$1.00	$0.02	4,584,792	$75,561
2012	Dec	6,526	$0.00	$0.05	$0.00	5,179,876	$5,975
2013	Jan	6,965	$0.00	$2.00	$0.01	5,182,020	$45,337
2013	Feb	6,955	$0.00	$0.75	$0.00	4,673,491	$20,062
2013	Mar	6,543	$0.00	$1.00	$0.02	4,861,811	$75,071
2013	Apr	5,859	$0.00	$0.05	$0.00	4,218,720	$8,863
2013	May	6,129	$0.00	$23.37	$0.20	4,560,238	$873,943
2013	Jun	7,262	$0.00	$15.88	$0.12	5,228,554	$615,557
2013	Jul	8,129	$0.00	$230.10	$6.76	6,015,476	$37,265,364
2013	Aug	7,559	$0.00	$1.00	$0.01	5,623,824	$55,766
2013	Sep	6,652	$0.00	$119.62	$1.23	4,789,728	$5,245,835
2013	Oct	6,077	$0.00	$0.05	$0.00	4,497,258	$2,363
2013	Nov	6,479	$0.00	$0.10	$0.00	4,665,156	$5,123
2013	Dec	7,033	$0.00	$0.80	$0.01	5,232,625	$25,192
2014	Jan	7,053	$0.00	$534.66	$8.43	5,212,272	$35,349,969
2014	Feb	6,759	$0.00	$5.00	$0.05	4,541,860	$188,762
2014	Mar	6,247	$0.00	$3.00	$0.01	4,647,607	$47,924

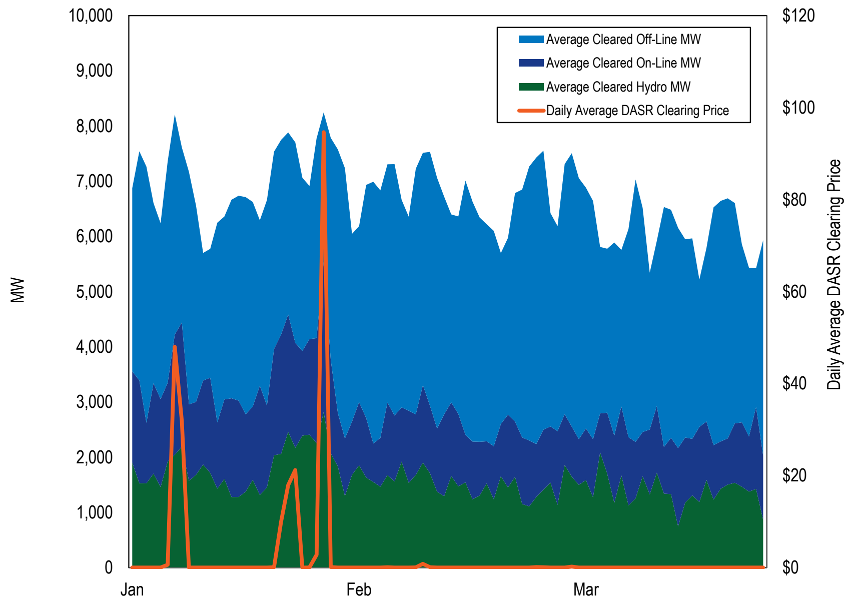
Figure 10-20 Daily average components of DASR clearing price, marginal unit offer and LOC: January through March 2014



The secondary reserve requirement is satisfied by the DASR market at $0.00 in 84 percent of hours. When energy demand is high the reserve requirement cannot be filled without redispatching online resources which significantly affects the price. Figure 10-20 shows the impact of LOC on price when online resources must be redispatched to satisfy the DASR requirement.

Figure 10-21 illustrates the sensitivity of DASR prices to high energy dispatch and the resource types (on-line, off-line, and hydro) used for secondary reserve. DASR prices remain very low even at high energy dispatch levels. DASR prices increase very suddenly at peak loads driven by high LOCs (Figure 10-20).

Figure 10-21 Daily average DASR prices and MW by classification: January through March, 2014



On September 10, 2013, a 68-minute spinning event was declared as a result of low ACE. On January 6, 2014 another 68-minute spinning event was declared, this time as the result of a unit trip. Different classes of reserve exist for different classes of imbalance. A 68-minute inability to bring ACE into balance with or without a sudden generator outage is the type of imbalance that 30-minute secondary reserve was created to recover from. On January 6, 2014 the average required DASR was 7,162 MW. On September 10, 2013, the 30-minute reserve requirement was 8,893 MW. Those required amounts of DASR were cleared day-ahead.

It is not clear why secondary reserve (DASR) was either unavailable to the dispatchers or was never called on the operating day when it was apparently needed. PJM dispatch called on tier 1, tier 2, and non-synchronized reserve and was unable to restore balance for 68 minutes. It is not clear why the secondary reserve, already paid for, was not called or not callable.

The MMU recommends that PJM determine why secondary reserve was either unavailable or not dispatched on September 10, 2013, and January 6, 2014, and that PJM evaluate replacing the DASR market with a real time secondary reserve product that is available and dispatchable in real time.

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 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 give PJM substantial flexibility in procuring black start resources and make 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.[36] 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

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

14, 2014. (The selection process will be completed in the first half of 2014.) PJM and the MMU have coordinated closely during the selection process.

Black start payments are non-transparent 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.

Total black start charges is 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 for scheduling in the Day-Ahead Energy Market or committing in real time units that provide black start service. Total black start charges are allocated monthly to PJM customers proportionally to their zone and non-zone peak transmission use and point to point transmission reservations.

In the first three months of 2014, total black start charges were $12.7 million, a $15.0 million (54.2 percent) decrease from the January through March 2013 level of $27.6 million. Operating reserve charges declined from $22.2 million in the first three months of 2013 to $7.6 million in the first three months of 2014. This decrease was due to higher LMPs that caused more ALR black start units to run economically rather than out of merit.($21.0 million in January through March 2013 to $7.0 million in January through March 2014). Table 10-25 shows total revenue requirement charges from the first three months of years 2009 through 2014. (Prior to December 2012, PJM did not define a black start operating reserve category.)

Table 10-25 Black start revenue requirement charges: January through March, 2009 through 2014

Year (Jan-Mar)	Revenue Requirement Charges
2009	$3,575,056
2010	$2,673,689
2011	$2,793,709
2012	$3,864,301
2013	$5,412,855
2014	$5,104,104

Black start zonal charges in the first three months of 2014 ranged from $0.02 per MW-day in the ATSI Zone (total charges were $28,280) to $3.50 per MW-day in the AEP Zone (total charges were $7,202,857). For each zone, Table 10-26 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 $0.07 per MW of reserve capacity during the first three months of 2014.

Table 10-26 Black start zonal charges for network transmission use: January through March, 2013 and 2014

Zone	Jan-Mar 2013 Revenue Requirement Charges	Jan-Mar 2013 Operating Reserve Charges	Jan-Mar 2013 Total Charges	Jan-Mar 2013 Peak Load (MW-day)	Jan-Mar 2013 Black Start Rate ($/MW-day)	Jan-Mar 2014 Revenue Requirement Charges	Jan-Mar 2014 Operating Reserve Charges	Jan-Mar 2014 Total Charges	Jan-Mar 2014 Peak Load (MW-day)	Jan-Mar 2014 Black Start Rate ($/MW-day)
AECO	$129,109	$0	$129,109	252,810	$0.51	$153,360	$0	$153,360	246,528	$0.62
AEP	$152,241	$21,031,906	$21,184,148	2,097,774	$10.10	$166,432	$7,036,425	$7,202,857	2,056,167	$3.50
APS	$62,489	$0	$62,489	767,187	$0.08	$68,326	$0	$68,326	780,966	$0.09
ATSI	$36,944	$0	$36,944	1,216,341	$0.03	$28,280	$0	$28,280	1,182,699	$0.02
BGE	$1,948,411	$2,379	$1,950,791	630,180	$3.10	$1,139,947	$0	$1,139,947	614,727	$1.85
ComEd	$994,046	$0	$994,046	2,124,081	$0.47	$1,021,927	$0	$1,021,927	2,004,210	$0.51
DAY	$58,100	$5,252	$63,351	315,639	$0.20	$60,441	$6,511	$66,951	306,837	$0.22
DEOK	$78,620	$0	$78,620	490,050	$0.16	$281,806	$0	$281,806	463,140	$0.61
Dominion	NA	NA	NA	NA	NA	$248,851	$0	$248,851	1,688,670	$0.15
DPL	$139,995	$1,821	$141,816	370,269	$0.38	$136,765	$1,357	$138,122	361,683	$0.38
DLCO	$14,302	$0	$14,302	274,869	$0.05	$14,378	$0	$14,378	265,635	$0.05
EKPC	NA	NA	NA	NA	NA	$90,113	$0	$90,113	227,934	$0.40
JCPL	$138,665	$0	$138,665	559,746	$0.25	$119,801	$0	$119,801	574,101	$0.21
Met-Ed	$174,830	$0	$174,830	273,276	$0.64	$208,834	$0	$208,834	271,107	$0.77
PECO	$326,964	$8,104	$335,067	769,410	$0.44	$360,442	$2,343	$362,785	775,656	$0.47
PENELEC	$131,542	$0	$131,542	261,720	$0.50	$122,181	$0	$122,181	277,857	$0.44
Pepco	$71,788	$0	$71,788	604,863	$0.12	$75,854	$0	$75,854	588,006	$0.13
PPL	$40,195	$0	$40,195	664,335	$0.06	$35,102	$0	$35,102	665,298	$0.05
PSEG	$633,624	$0	$633,624	942,282	$0.67	$418,230	$0	$418,230	937,296	$0.45
RECO	$0	$0	$0	0	NA	$0	$0	$0	0	NA
(Imp/Exp/Wheels)	$280,990	$1,161,185	$1,442,175	691,609	$2.09	$353,034	$509,843	$862,877	1,062,418	$0.81
Total	$5,412,855	$22,210,646	$27,623,501	13,306,441	$2.08	$5,104,104	$7,556,479	$12,660,583	15,350,935	$0.82

Table 10-27 shows estimated black start revenue requirements by zone for delivery years 2014-2015 through 2016-2017 based on current, incoming, and outgoing black start resources.

Table 10-27 Revenue Requirement Estimate: Delivery Years 2014-2015 through 2016-2017

Zone	2014-2015 Revenue Requirement	2015-2016 Revenue Requirement	2016-2017 Revenue Requirement
AECO	$881,923	$2,422,980	$2,712,515
AEP	$10,739,321	$18,054,481	$18,070,565
APS	$309,424	$4,253,581	$4,256,090
ATSI	$2,592,447	$3,084,911	$3,086,491
BGE	$2,009,693	$1,488,297	$1,538,482
ComEd	$4,672,575	$5,292,902	$3,721,520
DAY	$272,203	$271,052	$274,403
DEOK	$1,224,221	$1,223,003	$1,226,548
Dominion	$1,606,732	$4,293,407	$5,985,460
DPL	$857,173	$2,160,879	$2,715,141
DLCO	$63,794	$185,467	$187,744
EKPC	$408,714	$406,733	$412,501
JCPL	$2,270,287	$7,428,656	$7,449,817
Met-Ed	$856,576	$812,061	$858,183
PECO	$1,613,435	$1,796,320	$1,873,591
PENELEC	$543,679	$4,629,185	$4,679,970
Pepco	$1,086,225	$2,604,867	$2,611,127
PPL	$199,874	$851,869	$859,863
PSEG	$7,085,539	$9,780,520	$9,802,397
RECO	$0	$0	$0
Total	$39,293,835	$71,041,172	$72,322,407

Table 10-28 shows new black start NERC critical infrastructure protection (CIP) capital costs being recovered by black start units in PJM. These costs were located in multiple zones, including ComEd, DEOK, DLCO, JCPL, Met-Ed, PENELEC and Pepco. These costs are recoverable through Schedule 6A of the tariff, and include both physical security and cyber security investments in order to protect black start units deemed critical. This included equipment necessary to restrict access to both physical sites, as well as firewall and software upgrades necessary protect cyber assets and monitor unit operations.

Table 10-28 NERC CIP Costs: January through March 2014

Capital Cost Requested	Cost Recovered in Jan-Mar 2014	Number of Units	MW
$1,736,971	$157,630	33	678

Reactive Service

Reactive Service, Reactive Supply and Voltage Control from Generation or Other Sources Service, is provided by generation and other sources (such as static VAR compensators and capacitor banks) of reactive power (measured in VAR).[37] Reactive power helps maintain appropriate voltages on the transmission system and is essential to the flow of real power (measured in MW). Without Reactive Service in the necessary amounts across the RTO footprint, transmission system voltages fall, generating units and transmission lines shut down, and no real power flows.

Total reactive service charges are the sum of reactive service revenue requirement charges and reactive service operating reserve charges. Reactive service revenue requirements are based on FERC-approved filings. Reactive service revenue requirement charges are allocated monthly to PJM customers in the zone or zones where the reactive service was provided proportionally to their zone and non-zone peak transmission use and point to point transmission reservations. Reactive service operating reserve charges are paid for scheduling in the Day-Ahead Energy Market and committing in real time units that provide reactive service. These operating reserve charges are allocated daily to the zone or zones where the reactive service was provided.

In the first three months of 2014, total reactive service charges were $77.7 million, a 37.3 percent decrease from the January through March 2013 level of $124.0 million.[38] While revenue requirement charges increased from $68.3 million to $70.2 million, operating reserve charges fell from $55.6 million to $7.5 million. The decrease in operating reserve charges was due to higher LMPs that caused more units that provide reactive service to be run economically rather than out of merit. Total charges in the first three months of 2014 ranged from $487 in the RECO Zone to $10.1 million in the AEP Zone.

37 PJM OATT. Schedule 2 "Reactive Supply and Voltage Control from Generation Sources Service," (Effective Date: February 18, 2012).
38 See the *2013 State of the Market Report for PJM*, Volume II, Section 4, "Energy Uplift."

For each zone in the first three months of 2013 and 2014, Table 10-29 shows Reactive Service operating reserve charges, revenue requirement charges and total charges (the sum of operating reserve and revenue requirement charges).

Table 10-29 Reactive zonal charges for network transmission use: January through March 2013 and 2014

Zone	Jan-Mar 2013 Operating Reserve Charges	Jan-Mar 2013 Revenue Requirement Charges	Jan-Mar 2013 Total Charges	Jan-Mar 2014 Operating Reserve Charges	Jan-Mar 2014 Revenue Requirement Charges	Jan-Mar 2014 Total Charges
AECO	$2,131,642	$1,286,113	$3,417,756	$81,431	$1,255,482	$1,336,913
AEP	$3,261,003	$10,098,164	$13,359,167	$196,208	$9,857,657	$10,053,865
APS	$1,241,559	$5,498,190	$6,739,749	$249,479	$5,367,240	$5,616,719
ATSI	$19,213,959	$3,598,790	$22,812,749	$3,389,443	$3,963,356	$7,352,799
BGE	$926,837	$1,947,253	$2,874,090	$33,662	$1,900,875	$1,934,537
ComEd	$2,322,042	$6,156,138	$8,478,180	$34,089	$6,009,518	$6,043,607
DAY	$405,838	$2,114,120	$2,519,958	$5,699	$2,063,768	$2,069,468
DEOK	$632,597	$1,443,031	$2,075,629	$9,035	$1,408,663	$1,417,698
Dominion	$343,588	$7,498,436	$7,842,023	$4,883	$7,319,846	$7,324,729
DPL	$2,637,077	$2,428,619	$5,065,696	$33,131	$2,636,968	$2,670,099
DLCO	$6,554,423	$0	$6,554,423	$1,409,136	$0	$1,409,136
EKPC	NA	NA	$0	$4,764	$523,492	$528,256
JCPL	$5,080,722	$1,567,966	$6,648,689	$7,964	$1,743,078	$1,751,042
Met-Ed	$472,447	$1,874,196	$2,346,644	$15,074	$1,829,559	$1,844,633
PECO	$947,602	$4,415,638	$5,363,241	$259,820	$4,310,471	$4,570,292
PENELEC	$4,776,894	$1,165,247	$5,942,141	$1,339,940	$1,137,495	$2,477,435
Pepco	$853,079	$1,317,377	$2,170,455	$29,749	$1,286,001	$1,315,750
PPL	$1,030,291	$4,594,362	$5,624,653	$15,867	$4,710,500	$4,726,367
PSEG	$2,714,124	$6,832,188	$9,546,312	$357,998	$6,669,467	$7,027,465
RECO	$33,631	$0	$33,631	$487	$0	$487
(Imp/Exp/Wheels)	$0	$4,555,417	$4,555,417	$0	$6,239,393	$6,239,393
Total	$55,579,356	$68,391,246	$123,970,602	$7,477,860	$70,232,829	$77,710,689