# Ancillary Service Markets

The United States Federal Energy Regulatory Commission (FERC) defined six ancillary services in Order No. 888: 1) scheduling, system control and dispatch; 2) reactive supply and voltage control from generation service; 3) regulation and frequency response service; 4) energy imbalance service; 5) operating reserve – synchronized reserve service; and 6) operating reserve – supplemental reserve service.[1] Of these, PJM currently provides regulation, energy imbalance, synchronized reserve, and operating reserve – supplemental reserve services through market-based mechanisms. PJM provides energy imbalance service through the Real-Time Energy Market. PJM provides the remaining ancillary services on a cost basis. 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.

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.[2] Regulation is provided, independent of economic signal, by generators with a short-term response capability (i.e., less than five minutes) or by demand-side response (DSR). Longer-term deviations between system load and generation are met via primary and secondary reserve and generation responses to economic signals. Synchronized reserve is a form of primary reserve. To provide synchronized reserve a generator must be synchronized to the system and capable of providing output within 10 minutes. Synchronized reserve can also be provided by DSR. The term, Synchronized Reserve Market, refers only to supply of and demand for Tier 2 synchronized reserve.

Both the Regulation and Synchronized Reserve Markets are cleared on a real-time basis. A unit can be selected for either regulation or synchronized reserve, but not for both. The Regulation and the Synchronized Reserve Markets are cleared interactively with the Energy Market and operating reserve requirements to minimize the cost of the combined products, subject to reactive limits, resource constraints, unscheduled power flows, interarea transfer limits, resource distribution factors, self-scheduled resources, limited fuel resources, bilateral transactions, hydrological constraints, generation requirements and reserve requirements.

1 75 FERC ¶ 61,080 (1996).

2 See the *2011 State of the Market Report for PJM* for a full discussion of Ancillary Service markets and issues.

The purpose of the Day-Ahead Scheduling Reserve (DASR) market is to satisfy 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 the market clearing price.[3]

PJM does not provide a market for reactive power, but does ensure its adequacy through member requirements and scheduling. Generation owners are paid according to FERC-approved, reactive revenue requirements. Charges are allocated to network customers based on their percentage of load, as well as to point-to-point customers based on their monthly peak usage.

The Market Monitoring Unit (MMU) analyzed measures of market structure, conduct and performance for the PJM Regulation Market, the two regional Synchronized Reserve Markets, and the PJM DASR Market for the first six months of 2012.

### Table 9-1 The Regulation Market results were not competitive[4] (See 2011 SOM, Table 9-1)

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

3 See 117 FERC ¶ 61,331 at P 29 n32 (2006).

4 As Table 9-1 indicates, the Regulation Market results are not the result of the offer behavior of market participants, which was competitive as a result of the application of the three pivotal supplier test. The Regulation Market results are not competitive because the changes in market rules, in particular the changes to the calculation of the opportunity cost, resulted in a price greater than the competitive price in some hours, resulted in a price less than the competitive price in some hours, and because the revised market rules are inconsistent with basic economic logic. The competitive price is the actual marginal cost of the marginal resource in the market. The competitive price in the Regulation Market is the price that would have resulted from a combination of the competitive offers from market participants and the application of the prior, correct approach to the calculation of the opportunity cost. The correct way to calculate opportunity cost and maintain incentives across both regulation and energy markets is to treat the offer on which the unit is dispatched for energy as the measure of its marginal costs for the energy market. To do otherwise is to impute a lower marginal cost to the unit than its owner does and therefore impute a higher or lower opportunity cost than its owner does, depending on the direction the unit was dispatched to provide regulation. If the market rules and/or their implementation produce inefficient outcomes, then no amount of competitive behavior will produce a competitive outcome.

- The Regulation Market structure was evaluated as not competitive because the Regulation Market had one or more pivotal suppliers which failed PJM's three pivotal supplier (TPS) test in 53 percent of the hours in January through June 2012.
- Participant behavior was evaluated as competitive 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 not competitive, despite competitive participant behavior, because the changes in market rules, in particular the changes to the calculation of the opportunity cost, resulted in a price greater than the competitive price in some hours, resulted in a price less than the competitive price in some hours, and because the revised market rules are inconsistent with basic economic logic.[5]
- Market design was evaluated as flawed because while PJM has improved the market by modifying the schedule switch determination, the lost opportunity cost calculation is inconsistent with economic logic and there are additional issues with the order of operation in the assignment of units to provide regulation prior to market clearing.

### Table 9-2 The Synchronized Reserve Markets results were competitive (See 2011 SOM, Table 9-2)

| Market Element | Evaluation | Market Design |
|---|---|---|
| Market Structure: Regional Markets | Not Competitive | |
| Participant Behavior | Competitive | |
| Market Performance | Competitive | Effective |

- The Synchronized Reserve Market structure was evaluated as not competitive because of high levels of supplier concentration and inelastic demand. The Synchronized Reserve Market had one or more pivotal suppliers which failed the three pivotal supplier test in 40 percent of the hours in January through June of 2012.
- 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 prices that reflect marginal costs.
- Market design was evaluated as effective because market power mitigation rules result in competitive outcomes despite high levels of supplier concentration.

### Table 9-3 The Day-Ahead Scheduling Reserve Market results were competitive (See 2011 SOM, Table 9-3)

| 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 the market did not fail the three pivotal supplier test.
- Participant behavior was evaluated as mixed because while most offers appeared consistent with marginal costs (zero), about 13 percent of offers reflected economic withholding, with offer prices above $5.00.
- 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.

5 PJM agrees that the definition of opportunity cost should be consistent across all markets and should, in all markets, be based on the offer schedule accepted in the market. This would require a change to the definition of opportunity cost in the Regulation Market which is the change that the MMU has recommended. The MMU also agrees that the definition of opportunity cost should be consistent across all markets.

## Highlights

- The weighted average Regulation Market clearing price, including opportunity cost, for January through June 2012 was $13.90 per MW.[6] This was a decrease of $1.63, or 10.5 percent, from the average price for regulation in January through June 2011. The total cost of regulation decreased by $11.91 from $30.89 per MW in January through June 2011, to $18.98, or 38.6 percent. In January through June 2012, the weighted Regulation Market clearing price was 76 percent of the total regulation cost per MW, compared to 49 percent of the total regulation cost per MW in January through June 2011.
- On May 7, 2012, PJM upgraded the ancillary services market clearing software from the Synchronized Reserve and Regulation Optimizer (SPREGO) to the Ancillary Services Optimizer (ASO). This upgrade includes an improved co-optimization algorithm. An initial problem lead to four hours in which regulation market prices had to be recalculated.
- The weighted average clearing price for Tier 2 Synchronized Reserve Market in the Mid-Atlantic Subzone was $6.32 per MW in January through June 2012, a $5.86 per MW decrease from January through June 2011.[7] The total cost of synchronized reserves per MWh in January through June 2011 was $8.16, a 48 percent decrease from the total cost of synchronized reserves ($15.82) during January through June 2011. The weighted average Synchronized Reserve Market clearing price was 79 percent of the weighted average total cost per MW of synchronized reserve in January through June 2011. This is the same percentage of price to cost as in January through June 2011.
- The weighted DASR market clearing price in January through June 2012 was $0.41 per MW. In January through June 2011, the weighted price of DASR was $0.44 per MW. The average hourly purchased DASR increased by eight percent from 6,093 MW to 6,614 MW reflecting PJM's larger footprint with the integration of DEOK on January 1, 2012.
- Black start zonal charges in January through June 2012 ranged from $0.02 per MW in the ATSI zone to $2.10 per MW in the AEP zone

## Ancillary Services costs per MW of load: 2001 - 2012

Table 9-4 shows PJM ancillary services costs for January through June for 2001 through 2012 on a per MW of load basis. 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.

### Table 9-4 History of ancillary services costs per MW of Load[8]: January through June, 2001 through 2012 (See 2011 SOM, Table 9-4)

| Year | Regulation | Scheduling, Dispatch, and System Control | Reactive | Synchronized Reserve | Supplementary Operating Reserve |
|---|---|---|---|---|---|
| 2001 (Jan-Jun) | $0.50 | $0.45 | $0.22 | $0.00 | $1.18 |
| 2002 (Jan-Jun) | $0.37 | $0.55 | $0.23 | $0.00 | $0.59 |
| 2003 (Jan-Jun) | $0.57 | $0.61 | $0.24 | $0.14 | $0.81 |
| 2004 (Jan-Jun) | $0.53 | $0.66 | $0.26 | $0.16 | $0.93 |
| 2005 (Jan-Jun) | $0.57 | $0.51 | $0.27 | $0.11 | $0.60 |
| 2006 (Jan-Jun) | $0.48 | $0.48 | $0.29 | $0.08 | $0.32 |
| 2007 (Jan-Jun) | $0.61 | $0.46 | $0.30 | $0.09 | $0.50 |
| 2008 (Jan-Jun) | $0.73 | $0.37 | $0.30 | $0.08 | $0.66 |
| 2009 (Jan-Jun) | $0.37 | $0.43 | $0.37 | $0.04 | $0.50 |
| 2010 (Jan-Jun) | $0.37 | $0.38 | $0.36 | $0.06 | $0.75 |
| 2011 (Jan-Jun) | $0.33 | $0.38 | $0.41 | $0.11 | $0.80 |
| 2012 (Jan-Jun) | $0.20 | $0.44 | $0.47 | $0.03 | $0.65 |

## Conclusion

The MMU continues to conclude that the results of the Regulation Market are not competitive.[9] The Regulation Market results are not competitive because the changes in market rules, in particular the changes to the calculation of the opportunity cost, resulted in a price greater than the competitive price in

6 The term "weighted" when applied to clearing prices in the Regulation Market means clearing prices weighted by the MW of cleared regulation.

7 The term "weighted" when applied to clearing prices in the Synchronized Reserve Market means clearing prices weighted by the MW of cleared synchronized reserve.

8 Results in this table differ slightly from the results reported previously because accounting load is used in the denominator in this table.

9 The *2009 State of the Market Report for PJM* provided the basis for this recommendation. The *2009 State of the Market Report for PJM* summarized the history of the issues related to the Regulation Market. See the *2009 State of the Market Report for PJM*, Volume II, Section 6, "Ancillary Service Markets."

some hours, resulted in a price less than the competitive price in some hours, and because the revised market rules are inconsistent with basic economic logic and the definition of opportunity cost elsewhere in the PJM tariff. This conclusion is not based on the behavior of market participants, which remains competitive.

PJM agrees that the definition of opportunity cost should be consistent across all markets and should, in all markets, be based on the offer schedule accepted in the market. This would require a change to the definition of opportunity cost in the Regulation Market which is the change that the MMU has recommended. The MMU also agrees that the definition of opportunity cost should be consistent across all markets.

The structure of each 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. (The term Synchronized Reserve Market refers only to Tier 2 synchronized reserve.) 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. However, compliance with calls to respond to actual spinning events has been an issue. As a result, the MMU is recommending that the rules for compliance be reevaluated.

The MMU concludes that the DASR Market results were competitive in January through June 2012, although concerns remain about economic withholding and the absence of the three pivotal supplier test in this market.

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.

Overall, the MMU concludes that the Regulation Market results were not competitive in January through June 2012 as a result of the identified market design issues. The MMU is hopeful that the opportunity cost can be resolved in 2012 as part of the regulation market redesign. This conclusion is not the result of participant behavior, which was generally competitive. The MMU concludes that the Synchronized Reserve Market results were competitive in January through June 2012. The MMU concludes that the DASR Market results were competitive in January through June 2012.

## Regulation Market

The PJM Regulation Market in January through June, 2012, continued to be operated as a single market. There have been no structural changes since December 1, 2008.[10]

On May 7, 2012, PJM upgraded the ancillary services market clearing software from the Synchronized Reserve and Regulation Optimizer (SPREGO) to the Ancillary Services Optimizer (ASO). This upgrade includes an improved co-optimization algorithm. An initial problem lead to four hours in which regulation market prices had to be recalculated. These hours and the before/after prices are 5/20/2012 HE19 $174.92/$13.09, 5/20/2012 HE20 $174.84/$18.58, 5/21/2012 HE15 $174.48/$16.05, and 5/21/2012 HE18 $174.41/$14.04. The software problem that caused these high prices was quickly resolved.

### Proposed Market Design Changes

Although the current market design satisfies the requirements of regulation, namely that it keep the reportable metrics CPS1 and BAAL within acceptable limits, a new market design initiative began in 2011 in response to a FERC rulemaking.[11] On October 20, 2011, FERC issued Order No. 755 directing PJM and other RTOs/ISOs to modify their regulation markets so as to make use of

10 All existing PJM tariffs, and any changes to these tariffs, are approved by FERC. The MMU describes the full history of the changes to the tariff provisions governing the Regulation Market in the *2011 State of the Market Report for PJM*, Volume II, Section 9, "Ancillary Service Markets."

11 See *2011 State of the Market Report for PJM*, Appendix F, "Ancillary Service Markets".

and properly compensate a mix of fast and traditional response regulation resources.[12]

On March 5, 2012, PJM filed proposed tariff revisions intended to implement Order No. 755.[13] The MMU protested that the Commission should not approve PJM's filing until PJM completed and filed undeveloped aspects of its proposal.[14] The MMU also protested that PJM's proposal failed to reflect the incremental cost of providing capability or the true lost opportunity cost of capability. The Commission required that PJM, through the stakeholder process, address the issues raised by the MMU and other parties and resubmit their proposal.[15] Since this decision, PJM and the MMU have worked with the membership to address the issues identified by the Commission. At the time of this report, the only remaining difference between PJM and the MMU is the definition of performance related costs which both PJM and the MMU have agreed will be resolved in the Cost Development Subcommittee (CDS).

## Market Structure

### Supply

Table 9-5 shows capability, daily offer and average hourly eligible MW for all hours as well as for off-peak and on-peak hours. The average hourly regulation capability increased in January through June of 2012, to 9,298 MW from 8,764 MW in the same time period of 2011.

12 *Frequency Regulation Compensation in the Organized Wholesale Power Markets*, 137 FERC ¶ 61,064 (2011) ("Order No. 755").
13 PJM filing in Docket No. ER12-1204.
14 Protest of the Independent Market Monitor for PJM filed in Docket No. ER12-1204 (March 26, 2012); Answer and Motion for Leave to Answer of the Independent Market Monitor for PJM filed in Docket No. ER12-1204 (April 25, 2012).
15 139 FERC ¶ 61,130 (2012) at PP 71, 73–74 ("[W]e agree with the IMM that PJM's performance payment fails to specify how clearing prices will reflect the actual requested mileage based on the regulation signal. While PJM describes the basic components of its proposal, PJM fails to explain how these components will be combined to calculate the accuracy score. While PJM's Manual 12 provides that the accuracy score will be the weighted average of the three components (i.e., the Energy Score, the Delay Score and the Correlation Score), PJM's proposal fails to define the process for calculating the various component scalars. Accordingly, we direct PJM to include in its compliance filing additional tariff language detailing each component of the accuracy score, and describing how each component scalar in the accuracy score calculation will be determined. As to the IMM's argument that the interaction between the performance offer and performance clearing price erroneously assumes a fixed relationship before the actual hour between a MW of cleared capability and the amount of work done, as we state above, we direct PJM to submit a compliance filing regarding the components of the accuracy score. Similarly, because the accuracy score affects eventual settlement, we will require PJM to submit as part of its compliance filing, additional tariff language outlining the settlement process. This should include how the accuracy score is used to determine payments and how settlement is affected by make-whole payments.")

#### Table 9-5 PJM regulation capability, daily offer[16] and hourly eligible: January through June 2012 (See 2011 SOM, Table 9-5)[17]

| Period | Regulation Capability (MW) | Average Daily Offer (MW) | Percent of Capability Offered | Average Hourly Eligible (MW) | Percent of Capability Eligible |
|---|---|---|---|---|---|
| All Hours | 9,298 | 6,736 | 72% | 3,009 | 32% |
| Off Peak | 9,298 | | | 2,952 | 32% |
| On Peak | 9,298 | | | 3,075 | 33% |

The supply of regulation can be affected by regulating units retiring from service. Table 9-6 shows the impact on the Regulation Market if all units requesting retirement retire through the end of 2015.

#### Table 9-6 Impact on PJM Regulation Market of currently regulating units scheduled to retire through 2015 (New Table)

| Current Regulation Units, Jan-Jun, 2012 | Settled MW, Jan-Jun, 2012 | Units Scheduled To Retire Through 2015 | Settled MW of Units Scheduled To Retire Through 2015 | Percent Of Regulation MW To Retire Through 2015 |
|---|---|---|---|---|
| 279 | 5,299,163 | 49 | 99,245 | 1.9% |

### Demand

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 and forecast load. In August 2008, the requirement was adjusted to be 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. Table 9-7 shows the required regulation and its relationship to the supply of regulation.

16 Average Daily Offer MW exclude units that have offers but make themselves unavailable for the day.
17 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 9-7 PJM Regulation Market required MW and ratio of eligible supply to requirement: January through June 2012 and 2011 (See 2011 SOM, Table 9-6)

| Month | Average Required Regulation, Jan-Jun 2011 | Average Required Regulation, Jan-Jun 2012 | Ratio of Supply To Requirement, Jan-Jun 2011 | Ratio of Supply To Requirement, Jan-Jun 2012 |
|---|---|---|---|---|
| Jan | 960 | 1,005 | 3.19 | 3.29 |
| Feb | 897 | 979 | 3.06 | 3.45 |
| Mar | 823 | 876 | 3.02 | 3.14 |
| Apr | 748 | 826 | 2.88 | 3.19 |
| May | 786 | 918 | 2.84 | 3.26 |
| Jun | 1,036 | 1,055 | 2.73 | 3.21 |

## Market Concentration

Table 9-8 shows Herfindahl-Hirschman Index (HHI) results for the January through June 2012 period. The average HHI of 1557 is classified as "moderately concentrated."

Table 9-8 PJM cleared regulation HHI: January through June 2012 and 2011 (See 2011 SOM, Table 9-7)

| Market Type | Minimum HHI | Weighted Average HHI | Maximum HHI |
|---|---|---|---|
| Cleared Regulation, Jan-Jun, 2012 | 813 | 1557 | 4962 |
| Cleared Regulation, Jan-Jun, 2011 | 818 | 1720 | 3683 |

Figure 9-1 compares the January through June 2012 HHI distribution curve with distribution curves for the same period of 2011 and 2010.

Figure 9-1 PJM Regulation Market HHI distribution: January through June of 2010, 2011 and 2012 (See 2011 SOM, Figure 9-1)

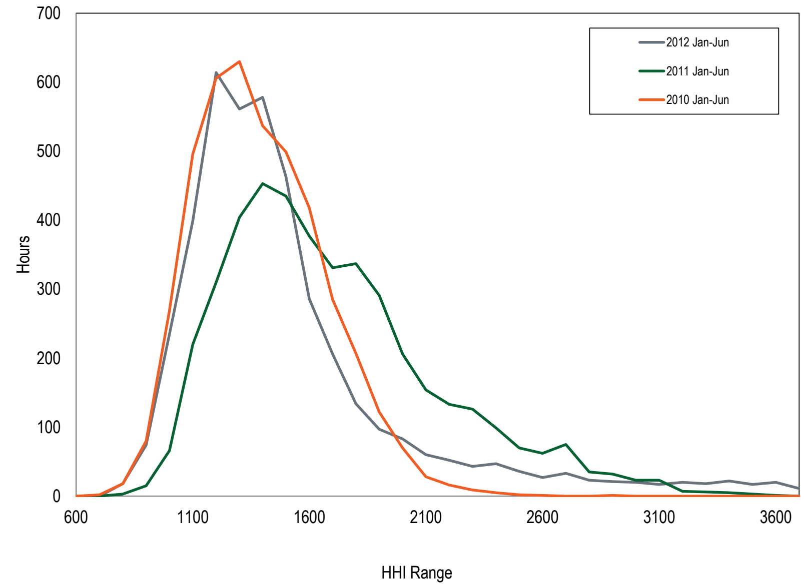



Table 9-9 includes a monthly summary of three pivotal supplier results. In January through June 2012, 53 percent of hours had one or more pivotal suppliers which failed or should have failed PJM's three pivotal supplier test.

The MMU noticed that pivotal supplier results, and the resulting market power mitigation, appeared to be erroneous and tracked the start of the problem to May 7, 2012. The MMU reported this issue to PJM and it was corrected on July 21, 2012. An apparent error in the May 7, 2012, implementation of the new ASO optimizer resulted in the software failing to correctly identify pivotal hours and pivotal suppliers. Between May 7 and June 31, 2012 only 29 hours failed the three-pivotal supplier test as incorrectly applied. MMU analysis indicates that 482 hours should have failed the pivotal supplier test and in 270 of those hours the correct application of market power mitigation would have resulted in a lower RMCP. PJM and the MMU are estimating the effect of this error on total billing. In the hours with an error, the excess credits paid to regulation providers would be partially offset by lower after market LOCs paid during settlement because as the clearing price goes down the difference between the required after the fact LOC and the clearing price increases for those units that require an after the fact LOC.

The MMU concludes from these results that the PJM Regulation Market in January through June 2012 was characterized by structural market power in 53 percent of the hours.

Table 9-9 Regulation market monthly three pivotal supplier results: January through June 2010, 2011 and 2012 (See 2011 SOM, Table 9-9)

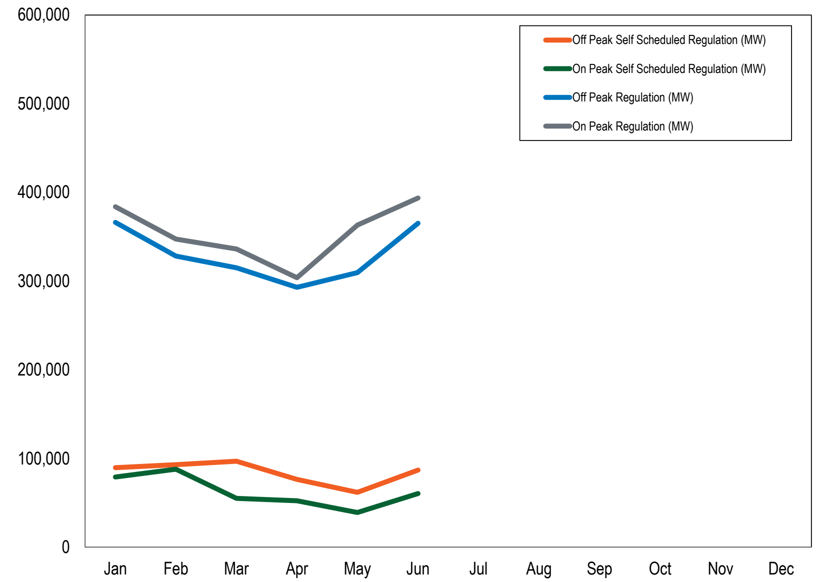
| | 2012 | | 2011 | | 2010 | |
|---|---|---|---|---|---|---|
| Month | Percent of Hours Pivotal | Percent of Hours When Marginal Supplier is Pivotal | Percent of Hours Pivotal | Percent of Hours When Marginal Supplier is Pivotal | Percent of Hours Pivotal | Percent of Hours When Marginal Supplier is Pivotal |
| Jan | 71% | 60% | 95% | 88% | 74% | 67% |
| Feb | 67% | 60% | 93% | 87% | 70% | 58% |
| Mar | 64% | 52% | 94% | 89% | 83% | 71% |
| Apr | 41% | 16% | 97% | 92% | 82% | 81% |
| May | 37% | 16% | 95% | 87% | 79% | 78% |
| Jun | 40% | 16% | 89% | 80% | 81% | 76% |

## Market Conduct

### Offers

Regulation Market participation is a function of the obligation of all LSEs 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 (Figure 9-2).[18]

Figure 9-2 Off peak and on peak regulation levels: January through June 2012 (See 2011 SOM, Figure 9-2)




Increased self scheduled regulation lowers the requirement for cleared regulation, resulting in fewer MW cleared in the market and lower clearing prices. Of the LSEs' obligation to provide regulation during January through June 2012, 76 percent was purchased in the spot market (81 percent in January through June 2011), 21 percent was self scheduled (16 percent in January through June 2011), and 3 percent was purchased bilaterally (3 percent in January through June 2011). (Table 9-10)

18 See PJM "Manual 28: Operating Agreement Accounting," Revision 52, (June 1, 2012); para 4.2, pp 14-15.

Table 9-10 Regulation sources: spot market, self-scheduled, bilateral purchases: January through June 2012 (See 2011 SOM, Table 9-10)

| Month | Spot Regulation (MW) | Self Scheduled Regulation (MW) | Bilateral Regulation (MW) | Total Regulation (MW) |
|---|---|---|---|---|
| Jan | 553,686 | 164,806 | 21,261 | 739,753 |
| Feb | 481,004 | 175,757 | 20,456 | 677,217 |
| Mar | 477,564 | 144,408 | 19,683 | 641,655 |
| Apr | 426,564 | 124,750 | 21,083 | 572,397 |
| May | 542,585 | 97,574 | 17,849 | 658,008 |
| Jun | 582,078 | 140,769 | 22,309 | 745,156 |

Demand resources offered and cleared regulation for the first time in November 2011. Since they do not offer energy, demand resources self schedule rather than offer into the market.[19] The impact of demand response on the Regulation Market has been negligible.

The Minimum Regulation MW parameter was reintroduced in 2012. This parameter allows regulation owners to specify a minimum amount of regulation that can be cleared, which imposes a constraint on the ASO's three product optimization. For the marginal unit, the ASO may need to clear less than an individual unit's offered amount of regulation in order to meet the regulation requirement. As a result of this parameter, there are a significant number of hours in which the ASO will have to clear more MW than is optimal or skip the marginal unit with a binding parameter and clear a more expensive unit resulting in a higher Regulation Market Clearing Price.

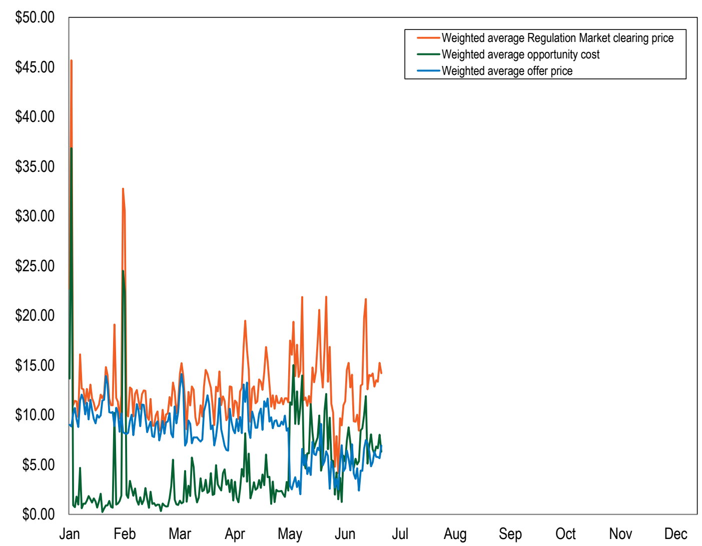
## Market Performance

### Price

The weighted average regulation market clearing price for January through June, 2012, was $13.90. This is a 10.5 percent decrease from the weighted average market clearing price of $15.53 for the same period in 2011. Figure 9-3 shows the daily average Regulation Market clearing price and the opportunity cost component for the marginal units in the PJM Regulation Market. All units chosen to provide regulation received the higher of the clearing price, or the unit's regulation offer plus the individual unit's real-time opportunity cost, based on actual LMP.[20]

The weighted average offer (excluding opportunity cost) of the marginal unit for the PJM Regulation Market during January through June, 2012, was $8.20 per MWh, a decrease from the weighted average offer in January through June 2011 of $9.89. The weighted average opportunity cost of the marginal unit for the PJM Regulation Market in January through June 2012 was $4.28. This is a decrease from the weighted average opportunity cost for the marginal unit during the same period of 2011 of $5.05. In the PJM Regulation Market the marginal unit opportunity cost was, on a weighted average basis, 24.2 percent of the RMCP. This is an increase from the January through June, 2011, weighted average of 16.1 percent.

Figure 9-3 PJM Regulation Market daily weighted average market-clearing price, marginal unit opportunity cost and offer price (Dollars per MWh): January through June 2012 (See 2011 SOM, Figure 9-3)




19 The demand resources self schedule because SPREGO might otherwise schedule them for energy which they cannot provide.

20 See PJM. "Manual 28: Operating Agreement, Accounting," Revision 52, Section 4.2, "Regulation Credits" (June 1, 2012), p. 14. PJM uses estimated opportunity cost to clear the market and actual opportunity cost to compensate generators that provide regulation and synchronized reserve.

Figure 9-4 shows the level of demand for regulation by month in January through June 2012 and the corresponding level of regulation price.

### Figure 9-4 Monthly average regulation demand and price: January through June 2012 (See 2011 SOM, Figure 9-4)

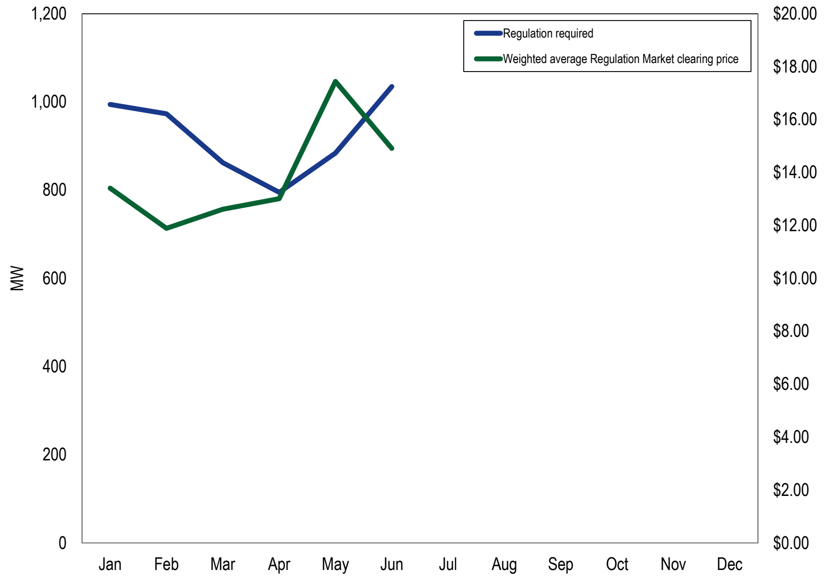
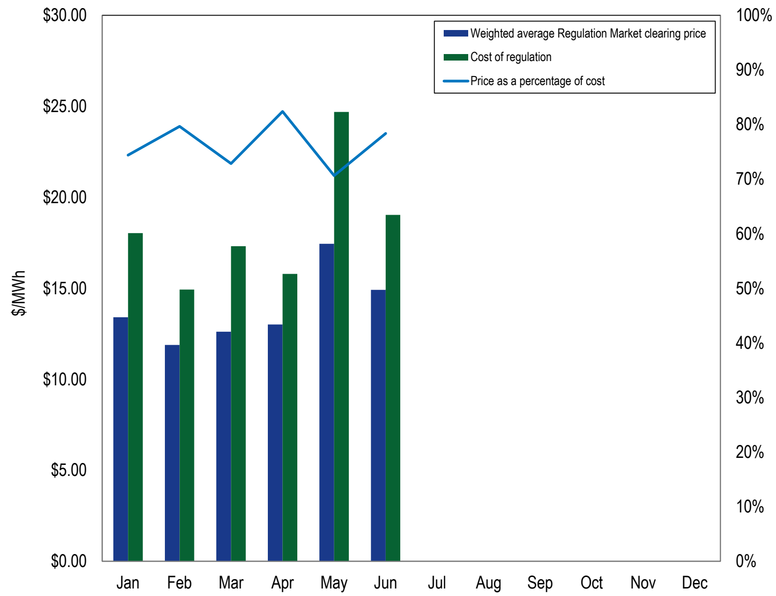



Figure 9-5 compares the regulation total cost per MWh (clearing price plus post market opportunity costs) with the regulation clearing price.

### Figure 9-5 Monthly weighted, average regulation cost and price: January through June 2012 (See 2011 SOM, Figure 9-5)



Total scheduled regulation MW, total regulation charges, regulation price and regulation cost are shown in Table 9-11.

### Table 9-11 Total regulation charges: January through June 2012 (See 2011 SOM, Table 9-11)

| Month | Scheduled Regulation (MWh) | Total Regulation Charges | Simple Average Regulation Market Clearing Price | Weighted Average Regulation Market Price | Cost of Regulation |
|---|---|---|---|---|---|
| Jan | 739,753 | $13,338,201 | $13.70 | $13.41 | $18.03 |
| Feb | 677,217 | $10,108,296 | $12.09 | $11.89 | $14.93 |
| Mar | 641,655 | $11,109,763 | $12.44 | $12.61 | $17.31 |
| Apr | 572,397 | $9,038,430 | $12.76 | $13.01 | $15.79 |
| May | 658,008 | $16,248,950 | $16.85 | $17.44 | $24.69 |
| Jun | 745,156 | $14,181,461 | $14.02 | $14.91 | $19.03 |

Table 9-12 provides a comparison of the weighted annual price and cost for PJM Regulation. The difference between the Regulation Market price and the actual cost of regulation was less in January through June 2012 than it was in the same period of 2011.

### Table 9-12 Comparison of weighted price and cost for PJM Regulation, January through June 2006 through 2012[21] (See 2011 SOM, Table 9-12)

| Year | Weighted Regulation Market Price | Weighted Regulation Market Cost | Regulation Price as Percent Cost |
|---|---|---|---|
| 2006 | $32.69 | $44.98 | 73% |
| 2007 | $36.86 | $52.91 | 70% |
| 2008 | $42.09 | $64.43 | 65% |
| 2009 | $23.56 | $29.87 | 79% |
| 2010 | $18.08 | $32.07 | 56% |
| 2011 | $15.53 | $30.89 | 50% |
| 2012 | $13.90 | $18.35 | 76% |

21 The PJM Regulation Market in its current structure began August 1, 2005. See the *2005 State of the Market Report for PJM*, "Ancillary Service Markets." pp. 249-250.

# Synchronized Reserve Market

PJM continued to operate the two synchronized reserve markets it implemented on February 1, 2007. The RFC Synchronized Reserve Zone reliability requirements are set by the Reliability*First* Corporation. The Southern Synchronized Reserve Zone (Dominion) reliability requirements are set by the Southeastern Electric Reliability Council (SERC).

The integration of the Trans-Allegheny Line (TrAIL) project resulted in a change to the interface defining the Mid-Atlantic subzone of the RFC Synchronized Reserve Market.[22] After the implementation of TrAIL, Bedington – Black Oak became the most limiting interface. PJM reserves the right to revise the interface defining the Mid-Atlantic Subzone in accordance with operational and reliability needs.[23] From May 20, 2011, through the end of September the percent of Tier 1 synchronized reserve available west of the interface that is available in the Mid-Atlantic subzone (transfer capacity) was set to 30 percent. Since then, PJM changed the transfer capacity several times, varying from 50 percent to 15 percent at the end of 2011. From January through June 2012, the transfer capacity has remained at 15 percent. Synchronized reserves added out of market were 3.3 percent of all synchronized reserves in January through June 2012, up from 3.0 percent in January through June, 2011. After-market opportunity cost payments accounted for 21.6 percent of total costs in January through June, 2012 compared to 18.7 percent in January through June, 2011.

## Market Structure

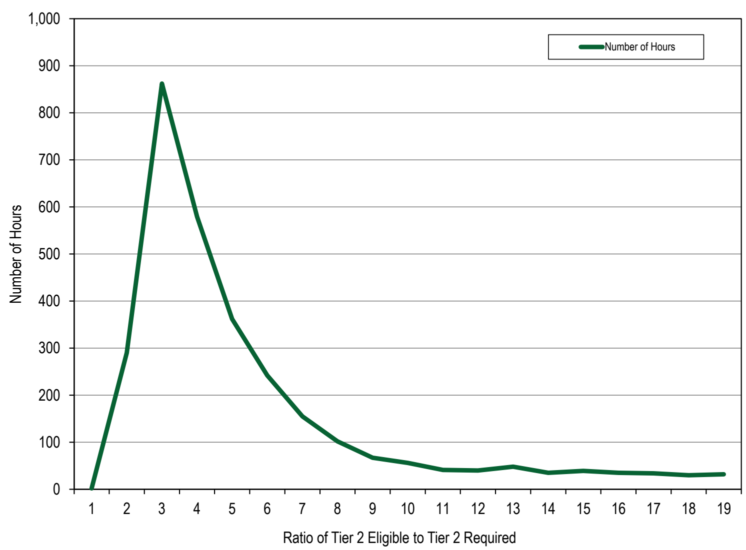
### Supply

In January through June, 2012, the supply of offered and eligible synchronized reserve was both stable and adequate. The contribution of DSR to the Synchronized Reserve Market remained significant. Demand side resources are relatively low cost, and their participation lowers overall Synchronized Reserve prices. The ratio of offered and eligible synchronized reserve MW to the synchronized reserve required (1,300 MW) was 1.18 for the Mid-

22 PJM.com "TrAIL Operational Impacts," <http://www.pjm.com/~/media/committees-groups/committees/oc/20111018/20111018-item-08-trail-operational-impacts.ashx> (October 2011).
23 See PJM, "Manual 11, Energy and Ancillary Services Market Operations," Revision 50 (April 3, 2012), p. 67.

Atlantic Subzone.[24] This is a 14.6 percent increase from the first six months of 2011 when the ratio was 1.03. Much of the required synchronized reserve is supplied from on-line (Tier 1) synchronized reserve resources. The ratio of eligible synchronized reserve MW to the required Tier 2 MW is much higher. The ratio of offered and eligible synchronized reserve to the required Tier 2 depends on how much Tier 2 synchronized reserve is needed but the median ratio for all cleared Tier 2 hours in January through June 2012 was 3.67 for the Mid-Atlantic Subzone. This is a 21.5 percent increase from January through June 2011 when the ratio was 3.02. For the RFC Zone the offered and eligible excess supply ratio is determined using the administratively required level of synchronized reserve. The requirement for Tier 2 synchronized reserve is lower than the required reserve level for synchronized reserve because there is usually a significant amount of Tier 1 synchronized reserve available. (See Figure 9-6)

**Figure 9-6 Ratio of Eligible Synchronized Reserve to Required Tier 2 for all cleared hours in the Mid-Atlantic Subzone: January through June 2012 (See 2011 SOM, Figure 9-6)**




24 The Synchronized Reserve Market in the Southern Region cleared in so few hours that related data for that market are not meaningful.

## Demand

PJM made no changes to the default hourly required synchronized reserve requirement in January through June 2012.

In January through June 2012, in the Mid-Atlantic Subzone, a Tier 2 synchronized reserve market was cleared in 73 percent of hours compared to 86 percent of hours for January through June 2011. In January through June, 2012, the average required Tier 2 synchronized reserve (including self scheduled) for all cleared hours was 441 MW. In January through June, 2011, the average required Tier 2 synchronized reserve was 564 MW.

Synchronized reserves added out of market were 3.3 percent of all Mid-Atlantic Subzone synchronized reserves in January through June, 2012, compared to 3.0 percent in January through June 2011.

The market demand for Tier 2 synchronized reserve is determined by subtracting the amount of forecast Tier 1 synchronized reserve available from each synchronized reserve zone's synchronized reserve requirement for the period. Market demand is further reduced by subtracting the amount of self scheduled Tier 2 resources. The total synchronized reserve requirement is different for the two Synchronized Reserve Markets. The synchronized reserve requirement is determined at the discretion of PJM to ensure system reliability and to maintain compliance with applicable NERC and regional reliability organization requirements. RFC and Dominion reserve requirements are determined on at least an annual basis. Mid-Atlantic Subzone requirements are established on a seasonal basis.[25]

Currently the RFC synchronized reserve requirement is the greater of the Reliability*First* Corporation's imposed minimum requirement or the system's largest contingency. The actual synchronized reserve requirement for the RFC Zone was 1,350 MW for January through June, 2012. For the Mid-Atlantic Subzone the requirement was 1,300 MW for January through June, 2012. (Table 9-13)

25 See PJM. "Manual 10: Pre-Scheduling Operations," Revision 25 (January 1, 2010), p. 18.

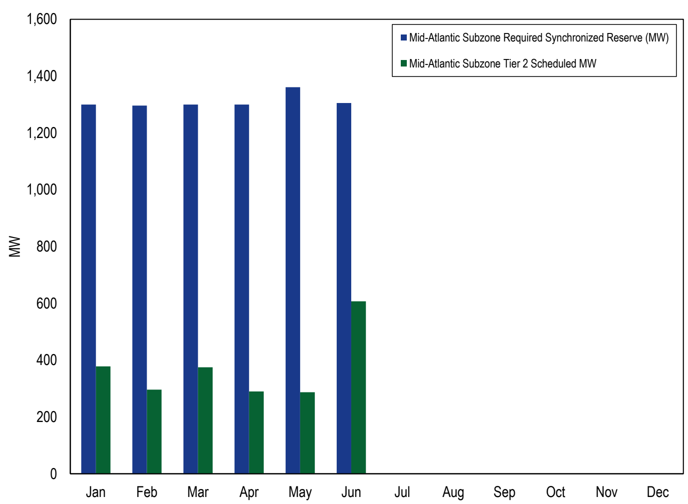
### Table 9-13 Synchronized Reserve Market required MW, RFC Zone and Mid-Atlantic Subzone, December 2008 through June 2012 (See 2011 SOM, Table 9-16)

| Mid-Atlantic Subzone | | | RFC 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 | Jun 30, 2012 | 1,300 | Mar 15, 2010 | Jun 30, 2012 | 1,350 |

Exceptions to this requirement can occur when grid maintenance or outages change the largest contingency. The requirement in the Mid-Atlantic Subzone was raised to 1,700 MW for several hours in May and June. The requirement in the Mid-Atlantic Subzone was also raised to 1,350 MW for several hours in May.

Figure 9-7 shows the average monthly synchronized reserve required and the average monthly Tier 2 synchronized reserve MW scheduled during January through June 2012 for the RFC Synchronized Reserve Market.

### Figure 9-7 Mid-Atlantic Synchronized Reserve Subzone monthly average synchronized reserve required vs. Tier 2 scheduled MW: January through June 2012 (See 2011 SOM, Figure 9-7)

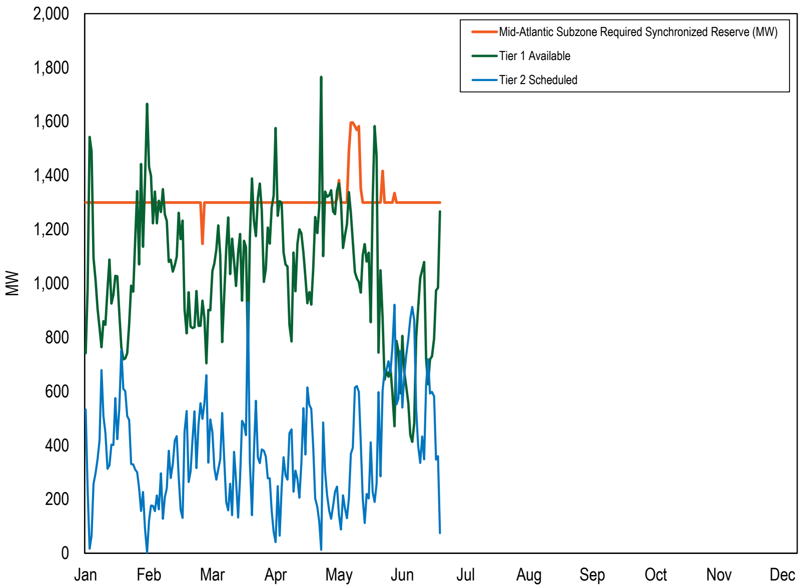



The RFC Synchronized Reserve Zone almost always has enough Tier 1 to cover its synchronized reserve requirement. Available Tier 1 in the western part of the RFC Synchronized Reserve Zone generally exceeds the total synchronized reserve requirement in the west. In January through June 2012, the RFC Synchronized Reserve Zone cleared a Tier 2 Synchronized Reserve Market in only two hours with an average SRMCP of $0.26. The Mid-Atlantic Subzone of the RFC Synchronized Reserve Zone cleared a separate Tier 2 market in 73 percent of all hours during January through June, 2012. Figure 9-7 compares the required synchronized reserve MW to the scheduled Tier 2 MW for the Mid-Atlantic Subzone.

The actual synchronized reserve requirement for the Mid-Atlantic Subzone for January through June 2012 was usually 1,300 MW. The difference between the level of required synchronized reserve and the level of Tier 2 synchronized reserve scheduled is the amount of Tier 1 synchronized reserve available on the system.

Figure 9-8 shows the relationship among the PJM Mid-Atlantic synchronized reserve required, the estimated Tier 1 available and the amount of Tier 2 synchronized reserve needed to be purchased.

Figure 9-8 RFC Synchronized Reserve Zone, Mid-Atlantic Subzone daily average hourly synchronized reserve required, Tier 2 MW scheduled, and Tier 1 MW estimated: January through June 2012 (See 2011 SOM, Figure 9-9)




The Southern Synchronized Reserve Zone is part of the Virginia and Carolinas Area (VACAR) subregion of SERC. VACAR specifies that available, 15 minute quick start reserve can be subtracted from Dominion's share of the largest contingency to determine synchronized reserve requirements.[26] The amount of 15 minute quick start reserve available in VACAR is sufficient to eliminate Tier 2 synchronized reserve demand for most hours. The Southern Synchronized Reserve Zone cleared a Tier 2 market for 94 hours in January through June 2012.

## Market Concentration

The RFC Tier 2 Synchronized Reserve Market was more concentrated in January through June 2012 than it had been in the same period of 2011. The RFC Synchronized Reserve Market remains highly concentrated and dominated by a relatively small number of companies. The HHI for the Mid-Atlantic Subzone of the January through June 2012 RFC cleared Synchronized Reserve Market was 3010, which is defined as highly concentrated. The HHI for the Mid-Atlantic Subzone for the same period in 2011 was 2616. 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 (compared to 45 percent of all hours in January through June 2011).

In January through June, 2012, 40 percent of hours in the Mid-Atlantic Subzone of the RFC Synchronized Reserve Market failed the three pivotal supplier test. For the same time period of 2011 68 percent of hours failed the three pivotal supplier test. These results indicate that the Mid-Atlantic Subzone of the RFC Synchronized Reserve Market, the only synchronized reserve market that clears on a regular basis, is not structurally competitive.

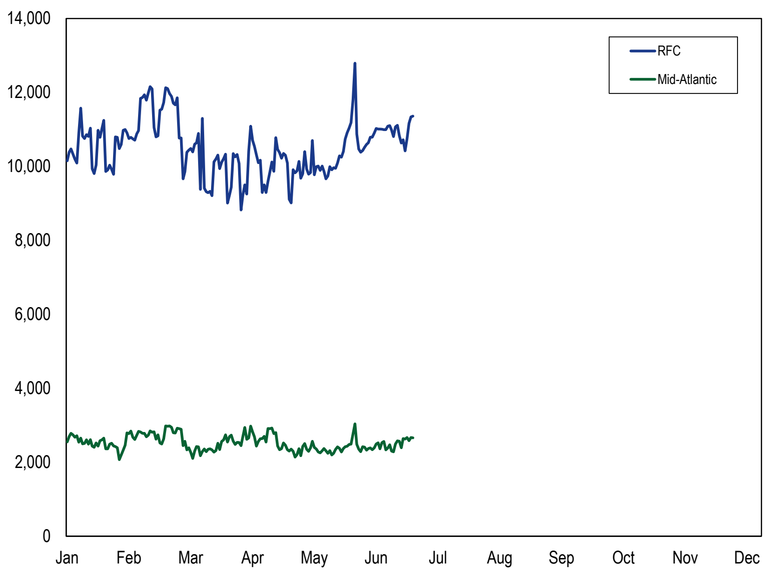
26 See PJM. "Manual 11: Energy & Ancillary Services Market Operations," Revision 50 (April 3, 2012), p. 67.

# Market Conduct

## Offers

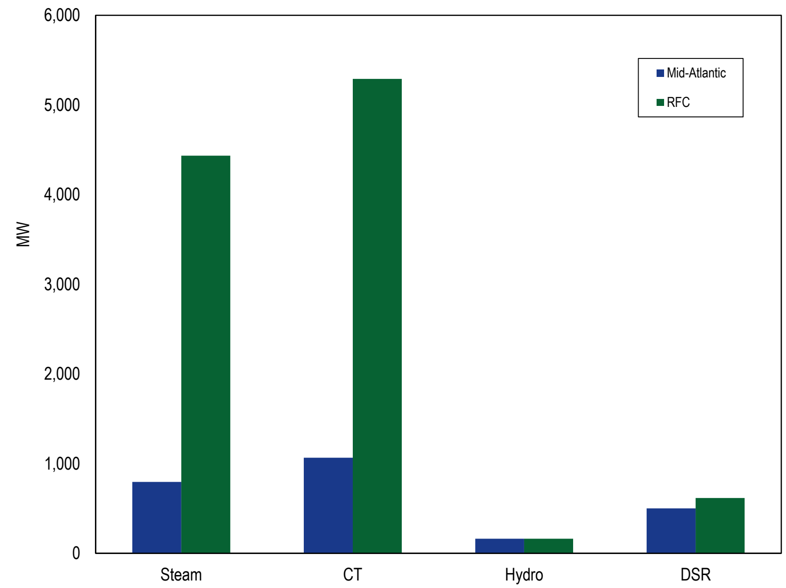
Figure 9-9 shows the daily average hourly offered Tier 2 synchronized reserve MW.

Figure 9-9 Tier 2 synchronized reserve average hourly offer volume (MW): January through June 2012 (See 2011 SOM, Figure 9-10)




Synchronized reserve is offered by steam, CT, hydroelectric and DSR resources. Figure 9-10 shows average offer MW volume by market and unit type.

Figure 9-10 Average daily Tier 2 synchronized reserve offer by unit type (MW): January through June 2012 (See 2011 SOM, Figure 9-11)




## DSR

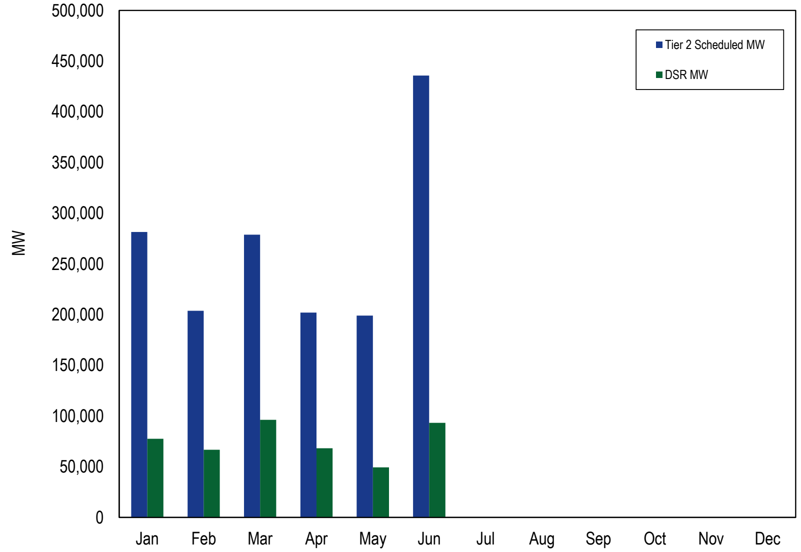
Demand-side resources were permitted to participate in the Synchronized Reserve Markets effective August, 2006. DSR continues to have a significant impact on the Synchronized Reserve Market. (Figure 9-10) In January through June 2012, DSR accounted for 36 percent of all cleared Tier 2 synchronized reserves, compared to 19 percent for the same period in 2011. In eight percent of hours when a synchronized reserve market was cleared, all cleared MW were DSR compared to five percent in January through June 2011. (See Table 9-14) In the hours when all supply was DSR, the simple average SRMCP was $1.13. The simple average SRMCP for all cleared hours was $3.38 (the simple average SRMCP in January through June 2011 was $8.46).

Table 9-14 Average RFC SRMCP when all cleared synchronized reserve is DSR, average SRMCP, and percent of all cleared hours that all cleared synchronized reserve is DSR: January through June 2010, 2011, 2012 (See 2011 SOM, Table 9-18)

| Year | Month | Weighted Average SRMCP | Weighted Average SRMCP when all cleared synchronized reserve is DSR | Percentage of cleared hours all synchronized reserve is DSR |
|---|---|---|---|---|
| 2010 | Jan | $5.84 | $2.03 | 4% |
| 2010 | Feb | $5.97 | $0.10 | 1% |
| 2010 | Mar | $8.45 | $2.03 | 6% |
| 2010 | Apr | $7.84 | $1.86 | 17% |
| 2010 | May | $9.98 | $1.68 | 15% |
| 2010 | Jun | $9.61 | $0.74 | 9% |
| 2011 | Jan | $10.75 | $0.10 | 0% |
| 2011 | Feb | $10.91 | NA | 0% |
| 2011 | Mar | $11.34 | $2.04 | 2% |
| 2011 | Apr | $12.64 | $1.84 | 10% |
| 2011 | May | $8.64 | $1.71 | 14% |
| 2011 | Jun | $9.05 | $1.18 | 10% |
| 2012 | Jan | $6.30 | $1.71 | 11% |
| 2012 | Feb | $5.47 | $1.78 | 24% |
| 2012 | Mar | $6.40 | $1.40 | 6% |
| 2012 | Apr | $5.01 | $0.91 | 4% |
| 2012 | May | $9.29 | $0.54 | 2% |
| 2012 | Jun | $4.05 | $0.43 | 1% |

Figure 9-11 shows total cleared plus self-scheduled monthly synchronized reserve MW and cleared plus self-scheduled MW for DSR synchronized reserve.

Figure 9-11 PJM RFC Zone Tier 2 synchronized reserve scheduled MW: January through June 2012 (See 2011 SOM, Figure 9-12)




## Market Performance

### Price

Figure 9-12 shows the weighted average Tier 2 price and the cost per MW associated with meeting PJM demand for synchronized reserve. The price of Tier 2 synchronized reserve is the Synchronized Reserve Market-clearing price (SRMCP).

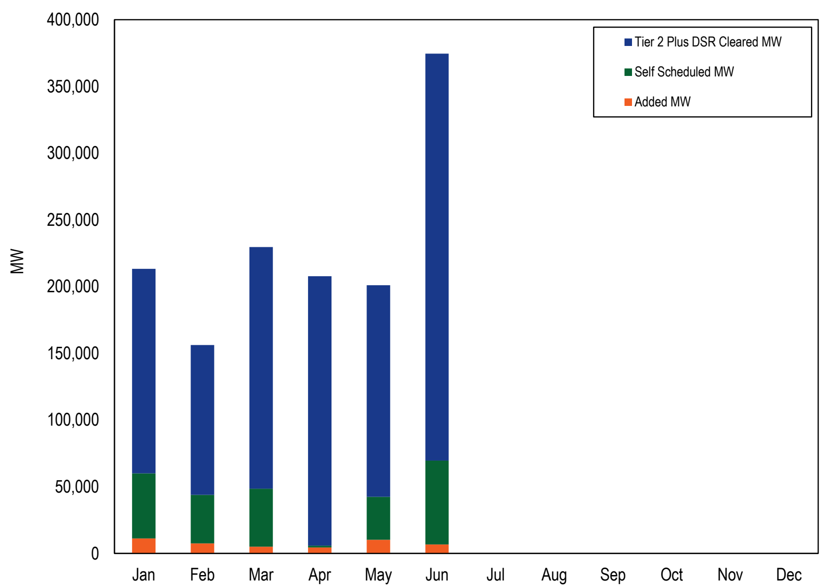
The weighted average price for synchronized reserve in the PJM Mid-Atlantic Subzone of the RFC Synchronized Reserve Market in January through June 2012 was $6.32 while the corresponding cost of synchronized reserve was $8.16. Both price and cost are a significant reduction from the price ($12.18) and cost ($15.82) for the same period in 2011.

The RFC Synchronized Reserve requirement was satisfied by Tier 1 in all but two hours of January through June 2012. Both hours occurred in June with clearing prices of $0.04 and $0.50 respectively. The Southern Synchronized Reserve Zone cleared a market in 94 hours of January through June 2012 with a weighted average clearing price of $20.47.

## Price and Cost

A price to cost ratio close to 1.0 is an indicator of an efficient market design, where the costs are the result of the economic solution. The primary reason for the relatively low actual price to cost ratio is the difference in opportunity cost calculated using the forecast LMP and the actual LMP. In addition, the low price to cost ratio is in part a result of out of market purchases of Tier 2 synchronized reserve when PJM dispatchers need the reserves for reliability reasons.

### Figure 9-12 Tier 2 synchronized reserve purchases by month for the Mid-Atlantic Subzone: January through June 2012 (See 2011 SOM, Figure 9-14)




In the Mid-Atlantic Subzone of the RFC Synchronized Reserve Market for January through June 2012, the cost of Tier 2 synchronized reserves was 21 percent higher than the weighted price. In January through June 2011, this difference was 23 percent (Figure 9-13).

### Figure 9-13 Impact of Tier 2 synchronized reserve added MW to the RFC Synchronized Reserve Zone, Mid-Atlantic Subzone: January through June 2012 (See 2011 SOM, Figure 9-15)

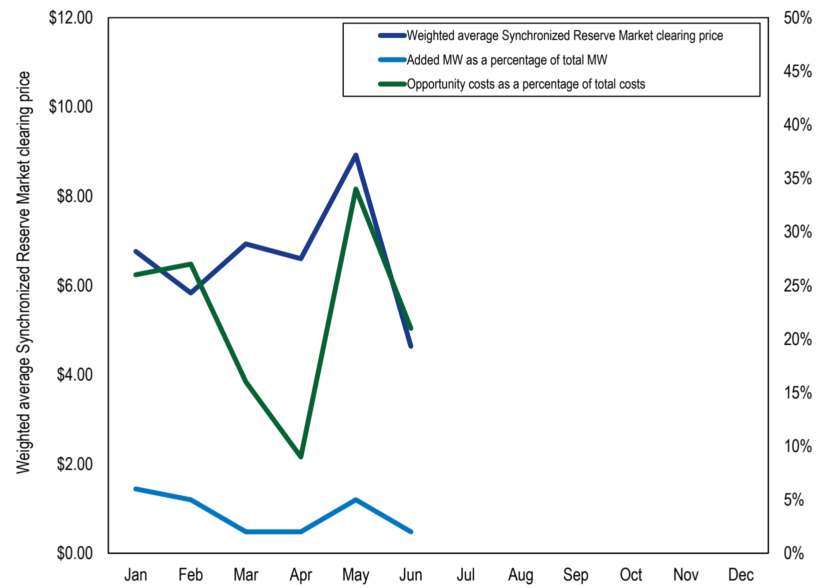


Figure 9-14 Comparison of Mid-Atlantic Subzone Tier 2 synchronized reserve weighted average price and cost (Dollars per MW): January through June 2012 (See 2011 SOM, Figure 9-16)

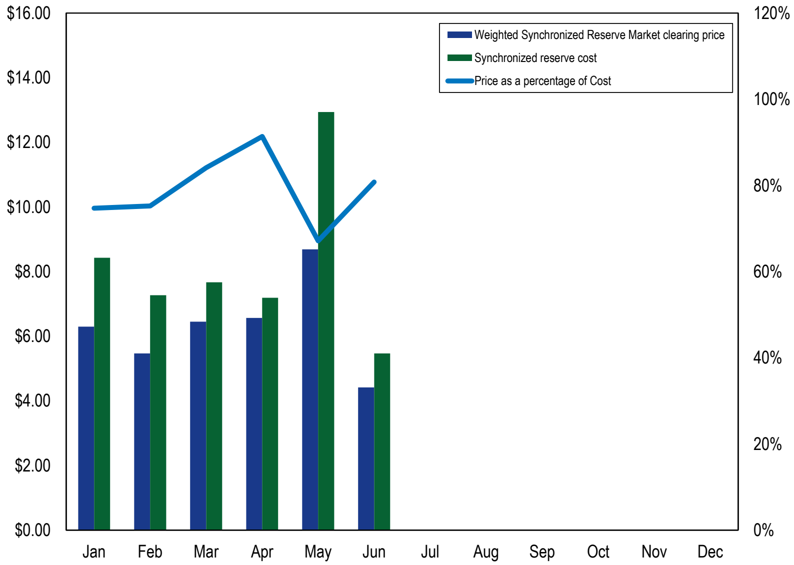



Table 9-15 shows the price and cost history of the Synchronized Reserve Market since 2005.

Table 9-15 Comparison of weighted average price and cost for PJM Synchronized Reserve, January through June, 2005 through 2012 (See 2011 SOM, Table 9-19)

| Year | Weighted Synchronized Reserve Market Price | Weighted Synchronized Reserve Cost | Synchronized Reserve Price as Percent of Cost |
|---|---|---|---|
| 2005 (Jan-Jun) | $11.77 | $15.52 | 76% |
| 2006 (Jan-Jun) | $12.10 | $18.25 | 66% |
| 2007 (Jan-Jun) | $20.08 | $22.89 | 88% |
| 2008 (Jan-Jun) | $11.86 | $17.46 | 68% |
| 2009 (Jan-Jun) | $5.89 | $10.15 | 58% |
| 2010 (Jan-Jun) | $8.92 | $12.13 | 74% |
| 2011 (Jan-Jun) | $12.18 | $15.72 | 77% |
| 2012 (Jan-Jun) | $6.32 | $8.16 | 77% |

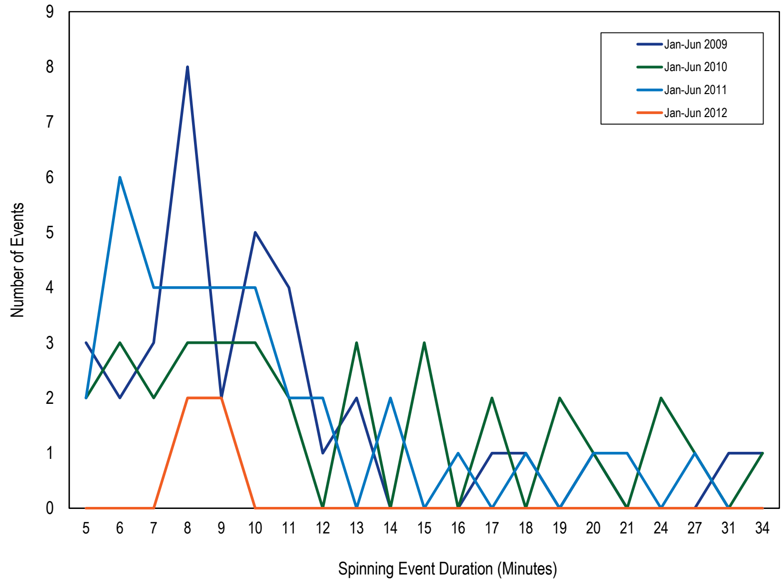
Spinning events (Table 9-16) are usually caused by a sudden generation outage or transmission disruption requiring PJM to load primary synchronized reserve (spinning reserve).[27] The reserve remains loaded until system balance is recovered. From January 2009 through June 2012 PJM experienced 116 spinning events. This is almost three events per month. Spinning events generally lasted between 7 minutes and 20 minutes with an average length of 11.5 minutes, although several events have lasted longer than 30 minutes.

27 See PJM. "Manual 12, Balancing Operations," Revision 24 (April 3, 2012), pp. 36-37.

## Table 9-16 Spinning Events, January 2009 through June 2012 (See 2011 SOM, Table 9-20)

| 2009 | | | 2010 | | | 2011 | | | 2012 | | |
|---|---|---|---|---|---|---|---|---|---|---|---|
| Effective Time | Region | Duration (Minutes) | Effective Time | Region | Duration (Minutes) | Effective Time | Region | Duration (Minutes) | Effective Time | Region | Duration (Minutes) |
| JAN-17-2009 09:37 | RFC | 7 | FEB-18-2010 13:27 | Mid-Atlantic | 19 | JAN-11-2011 15:10 | Mid-Atlantic | 6 | JAN-03-2012 16:51 | RFC | 9 |
| JAN-20-2009 17:33 | RFC | 10 | MAR-18-2010 11:02 | RFC | 27 | FEB-02-2011 01:21 | RFC | 5 | JAN-06-2012 23:25 | RFC | 8 |
| JAN-21-2009 11:52 | RFC | 9 | MAR-23-2010 20:14 | RFC | 13 | FEB-08-2011 22:41 | Mid-Atlantic | 11 | JAN-23-2012 15:02 | Mid-Atlantic | 8 |
| FEB-18-2009 18:38 | Mid-Atlantic | 10 | APR-11-2010 13:12 | RFC | 9 | FEB-09-2011 11:40 | Mid-Atlantic | 16 | MAR-02-2012 19:54 | RFC | 9 |
| FEB-19-2009 11:01 | RFC | 6 | APR-28-2010 15:09 | Mid-Atlantic | 8 | FEB-13-2011 15:35 | Mid-Atlantic | 14 | | | |
| FEB-28-2009 06:19 | RFC | 5 | MAY-11-2010 19:57 | Mid-Atlantic | 9 | FEB-24-2011 11:35 | Mid-Atlantic | 14 | | | |
| MAR-03-2009 05:20 | Mid-Atlantic | 11 | MAY-15-2010 03:03 | RFC | 6 | FEB-25-2011 14:12 | RFC | 10 | | | |
| MAR-05-2009 01:30 | Mid-Atlantic | 43 | MAY-28-2010 04:06 | Mid-Atlantic | 5 | MAR-30-2011 19:13 | RFC | 12 | | | |
| MAR-07-2009 23:22 | RFC | 11 | JUN-15-2010 00:46 | RFC | 34 | APR-02-2011 13:13 | Mid-Atlantic | 11 | | | |
| MAR-23-2009 23:40 | Mid-Atlantic | 10 | JUN-19-2010 23:49 | Mid-Atlantic | 9 | APR-11-2011 00:28 | RFC | 6 | | | |
| MAR-23-2009 23:42 | RFCNonMA | 8 | JUN-24-2010 00:56 | RFC | 15 | APR-16-2011 22:51 | RFC | 9 | | | |
| MAR-24-2009 13:20 | Mid-Atlantic | 8 | JUN-27-2010 19:33 | Mid-Atlantic | 15 | APR-21-2011 20:02 | Mid-Atlantic | 6 | | | |
| MAR-25-2009 02:29 | RFC | 9 | JUL-07-2010 15:20 | RFC | 8 | APR-27-2011 01:22 | RFC | 8 | | | |
| MAR-26-2009 13:08 | RFC | 10 | JUL-16-2010 20:45 | Mid-Atlantic | 19 | MAY-02-2011 00:05 | Mid-Atlantic | 21 | | | |
| MAR-26-2009 18:30 | Mid-Atlantic | 20 | AUG-11-2010 19:09 | RFC | 17 | MAY-12-2011 19:39 | RFC | 9 | | | |
| APR-24-2009 16:43 | RFC | 11 | AUG-13-2010 23:19 | RFC | 6 | MAY-26-2011 17:17 | Mid-Atlantic | 20 | | | |
| APR-26-2009 03:04 | Mid-Atlantic | 5 | AUG-16-2010 07:08 | RFC | 17 | MAY-27-2011 12:51 | RFC | 6 | | | |
| MAY-03-2009 15:07 | RFC | 10 | AUG-16-2010 19:39 | Mid-Atlantic | 11 | MAY-29-2011 09:04 | RFC | 7 | | | |
| MAY-17-2009 07:41 | RFC | 5 | SEP-15-2010 11:20 | RFC | 13 | MAY-31-2011 16:36 | RFC | 27 | | | |
| MAY-21-2009 21:37 | RFC | 13 | SEP-22-2010 15:28 | Mid-Atlantic | 24 | JUN-03-2011 14:23 | RFC | 7 | | | |
| JUN-18-2009 17:39 | RFC | 12 | OCT-05-2010 17:20 | RFC | 10 | JUN-06-2011 22:02 | Mid-Atlantic | 9 | | | |
| JUN-30-2009 00:17 | Mid-Atlantic | 8 | OCT-16-2010 03:22 | Mid-Atlantic | 10 | JUN-23-2011 23:26 | RFC | 8 | | | |
| JUL-26-2009 19:07 | RFC | 18 | OCT-16-2010 03:25 | RFCNonMA | 7 | JUN-26-2011 22:03 | Mid-Atlantic | 10 | | | |
| JUL-31-2009 02:01 | RFC | 6 | OCT-27-2010 10:35 | RFC | 7 | JUL-10-2011 11:20 | RFC | 10 | | | |
| AUG-15-2009 21:07 | RFC | 17 | OCT-27-2010 12:50 | Mid-Atlantic | 10 | JUL-28-2011 18:49 | RFC | 12 | | | |
| SEP-08-2009 10:12 | Mid-Atlantic | 8 | NOV-26-2010 14:24 | RFC | 13 | AUG-02-2011 01:08 | RFC | 6 | | | |
| SEP-29-2009 16:20 | RFC | 7 | NOV-27-2010 11:34 | RFC | 8 | AUG-18-2011 06:45 | Mid-Atlantic | 6 | | | |
| OCT-01-2009 10:13 | RFC | 11 | DEC-08-2010 01:19 | RFC | 11 | AUG-19-2011 14:49 | RFC | 5 | | | |
| OCT-18-2009 22:40 | Mid-Atlantic | 8 | DEC-09-2010 20:07 | RFC | 5 | AUG-23-2011 17:52 | RFC | 7 | | | |
| OCT-26-2009 01:01 | RFC | 7 | DEC-14-2010 12:02 | Mid-Atlantic | 24 | SEP-24-2011 15:48 | RFC | 8 | | | |
| OCT-26-2009 11:05 | RFC | 13 | DEC-16-2010 18:40 | Mid-Atlantic | 20 | SEP-27-2011 14:20 | RFC | 7 | | | |
| OCT-26-2009 19:55 | RFC | 8 | DEC-17-2010 22:09 | Mid-Atlantic | 6 | SEP-27-2011 16:47 | RFC | 9 | | | |
| NOV-20-2009 15:30 | RFC | 8 | DEC-29-2010 19:01 | Mid-Atlantic | 15 | OCT-30-2011 22:39 | Mid-Atlantic | 10 | | | |
| DEC-09-2009 22:34 | Mid-Atlantic | 34 | | | | DEC-15-2011 14:35 | Mid-Atlantic | 8 | | | |
| DEC-09-2009 22:37 | RFCNonMA | 31 | | | | DEC-21-2011 14:26 | RFC | 18 | | | |
| DEC-14-2009 11:11 | Mid-Atlantic | 8 | | | | | | | | | |

Figure 9-15 Spinning events duration distribution curve, January through June 2009 to 2012 (See 2011 SOM, Figure 9-17)




## Adequacy

A synchronized reserve deficit occurs when the combination of Tier 1 and Tier 2 synchronized reserve is not adequate to meet the synchronized reserve requirement. Neither PJM Synchronized Reserve Market, nor the Mid-Atlantic subzone of the RFC market experienced deficits in January through June 2012.

# Day Ahead Scheduling Reserve (DASR)

The Day-Ahead Scheduling Reserve Market is a market based mechanism for the procurement of supplemental, 30-minute reserves on the PJM System.[28]

The DASR 30-minute reserve requirements are determined by the reliability region.[29] In the Reliability*First* (RFC) region, reserve requirements are calculated based on historical under-forecasted load rates and generator forced outage rates.[30] If the DASR Market does not result in procuring adequate scheduling reserves, PJM is required to schedule additional operating reserves.

## Market Structure

In January through June 2012, the required DASR was 7.03 percent of peak load forecast, up from 7.11 percent in 2011.[31] DASR MW purchased increased by 9 percent in January through June 2012 over the same period in 2011, from 26.4 MMW to 28.9 MMW.

In January through June 2012, zero hours failed the three pivotal supplier test in the DASR Market. Zero hours failed the pivotal supplier test during the same period in 2011.

Load response resources which are registered in PJM's Economic Load Response and are dispatchable by PJM are also eligible to provide DASR, but remained insignificant. No demand side resources cleared the DASR market in January through June 2012.

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

Economic withholding remains an issue in the DASR Market. The marginal cost of providing DASR is zero. Between January and June, 2012, twelve percent of all units offered DASR at levels above $5 per MW. The impact on DASR prices of high offers was minor as a result of a favorable balance between supply and demand.

## Market Performance

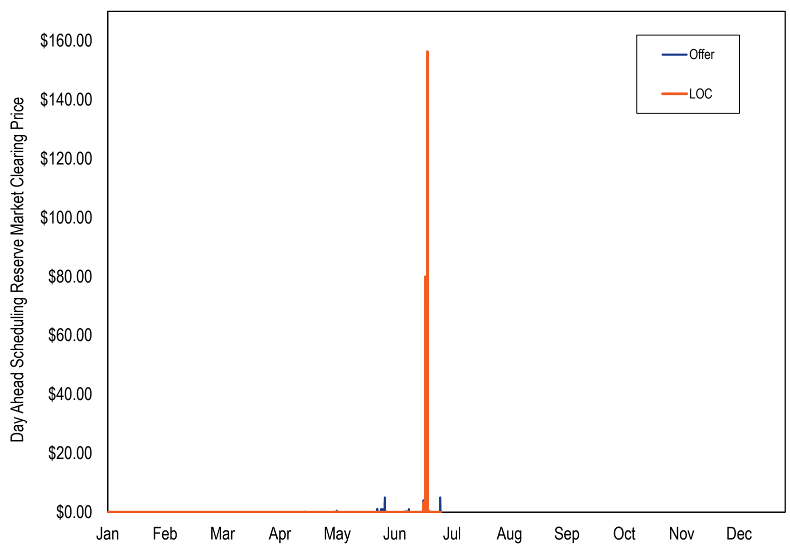
For 89 percent of hours in January through June 2012 DASR cleared at a price of $0.00. (Figure 9-16)

28 PJM uses the terms "supplemental operating reserves" and "scheduling operating reserves" interchangeably.
29 PJM. "Manual 13, Emergency Requirements," Revision 48 (April 3, 2012), pp. 11-12.
30 PJM. "Manual 10, Pre-Scheduling Operations," Revision 25 (January 1, 2010), p. 17.
31 See the *2011 State of the Market Report for PJM*, Volume II, Section 9, "Ancillary Services" at Day Ahead Scheduling Reserve (DASR).
32 PJM. "Manual 11, Emergency and Ancillary Services Operations," Revision 50 (April 3, 2012), p. 122.

Table 9-17 PJM Day-Ahead Scheduling Reserve Market MW and clearing prices: January through June 2011 and 2012 (See 2011 SOM, Table 9-21)

| Year | Month | Average Required Hourly DASR (MW) | Minimum Clearing Price | Maximum Clearing Price | Weighted Average Clearing Price | Total DASR MW Purchased | Total DASR Credits |
|---|---|---|---|---|---|---|---|
| 2011 | Jan | 6,536 | $0.00 | $1.00 | $0.03 | 4,862,520 | $127,837 |
| 2011 | Feb | 6,180 | $0.00 | $1.00 | $0.02 | 4,152,665 | $61,682 |
| 2011 | Mar | 5,720 | $0.00 | $1.00 | $0.01 | 4,249,733 | $45,885 |
| 2011 | Apr | 5,265 | $0.00 | $0.05 | $0.01 | 3,790,932 | $24,463 |
| 2011 | May | 5,554 | $0.00 | $25.52 | $0.29 | 4,132,056 | $894,607 |
| 2011 | Jun | 7,305 | $0.00 | $193.97 | $2.26 | 5,259,795 | $9,653,815 |
| 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 |

Figure 9-16 Hourly components of DASR clearing price: January through June 2012 (See 2011 SOM, Figure 9-18)




## Black Start Service

Black start service is necessary to help 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 with a high operating factor to automatically remain operating at reduced levels 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 all costs associated with providing this service.

PJM ensures the availability of black start by charging transmission customers according to their zonal load ratio share and compensating black start unit owners according to an incentive rate or their revenue requirements (Table 9-18).

In January through June 2012, charges were $12.7 million. This is 108 percent higher than January through June 2011, when total black start service charges were $6.1 million. There was substantial zonal variation. Black start zonal charges in January through June 2012 ranged from $0.02 per MW in the ATSI zone to $2.10 per MW in the AEP zone.

The increased cost of black start is attributable to updated Schedule 6A (to the OATT) rates for all units, major refurbishments of black start resources in the BGE zone, and operating reserve charges associated with black start resources that should have been included in black start charges. The black start charges in Table 9-18 include an estimated $4.51 million of charges that were allocated to customers as operating reserve charges but that were in fact to pay for the operation of ALR black start units.[33]

33 The $4.51 million is included in operating reserves. See the *2012 State of the Market Report for PJM: January through June*, Section 3, "Operating Reserves", at "Operating Reserve Charges."

### Table 9-18 Black start yearly zonal charges for network transmission use: January through June 2012 (See 2011 SOM, Table 9-22)

| ZONE | Network Charges | Black Start Rate ($/MW) |
|---|---:|---:|
| AECO | $279,082 | $0.52 |
| AEP | $4,851,035 | $2.10 |
| AP | $84,858 | $0.05 |
| ATSI | $42,561 | $0.02 |
| BGE | $1,634,774 | $1.24 |
| ComEd | $2,121,455 | $0.49 |
| DAY | $84,686 | $0.13 |
| DEOK | $123,239 | $0.12 |
| DLCO | $20,212 | $0.04 |
| DPL | $256,414 | $0.33 |
| JCPL | $256,168 | $0.21 |
| Met-Ed | $253,734 | $0.45 |
| PECO | $535,873 | $0.33 |
| PENELEC | $189,403 | $0.33 |
| Pepco | $174,517 | $0.14 |
| PPL | $70,236 | $0.05 |
| PSEG | $1,708,174 | $0.86 |