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 (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.

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- 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 44 percent of the hours in January through September 2012.[5]
- 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.[6]
- 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 24 percent of the hours in January through September 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 17 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 These TPS results reflect MMU estimates for the period between May 6 and July 21, 2012, when the TPS test was not correctly applied by PJM.

6 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.

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Highlights

- The weighted average Regulation Market clearing price, including opportunity cost, for January through September 2012 was $14.92 per MW.[7] This was a decrease of $2.11, or 12.4 percent, from the average price for regulation in January through September 2011. The total cost of regulation decreased by $12.13 from $32.71 per MW in January through September 2011, to $20.58, or 37.1 percent. In January through September 2012, the weighted Regulation Market clearing price was 72 percent of the total regulation cost per MW, compared to 52 percent of the total regulation cost per MW in January through September 2011.
- The weighted average Tier 2 Synchronized Reserve Market clearing price in the Mid-Atlantic Subzone was $7.06 per MW in January through September 2012, a $4.94 per MW decrease from January through September 2011.[7] The total cost of synchronized reserves per MW in January through September 2012, was $10.96, a 23 percent decrease from the total cost of synchronized reserves ($14.21) during January through September 2011. The weighted average Synchronized Reserve Market clearing price was 64 percent of the weighted average total cost per MW of synchronized reserve in January through September 2012. The price to cost ratio was 84 percent in January through September 2011.
- The weighted DASR market clearing price was $0.91 per MW in January through September 2012. In January through September 2011, the weighted price of DASR was $1.04 per MW. The average hourly purchased DASR was 7,042 MW, an increase from 6,622 MW during the same period of 2011, reflecting PJM's larger footprint with the integration of DEOK on January 1, 2012.
- Black start zonal charges in January through September 2012 ranged from $0.02 per MW in the ATSI zone to $1.80 per MW in the BGE zone.

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.

Ancillary services costs per MW of load: 2001 - 2012

Table 9-4 shows PJM ancillary services costs for January through September 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 September, 2001 through 2012 (See 2011 SOM, Table 9-4)

Year (Jan-Sep)	Regulation	Scheduling, Dispatch, and System Control	Reactive	Synchronized Reserve	Supplementary Operating Reserve
2001	$0.55	$0.43	$0.22	$0.00	$1.18
2002	$0.47	$0.52	$0.21	$0.00	$0.66
2003	$0.53	$0.59	$0.23	$0.09	$0.88
2004	$0.50	$0.64	$0.25	$0.14	$0.90
2005	$0.78	$0.47	$0.25	$0.11	$0.88
2006	$0.55	$0.48	$0.28	$0.07	$0.44
2007	$0.65	$0.47	$0.29	$0.06	$0.58
2008	$0.75	$0.34	$0.29	$0.07	$0.55
2009	$0.36	$0.36	$0.36	$0.05	$0.47
2010	$0.37	$0.38	$0.36	$0.06	$0.75
2011	$0.35	$0.36	$0.39	$0.09	$0.87
2012	$0.23	$0.44	$0.44	$0.03	$0.75

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 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

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."

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

Regulation Market

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

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 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

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".
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).

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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, average 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 September of 2012, to 9,413 MW from 8,808 MW in the same time period of 2011.

Table 9-5 PJM regulation capability, daily offer[16] and hourly eligible: January through September 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	9,413	6,656	71%	3,089	33%
Off Peak	9,413			3,025	32%
On Peak	9,413			3,164	34%

The supply of regulation can be affected by regulating units retiring from service. Table 9-6 shows what the impact on the Regulation Market would be if all units retire that are requesting retirement 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-Sep, 2012	Settled MW, Jan-Sep, 2012	Units Scheduled To Retire Through 2015	Settled MW of Units Scheduled To Retire Through 2015	Percent Of Regulation MW To Retire Through 2015
296	7,608,983	52	171,402	2.25%

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. The requirement is 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.

Table 9-7 PJM Regulation Market required MW and ratio of eligible supply to requirement: January through September 2012 and 2011 (See 2011 SOM, Table 9-6)

Month	Average Required Regulation, January Through September 2011	Average Required Regulation, January Through September 2012	Ratio of Supply To Requirement, January Through September 2011	Ratio of Supply To Requirement, January Through September 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	1,037	1,055	2.81	3.21
Jul	1,214	1,246	2.79	2.94
Aug	1,093	1,134	2.83	2.97
Sep	922	941	2.74	3.33

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.")

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.

Market Concentration

Table 9-8 shows Herfindahl-Hirschman Index (HHI) results for the January through September 2012 period. The average HHI of 1529 is classified as moderately concentrated.

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

Market Type	Minimum HHI	Weighted Average HHI	Maximum HHI
Cleared Regulation, January through September, 2012	810	1529	4962
Cleared Regulation, January through September, 2011	818	1645	3683

Figure 9-1 compares the January through September 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 September of 2010, 2011 and 2012 (See 2011 SOM, Figure 9-1)

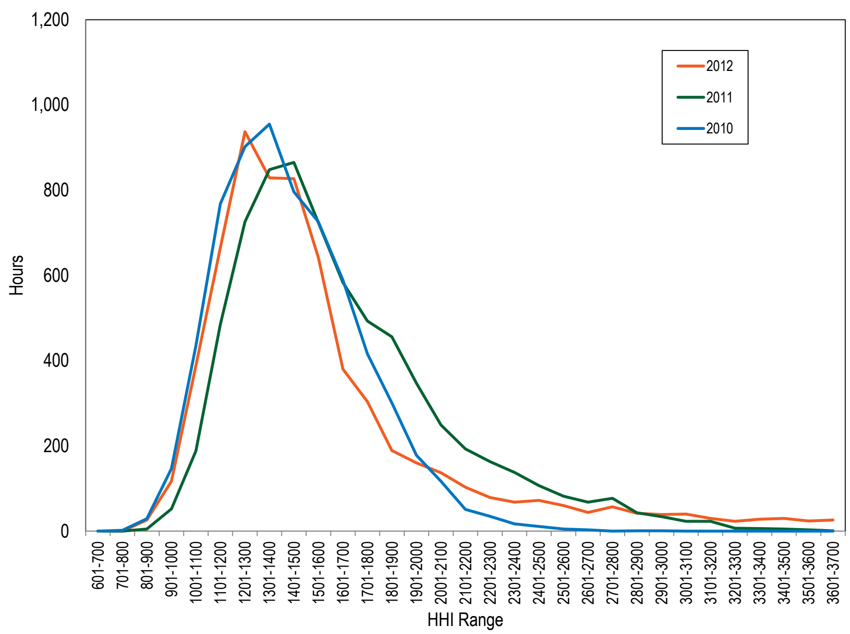

Table 9-9 includes a monthly summary of three pivotal supplier results. In January through September 2012, 44 percent of hours had one or more pivotal suppliers which failed or should have failed PJM's three pivotal supplier test.[18]

The MMU concludes from these results that the PJM Regulation Market in January through September 2012 was characterized by structural market power in 44 percent of the hours.

Table 9-9 Regulation market monthly three pivotal supplier results: January through September 2010, 2011 and 2012 (See 2011 SOM, Table 9-9)[19]

	2012	2011	2010
Month	2012 Percent of Hours Pivotal	2011 Percent of Hours Pivotal	2010 Percent of Hours Pivotal
Jan	71%	95%	74%
Feb	67%	93%	70%
Mar	64%	94%	83%
Apr	41%	97%	82%
May	*37%	95%	79%
Jun	*40%	89%	81%
Jul	*13%	89%	75%
Aug	32%	83%	69%
Sep	35%	87%	70%

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)[20]

18 The MMU monitors the application of the TPS test by PJM and brings any issues to the attention of PJM.
19 The results for May, June and July, 2012 are MMU estimates.
20 See PJM "Manual 28: Operating Agreement Accounting," Revision 54, (October 1, 2012); para 4.2, pp 15-16.

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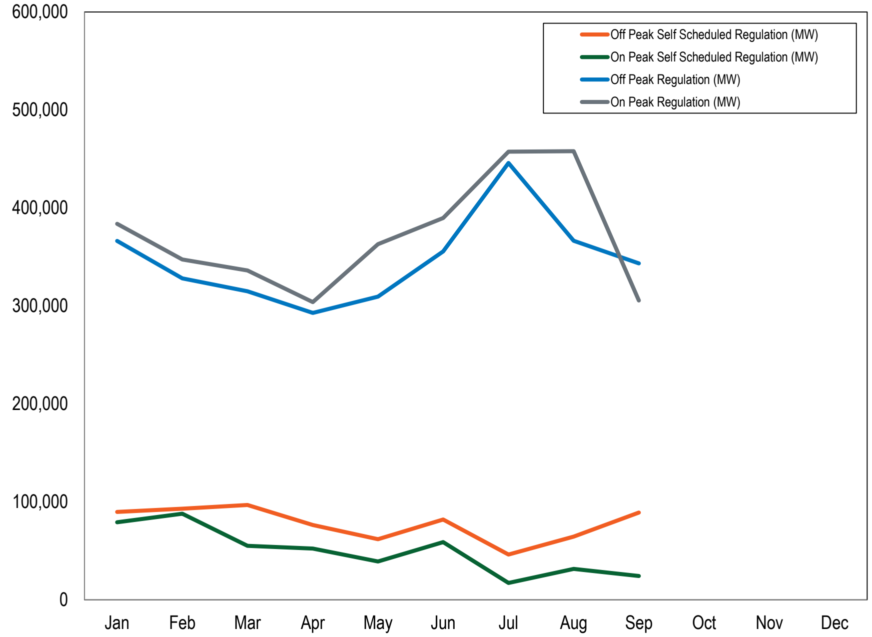
Figure 9-2 Off peak and on peak regulation levels: January through September 2012 (See 2011 SOM, Figure 9-2)



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 September 2012, 80 percent was purchased in the spot market (84 percent in January through September 2011), 17 percent was self-scheduled (13 percent in January through September 2011), and 3 percent was purchased bilaterally (3 percent in January through September 2011) (Table 9-10).

Table 9-10 Regulation sources: spot market, self-scheduled, bilateral purchases: January through September 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
Jul	819,897	63,415	19,711	903,024
Aug	710,715	95,949	17,687	824,350
Sep	515,732	113,351	19,726	648,809

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.[21] 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 and clear a more expensive unit resulting in a higher Regulation Market Clearing Price.

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

Market Performance

Price

The weighted average regulation market clearing price for January through September, 2012, was $14.92. This is a 12.4 percent decrease from the weighted average market clearing price of $17.03 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. Table 9-11 shows monthly average regulation market clearing price, average marginal unit offer price, and average marginal unit LOC. 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.[22]

The average offer (excluding opportunity cost) of the marginal unit for the PJM Regulation Market during January through September, 2012, was $7.60 per MWh, a decrease from the average offer in January through September 2011 of $10.43 (Table 9-11). The average opportunity cost of the marginal unit for the PJM Regulation Market in January through September 2012 was $6.18. This is a decrease from the average opportunity cost for the marginal unit during the same period of 2011 of $6.00. In the PJM Regulation Market the marginal unit opportunity cost was 42.9 percent of the RMCP. This is an decrease from the January through September, 2011, average of 63.5 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 September 2012 (See 2011 SOM, Figure 9-3)

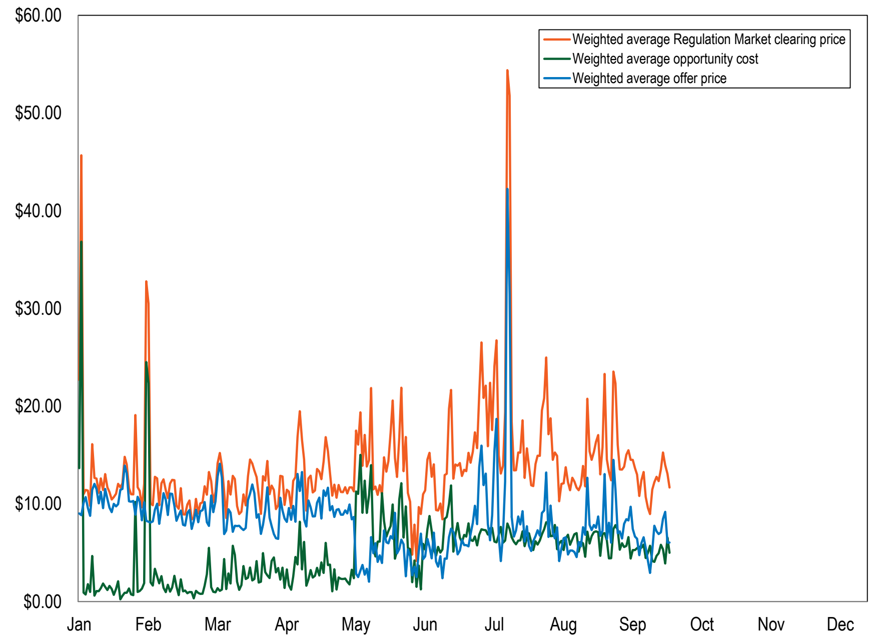


Figure 9-4 shows the level of demand for regulation by month in January through June 2012 and the corresponding level of regulation price.

22 See PJM. "Manual 28: Operating Agreement, Accounting," Revision 54, Section 4.2, "Regulation Credits" (October 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.

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Table 9-11 PJM Regulation Market monthly weighted average market-clearing price, marginal unit opportunity cost and offer price (Dollars per MWh): January through September 2012 (New Table)

Month	Weighted Average Regulation Market Clearing Price	Weighted Average Regulation Marginal Unit Offer	Weighted Average Regulation Marginal Unit LOC
Jan	$13.27	$10.58	$2.70
Feb	$11.52	$8.84	$2.68
Mar	$12.30	$8.82	$3.48
Apr	$12.71	$8.63	$4.07
May	$16.80	$6.52	$9.89
Jun	$13.83	$6.21	$6.94
Jul	$19.32	$6.60	$10.70
Aug	$15.12	$6.50	$7.37
Sep	$13.67	$5.46	$7.16

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

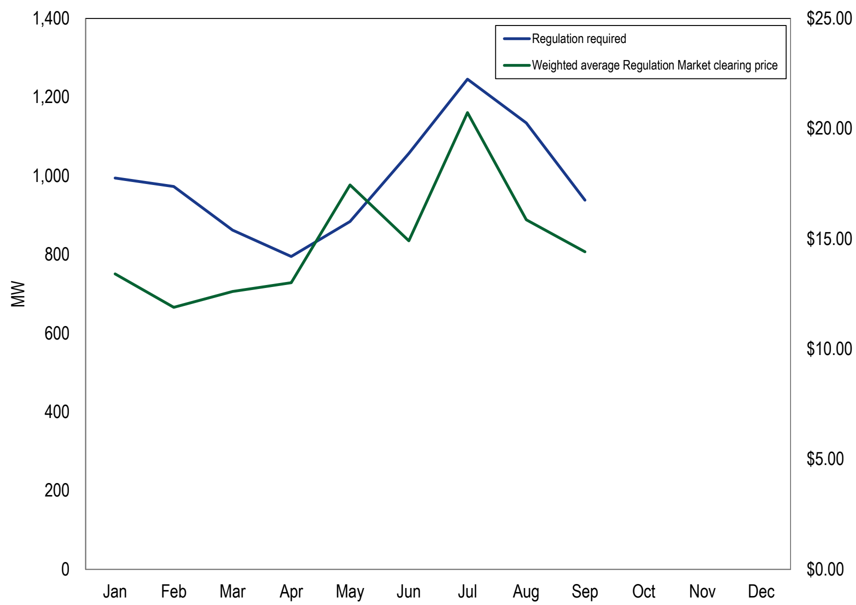
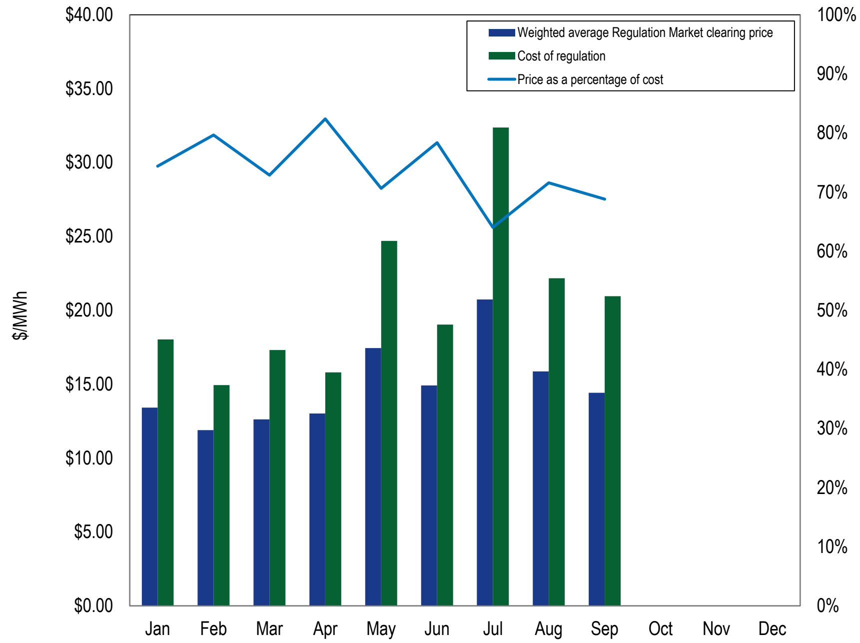


Figure 9-5 compares the regulation total cost per MWh (clearing price plus post market opportunity costs) with the regulation clearing price.

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



Total scheduled regulation MW, total regulation charges, regulation price and regulation cost are shown in Table 9-12.

Table 9-12 Total regulation charges: January through September 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
Jul	903,024	$29,228,039	$19.37	$20.73	$32.37
Aug	824,350	$18,273,264	$15.21	$15.86	$22.17
Sep	648,809	$13,593,245	$13.83	$14.41	$20.95

Table 9-13 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 less in January through September 2012 than it was in the same period of 2011.

Table 9-13 Comparison of average price and cost for PJM Regulation, January through September 2006 through 2012 (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	$17.03	$32.71	52%
2012	$14.92	$20.58	72%

Synchronized Reserve Market

PJM operates two synchronized reserve markets. 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.[23] 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.[24] From May 20, 2011, through the end of September 2011, 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 September 2012, the transfer capacity has remained at 15 percent.

Market Structure

Supply

In January through September, 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 1.26 for the Mid-Atlantic Subzone.[25] This is a 15.6 percent increase from the first six months of 2011 when the ratio was 1.09. Much of the required synchronized reserve is supplied from on-line (Tier 1) synchronized reserve resources. The ratio of offered and eligible synchronized reserve to the required Tier 2 for all cleared Tier 2 hours in January through September 2012 was 4.3 for the Mid-Atlantic Subzone. This is a 27 percent increase from January through September 2011 when the ratio was 3.09. 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

23 PJM.com "TrAIL Operational Impacts," <http://www.pjm.com/~/media/committees-groups/committees/oc/20111018/20111018-item-08-trail-operational-impacts.ashx> (October 2011).
24 See PJM, "Manual 11, Energy and Ancillary Services Market Operations," Revision 52 (October 1, 2012), p. 72.
25 The Synchronized Reserve Market in the Southern Region cleared in so few hours that related data for that market are not meaningful.

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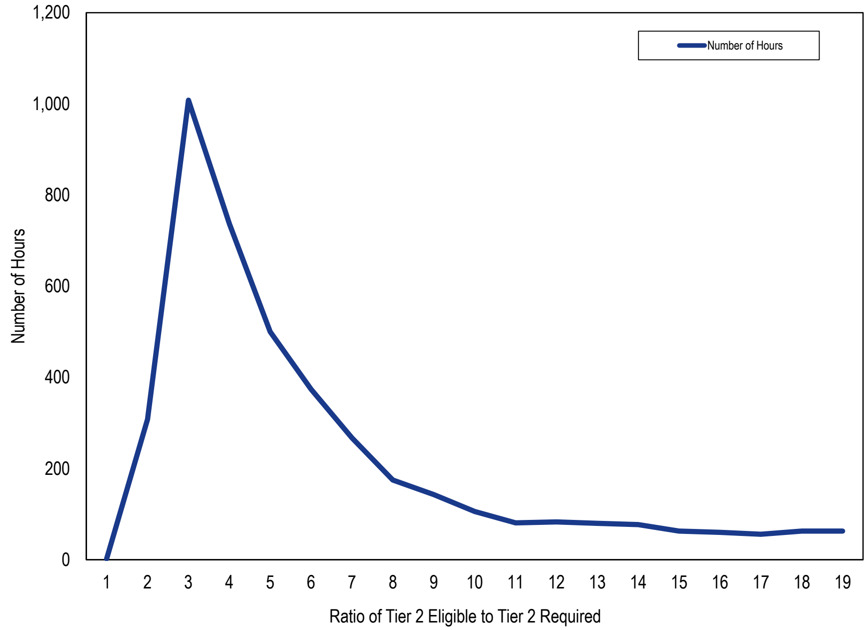
is usually a significant amount of Tier 1 synchronized reserve available. (See Figure 9-6)

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



Demand

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

In January through September, 2012, in the Mid-Atlantic Subzone, a Tier 2 synchronized reserve market was cleared in 69 percent of hours compared to 79 percent of hours for January through September 2011. In January through September, 2012, the average required Tier 2 synchronized reserve (including self-scheduled) for all cleared hours was 388 MW. In January through September, 2011, the average required Tier 2 synchronized reserve was 448 MW.

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.[26]

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 September, 2012. For the Mid-Atlantic Subzone the requirement was 1,300 MW for January through September, 2012. (Table 9-14)

Table 9-14 Synchronized Reserve Market required MW, RFC Zone and Mid-Atlantic Subzone, December 2008 through September 2012 (See 2011 SOM, Table 9-16)

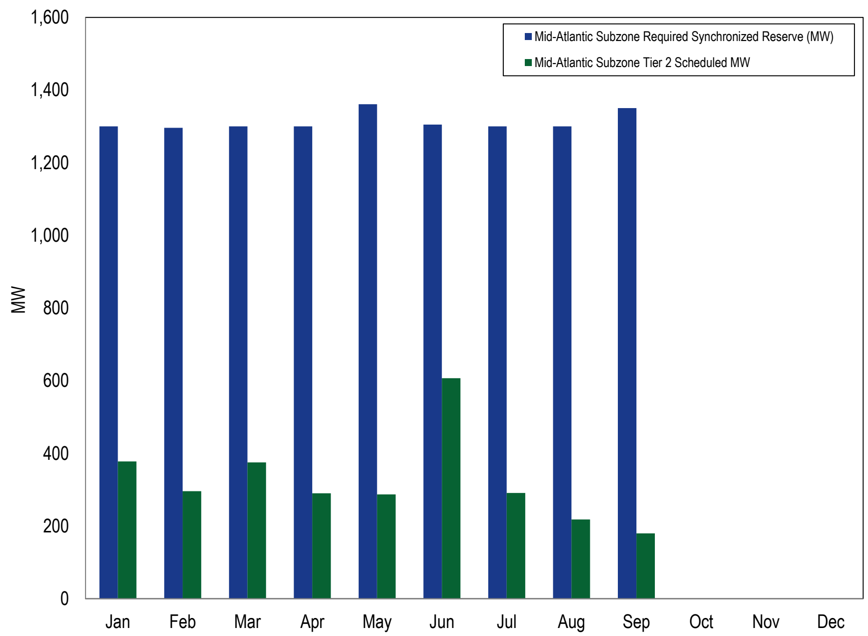
Mid-Atlantic Subzone			RFC Synchronized Reserve Zone		
From Date	To Date	Required MW	From Date	To Date	Required MW
May 10, 2008	May 8, 2010	1,150	May 10, 2008	Jan 1, 2009	1,305
May 8, 2010	Jul 13, 2010	1,200	Jan 1, 2009	Mar 15, 2010	1,320
July 13, 2010	Sep 30, 2012	1,300	Mar 15, 2010	Sep 30, 2012	1,350

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. The requirement in the Mid-Atlantic Subzone was raised to 1,716 MW from September 24 through 28.

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

Figure 9-7 shows the average monthly synchronized reserve required and the average monthly Tier 2 synchronized reserve MW scheduled during January through September 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 September 2012 (See 2011 SOM, Figure 9-7)

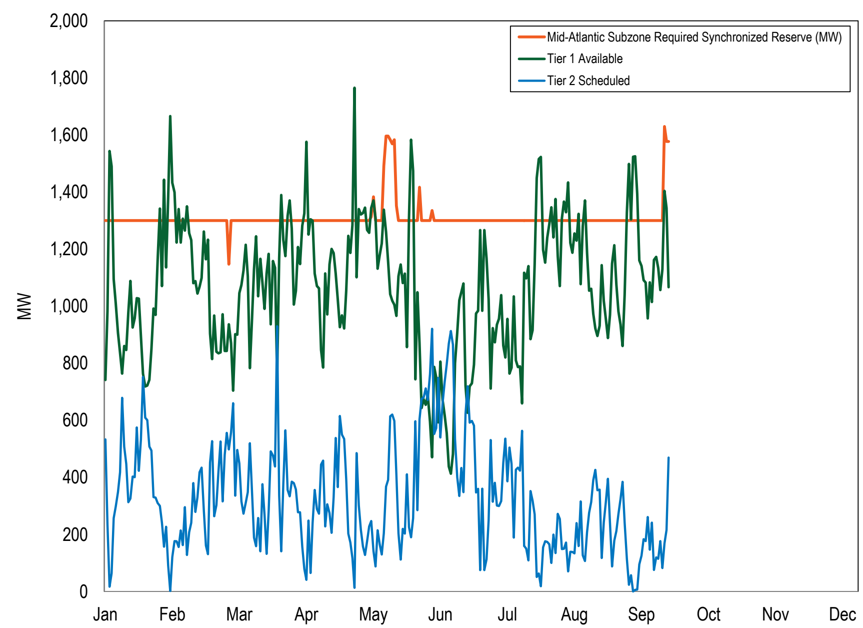


The RFC Synchronized Reserve Zone almost always has enough Tier 1 to cover its synchronized reserve requirement. Available Tier 1 in the western part of the RFC Synchronized Reserve Zone generally exceeds the total synchronized reserve requirement in the west. In January through September 2012, the RFC Synchronized Reserve Zone cleared a Tier 2 Synchronized Reserve Market in only four hours with an average SRMCP of $0.52. The Mid-Atlantic Subzone of the RFC Synchronized Reserve Zone cleared a separate Tier 2 market in 69 percent of all hours during January through September, 2012 at a weighted SRMCP of $7.06. 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 September 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 September 2012 (See 2011 SOM, Figure 9-9)



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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.[27] 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 September 2012 at a weighted average clearing price of $20.47.

Market Concentration

The RFC Tier 2 Synchronized Reserve Market was more concentrated in January through September 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 September 2012 RFC cleared Synchronized Reserve Market was 3202, which is defined as highly concentrated. The HHI for the Mid-Atlantic Subzone for the same period in 2011 was 2768. The largest hourly market share was 100 percent and 45 percent of all hours had a maximum market share greater than or equal to 40 percent (compared to 51 percent of all hours in January through September 2011).

In January through September, 2012, 24 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 56 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.

Table 9-15 Synchronized Reserve market monthly three pivotal supplier results: January through September 2011 and 2012 (See 2011 SOM, Table 9-9)

Month	2012 Percent of Hours Pivotal	2011 Percent of Hours Pivotal	2010 Percent of Hours Pivotal
Jan	45%	92%	64%
Feb	40%	99%	49%
Mar	38%	74%	65%
Apr	33%	83%	31%
May	15%	46%	45%
Jun	29%	14%	10%
Jul	10%	19%	23%
Aug	3%	25%	18%
Sep	4%	56%	17%

27 See PJM. "Manual 11: Energy & Ancillary Services Market Operations," Revision 51 (August 8, 2012), p. 66.

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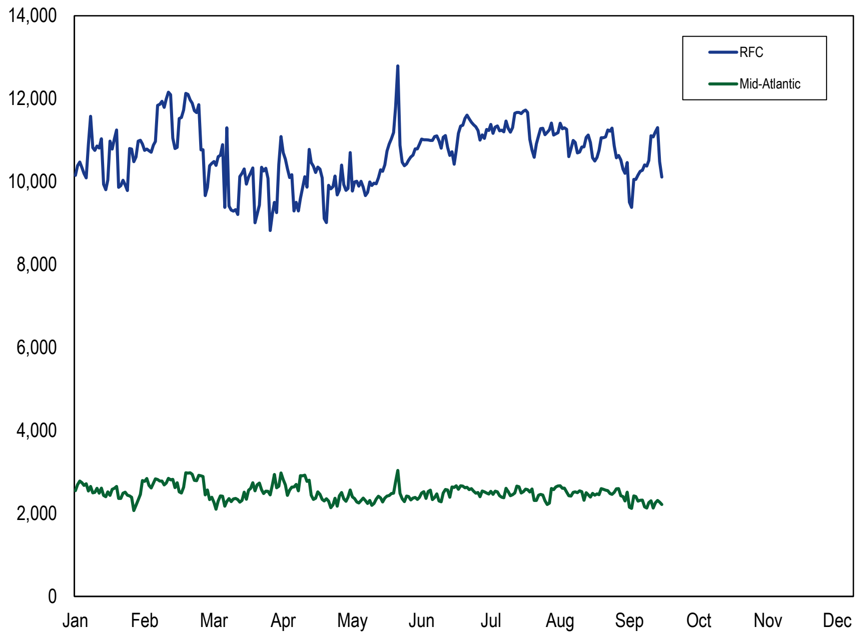
Market Conduct

Offers

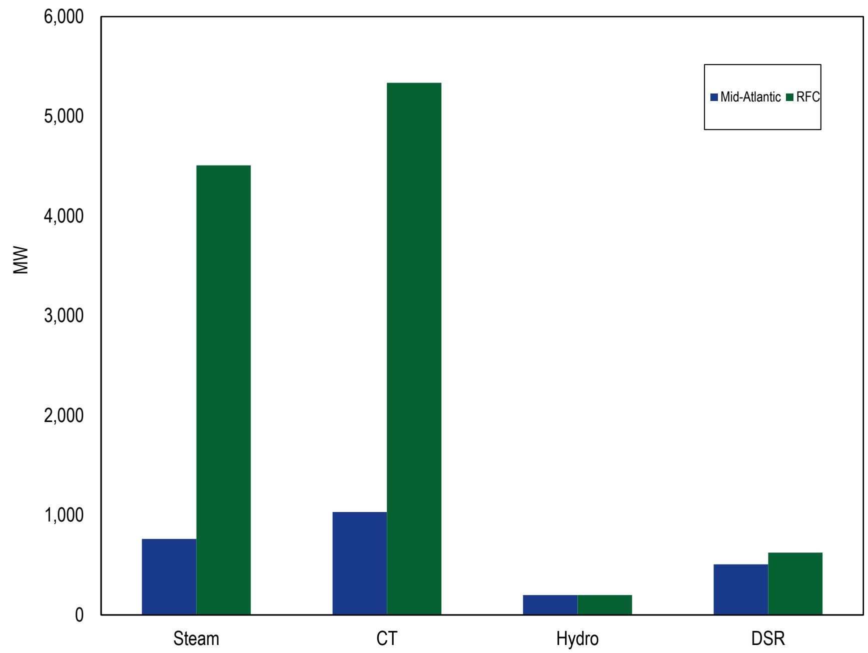
Figure 9-9 shows the daily average of hourly offered Tier 2 synchronized reserve MW.

Figure 9-9 Tier 2 synchronized reserve average hourly offer volume (MW): January through September 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 September 2012 (See 2011 SOM, Figure 9-11)



DSR

Demand-side resources were permitted to participate in the Synchronized Reserve Markets effective August, 2006. DSR has a significant impact on the Synchronized Reserve Market (Figure 9-10). In January through September 2012, DSR was 36 percent of all cleared Tier 2 synchronized reserves, compared to 21 percent for the same period in 2011. The reason is that Tier 2 demand was lower in the first nine months of 2012 than it was in the same time period of 2011 and DSR comprised a larger share of the bottom of the supply curve. In six percent of the hours in which a synchronized reserve market was cleared, all cleared MW were DSR compared to seven percent in January through September 2011. (See Table 9-16.) In the hours when all cleared MW

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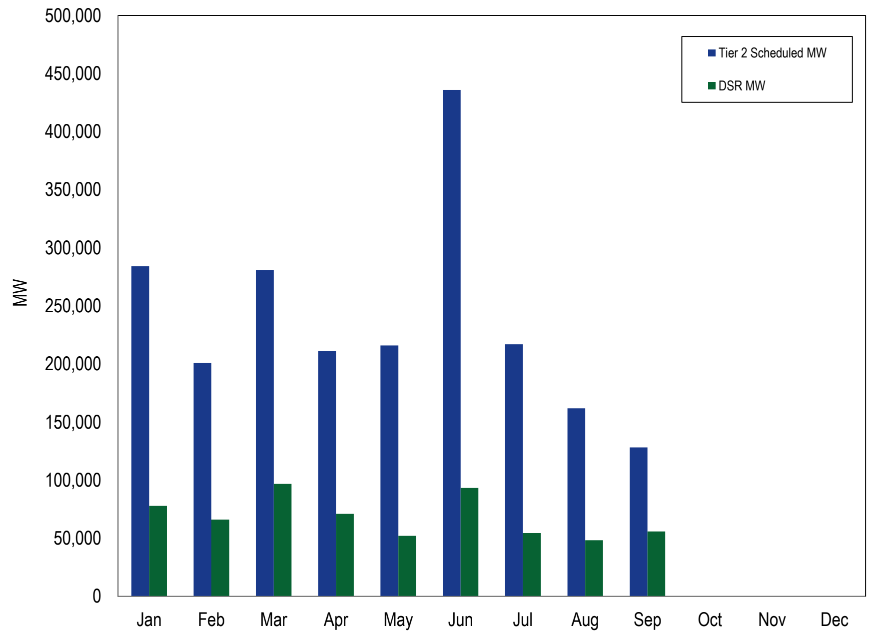
were DSR, the simple average SRMCP was $0.97. The simple average SRMCP for all cleared hours was $4.86.

Table 9-16 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 September 2010, 2011, 2012 (See 2011 SOM, Table 9-18)

Year	Month	Average SRMCP	Average SRMCP when all cleared synchronized reserve is DSR	Percent 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	$2.01	6%
2010	Apr	$7.84	$1.86	17%
2010	May	$9.98	$1.68	15%
2010	Jun	$9.61	$0.74	9%
2010	Jul	$16.30	$0.79	7%
2010	Aug	$11.17	$0.93	12%
2010	Sep	$10.45	$1.15	12%
2011	Jan	$9.31	$0.10	0%
2011	Feb	$10.58	NA	0%
2011	Mar	$9.70	$2.04	2%
2011	Apr	$12.64	$1.84	10%
2011	May	$8.64	$1.71	14%
2011	Jun	$9.05	$1.18	10%
2011	Jul	$12.33	$0.62	6%
2011	Aug	$8.25	$0.78	7%
2011	Sep	$9.05	$1.73	15%
2012	Jan	$5.47	$1.71	11%
2012	Feb	$4.90	$1.78	24%
2012	Mar	$5.60	$1.40	6%
2012	Apr	$5.01	$0.91	4%
2012	May	$9.29	$0.54	2%
2012	Jun	$4.05	$0.43	1%
2012	Jul	$9.88	$0.10	0%
2012	Aug	$5.61	$0.60	1%
2012	Sep	$4.74	$1.23	2%

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 September 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 September 2012 was $7.06 while the corresponding cost of synchronized reserve was $10.96. Both price and cost are lower than for the same period in 2011, when price was $12.00 and cost was $14.21.

The RFC Synchronized Reserve requirement was satisfied by Tier 1 in all but four hours of January through June 2012. The Southern Synchronized Reserve Zone cleared a market in 94 hours of January through September 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. In the Mid-Atlantic Subzone of the RFC Synchronized Reserve Market for January through September 2012, the price of Tier 2 synchronized reserves was 64 percent of the cost (Table 9-17 and Figure 9-12).

Figure 9-12 Comparison of Mid-Atlantic Subzone Tier 2 synchronized reserve weighted average price and cost (Dollars per MW): January through September 2012 (See 2011 SOM, Figure 9-16)

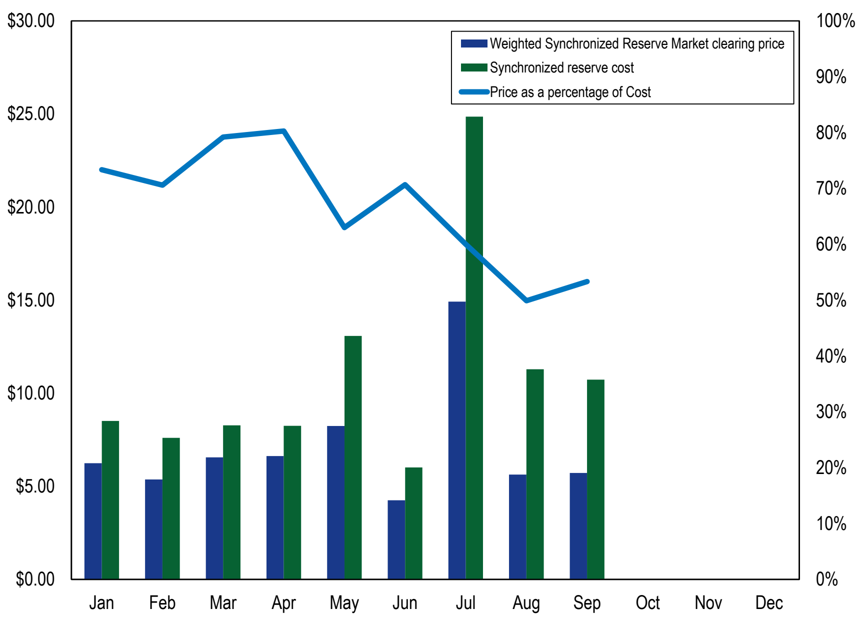


Table 9-17 shows the price and cost history of the Synchronized Reserve Market since 2005.

Table 9-17 Comparison of weighted average price and cost for PJM Synchronized Reserve, January through September, 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-Sep)	$12.81	$17.01	75%
2006 (Jan-Sep)	$14.40	$27.78	52%
2007 (Jan-Sep)	$18.24	$21.27	86%
2008 (Jan-Sep)	$10.87	$16.76	65%
2009 (Jan-Sep)	$6.38	$10.41	61%
2010 (Jan-Sep)	$11.51	$16.54	70%
2011 (Jan-Sep)	$12.00	$14.21	84%
2012 (Jan-Sep)	$7.06	$10.96	64%

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. The percentage of settled Tier 2 MW that was added by PJM dispatchers from January through September 2012, after market clearance was 6.6 percent (it was 3.2 percent in January through September 2011, 5.2 percent in January through September 2010, 11.6 percent in January through September 2009, and 68.8 percent in January through September 2008).

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Figure 9-13 Tier 2 synchronized reserve purchases by month for the Mid-Atlantic Subzone: January through September 2012 (See 2011 SOM, Figure 9-14)

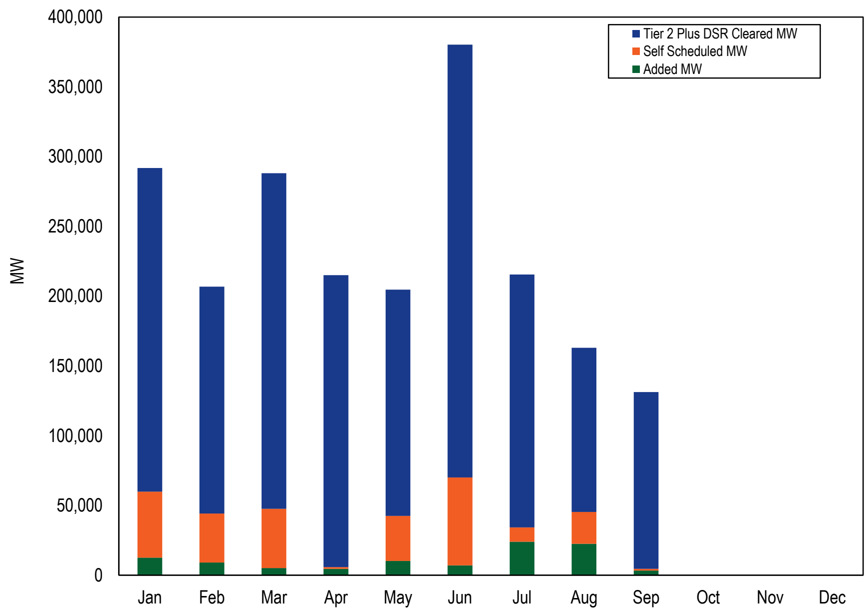
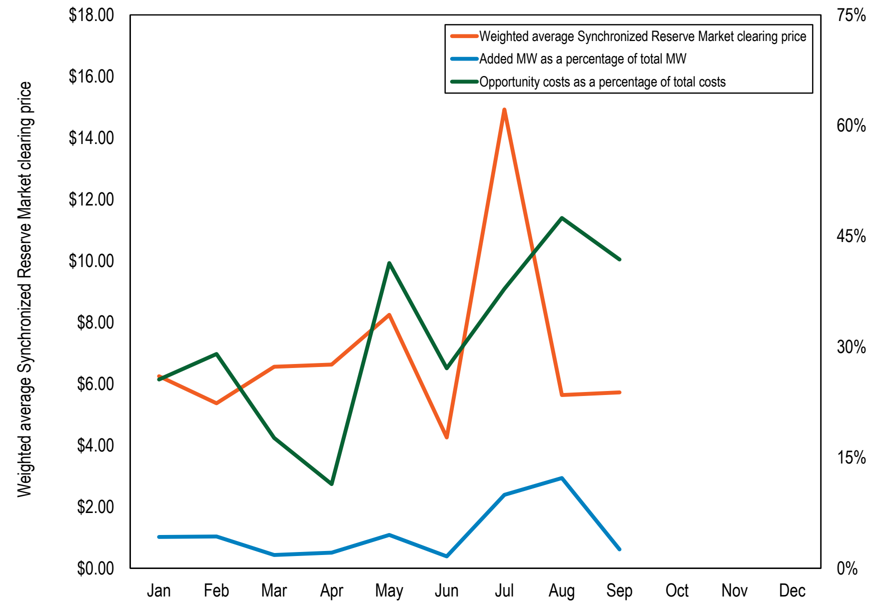


Figure 9-14 Impact of Tier 2 synchronized reserve added MW to the RFC Synchronized Reserve Zone, Mid-Atlantic Subzone: January through September 2012 (See 2011 SOM, Figure 9-15)



Tier 1 bias means the manual subtraction from (or addition to) the Tier 1 estimate that the market software uses to determine how much Tier 2 MW to buy. In 2010, PJM significantly increased its use of Tier 1 bias in market solutions. By subtracting from the estimated Tier 1 MW, PJM Market Operations forces the market software to purchase more Tier 2 MW than it estimates it needs. This reduces the need for PJM Dispatch to add Tier 2 MW after market clearance but means purchasing more Tier 2 MW than are required. Tier 1 bias is used to change the Synchronized Reserve requirement (1,300 MW in the Middle Atlantic subzone) hour to hour without explicit guidelines or explicit rationale. Table 9-18 includes information on PJM's use of Tier 1 bias since 2008. The use of this bias factor appears to mean that there is a significant problem with the way Tier 1 MW are calculated or that the Tier 2 Synchronized Reserve requirement is not correct. The MMU recommends

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that PJM reevaluate its use of the Tier 1 bias factor and define explicit and transparent rules for calculating available Tier 1 MW and calculating required Tier 2 MW.

Table 9-18 Tier 1 bias used by PJM Dispatch January through September, 2008 through 2012 (New Table)

Year (Jan-Sep)	Total Net Tier 1 Bias (MW)	Percent of Hours with Tier 1 Bias	Average Bias (MW) of Hours with Tier 1 Bias	Added MW as a Percentage of Total Settled MW
2008 (Jan-Sep)	(92,800)	4.2%	(356)	68.8%
2009 (Jan-Sep)	(52,150)	3.1%	(258)	11.6%
2010 (Jan-Sep)	(747,745)	24.5%	(467)	5.2%
2011 (Jan-Sep)	(762,325)	28.5%	(408)	3.2%
2012 (Jan-Sep)	(599,054)	24.9%	(366)	6.6%

History of Spinning Events

Spinning events (Table 9-19) are usually caused by a sudden generation outage or transmission disruption requiring PJM to load synchronized reserve.[28] The reserve remains loaded until system balance is recovered. From January 2009 through September 2012 PJM experienced 120 spinning events, or 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.

28 See PJM. "Manual 12, Balancing Operations," Revision 25 (June 28, 2012), pp. 36-37.

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Table 9-19 Spinning Events, January 2009 through September 2012 (See 2011 SOM, Table 9-20)

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	MAR-08-2012 17:04	RFC	6
FEB-28-2009 06:19	RFC	5	MAY-11-2010 19:57	Mid-Atlantic	9	FEB-24-2011 11:35	Mid-Atlantic	14	MAR-19-2012 10:14	RFC	10
MAR-03-2009 05:20	Mid-Atlantic	11	MAY-15-2010 03:03	RFC	6	FEB-25-2011 14:12	RFC	10	APR-16-2012 00:20	Mid-Atlantic	9
MAR-05-2009 01:30	Mid-Atlantic	43	MAY-28-2010 04:06	Mid-Atlantic	5	MAR-30-2011 19:13	RFC	12	APR-16-2012 11:18	RFC	8
MAR-07-2009 23:22	RFC	11	JUN-15-2010 00:46	RFC	34	APR-02-2011 13:13	Mid-Atlantic	11	APR-19-2012 11:54	RFC	16
MAR-23-2009 23:40	Mid-Atlantic	10	JUN-19-2010 23:49	Mid-Atlantic	9	APR-11-2011 00:28	RFC	6	APR-20-2012 11:08	Mid-Atlantic	7
MAR-23-2009 23:42	RFCNonMA	8	JUN-24-2010 00:56	RFC	15	APR-16-2011 22:51	RFC	9	JUN-20-2012 13:35	RFC	7
MAR-24-2009 13:20	Mid-Atlantic	8	JUN-27-2010 19:33	Mid-Atlantic	15	APR-21-2011 20:02	Mid-Atlantic	6	JUN-26-2012 17:51	RFC	7
MAR-25-2009 02:29	RFC	9	JUL-07-2010 15:20	RFC	8	APR-27-2011 01:22	RFC	8	JUL-23-2012 21:45	RFC	18
MAR-26-2009 13:08	RFC	10	JUL-16-2010 20:45	Mid-Atlantic	19	MAY-02-2011 00:05	Mid-Atlantic	21	AUG-03-2012 12:44	RFC	10
MAR-26-2009 18:30	Mid-Atlantic	20	AUG-11-2010 19:09	RFC	17	MAY-12-2011 19:39	RFC	9	SEP-08-2012 04:34	RFC	12
APR-24-2009 16:43	RFC	11	AUG-13-2010 23:19	RFC	6	MAY-26-2011 17:17	Mid-Atlantic	20	SEP-27-2012 17:19	Mid-Atlantic	7
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									

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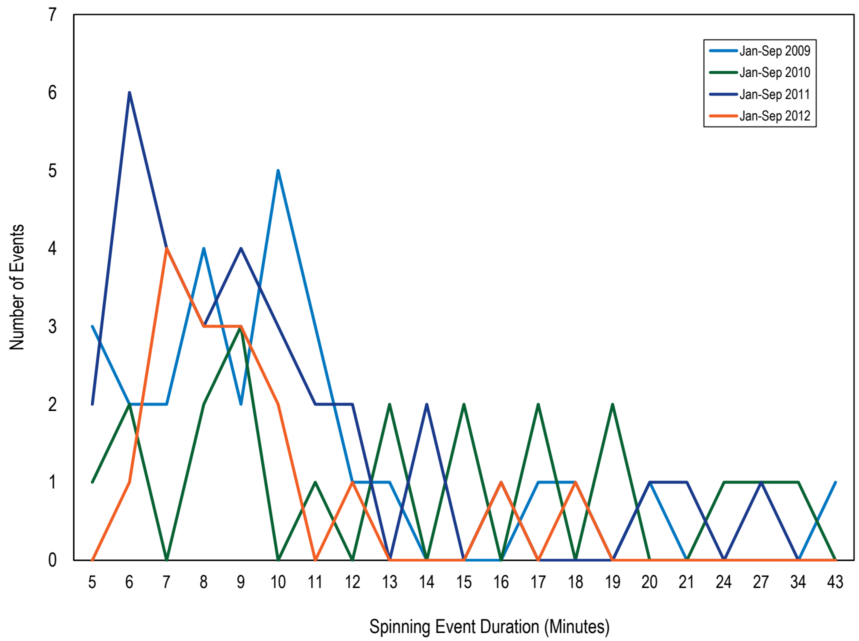
Figure 9-15 Spinning events duration distribution curve, January through September 2009 to 2012 (See 2011 SOM, Figure 9-17)



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 September 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.[29]

29 PJM uses the terms "supplemental operating reserves" and "scheduling operating reserves" interchangeably.

The DASR 30-minute reserve requirements are determined by the reliability region.[30] In the Reliability*First* (RFC) region, reserve requirements are calculated based on historical under-forecasted load rates and generator forced outage rates.[31] 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 September 2012, the required DASR was 7.03 percent of peak load forecast, down from 7.11 percent in 2011.[32] DASR MW purchased increased by 6.5 percent in January through September 2012 over the same period in 2011, from 43.4 million MW to 46.2 million MW.

In January through September 2012, no 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 September 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.[33] 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. However, there is a positive opportunity cost in addition to this direct marginal cost. As of September 30, 2012, fourteen 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.

30 PJM. "Manual 13, Emergency Requirements," Revision 48 (April 3, 2012), pp. 11-12.
31 PJM. "Manual 10, Pre-Scheduling Operations," Revision 25 (January 1, 2010), p. 17.
32 See the *2011 State of the Market Report for PJM*, Volume II, Section 9, "Ancillary Services" at Day Ahead Scheduling Reserve (DASR).
33 PJM. "Manual 11, Emergency and Ancillary Services Operations," Revision 52 (October 1, 2012), p. 122.

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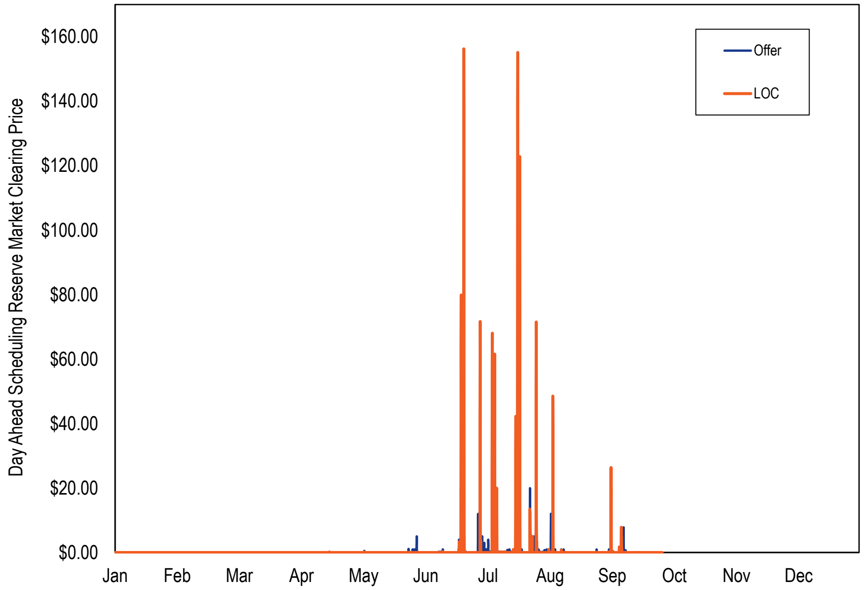
Market Performance

For 82 percent of hours in January through September 2012, DASR cleared at a price of $0.00. (Figure 9-16). For all of January through September, 2012 the weighted DASR price was $0.91, a $0.13 reduction from the weighted price during the same period in 2011.

Table 9-20 PJM Day-Ahead Scheduling Reserve Market MW and clearing prices: January through September 2011 and 2012 (See 2011 SOM, Table 9-21)

Year	Month	Average Required Hourly DASR (MW)	Minimum Clearing Price	Maximum Clearing Price	Average Weighted Clearing Price	Total DASR Credits
2011	Jan	6,536	$0.00	$1.00	$0.03	$127,837
2011	Feb	6,180	$0.00	$1.00	$0.02	$61,682
2011	Mar	5,720	$0.00	$1.00	$0.01	$45,885
2011	Apr	5,265	$0.00	$0.05	$0.01	$24,463
2011	May	5,554	$0.00	$25.52	$0.29	$894,607
2011	Jun	7,305	$0.00	$193.97	$2.26	$9,653,815
2011	Jul	8,647	$0.00	$217.12	$4.21	$22,880,723
2011	Aug	7,787	$0.00	$61.91	$0.75	$3,577,433
2011	Sep	6,535	$0.00	$5.00	$0.07	$292,252
2012	Jan	6,944	$0.00	$0.02	$0.00	$604
2012	Feb	6,777	$0.00	$0.02	$0.00	$2,037
2012	Mar	6,180	$0.00	$0.05	$0.00	$5,031
2012	Apr	5,854	$0.00	$0.10	$0.00	$5,572
2012	May	6,491	$0.00	$5.00	$0.05	$226,881
2012	Jun	7,454	$0.00	$156.29	$2.39	$11,422,377
2012	Jul	8,811	$0.00	$155.15	$3.69	$20,723,970
2012	Aug	8,007	$0.00	$55.55	$0.51	$2,601,271
2012	Sep	6,656	$0.00	$7.80	$0.12	$540,586

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



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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 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's goal is to charge transmission customers for black start service according to their zonal load ratio share (Table 9-21).

In January through September 2012, black start charges were $19.7 million. This is 97 percent higher than January through September 2011, when total black start service charges were $10.02 million. There was substantial zonal variation. Black start zonal charges in January through September 2012 ranged from $0.02 per MW in the ATSI zone to $1.80 per MW in the BGE 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 9-21 include an estimated $6.19 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.[34]

Table 9-21 Black start yearly zonal charges for network transmission use: January through September 2012 (See 2011 SOM, Table 9-22)

Zone	Network Charges	Black Start Rate ($/MW)
AECO	$422,507	$0.52
AEP	$6,775,514	$1.01
AP	$146,568	$0.06
ATSI	$79,073	$0.02
BGE	$3,558,896	$1.80
ComEd	$3,332,988	$0.51
DAY	$142,060	$0.14
DEOK	$200,880	$0.13
DLCO	$32,711	$0.04
DPL	$390,945	$0.34
JCPL	$356,876	$0.20
Met-Ed	$368,772	$0.43
PECO	$929,412	$0.38
PENELEC	$323,632	$0.38
Pepco	$224,158	$0.12
PPL	$106,012	$0.05
PSEG	$2,316,319	$0.77

34 The $6.19 million is included in operating reserves. See the *2012 State of the Market Report for PJM: January through September*, Section 3, "Operating Reserves", at "Operating Reserve Charges."

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