SECTION 6 – ANCILLARY SERVICE MARKETS

The United States Federal Energy Regulatory Commission (FERC) defined six ancillary services in Order 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.

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 the 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.

On June 1, 2008 PJM introduced the Day-Ahead Scheduling Reserve Market (DASR), as required by the settlement in the RPM case.[3] The purpose of this 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.

1 75 FERC ¶ 61,080 (1996).
2 Regulation is used to help control the area control error (ACE). See *2008 State of the Market Report,* Volume II, Appendix F, "Ancillary Service Markets," for a full definition and discussion of ACE. Regulation resources were almost exclusively generating units in 2008.
3 See PJM Interconnection, L.L.C., 117 FERC ¶ 61,331 (2006).

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.

PJM does not provide a market for black start services, which are procured and paid zonally, but does review the adequacy of black start resources.

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 from January through September 2009.

Overview

Regulation Market

The PJM Regulation Market in 2009 continues to be operated as a single market. There have been no structural changes since December 1, 2008. On December 1, 2008, PJM implemented changes to the Regulation Market including the introduction of the three pivotal supplier test for market power, a change to the calculation of lost opportunity cost (LOC) and a change to the treatment of regulation revenues with respect to operating reserve credits. The MMU will provide a report to FERC on November 26, 2009 on the impact of these changes.

Market Structure

- **Supply.** During the first nine months of 2009, the supply of offered and eligible regulation in PJM was generally both stable and adequate. Although PJM rules allow up to 25 percent of the regulation requirement to be satisfied by demand resources, none qualified to make regulation offers in 2009. The ratio of eligible regulation offered to regulation required averaged 2.98 throughout the first nine months of 2009, an increase from the 2008 ratio.

- **Demand.** Beginning August 7, 2008, PJM began to define separate on-peak and off-peak regulation requirements. The on-peak requirement is equal to 1.0 percent of the forecast peak load for the PJM RTO for the day and the off-peak requirement is equal to 1.0 percent of the forecast valley load for the PJM RTO for the day. Previously the requirement had been fixed daily at 1.0 percent of the daily forecast operating load. The average hourly regulation demand in the first nine months of 2009 was 863 MW, compared to 947 MW for the first nine months of 2008.

- **Market Concentration.** During the first nine months of 2009, the PJM Regulation Market had a load weighted, average Herfindahl-Hirschman Index (HHI) of 1290 which is classified as "moderately concentrated."[4] The minimum hourly HHI was 699 and the maximum hourly HHI was 7551. The largest hourly market share in any single hour was 86 percent, and 66 percent of all hours had a maximum market share greater than 20 percent.

  The high hourly HHIs resulted from an increase in high maximum market share hours during early morning off-peak hours in July, August, and September. An increase in self scheduled regulation reduced the amount of regulation procured from the market. This appears to be related to PJM changes to the calculation of LOC, which resulted in higher off-peak clearing prices. In the first nine months of 2009, 46 percent of hours had one or more pivotal suppliers. The MMU concludes from these results that the PJM Regulation Market in the first nine months of 2009 was characterized by structural market power in 46 percent of the hours.

Market Conduct

- **Offers.** Daily regulation offer prices are submitted for each unit by the unit owner, and PJM adds LOC calculated using LMP forecasts, which together comprise the total offer to the Regulation Market for each unit. Beginning December 1, 2008 PJM implemented a three pivotal supplier test in the regulation market. As part of the implementation, owners are required to submit unit specific cost based offers which may include up to a $12 per MWh margin adder, and owners have the option to submit price based offers. All offers remain subject to the $100 per MWh cap. All units of owners who fail the three pivotal supplier test for an hour are offered at the lesser of their cost based or price based offer. As part of the changes to the regulation market implemented on December 1, 2008, PJM no longer nets regulation revenue against operating reserve revenue and PJM calculates lost opportunity costs using the lower of cost based or price based offers as the reference rather than the offer on which the unit is operating.

Market Performance

- **Price.** For the PJM Regulation Market during the first nine months of 2009 the load weighted, average price per MWh (the regulation market clearing price, including lost opportunity cost) associated with meeting PJM's demand for regulation was $24.99. This is a significant reduction from the $45.40 average load weighted price for January through September of 2008.

Synchronized Reserve Market

PJM retained 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).

PJM made two significant changes to the Synchronized Reserve Market in 2009. These changes were intended to ensure that the synchronized reserve requirement accurately reflects the needs of PJM dispatch. This includes ensuring that the forecast amount of Tier 1 synchronized reserve is actually available to PJM dispatch during the operating hour. PJM changed the primary constraint which defines the Mid-Atlantic subzone within the RFC Synchronized Reserve Market from Bedington-Black Oak to AP South. PJM reduced from 70 percent to 15 percent the percentage of Tier 1 available south of the AP South interface that it will consider as available to the Mid-Atlantic subzone when it calculates the amount of Tier 2 required. These changes were made to address the fact that PJM Dispatch needed more synchronized reserve than was defined as the requirement to be met by the market. This problem has existed in the Synchronized Reserve Market since late 2007. These changes reduced the amount of additional, out of market, synchronized reserve required by PJM dispatch, which reduced LOC payments and aligned the total cost of synchronized reserves with Synchronized Reserve Market prices. Synchronized reserves added out of market were less than three percent of all synchronized reserve during April through September of 2009 while they were 47 percent for the same

4 See the *2008 State of the Market Report for PJM*, Volume II, Section 2, "Energy Market, Part I," at "Market Concentration" for a more complete discussion of concentration ratios and the Herfindahl-Hirschman Index (HHI).

time period in 2008. LOC accounted for 23 percent of total costs during April through August of 2009 compared to 55 percent during the same time period in 2008.

Market Structure

- **Supply.** For the period January through September 2009, the offered and eligible excess supply ratio was 1.38 for the PJM Mid-Atlantic Synchronized Reserve Region.[5] The excess supply ratio is determined using the administratively required level of synchronized reserve. The actual requirement for Tier 2 synchronized reserve is lower than the required reserve level because there is usually a significant amount of Tier 1 synchronized reserve available. In the first nine months of 2009, the contribution of DSR resources to the Synchronized Reserve Market remained significant and resulted in lower overall Synchronized Reserve prices.

- **Demand.** The average synchronized reserve requirements were 1,360 MW for the RFC Synchronized Reserve Zone and 1,170 MW for the Mid-Atlantic Subzone. Market demand is less than the requirement by the amount of forecast Tier 1 synchronized reserve available at the time a Synchronized Reserve Market is cleared.

  Demand for synchronized reserve in the Mid-Atlantic subzone increased substantially during September as a result of three consecutive days (September 14, 15, and 16) of double spinning requirements. As a result of the level of Tier 1 reserves in the RFC Synchronized Reserve Zone, less than one percent of hours cleared a Tier 2 Synchronized Reserve market in the RFC. In the Southern Synchronized Reserve Zone only six hours cleared a Tier 2 market in 2009. In the PJM Mid-Atlantic Synchronized Reserve Region, 67 percent of hours cleared a Tier 2 Synchronized Reserve Market. The average demand for Tier 2 synchronized reserve in the Mid-Atlantic Subzone of the RFC Synchronized Reserve Zone was 300 MW.

  The problem of additional procurement of Tier 2 synchronized reserves by PJM dispatch after Synchronized Reserve Market settlement has been greatly reduced. For January through September 2009, 19 percent of all purchased Tier 2 synchronized reserves were added after the market cleared. Most of the added synchronized reserve occurred in the January through March period. From April through September 2009 less than three percent of all purchased Tier 2 synchronized reserves were added after the market cleared.

- **Market Concentration.** The average load weighted cleared Synchronized Reserve Market HHI for the Mid-Atlantic Subzone of the RFC Synchronized Reserve Zone for January through September 2009 was 2765. For purchased synchronized reserve (cleared plus added) the HHI was 3393. Less than one percent of all hours had a market share of 100 percent. In 41 percent of hours the maximum market share was greater than 40 percent (compared to 56 percent of hours in 2008). In the Mid-Atlantic Subzone of the RFC Synchronized Reserve Market, for the period January through September 2009, 93 percent of hours had three or fewer pivotal suppliers. The MMU concludes from these results that the PJM Synchronized Reserve Markets in 2009 are characterized by structural market power.

Market Conduct

- **Offers.** Daily offer prices are submitted for each unit by the unit owner, and PJM adds LOC calculated using LMP forecasts, which together comprise the total offer for each unit to the Synchronized Reserve Market. The synchronized reserve offer made by the unit owner is subject to an offer cap of marginal cost plus $7.50 per MW, plus lost opportunity cost. All suppliers are paid the higher of the market clearing price or their offer plus their unit specific opportunity cost.

Market Performance

- **Price.** During January and to a lesser extent February, only a very small amount of Tier 2 was needed, which resulted in lower clearing prices. The load weighted, average PJM price for Tier 2 synchronized reserve in the Mid-Atlantic Subzone of the RFC Synchronized Reserve Market was $7.55 per MW for January through September 2009, a $3.32 per MW decrease from January through September 2008.

- **Demand.** Demand for Tier 2 synchronized reserve was varied substantially during the first quarter of 2009 as a result of PJM changes to the definition of the market. On December 1, 2008 PJM began to significantly increase the amount of Tier 1 forecast during the market solution, which reduced the demand for Tier 2 in January and February 2009. On March 13, 2009 PJM reduced the amount of Tier 1 from outside the Mid-Atlantic subzone that is included for the operational hour, which increased demand for Tier 2. Demand side resources

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

remained significant participants in the Synchronized Reserve Market from January through September 2009. In 18 percent of hours in which a Tier 2 Synchronized Reserve Market was cleared for the Mid-Atlantic Subzone, all synchronized reserves were provided by DSR.

- **Availability.** 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 experienced a deficit during January through September 2009.

DASR

On June 1, 2008 PJM introduced the Day-Ahead Scheduling Reserve Market (DASR), as required by the RPM settlement.[6] The purpose of this 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 a single market clearing price. The DASR 30-minute reserve requirements are determined annually by the reliability region.[7] The RFC and Dominion DASR requirements are added together to form a single RTO DASR Requirement which is obtained via the DASR Market. The requirement is applicable for all hours of the operating day. If the DASR Market does not result in procuring adequate reserves, PJM is required to schedule additional operating reserves.

Market Structure

The DASR Market from January through September 2009 had three pivotal suppliers in a monthly average of 32 percent of all hours. The MMU concludes from these results that the PJM DASR Market in the first nine months of 2009 was characterized by structural market power.

Market Conduct

Economic withholding remains a problem in the DASR market. Continuing a pattern seen since the inception of the DASR market, a significant number of units offered at levels effectively guaranteed not to clear. In September, almost six percent of units offered at $50 or more and four percent of units offered at $990 or more, in a market with an average clearing price of $0.05 and a maximum clearing price of $1.00.

Market Performance

For January through September, 2009, the load weighted price of DASR was $0.05, including the almost 40 percent of hours when the market cleared at a price of $0.00. Demand side resources do participate in the DASR market but remain insignificant.

Black Start Services

Black Start Service is necessary to help ensure the reliable restoration of the grid following a black out. Black Start Service is the ability of a generating unit to start without an outside electrical supply, or is the demonstrated ability of a generating unit with a high operating factor to automatically remain operating at reduced levels when disconnected from the grid.[8]

Individual transmission owners, with PJM, identify the black start units included in each transmission owner's system restoration plan. PJM defines required black start capability zonally and ensures the availability of black start service by charging transmission customers according to their zonal load ratio share and compensating black start unit owners.

PJM does not have a market to provide black start service, but compensates black start resource owners for all costs associated with providing this service, as defined in the tariff. For 2008, charges to PJM members for providing black start services were just over $13 million. For the first nine months of 2009, charges were about $9.2 million.

As a consequence of PJM's filing to revise its formula rate for black start service to allow for the recovery of the costs of compliance with Critical Infrastructure Protection standards, black start costs likely will increase substantially. The revised filing also provides a better match between the sellers' commitment period and the cost recovery period.

The MMU recommends that PJM, FERC and state regulators reevaluate the way in which black start service is procured in order to ensure that procurement is done in a least cost manner for the entire PJM market.

6 See PJM Interconnection, L.L.C., 117 FERC ¶ 61,331 (2006).
7 PJM Manual 13, Emergency Requirements, Rev 38, 10/05/2009; pp 11-12.
8 PJM Tariff, Second Revised Sheet No. 33.01, March 1, 2007.

Conclusion

PJM consolidated its Regulation Markets into a single Combined Regulation Market, on a trial basis, effective August 1, 2005. The MMU has consistently found since that time that the PJM Regulation Market is characterized by structural market power during a significant number of hours. This conclusion is based on the results of the three pivotal supplier test.

In 2008, PJM and its stakeholders addressed the issue of market power mitigation for the Regulation Market in the Three Pivotal Supplier Task Force (TPSTF), which was convened pursuant to PJM's 2007 Strategic Report to review market power mitigation issues.[9] The TPSTF achieved a consensus supporting the application of the three pivotal supplier (TPS) test to the Regulation Market, provided that three adjustments to the rules were included, all of which increased margins for regulation units. PJM filed the proposed revisions on October 1, 2008.[10] A number of parties filed comments, including the MMU on October 20, 2008.[11] The MMU supported the consensus but requested that the Commission direct the MMU to report on the three adjustments to the rules: increasing the current $7.50 adder to cost based offers to $12; modifying the calculation of opportunity costs to use the lower of cost based or price based offers as the reference; and eliminating the netting of revenues from the Regulation Market from make whole balancing operating reserve payments. The Commission, in accepting PJM's filing on November 26, 2008, directed the Market Monitoring Unit to prepare a report due on November 26, 2009.[12]

On December 1, 2008, the three pivotal supplier test was implemented in the Regulation Market to address the identified market power problems. As a result, the Regulation Market results in the first half of 2009 were competitive.

The MMU also concludes that the other changes to the Regulation Market implemented on December 1, 2008 significantly increased the price of regulation compared to what prices would have been absent those changes. The MMU will provide an updated analysis of results and associated recommendations to FERC, due November 26, 2009.

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.

The MMU concludes that the DASR Market is not structurally competitive in a significant number of hours based on the results of the three pivotal supplier test. The MMU recommends that the DASR Market rules be modified to incorporate the application of the three pivotal supplier test. The MMU also concludes that the DASR Market results were competitive in the first half of 2009.

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 competitive in the first three quarters of 2009. The MMU concludes that the Synchronized Reserve Market results were competitive in the first three quarters of 2009. The MMU concludes that the DASR Market results were competitive in the first three quarters of 2009.

9 See PJM 2007 Strategic Report at 65 (April 2, 2007). This report is posted on PJM's Website at: http://www2.pjm.com/documents/downloads/strategic-responses/report/20070402-pjm-strategic-report.pdf.
10 PJM submitted its initial filing in FERC Docket No. ER09-13-000.
11 Comments and Motion for Leave to Intervene of the Independent Market Monitor for PJM, Docket No. ER09-13-000. These comments are posted on the Monitoring Analytics website at http://www.monitoringanalytics.com.
12 *PJM Interconnection, L.L.C.*, 125 FERC ¶ 61,231, at P 18 (2008).

Regulation Market

Market Structure

Table 6-1 PJM Regulation Market Required MW and Ratio of Supply to Requirement: January through September 2009 (See 2008 SOM Table 6-1)

Period Type	Average Required Regulation (MW)	Ratio of Supply to Requirement
2009 (Jan - Sep)	863	2.98
Fall	802	3.27
Spring	771	2.89
Summer	929	3.14
Winter	938	2.74
Off-Peak	784	2.90
On-Peak	951	3.07

Market Concentration

Table 6-2 PJM regulation capability, daily offer and hourly eligible: January through September 2009 (See 2008 SOM Table 6-2)

Period	Regulation Capability (MW)	Average Daily Offer (MW)	Percentage of Capability Offered	Average Hourly Eligible (MW)	Percent of Capability Eligible
All Hours	7,629	6,313	83%	2,563	34%
Off Peak	7,629			2,236	29%
On Peak	7,629			2,925	38%

Table 6-3 PJM cleared regulation HHI: January through September 2009 (See 2008 SOM Table 6-3)

Market Type	Minimum HHI	Load-weighted Average HHI	Maximum HHI
Cleared Regulation, 2009	699	1290	7551

Figure 6-1 PJM Regulation Market HHI distribution: January through September 2009 (See 2008 SOM Figure 6-1)

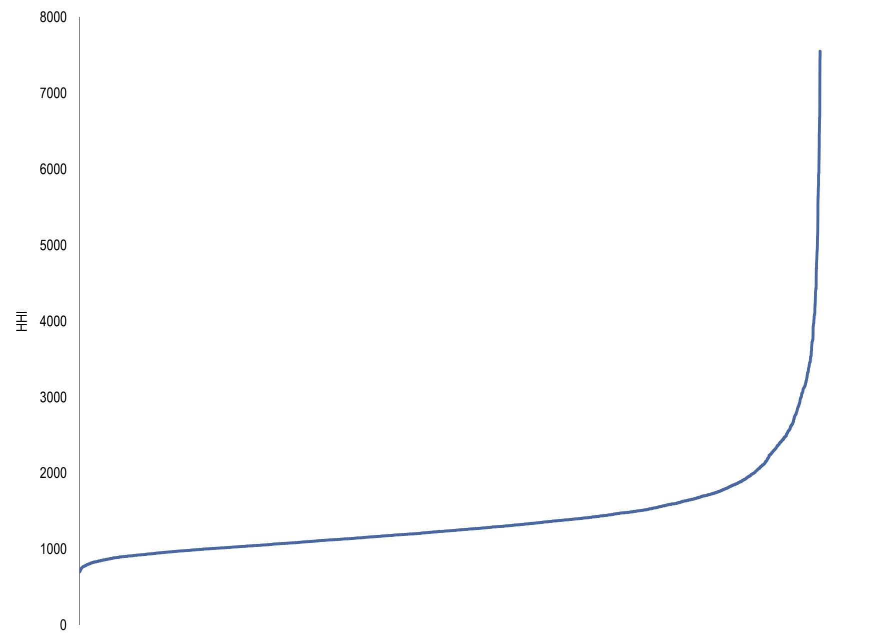


Table 6-4 Highest annual average hourly Regulation Market shares: January through September 2009 (See 2008 SOM Table 6-4)

Company Market Share Rank	Cleared Regulation Top Market Shares
1	16%
2	9%
3	9%
4	8%
5	7%

Table 6-5 Regulation market monthly three pivotal supplier results: January through September 2009 (See 2008 SOM Table 6-5)

Month	Percent of Hours With Three Pivotal Suppliers
Jan	84%
Feb	61%
Mar	42%
Apr	40%
May	31%
Jun	37%
Jul	39%
Aug	35%
Sep	47%

Market Performance

Price

Figure 6-2 PJM Regulation Market daily average market-clearing price, lost opportunity cost and offer price (Dollars per MWh): January through September 2009 (See 2008 SOM Figure 6-2)

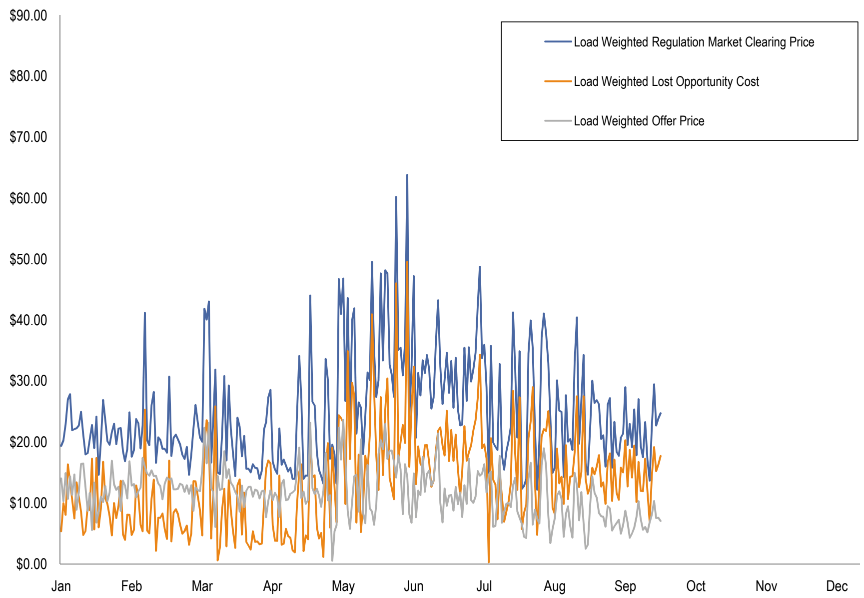


Figure 6-3 Monthly average regulation demand (required) vs. price: January through September 2009 (See 2008 SOM Figure 6-3)

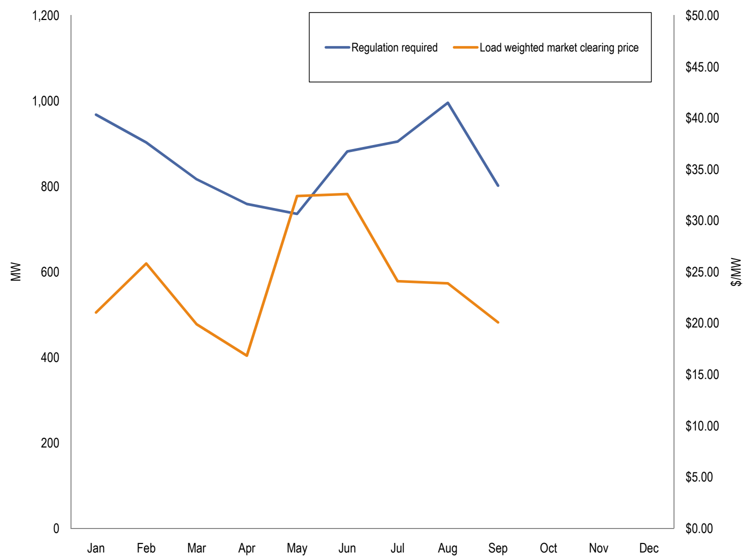


Figure 6-4 Monthly load weighted, average regulation cost and price: January through September 2009 (See 2008 SOM Figure 6-4)

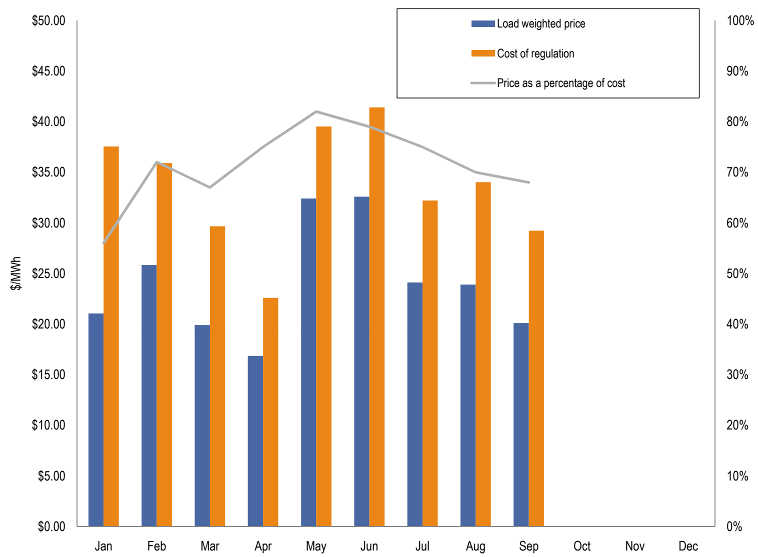


Table 6-6 Total regulation charges: January through September 2009 (See 2008 SOM Table 6-6)

Month	Total Purchased Regulation (MW)	Total Regulation Charges ($)	Weighted Average Regulation Market Price	Regulation Cost (per MW Regulation)
Jan	708,801	$26,614,050	$21.04	$37.55
Feb	597,418	$21,455,212	$25.83	$35.91
Mar	601,980	$17,853,025	$19.90	$29.66
Apr	538,993	$12,172,449	$16.84	$22.58
May	535,862	$21,180,526	$32.41	$39.53
Jun	595,554	$24,664,652	$32.59	$41.41
Jul	628,265	$20,237,959	$24.10	$32.21
Aug	677,555	$23,049,672	$23.89	$34.02
Sep	521,875	$15,251,640	$20.09	$29.22

Synchronized Reserve Market

Figure 6-5 RFC Synchronized Reserve Zone monthly average synchronized reserve required vs. Tier 2 scheduled MW: January through September 2009 (See 2008 SOM Figure 6-5)

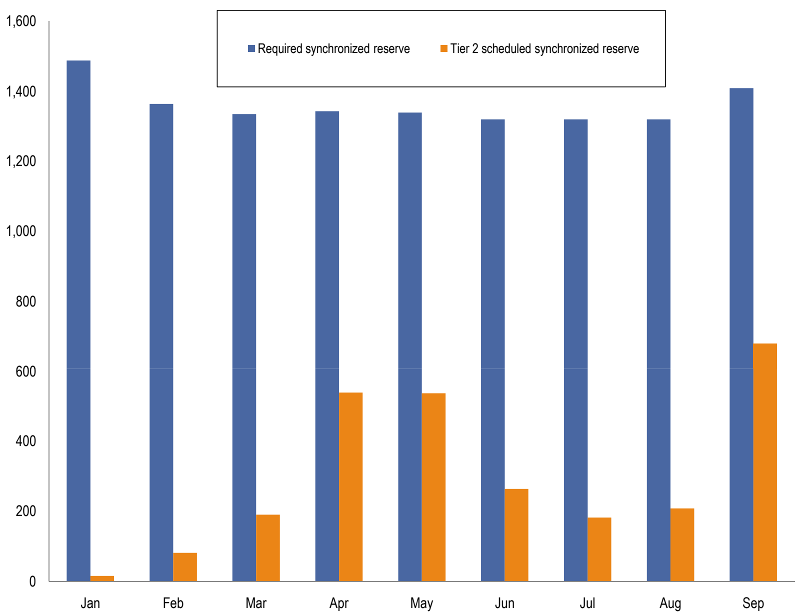
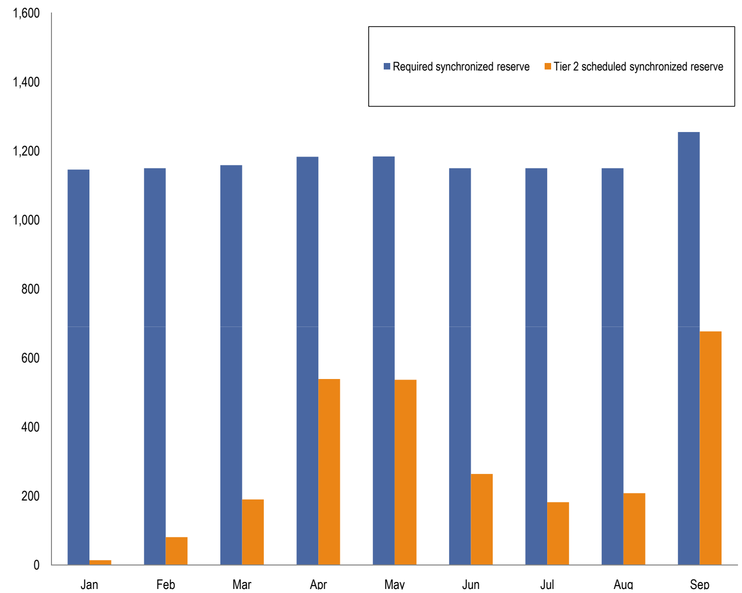
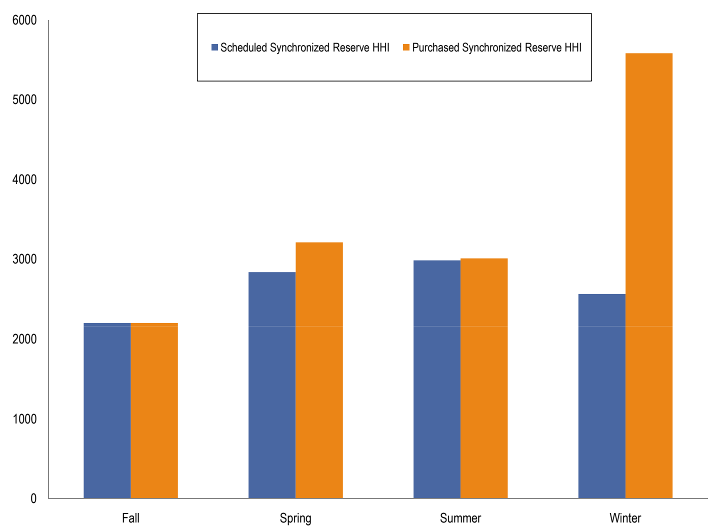


Figure 6-6 RFC Synchronized Reserve Zone, Mid-Atlantic Subzone average hourly synchronized reserve required vs. Tier 2 scheduled: January through September 2009 (See 2008 SOM Figure 6-6)



Market Concentration

Figure 6-7 Cleared Mid-Atlantic Subzone RFC Tier 2 Synchronized Reserve Market seasonal HHI: January through September 2009 (See 2008 SOM Figure 6-7)



Market Conduct

Offers

Figure 6-8 Tier 2 synchronized reserve average hourly offer volume (MW): January through September 2009 (See 2008 SOM Figure 6-8)

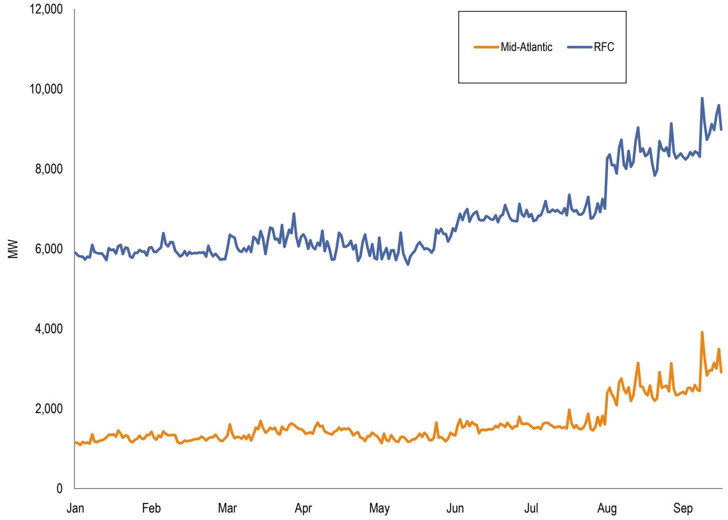
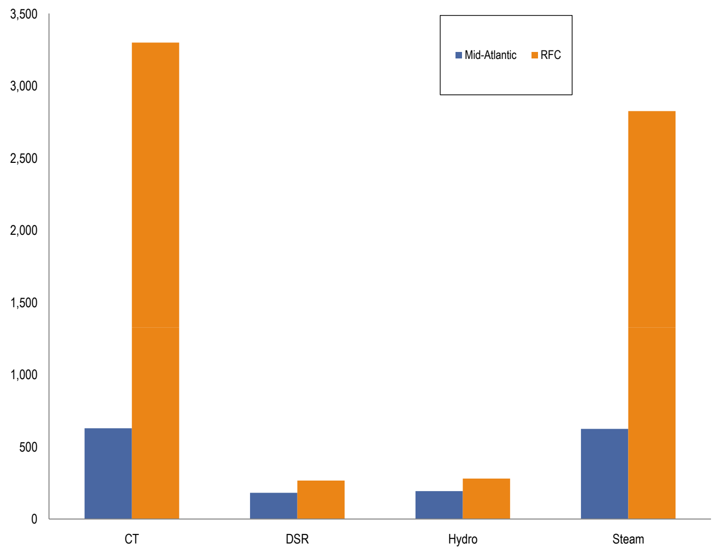


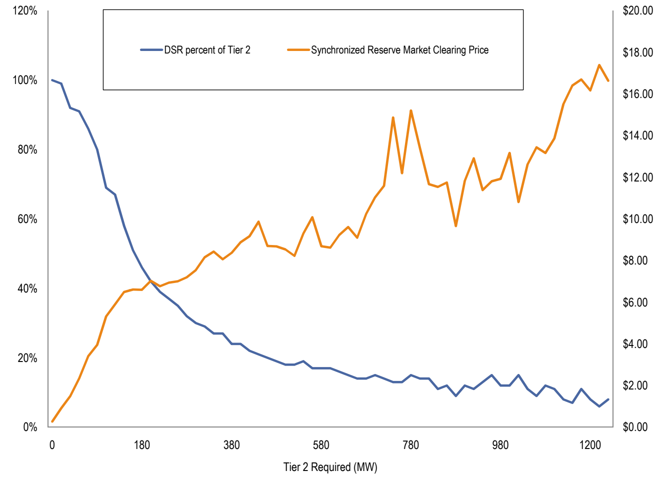
Figure 6-9 Average daily Tier 2 synchronized reserve offer by unit type (MW): January through September 2009 (See 2008 SOM Figure 6-9)



Market Performance

Price

Figure 6-10 Required Tier 2 synchronized reserve, synchronized reserve market clearing price, and DSR percent of Tier 2: January through September 2009 (See 2008 SOM Figure 6-10)



Price and Cost

Figure 6-11 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 2009 (See 2008 SOM Figure 6-11)

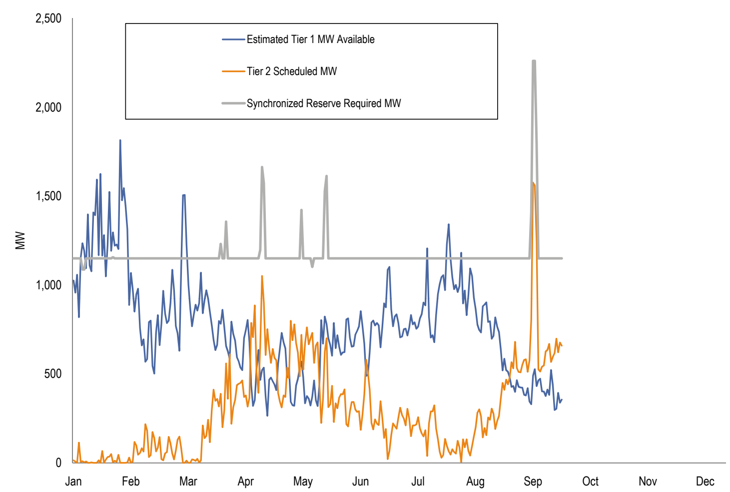


Figure 6-12 Synchronized reserve purchases by month; PJM scheduled, self-scheduled, and added: January through September 2009 (See 2008 SOM Figure 6-12)

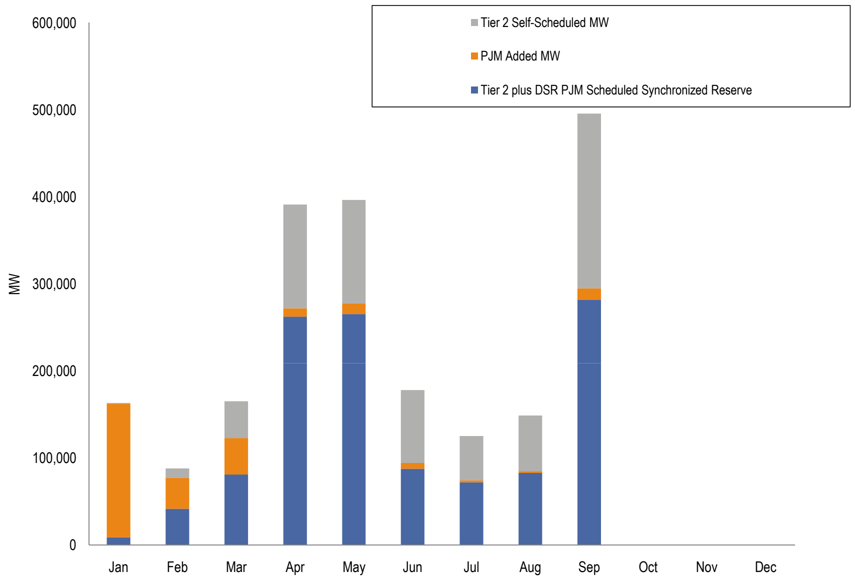


Figure 6-13 Impact of Tier 2 synchronized reserve added MW to the RFC Synchronized Reserve Zone, Mid-Atlantic subzone: January through September 2009 (See 2008 SOM Figure 6-13)

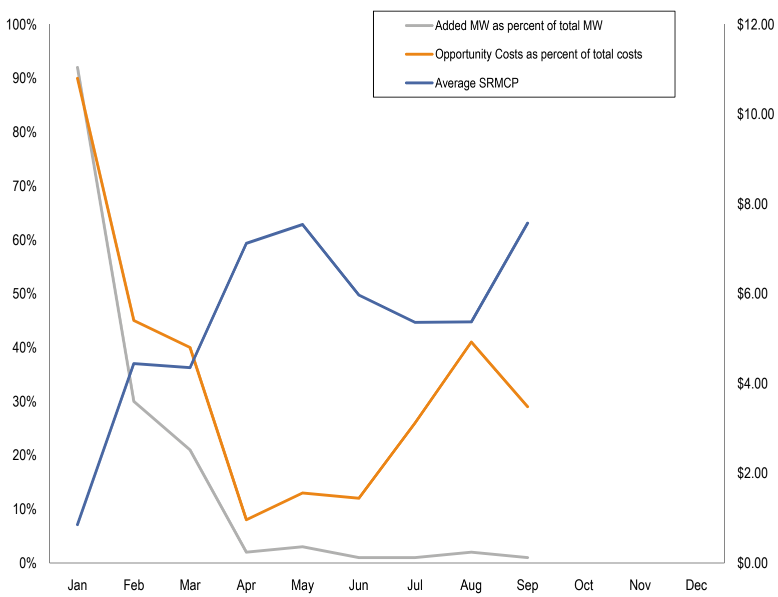
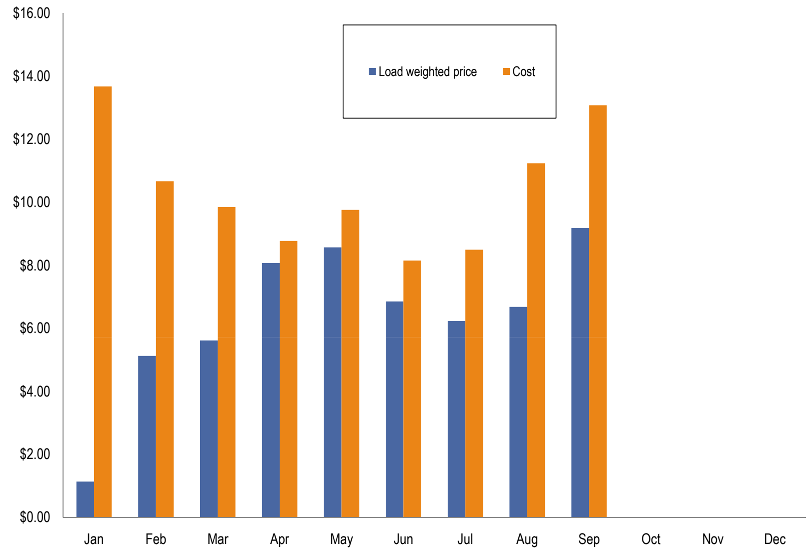


Figure 6-14 Comparison of RFC Tier 2 synchronized reserve price and cost (Dollars per MW): January through September 2009 (See 2008 SOM Figure 6-14)



Market Solution and Actual Dispatch of Ancillary Services

DSR

Table 6-7 Average SRMCP when all cleared synchronized reserve is DSR: January through September 2009 (See 2008 SOM Table 6-8)

Month	Average SRMCP when all cleared synchronized reserve is DSR	Average SRMCP	Percent of cleared hours all synchronized reserve is DSR
Jan	$1.24	$5.90	43%
Feb	$2.01	$5.09	47%
Mar	$1.98	$5.50	26%
Apr	$2.49	$7.12	9%
May	$1.91	$7.56	12%
Jun	$1.76	$5.97	27%
Jul	$1.95	$5.41	31%
Aug	$1.36	$5.37	13%
Sep	$1.77	$7.65	2%

Figure 6-15 PJM RFC Zone Tier 2 synchronized reserve scheduled MW: January through September 2009 (See 2008 SOM Figure 6-15)

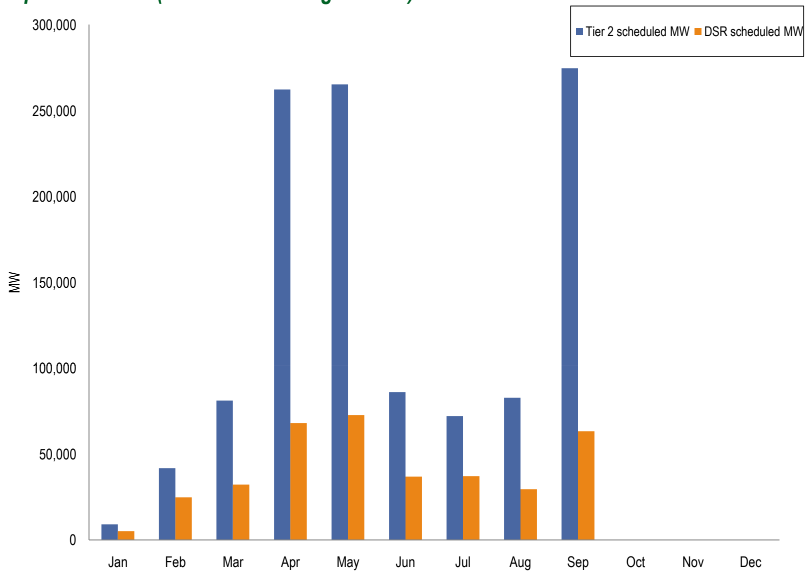


Table 6-9 2008 PJM, Day-Ahead Scheduling Reserve Market pivotal supplier results: January through September 2009 (See 2008 SOM Table 6-10)

Month	Percentage of Hours With Three Pivotal Suppliers
Jan	15%
Feb	61%
Mar	76%
Apr	55%
May	48%
Jun	5%
Jul	3%
Aug	21%
Sep	0%

Availability

Day Ahead Scheduling Reserve (DASR)

Table 6-8 PJM, Day-Ahead Scheduling Reserve Market MW and clearing prices: January through September 2009 (See 2008 SOM Table 6-9)

Month	Average Required Hourly DASR MW	Minimum Clearing Price	Maximum Clearing Price	Average Load Weighted Clearing Price	Total DASR MW Purchased	Total DASR Credits
Jan	5,875	$0.00	$0.50	$0.09	4,103,463	$381,735
Feb	5,517	$0.00	$0.25	$0.05	3,510,983	$180,767
Mar	5,068	$0.00	$1.00	$0.03	3,499,722	$113,507
Apr	4,910	$0.00	$0.50	$0.03	3,354,999	$92,158
May	4,957	$0.00	$0.07	$0.02	3,478,374	$77,850
Jun	5,936	$0.00	$0.75	$0.05	4,006,547	$191,578
Jul	6,071	$0.00	$0.50	$0.04	4,191,307	$155,790
Aug	6,725	$0.00	$4.00	$0.13	4,773,330	$620,430
Sep	5,438	$0.00	$0.42	$0.02	3,764,923	$77,945

Black Start Service

Table 6-10 Black Start yearly zonal charges for network transmission use: January through September 2009 (See 2008 SOM Table 6-11)

Zone	Network Charges
AECO	$313,486
AEP	$548,359
AP	$101,432
BGE	$359,347
ComEd	$5,078,367
DAY	$109,013
DPL	$264,246
DLCO	$19,890
JCPL	$325,524
Met-Ed	$302,662
PECO	$539,893
PENELEC	$250,272
Pepco	$166,311
PPL	$92,933
PSEG	$706,225