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. Although not defined by the FERC as an ancillary service, black start service plays a comparable role. Black start service is provided 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 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.

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.

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 nine months of 2010.

Overview

Regulation Market

The PJM Regulation Market in 2010 continues to be operated as a single market. There have been no structural changes since December 1, 2008. On December 1, 2008, PJM implemented four changes to the Regulation Market: introducing the Three Pivotal Supplier test for market power; increasing the margin for cost-based regulation offers; modifying the calculation of lost opportunity cost (LOC); and terminating the offset of regulation revenues against operating reserve credits. At the FERC's direction, the MMU prepared and submitted a report on November 30, 2009, on the impact of these changes.[4] The MMU also reported on the impact of these changes in the 2009 State of the Market Report.[5]

1 75 FERC ¶ 61,080 (1996).
2 Regulation is used to help control the area control error (ACE). See *2009 State of the Market Report for PJM,* Volume II, Appendix F, "Ancillary Service Markets," for a full definition and discussion of ACE. Regulation resources were almost exclusively generating units in the first nine months of 2010.
3 See 117 FERC ¶ 61,331 at P 29 n32 (2006).
4 The MMU report filed in Docket No. ER09-13-000 is posted at: <http://www.monitoringanalytics.com/reports/Reports/2009/IMM_PJM_Regulation_Market_Impact_20081201_Changes_20091130.pdf>(465 KB).
5 See the *2009 State of the Market Report for PJM*, Volume II, Section 6, "Ancillary Service Markets."

Market Structure

- **Supply.** During the first nine months of 2010, 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 the first nine months of 2010. The ratio of eligible regulation offered to regulation required averaged 2.86 for the first nine months of 2010, slightly lower than the 2009 ratio of 2.97.

- **Demand.** Beginning August 7, 2008, PJM began to define separate on-peak and off-peak regulation requirements, resulting in a decrease in total demand for regulation. 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 for the first nine months of 2010 increased to 913 MW, from 863 MW for the first nine months of 2009, as a result of increased forecast loads.

- **Market Concentration.** During the first nine months of 2010, the PJM Regulation Market had a load weighted, average Herfindahl-Hirschman Index (HHI) of 1401 which is classified as "moderately concentrated."[6] The minimum hourly HHI was 761 and the maximum hourly HHI was 2983. The largest hourly market share in any single hour was 51 percent, and 79 percent of all hours had a maximum market share greater than 20 percent.[7] For the first nine months of 2010, 76 percent of hours had one or more pivotal suppliers which failed PJM's three pivotal supplier test. The MMU concludes from these results that the PJM Regulation Market for the first nine months of 2010 was characterized by structural market power in 76 percent of the hours.

6 See the *2009 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). Consistent with common application, the market share and HHI calculations presented in the SOM are based on supply that is cleared in the market in every hour, not on measures of available capacity.

7 HHI and market share are commonly used but potentially misleading metrics for structural market power. Traditional HHI and market share analyses tend to assume homogeneity in the costs of suppliers. It is often assumed, for example, that small suppliers have the highest costs and that the largest suppliers have the lowest costs. This assumption leads to the conclusion that small suppliers compete among themselves at the margin, and therefore participants with small market share do not have market power. This assumption and related conclusion are not generally correct in electricity markets, like the Regulation Market, where location and unit specific parameters are significant determinants of the costs to provide service, not the relative market share of the participant. The three pivotal supplier test provides a more accurate metric for structural market power because it measures, for the relevant time period, the relationship between demand in a given market and the relative importance of individual suppliers in meeting that demand. The MMU uses the results of the three pivotal supplier tests, not HHI or market share measures, as the basis for conclusions regarding structural market power.

Market Conduct

- **Offers.** Daily regulation offer prices are submitted for each unit by the unit owner. Beginning December 1, 2008, owners are required to submit unit specific cost based offers and owners also have the option to submit price based offers. Cost based offers are valid for the entire day and are subject to validation using unit specific parameters submitted with the offer. All price based offers remain subject to the $100 per MWh offer cap.[8] In computing the market solution, PJM calculates a unit specific opportunity cost based on forecast LMP, and adds it to each offer. The offers made by unit owners and the opportunity cost adder comprise the total offer to the Regulation Market for each unit. Using a supply curve based on these offers, PJM solves the regulation market and then tests that solution to see which, if any, suppliers of eligible regulation are pivotal. The offers of all units of owners who fail the three pivotal supplier test for an hour are capped at the lesser of their cost based or price based offer. The regulation market is then re-solved.

  As part of the changes to the regulation market implemented on December 1, 2008, cost based offers may include a margin of $12.00 rather than the prior maximum margin of $7.50. The impact of this change was to increase cost based offer prices.

  As part of the changes to the regulation market implemented on December 1, 2008, PJM was to calculate unit specific opportunity costs using the lesser of the available price based energy offer or the most expensive available cost based energy offer as the reference, rather than the offer on which the unit was operating in the energy market.[9] However, PJM did not correctly implement this rule change until the third quarter of 2010. Depending on whether the units affected by the rule change are backed down or raised to regulate determines whether the application of the rule change increased or decreased the unit's applicable opportunity costs relative to the correct original rule used prior to December 1, 2008. The impact of these changes to the calculation is that the regulation market clearing price was either higher or lower than the outcome that would have occurred under the correct opportunity cost calculation used prior to December 1, 2008. The actual impact was reduced as a result of the incorrect implementation of the rule.

8 PJM. "Manual 11: Scheduling Operations," Revision 45 (June 23, 2010), p. 39.

9 See PJM. "Manual 11: Scheduling Operations," Revision 45 (June 23, 2010), p. 59: "SPREGO utilizes the lesser of the available price-based energy schedule or most expensive available cost-based energy schedule (the "lost opportunity cost energy schedule"), and forecasted LMPs to determine the estimated opportunity cost each resource would incur if it adjusted its output as necessary to provide its full amount of regulation. "

Market Performance

- **Price.** For the PJM Regulation Market during the first nine months of 2010, the load weighted, average price per MWh (the regulation market clearing price, including opportunity cost) associated with meeting PJM's demand for regulation was $19.28. This was a decrease of $4.80, or 20 percent, from the average price for regulation during the first nine months of 2009. The total cost of regulation increased by $0.35 from $33.57, for the first nine months of 2009, to $33.92, or 1 percent. The difference between total regulation cost per MW and regulation price remains high. The market clearing price was only 57 percent of the total regulation cost per MW.

- **Price and Opportunity Cost.** Prices in the PJM Regulation Market during the first nine months of 2010 were higher than they would have been in some hours and lower than they would have been in some hours as a result of the change to the definition of opportunity cost. The modified definition of opportunity cost resulted in a switch of the offer schedule used for the calculation of opportunity cost and therefore resulted in an impact on the regulation market clearing price.

  As actually implemented by PJM in 2009, the MMU calculates that schedule switching of marginal units occurred in 875 hours, of which 621 hours had higher than correct opportunity costs and 254 hours had lower than correct opportunity costs added to the marginal regulation offer.

  However, PJM did not correctly implement the rule in 2009. Had the revised opportunity cost rule been implemented as written in 2009, the schedule switching of marginal units in the regulation market would have occurred in 2,210 hours, of which 1,274 would have resulted in higher opportunity costs, and 926 would have resulted in lower opportunity costs being added to the marginal regulation offer. In the remaining 10 hours the schedule switch would not have affected the opportunity cost calculation of the marginal unit.

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 March 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 west 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 opportunity cost payments and aligned the total cost of synchronized reserves more closely with Synchronized Reserve Market prices. Synchronized reserves added out of market were four percent of all synchronized reserves during the first nine months of 2010, while they were 19 percent for the same time period in 2009. Opportunity cost payments accounted for 27 percent of total costs during the first nine months of 2010 compared to 34 percent for the same time period in 2009.

Market Structure

- **Supply.** For the first nine months of 2010, synchronized reserve offers were somewhat higher than for the equivalent period in 2009. The offered and eligible excess supply ratio was 1.23 for the PJM Mid-Atlantic Synchronized Reserve Region.[10] For the RFC zone, the excess supply ratio was 2.69. 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 2010, the contribution of DSR resources to the Synchronized Reserve Market remained significant and resulted in lower overall Synchronized Reserve prices.

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

- **Demand.** PJM made several changes to the hourly required synchronized reserve in 2010. For the first nine months of 2010 average synchronized reserve requirements were 1,211 MW for the Mid-Atlantic Subzone. On May 5, 2010, the synchronized reserve demand in the Mid-Atlantic Subzone was increased from 1,150 MW to 1,200 MW. This change was made to accommodate a dynamically changing largest contingency for the AP South constraint. In addition, double spinning was declared for May 24 and 25 of 1,800 MW because of a planned outage. On July 17, 2010, the synchronized reserve requirement for the Mid-Atlantic Subzone was increased from 1,200 MW to 1,300 MW.

  For the first nine months of 2010, in the Mid-Atlantic Subzone no Tier 2 synchronized reserve was needed in 36 percent of hours. The average required Tier 2 (including self scheduled) was 312 MW. The average required Tier 2 fell to 207 MW for the July through September period from 365 MW during the January through June period. The decrease in Tier 2 resulted from an increase in Tier 1 during the summer months.

  For the first six months of 2010, the synchronized reserve requirement was 1,320 MW for the RFC Synchronized Reserve Zone. On July 1, 2010, the requirement for the RFC Synchronized Reserve Zone was increased from 1,320 MW to 1,350 MW. The change was made to accommodate the largest single unit contingency. Additionally, there were 85 hours between September 20 and September 29 when the synchronized reserve requirement for the RFC Synchronized Reserve Zone was increased to 1,700 MW as a result of outages. 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.

  Synchronized reserves added out of market were four percent of all synchronized reserves during January through September of 2010.

  In the PJM Mid-Atlantic Synchronized Reserve Subzone, 64 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 312 MW. The lower demand for Tier 2 from the first six months of 2010 was the result of a larger supply of Tier 1 synchronized reserve. The demand was met by self scheduled synchronized reserves, which averaged 122 MW for the first nine months, and cleared Tier 2 synchronized reserves, which averaged 190 MW for the first nine months.

  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. A Tier 2 Synchronized Reserve Market was cleared for the Southern Synchronized Reserve Zone for only eight hours in the first nine months of 2010.

- **Market Concentration.** The average load weighted cleared Synchronized Reserve Market HHI for the Mid-Atlantic Subzone of the RFC Synchronized Reserve Zone for the first nine months of 2010 was 2642 which is classified as "highly concentrated."[11] For purchased synchronized reserve (cleared plus added) the HHI was 2686. During the first nine months of 2010, in 40 percent of hours the maximum market share was greater than 40 percent, compared to 41 percent of hours in the first nine months of 2009.

  In the Mid-Atlantic Subzone of the RFC Synchronized Reserve Market, for the first nine months of 2010, 36 percent of hours had three or fewer pivotal suppliers. The MMU concludes from these results that the PJM Synchronized Reserve Markets in the first nine months of 2010, were characterized by structural market power.

Market Conduct

- **Offers.** Daily cost based offer prices are submitted for each unit by the unit owner, and PJM adds opportunity cost 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.

  Demand side resources remained significant participants in the Synchronized Reserve Market in the first nine months of 2010. In nine percent of hours in which a Tier 2 Synchronized Reserve Market was cleared for the Mid-Atlantic Subzone, all synchronized reserves were provided by demand side resources.

11 See the *2009 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).

Market Performance

- **Price.** The load weighted, average PJM price for Tier 2 synchronized reserve in the Mid-Atlantic Subzone of the RFC Synchronized Reserve Market was $11.51 per MW for the first nine months of 2010, a $3.76 per MW increase from 2009. The market clearing price was only 70 percent of the total synchronized reserve cost per MW, lower than 2010. The difference between price and cost narrowed during 2009 as a result of several efforts by PJM to have the Synchronized Reserve Market more closely satisfy the needs of PJM dispatch.[12] As of September 2010, the price/cost ratio of synchronized reserve appears to be returning to its pre-2009 value of approximately 70 percent.

- **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 experienced a deficit during the first nine months of 2010.

DASR

On June 1, 2008 PJM introduced the Day-Ahead Scheduling Reserve Market (DASR), as required by the RPM settlement.[13] 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 for each reliability region.[14] 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 scheduling reserves, PJM is required to schedule additional operating reserves.

Market Structure

- **Concentration.** For the first nine months of 2010 less than two percent of hours failed the three pivotal supplier test in the DASR Market.

- **Demand.** Since January 2010, the required DASR is 6.88 percent of peak load forecast, up from 6.75 percent in 2009. [15] As a result of increased demand for energy, reflected in higher forecast peak loads and increased DASR requirements, the DASR MW purchased increased by 15 percent in the first nine months of 2010 over the same period in 2009.

12 See the *2009 State of the Market Report for PJM*, Volume II, Section 6, "Ancillary service Markets," at "Price and Cost", p. 392.
13 See PJM Interconnection, L.L.C., 117 FERC ¶ 61,331 (2006).
14 PJM. "Manual 13: Emergency Operations," Revision 40, (August 13, 2010); pp 11-12.
15 See the *2009 State of the Market Report for PJM*, Volume II, Section 6, "Ancillary Services" at Day Ahead Scheduling Reserve *(DASR)*, p. 397.

Market Conduct

- **Withholding.** 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. Five percent of units offered at $50 or more and four percent of units offered at more than $900, in a market with an average clearing price of $0.18 and a maximum clearing price of $39.99.

- **DSR.** Demand side resources do participate in the DASR Market but remain insignificant.

Market Performance

- **Price.** For the first nine months of 2010, the load weighted average price of DASR was $0.18, a significant increase over the average prices from January through June of $0.06 (See Table 6-14). DASR prices have been higher throughout 2010, and significantly higher in the third quarter.

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 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.[16]

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

16 PJM OATT Schedule § 1.3BB, Second Revised Sheet No. 33.01, March 1, 2007.

service, as defined in the tariff. For 2009, charges were about $12.3 million. For the first nine months of 2010 charges were $7.3 million. There was substantial zonal variation.

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.

Conclusion

The MMU concludes that the results of the Regulation Market are not competitive. The *2009 State of the Market Report for PJM* summarized the history of the issues related to the Regulation Market.[17] The MMU's conclusion regarding the results of the Regulation Market are not the result of the behavior of market participants, which was competitive, in part as a result of the application of the three pivotal supplier test, but are the result of the market design changes. The results of the Regulation Market are not competitive because the changes in market rules, in particular the changes to the calculation of the opportunity cost, are inconsistent with basic economic logic, and because of incorrect implementation of the market rules. For example, the changes to the calculation of the opportunity cost resulted in offers greater than competitive offers in some hours and therefore in prices greater than competitive prices in some hours, resulted in offers less than competitive offers in some hours and therefore in prices less than competitive prices in some hours.[18] The competitive price is the price that would have resulted from a combination of the competitive offers from market participants and the application of the prior, correct and consistent approach to the calculation of the opportunity cost. The offers from market participants are not at issue, as PJM directly calculates and adds opportunity costs to the offers of participants, following the revised market rules.

17 See the *2009 State of the Market Report for PJM*, Volume II, "Ancillary Service Markets."

18 The MMU has determined that the MMU's prior quantification of the impact on the clearing price of the changed calculation of opportunity cost is not correct. The MMU is working on improved calculations which will be made available when ready. A complete quantification of the impact is not required as a precondition to modifying the flawed market design. Differences from PJM estimates were the result of incorrect calculations by the MMU, which accounted for much of the difference, but were also the result of incorrect implementation of the rules by PJM.

The MMU recommends that the December 1, 2008, modification to the definition of opportunity cost be reversed and that the elimination of the offset against operating reserve credits be reversed based on the MMU conclusion that these features result in a non-competitive market outcome, and because they are inconsistent with the treatment of the same issues in other PJM markets and inconsistent with basic economic logic. The MMU also recommends that, to the extent that it is believed that additional revenue to generation owners is needed to maintain the outcome of the settlement in the short run, revenue neutrality be maintained by modifying the margin from its current level of $12.00 per MW at the same time that the opportunity cost definition is corrected. This change would maintain transparent incentives consistent with an effective market design. In the longer run, the proposed modifications to the pricing of regulation by both PJM and the MMU in their scarcity pricing recommendations will result in revenue increases that are expected to exceed any revenue loss from correcting the opportunity cost calculation.19 The MMU recommends that when the scarcity related modifications are implemented, the margin be reduced to its current level.

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 recommends that the DASR Market rules be modified to incorporate the application of the three pivotal supplier test. The MMU concludes that the DASR Market results were competitive in the first nine months of 2010.

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 the first nine months of 2010 as a result of the identified market design changes and their implementation, and not participant behavior, which was generally competitive. The MMU concludes that the Synchronized Reserve Market results were competitive in the first nine months of 2010. The MMU concludes that the DASR Market results were competitive in the first nine months of 2010.

Regulation Market

Market Structure

Supply and Demand

Table 6-1 PJM Regulation Market required MW and ratio of eligible supply to requirement: January through September 2010 (See 2009 SOM, Table 6-1)

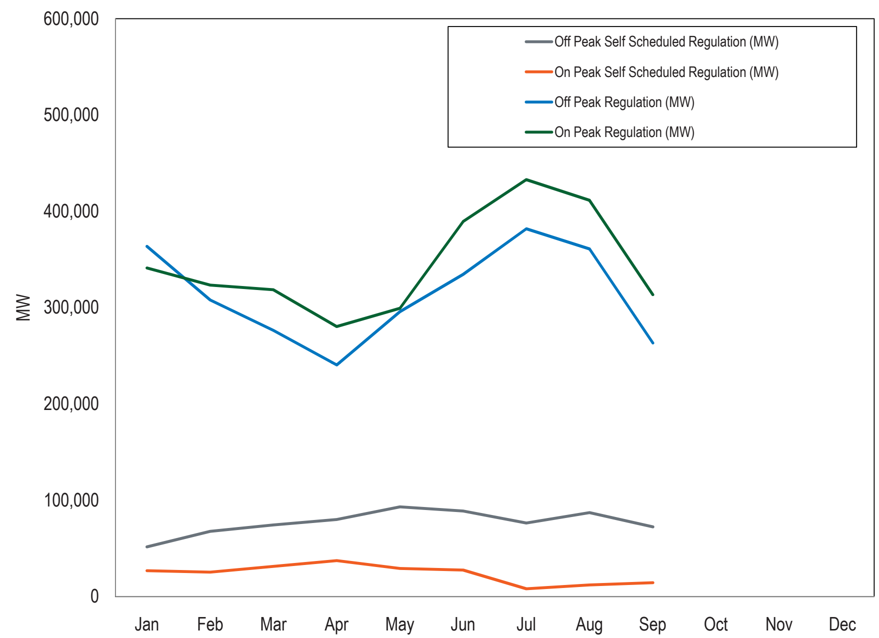
Month	Average Required Regulation (MW)	Ratio of Eligible Supply to Requirement
Jan	948	2.78
Feb	942	2.88
Mar	800	2.64
Apr	724	2.86
May	800	2.9
Jun	1,005	2.91
Jul	1,094	2.83
Aug	1,040	2.91
Sep	862	3.04

Table 6-2 PJM regulation capability, daily offer[19] and hourly eligible: January through September 2010 (See 2009 SOM, Table 6-2)

Period	Regulation Capability (MW)	Average Daily Offer (MW)	Percent of Capability Offered	Average Hourly Eligible (MW)	Percent of Capability Eligible
All Hours	7,863	5,594	71%	2,583	33%
Off Peak	7,863			2,307	29%
On Peak	7,863			2,888	37%

19 Average Daily Offer MW exclude units that have offers but make themselves unavailable for the day.

Figure 6-1 Off peak and on peak regulation levels: January through September 2010 (See 2009 SOM, Figure 6-2)



Market Concentration

Table 6-3 PJM cleared regulation HHI: January through September 2010 (See 2009 SOM, Table 6-3)

Market Type	Minimum HHI	Load-weighted Average HHI	Maximum HHI
Cleared Regulation, January - September, 2010	763	1401	2983

Figure 6-2 PJM Regulation Market HHI distribution: January through September 2010 (See 2009 SOM, Figure 6-1)

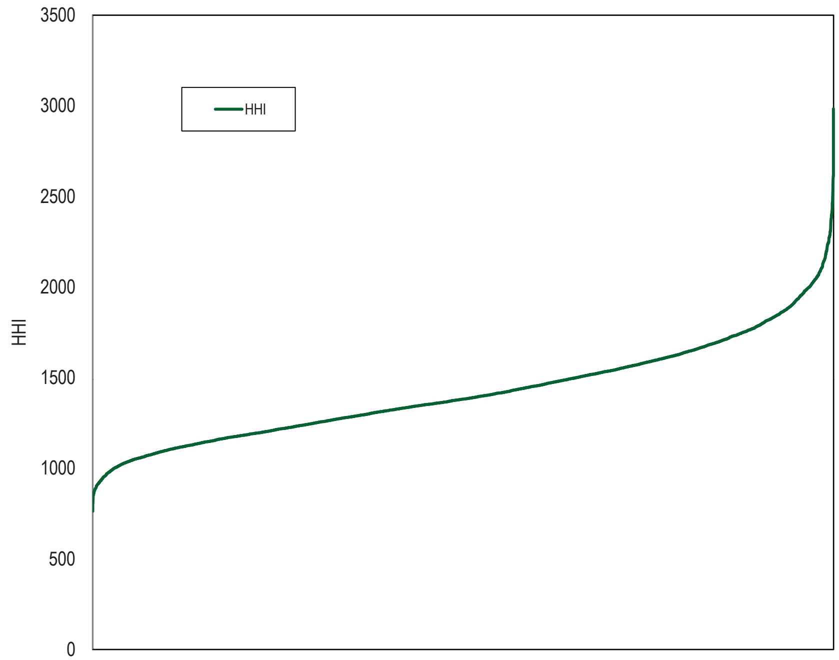


Table 6-4 Highest annual average hourly Regulation Market shares: January through September 2010 (See 2009 SOM, Table 6-4)

Company Market Share Rank	Cleared Regulation Top Yearly Market Shares
1	17%
2	15%
3	15%
4	14%
5	9%

Table 6-5 Regulation market monthly three pivotal supplier results: January through September 2010 (See 2009 SOM, Table 6-5)

Month	Percent of Hours With Three Pivotal Suppliers
Jan	74%
Feb	70%
Mar	81%
Apr	82%
May	79%
Jun	81%
Jul	75%
Aug	69%
Sep	70%

Table 6-6 Percent of hours when marginal unit supplier failed PJM's three pivotal supplier test: January through September 2010 (See 2009 SOM, Table 6-6)

Month	Percent of Hours When Marginal Supplier is Pivotal
Jan	67%
Feb	58%
Mar	71%
Apr	81%
May	78%
Jun	76%
Jul	69%
Aug	60%
Sep	57%

Market Performance

Price

Figure 6-3 PJM Regulation Market daily average market-clearing price, opportunity cost and offer price (Dollars per MWh): January through September 2010 (See 2009 SOM, Figure 6-3)

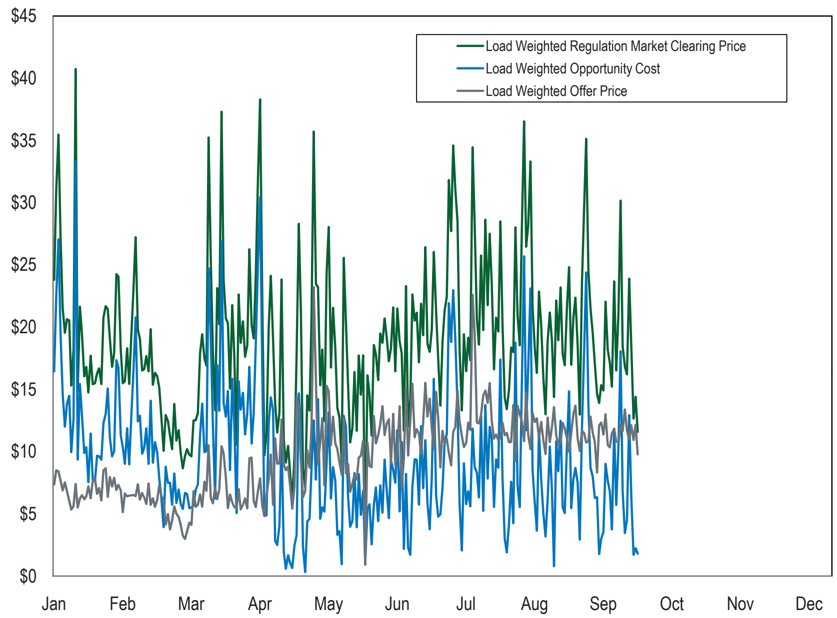


Figure 6-4 Monthly average regulation demand (required) vs. price: January through September 2010 (See 2009 SOM, Figure 6-4)

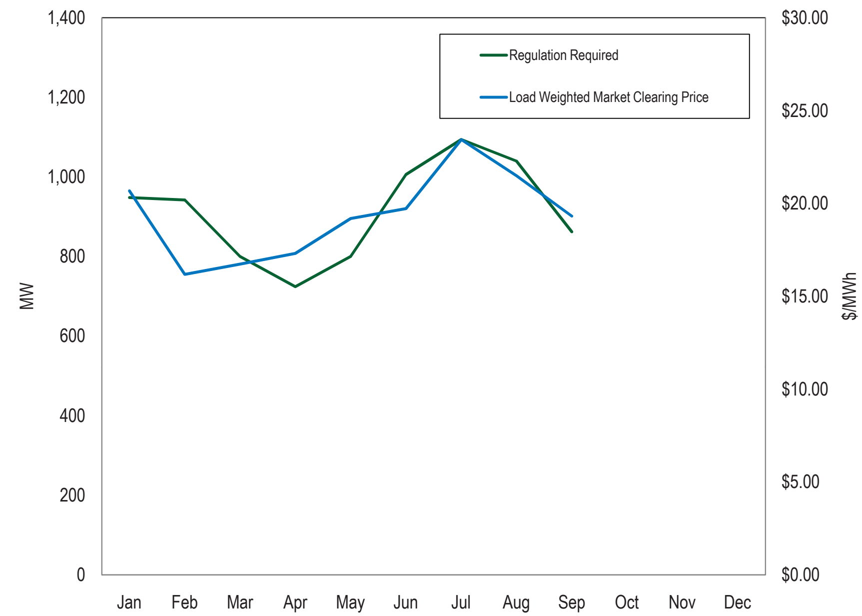


Figure 6-5 Monthly load weighted, average regulation cost and price: January through September 2010 (See 2009 SOM, Figure 6-5)

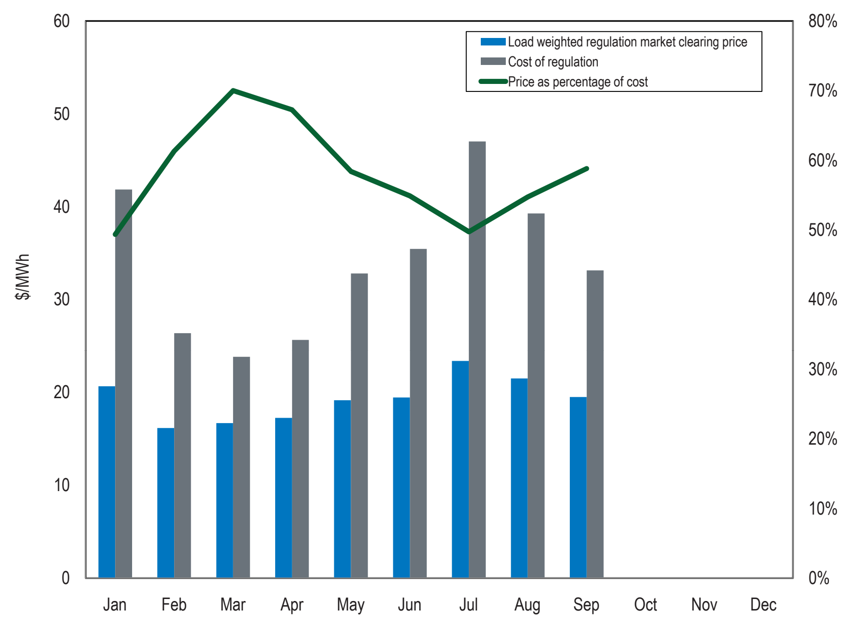


Table 6-7 Total regulation charges: January through September 2010 (See 2009 SOM, Table 6-7)

Month	Scheduled Regulation (MW)	Total Regulation Charges	Load Weighted Regulation Market Clearing Price ($/MWh)	Cost of Regulation ($/MWh)
Jan	704,362	$29,479,645	$20.66	$41.85
Feb	632,007	$16,673,515	$16.17	$26.38
Mar	594,378	$14,167,033	$16.69	$23.84
Apr	518,526	$13,307,387	$17.26	$25.66
May	588,452	$19,307,043	$19.16	$32.81
Jun	658,837	$23,355,270	$19.46	$35.45
Jul	723,322	$34,017,913	$23.39	$47.03
Aug	750,524	$29,482,419	$21.50	$39.28
Sep	580,410	$19,238,702	$19.27	$32.98

Table 6-8 Comparison of load weighted price and cost for PJM Regulation, August 2005 through September 2010[20] (New Table)

Year	Load Weighted Regulation Market Price	Load Weighted Regulation Market Cost	Regulation Price as Percent Cost
2005	$64.03	$77.39	83%
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 (Jan-Sep)	$19.28	$33.92	57%

Regulation Market Changes

Table 6-9 Summary of changes to Regulation Market design (See 2009 SOM, Table 6-8)

Prior Regulation Market Rules (Effective May 1, 2005 through November 30, 2008)	New Regulation Market Rules (Effective December 1, 2008)
1. No structural test for market power.	1. Three Pivotal Supplier structural test for market power.
2. Offers capped at cost for identified dominant suppliers. (American Electric Power Company(AEP) and Virginia Electric Power Company (Dominion)) Price offers capped at $100 per MW.	2. Offers capped at cost for owners that fail the TPS test. Price offers capped at $100 per MW.
3. Cost based offers include a margin of $7.50 per MW.	3. Cost based offers include a margin of $12.00 per MW.
4. Opportunity cost calculated based on the offer schedule on which the unit is dispatched in the energy market.	4. Opportunity cost calculated based on the lesser of the price-based offer schedule or the highest cost-based offer schedule in the energy market.
5. All regulation net revenue above offer plus opportunity cost credited against operating reserve credits to unit owners.	5. No regulation market revenue above offer plus opportunity cost credited against operating reserve credits to unit owners.

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

TPS Testing

Table 6-10 Regulation Market pivotal supplier test results: December 2008 through September 2010 and December 2007 through September 2009 (See 2009 SOM, Table 6-9)

Year	Month	Percent of Hours With Three Pivotal Suppliers	Year	Month	Percent of Hours With Three Pivotal Suppliers
2008	Dec	92%	2007	Dec	79%
2009	Jan	84%	2008	Jan	84%
2009	Feb	61%	2008	Feb	83%
2009	Mar	42%	2008	Mar	89%
2009	Apr	39%	2008	Apr	88%
2009	May	31%	2008	May	97%
2009	Jun	37%	2008	Jun	77%
2009	Jul	39%	2008	Jul	75%
2009	Aug	35%	2008	Aug	80%
2009	Sep	47%	2008	Sep	74%
2009	Oct	64%	2008	Oct	89%
2009	Nov	62%	2008	Nov	59%
2009	Dec	80%	2008	Dec	92%
2010	Jan	74%	2009	Jan	84%
2010	Feb	70%	2009	Feb	61%
2010	Mar	83%	2009	Mar	42%
2010	Apr	82%	2009	Apr	39%
2010	May	79%	2009	May	31%
2010	Jun	81%	2009	Jun	37%
2010	Jul	75%	2009	Jul	39%
2010	Aug	69%	2009	Aug	35%
2010	Sep	70%	2009	Sep	47%

Synchronized Reserve Market

Market Structure

Demand

Figure 6-6 RFC Synchronized Reserve Zone monthly average synchronized reserve required vs. Tier 2 scheduled MW: January through September 2010 (See 2009 SOM, Figure 6-6)

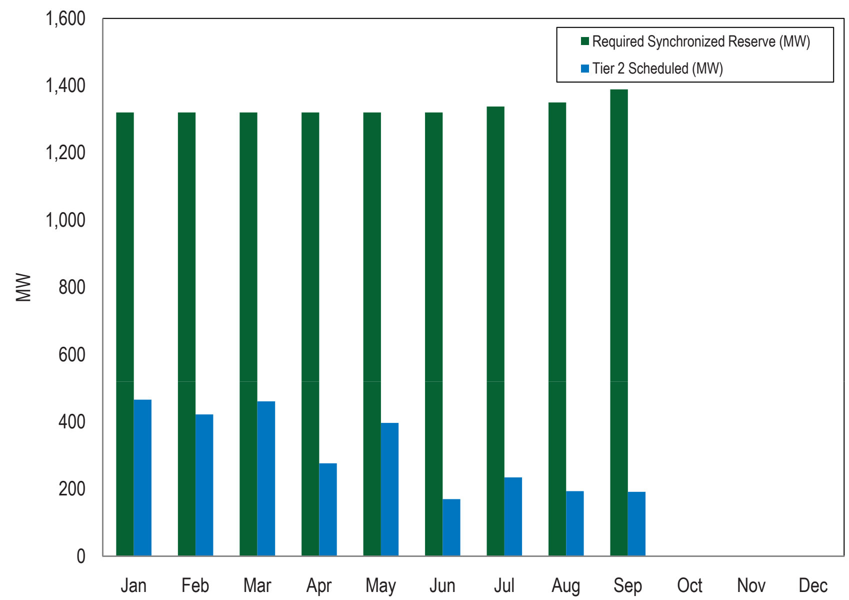
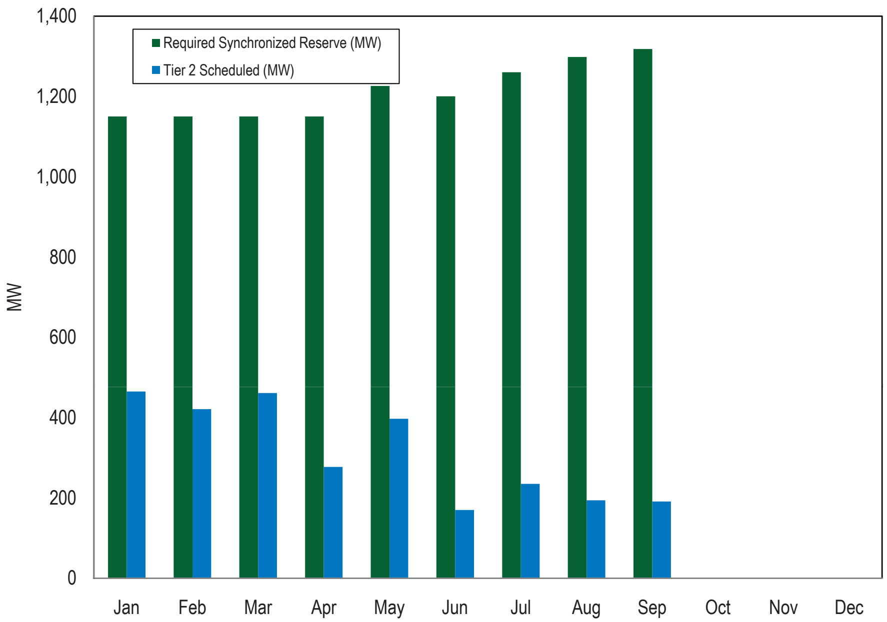


Figure 6-7 RFC Synchronized Reserve Zone, Mid-Atlantic Subzone average hourly synchronized reserve required vs. Tier 2 scheduled: January through September 2010 (See 2009 SOM, Figure 6-7)



Market Concentration

Figure 6-8 Purchased Mid-Atlantic Subzone RFC Tier 2 Synchronized Reserve Market seasonal HHI: January through September 2010 (See 2009 SOM, Figure 6-8)

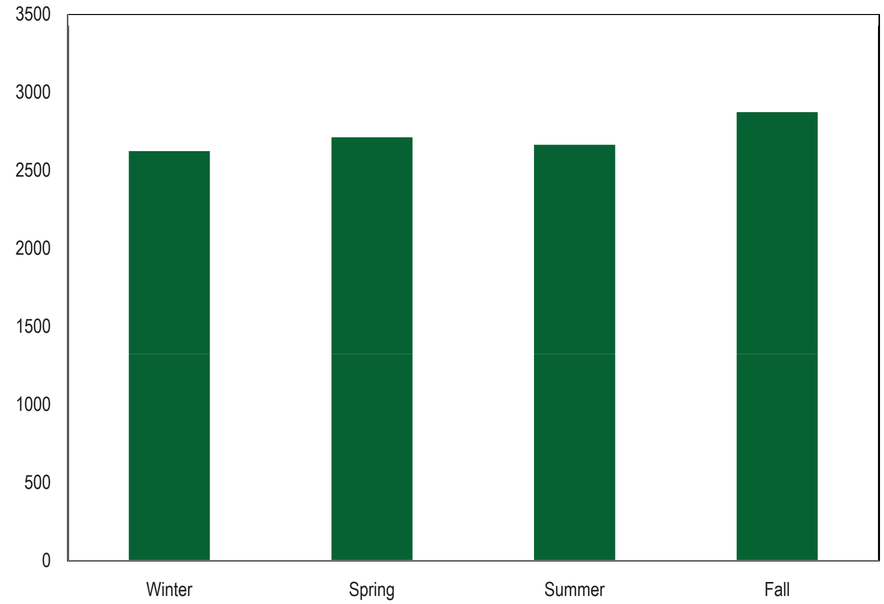


Table 6-11 Mid-Atlantic Subzone RFC Tier 2 Synchronized Reserve Market's cleared market shares: January through September 2010 (See 2009 SOM, Table 6-15)

Company Market Share Rank	Cleared Synchronized Reserve Top Market Shares
1	32%
2	27%
3	24%
4	20%
5	18%

Market Conduct

Offers

Figure 6-9 Tier 2 synchronized reserve average hourly offer volume (MW): January through September 2010 (See 2009 SOM, Figure 6-9)

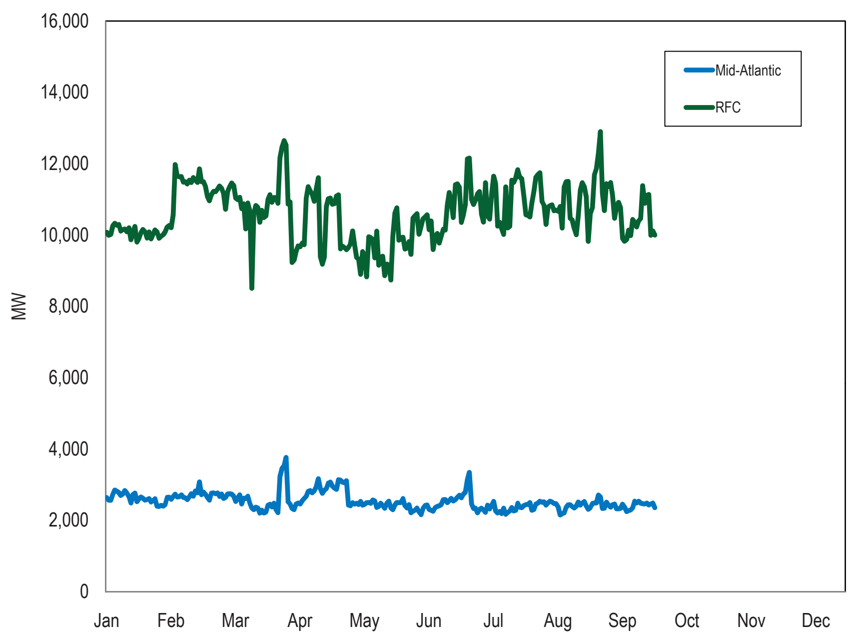
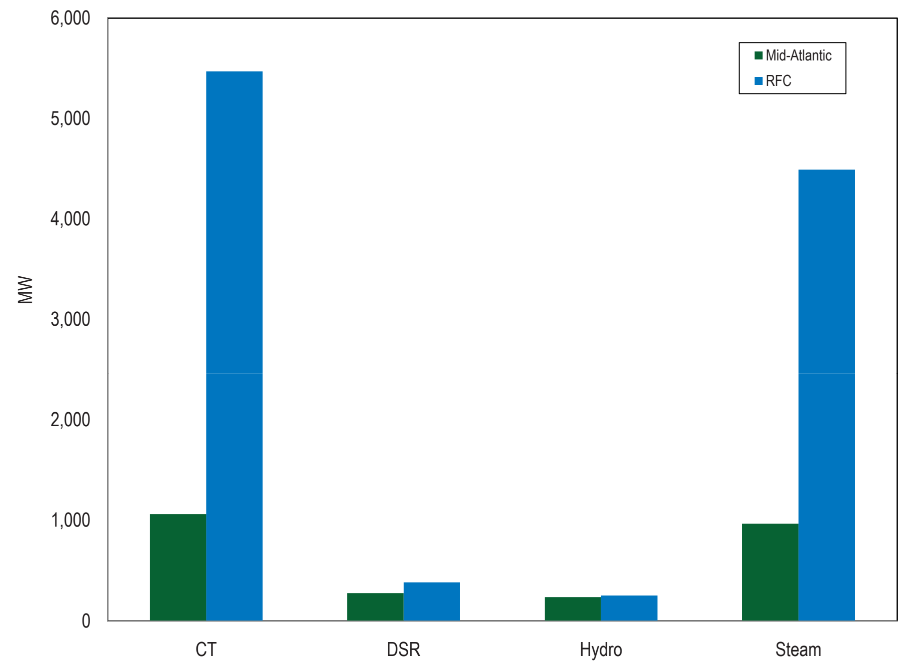


Figure 6-10 Average daily Tier 2 synchronized reserve offer by unit type (MW): January through September 2010 (See 2009 SOM, Figure 6-10)

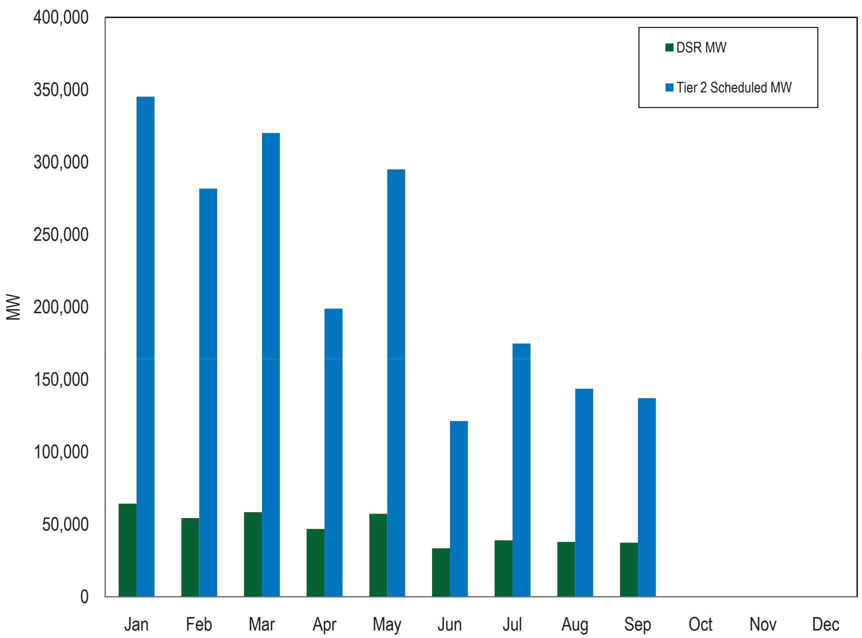


DSR

Table 6-12 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 (See 2009 SOM, Table 6-16)

Month	Average SRMCP when all cleared synchronized reserve is DSR	Percent of scheduled synchronized reserve is DSR	Average SRMCP	Percent of cleared hours all synchronized reserve is DSR
Jan	$5.84	33%	$2.03	4%
Feb	$5.97	31%	$0.10	1%
Mar	$8.45	39%	$2.01	6%
Apr	$7.84	34%	$1.86	17%
May	$9.98	25%	$1.68	15%
Jun	$9.61	32%	$0.74	9%
Jul	$16.30	28%	$0.79	7%
Aug	$11.17	34%	$0.93	12%
Sep	$10.45	33%	$1.15	12%

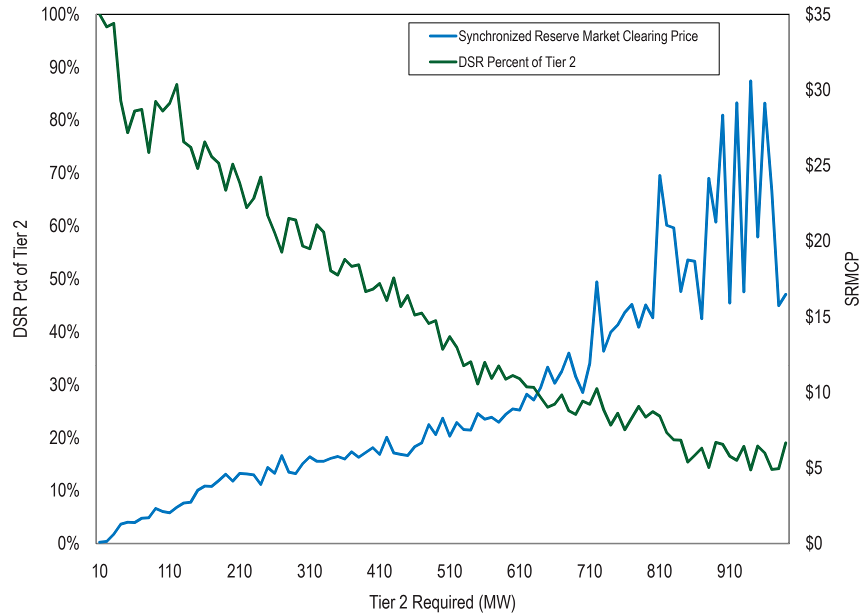
Figure 6-11 PJM RFC Zone Tier 2 synchronized reserve scheduled MW: January through September 2010 (See 2009 SOM, Figure 6-11)



Market Performance

Price

Figure 6-12 Required Tier 2 synchronized reserve, Synchronized Reserve Market clearing price, and DSR percent of Tier 2: January through September 2010 (See 2009 SOM, Figure 6-12)



Price and Cost

Figure 6-13 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 2010 (See 2009 SOM, Figure 6-13)

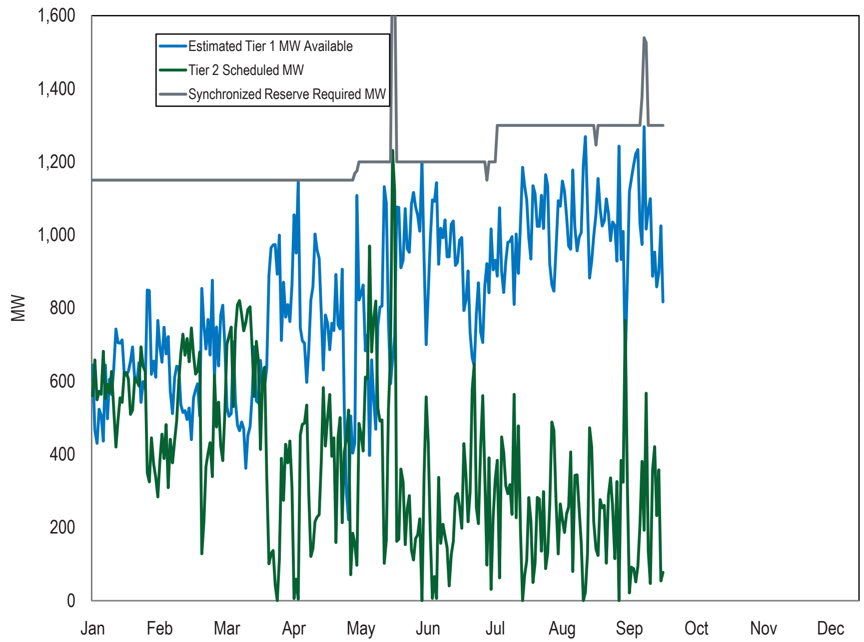


Figure 6-14 Tier 2 synchronized reserve purchases by month for the Mid-Atlantic Subzone: January through September 2010 (See 2009 SOM, Figure 6-14)

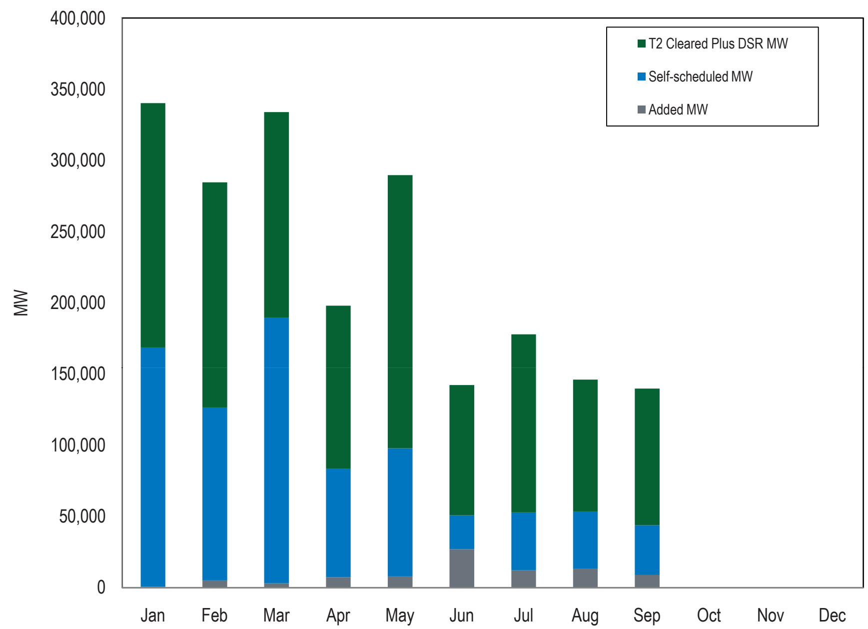


Figure 6-15 Impact of Tier 2 synchronized reserve added MW to the RFC Synchronized Reserve Zone, Mid-Atlantic Subzone: January through September 2010 (See 2009 SOM, Figure 6-15)

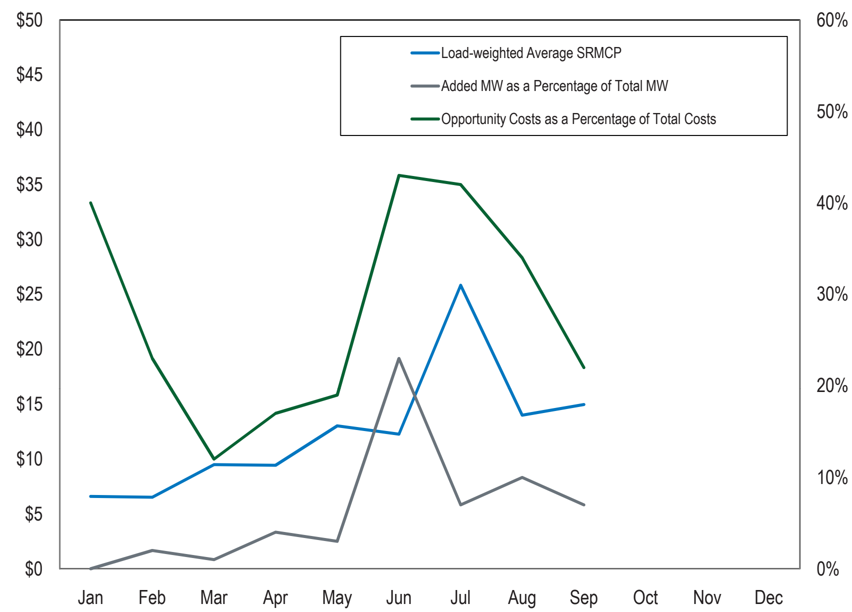


Figure 6-16 Comparison of RFC Mid-Atlantic Subzone Tier 2 synchronized reserve price and cost (Dollars per MW): January through September 2010 (See 2009 SOM, Figure 6-16)

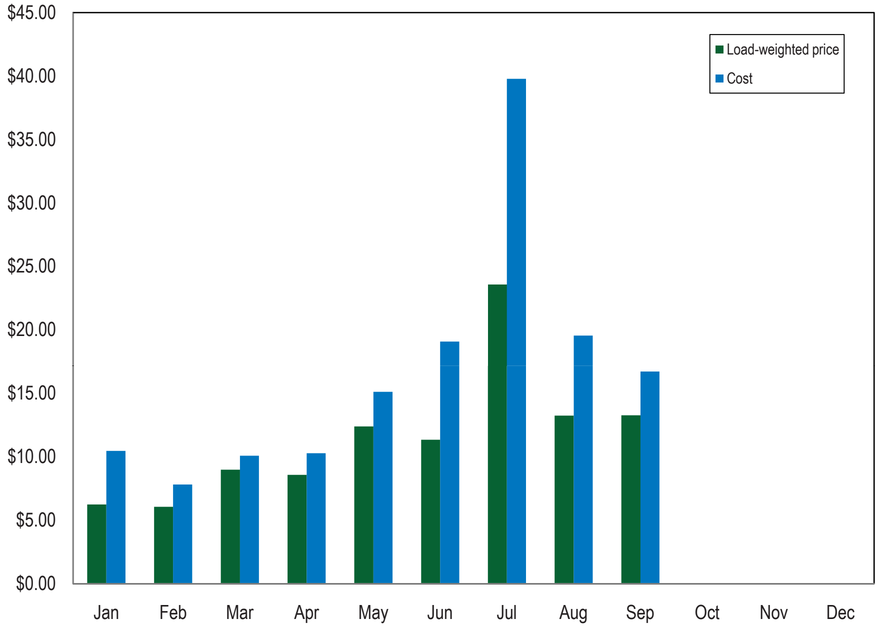


Table 6-13 Comparison of load weighted price and cost for PJM Synchronized Reserve, January 2005 through September 2010 (New Table)

Year	Load Weighted Synchronized Reserve Market Price	Load Weighted Synchronized Reserve Cost	Synchronized Reserve Price as Percent of Cost
2005	$13.29	$17.59	76%
2006	$14.57	$21.65	67%
2007	$11.22	$16.26	69%
2008	$10.65	$16.43	65%
2009	$7.75	$9.77	79%
2010 (Jan-Sep)	$11.51	$16.54	70%

Day-Ahead Scheduling Reserve (DASR)

Table 6-14 PJM, Day-Ahead Scheduling Reserve Market MW and clearing prices: January through September 2010 (See 2009 SOM, Table 6-17)

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	6,246	$0.00	$0.75	$0.05	4,647,334	$242,018
Feb	6,191	$0.00	$0.50	$0.06	4,160,064	$228,087
Mar	5,441	$0.00	$0.50	$0.03	4,042,540	$109,862
Apr	4,871	$0.00	$0.42	$0.01	3,789,115	$45,352
May	5,487	$0.00	$2.00	$0.05	4,082,028	$164,277
Jun	6,864	$0.00	$5.00	$0.18	4,941,835	$838,178
Jul	7,464	$0.00	$39.99	$0.76	5,553,319	$3,606,940
Aug	7,131	$0.00	$12.00	$0.38	5,305,750	$1,754,295
Sep	5,889	$0.00	$5.00	$0.06	4,239,965	$241,798

Black Start Service

Table 6-15 Black Start yearly zonal charges for network transmission use: January through September 2010 (See 2009 SOM, Table 6-18)

Zone	Network Charges
AECO	$274,395
AEP	$481,242
AP	$99,639
BGE	$362,682
ComEd	$2,753,344
DAY	$102,563
DLCO	$20,730
DPL	$269,639
JCPL	$324,274
Met-Ed	$301,423
PECO	$561,358
PENELEC	$245,883
Pepco	$178,292
PPL	$111,807
PSEG	$1,089,557
UGI	$111,807