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 2009.

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 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 2009.
3 See 117 FERC ¶ 61,331 at P 29 n32 (2006).

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 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 findings of the report have been updated and corrected and the results are presented below. The changes to the Regulation Market rules resulted in a significant (23 percent) increase in payments to the providers of regulation compared to what they would have otherwise received and compared to what they would have received in a competitive market design.

Market Structure

- **Supply.** During 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 2009, an increase from the 2008 ratio of 2.39.

- **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 for all of 2009 was 849 MW, compared to 922 MW for 2008.

- **Market Concentration.** During 2009, the PJM Regulation Market had a load weighted, average Herfindahl-Hirschman Index (HHI) of 1365 which is classified as "moderately concentrated."[5] The minimum hourly HHI was 699 and the maximum hourly HHI was 9405. The largest hourly market share in any single hour was 97 percent, and 71 percent of all hours had a maximum market share greater than 20 percent. The maximum HHI and the average HHI were higher in 2009 than in 2008. The increase in concentration began in May 2009, when there was a significant increase in self-scheduled regulation during off-peak hours, which reduced the amount of regulation purchased in the market.

  For 2009, 52 percent of hours had one or more pivotal suppliers. The MMU concludes from these results that the PJM Regulation Market for 2009 was characterized by structural market power in 52 percent of the hours.

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 2, "Energy Market, Part I," at "Market Concentration" for a more complete discussion of concentration ratios and the Herfindahl-Hirschman Index (HHI).

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. All offers remain subject to the $100 per MWh cap.[6] In computing the market solution, PJM adds opportunity cost. 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. All units of owners who fail the three pivotal supplier test for an hour have their offers 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 calculates opportunity costs using LMP forecasts and the lesser of the available price based offer or the most expensive available cost based offer as the reference, rather than the offer on which the unit is operating.[7] PJM adds this opportunity cost to the offers of the market participants. The impact of this change was to increase cost based and price based offer prices.

Market Performance

- **Price.** For the PJM Regulation Market during 2009, the load weighted, average price per MWh (the regulation market clearing price, including opportunity cost) associated with meeting PJM's demand for regulation was $23.56. This was a decrease of $18.53, or 44 percent, from the average price for regulation during 2008.

- **Price and Opportunity Cost.** Prices in the PJM Regulation Market were approximately 19 percent higher than they would have been but for the change to the definition of opportunity cost.

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

6 See PJM. "Manual 11: Scheduling Operations," Revision 43 (September 24, 2009), p.39.

7 See PJM. "Manual 11: Scheduling Operations," Revision 43 (September 24, 2009), p. 43: "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. "

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 two percent of all synchronized reserve during April through December of 2009, while they were 39 percent for the same time period in 2008. Opportunity cost payments accounted for 23 percent of total costs during April through December of 2009 compared to 43 percent during the same time period in 2008.

Market Structure

- **Supply.** For 2009, the offered and eligible excess supply ratio was 1.53 for the PJM Mid-Atlantic Synchronized Reserve Region.[8] For the RFC zone, the excess supply ratio was 1.93. 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 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 1,351 MW for the RFC Synchronized Reserve Zone and 1,168 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 Tier 2 synchronized reserve 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.

  The problem of additional procurement of Tier 2 synchronized reserves by PJM dispatch after Synchronized Reserve Market settlement has been greatly reduced. For all of 2009, 9 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 December 2009 two percent of all purchased Tier 2 synchronized reserves were added after the market cleared.

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

As a result of the level of Tier 1 reserves in the RFC Synchronized Reserve Zone, less than three percent of hours cleared a Tier 2 Synchronized Reserve Market in the RFC. In the Southern Synchronized Reserve Zone only one half of one percent of hours cleared a Tier 2 market in 2009. In the PJM Mid-Atlantic Synchronized Reserve Region, 74 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 297 MW.

- **Market Concentration.** The average load weighted cleared Synchronized Reserve Market HHI for the Mid-Atlantic Subzone of the RFC Synchronized Reserve Zone for all of 2009 was 2619 which is classified as "highly concentrated."[9] For purchased synchronized reserve (cleared plus added) the HHI was 3070. Less than one percent of all hours had a market share of 100 percent. In 36 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 all of 2009, 95 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 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 2009. In 12 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.

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 $7.46 per MW for all of 2009, a $3.19 per MW decrease from 2008.

- **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 2009.

9 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).

DASR

On June 1, 2008 PJM introduced the Day-Ahead Scheduling Reserve Market (DASR), as required by the RPM settlement.[10] 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.[11] 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.** The DASR Market for all of 2009 had three pivotal suppliers in an average of 24 percent of all hours. The MMU concludes from these results that the PJM DASR Market in 2009 was characterized by structural market power.

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. 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 $4.00.

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

Market Performance

- **Price.** For 2009, the load weighted price of DASR was $0.05, including the 37 percent of hours when the market cleared at a price of $0.00.

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.[12]

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

10 See PJM Interconnection, L.L.C., 117 FERC ¶ 61,331 (2006).
11 PJM Manual 13, Emergency Requirements, Revision 39, 01/01/2010; pp 11-12.
12 PJM OATT Schedule § 1.3BB, Second Revised Second Revised Sheet No. 33.01, March 1, 2007.

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 2009, charges were about $14.2 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

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.[13] 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.[14] A number of parties filed comments, including the MMU on October 20, 2008.[15]

The MMU welcomed the application of the TPS test to the Regulation Market, but expressed concerns regarding the three adjustments to the regulation market design. The MMU supported the October 1st filing with the caveat that if the MMU review of the actual impact of the changes "results in a conclusion that these features result in non-competitive market outcomes, the Market Monitor will request that one or more of these provisions be removed or modified."

The MMU requested that the Commission direct the MMU to report on the three adjustments to the rules: (i) increasing the margin on cost based offers from $7.50 to $12.00 per MW; (ii) modifying the calculation of opportunity costs to use the lower of cost based or price based offers rather than the current dispatch schedule as the reference; and (iii) eliminating the netting of regulation revenues from make whole balancing operating reserve payments. The Commission, in its order accepting PJM's filing on November 26, 2008, directed the MMU to prepare a report due on November 26, 2009.[16]

On December 1, 2008, the TPS test was implemented in the Regulation Market to address the identified market power problems. The three other market design changes were also implemented on December 1, 2008.

13 See PJM 2007 Strategic Report at 65 (April 2, 2007). This report is posted on PJM's website at: <http://www.pjm.com/~/media/documents/downloads/strategic-responses/report/20070402-pjm-strategic-report.ashx>(1.23 MB).

14 PJM submitted its initial filing in FERC Docket No. ER09-13-000.

15 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/reports/Reports/2008/imm-motion-to-intervene-and-comments.pdf>.

16 125 FERC ¶ 61,231, at P 18 (2008).

The MMU presented a preliminary analysis of the impact of the three adjustments in its quarterly state of the market reports issued August 14 and November 13, 2009. The MMU concluded, on the basis of the first six months, "The impact on market performance for these December 1, 2008 PJM changes has been significant" and that "the other changes to the Regulation Market implemented on December 1, 2008 have significantly increased the price of regulation."[17] In the next quarterly report, the MMU similarly stated, "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.[18]

Consistent with the directive in the November 26th order, the MMU analyzed the impact of the three adjustments to the regulation market during the twelve months after implementation and submitted a report to the FERC on November 30, 2009.[19] The report concluded, in part, that "The market design changes added a substantial cost to those paying for regulation without any evidence that this cost was required for either cost recovery or incentives."[20] The report stated: "The MMU recommends that the modification to the definition of opportunity cost be reversed and that the elimination of the offset against operating reserve credits be reversed as they are inconsistent with the treatment of the same issues in other PJM markets and inconsistent with basic economic logic."[21] The report also recognized that the Regulation Market is more competitive as a result of the implementation of the three pivotal supplier test but concluded that "the changes are not consistent with an efficient or competitive market design and are not consistent with the way in which the same issues are addressed for other PJM markets in the PJM tariff."[22]

The MMU has updated the calculations, improved the calculations and made corrections as necessary, based in part on PJM's comments.[23] This updated and improved analysis is presented below.

Together, the changes to the tariff related to the Regulation Market resulted in an increase in payments to the providers of regulation of $55.1 million over the 13 month period from December 2008 through December 2009, compared to what they would have received in the absence of these three changes. This represents an increase in total regulation payments of 25 percent for the 13 month period. While these results are based on estimates of how the market would have worked in the absence of the changes in market design, the calculations reflect detailed hourly data about the individual units in the Regulation Market supply curve. There is no question that the changes in market design significantly increased the payments for regulation service, regardless of any disagreements about the details of the calculation methods.

The MMU concludes, based on the analysis of the Regulation Market operating under the revised rules, that the results of the Regulation Market are not competitive. 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, resulted in offers greater than competitive offers and therefore in prices greater than competitive prices. The competitive price is the price that would have resulted

17 *2009 Quarterly State of the Market Report for PJM: January through June* at 120, 124.
18 *2009 Quarterly State of the Market Report for PJM: January through September* at 115.
19 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).
20 *Id.* at 2.
21 *Id.*
22 *Id.* at 8.
23 Comments of PJM Interconnection, L.L.C. to Report of Independent Market Monitor filed in ER09-13 (December 30, 2009). The Illinois Commerce Commission also filed comments on the MMU's report: Comments of the Illinois Commerce Commission filed in ER09-13 (January 6, 2010).

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. The Regulation Market results are the result of the market design changes and are not the result of the behavior of market participants, which was competitive as a result of the application of the three pivotal supplier test.

The MMU recommends that the 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 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 calculated by the MMU. 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 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 not competitive in 2009. The MMU concludes that the Synchronized Reserve Market results were competitive in 2009. The MMU concludes that the DASR Market results were competitive in 2009.

Regulation Market

Market Structure

The market structure of the 2009 PJM Regulation Market remained similar to the market structure of the 2008 Regulation Market. Rule changes significantly affected the design of the Regulation Market.

Supply

The supply of regulation can be measured as regulation capability, regulation offered, or regulation offered and eligible. For purposes of evaluating the Regulation Market, the relevant regulation supply is the level of supply that is both offered to the market on an hourly basis and is eligible to participate in the market on an hourly basis. This is the only supply that is actually considered in the determination of market prices. The level of supply that clears in the market on an hourly basis is called cleared regulation. Assigned regulation is the total of self-scheduled and cleared regulation. Assigned regulation is selected from regulation that is eligible to participate.

Regulation capability is the sum of the maximum daily offers for each unit and is a measure of the total volume of regulation capability as reported by resource owners.

Regulation offered represents the level of regulation capability offered to the PJM Regulation Market. Resource owners may offer those units with approved regulation capability into the PJM Regulation Market. PJM does not require a resource capable of providing regulation service to offer its capability to the market. Regulation offers are submitted on a daily basis.

Regulation offered and eligible represents the level of regulation capability offered to the PJM Regulation Market and actually eligible to provide regulation in an hour. Some regulation offered to the market is not eligible to participate in the Regulation Market as a result of identifiable offer parameters specified by the supplier. As an example, the regulation capability of a unit is included in regulation offered based on the daily offer and availability status, but that regulation capability is not eligible in one or more hours because the supplier sets the availability status to unavailable for one or more hours of that same day. (The availability status of a unit may be set in both a daily offer and an hourly update table in the PJM market user interface.) As another example, the regulation capability of a unit is included in regulation offered if the owner of a unit offers regulation, but that regulation capability is not eligible if the owner sets the unit's economic maximum generation level equal to its economic minimum generation level. In that case, the unit cannot provide regulation and is not eligible to provide regulation. As another example, the regulation capability of a unit is included in regulation offered, but that regulation capability is not eligible if the unit is not operating, unless the unit meets specific operating parameter requirements. A unit whose owner has not submitted a cost based offer will not be eligible to regulate even if the unit is a regulation resource.

Only those offers eligible to provide regulation in an hour are part of supply for that hour, and only eligible offers are considered by PJM for purposes of clearing the market. Regulation assigned represents those regulation resources selected through the regulation market clearing mechanism to provide regulation service for a given hour.

The average eligible regulation supply-to-requirement ratio in the PJM Regulation Market during 2009 was 2.98. Even during periods of diminished supply such as off-peak hours, eligible regulation supply was adequate to meet the regulation requirement.

Demand

Demand for regulation does not change with price, i.e. demand is price inelastic. The demand for regulation is set administratively based on reliability objectives and forecast load. Regulation demand is also referred to in the *2009 State of the Market Report for PJM* as "required regulation."

The PJM regulation requirement is set by PJM Interconnection in accordance with NERC control standards. In August 2008 the requirement was adjusted to be 1.0 percent of the forecast peak load for on peak hours and 1.0 percent of the forecast valley load for off peak hours.[24] During 2009 the PJM regulation requirements ranged from 501 MW to 1,279 MW. The average required regulation off-peak was 773 and the average required regulation on-peak was 933 MW (Table 6-1).

Table 6-1 PJM Regulation Market required MW and ratio of supply to requirement: Calendar year 2009

Period Type	Average Required Regulation (MW)	Ratio of Supply to Requirement
All of 2009	849	2.98
Fall	772	3.1
Spring	771	2.9
Summer	929	3.15
Winter	928	2.76
Off Peak	773	2.89
On Peak	933	3.08

Market Concentration

During 2009 the PJM Regulation Market total capability was 7,805 MW.[25] Total capability is a theoretical measure which is never actually achieved. The level of regulation resources offered on a daily level and the level of regulation resources eligible to participate on an hourly level in the market were lower than the total regulation capability. In 2009 the average daily offer level was 6,343 MW or 81 percent of total capability while the average hourly eligible offer level was 2,537 MW or 33 percent of total capability. In 2009 the average hourly eligible offer level was 40 percent of the average daily offer level. Although regulation is offered daily, eligible regulation changes hourly. Typically less regulation is eligible during off-peak hours because fewer steam units are running during those hours. Table 6-2 shows capability, daily offer and average hourly eligible MW for all hours as well as for off-peak and on-peak hours.

24 See Reliability*First* Corporation <http://www.rfirst.org/> (1 KB).

25 Total offer capability is defined as the sum of the maximum daily offer volume for each offering unit during the period, without regard to the actual availability of the resource or to the day on which the maximum was offered.

Table 6-2 PJM regulation capability, daily offer and hourly eligible: Calendar year 2009

Period	Regulation Capability (MW)	Average Daily Offer (MW)	Percent of Capability Offered	Average Hourly Eligible (MW)	Percent of Capability Eligible
All Hours	7,805	6343	81%	2,537	33%
Off Peak	7,805			2,190	28%
On Peak	7,805			2,865	37%

The ratio of the hourly eligible regulation supply to the hourly regulation requirement averaged 2.98 for PJM during 2009. When this ratio equals 1.0, it indicates that offered supply exactly equals demand for the referenced time period.

Hourly HHI values were calculated based on cleared regulation. In 2009 HHI values ranged from a maximum of 9405 to a minimum of 699, with a load weighted average value of 1365, which is categorized as moderately concentrated by the FERC definitions. Table 6-3 summarizes the 2009 PJM Regulation Market HHIs. The maximum HHI and the average HHI were higher in 2009 than in 2008. The increase in concentration began in May 2009, when there was a significant increase in self-scheduled regulation during off-peak hours, which reduced the amount of regulation purchased in the market.

Table 6-3 PJM cleared regulation HHI: Calendar year 2009

Market Type	Minimum HHI	Load-Weighted Average HHI	Maximum HHI
Cleared Regulation, 2008	707	1290	2767
Cleared Regulation, January through July	707	1226	2767
Cleared Regulation, August through December	736	1397	2480

In 2009, 13 percent of all periods had an HHI less than 1000 and 18 percent of all periods had an HHI greater than 1800, with a maximum of 9405. An HHI of 1800 is the threshold for “highly concentrated” by the FERC definitions. The maximum period HHI in 2008 was 2767. See the HHI distribution curve in Figure 6-1.

Figure 6-1 PJM Regulation Market HHI distribution: Calendar year 2009

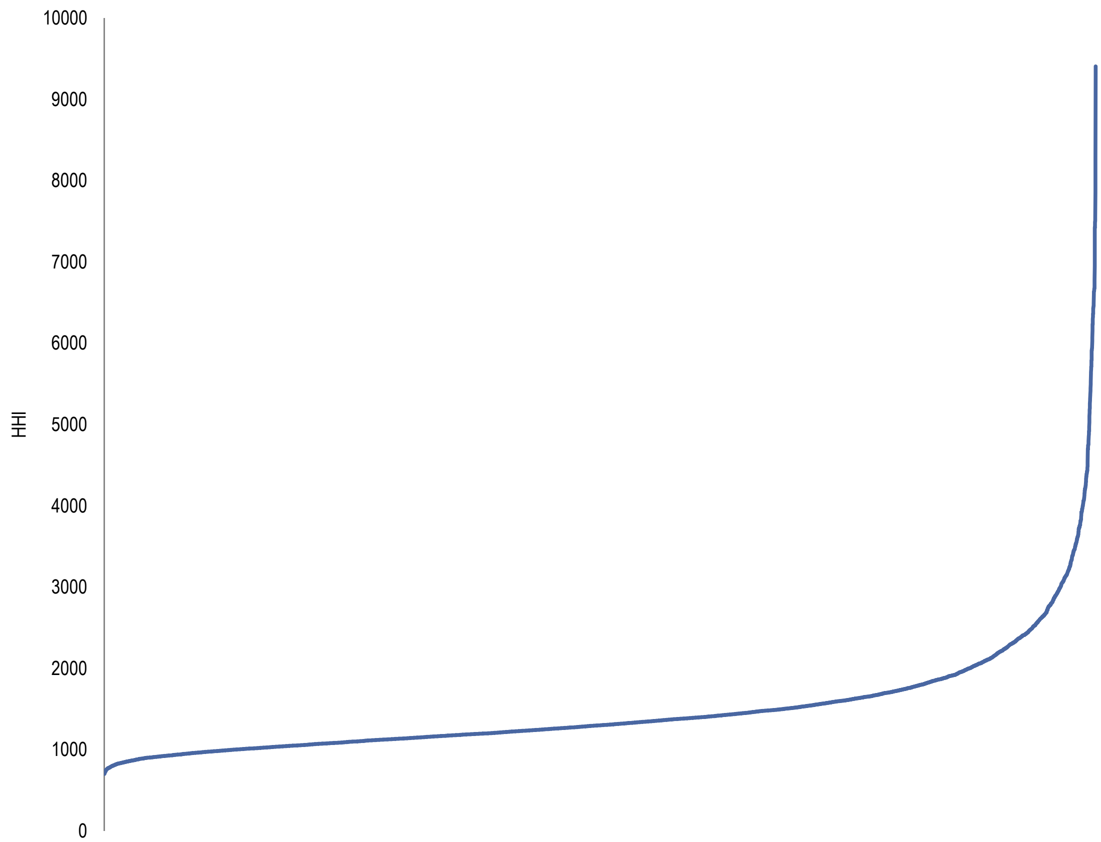
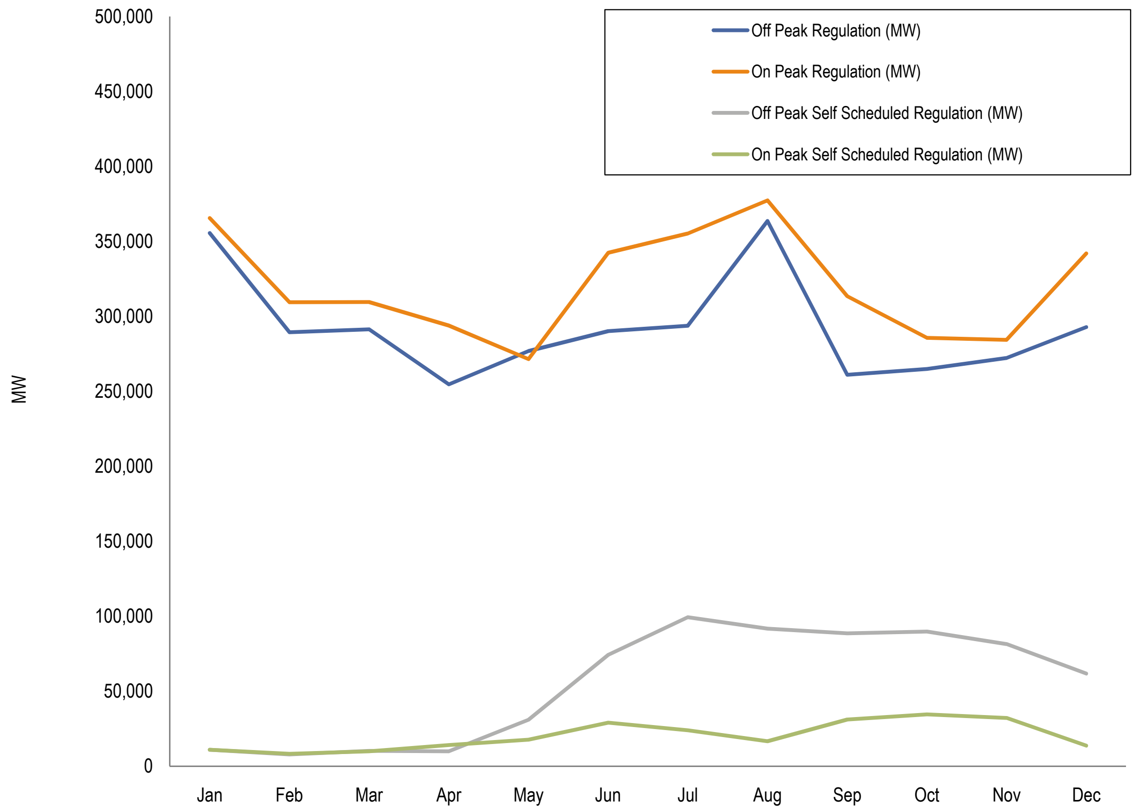


Figure 6-2 shows monthly regulation total MW off-peak and on-peak. The volume of self-scheduled regulation rose in May during off-peak hours. The rise in off-peak self scheduled regulation lowered the requirement for cleared regulation, putting downward pressure on prices and resulted in a reduced level of MW cleared in the market.

Figure 6-2 Off peak and on peak regulation levels: Calendar year 2009



The highest hourly market share was 97 percent (compared to the highest hourly market share in 2008 of 49 percent). Seventy two percent of all hours had a maximum market share greater than 20 percent in 2009. The largest annual average hourly market share by a company was 15 percent. The top five annual average hourly market shares for cleared regulation in 2009 are listed in Table 6-4.

Table 6-4 Highest annual average hourly Regulation Market shares: Calendar year 2009

Company Market Share Rank	Cleared Regulation Top Market Shares
1	15%
2	10%
3	9%
4	8%
5	8%

In 2009, 52 percent of hours failed the three pivotal supplier test. This means that for 52 percent of hours the total regulation requirement could not be met in the absence of the three largest suppliers. One supplier of regulation was pivotal in 99 percent of pivotal hours. A second company was pivotal in 89 percent of the pivotal hours. A third company was pivotal in 81 percent of pivotal hours. Table 6-5 includes a monthly summary of three pivotal supplier results.

Table 6-5 Regulation market monthly three pivotal supplier results: Calendar year 2009

Month	Percent Hours With Three Pivotal Suppliers
Jan	84%
Feb	61%
Mar	42%
Apr	39%
May	31%
Jun	37%
Jul	39%
Aug	35%
Sep	47%
Oct	64%
Nov	62%
Dec	80%

Thus, in addition to failing the three pivotal supplier test in a significant number of hours, the pivotal suppliers in the Regulation Market were the same suppliers in the majority of hours when the test was failed. This is a further indication that the structural market power issue in the Regulation Market remained persistent and repeated during 2009.

The MMU concludes from these results that the PJM Regulation Market in 2009 was characterized by structural market power. This conclusion is based on the results of the three pivotal supplier test.

Market Conduct

Offers

PJM implemented the three pivotal supplier test in the Regulation Market in December 2008. As a result, generators wishing to participate in the PJM Regulation Market must submit cost based regulation offers for specific units by 1800 Eastern Prevailing Time (EPT) of the day before the operating day. Generators may also submit price based offers. The regulation cost based offer price is limited to costs plus $12.00. The costs are validated in accordance with unit specific operating parameters entered with the cost based offer. A unit is not required to provide these parameters if its offer is less than $12.00. The unit specific operating parameters are heat rate at economic maximum, heat rate at regulation minimum, VOM rate and fuel cost. Regulation offers are applicable for the entire 24 hour period for which they are submitted. As in any competitive market, regulation offers at marginal cost are considered to be competitive.

The cost based and price based offers and the associated cost related parameters are the only components of the regulation offer applicable for the entire operating day. The following information must be included in each offer, but can be entered or changed up to 60 minutes prior to the operating hour: regulating status (i.e., available, unavailable or self-scheduled); regulation capability; regulation minimum (may be increased but not decreased); and regulation maximum (may be decreased but not increased). The Regulation Market is cleared on a real-time basis and regulation prices are posted hourly throughout the operating day. The amount of self-scheduled regulation is confirmed 60 minutes before each operating hour, and regulation assignments are made at least 30 minutes before each operating hour.

PJM's Regulation Market is cleared hourly, based on both offers submitted by the units and the hourly lost opportunity cost of each unit, calculated based on the forecast LMP at the location of each regulating unit.[26] The total offer price is the sum of the unit specific offer and the opportunity cost. In order to clear the market, PJM ranks the offer of all offered and eligible regulating resources in ascending total offer price order; it does the same for synchronized reserve and simultaneously determines the least expensive set of resources necessary to provide regulation, synchronized reserve and energy for the operating hour, taking into account any resources self-scheduled to provide any of these services. Units are assigned to regulate in ascending merit order by price until the required regulation is satisfied. The resulting assignments are evaluated to see which if any of the owning companies are pivotal. Pivotal companies will have their resources offer capped at the lesser of their cost based or price based offer. The generating units of companies which are not pivotal will then have their offer reset to their price based offer and the market is cleared.[27] The Regulation Market Clearing Price that results is the RMCP and the unit that sets this price is the marginal unit.

Market Performance

Price

Figure 6-3 shows the daily average regulation market clearing price and the opportunity cost component for the marginal units in the PJM Regulation Market. All units chosen to provide regulation received as payment the higher of the clearing price multiplied by the unit's assigned regulating capability, or the unit's regulation offer plus the individual unit's real-time opportunity cost, multiplied by its assigned regulating capability.[28]

For 2009, 35 percent of marginal units were pivotal. In 35 percent of hours the marginal unit failed the pivotal supplier test. This means that in 35 percent of hours the marginal unit's offer price was the lesser of its price based or cost based offer.

26 PJM estimates the opportunity cost for units providing regulation based on a forecast of locational marginal price (LMP) for the upcoming hour. In May 2009, PJM also began including the lost opportunity cost impact in adjoining hours of dispatching a unit to its regulation set point. As part of the settlement that included the implementation of the three pivotal supplier test on December 1, 2008, the opportunity cost calculator now uses the lesser of the available price based energy schedule or the most expensive available cost based energy schedule.

27 See PJM. "Manual 11: Scheduling Operations," Revision 43 (Redline), Regulation Market Clearing, September 24, 2009, p. 43.

28 See PJM. "Manual 28: Operating Agreement, Accounting," Revision 42, Section 4, "Regulation Credits" (July 31, 2009), p. 25. PJM uses estimated opportunity cost to clear the market and real-time opportunity cost to compensate generators that provide regulation and synchronized reserve. Real-time opportunity cost is calculated using real-time LMP.

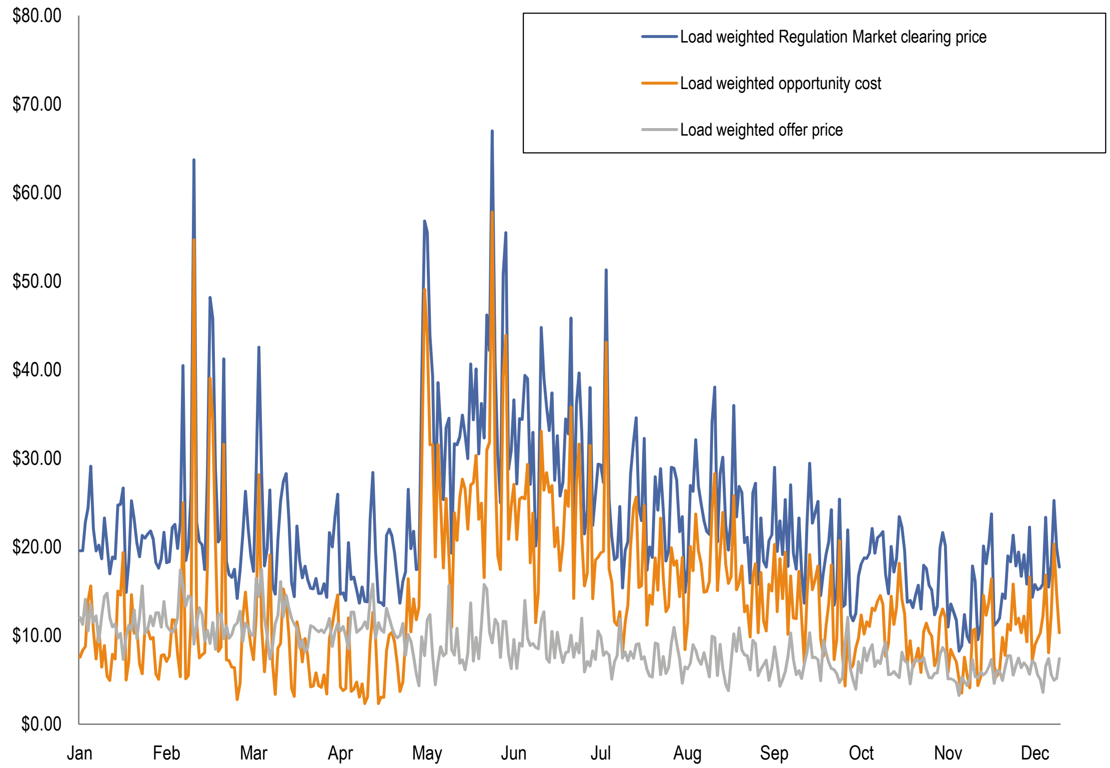
Table 6-6 Percent of hours when marginal unit supplier was pivotal: Calendar year 2009

Month	Percent of Hours When Marginal Supplier is Pivotal
Jan	37%
Feb	38%
Mar	20%
Apr	20%
May	19%
Jun	23%
Jul	21%
Aug	29%
Sep	40%
Oct	52%
Nov	55%
Dec	73%

Regulation credits are awarded to generation owners that have either self-scheduled or sold regulation into the market. Regulation credits for units self-scheduled to provide regulation are equal to the RMCP times the unit's self-scheduled regulating capability. Regulation credits for units that offer regulation into the market and are selected to provide regulation are the higher of the RMCP times the unit's assigned regulating capability, or the unit's regulation offer plus the opportunity cost that the unit has incurred times its assigned regulating capability. Although most units are paid RMCP times their assigned regulation MWh, a substantial portion of the RMCP is the opportunity cost calculated during market clearing based on forecast LMP of the marginal unit. This means that a substantial portion of the total cost of regulation is determined by opportunity cost. As shown in Figure 6-3, about half of the regulation price is the opportunity cost of the marginal unit. Opportunity cost is a greater percentage of price when prices are high since offers tend to remain constant.

The load weighted, average offer of the marginal unit for the PJM Regulation Market during 2009 was $8.79 per MWh. This is a significant reduction from the load weighted average offer in 2008 of $11.94. The lower offers are in part the result of the application of the three pivotal supplier test, which prevented non competitive offers from setting price. The load weighted, average opportunity cost of the marginal unit for the PJM Regulation Market during 2009 was $11.62. In the PJM Regulation Market the marginal unit opportunity cost averaged 49 percent of the RMCP. This is a significant reduction from the 2008 level of 72 percent meaning that the direct unit offers had a larger impact on the clearing price in 2009 than in 2008. The reduction in opportunity cost was clearly a function of lower energy prices.

Figure 6-3 PJM Regulation Market daily average market-clearing price, opportunity cost and offer price (Dollars per MWh): Calendar year 2009

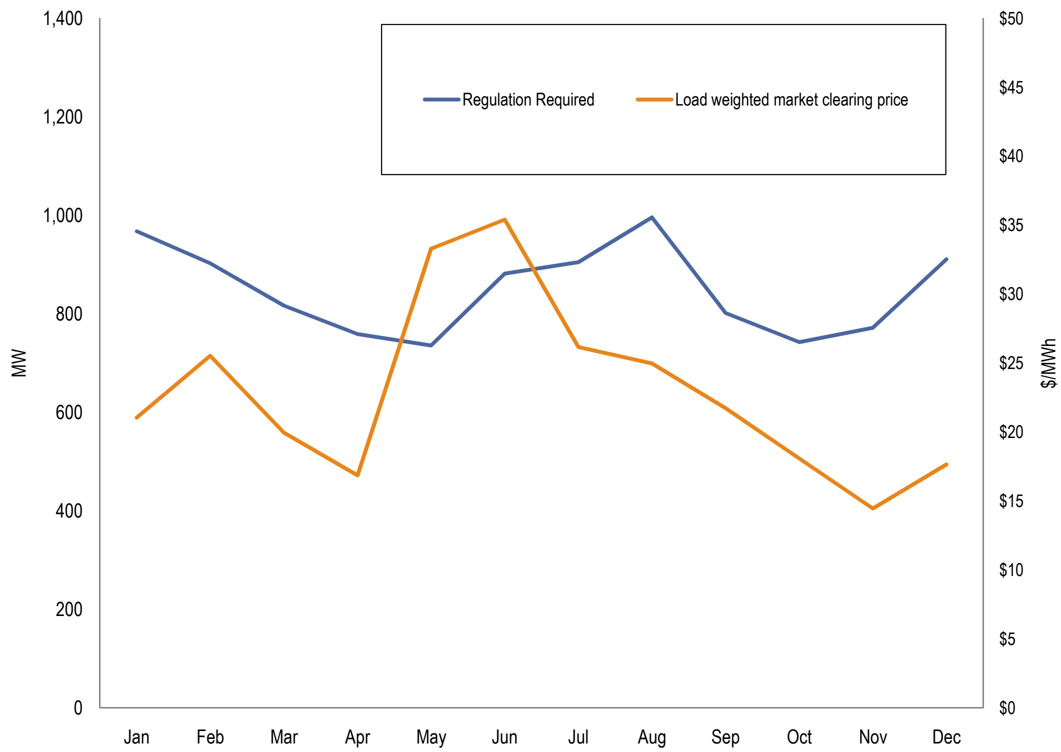


On a shorter term basis, regulation prices follow daily and weekly patterns. The supply of regulation is largest during on-peak hours, between 0600 and 2300 EPT, Monday through Friday.

During weekends and North American Electric Reliability Council (NERC) holidays, and weekdays between the hour ending at 2300 until the hour ending at 0800 (i.e., the off-peak hours), fewer steam generators are running and available to regulate. At times, units must be kept running for regulation that are not economic for energy, resulting in an increase in the opportunity cost portion of the clearing price. At other times, expensive combustion turbine generators must be started to meet regulation requirements. Although the regulation requirement is a function of reliability concerns, lower off-peak load allowed PJM to decrease the off-peak regulation requirement in August 2008, thus aligning demand with supply and moderating prices.

Figure 6-4 shows the level of demand for regulation by month in 2009 and the corresponding level of regulation price. The data show a correlation between price and demand.

Figure 6-4 Monthly average regulation demand (required) vs. price: Calendar year 2009



As with all ancillary services, the total cost of the service per MWh will exceed the price per MWh because some regulation is procured out of the market or because there are adjustments to unit specific opportunity cost after the market clears. A well designed and efficient market will minimize this difference. Units which provide regulation are paid the higher of the RMCP, or their offer plus their unit specific opportunity cost. The offer plus the unit specific opportunity cost may be higher than the RMCP for a number of reasons. If real time LMP is greater than the LMP forecast prior to the operating hour and included in the RMCP, unit specific opportunity costs will be higher than forecast. Such higher LMPs can be local, because of congestion, or more general, if system conditions change. Other reasons include unit redispatch because of constraints or unanticipated unit performance problems. When some units are paid more than the RMCP based on unit specific lost opportunity costs, the result is that PJM's regulation cost per MWh is higher than the RMCP. Figure 6-5 compares the regulation cost per MWh (price plus settled lost opportunity costs) with the regulation clearing price to show the difference between the price of regulation and the cost of regulation.

Figure 6-5 Monthly load weighted, average regulation cost and price: Calendar year 2009

Total scheduled regulation MWh, total regulation charges, regulation price and regulation cost are listed in Table 6-7.

Table 6-7 Total regulation charges: Calendar year 2009

Month	Scheduled Regulation (MW)	Total Regulation Charges	Load Weighted Regulation Market Clearing Price ($/MWh)	Cost Of Regulation ($/MWh)
Jan	719,972	$26,614,105	$21.04	$36.97
Feb	606,112	$20,972,293	$25.17	$34.60
Mar	609,426	$17,618,413	$19.90	$28.91
Apr	547,446	$12,171,811	$16.84	$22.23
May	547,941	$21,166,797	$32.41	$38.63
Jun	633,938	$24,566,721	$32.59	$38.75
Jul	673,708	$20,065,104	$24.10	$29.78
Aug	739,915	$23,010,216	$23.89	$31.10
Sep	574,820	$15,216,790	$20.09	$26.47
Oct	550,255	$12,882,665	$17.20	$23.41
Nov	557,139	$10,695,843	$14.06	$19.20
Dec	679,575	$17,303,919	$17.75	$25.46

For 2009, the load weighted, average regulation price was $23.56 per MWh. The average regulation cost was $29.87 per MWh. The difference between the Regulation Market price and the actual cost of regulation was narrower in 2009 than it was in 2008 but still remains significant. The cost of regulation was 27 percent higher than the market price of regulation. The payment of a large portion of regulation charges on a unit specific basis rather than on the basis of a market clearing price remains a cause for concern as it results in a weakened market price signal to the providers of regulation.

Analysis of Regulation Market Changes

There were significant changes made to Regulation Market effective December 1, 2008. The rule changes are summarized in Table 6-8.The changes were the result of a filing by PJM that reflected a compromise among market participants in the PJM process.[29] The MMU filed comments.[30] The MMU supported the filing with the caveat that if the MMU review of the actual impact of the changes "results in a conclusion that these features result in non-competitive market outcomes, the Market Monitor will request that one or more of these provisions be removed or modified."[31]

Table 6-8 Summary of changes to Regulation Market design

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.

As directed by the FERC, the MMU performed an analysis of these Regulation Market rule changes, delivering a report on November 30, 2009.[32] The results of that report are updated and corrected here.

Introduction of TPS Testing

The implementation of the TPS test is consistent with the longstanding MMU recommendation that real-time, hourly market structure tests be implemented in the Regulation Market, that market

29 PJM filing initiating Docket No. ER09-13-000 (October 1, 2008).

30 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/reports/Reports/2008/imm-motion-to-intervene-and-comments.pdf>.

31 *Id.* at 2.

32 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).

power mitigation be applied only for hours in which the market structure is noncompetitive and that market power mitigation be applied only to the companies failing the market structure tests. This more flexible and real-time approach to mitigation represents an improvement over the approach to mitigation which had been in place from August 2005 through November 2008, which required cost based offers from the two dominant suppliers at all times.

The results of the three pivotal supplier test for each hourly Regulation Market solution are shown in Table 6-9.

Table 6-9 Regulation Market pivotal supplier test results: December 2008 through December 2009 and December 2007 through December 2008

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%

Increase Offer Margin from $7.50 to $12.00

The tariff modifications included an increase of the margin that may be added to cost-based regulation offers from $7.50 to $12.00 per MW. The average cost based regulation offer is less than $10.00 per MW, so this margin represents a substantial adder to costs. The MMU does not now recommend reducing the margin to the prior level of $7.50 per MW. While there was no analytical support provided for the increased margin, it is simply a direct increase in payments. If an increase in payments for regulation is the goal, this is the best mechanism for implementing that goal as it is transparent and does not require inconsistent changes in market rules to increase revenues to the owners of regulation.

Table 6-10 shows the additional revenues that are paid as a result of the rule change that increased the margin on cost based offers from $7.50 to $12.00 per MWh. In the November 30, 2009 report the MMU calculated the additional revenues based only on the offer margin of the unit that was marginal under the new rule. The MMU has refined this calculation (Table 6-10). The impact of the increased margin is now calculated using the offer margin of all offering units, creating a new supply curve, and re-solving for the new marginal unit and new RMCP. The calculation assumes that synchronized reserve assignments and operating reserve allocations remain the same as in the existing solution. In Table 6-10, the column “Load Weighted Regulation Market Clearing Price” is the monthly load weighted RMCP under the existing rules. The column “Load Weighted Regulation Market Clearing Price With Old Rule” is the recalculated RMCP that would have resulted if the old offer margin of $7.50 had remained in effect. The column “Regulation Credits Attributable to the New Rule” shows the additional charges for regulation that result from the rule change increasing the offer margin from $7.50 to $12.00. The percent increase in the last column, 2.5 percent, is the percent increase in total regulation credits that results from this change. The increase in credits paid, of $6,189,406, is a result of the higher offer margin permitted under the new rules.

Table 6-10 Impact of $12 adder to cost based regulation offer: December 2008 through December 2009

Year	Month	Load Weighted Regulation Market Clearing Price	Load Weighted Regulation Market Clearing Price With Old Rule	Total Regulation Credits	Regulation Credits Attributable to New Rule	Percent Increase in Total Credits Due to Increase of Markup from $7.50 to $12.00
2008	Dec	$24.79	$23.47	$25,608,465	$890,749	3%
2009	Jan	$21.04	$19.91	$26,614,105	$813,654	3%
2009	Feb	$25.17	$23.95	$20,972,293	$734,061	4%
2009	Mar	$19.90	$19.37	$17,618,413	$316,889	2%
2009	Apr	$16.84	$16.36	$12,171,811	$258,778	2%
2009	May	$32.41	$31.93	$21,166,797	$265,494	1%
2009	Jun	$32.59	$32.19	$24,566,721	$312,979	1%
2009	Jul	$24.10	$23.25	$20,065,104	$414,408	2%
2009	Aug	$23.89	$23.37	$23,010,216	$369,407	2%
2009	Sep	$20.09	$19.32	$15,216,790	$497,484	3%
2009	Oct	$17.20	$16.31	$12,882,665	$445,635	3%
2009	Nov	$14.06	$13.48	$10,695,843	$269,283	3%
2009	Dec	$17.75	$16.72	$17,303,919	$600,585	3%
Total				$247,893,142	$6,189,406	2.5%

Change in the Definition of Opportunity Cost

The tariff modifications included a change in the definition of opportunity cost. Offers in the Regulation Market consist of the direct offer price made by the market participant and the opportunity cost, which is calculated by PJM based on forecast LMP for the next hour and added by PJM to the direct offer price to get the total offer price. The tariff change to the definition of opportunity cost is the most significant, because the opportunity cost is, on average, more than half the total offer price. Any modification to the measurement of opportunity cost will have a significant impact on the Regulation Market. The opportunity cost is also directly affected by the levels of LMP. As LMP decreased in 2009, opportunity costs decreased, total offer prices decreased and the Regulation Market clearing prices decreased. As a result, the impact of this change to the definition of opportunity cost was lower in 2009 than it would have been had LMP levels been higher. The impact of this change will increase if LMP levels increase.

The change to the tariff is inconsistent with the definition of opportunity cost, is inconsistent with the way in which opportunity cost is calculated elsewhere in the PJM tariff and is inconsistent with the way in which opportunity cost has been calculated for regulation under the PJM tariff for approximately ten years. The MMU recommends that this modification be reversed and that the correct definition of opportunity cost be reinstated for regulation. In addition to getting the price right, the concept and application of opportunity cost is critical to ensuring an efficient allocation of resources between the energy market and the ancillary services markets. The goal is to hold generators neutral to the decision whether to sell MWh in the energy market or to regulate, in order to ensure that the energy markets and the ancillary markets all clear in an efficient manner.

The correct way to calculate opportunity cost and maintain incentives across both markets is to treat the offer on which the unit is dispatched as the measure of its marginal costs for both the energy market and the Regulation Market. To do otherwise is to impute a lower marginal cost to the unit than its owner does and therefore impute a higher opportunity cost than the owner does.

Table 6-11 shows the additional revenues that are paid as a result of the rule change to the definition of opportunity cost. The percent increase in the last column, 19 percent, refers to the percent increase in total regulation credits that results from this change. The increase in credits paid, of $47,463,833, is a result of the higher opportunity costs calculated under the new rules.

Table 6-11 Impact to Regulation Market Clearing Price of using lesser of price based energy schedule or most expensive cost-based energy schedule

			New Rule		Old Rule			
Year	Month	Average Regulation Required (MW)	Load Weighted RMCP Using Lesser Schedule for Opportunity Cost	Using Lesser Schedule For Opportunity Costs, Total Charges	Load Weighted RMCP Using Current Dispatch Schedule for Opportunity Costs	Using Current Dispatch Schedule for Opportunity Costs, Total Charges	Additional Regulation Credits Paid Using New Rule	Pecentage Increase in Regulation Credits
2008	Dec	912	$24.79	$25,608,465	$22.50	$24,039,842	$1,568,623	6%
2009	Jan	970	$21.04	$26,614,105	$17.62	$24,136,240	$2,477,865	9%
2009	Feb	905	$25.83	$20,972,293	$17.10	$16,257,318	$4,714,975	22%
2009	Mar	819	$19.90	$17,618,413	$16.34	$15,645,792	$1,972,621	11%
2009	Apr	762	$16.84	$12,171,811	$13.93	$10,569,368	$1,602,443	13%
2009	May	738	$32.41	$21,166,797	$24.63	$16,514,576	$4,652,221	22%
2009	Jun	884	$32.59	$24,566,721	$23.08	$17,198,351	$7,368,370	30%
2009	Jul	908	$24.10	$20,065,104	$15.33	$12,992,257	$7,072,847	35%
2009	Aug	998	$23.89	$23,010,216	$14.18	$15,047,460	$7,962,756	35%
2009	Sep	803	$20.09	$15,216,790	$13.72	$10,656,302	$4,560,488	30%
2009	Oct	744	$17.20	$12,882,665	$13.62	$11,167,730	$1,714,935	13%
2009	Nov	779	$14.06	$10,695,843	$10.83	$9,230,018	$1,465,825	14%
2009	Dec	781	$17.75	$17,303,919	$11.71	$16,974,055	$329,864	2%
Total				$247,893,142		$200,429,309	$47,463,833	19%

Eliminate Offset Against Balancing Operating Reserves Credits

The tariff modifications included eliminating the offset of the net revenues earned in the Regulation Market against operating reserve credits. There was no specific rationale advanced for this change. This tariff modification is directly counter to the fundamentals of the PJM markets and the purpose of operating reserve credits. The MMU recommends that this modification be reversed and that the net revenues earned in the Regulation Market be offset against operating reserve credits in the same manner that all net revenues from all other PJM markets are offset against operating reserve credits and in the same manner that Regulation Market credits were offset against operating reserve credits prior to December 1, 2008.

The logic of including all market revenues in the calculation of operating reserve credits is clear. The goal is to ensure that unit owners are never required to run their units without compensation of all marginal costs, but all market compensation is included when determining whether there is a shortfall. The exclusion of the regulation revenues is arbitrary and results in an increase in operating reserve charges and a shift of revenues to the owners of regulating units from those who pay operating reserve charges. There is no reason to modify a fundamental market rule in order to provide greater incentives in the regulation market. This argument is reinforced by the appropriately increased scrutiny paid to operating reserve in recent years and given the overall goal to reduce these non market payments. If there is actually a need for greater incentives, it should be established directly and the incentive payment made directly in the Regulation Market, for example through the offer margin.

In the calculation of the impact of this change in the MMU report to the FERC of November 30, 2009, the MMU report did not reflect the modifications to the PJM operating reserve rules, effective December 1, 2008, including the implementation of segmented make-whole payments, and did include self-scheduled regulating units, which should not have been included. Table 6-12 below is a revision as well as an update to the November 30, 2009 report. These calculations reflect the changes to the operating reserves rules and exclude self-scheduled regulating units.

Table 6-12 shows the additional revenue paid as a result of the rule change that no longer nets regulation revenue against balancing operating reserves. This rule change did not change the regulation market clearing price. The additional revenue was paid to generators through operating reserves rather than through the regulation market as a direct result of this December 1, 2008 regulation market rule change. The percent increase in the last column, one percent, refers to the percent increase in total regulation credits that results from this change. The increase in credits paid, of $2,297,348, is a result of the elimination of the offset against operating reserve credits that results from the new rules.

Table 6-12 Additional credits paid to regulating units from no longer netting credits above RMCP against operating reserves: December 2008 through December 2009

Year	Month	Balancing Operating Reserve Credits No Longer Offset	Total Regulation Credits	Percent of Regulation Credits No Longer Offsetting Operating Reserves
2008	Dec	$253,165	$25,608,465	1%
2009	Jan	$127,036	$26,614,105	0%
2009	Feb	$220,460	$20,972,293	1%
2009	Mar	$79,726	$17,618,413	0%
2009	Apr	$8,893	$12,171,811	0%
2009	May	$182,624	$21,166,797	1%
2009	Jun	$274,916	$24,566,721	1%
2009	Jul	$191,538	$20,065,104	1%
2009	Aug	$267,116	$23,010,216	1%
2009	Sep	$252,136	$15,216,790	2%
2009	Oct	$169,130	$12,882,665	1%
2009	Nov	$166,112	$10,695,843	2%
2009	Dec	$104,496	$17,303,919	1%
Total		$2,297,348	$247,893,142	1%

Summary

The increase in total charges for regulation that resulted from each of the December 1, 2008 rule changes are summarized in Table 6-13.

Together, the changes to the tariff related to the Regulation Market resulted in an increase in payments to the providers of regulation of $56 million over the 13 month period from December 2008 through December 2009, compared to what they would have received in the absence of these three changes. This represents an increase in total regulation payments of 23 percent for the 13 month period. While these results are based on estimates of how the market would have worked in the absence of the changes in market design, the calculations reflect detailed hourly data about the individual units in the Regulation Market supply curve. There is no question that the changes in market design significantly increased the payments for regulation service compared to what they would have been with a competitive market design.

The addition of the Three Pivotal Supplier Test to the Regulation Market improved the competitiveness of the Regulation Market results, compared to the prior market design without the additional changes, by eliminating the non-competitive behaviors that had existed in prior years. However, the other changes in the rules for the Regulation Market, in particular the change to the calculation of the opportunity cost, produced market results that were not competitive. The other changes in the rules resulted in substantial price increases in the Regulation Market compared to the competitive price that would have resulted without these changes. While overall Regulation Market prices were lower in 2009 than in 2008, this was a result of lower LMPs. If LMPs increase, the impact of the rule changes on total regulation charges will be amplified. The result was a price greater than the competitive price. The competitive price is the price that would have resulted from the application of the prior, correct approach to the calculation of the opportunity cost and to the calculation of the offset against operating reserves. These regulation market results are not based on the behavior of market participants, which is competitive as a result of the application of the three pivotal supplier test.

As a result, the MMU concludes that the results of the Regulation Market were not competitive in 2009.

Table 6-13 Summary of additional charges paid as a result of December 1, 2008 changes to Regulation Market rules: December 2008 through December 2009

			Increasing Markup from $7.50 to $12.00		Opportunity Cost Calculated Using Lower of Price Based or Cost Based Price		Regulation Credits Above Cost Plus Opportunity Costs no Longer Offset Against Operating Reserves		Changes for Three Pivotal Supplier Testing, December 1, 2008 - Summary	
Year	Month	Total Regulation Credits	RMCP Credits Attributable to Marginal Units Cost Offer > Costs Plus $7.50	Percent Increase in Total Credits Due to Marginal Unit With Offer > Cost Plus $7.50	Additional Regulation Credits Paid Due to New Opportunity Cost Calculation	Percentage Increase in Regulation Credits Due to New Opportunity Cost Calculation	Balancing Operating Reserve Credits No Longer Offset	Percent of Regulation Credits No Longer Offsetting Operating Reserves	Total Additional Generator Credits	Total Percent of Regulation Credits Additional
2008	Dec	$25,608,465	$890,749	3%	$1,568,623	6%	$253,165	1%	$2,712,537	11%
2009	Jan	$26,614,105	$813,654	3%	$2,477,865	9%	$127,036	0%	$3,418,555	13%
2009	Feb	$20,972,293	$734,061	4%	$4,714,975	22%	$220,460	1%	$5,669,496	27%
2009	Mar	$17,618,413	$316,889	2%	$1,972,621	11%	$79,726	0%	$2,369,236	13%
2009	Apr	$12,171,811	$258,778	2%	$1,602,443	13%	$8,893	0%	$1,870,114	15%
2009	May	$21,166,797	$265,494	1%	$4,652,221	22%	$182,624	1%	$5,100,339	24%
2009	Jun	$24,566,721	$312,979	1%	$7,368,370	30%	$274,916	1%	$7,956,265	32%
2009	Jul	$20,065,104	$414,408	2%	$7,072,847	35%	$191,538	1%	$7,678,793	38%
2009	Aug	$23,010,216	$369,407	2%	$7,962,756	35%	$267,116	1%	$8,599,279	37%
2009	Sep	$15,216,790	$497,484	3%	$4,560,488	30%	$252,136	2%	$5,310,108	35%
2009	Oct	$12,882,665	$445,635	3%	$1,714,935	13%	$169,130	1%	$2,329,700	18%
2009	Nov	$10,695,843	$269,283	3%	$1,465,825	14%	$166,112	2%	$1,901,220	18%
2009	Dec	$17,303,919	$600,585	3%	$329,864	2%	$104,496	1%	$1,034,945	6%
Total		$247,893,142	$6,189,406	2.5%	$47,463,833	19%	$2,297,348	1%	$55,950,587	23%

Synchronized Reserve Market

Market Structure

PJM retained the two synchronized reserve markets it implemented on February 1, 2007. The RFC Synchronized Reserve Zone Market's reliability requirements are set by the Reliability*First* Corporation. The Southern Synchronized Reserve Zone Market's (Dominion) reliability requirements are set by the Southeastern Electric Reliability Council (SERC). PJM sets the synchronized reserve requirement for the RFC Synchronized Reserve Zone as the larger of ReliabilityFirst Corporation's imposed minimum requirement or the largest contingency on the system. The Southern Region's Synchronized Reserve Market remains a separate market. It falls under the reliability requirements of SERC and is referred to as the Southern Synchronized Reserve Zone. Although the RFC Synchronized Reserve Market is one market, transmission constraints often limit the amount of Tier 1 synchronized reserve that can be made available in the PJM Mid-Atlantic Subzone of the RFC. This subzone is defined as the RFC Synchronized Reserve Zone exclusive of parts of AP, parts of AEP, Dayton, Duquesne, and ComEd zones.[33] Therefore PJM's market must clear enough Tier 2 synchronized reserve in the Mid-Atlantic (Eastern) Subzone of the RFC Synchronized Reserve Market to ensure that the Mid-Atlantic locational synchronized reserve requirement of 1,150 MW is met, after accounting for available Tier 1 supply. This results in a separate Mid-Atlantic Subzone clearing price.

Supply

Synchronized reserve is an ancillary service defined as generation or curtailable load that is synchronized to the system and capable of producing output or shedding load within 10 minutes. Synchronized reserve can, at present, be provided by a number of resources, including steam units with available ramp, condensing hydroelectric units, condensing combustion turbines (CTs) and CTs running at minimum generation. Synchronized reserve can also be supplied by DSR resources subject to the limit that they provide no more than 25 percent of the total synchronized reserve requirement. Synchronized reserve DSR resources can be provided by behind the meter generation or by load reductions.

All of the resources that participate in the Synchronized Reserve Markets are categorized as Tier 2 synchronized reserve. Tier 1 resources are those resources that are online, following economic dispatch, and able to respond to a spinning event by ramping up from their present output. All resources operating on the PJM system are considered potential Tier 1 resources, except for those explicitly assigned to Tier 2 synchronized reserve. Tier 2 resources include units that are backed down to provide synchronized reserve capability, condensing units synchronized to the system and available to increase output and demand side resources.

Under Synchronized Reserve Market rules, Tier 1 resources are paid when they respond to an identified spinning event as an incentive to respond when needed.[34] Tier 1 synchronized reserve payments or credits are equal to the integrated increase in MW output above economic dispatch from each generator over the length of a spinning event, multiplied by the synchronized reserve energy premium less the hourly integrated LMP. The synchronized reserve energy premium is

33 See PJM. "Manual 11: Scheduling Operations," Revision 43 (September 24, 2009), p. 51.
34 See PJM. "Manual 11: Scheduling Operations," Revision 43 (September 24, 2009), p. 58.

defined as the average of the five minute LMPs calculated during the spinning event plus $50 per MWh. All units called on to supply Tier 1 or Tier 2 synchronized reserve have their actual MW monitored. Tier 1 units are not penalized if their output fails to match their expected response as they are only compensated for their actual response.

Under Synchronized Reserve Market rules, Tier 2 synchronized reserve resources are paid to be available as synchronized reserve, regardless of whether the units are called upon to generate in response to a spinning event, and are subject to penalties if they do not provide synchronized reserve when called. The price for Tier 2 synchronized reserve is determined in a market for Tier 2 synchronized reserves. This market is termed the Synchronized Reserve Market. Several steps are necessary before the hourly Synchronized Reserve Market is cleared. Ninety minutes prior to the start of the hour, PJM estimates the amount of Tier 1 reserve available from every unit; 60 minutes prior to the start of the hour, self-scheduled Tier 2 units are identified. Thirty minutes prior to the hour, Tier 1 is estimated again. If synchronized reserve requirements are not met by Tier 1 and self-scheduled Tier 2 resources, then a Tier 2 clearing price is determined at least 30 minutes prior to the start of the hour. This Tier 2 price is equivalent to the merit-order price of the highest-priced, Tier 2 resource needed to meet the demand for synchronized reserve requirements, the marginal unit, based on the simultaneous clearing of the Regulation Market and the Synchronized Reserve Market.[35]

The synchronized reserve offer price submitted for a unit can be no greater than the unit's incremental operating and maintenance cost plus a $7.50 per MWh margin.[36, 37] The market clearing price is comprised of the marginal unit's synchronized reserve offer price, the cost of energy use, the startup cost (if the unit is not running) and the unit's lost opportunity cost. Opportunity cost is calculated by PJM based on forecast LMPs and generation schedules from the unit dispatch system. Opportunity cost for demand-side resources is always zero. All units cleared in the Synchronized Reserve Markets are paid the higher of either the market-clearing price or the unit's synchronized reserve offer plus the unit specific opportunity cost and the cost of energy use incurred.

The Tier 2 Synchronized Reserve Market in each of PJM's synchronized reserve areas is cleared on cost based offers because the structural conditions for competition do not exist. The market structure issue can be even more severe when the Synchronized Reserve Market becomes local because of transmission constraints.

For the RFC Synchronized Reserve Zone during 2009, the offered and eligible excess supply ratio was 1.93. Within the Mid-Atlantic Subzone of the RFC Synchronized Reserve Zone, the offered and eligible excess supply ratio was 1.53.[38] These excess supply ratios are determined using the administratively established requirement for synchronized reserve. Actual market demand for Tier 2 synchronized reserve is lower than the synchronized reserve requirement because a significant amount of Tier 1 synchronized reserve is usually available.

35 Although it is unusual, a PJM dispatcher can deselect units which have been committed after the clearing price has been established. This only happens if real-time system conditions require dispatch of a spinning unit for constraint control, or problems with a generator or monitoring equipment are reported.

36 See PJM. "Manual 11: Scheduling Operations," Revision 43 (September 24, 2009), p. 50.

37 See PJM. "Manual 15: Cost Development Guidelines," Revision 10 (June 1, 2009), p. 41.

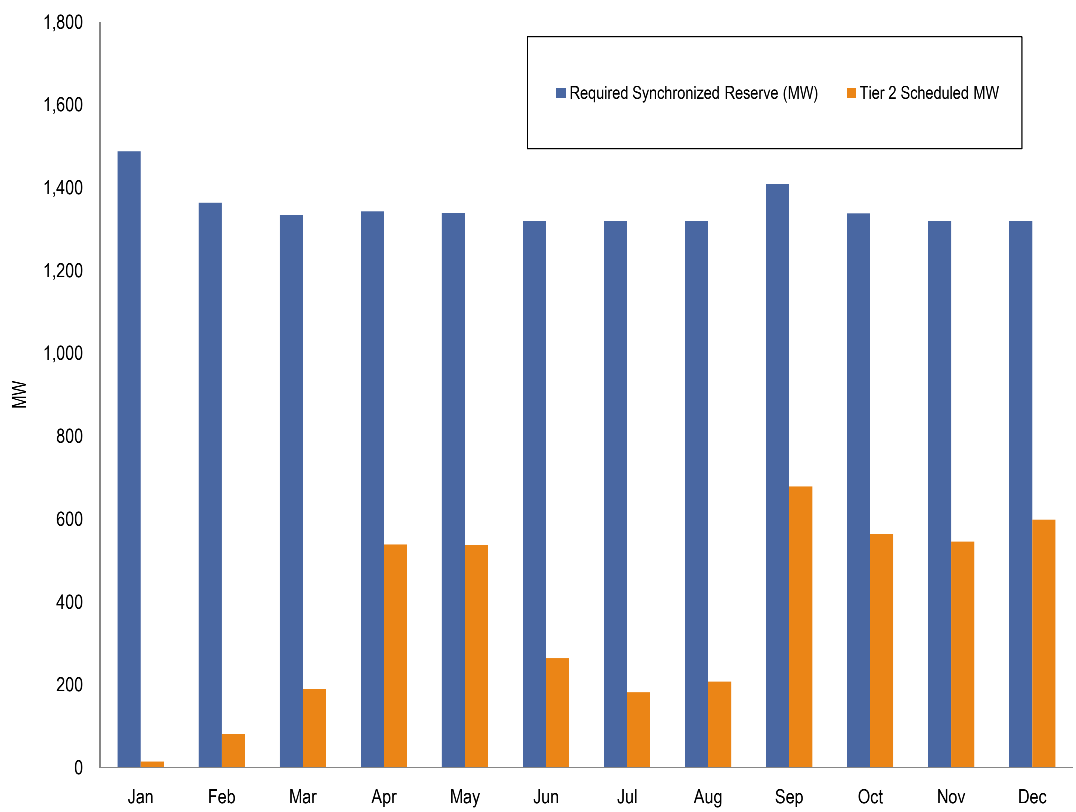
38 The Synchronized Reserve Market in the PJM Southern Region cleared in so few hours that related data for that market are not meaningful.

Demand

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 after careful review to ensure appropriate 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, recognizing potential deliverability issues.[39]

Currently the RFC synchronized reserve requirement is the greater of the ReliabilityFirst Corporation's imposed minimum requirement or the system's largest contingency. The actual synchronized reserve requirement for the RFC Zone for January, 2009 was 1,305 MW. For the rest of 2009 it has remained at 1,320 MW. Exceptions to this requirement can occur when grid maintenance or outages change the largest contingency. Such a condition occurred between January 5 and January 23 and from February 23 through February 27, when the synchronized reserve requirement was set to 1,700 MW. A change in the synchronized reserve requirement to 1,755 MW occurred on April 16 and April 17. A change in the synchronized reserve requirement to 1,695 MW occurred on October 2 and October 3. Figure 6-6 shows the average monthly synchronized reserve required and the average monthly Tier 2 synchronized reserve MW scheduled during 2009 for the RFC Synchronized Reserve Market.

Figure 6-6 RFC Synchronized Reserve Zone monthly average synchronized reserve required vs. Tier 2 scheduled MW: Calendar year 2009



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

The RFC Synchronized Reserve Zone is large and some available Tier 1 must be physically located in the Mid-Atlantic Subzone as a result of transmission limits between the western and eastern portions of the zone. PJM calculates the transfer capability of these transmission facilities. The calculation of Mid-Atlantic Subzone Tier 1 includes what is available in the east plus the amount of Tier 1 synchronized reserve in the west that can be transferred into the east. The PJM Synchronized Reserve Market solution is especially sensitive to this limit (known as transfer capacity). The higher this transfer capacity, the greater is the amount of Tier 1 synchronized reserve available in the East and so the less Tier 2 synchronized reserve that needs to be cleared to satisfy the synchronized reserve requirement. Since 2007, PJM market operations had estimated this transfer capacity at 70 percent. Oftentimes however PJM dispatch saw a more restrictive limitation on the western interface (Bedington—Black Oak) and needed to add additional synchronized reserve outside of the market solution in order to cover what they saw as a contingent need. This was the source of Added Synchronized Reserve resulting in lost opportunity costs being added to synchronized reserve costs.[40]

In mid March of 2009, PJM reset the transfer capacity from 70 percent to 15 percent. PJM also changed the transfer interface from Bedington – Black Oak to AP South. As a result, less Tier 1 synchronized reserve was available to the East for the market solution, increasing the amount of Tier 2 that had to be cleared to satisfy the requirement. This reduced the amount of Tier 2 synchronized reserve that had to be added by PJM dispatch after market. The impact of this transfer capacity change was immediate and significant (Table 6-14).

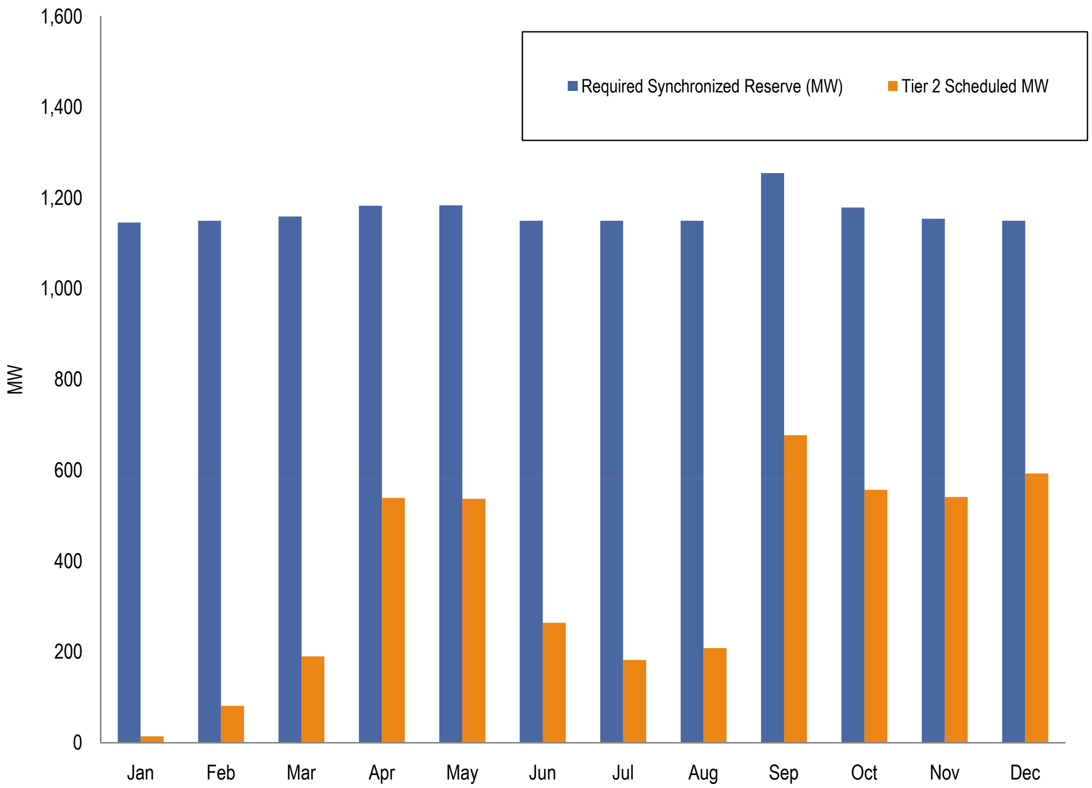
40 See *2007 State of the Market Report*, Volume II, section 6 Ancillary Service Markets pp. 299, 300. Also *2008 State of the Market Report for PJM*, Volume II, section 6 Ancillary Service Markets, p. 328.

Table 6-14 Effect of transfer capacity change on synchronized reserve market scheduled, self-scheduled, and added MW, daily totals: March, 2009

Day (March, 2009)	Eastern Synchronized Reserve Requirement (MW)	Remaining Capacity Parameter	Tier 2 Scheduled (MW)	Tier 2 Self-Scheduled (MW)	Tier 2 Added (MW)
1	1,150	70%	2,379	990	7,201
2	1,150	70%	1,643	0	4,614
3	1,150	70%	0	0	3,150
4	1,150	70%	0	0	0
5	1,150	70%	300	0	1,265
6	1,150	70%	2	0	148
7	1,150	70%	0	0	0
8	1,150	70%	445	0	2,348
9	1,150	70%	397	0	3,139
10	1,150	70%	256	0	2,734
11	1,150	70%	534	0	4,498
12	1,150	70%	51	0	3,038
13	1,150	49%	338	0	2,250
14	1,150	15%	2,528	1,710	519
15	1,150	15%	1,728	1,215	0
16	1,150	15%	3,124	45	1,677
17	1,150	15%	2,901	1,800	1,036
18	1,150	15%	1,711	945	0
19	1,150	15%	5,592	0	403
20	1,150	15%	6,549	2,790	359
21	1,150	15%	4,898	3,330	143
22	1,150	15%	3,719	4,170	381
23	1,150	15%	3,971	2,407	560
24	1,231	15%	5,261	2,520	138
25	1,150	15%	3,302	1,575	725
26	1,150	15%	3,742	2,430	431
27	1,356	15%	6,933	3,385	42
28	1,150	15%	5,543	3,110	178
29	1,150	15%	7,364	3,820	425
30	1,150	15%	2,261	2,910	373
31	1,150	15%	3,769	3,165	0

As a whole, 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 2009, the RFC Synchronized Reserve Zone cleared a Tier 2 Synchronized Reserve Market in less than 3 percent of all hours. This is not the case in the Mid-Atlantic Subzone. As a result, there is frequently a Tier 2 synchronized reserve requirement only in the Mid-Atlantic Subzone and a separate clearing price for the Mid-Atlantic Subzone. The Mid-Atlantic Subzone of the RFC Synchronized Reserve Zone cleared a separate Tier 2 market in 74 percent of all hours. Figure 6-7 compares the required synchronized reserve MW to the scheduled Tier 2 MW for the Mid-Atlantic Subzone only.

Figure 6-7 RFC Synchronized Reserve Zone, Mid-Atlantic Subzone average hourly synchronized reserve required vs. Tier 2 scheduled: Calendar year 2009



The actual synchronized reserve requirement for the Mid-Atlantic Subzone for all of 2009 was usually 1,150 MW but there were several days when temporary grid conditions created a double contingency which increased the requirements. Required synchronized reserve was as high as 2,385 MW on September 14-16, 2009. Throughout all of 2009, the average synchronized reserve required MW in the Mid-Atlantic Subzone was 1,168 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.

The Mid-Atlantic Subzone, Synchronized Reserve Market MW accounts for 99.2 percent of Tier 2 Synchronized Reserve Market MW.

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.[41] The amount of 15 minute quick start reserve available in VACAR is sufficient to make

41 See PJM. "Manual 11: Scheduling Operations," Revision 43 (September 24, 2009), p. 51.

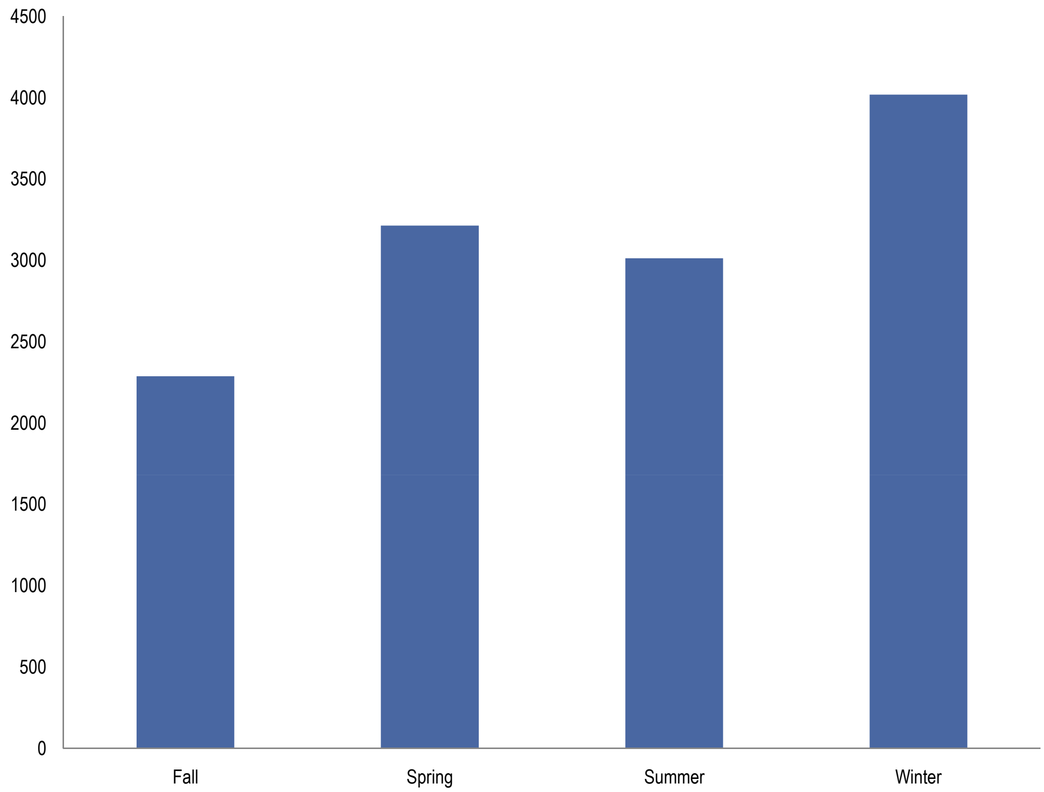
Tier 2 synchronized reserve demand zero for most hours. The actual hourly Southern Synchronized Reserve Zone's synchronized reserve requirement was usually zero because Dominion's share of the largest contingency within VACAR was offset by its quick start capability. On average, the hourly synchronized reserve requirement in Dominion was 3 MW.

Market Concentration

The Tier 2 Synchronized Reserve Market is the only Synchronized Reserve Market cleared by PJM. Although the RFC Tier 2 Synchronized Reserve Market was slightly less concentrated in 2009 than it had been in 2008, the 2009 RFC Synchronized Reserve Market remains highly concentrated and dominated by a relatively small number of companies. Concentration levels have been reduced as a result of the increased participation of demand-side response in the synchronized reserve market.

The HHI for the Mid-Atlantic Subzone of the 2009 RFC Synchronized Reserve Market was 3070, which is defined as "highly concentrated." (See Figure 6-8 which also provides seasonal details.)

Figure 6-8 Purchased Mid-Atlantic Subzone RFC Tier 2 Synchronized Reserve Market seasonal HHI: Calendar year 2009



The largest hourly market share was 100 percent and 36 percent of all hours had a maximum market share greater than or equal to 40 percent. In less than one percent of Mid-Atlantic Subzone hours during which a market was cleared in 2009, a single company had 100 percent of the market share. The highest annual average market share for a single company for all hours in which it had any market share, was 37 percent. In other words, a single company sold 37 percent of synchronized reserves on average for all hours in which it had market share over the entire year. (See Table 6-15)

Table 6-15 Mid-Atlantic Subzone RFC Tier 2 Synchronized Reserve Market's cleared market shares: Calendar year 2009

Company Market Share	Cleared Synchronized Reserve: All Units
1	37%
2	30%
3	26%
4	26%
5	23%

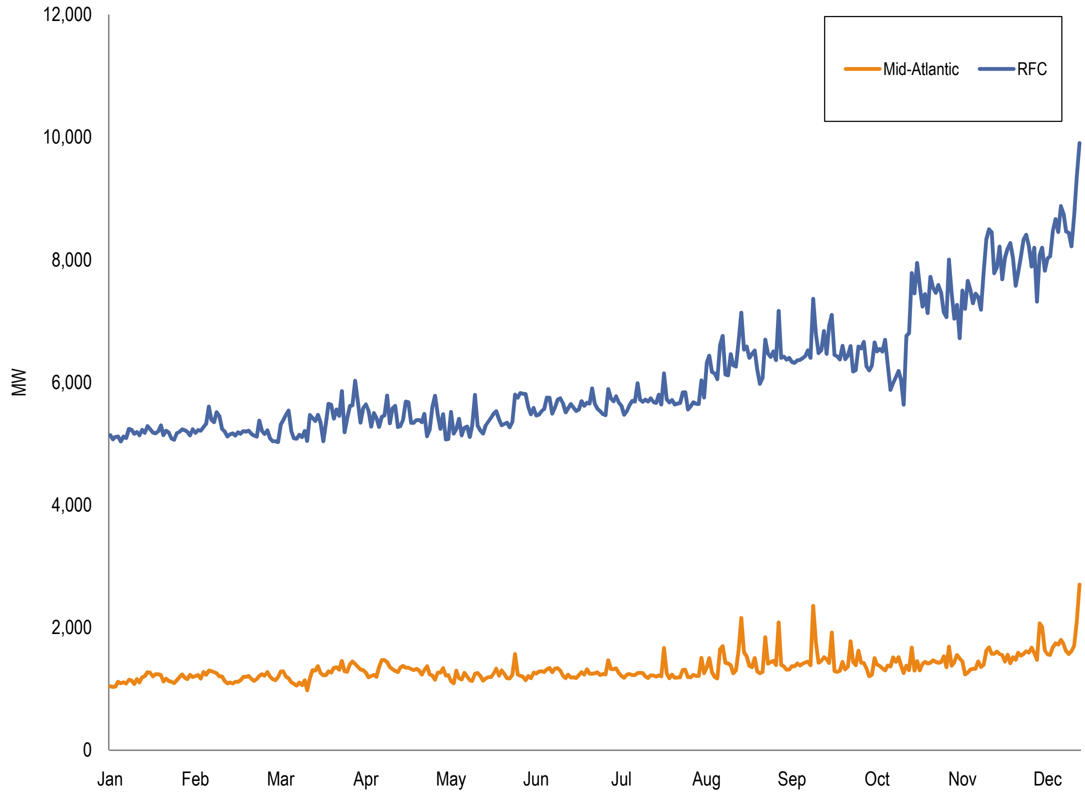
In 2009, 95 percent of hours in the Mid-Atlantic Subzone of the RFC Synchronized Reserve Market failed the three pivotal supplier test. One company was pivotal in 57 percent of all pivotal hours, a second company was pivotal in 53 percent of all pivotal hours, and a third company was pivotal in 51 percent of all pivotal hours. 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.

Market Conduct

Offers

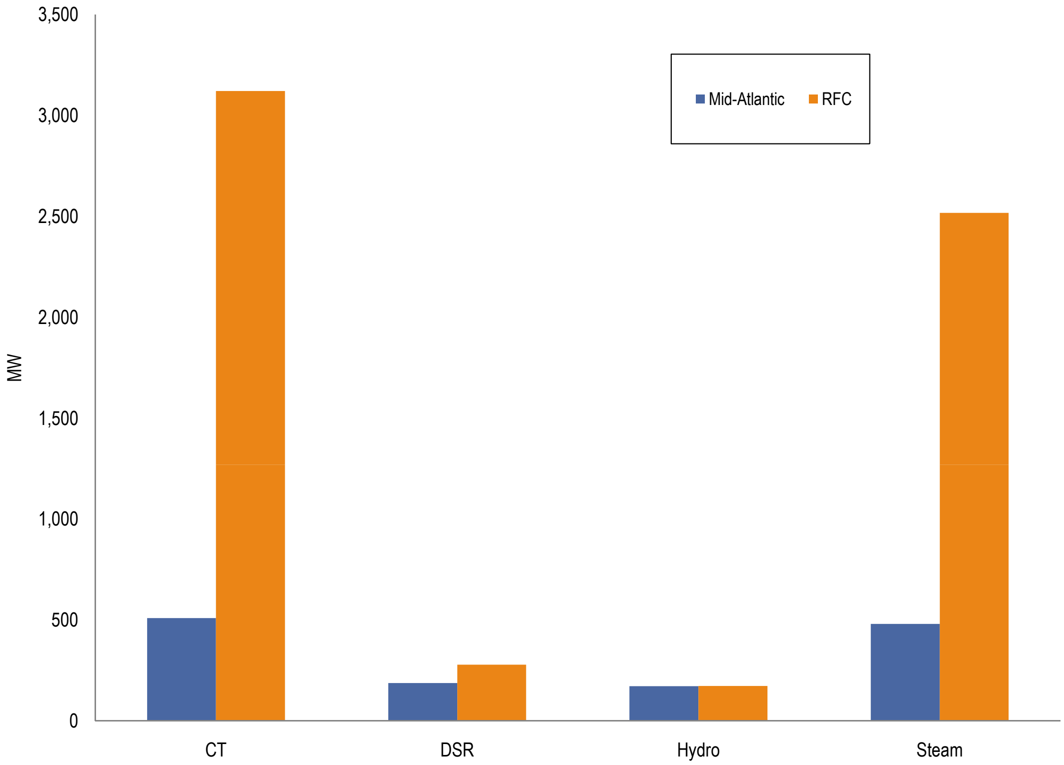
Figure 6-9 shows the daily average hourly offered Tier 2 synchronized reserve MW. For steam units, offered MW are eligible only if the offering unit is running. For that reason, the eligible offer volume shows weekly variability based on off-peak/on-peak operating cycles as well as seasonal variability.

Figure 6-9 Tier 2 synchronized reserve average hourly offer volume (MW): Calendar year 2009



Synchronized reserve is offered by steam, CT, hydroelectric and DSR resources. Figure 6-10 shows average offer MW volume by market and unit type.

Figure 6-10 Average daily Tier 2 synchronized reserve offer by unit type (MW): Calendar year 2009



The contribution of DSR resources to the Synchronized Reserve Market remained significant in 2009. The significance of DSR in the Synchronized Reserve Markets is greater than its eligible offer MW as illustrated in Figure 6-10. In 2009, DSR accounted for all cleared Tier 2 synchronized reserves in 12 percent of hours when a synchronized reserve market was cleared. In the hours when all supply was DSR, the unweighted average SRMCP was $1.87. The unweighted average SRMCP for all cleared hours was $6.47. As defined by PJM, demand-side resources may at times be generation that is behind the meter.

DSR

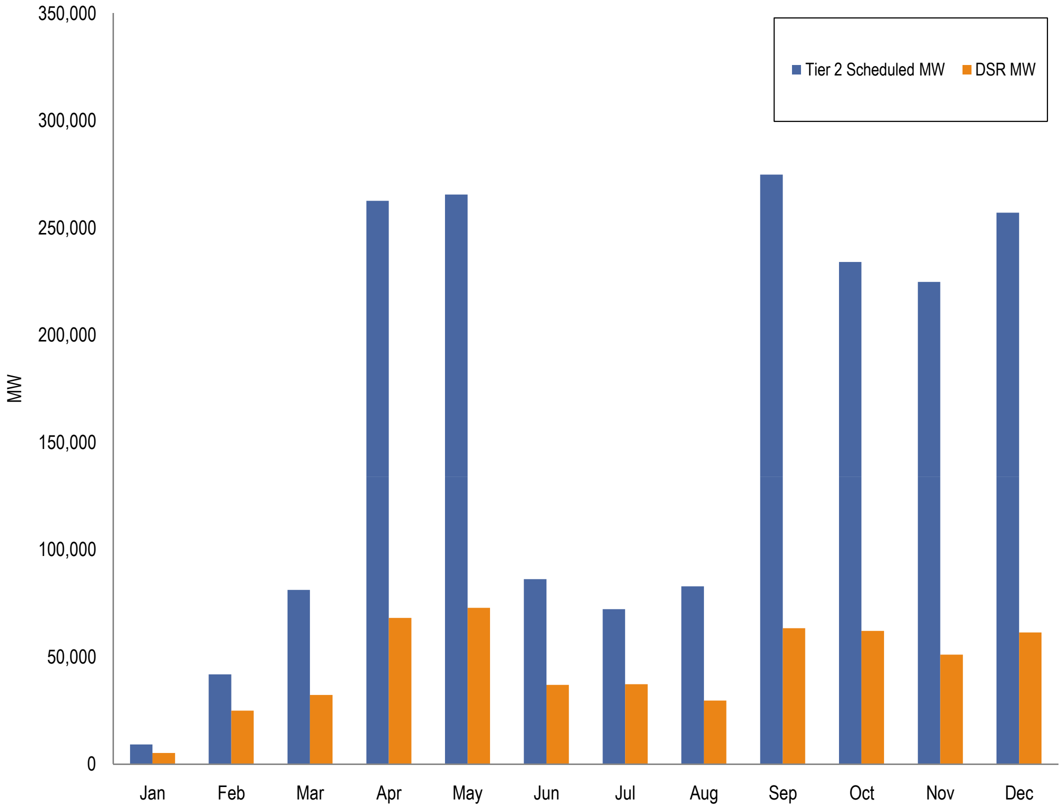
Demand-side resources were permitted to participate in the Synchronized Reserve Markets in August 2006. Although less significant in 2009 than in 2008, DSR continues to have a significant impact on the Synchronized Reserve Market. In 12 percent of hours where a synchronized reserve market was cleared in the Mid-Atlantic Subzone of the RFC (see Table 6-16), all cleared synchronized reserve was DSR synchronized reserve. The clearing price for those hours was significantly lower than the average clearing price overall.

Table 6-16 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: Calendar year 2009

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%
Oct	$1.37	$5.94	0%
Nov	$0.50	$6.47	1%
Dec	$1.05	$7.11	1%

Figure 6-11 shows total monthly synchronized reserve PJM-scheduled MW and cleared MW for DSR synchronized reserve. Participation of demand response in the Synchronized Reserve Market remained strong. Demand response remained significantly less expensive than other forms of synchronized reserve. Demand resources typically offer at a lower price, and demand resources do not have lost opportunity costs added to their offer in market clearing.

Figure 6-11 PJM RFC Zone Tier 2 synchronized reserve scheduled MW: Calendar year 2009



Market Performance

Price

Figure 6-11 shows the relationship among required Tier 2 synchronized reserve, Synchronized Reserve Market clearing price, and percent of cleared synchronized reserve satisfied by DSR in the Eastern Subzone of the PJM Synchronized Reserve Market. This figure shows both that the synchronized reserve clearing price tends to increase with demand and that DSR satisfies a large percentage of Tier 2 synchronized reserve when the demand is low.

Figure 6-12 Required Tier 2 synchronized reserve, Synchronized Reserve Market clearing price, and DSR percent of Tier 2

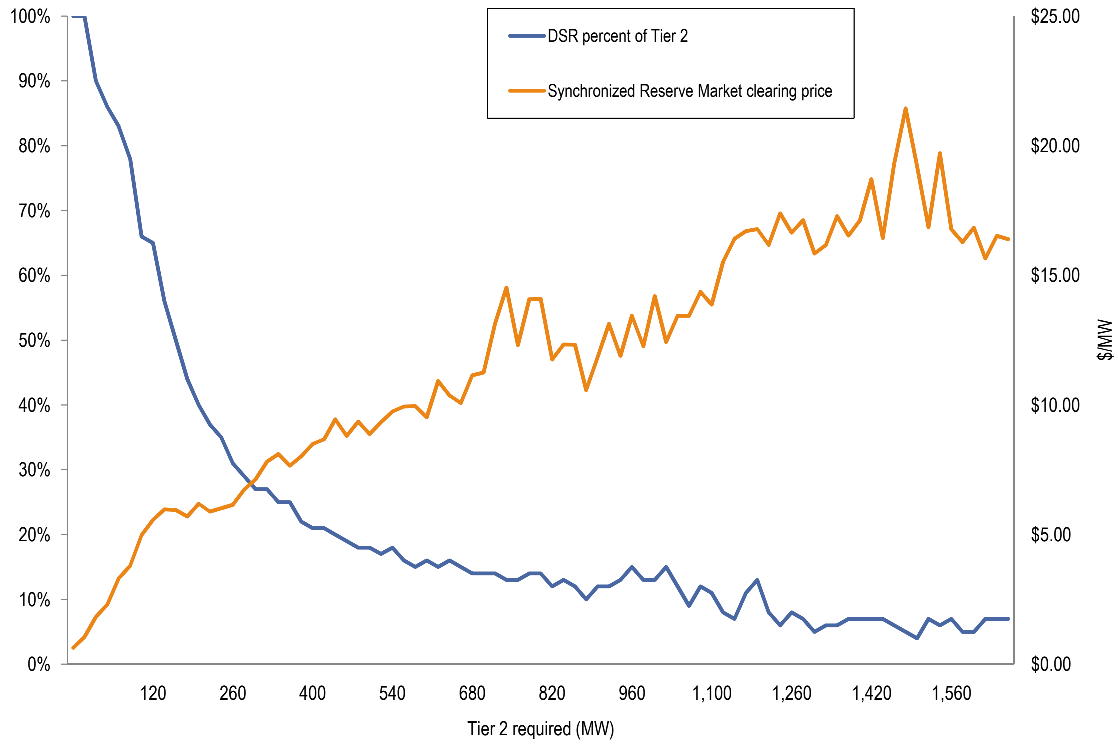


Figure 6-16 shows the load weighted, average Tier 2 price and the cost per MW associated with meeting PJM demand for synchronized reserve. The price of Tier 2 synchronized reserve is called the Synchronized Reserve Market-clearing price (SRMCP). Resources which provide synchronized reserve are paid the higher of the SRMCP or their offer plus their unit specific opportunity cost. The offer plus the unit specific opportunity cost may exceed the SRMCP for a number of reasons. If real time LMP is greater than the LMP forecast prior to the operating hour and included in the SRMCP, unit specific opportunity cost will be higher than forecast. Such higher LMPs can be local because of congestion or more general if system conditions change. The additional costs of noneconomic dispatch are added to the total cost of synchronized reserve. When some units are paid the value of their offer plus their unit specific opportunity cost, the result is that PJM's synchronized reserve cost per MW is higher than the SRMCP.

The RFC Synchronized Reserve Market cleared as a single market less than 3 percent of all hours in 2009 with a load weighted average $3.91 clearing price. The load weighted, average price for synchronized reserve in the PJM Mid-Atlantic Subzone of the RFC Synchronized Reserve Market in 2009 was $7.75 while the corresponding cost of synchronized reserve was $9.77.

Price and Cost

In 2009, PJM appears to have solved the problem of needing a significant amount of non-economic, out of market Tier 2 resources added to the resources procured in the Synchronized Reserve Market. Previously PJM dispatch procured additional Tier 2 reserves to cover anticipated operational needs because of an operations concern that Tier 1 resources located west of the

Bedington – Black Oak interface would not be available in the Mid-Atlantic Subzone if a spinning event should occur. This added Tier 2 MW increased the cost of Tier 2 synchronized reserve and has been a significant contributor to total synchronized reserve costs.

PJM had set the transfer capacity (a measure of the percent of Tier 1 available west of Bedington – Black Oak to the Mid-Atlantic Subzone) at 70 percent. On March 13, 2009, PJM reset the transfer capacity to 15 percent. PJM also changed the transfer interface from Bedington – Black Oak to AP South. These changes had the effect of segregating the Eastern Subzone from the rest of the RFC synchronized reserve zone. As a result, less Tier 1 synchronized reserve was available to the East during the market solution, increasing the amount of Tier 2 that had to be cleared to satisfy the requirement. This reduced the amount of Tier 2 synchronized reserve that had to be added by PJM dispatch after market clearing. The effect of this transfer capacity change can be seen clearly in Table 14, Figure 6-12, and Figure 6-13. This change has significantly affected the Synchronized Reserve Market since it was made on March 13. The result of this change was to minimize the amount of Tier 2 added by dispatch after the market cleared and maximize the amount of Tier 2 purchased through the market, resulting in an accurate clearing price and more closely aligning Tier 2 costs with prices; see Figure 6-14 and Figure 6-15.

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

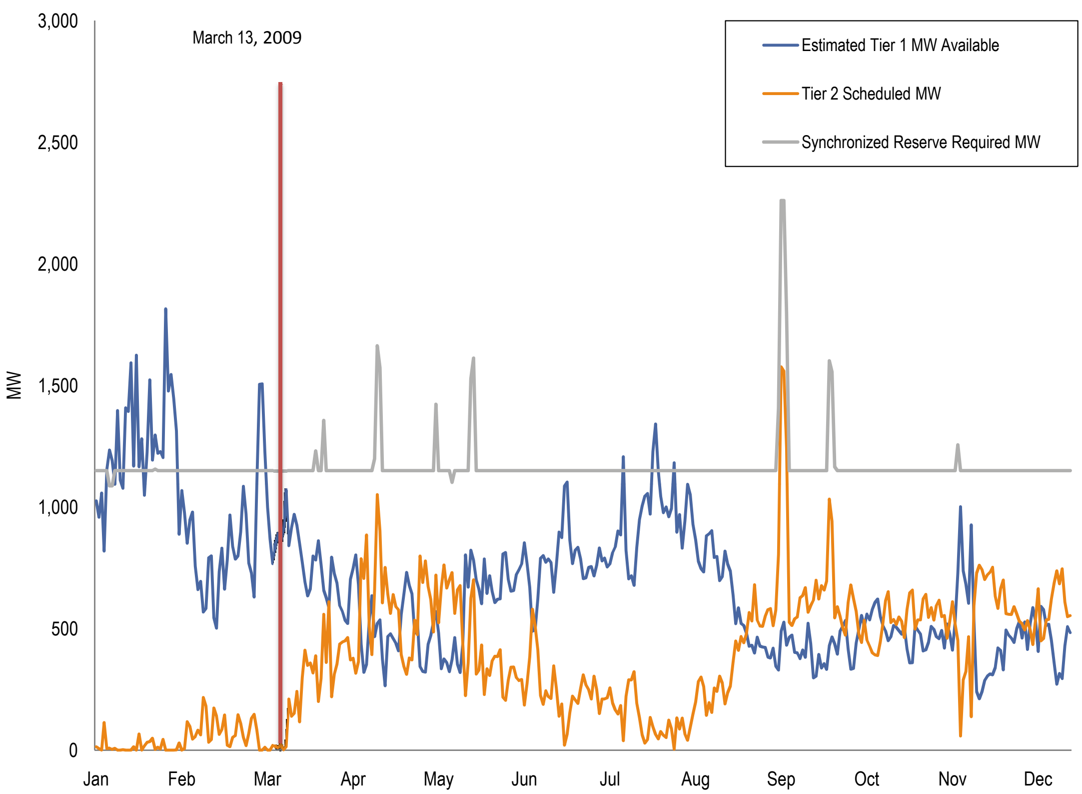
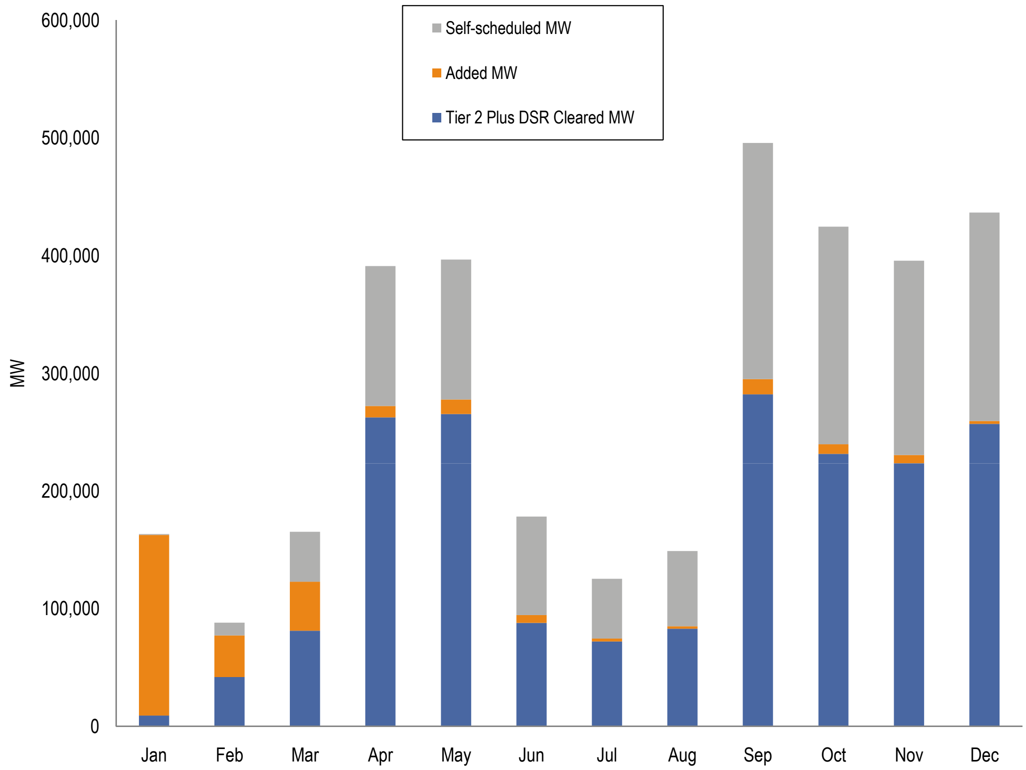


Figure 6-14 Tier 2 synchronized reserve purchases by month for the Mid-Atlantic Subzone



The problem of out-of-market purchases of Tier 2 synchronized reserve was greatly diminished by the March 13, 2009 change in the transfer capacity used in the market solution. Figure 6-14 shows that added MW as a percentage of total MWs and opportunity costs as a percentage of total costs fell in March.

The difference between the Tier 2 Synchronized Reserve Market price and the cost for Tier 2 synchronized reserve in 2009 was significantly lower than it had been in 2008 (Figure 6-14). In the Mid-Atlantic Subzone of the RFC Synchronized Reserve Market for 2009 the cost of Tier 2 synchronized reserves was 26 percent higher than the load-weighted price. In 2008 this difference had been 54 percent (see Figure 6-15).

Figure 6-15 Impact of Tier 2 synchronized reserve added MW to the RFC Synchronized Reserve Zone, Mid-Atlantic Subzone: Calendar year 2009

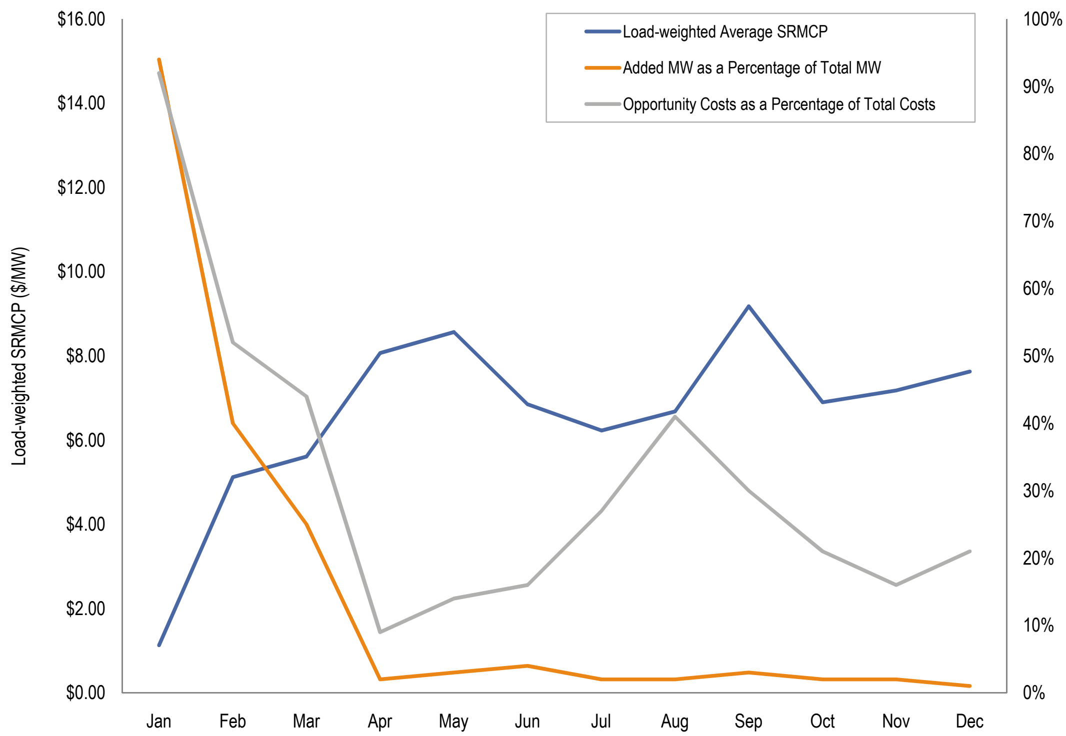
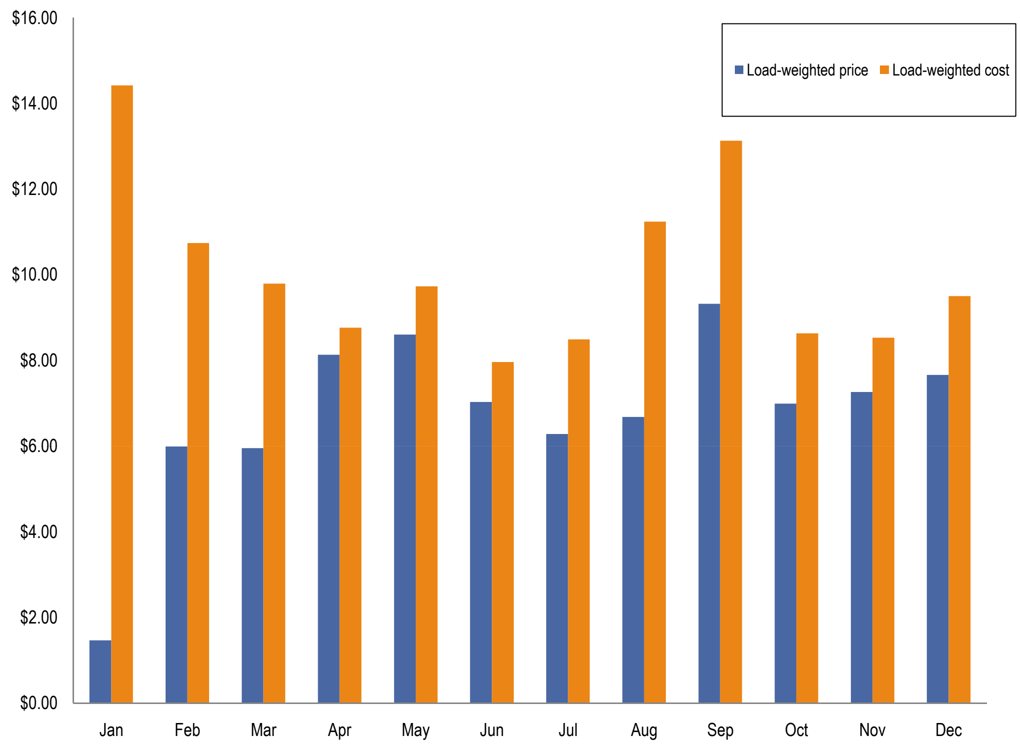


Figure 6-16 Comparison of RFC Mid-Atlantic Subzone Tier 2 synchronized reserve price and cost (Dollars per MW): Calendar year 2009



Market Solution and Actual Dispatch of Ancillary Services

The actual dispatch of ancillary services can and does differ from the market solution, in many cases, as a result of legitimate reliability concerns. The result is usually that total costs per MW (credits/MW) are higher than the clearing price (RMCP). The MMU analyzes this cost/price differential and reports the cost and price.

The market solution software (SPREGO) optimizes regulation and spinning using a theoretical unit dispatch and estimated Tier 1 synchronized reserve based on forecast load. The MMU attempts to document and categorize deviations from market solutions although there tends to be insufficient PJM documentation. Dispatchers can deselect a unit from regulation, Tier 1 or Tier 2 synchronized reserve, or unit dispatch prior to running the market solution. This is the equivalent of imposing a constraint on the market solution. The MMU recommends that a full list of potential reasons for unit deselection be published in PJM's M-11 Scheduling Operations Manual. The MMU recommends that dispatchers classify the reasons for unit deselection and document all unit deselections.

Deselection of units as Tier 1 resources played a role in the synchronized reserve markets in the early part of 2009. After a PJM review of the accrued deselections, PJM reversed many of the deselections. The result was more Tier 1 resources available than had been reflected in market solutions but which had been showing up during spinning events when Tier 1 was called. This process significantly reduced the perceived need for Tier 2 purchases. The low level of purchased synchronized reserve in January 2009 (see Figure 6-13) as well as December 2008 was the result of PJM Market Operations undoing the deselection for Tier 1 that it had made for many units over time.[42] (See Figure 6-12.)

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 deficits during 2009.

Day Ahead Scheduling Reserve (DASR)

PJM has a requirement to procure supplemental reserves to ensure that differences in forecasted loads and forced generator outages will not have a negative impact on grid reliability.[43] Prior to June 1, 2008, PJM obtained supplemental reserves from several sources including available unused capacity of generating units that had been dispatched for energy, available capacity of units not dispatched for energy but capable of coming online in 30 minutes and dispatch of additional units for the purpose of making supplemental reserve available.

On June 1, 2008 PJM introduced the Day-Ahead Scheduling Reserve Market (DASR), as required by the settlement in the RPM case.[44] 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

42 See the *2008 State of the Market Report for PJM*, Volume II, Figure 6-12, p. 328 "Tier 2 synchronized reserve purchases by month for the Mid-Atlantic subzone DSR."
43 PJM uses the terms "supplemental operating reserves" and "scheduling operating reserves" interchangeably.
44 See PJM Interconnection, L.L.C., 117 FERC ¶ 61,331 (2006).

clearing price. The DASR 30-minute reserve requirements are determined by the reliability region.[45] In the Reliability*First* (RFC) region, reserve requirements are calculated based on historical under-forecasted load rates and generator forced outage rates.[46] Under-forecasted load rates are based on the 80th percentile of a rolling three-year average (November 1 – October 31). For 2009 the load forecast error component of this calculation was 2.10 percent of peak load forecast. The forced outage rate component of the calculation is based on a three-year rolling average of the forced outage rate that occurs from 1800 of the scheduling day through the operating day at 2000. For 2009 the forced outage component of the Day-Ahead Scheduling Reserve was 4.64 percent. For 2009 the Day-Ahead Scheduling Reserve for RFC areas of PJM was 6.75 percent times Peak Load Forecast for RFC. Dominion Day-Ahead Scheduling Reserve is based on its share of the VACAR Reserve Sharing agreement and is set annually. In 2009 VACAR scheduling reserve was set at 418 MW. The RFC and Dominion Day-Ahead Scheduling Reserve 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.

DASR is an offer-based market that clears for all hours of the day at 1600 EPT day-ahead. DASR Market clearing is simultaneous with the Day-Ahead Energy Market.

All generating resources capable of increasing their output in 30 minutes are eligible to provide DASR. Load response resources which are registered in PJM's Economic Load Response and are dispatchable by PJM are also eligible to provide DASR. All DASR offers must be submitted by 1200 EPT day-ahead. There is a must offer requirement in the DASR Market, but any offer price will satisfy the requirement. Resources which are eligible for DASR but which have not offered into the market will have their offers set to $0.00.

In 2009, approximately half of all generating units had no DASR offers or offers of $0. About 4% of all units had offers of $990 or above. Such an offer is high enough to ensure that that unit will never clear and thus constitutes economic withholding. In spite of this withholding, the DASR Market has been relatively stable and characterized by low prices.

45 PJM. "Manual 13, Emergency Requirements," Revision 35 (November 7, 2008), pp. 11-12.
46 PJM. "Manual 10, Pre-Scheduling Operations," Revision 25 (January 1, 2010), p. 17.

Table 6-17 2009 PJM, Day-Ahead Scheduling Reserve Market MW and clearing prices

Month	Average Required Hourly DASR (MW)	Minimum Clearing Price	Maximum Clearing Price	Average Load Weighted Clearing Price	Total DASR MW Puchased	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
Oct	5,023	$0.00	$0.42	$0.03	3,610,812	$102,984
Nov	5,188	$0.00	$0.42	$0.03	3,556,557	$113,027
Dec	5,992	$0.00	$0.50	$0.05	3,921,732	$191,599

DASR prices are closely related to energy prices, peaking in August. In 2009, the load weighted price of DASR was $0.05. DSR began to offer and clear the DASR market in November 2008. DSR participated in the market throughout 2009 but was less than one percent of cleared DASR MW and did not clear at all from July through December. Lower energy prices led to a reduction of demand response participation in all markets in the second half of 2009. The DASR Market in 2009 had three pivotal suppliers in a monthly average of 23 percent of all hours.

In December, about 5.3 percent of all units engaged in economic withholding from the DASR Market by providing high offers. Conversely, 48 percent of units had offers of $0.00, either by choice or by default.

The fact that there is substantial structural market power in the DASR Market, together with the fact that the clearing prices are low, suggests that market participants have the ability to exercise market power in this market but have not yet done so in a way that has affected market clearing prices.

There have been no significant impacts of the market power issues in the DASR market as a result of a favorable balance between supply and demand, but that balance could change quickly as a result of weather or other factors and the impacts could be significant.

The MMU concludes that the results of the DASR Market were competitive in 2009. The MMU concludes that the DASR Market is not structurally competitive, based on the analysis for 2009. The MMU recommends that the DASR Market rules be modified to incorporate the application of the three pivotal supplier test in order to address the identified market power issues.

Black Start Service

PJM and its transmission owners must provide for sufficient and appropriately located resources that are capable of providing black start service in the PJM region. To accomplish this, transmission owners prepare system restoration plans that identify critical resources for reenergizing the grid following a possible blackout. Individual transmission owners, with PJM, identify the black start units included in each transmission owner's system restoration plan. PJM ensures the availability of black start by charging transmission customers according to their zonal load ratio share and compensating black start unit owners according to their revenue requirements (see Table 6-18 below). PJM defines a minimum critical black start for each transmission zone.[47]

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 the demonstrated ability of a generating unit with a high operating factor to automatically remain operating at reduced levels when disconnected from the grid.[48]

Individual transmission owners, with PJM, identify the black start units included in each transmission owner's restoration plan. PJM defines required black start capability zonally and ensures the availability of black start by charging transmission customers according to their zonal load ratio share and compensating black start unit owners according to their revenue requirements (see Table 6-18). PJM defines a minimum critical black start for each transmission zone.[49]

Table 6-18 Black Start yearly zonal charges for network transmission use

Zone	Network Charges
AECO	$408,761
AEP	$737,082
AP	$136,340
BGE	$483,019
ComEd	$6,826,137
DAY	$146,531
DLCO	$26,736
DPL	$361,745
JCPL	$437,556
Met-Ed	$406,825
PECO	$726,207
PENELEC	$337,079
Pepco	$223,548
PPL	$122,610
PSEG	$949,280

Schedule 6A of the PJM OATT makes available formula rates for units identified as "critical" in system restoration plans to collect their costs and authorizes PJM to perform billing and settlement

47 PJM. "Manual 36, System Restoration," Revision 12 (January 1, 2010) p. 53.
48 PJM Tariff, Second Revised Sheet No. 33.01, March 1, 2007.
49 PJM. "Manual 36, System Restoration," Revision 12, (January 1, 2010) p. 53.

of these costs (including costs collected pursuant to separately filed and eligible FERC tariffs). Schedule 6A was originally implemented in a manner most suited to the needs of existing older units that were equipped to provide black start service. Because the investment in the equipment needed to provide black start service by these units was made some time ago, the purpose of Schedule 6A was primarily to provide a level of compensation sufficient to encourage the owners of identified critical resources to continue providing the service.[50] These provisions established a rolling two-year commitment, appropriate for older units with no requirement for new investment in black start related equipment.

In 2003, PJM, working with American Electric Power Service Corporation ("AEP"), determined that new black start capability was needed at a certain location on the AEP system, partly as a result of the retirement of a legacy black start service unit. PJM issued a request for proposal, and received only offers from suppliers who would need to install new equipment in order to provide the service. PJM selected from the few potentially viable projects, Constellation's offer to provide black start service from its Big Sandy Peaker Plant ("Big Sandy"). Big Sandy required approximately $667,000 to install a 750 kW diesel generator and associated controls. Constellation deemed the recovery provisions included in Schedule 6A inadequate, especially in light of the maximum two-year commitment to which AEP would agree. Constellation therefore sought and obtained FERC approval to collect its entire capital investment over that two-year period, citing as precedent a comparable arrangement between University Park Energy, LLC ("UPE") and Commonwealth Edison Company ("ComEd") that PJM grandfathered in the course of integrating ComEd's system into PJM.[51] Constellation indicated to the Commission its expectation that Big Sandy, like UPE, expected to collect payment under Schedule 6A's formula rates after completing recovery of 100 percent of its investment. This might also have served as the pattern for the procurement of black start services from Lincoln Generating Facility, LLC, except that, partly in response to concerns raised by the MMU, Lincoln agreed to file for a longer five-year commitment period, although full investment cost recovery was accelerated to the first two years.[52]

The MMU had concerns that Schedule 6A was not providing an appropriate framework for the procurement of black start service from new resources. The fundamental problem was that transmission customers in the PJM Region were paying over a short time the cost of substantial capital investments in black start capable resources with no assurance that those resources would continue to provide black start service after the expiration of the initial two-year term. Moreover, the rates of return for a new black start unit that recovered its full capital cost in two years and then reverted to the incentive structure under the formula rates, recovering its cost twice, were far in excess of returns typical for services procured under cost-of-service ratemaking.

In late 2007, PJM reactivated the Black Start Service Working Group ("BSSWG") in order to consider how to recover the new costs of compliance with the NERC's Critical Infrastructure Protection Standards (CIPS) applicable specifically to black start units and to update an outdated reference in the formula to the pre-RPM "Capacity Deficiency Rate." PJM's stakeholders agreed to also develop modifications to provide for a mechanism that conforms the commitment period to provide black start service to the period for recovery of the costs of new investment in black start equipment. The revisions to Schedule 6A developed by the BSSWG to address these and other issues were filed with the FERC on February 19, 2009.[53] By order issued May 29, 2009, the Commission approved the reforms.[54] The Commission did not approve a measure supported by the MMU that would

50 See PJM filing initiating FERC Docket No. ER02-2651-000 at 4 (September 30, 2002)("2002 Schedule 6A Filing").
51 See Big Sandy Peaker Plant, LLC filing initiating FERC Docket No. ER06-1357-000 (August 11, 2006), and the Letter Order of acceptance (September 13, 2006); University Park Energy, LLC filing initiating FERC Docket No. ER04-212-000 (November 21, 2003), and Letter Order of acceptance (January 29, 2004).
52 See Lincoln Generating Facility, LLC filing initiating FERC Docket No. ER08-63-000 (October 16, 2007), and Letter Order of acceptance (December 12, 2007).
53 PJM filed the revised Schedule 6A in FERC Docket No. ER09-730-000.
54 127 FERC ¶61,197.

have prevented double recovery of revenues by certain black start units that received accelerated recovery of investment in black start equipment prior to the reforms becoming effective on April 21, 2009.[55]

Structure

There is no organized market for black start service in PJM. PJM in conjunction with its transmission owners identifies locations where critical black start units are needed and conducts requests for proposals to procure service at those locations. Proposals are accepted from any party willing and able to provide the service at the required location. No customers or their representatives are involved in this process. The MMU is not aware that any request for proposal process has received more than a handful of offers. This result is not unexpected, as there are a very limited number of existing facilities at particular locations indentified in PJM's system restoration plans eligible to provide the service needed. The MMU has concerns that there is a disconnect between a service that is required for system reliability and the need to secure voluntary participation in the system restoration plans from the relatively few potentially cost-effective providers at the critical locations identified. Clearly, the owners of the few facilities able to respond to the requests for proposal have local market power in the provision of black start services as a result both of inelastic demand and the small size of the local market. The significantly increasing costs and risks associated with providing this service as a result of more rigorous and enforceable security standards may aggravate this problem, despite PJM's efforts to address this issue.

Conduct

PJM generally has managed the request-for-proposals process in an orderly and transparent manner. PJM has ensured the provision of black start service. The MMU is concerned that the process does not ensure adequate scrutiny of the proposals or meaningful competition.

Performance

Although the procurement process is transparent and administered well, it is not a "competitive" process. The request for proposal process cannot be relied upon to ensure just and reasonable rates for black start service because the market is characterized by inelastic demand and substantial local market power. PJM has correctly described Schedule 6A and its formula rates as a cost-of-service recovery mechanism, and its performance should be evaluated in that framework.[56]

As revised, the formula under Schedule 6A allows black start service providers to recover the costs of new investment and reasonably conforms the terms of commitment by the providers of black start service to the period over which investment costs are recovered. However, the inclusion of CIPS costs applicable to black start service may lead to substantial increases in the cost of black start service. Certain units may incur these costs and continue to be included in system restoration plans even though the plans could be developed in a manner that would provide the same service at much lower cost. The principal obstacle is that PJM does not have the authority to develop a

55 See Motion for Leave to Answer and Answer of the Independent Market Monitor for PJM filed in ER09-730-002 (August 28, 2009); 128 FERC ¶ 61,249 at PP 18—20 (September 17, 2009).
56 See 2002 Schedule 6A Filing at 4.

comprehensive system restoration plan or a clear mandate to conduct procurement in manner that results in a least cost solution for the entire system. The MMU recommends that PJM and the FERC, as well state regulators, reevaluate how black start service is procured in order to ensure that procurement is done in a least cost manner for the entire PJM market.