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 the basis of incentive rates or cost.

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

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

1 75 FERC ¶ 61,080 (1996).

2 Regulation is used to help control the area control error (ACE). See the *2010 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 2011.

The purpose of the Day-Ahead Scheduling Reserve (DASR) market is to satisfy supplemental (30-minute) reserve requirements with a market-based mechanism that allows generation resources to offer their reserve energy at a price and compensates cleared supply at the market clearing price.[3]

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

The Market Monitoring Unit (MMU) analyzed measures of market structure, conduct and performance for the PJM Regulation Market, the two regional Synchronized Reserve Markets, and the PJM DASR Market for the first nine months of 2011.

Table 6-1 The Regulation Market results were not competitive[4]

Market Element	Evaluation	Market Design
Market Structure	Not Competitive	
Participant Behavior	Competitive	
Market Performance	**Not Competitive**	**Flawed**

- The Regulation Market structure was evaluated as not competitive because the Regulation Market had one or more pivotal suppliers which failed PJM's three pivotal supplier (TPS) test in 91 percent of the hours in the first nine months of 2011.

- Participant behavior was evaluated as competitive because market power mitigation requires competitive offers when the three pivotal

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

4 As Table 6-1 indicates, the Regulation Market results are not the result of the offer behavior of market participants, which was competitive as a result of the application of the three pivotal supplier test. The Regulation Market results are not competitive because the changes in market rules, in particular the changes to the calculation of the opportunity cost, resulted in a price greater than the competitive price in some hours, resulted in a price less than the competitive price in some hours, and because the revised market rules are inconsistent with basic economic logic. The competitive price is the actual marginal cost of the marginal resource in the market. The competitive price in the Regulation Market is the price that would have resulted from a combination of the competitive offers from market participants and the application of the prior, correct approach to the calculation of the opportunity cost. The correct way to calculate opportunity cost and maintain incentives across both regulation and energy markets is to treat the offer on which the unit is dispatched for energy as the measure of its marginal costs for the energy market. To do otherwise is to impute a lower marginal cost to the unit than its owner does and therefore impute a higher or lower opportunity cost than its owner does, depending on the direction the unit was dispatched to provide regulation. If the market rules and/or their implementation produce inefficient outcomes, then no amount of competitive behavior will produce a competitive outcome.

supplier test is failed and there was no evidence of generation owners engaging in anti-competitive behavior.

- Market performance was evaluated as not competitive, despite competitive participant behavior, because the changes in market rules, in particular the changes to the calculation of the opportunity cost, resulted in a price greater than the competitive price in some hours, resulted in a price less than the competitive price in some hours, and because the revised market rules are inconsistent with basic economic logic.

- Market design was evaluated as flawed because while PJM has improved the market by modifying the schedule switch determination, the lost opportunity cost calculation is inconsistent with economic logic and there are additional issues with the order of operation in the assignment of units to provide regulation prior to market clearing.

Table 6-2 The Synchronized Reserve Markets results were competitive

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

- The Synchronized Reserve Market structure was evaluated as not competitive because of high levels of supplier concentration and inelastic demand. The Synchronized Reserve Market had one or more pivotal suppliers which failed the three pivotal supplier test in 56 percent of the hours in the first nine months of 2011.

- Participant behavior was evaluated as competitive because the market rules require competitive, cost based offers.

- Market performance was evaluated as competitive because the interaction of the participant behavior with the market design results in prices that reflect marginal costs.

- Market design was evaluated as effective because market power mitigation rules result in competitive outcomes despite high levels of supplier concentration.

Table 6-3 The Day-Ahead Scheduling Reserve Market results were competitive

Market Element	Evaluation	Market Design
Market Structure	Competitive	
Participant Behavior	Mixed	
Market Performance	**Competitive**	**Mixed**

- The Day-Ahead Scheduling Reserve Market structure was evaluated as competitive because the market failed the three pivotal supplier test in only a limited number of hours.

- Participant behavior was evaluated as mixed because while most offers appeared consistent with marginal costs, about ten percent of offers reflected economic withholding.

- Market performance was evaluated as competitive because there were adequate offers at reasonable levels in every hour to satisfy the requirement and the clearing price reflected those offers.

- Market design was evaluated as mixed because while the market is functioning effectively to provide DASR, the three pivotal supplier test should be added to the market to ensure that market power cannot be exercised at times of system stress.

Highlights

- The load weighted average Regulation Market clearing price, including opportunity cost, for the first nine months of 2011 was $17.03 per MW.[5] This was a decrease of $2.25, or 12 percent, from the average price for regulation during the same period in 2010. The total cost of regulation decreased by $1.21 from $33.92 per MW for the first nine months of 2010, to $32.71, or 3.6 percent. For the first nine months of 2011 the load weighted Regulation Market clearing price was only 52 percent of the total regulation cost per MW, compared to 57 percent of the total costs of regulation per MW in the first nine months of 2010.

- The load weighted average clearing price for Tier 2 Synchronized Reserve Market in the Mid-Atlantic Subzone was $12.00 per MW in the first nine months of 2011, a $0.49 per MW increase from the same period in 2010.[6] The total cost of synchronized reserves per MWh for the first nine months of 2011 was $14.21, a 4.0 percent decrease from

5 The term "load weighted" in the Regulation Market refers to regulation MW weighted.
6 The term "load weighted" in the Synchronized Reserve Market refers to synchronized reserve MW weighted.

the total cost of synchronized reserves ($14.81) during the first nine months of 2010. The load weighted average Synchronized Reserve Market clearing price was 73 percent of the load weighted average total cost per MW of synchronized reserve in the first nine months of 2011, up from 70 percent in the same time period of 2010.

- The load weighted DASR market clearing price in the first nine months of 2011 was $1.04 per MW. In the first nine months of 2010, the load weighted price of DASR was $0.18 per MW. The year over year increase in the load weighted average price per MW of DASR was attributable to several days of high DASR prices in June, July and August.

- Black start zonal charges in the first nine months of 2011 ranged from $0.02 per MW in the ATSI zone to $0.75 per MW in the PSEG zone.

Recommendations

- In this *2011 Quarterly State of the Market Report for PJM: January through September*, the recommendations from the *2010 State of the Market Report for PJM* remain MMU recommendations. The additional recommendation from the *2011 Quarterly State of the Market Report for PJM: January through June*, that the Synchronized Reserve Market design be modified to address the issue of units which offer and clear synchronized reserve but fail to provide synchronized reserve when an actual spinning event occurs, also remains an MMU recommendation.

Overview

Regulation Market

The PJM Regulation Market in the first nine months of 2011 continued to be operated as a single market. There have been no structural changes since December 1, 2008, when 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.[7]

7 All existing PJM tariffs, and any changes to these tariffs, are approved by FERC. The MMU describes the full history of the changes to the tariff provisions governing the Regulation Market in the *2010 State of the Market Report for PJM*, Volume II, Section 6, "Ancillary Service Markets."

Market Structure

- **Supply.** In the first nine months of 2011, the supply of offered and eligible regulation in PJM was both stable and adequate. Although PJM rules allow up to 25 percent of the regulation requirement to be satisfied by demand resources, none qualified to make regulation offers in the first nine months of 2011. The ratio of offered and eligible regulation to regulation required averaged 2.95 for the first nine months of 2011. This is a 3.1 percent increase over the first nine months of 2010 when the ratio was 2.86.

- **Demand.** The on-peak regulation 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. The average hourly regulation demand for the first nine months of 2011 was 943 MW (856 MW off peak, and 1039 MW on peak). This is a 30 MW increase in the average hourly regulation demand for the first nine months of 2010 (830 MW off peak, and 1008 MW on peak).

  Of the LSEs' obligation to provide regulation during the first nine months of 2011, 84 percent was purchased in the spot market, 13 percent was self scheduled, and three percent was purchased bilaterally.

- **Market Concentration.** During the first nine months of 2011, the PJM Regulation Market had a load weighted, average Herfindahl-Hirschman Index (HHI) of 1645 which is classified as "moderately concentrated."[8] The minimum hourly HHI was 818 and the maximum hourly HHI was 3683. The largest hourly market share in any single hour was 58 percent, and 84 percent of all hours had a maximum market share greater than 20 percent.[9] In the first nine months of 2011, 91 percent of hours had one or more pivotal suppliers which failed PJM's three pivotal supplier test. The MMU concludes from these results that the PJM Regulation Market in the first nine months of 2011 was characterized by structural market power in 91 percent of the hours.

8 See the *2010 State of the Market Report for PJM*, Volume II, Section 2, "Energy Market, Part I," at "Market Concentration" for a more complete discussion of concentration ratios and the Herfindahl-Hirschman Index (HHI). Consistent with common application, the market share and HHI calculations presented in the SOM are based on supply that is cleared in the market in every hour, not on measures of available capacity.

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

Market Conduct

- **Offers.** Daily regulation offer prices are submitted for each unit by the unit owner. Owners are required to submit unit specific cost based offers and owners also have the option to submit price based offers. Cost based offers apply for the entire day and are subject to validation using unit specific parameters submitted with the offer. All price based offers remain subject to the $100 per MWh offer cap.[10] In computing the market solution, PJM calculates a unit specific opportunity cost based on forecast LMP, and adds it to each offer. The offers made by unit owners and the opportunity cost adder comprise the total offer to the Regulation Market for each unit. Using a supply curve based on these offers, PJM solves the Regulation Market and then tests that solution to see which, if any, suppliers of eligible regulation are pivotal. The offers of all units of owners who fail the three pivotal supplier test for an hour are capped at the lesser of their cost based or price based offer. The Regulation Market is then cleared again.

Market Performance

- **Price.** The load weighted Regulation Market clearing price for the PJM Regulation Market in the first nine months of 2011 was $17.03 per MW. This was a decrease of $2.25, or 12 percent, from the average price for regulation during the same period in 2010. The total cost of regulation decreased by $1.21 from $33.92 per MW for the first nine months of 2010, to $32.71, or 3.6 percent. For the first nine months of 2001 the load weighted Regulation Market clearing price was only 52 percent of the total regulation cost per MW, compared to 57 percent of the total costs of regulation per MW in the first nine months of 2010. This change was primarily the result of using forecasted LMP to calculate the opportunity costs which are incorporated in the offers used to clear the market. The actual costs of regulation include payments to each individual unit for its after the fact opportunity cost, which is based on actual LMP.

  The difference between the total cost of regulation and the clearing price of regulation was primarily the result of using forecasted LMP to calculate the opportunity costs which are incorporated in the offers used to clear the market. The actual costs of regulation include payments to each individual unit for its after the fact opportunity cost, which is based on actual LMP. In addition, units scheduled to regulate are, at times, switched with other units in an owner's fleet of regulation units by the owner or at the direction of PJM Dispatch as a result of binding constraints or performance problems.

10 See PJM. "Manual 11, Energy and Ancillary Services Market Operations," Revision 46 (June 1, 2011) p. 55.

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).

The integration of the Trans-Allegheny Line (TrAIL)[11] project (performed in three stages April 8, May 13, and May 20, 2011) resulted in a change to the interface defining the Mid-Atlantic subzone of the RFC Synchronized Reserve Market. That interface had been the AP South interface since March 2009. [12] After the implementation of TrAIL, Bedington – Black Oak became the most limiting interface. This change is being made to PJM's Manual 11, Energy and Ancillary Services Market Operations and was made in the software that clears the regulation and synchronized reserve markets at the end of September. From May 20, 2011, through the end of September the percent of Tier 1 synchronized reserve available west of the interface that is also available in the Mid-Atlantic subzone (transfer capacity) was set to 30 percent. PJM is currently studying the Synchronized Reserve Market to see if the transfer capacity needs further adjustment after the change to Bedington—Black Oak as the Mid-Atlantic Subzone interface. The more Tier 1 synchronized reserve available, the less Tier 2 synchronized reserve needs to be cleared. These changes to the transfer interface capacity did affect the Synchronized Reserve Market by changing the amount of Tier 2 required in the Mid Atlantic Subzone. Synchronized reserves added out of market were 2.5 percent of all synchronized reserves during the first nine months of 2011, down from 4.1 percent for the same time period in 2010. After-market opportunity cost payments accounted for 25 percent of total costs during the first nine months of 2011 compared to 28 percent for the first nine months of 2010.

In December of 2010, PJM Market Operations changed the transfer capacity across the AP South interface from 15 percent of available Tier 1

11 <http://www.pjm.com/planning/rtep-upgrades-status/backbone-status/trail.aspx>
12 See PJM. "Manual 11, Energy and Ancillary Services Market Operations," Revision 46 (June 1, 2011) p. 67.

to five percent.[13] Less Tier 1 synchronized reserve available means more Tier 2 synchronized reserve is required in the Mid-Atlantic Subzone in order to satisfy the 1,300 MW requirement. This resulted in significant increases in scheduled Tier 2 synchronized reserves in the Mid-Atlantic Subzone Synchronized Reserve market from January through May 2011. PJM has kept the Tier 1 synchronized reserve transfer capacity at 30 percent since early June.

Market Structure

- **Supply.** In the first nine months of 2011 the supply of offered and eligible synchronized reserve was both stable and adequate. The contribution of DSR to the Synchronized Reserve Market remains significant. Demand side resources are low cost, and their participation in this market lowers overall Synchronized Reserve prices. The ratio of offered and eligible synchronized reserve to synchronized reserve required was 1.09 for the Mid-Atlantic Subzone.[14] This is an 11 percent decrease from first nine months of 2010 when the ratio was 1.23. The ratio of offered and eligible synchronized reserve was 3.09 for the RFC Zone. This is a 15 percent increase from the first nine months of 2010 when the ratio was 2.69. The offered and eligible excess supply ratio is determined using the administratively required level of synchronized reserve. The requirement for Tier 2 synchronized reserve is lower than the required reserve level for synchronized reserve because there is usually a significant amount of Tier 1 synchronized reserve available.

- **Demand.** PJM made several changes to the hourly required synchronized reserve requirements between December, 2008 and September, 2011 (Table 6-16). The synchronized reserve requirement in the RFC zone was raised to 1,700 MW on February 9 and 10, 2011 for double spinning, and was raised to 1,760 MW on May 3, 4, 5 and 6 for double spinning. On September 7 the Synchronized Reserve requirement was raised to 1,700 MW for most of the day for double spinning. Table 6-20 lists all spinning events from January 2009 through September 2011. Although providers of Tier 2 synchronized reserve are paid for making synchronized reserve MW available every hour, it is only during spinning events that such Tier 2 synchronized reserve is actually used. Because the number of hours when a spinning event occurs is small compared to the number of hours a synchronized reserve market is cleared, adequate reductions in payments should apply to providers who clear the market but provide less synchronized reserve MW during spinning events than they are paid for.

  For the first nine months of 2011, in the Mid-Atlantic Subzone, a Tier 2 synchronized reserve market was cleared in 79 percent of hours. In the first nine months of 2010 a Tier 2 synchronized reserve market was cleared in 64 percent of hours. For the first nine months of 2011, the average required Tier 2 synchronized reserve (including self scheduled) was 562 MW. For the first nine months of 2010 the average required Tier 2 synchronized reserve was 312 MW. The Tier 2 requirement for January through March 2011 was 756 MW but only 346 MW for April through September 2011. This drop was primarily because the TrAIL line increased the transfer capacity of the most constraining interface allowing more Tier 1 to be available in the Mid Atlantic Subzone. The full impact of TrAIL on the amount of Tier 1 synchronized reserve available across the Bedington—Black Oak constraint is still being studied and may result in further changes to the transfer capability.

  Synchronized reserves added out of market were two and a half percent of all Mid-Atlantic Subzone synchronized reserves in the first nine months of 2011. Synchronized reserves added out of market were four percent of all Mid-Atlantic Subzone synchronized reserves in the first nine months of 2010.

- Market demand for Tier 2 is less than the requirement for synchronized reserve by the amount of forecast Tier 1 synchronized reserve available at the time a Synchronized Reserve Market is cleared. As a result of the level of Tier 1 reserves in the RFC Synchronized Reserve Zone, less than one percent (16 hours) cleared a Tier 2 Synchronized Reserve Market in the RFC during the first nine months of 2011. A Tier 2 Synchronized Reserve Market was cleared for the Southern Synchronized Reserve Zone in 20 hours during the first nine months of 2011.

- **Market Concentration.** The average load weighted cleared Synchronized Reserve Market HHI for the Mid-Atlantic Subzone for the first nine months of 2011 was 2768, which is classified as "highly concentrated."[15] For purchased synchronized reserve (cleared plus added) the HHI was 2816. In the first nine months of 2011, 51 percent of hours had a maximum market share greater than 40 percent, compared to 40 percent of hours in the same period of 2010.

  In the Mid-Atlantic Subzone, in the first nine months of 2011, 56 percent of hours that cleared a synchronized reserve market had three or fewer

13 See the *2010 State of the Market Report for PJM*, Section 6, "Ancillary Service Markets", p. 452.
14 The Synchronized Reserve Market in the Southern Region cleared in so few hours that related data for that market is not meaningful.
15 See the *2010 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).

pivotal suppliers. In the same period of 2010, 36 percent of hours had three or fewer pivotal suppliers. The MMU concludes from these TPS results that the Mid-Atlantic Subzone Synchronized Reserve Market in the first nine months of 2011 was 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.

  Total MW of cleared demand side resources increased in the first nine months of 2011 over the first nine months of 2010 (from 392,783 MW to 623,918 MW) but their share of the total Synchronized Reserve Market declined from 32 percent to 29 percent. Demand side resources satisfied 100 percent of the Tier 2 Synchronized Reserve market in seven percent of hours in the first nine months of 2011 compared to nine percent of hours on the first nine months of 2010.

- **Compliance.** There is a compliance issue in the Synchronized Reserve Market. A substantial proportion of synchronized reserves which clear the market fail to provide their full amount of synchronized reserve when an actual spinning event occurs. The penalty structure is adequate to address this behavior.[16] The problem is that the penalty structure permits egregious non-compliance, a situation in which providers do not comply at all or at a very low (less than 30 percent) level. The penalty structure is inadequate to address this behavior. The MMU recommends that the Synchronized Reserve Market design, including compliance monitoring and non-compliance penalties, be restructured to address this issue and provide stronger incentives for compliance.

Market Performance

- **Price.** The load weighted average price for Tier 2 synchronized reserve in the Mid-Atlantic Subzone was $12.00 per MW in the first nine months of 2011, a $0.49 per MW increase from the same period in 2010. The total cost of synchronized reserves per MWh for the first nine months of 2011 was $14.21, a 4.0 percent decrease from the total cost of synchronized reserves ($14.81) during the first nine months of 2010. The market clearing price was 73 percent of the total synchronized reserve cost per MW in the first nine months of 2011, up from 70 percent in the same time period of 2010.

  The difference between the total cost of synchronized reserve and the clearing price of synchronized reserve was largely the result of using forecasted LMP to calculate the opportunity costs which are incorporated in the offers used to clear the market. The actual costs of synchronized reserve include payments to each individual unit for its after the fact opportunity cost, which is based on actual LMP.

- **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 in the first nine months of 2011.

DASR

On June 1, 2008 PJM introduced the Day-Ahead Scheduling Reserve Market (DASR), as required by the RPM settlement.[17] 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.[18] 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.** In the first nine months of 2011, there were 21 hours in the DASR market which failed the three pivotal supplier test. All 21 hours occurred in June, July and August during periods of high demand. The current structure of PJM's DASR Market does not include

16 See PJM. "Manual 11, Energy and Ancillary Services Market Operations, 4.2.1.3 Non-Performance", Rev. 46 (June 1, 2011), p. 75

17 See 117 FERC ¶ 61,331 (2006).

18 See PJM. "Manual 13: Emergency Operations," Revision 44, (May 26, 2011); pp 11-12.

the three pivotal supplier test. The MMU recommends that the three pivotal supplier test be incorporated in the DASR market.

- **Demand.** In the first nine months of 2011, the required DASR was 7.11 percent of peak load forecast, up from 6.88 percent in the same time period for 2010.[19] The DASR requirement is a sum of the load forecast error and the forced outage rate. From 2010 the load forecast error declined from 1.90 percent to 1.87 percent. The forced outage rate increased from 4.98 percent to 5.23 percent. Added together the 2011 DASR requirement is now 7.11 percent. The DASR MW purchased averaged 6,622 MW per hour for the first nine months of 2011, an increase from 6,176 MW per hour during the same period in 2010.

Market Conduct

- **Withholding.** Economic withholding remains an issue in the DASR Market, but the nature of economic withholding in the DASR Market changed in June. The first five months of 2011 continued the pattern that has existed since the inception of the DASR Market in which five percent of units offered at $50 or more and four percent offered at more than $900. Most of these offers were reduced during the month of June but remained at levels exceeding competitive levels. PJM rules require all units with reserve capability that can be converted into energy within 30 minutes to offer into the DASR Market.[20] Units that do not offer have their offers set to zero, the incremental cost of providing DASR. The marginal cost of providing DASR is zero. As of June 2011, 17 percent of units offering into the DASR market are offering at $5.00 or more.

- **DSR.** Demand side resources do participate in the DASR Market, but no demand resource cleared the DASR Market in the first nine months of 2011.

Market Performance

- **Price.** The load weighted DASR market clearing price in the first nine months of 2011 was $1.04 per MW. In the first nine months of 2010, the load weighted price of DASR was $0.18 per MW. The year over year increase in the load weighted average price per MW of DASR was attributable to several days of high DASR prices in June, July and August. These high prices were primarily the result of high demand and limited supply which created the need for redispatch in the Day-Ahead Energy Market in order to provide DASR. The result was that DASR prices in these hours reflected opportunity costs associated with the redispatch. DASR prices are calculated as the sum of the offer price plus the opportunity cost. For most hours the price is comprised entirely of offer price. In 45 percent of hours from January through September the DASR Market Clearing Price was $0.00. Most, 97 percent, DASR clearing prices consist solely of the offer price. For a few of the high price hours the price is composed almost entirely of LOC. For the top 0.5 percent (average clearing price = $108.92) of hours 99.7 percent of the price is determined by opportunity cost. For the bottom 99.5 percent (average clearing price = $0.20) of hours only two percent of the price is composed of LOC (Figure 6-15).

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.[21]

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

PJM does not have a market to provide black start service, but compensates black start resource owners on the basis of an incentive rate or for all costs associated with providing this service, as defined in the tariff. For the first nine months of 2011, charges were $10.02 million. This is 37 percent higher than the first nine months of 2010, when total black start service charges were $7.29 million. There was substantial zonal variation. The increased cost of black start in 2011 is primarily attributable to updated Schedule 6A (to the OATT) rates for all units. The increased Schedule 6A rates included net cost of new entry, VOM, bond rates, and oil forward strip.

Black start zonal charges in the first nine months of 2011 ranged from $0.02 per MW in the ATSI zone to $0.75 per MW in the PSEG zone. Black start costs in the BGE zone increased due to major refurbishments of multiple

19 See the *2010 State of the Market Report for PJM*, Volume II, Section 6, "Ancillary Services" at Day Ahead Scheduling Reserve *(DASR)*.
20 PJM. "Manual 11, Energy and Ancillary Services Market Operations," Revision 46 (June 1, 2011), p. 124.
21 OATT Schedule 1 § 1.3BB.

black start resources. The black start resources were identified as critical assets in BGE's black start restoration plan by PJM and the transmission owner. The resources undergoing major refurbishment through the black start process are recovering capital investment costs to maintain the units as black start resources using the capital recovery factor (CRF) from Schedule 6A rather than the standard incentive rate provided in the tariff for black start resources. During the recovery period the unit's annual Black Start capital cost recovery will be limited to the greater of the black start payments or capacity market revenues.[22]

Ancillary Services costs per MW of load: 2001 - 2011

Table 6-4 shows PJM ancillary services costs from January through September for 2001 through 2011 on a per MW of load basis. The Scheduling, System Control, and Dispatch category of costs is comprised of PJM Scheduling, PJM System Control and PJM Dispatch; Owner Scheduling, Owner System Control and Owner Dispatch; Other Supporting Facilities; Black Start Services; Direct Assignment Facilities; and Reliability*First* Corporation charges. Supplementary Operating Reserve includes Day-Ahead Operating Reserve; Balancing Operating Reserve; and Synchronous Condensing.

Table 6-4 History of ancillary services costs per MW of Load: January through September of 2001 through 2011 (See 2010 SOM, Table 6-4)

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

22 <http://www.pjm.com/~/media/committees-groups/task-forces/bsstf/20100420/20100420-automated-formula-rate-adjustment-process.ashx>

Conclusion

The MMU continues to conclude that the results of the Regulation Market are not competitive.[23] The Regulation Market results are not competitive because the changes in market rules, in particular the changes to the calculation of the opportunity cost, resulted in a price greater than the competitive price in some hours, resulted in a price less than the competitive price in some hours, and because the revised market rules are inconsistent with basic economic logic and the definition of opportunity cost elsewhere in the PJM tariff. This conclusion is not based on the behavior of market participants, which remains competitive.

The structure of each Synchronized Reserve Market has been evaluated and the MMU has concluded that these markets are not structurally competitive as they are characterized by high levels of supplier concentration and inelastic demand. (The term Synchronized Reserve Market refers only to Tier 2 synchronized reserve.) As a result, these markets are operated with market-clearing prices and with offers based on the marginal cost of producing the service plus a margin. As a result of these requirements, the conduct of market participants within these market structures has been consistent with competition, and the market performance results have been competitive. However, compliance with calls to respond to actual spinning events has been an issue. As a result, the MMU is recommending that the rules for compliance be reevaluated.

The MMU concludes that the DASR Market results were competitive in the first nine months of 2011, although concerns remain about economic withholding and the absence of the three pivotal supplier test in this market.

The benefits of markets are realized under these approaches to ancillary service markets. Even in the presence of structurally noncompetitive markets, there can be transparent, market clearing prices based on competitive offers that account explicitly and accurately for opportunity cost. This is consistent with the market design goal of ensuring competitive outcomes that provide appropriate incentives without reliance on the exercise of market power and with explicit mechanisms to prevent the exercise of market power.

Overall, the MMU concludes that the Regulation Market results were not competitive in the first nine months of 2011 as a result of the identified

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

market design changes and their implementation. This conclusion is not the result of participant behavior, which was generally competitive. The MMU concludes that the Synchronized Reserve Market results were competitive in the first nine months of 2011. The MMU concludes that the DASR Market results were competitive in the first nine months of 2011.

Regulation Market

Market Structure

Supply

Table 6-5 PJM regulation capability, daily offer[24] and hourly eligible: January through September 2011 (See 2010 SOM, Table 6-5)

Period	Regulation Capability (MW)	Average Daily Offer (MW)	Percent of Capability Offered	Average Hourly Eligible (MW)	Percentage of Capability Eligible
All Hours	8,808	5,970	68%	2,742	31%
Off Peak	8,808			2,462	28%
On Peak	8,808			3,051	35%

Demand

Table 6-6 PJM Regulation Market required MW and ratio of eligible supply to requirement: January through September 2011 (See 2010 SOM, Table 6-6)

Month	Average Required Regulation (MW)	Ratio of Supply to Requirement
Jan	960	3.19
Feb	897	3.06
Mar	823	3.02
Apr	747	2.87
May	786	2.84
Jun	1,037	2.81
Jul	1,214	2.79
Aug	1,093	2.83
Sep	922	2.74

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

Market Concentration

Table 6-7 PJM cleared regulation HHI: January through September 2011 (See 2010 SOM, Table 6-7)

Market Type	Minimum HHI	Load-weighted Average HHI	Maximum HHI
Cleared Regulation	818	1645	3683

Figure 6-1 PJM Regulation Market HHI distribution: January through September 2011 (See 2010 SOM, Figure 6-1)

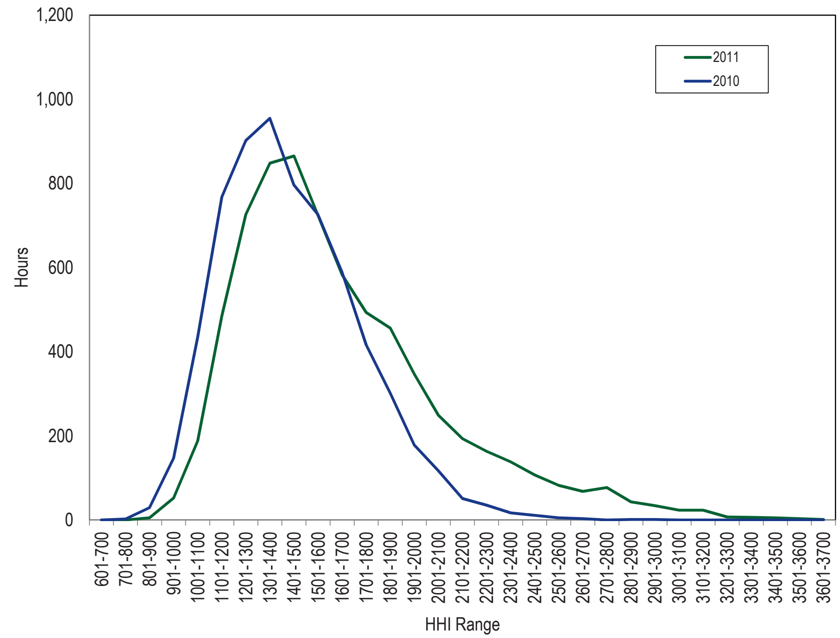


Table 6-8 Highest annual average hourly Regulation Market shares: January through September, 2011 (See 2010 SOM, Table 6-8)

Company Market Share Rank	Cleared Regulation Top Yearly Market Shares
1	22%
2	17%
3	15%
4	10%
5	9%

Table 6-9 Regulation market monthly three pivotal supplier results: January through September, 2011 (See 2010 SOM, Table 6-9)

Month	Percent of Hours When Marginal Supplier is Pivotal
Jan	88%
Feb	87%
Mar	89%
Apr	92%
May	87%
Jun	89%
Jul	89%
Aug	83%
Sep	87%

Market Conduct

Offers

Figure 6-2 Off peak and on peak regulation levels: January through September, 2011 (See 2010 SOM, Figure 6-2)

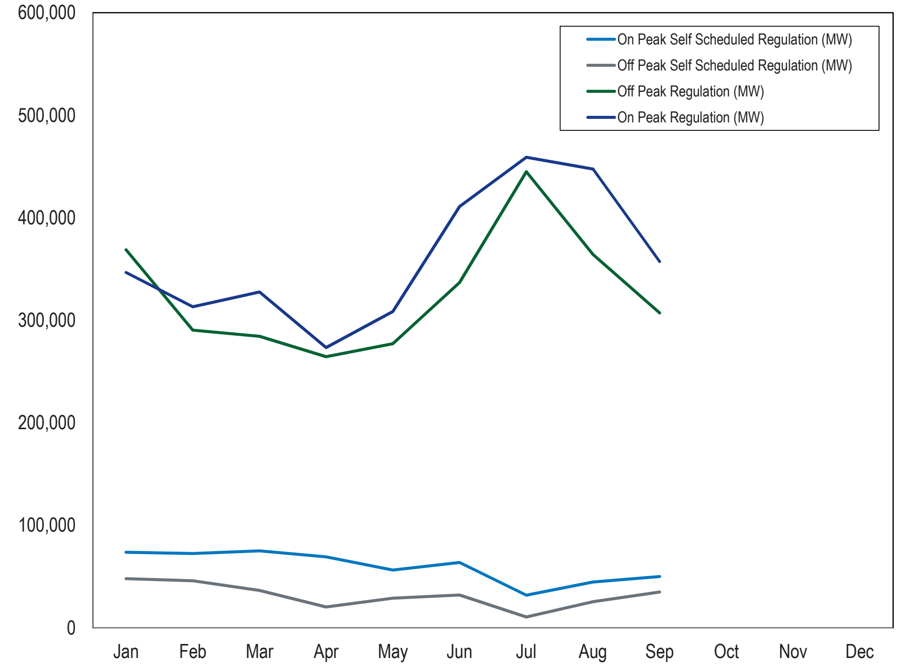


Table 6-10 Regulation sources: spot market, self-scheduled, bilateral purchases: January through September, 2011 (See 2010 SOM, Table 6-10)

Month	Spot Regulation (MW)	Self Scheduled Regulation (MW)	Bilateral Regulation (MW)
Jan	576,029	116,421	16,670
Feb	462,394	114,568	17,553
Mar	463,708	107,791	28,109
Apr	418,890	86,402	18,273
May	469,104	81,357	15,978
Jun	586,661	89,878	15,127
Jul	756,218	38,791	15,647
Aug	721,498	67,841	14,442
Sep	565,935	81,239	15,063

Market Performance

Price

Figure 6-3 PJM Regulation Market daily average market-clearing price, opportunity cost and offer price (Dollars per MWh): January through September, 2011 (See 2010 SOM, Figure 6-3)

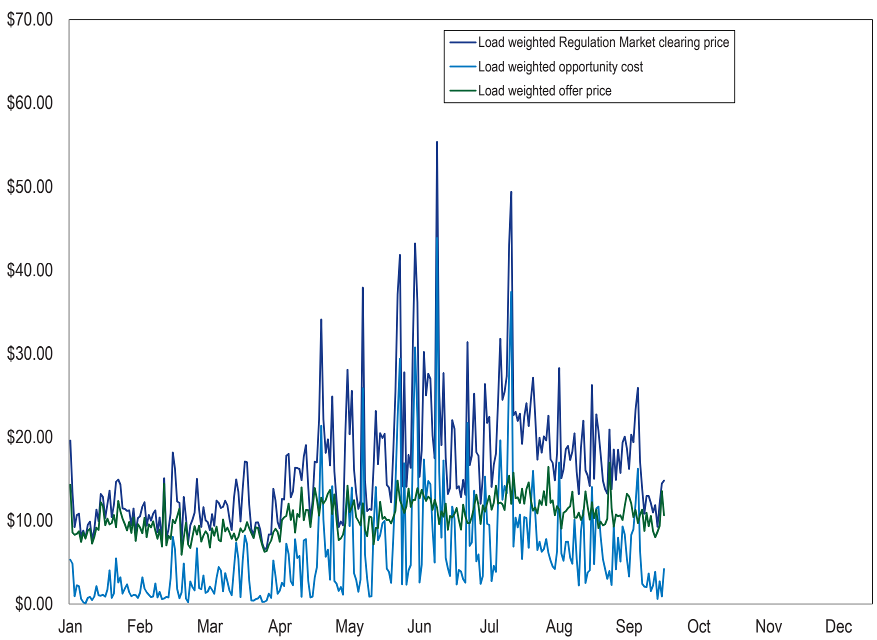


Figure 6-4 Monthly average regulation demand (required) vs. price: January through September, 2011 (See 2010 SOM, Figure 6-4)

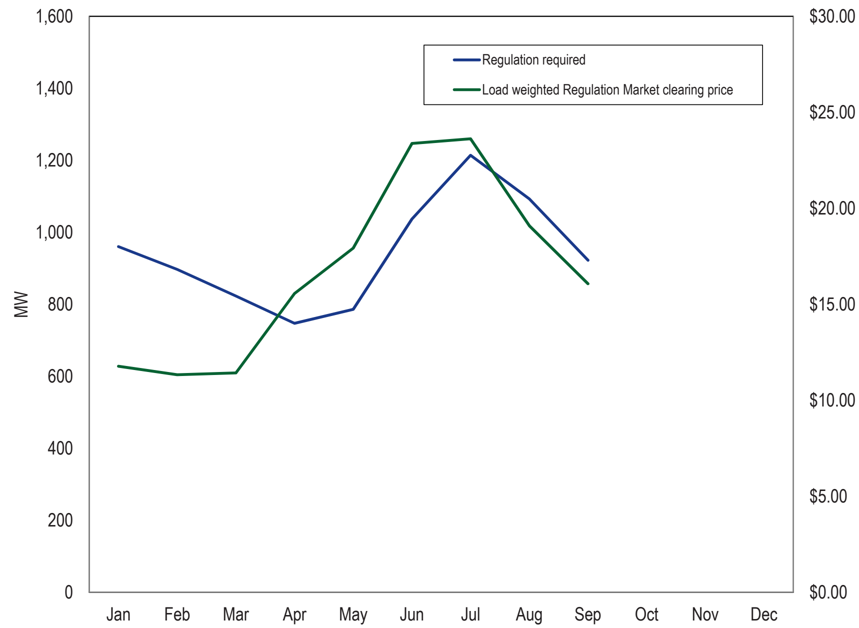


Figure 6-5 Monthly load weighted average regulation cost and price: January through September, 2011 (See 2010 SOM, Figure 6-5)

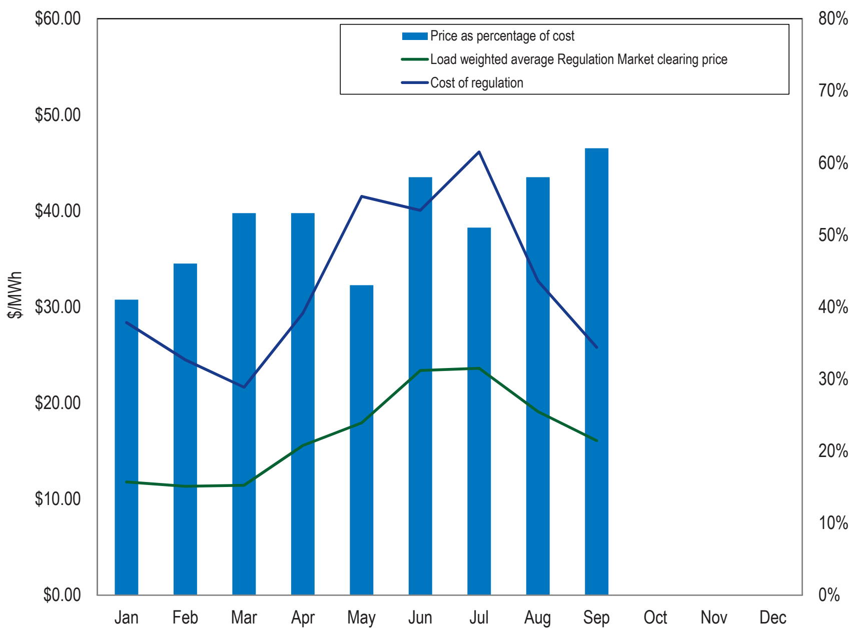


Table 6-11 Total regulation charges: January through September, 2011 (See 2010 SOM, Table 6-11)

Month	Scheduled Regulation (MW)	Total Regulation Charges	Weighted Regulation Market Clearing Price	Cost of Regulation
Jan	709,121	$20,116,704	$11.91	$28.37
Feb	594,515	$14,551,995	$11.49	$24.48
Mar	599,608	$12,967,924	$11.63	$21.63
Apr	523,565	$15,361,871	$16.06	$29.34
May	566,439	$23,500,438	$18.46	$41.49
Jun	691,666	$27,696,820	$23.38	$40.04
Jul	810,656	$37,375,988	$23.61	$46.11
Aug	803,781	$26,271,979	$19.10	$32.69
Sep	662,237	$17,074,805	$16.07	$25.78

Table 6-12 Comparison of load weighted price and cost for PJM Regulation, August 2005 through September 2011[25] (See 2010 SOM, Table 6-12)

Year	Load Weighted Regulation Market Price	Load Weighted Regulation Market Cost	Regulation Price as Percent Cost
2005	$64.03	$77.39	83%
2006	$32.69	$44.98	73%
2007	$36.86	$52.91	70%
2008	$42.09	$64.43	65%
2009	$23.56	$29.87	79%
2010	$18.08	$32.07	56%
2011	$17.03	$32.71	52%

Analysis of Regulation Market Changes

Table 6-13 Summary of changes to Regulation Market design (See 2010 SOM, Table 6-13)

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.

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

Increase Offer Margin from $7.50 to $12.00

Table 6-14 Impact of $12 adder to cost based regulation offer: December 2008 through September 2011 (See 2010 SOM, Table 6-14)

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	3.5%
2009	Jan	$21.04	$19.91	$26,614,105	$813,654	3.1%
2009	Feb	$25.17	$23.95	$20,972,293	$734,061	3.5%
2009	Mar	$19.90	$19.37	$17,618,413	$316,889	1.8%
2009	Apr	$16.84	$16.36	$12,171,811	$258,778	2.1%
2009	May	$32.41	$31.93	$21,166,797	$265,494	1.3%
2009	Jun	$32.59	$32.19	$24,566,721	$312,979	1.3%
2009	Jul	$24.10	$23.25	$20,065,104	$414,408	2.1%
2009	Aug	$23.89	$23.37	$23,010,216	$369,407	1.6%
2009	Sep	$20.09	$19.32	$15,216,790	$497,484	3.3%
2009	Oct	$17.20	$16.31	$12,882,665	$445,635	3.5%
2009	Nov	$14.06	$13.48	$10,695,843	$269,283	2.5%
2009	Dec	$17.75	$16.72	$17,303,919	$600,585	3.5%
2010	Jan	$20.66	$20.49	$29,465,392	$125,523	0.4%
2010	Feb	$16.17	$16.13	$16,640,892	$29,265	0.2%
2010	Mar	$16.70	$16.57	$14,156,600	$76,654	0.5%
2010	Apr	$17.26	$17.15	$13,246,951	$57,940	0.4%
2010	May	$19.16	$18.85	$19,286,137	$168,308	0.9%
2010	Jun	$19.46	$19.28	$23,333,299	$107,986	0.5%
2010	Jul	$23.47	$23.38	$31,927,050	$60,049	0.2%
2010	Aug	$21.50	$21.46	$28,928,214	$28,048	0.1%
2010	Sep	$19.30	$19.20	$19,592,362	$59,153	0.3%

Table 6-14 continued next page

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
2010	Oct	$13.57	$13.54	$10,613,185	$15,986	0.2%
2010	Nov	$11.69	$11.68	$11,930,514	$8,134	0.1%
2010	Dec	$14.04	$14.03	$25,225,775	$17,454	0.1%
2011	Jan	$11.77	$10.98	$20,116,696	$45,866	0.2%
2011	Feb	$11.33	$10.66	$14,551,986	$33,442	0.2%
2011	Mar	$11.42	$10.51	$12,967,915	$142,190	1.1%
2011	Apr	$15.56	$14.26	$15,361,860	$133,810	0.9%
2011	May	$17.92	$16.86	$23,500,428	$55,911	0.2%
2011	Jun	$23.38	$21.60	$27,696,810	$357,392	1.3%
2011	Jul	$23.61	$21.75	$37,375,975	$322,741	0.9%
2011	Aug	$19.10	$17.19	$26,271,969	$277,030	1.1%
2011	Sep	$16.07	$15.00	$17,074,790	$216,010	1.3%
Total				$687,157,940	$8,528,297	1.2%

Eliminate Offset Against Balancing Operating Reserves Credits

Table 6-15 Additional credits paid to regulating units from no longer netting credits above RMCP against operating reserves: December 2008 through September 2011 (See 2010 SOM, Table 6-15)

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	1.0%
2009	Jan	$127,036	$26,614,105	0.5%
2009	Feb	$220,460	$20,972,293	1.1%
2009	Mar	$79,726	$17,618,413	0.5%
2009	Apr	$8,893	$12,171,811	0.1%
2009	May	$182,624	$21,166,797	0.9%
2009	Jun	$274,916	$24,566,721	1.1%
2009	Jul	$191,538	$20,065,104	1.0%
2009	Aug	$267,116	$23,010,216	1.2%
2009	Sep	$252,136	$15,216,790	1.7%
2009	Oct	$169,130	$12,882,665	1.3%
2009	Nov	$166,112	$10,695,843	1.6%
2009	Dec	$104,496	$17,303,919	0.6%
2010	Jan	$64,990	$29,465,392	0.2%
2010	Feb	$64,727	$16,640,892	0.4%
2010	Mar	$109,344	$14,156,600	0.8%
2010	Apr	$134,738	$13,246,951	1.0%
2010	May	$74,352	$19,286,137	0.4%
2010	Jun	$41,065	$23,333,299	0.2%
2010	Jul	$85,961	$31,927,050	0.3%
2010	Aug	$110,610	$28,928,214	0.4%
2010	Sep	$58,587	$19,592,362	0.3%
2010	Oct	$34,911	$10,613,185	0.3%
2010	Nov	$33,676	$11,930,514	0.3%
2010	Dec	$126,074	$25,225,775	0.5%
2011	Jan	$22,174	$20,116,704	0.1%
2011	Feb	$25,834	$14,551,995	0.2%
2011	Mar	$62,678	$12,967,924	0.5%
2011	Apr	$103,567	$15,361,871	0.7%
2011	May	$51,631	$23,500,428	0.2%
2011	Jun	$66,439	$27,696,810	0.2%
2011	Jul	$77,705	$37,375,975	0.2%
2011	Aug	$61,704	$26,271,969	0.2%
2011	Sep	$50,593	$17,074,790	0.3%
Total		$3,758,706	$687,157,978	0.5%

Table 6-15 continued next column.

Synchronized Reserve Market

Market Structure

Demand

Figure 6-6 Mid-Atlantic Subzone average hourly Required synchronized reserve and Tier 2 scheduled: January through September, 2011 (See 2010 SOM, Figure 6-7)

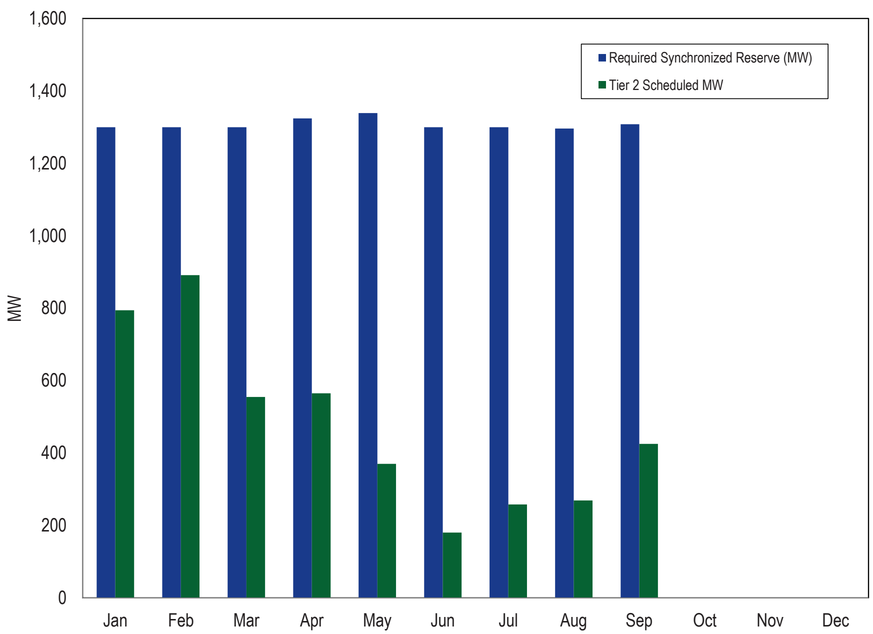


Figure 6-7 Mid-Atlantic Subzone daily average hourly synchronized reserve required, Tier 2 MW scheduled, and Tier 1 MW estimated: January through September, 2011 (See 2010 SOM, Figure 6-8)

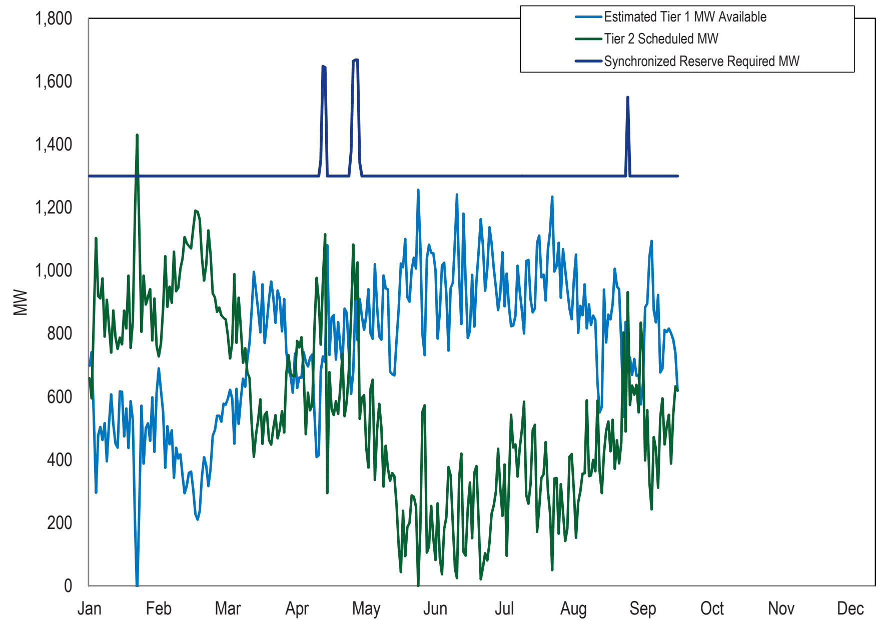


Table 6-16 ynchronized Reserve Market required MW, RFC zone and Mid-Atlantic subzone, December 2008 through September 2011 (New table)

Mid-Atlantic Subzone			RFC Synchronized Reserve Zone		
From Date	To Date	Required MW	From Date	To Date	Required MW
Dec 2008	May 2010	1,150	Dec 2008	Jan 2009	1,305
May 2010	Jul 2010	1,200	Jan 2009	Mar 2010	1,320
Jul 2010	Sep 2011	1,300	Mar 2010	Sep 2011	1,350

Market Concentration

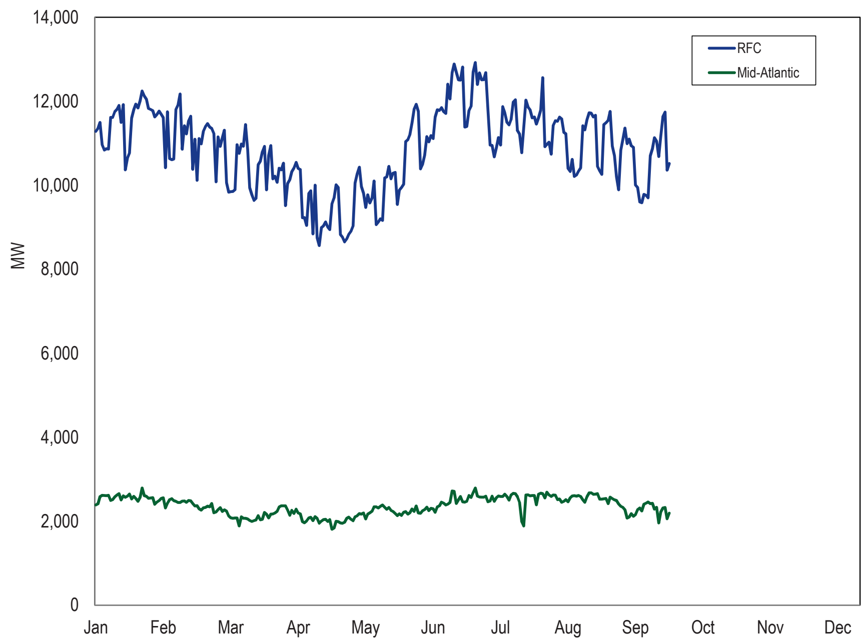
Table 6-17 Mid-Atlantic Subzone Tier 2 Synchronized Reserve Market cleared market shares[26]: January through September, 2011 (See 2010 SOM, Table 6-16)

Company Market Share Rank	Cleared Synchronized Reserve Average Market Share
1	33%
2	30%
3	21%
4	19%
5	16%
6	14%

Market Conduct

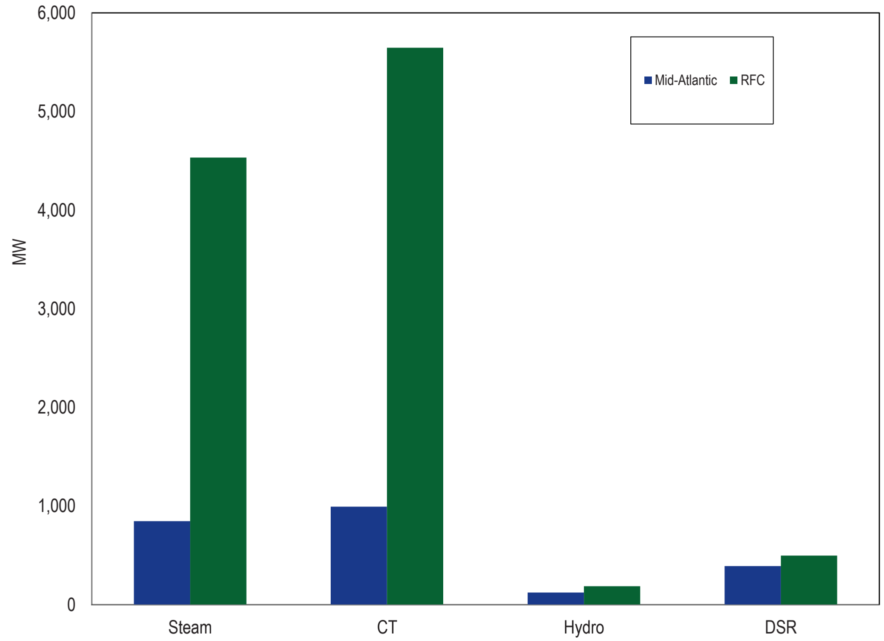
Offers

Figure 6-8 Tier 2 synchronized reserve average hourly offer volume (MW): January through September, 2011 (See 2010 SOM, Figure 6-9)



26 Note that the column "Cleared Synchronized Reserve Average Market Share" include the average market share for the provider only in hours when that provider had a market share greater than zero. For this reason it is possible for the market shares of all providers to sum to greater than one hundred percent.

Figure 6-9 Average daily Tier 2 synchronized reserve offer by unit type (MW): January through September, 2011 (See 2010 SOM, Table 6-10)

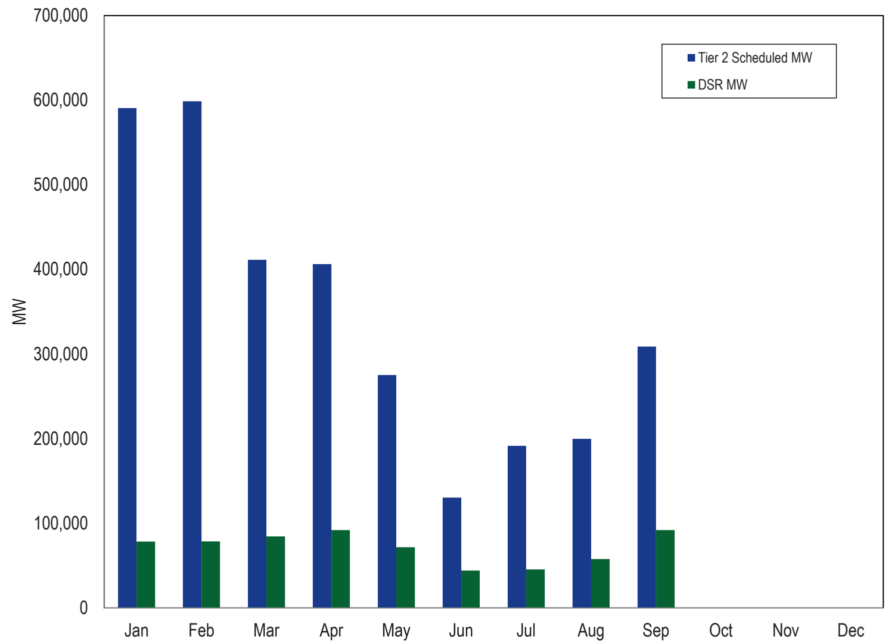


DSR

Table 6-18 Average SRMCP when all cleared synchronized reserve is DSR, average SRMCP, and percent of all cleared hours that all cleared synchronized reserve is DSR: January through September 2010 and 2011 (See 2010 SOM, Table 6-17)

Year	Month	Average SRMCP	Average SRMCP when all cleared sychronized reserve is DSR	Percent of cleared hours all synchronized reserve is DSR
2010	Jan	$5.84	$2.03	4%
2010	Feb	$5.97	$0.10	1%
2010	Mar	$8.45	$2.01	6%
2010	Apr	$7.84	$1.86	17%
2010	May	$9.98	$1.68	15%
2010	Jun	$9.61	$0.74	9%
2010	Jul	$16.30	$0.79	7%
2010	Aug	$11.17	$0.93	12%
2010	Sep	$10.45	$1.15	12%
2011	Jan	$9.31	$0.10	0%
2011	Feb	$10.58	NA	0%
2011	Mar	$9.70	$2.04	2%
2011	Apr	$12.64	$1.84	10%
2011	May	$8.64	$1.71	14%
2011	Jun	$9.05	$1.18	10%
2011	Jul	$12.33	$0.62	6%
2011	Aug	$8.25	$0.78	7%
2011	Sep	$9.05	$1.73	15%

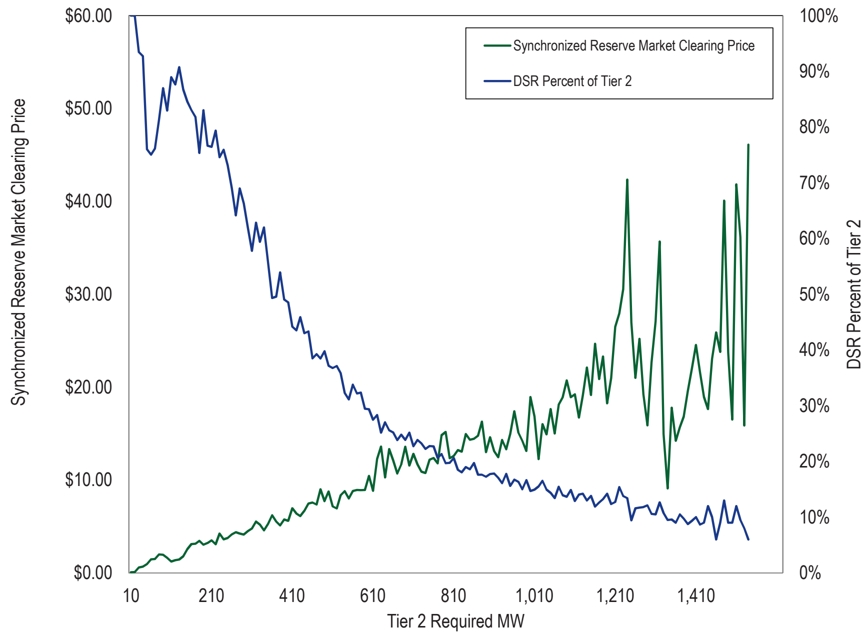
Figure 6-10 PJM RFC Zone Tier 2 synchronized reserve scheduled MW: January through September, 2011 (See 2010 SOM, Figure 6-11)



Market Performance

Price

Figure 6-11 Required Tier 2 synchronized reserve, Synchronized Reserve Market clearing price, and DSR percent of Tier 2: January through September, 2011 (See 2010 SOM, Figure 6-12)



Price and Cost

Figure 6-12 Tier 2 synchronized reserve purchases by month for the Mid-Atlantic Subzone: January through September, 2011 (See 2010 SOM, Figure 6-13)

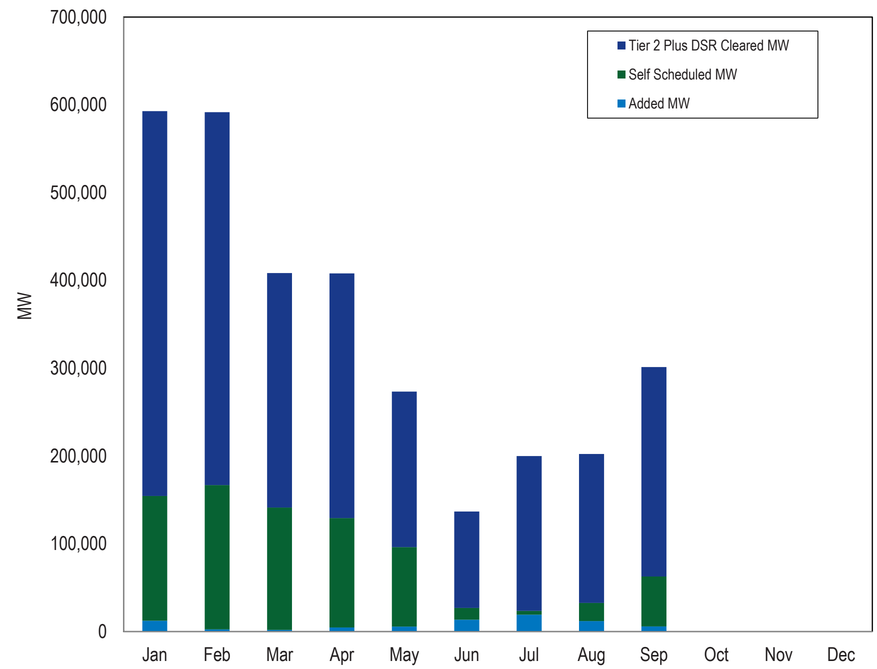


Figure 6-13 Impact of Tier 2 synchronized reserve added MW to the Mid-Atlantic Subzone: January through September, 2011 (See 2010 SOM, Figure 6-14)

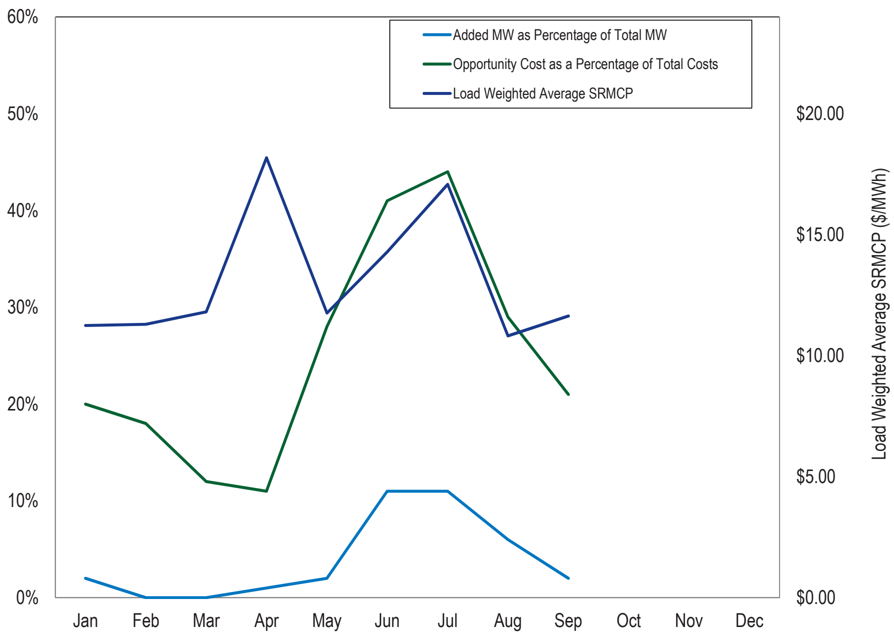


Table 6-19 Comparison of load weighted average price and cost for PJM Synchronized Reserve, January through September 2005 through 2011 (See 2010 SOM, Table 6-18)

Year	Load Weighted Average Synchronized Reserve Market Price	Load Weighted Average Synchronized Reserve Cost	Synchronized Reserve Price as Percent of Cost
2005 (Jan-Sep)	$12.81	$17.01	75%
2006 (Jan-Sep)	$14.40	$27.78	52%
2007 (Jan-Sep)	$18.24	$21.27	86%
2008 (Jan-Sep)	$10.87	$16.76	65%
2009 (Jan-Sep)	$6.38	$10.41	61%
2010 (Jan-Sep)	$11.51	$16.54	70%
2011 (Jan-Sep)	$12.00	$14.21	84%

Figure 6-14 Comparison of Mid-Atlantic Subzone Tier 2 synchronized reserve load weighted average price and cost (Dollars per MW): January through September, 2011 (See 2010 SOM, Figure 6-15)

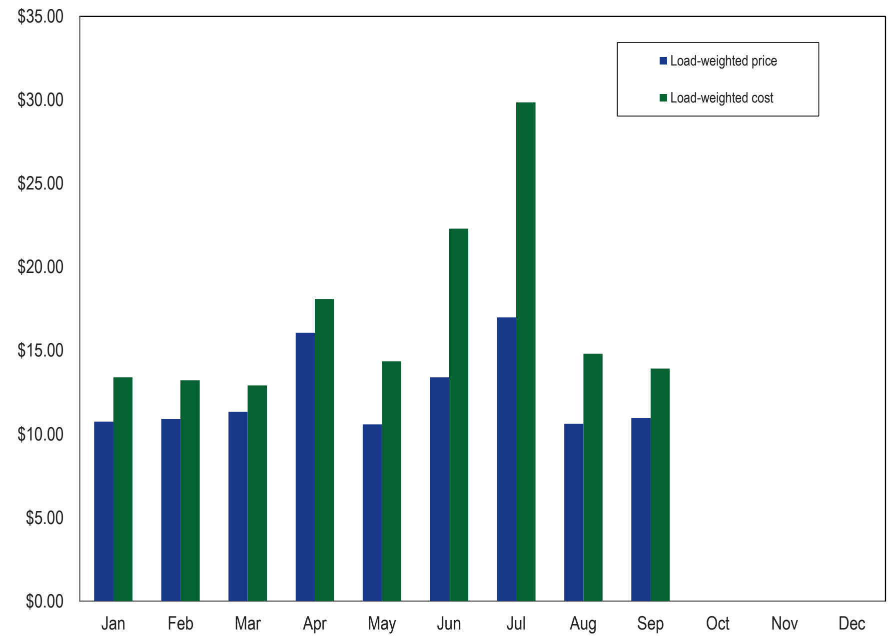


Table 6-20 Spinning Events, January 2009 through September 2011. (New table)

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

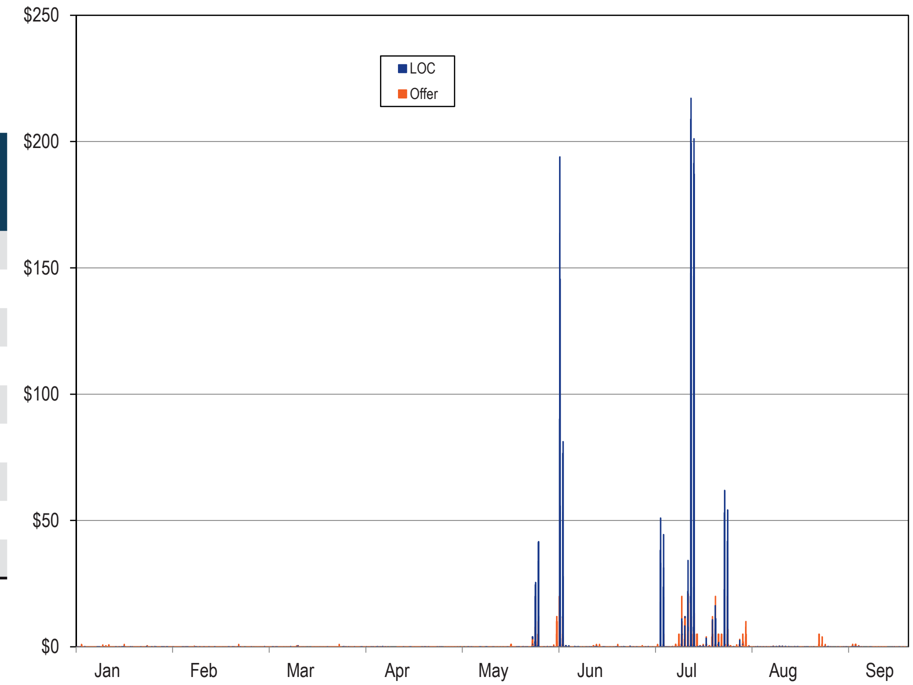
Day Ahead Scheduling Reserve (DASR)

Market Performance

Table 6-21 PJM, Day-Ahead Scheduling Reserve Market MW and clearing prices: January through September, 2011 (See 2010 SOM, Table 6-20)

Month	Average Required Hourly DASR (MW)	Minimum Clearing Price	Maximum Clearing Price	Average Load Weighted Clearing Price	Total DASR MW Purchased	Total DASR Credits
Jan	6,536	$0.00	$1.00	$0.03	4,862,520	$127,837
Feb	6,180	$0.00	$1.00	$0.02	4,152,665	$61,682
Mar	5,720	$0.00	$1.00	$0.01	4,249,733	$45,885
Apr	5,265	$0.00	$0.05	$0.01	3,790,932	$24,463
May	5,554	$0.00	$25.52	$0.29	4,132,056	$894,607
Jun	7,305	$0.00	$193.97	$2.26	5,259,795	$9,653,815
Jul	8,647	$0.00	$217.12	$4.21	6,433,574	$22,880,723
Aug	7,787	$0.00	$61.91	$0.75	5,793,554	$3,577,433
Sep	6,535	$0.00	$5.00	$0.07	4,704,950	$292,252

Figure 6-15 Hourly components of DASR clearing price: January through September 2011 (New Figure)



Black Start Service

Table 6-22 Black start yearly zonal charges for network transmission use: January through September, 2011 (See 2010 SOM, Table 6-21)

Blackstart Zone	Network Charges	Blackstart Rate ($/MW)
AECO	$347,152	$0.43
AEP	$447,904	$0.07
AP	$111,799	$0.05
ATSI	$34,687	$0.02
BGE	$1,376,538	$0.73
ComEd	$2,842,282	$0.48
DAY	$110,928	$0.12
DLCO	$26,354	$0.03
DPL	$312,969	$0.28
JCPL	$370,744	$0.21
Met-Ed	$359,639	$0.45
PECO	$746,996	$0.31
PENELEC	$263,270	$0.33
Pepco	$265,595	$0.15
PPL	$108,783	$0.05
PSEG	$2,193,049	$0.75
UGI	$108,783	$0.05