Ancillary Service Markets

The United States Federal Energy Regulatory Commission (FERC) defined six ancillary services in Order No. 888: 1) scheduling, system control and dispatch; 2) reactive supply and voltage control from generation service; 3) regulation and frequency response service; 4) energy imbalance service; 5) operating reserve – synchronized reserve service; and 6) operating reserve – supplemental reserve service.[1] Of these, PJM currently provides regulation, energy imbalance, synchronized reserve, and operating reserve – supplemental reserve services through market-based mechanisms. PJM provides energy imbalance service through the Real-Time Energy Market. PJM provides the remaining ancillary services on a cost basis. Although not defined by the FERC as an ancillary service, black start service plays a comparable role. Black start service is provided on the basis of incentive rates or cost.

Regulation matches generation with very short-term changes in load by moving the output of selected resources up and down via an automatic control signal.[2] Regulation is provided, independent of economic signal, by generators with a short-term response capability (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.

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 2011.

Table 9-1 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 82 percent of the hours in 2011.

1 75 FERC ¶ 61,080 (1996).

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

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

4 As Table 9-1 indicates, the Regulation Market results are not the result of the offer behavior of market participants, which was competitive as a result of the application of the three pivotal supplier test. The Regulation Market results are not competitive because the changes in market rules, in particular the changes to the calculation of the opportunity cost, resulted in a price greater than the competitive price in some hours, resulted in a price less than the competitive price in some hours, and because the revised market rules are inconsistent with basic economic logic. The competitive price is the actual marginal cost of the marginal resource in the market. The competitive price in the Regulation Market is the price that would have resulted from a combination of the competitive offers from market participants and the application of the prior, correct approach to the calculation of the opportunity cost. The correct way to calculate opportunity cost and maintain incentives across both regulation and energy markets is to treat the offer on which the unit is dispatched for energy as the measure of its marginal costs for the energy market. To do otherwise is to impute a lower marginal cost to the unit than its owner does and therefore impute a higher or lower opportunity cost than its owner does, depending on the direction the unit was dispatched to provide regulation. If the market rules and/or their implementation produce inefficient outcomes, then no amount of competitive behavior will produce a competitive outcome.

- Participant behavior was evaluated as competitive because market power mitigation requires competitive offers when the three pivotal supplier test is failed and there was no evidence of generation owners engaging in anti-competitive behavior.
- Market performance was evaluated as not competitive, despite competitive participant behavior, because the changes in market rules, in particular the changes to the calculation of the opportunity cost, resulted in a price greater than the competitive price in some hours, resulted in a price less than the competitive price in some hours, and because the revised market rules are inconsistent with basic economic logic.[5]
- Market design was evaluated as flawed because while PJM has improved the market by modifying the schedule switch determination, the lost opportunity cost calculation is inconsistent with economic logic and there are additional issues with the order of operation in the assignment of units to provide regulation prior to market clearing.

Table 9-2 The Synchronized Reserve Markets results were competitive

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 63 percent of the hours in 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 9-3 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 (zero), about 13 percent of offers reflected economic withholding, with offer prices above $5.00.
- Market performance was evaluated as competitive because there were adequate offers at reasonable levels in every hour to satisfy the requirement and the clearing price reflected those offers.
- Market design was evaluated as mixed because while the market is functioning effectively to provide DASR, the three pivotal supplier test and cost-based offer capping when the test is failed, should be added to the market to ensure that market power cannot be exercised at times of system stress.

Overview

Regulation Market

The PJM Regulation Market in 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.[6]

5 PJM agrees that the definition of opportunity cost should be consistent across all markets and should, in all markets, be based on the offer schedule accepted in the market. This would require a change to the definition of opportunity cost in the Regulation Market which is the change that the MMU has recommended. The MMU also agrees that the definition of opportunity cost should be consistent across all markets.

6 All existing PJM tariffs, and any changes to these tariffs, are approved by FERC. The MMU describes the full history of the changes to the tariff provisions governing the Regulation Market in the *2011 State of the Market Report for PJM*, Volume II, Section 9, "Ancillary Service Markets."

Market Structure

- **Supply.** In 2011, the supply of offered and eligible regulation in PJM was both stable and adequate. The ratio of offered and eligible regulation to regulation required averaged 3.00 for 2011. This is a 1.7 percent increase over 2010 when the ratio was 2.95.

  Although PJM rules allow up to 25 percent of the regulation requirement to be satisfied by demand resources, other rules (a minimum offer requirement of 1 MW as well as the prohibition of demand resources offering both economic and emergency demand reduction combined with a prohibition of a demand resource being represented by more than one CSP) made it impractical. On November 21, 2011, these rules were modified and the first two demand resources offered and cleared regulation.

- **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 in 2011 was 925 MW (842 MW off peak, and 1,017 MW on peak). This is a 32 MW increase in the average hourly regulation demand of 893 MW in 2010 (811 MW off peak, and 981 MW on peak).

  Of the LSEs' obligation to provide regulation during 2011, 81.8 percent was purchased in the spot market (82.2 percent in 2010), 15.6 percent was self scheduled (15.5 percent in 2010), and 2.6 percent was purchased bilaterally (2.3 percent in 2010).

- **Market Concentration.** In 2011, the PJM Regulation Market had a weighted, average Herfindahl-Hirschman Index (HHI) of 1630 which is classified as "moderately concentrated."[7] The minimum hourly HHI was 818 and the maximum hourly HHI was 4005. The largest hourly market share in any single hour was 58.9 percent, and 84.3 percent of all hours had a maximum market share greater than 20 percent.[8] In 2011, 82.1 percent of hours had one or more pivotal suppliers which failed PJM's three pivotal supplier test (73.3 percent of hours failed the three pivotal supplier test in 2010). The MMU concludes from these results that the PJM Regulation Market in 2011 was characterized by structural market power in 82.1 percent of the hours.

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 also apply for the entire day and remain subject to the $100 per MWh offer cap.[9] 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 weighted Regulation Market clearing price for the PJM Regulation Market in 2011 was $16.21 per MW. This was a decrease of $1.87, or 10 percent, from the weighted average price for regulation in 2010. The total cost of regulation decreased by $2.79 from $32.07 per MW in 2010, to $29.28, or

7 See the *2011 State of the Market Report for PJM*, Volume II, Section 2, "Energy Market," 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.

8 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.

9 See PJM. "Manual 11, Energy and Ancillary Services Market Operations," Revision 49 (January 1, 2012) p. 55.

8.7 percent. In 2011 the weighted Regulation Market clearing price was only 55 percent of the total regulation cost per MW, compared to 56 percent of the total costs of regulation per MW in 2010. 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.

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) 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.[10] That interface had been the AP South interface since March 2009. After the implementation of TrAIL, Bedington – Black Oak became the most limiting interface and remained so throughout 2011. PJM reserves the right to revise the interface defining the Mid-Atlantic Subzone in accordance with operational and reliability needs.[11] 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. Since then, PJM has changed the transfer capacity several times varying from 50 percent to 15 percent at the end of 2011. The higher the assumed transfer capability, the greater the supply of Tier 1 that is available from west of the interface to meet synchronized reserve requirements in the Mid-Atlantic subzone. 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 1.6 percent of all synchronized reserves in 2011, down from 3.4 percent in 2010.[12] After-market opportunity cost payments accounted for 16.8 percent of total costs in 2011 compared to 26.8 percent in 2010.

Market Structure

- **Supply.** In 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 relatively low cost, and their participation in this market lowers overall Synchronized Reserve prices. The ratio of offered and eligible synchronized reserve MW to the administrative synchronized reserve required (1,300 MW) was 1.08 for the Mid-Atlantic Subzone.[13] This is a six percent decrease from 2010 when the ratio was 1.16. Much of the required synchronized reserve is supplied from on-line (Tier 1) synchronized reserve resources. The ratio of eligible synchronized reserve MW to the required Tier 2 MW is much higher. The ratio of offered and eligible synchronized reserve to the required Tier 2 depends on how much Tier 2 synchronized reserve is needed but the median ratio for all cleared Tier 2 hours in 2011 was 2.89 for the Mid-Atlantic Subzone. The ratio of offered and eligible synchronized reserve to the required Tier 2 was 3.00 for the RFC Zone for all hours in which a Tier 2 market was cleared. This is an 11 percent increase from 2010 when the ratio was 2.68. For the RFC Zone the offered and eligible excess supply ratio is determined using the administratively required level of synchronized reserve. The requirement for Tier 2 synchronized reserve is lower than the required reserve level for synchronized reserve because there is usually a significant amount of Tier 1 synchronized reserve available.

10 PJM.com "TrAIL Operational Impacts," <http://www.pjm.com/~/media/committees-groups/committees/oc/20111018/20111018-item-08-trail-operational-impacts.ashx> (October 2011).

11 See PJM, "Manual 11, Energy and Ancillary Services Market Operations," Revision 49 (January 1, 2012), p. 67.

12 This figure was incorrectly reported as "five percent" in *2010 State of the Market Report for PJM*, Section 6, "Ancillary Service Markets", p.423.

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

- **Demand.** PJM made no changes to the default hourly required synchronized reserve requirements in 2011. 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 9-20 lists all spinning events from January 2009 through December 2011.

  In 2011, in the Mid-Atlantic Subzone, a Tier 2 synchronized reserve market was cleared in 83 percent of hours. This is a 24 percent increase from 2010, when the market cleared in 67 percent of hours. In 2011, the average required Tier 2 synchronized reserve (including self scheduled) was 527 MW. In 2010 the average required Tier 2 synchronized reserve was 358 MW.

  Synchronized reserves added out of market were 1.6 percent of all Mid-Atlantic Subzone synchronized reserves in 2011. Synchronized reserves added out of market were 3.4 percent of all Mid-Atlantic Subzone synchronized reserves in 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 in 2011. A Tier 2 Synchronized Reserve Market was cleared for the Southern Synchronized Reserve Zone in 26 hours in 2011.

- **Market Concentration.** The average weighted cleared Synchronized Reserve Market HHI for the Mid-Atlantic Subzone in 2011 was 2637, which is classified as "highly concentrated."[14] For purchased synchronized reserve (cleared plus added) the HHI was 2675. In 2011, 46 percent of hours had a maximum market share greater than 40 percent, compared to 68 percent of hours in the same period of 2010.

  In the Mid-Atlantic Subzone, in 2011, 63 percent of hours that cleared a synchronized reserve market had three or fewer pivotal suppliers. In 2010, 62 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 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 2011 over 2010 (from 613,762 MW to 982,434 MW). The DSR share of the total Synchronized Reserve Market increased from 16.5 percent in 2010 to 17.7 percent in 2011. Demand side resources satisfied 100 percent of the Tier 2 Synchronized Reserve market in 6.6 percent of hours in 2011 compared to 8.0 percent of hours in 2010.

- **Compliance.** The MMU has reviewed synchronized reserve non-compliance between 2009 and 2011 and concluded that the incentive/penalty structure is not adequate. 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. The result is that it is possible to provide the service profitably with a very low level of compliance. This behavior does exist in this market. PJM's synchronized reserve penalty structure fails to penalize this behavior adequately. The MMU recommends that the Synchronized Reserve Market non-compliance penalties be restructured to address this issue and provide stronger incentives for compliance.

Market Performance

- **Price.** The weighted average price for Tier 2 synchronized reserve in the Mid-Atlantic Subzone was $11.81 per MW in 2011, a $1.26 per MW increase

14 See the *2011 State of the Market Report for PJM*, Volume II, Section 2, "Energy Market" at "Market Concentration" for a more complete discussion of concentration ratios and the Herfindahl-Hirschman Index (HHI).

from 2010. The total cost of synchronized reserves per MWh in 2011 was $15.48, a $1.07 increase (7.4 percent) from the $14.41 cost of synchronized reserve in 2010. The market clearing price was 76 percent of the total synchronized reserve cost per MW in 2011, up from 73 percent in 2010.

The difference between the total cost of synchronized reserve and the clearing price of synchronized reserve can be attributed to two factors. 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.

PJM changed the estimates of Tier 1 reserves over a wide range in 2011, without providing an explanation of the determinants of Tier 1 reserves. These estimates have a significant impact on the market.

- **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 2011.

DASR

On June 1, 2008 PJM introduced the Day-Ahead Scheduling Reserve Market (DASR), as required by the RPM settlement.[15] 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.[16] 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 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 the three pivotal supplier test. The MMU recommends that the three pivotal supplier test be incorporated in the DASR market.
- **Demand.** In 2011, the required DASR was 7.11 percent of peak load forecast, up from 6.88 percent in 2010.[17] 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 was 7.11 percent. The DASR MW purchased averaged 6,500 MW per hour for 2011, an increase from 6,033 MW per hour 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 marginal cost of providing DASR is zero. In the first five months of 2011, 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. Between June 1, and December 31, 2011, thirteen percent of all units offered DASR at levels above $5, while less than one percent of units offered above $50. Two units offered above $900. PJM rules require all units with reserve capability that can be converted into energy within 30 minutes to offer into the DASR Market.[18] Units that do not offer have their offers set to zero.
- **DSR.** Demand side resources do participate in the DASR Market, but no demand resource cleared the DASR Market in 2011.

15 See 117 FERC ¶ 61,331 (2006).

16 See PJM. "Manual 13: Emergency Operations," Revision 47, (January 1, 2011); pp 11-12.

17 See the *2011 State of the Market Report for PJM*, Volume II, Section 9, "Ancillary Services" at Day Ahead Scheduling Reserve (DASR).

18 PJM. "Manual 11, Energy and Ancillary Services Market Operations," Revision 49 (January 1, 2012), pp. 123-124.

Market Performance

- **Price.** The weighted DASR market clearing price 2011 was $0.55 per MW. In 2010, the weighted price of DASR was $0.16 per MW. The increase in the weighted average price per MW of DASR can be attributed to several days of extremely high DASR prices in June, July and August (a maximum price of $217.12 occurred on July 21, 2011). 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 56 percent of hours in 2011 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 = $86.25) of hours 99.7 percent of the price is determined by opportunity cost. For the bottom 99.5 percent (average clearing price = $0.12) of hours less than two percent of the price is composed of LOC (Figure 9-18).

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.[19]

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.

The MMU has concerns that there is a disconnect between a service that is required for system reliability, the balkanized approach to procuring that service, and the need to secure voluntary participation in the system restoration plans from the relatively few potential providers at the critical locations identified. The current process provides for PJM and transmission owners to jointly develop and administer the black start service plan for each transmission zone. These rules should be revised to assign responsibility for administering the plan to PJM and allow transmission owners to play an advisory role.

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. In 2011, charges were $13.63 million. This is 37 percent higher than 2010, when total black start service charges were $9.98 million. There was substantial zonal variation. The increased cost of black start in 2011 is attributable to updated Schedule 6A (to the OATT) rates for all units, major refurbishments of black start resources in the BGE zone, and operating reserve charges associated with blacks start resources in the AEP zone. The increased Schedule 6A rates included net cost of new entry, VOM, bond rates, and oil forward strip.

Black start zonal charges in 2011 (including operating reserves for black start units) ranged from $0.04 per MW in the DLCO zone to $0.90 per MW in the BGE zone. Black start costs in the BGE zone increased due to major refurbishments of multiple 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 but the commitment to provide black start services from the units does not match the obligation of

19 OATT Schedule 1 § 1.3BB.

customers to pay 100 percent of the capital costs of the refurbishment over an accelerated period.[20]

Ancillary Services costs per MW of load: 2001 - 2011

Table 9-4 shows PJM ancillary services costs 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 9-4 History of ancillary services costs per MW of Load: 2001 through 2011

Year	Regulation	Scheduling, Dispatch, and System Control	Reactive	Synchronized Reserve	Supplementary Operating Reserve
2001	$0.50	$0.44	$0.22	$0.00	$1.07
2002	$0.45	$0.53	$0.21	$0.07	$0.63
2003	$0.50	$0.61	$0.24	$0.14	$0.83
2004	$0.50	$0.60	$0.25	$0.13	$0.90
2005	$0.79	$0.47	$0.26	$0.11	$0.93
2006	$0.53	$0.48	$0.29	$0.08	$0.43
2007	$0.63	$0.47	$0.29	$0.06	$0.58
2008	$0.68	$0.40	$0.31	$0.08	$0.59
2009	$0.34	$0.32	$0.37	$0.05	$0.48
2010	$0.34	$0.38	$0.41	$0.07	$0.73
2011	$0.32	$0.34	$0.42	$0.10	$0.77

Conclusion

The MMU continues to conclude that the results of the Regulation Market are not competitive.[21] 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.

PJM agrees that the definition of opportunity cost should be consistent across all markets and should, in all markets, be based on the offer schedule accepted in the market. This would require a change to the definition of opportunity cost in the Regulation Market which is the change that the MMU has recommended. The MMU also agrees that the definition of opportunity cost should be consistent across all markets.

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

The MMU concludes that the DASR Market results were competitive in 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.

While the current market design satisfies the requirements of regulation, namely that it keep the reportable metrics, CPS1 and BAAL within acceptable limits, a new market design initiative began in 2011 in response to a FERC

20 PJM.com "Automated Formula Rate Adjustment Process," Revision 0 <http://www.pjm.com/~/media/committees-groups/task-forces/bsstf/20100420/20100420-automated-formula-rate-adjustment-process.ashx> (March 24, 2010).

21 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."

Order.[22] On October 20, 2011, FERC issued Order No. 755 directing PJM and other RTOs/ISOs to modify their regulation markets so as to make use of and properly compensate a mix of fast and traditional response regulation resources.[23] PJM is currently working with stakeholders to develop market rules that would result in an optimal, least cost combination of fast and traditional resources. This creates market design challenges, which if resolved, could improve the regulation market.

Overall, the MMU concludes that the Regulation Market results were not competitive in 2011 as a result of the identified market design changes and their implementation. The MMU is hopeful that the opportunity cost can be resolved in 2012 as part of the regulation market redesign. 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 2011. The MMU concludes that the DASR Market results were competitive in 2011.

Detailed Recommendations

- The Regulation Market design and implementation continue to be flawed and require a detailed review to ensure that the market will produce competitive outcomes. Some of the flaws identified by the MMU were addressed by PJM in 2010, but some remain. The MMU recommends a number of market design changes designed to improve the performance of the Regulation Market, including use of a single clearing price based on actual LMP, modifications to the LOC calculation methodology, a software change to save some data elements necessary for verifying market outcomes, and further documentation of the implementation of the market design through SPREGO. MMU summarized and presented to the MIC on September 13, 2011 the deficiencies of the Regulation Market LOC calculation.[24] On January 11, 2012 PJM presented to the MIC a recommendation that energy-related opportunity costs calculations be standardized across all markets, tariffs, and manuals.[25] If implemented as recommended, this would resolve the opportunity cost issue in the Regulation Market.
    - — The MMU recommends that the single clearing price for regulation be determined based on the actual LMP. This is expected to result in a net increase in payments to providers of regulation as a result of an increase in the regulation clearing price which more than offsets unit specific reductions in unit specific, post clearing opportunity cost payments. This would improve the transparency of the Regulation Market as the resulting price of regulation would internalize some of the costs currently being collected through uplift and would thereby make the market price more reflective of the actual costs of providing the service.
    - — The MMU recommends that the December 1, 2008, modification to the definition of opportunity cost be reversed and that the elimination of the offset against operating reserve credits be reversed based on the MMU conclusion that these features result in a non-competitive market outcome, and because they are inconsistent with the treatment of the same issues in other PJM markets and inconsistent with basic economic logic.
    - — The MMU recommends that the December 1, 2008 modification to the net revenue offset elimination 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 MMU recommends that, to the extent that it is believed that additional revenue to generation owners is needed to maintain the outcome of the settlement in the short run, revenue neutrality be maintained by modifying the margin from its current level of $12.00 per MW at the same time that the opportunity cost definition is corrected.

22 See *2011 State of the Market Report for PJM*, "Appendix F."
23 Frequency Regulation Compensation in the Organized Wholesale Power Markets, 137 FERC ¶ 61,064 (2011).
24 PJM.com "Regulation Market: Opportunity Cost Issue," MIC, September 14, 2011. <http://www.pjm.com/~/media/committees-groups/committees/mic/20110913/20110914-item-14-definition-of-opportunity-cost.ashx>
25 PJM.com "Consistency of Energy-Related Opportunity Cost Calculations," MIC, January 11, 2012. <http://www.pjm.com/~/media/committees-groups/committees/mic/20110913/20110914-item-14-definition-of-opportunity-cost.ashx>.

- The MMU recommends that PJM save all data necessary to reproduce the market clearing results to ensure transparency of the price formation process and to permit checking the Regulation Market results for consistency with economic fundamentals.
- The MMU recommends that PJM improve the documentation it creates and maintains with respect to the detailed processes for clearing the Regulation Market.

- The MMU recommends that the synchronized market price signal be improved and the market rules be made more transparent.
  - The MMU recommends that the single clearing price for synchronized reserves be determined, after the fact, on the actual LMP. This is expected to result in a net increase in payments to providers of synchronized reserves as a result of an increase in the clearing price which more than offsets unit specific reductions in unit specific, post clearing opportunity cost payments. This would improve the transparency of the synchronized reserve market as the resulting price of synchronized reserve would internalize some of the costs currently being collected through uplift and would make the more reflective of the actual costs of providing the service.
  - The MMU recommends that PJM document the reasons each time it changes the Tier 1 synchronized reserve transfer capability into the Mid-Atlantic subzone market because of the potential impacts on the market.
- The MMU recommends that PJM modify it penalty rules for non-compliance in the Synchronized R eserve Market to correct the situation of gross non-compliance (less than 30% compliance in every spinning event) operating profitably because the total SRMCP credits can exceed total penalties.
  - 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 mandatory documentation of reasons for Tier 1 deselection as a way to improve transparency.
- 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.
- The MMU recommends that PJM, FERC, reliability authorities 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. Elements of such reform should include, at a minimum, the clear assignment of responsibility to PJM for determining a single system restoration plan that identifies locations where black start units are needed. Transmission owners should play an advisory role. PJM should assume an explicit obligation to secure black start service on a least cost basis and implement a method to evaluate competitive alternatives to providing black start service at identified locations on a rolling basis as service obligations of existing providers terminate.

Regulation Market

Market Structure

The market structure of the 2011 PJM Regulation Market remains unchanged since December 1, 2008. The rule changes of December 1, 2008, significantly affected the design of the Regulation Market. Both PJM and the MMU have done extensive analysis of these changes in 2010 resulting in several technical improvements to the market solution software.

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.

During 2011, the PJM Regulation Market total capability was 8,871 MW.[26] 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 2011, the average daily offer level, excluding units with offers which were made unavailable for the day, was 6,083 MW or 68.6 percent of total capability while the average hourly eligible offer level was 2,723 MW or 30.7 percent of total capability. In 2010, the average hourly eligible offer level was 32 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 9-5 shows capability, daily offer and average hourly eligible MW for all hours as well as for off-peak and on-peak hours.

Table 9-5 PJM regulation capability, daily offer[27] and hourly eligible: Calendar year 2011

Period	Regulation Capability (MW)	Average Daily Offer (MW)	Percent of Capability Offered	Average Hourly Eligible (MW)	Percentage of Capability Eligible
All Hours	8,871	6,083	69%	2,723	31%
Off Peak	8,871			2,467	28%
On Peak	8,871			3,007	34%

The average eligible regulation supply-to-requirement ratio in the PJM Regulation Market during 2011 was 3.00. When this ratio equals 1.0, it indicates that offered supply exactly equals demand for the referenced time period. Even during periods of diminished supply such as off-peak hours, eligible regulation supply was adequate to meet the regulation requirement.

26 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.

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

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 *2011 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. In 2011, the PJM regulation requirement ranged from 514 MW to 1,565 MW. The average required regulation off-peak was 842 and the average required regulation on-peak was 1,017 MW (Table 9-6). In 2011, PJM scheduled a total of 7,867,278 MW of regulation compared to 9,037,733 MW in 2010.

Table 9-6 PJM Regulation Market required MW and ratio of eligible supply to requirement: Calendar year 2011

Period Type	Average Required Regulation (MW)	Ratio of Supply to Requirement
2011	925	3.00
Fall	866	2.74
Spring	785	2.91
Summer	1,115	2.81
Winter	930	3.16
Off Peak	842	3.01
On Peak	1,017	2.98

Market Concentration

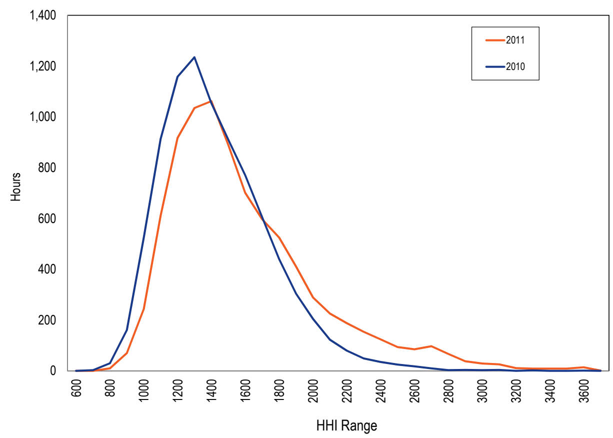
Hourly HHI values were calculated based on cleared regulation. Hourly HHIs ranged from a maximum of 4005 to a minimum of 818 in 2011 (compared to a range of 3675 to 763 in 2010), with a weighted average value of 1630, which is categorized as moderately concentrated by the FERC definitions. Table 9-7 summarizes the 2011 PJM Regulation Market HHIs. The minimum HHI, maximum HHI and the average HHI were all higher in 2011 than in 2010.

Table 9-7 PJM cleared regulation HHI: Calendar year 2011

Market Type	Minimum HHI	Weighted Average HHI	Maximum HHI
Cleared Regulation, 2011	818	1630	4005

In 2011, one percent of all periods had an HHI less than 1000 and 28 percent of all periods had an HHI greater than 1800, with a maximum HHI of 4005.[28] An HHI of 1800 is the threshold for "highly concentrated" by the FERC definitions. Figure 9-1 compares the 2011 HHI distribution with the 2010 HHI distribution.

Figure 9-1 PJM Regulation Market HHI distribution: Calendar years 2010 and 2011



The highest hourly market share in 2011 was 59 percent compared to the highest hourly market share in 2010 of 53 percent. 84 percent of all hours had a maximum market share greater than 20 percent in 2011 compared to 79 percent in 2010. The largest annual average hourly market share by a company was 22 percent. The top six annual average hourly market shares for cleared regulation in 2011 are listed in Table 9-8.

Table 9-8 Highest annual average hourly Regulation Market shares: Calendar year 2011

Company Market Share Rank	Cleared Regulation Top Yearly Market Shares
1	22
2	16
3	16
4	11
5	9
6	9

In 2011, 82 percent of hours failed the three pivotal supplier test. This means that for 82 percent of hours the total regulation requirement could not be met in the absence of the three largest suppliers. One supplier of

28 See the *2011 State of the Market Report for PJM*, Volume II, Section 2, "Energy Market" 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.

regulation was pivotal in 97 percent of pivotal hours. A second company was pivotal in 91 percent of the pivotal hours. A third company was pivotal in 89 percent of pivotal hours. Table 9-9 includes a monthly summary of three pivotal supplier results.

Table 9-9 Regulation market monthly three pivotal supplier results: Calendar year 2011

Month	Percent of Hours Pivotal	Percent of Hours When Marginal Supplier is Pivotal
Jan	95%	88%
Feb	93%	87%
Mar	94%	89%
Apr	97%	92%
May	95%	87%
Jun	89%	80%
Jul	89%	81%
Aug	83%	71%
Sep	87%	74%
Oct	67%	59%
Nov	46%	41%
Dec	50%	45%

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 2011.

The MMU concludes from these results that the PJM Regulation Market in 2011 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, variable operating and maintenance (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.[29] 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 offers of all offered and eligible regulating resources in ascending total offer price order; it does the same for synchronized reserve. PJM then 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. Prior to clearing and assignment of regulation in a given hour, the Regulation Market is subject to market power screening via the TPS test.

Regulation Market participation is a function of the obligation of all LSEs to provide regulation in proportion to their load share. LSEs can purchase regulation in the Regulation Market, purchase regulation from other

29 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.

providers bilaterally, or self-schedule regulation to satisfy their obligation (Figure 9-2).[30] Increased self scheduled regulation lowers the requirement for cleared regulation, resulting in fewer MW cleared in the market and lower clearing prices. Total self scheduled regulation MW in 2011 was 18.9 percent of all regulation, which is an increase from 15.5 percent in 2010. The amount of self scheduled regulation was higher during off peak hours than during on peak hours while the amount of cleared regulation is higher during on peak hours than during off peak hours (Table 9-10). The higher ratio of self scheduled regulation is due in part to the participation of newly added battery units.

Figure 9-2 Off peak and on peak regulation levels: Calendar year 2011

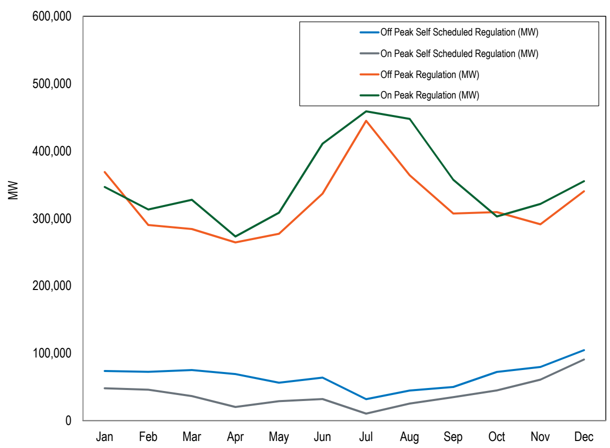


Table 9-10 Regulation sources: spot market, self scheduled, bilateral purchases: Calendar year 2011

Month	Spot Regulation (MW)	Self Scheduled Regulation (MW)	Bilateral Regulation (MW)	Total Regulation (MW)
Jan	576,029	116,421	16,670	709,121
Feb	462,394	114,568	17,553	594,515
Mar	463,708	107,791	28,109	599,608
Apr	418,890	86,402	18,273	523,565
May	469,104	81,357	15,978	566,439
Jun	586,661	89,878	15,127	691,666
Jul	756,218	38,791	15,647	810,656
Aug	721,498	67,841	14,442	803,781
Sep	565,935	81,239	15,063	662,237
Oct	479,328	113,824	15,062	608,213
Nov	457,665	137,603	16,315	611,582
Dec	475,935	190,778	19,182	685,895
Total	6,433,365	1,226,492	207,421	7,867,278

In November, 2011, demand resources (DSR) began participating in the Regulation Market.[31] DSR participation was approved in 2008, but several factors prevented DSR from qualifying. A rule preventing demand resources from being represented by more than one CSP kept some demand resources from participation if the resource was already represented by a CSP for any demand side product. In November, PJM members approved a rule change allowing a demand resource to be represented by more than one CSP. Another rule change was required to allow for equipment specific load data for regulation compliance instead of the previously required facility load data. A third rule was changed to allow regulation resources offering only 0.1 MW to participate. Previously PJM had required minimum offers of 0.5 MW for participation in the regulation market. Demand resources offered and cleared regulation for the first time in November 2011. Since they do not offer energy demand resources currently self schedule rather than offer competitively into the market.[32] These small amounts of regulation had virtually no impact on the regulation market in 2011.

Market Performance

Price

Figure 9-3 shows the daily average Regulation Market clearing price and the opportunity cost component for the marginal units in the PJM Regulation Market. All units chosen to provide regulation received as payment the higher of the clearing price, based on the forecast LMP, multiplied by the unit's assigned regulating capability, or the unit's regulation offer plus the individual unit's real-time opportunity cost, based on actual LMP, multiplied by its assigned regulating capability.[33]

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 clearing price times the unit's self scheduled regulating capability. Regulation credits for units that offer regulation into

30 See PJM "Manual 28: Operating Agreement Accounting," Revision 50, (January 1, 2012); para 4.2, pp 14-15.

31 See "DRS Proposed changes for DR in regulation market," MIC, <http://www.pjm.com/~/media/committees-groups/committees/mic/20111213/20111213-item-02a-proposed-changes-to-dr-in-regulation-market.ashx> (December 13, 2011).

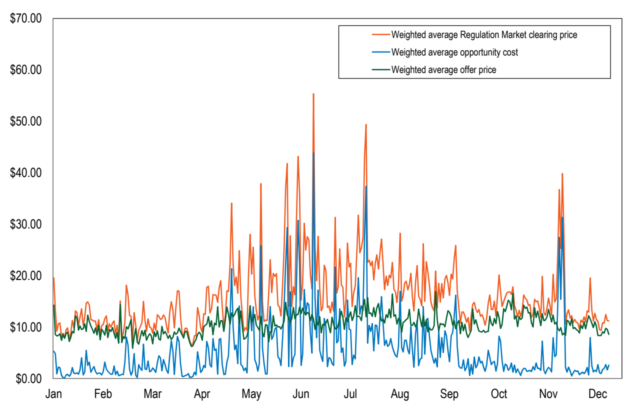
32 The reason for this is that SPREGO might otherwise optimally schedule them for energy which they could not provide. This is being studied and a solution is likely in 2012.

33 See PJM. "Manual 28: Operating Agreement, Accounting," Revision 50, Section 4.2, "Regulation Credits" (January 1, 2012), p. 14. 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.

the market and are selected to provide regulation are the higher of the clearing price times the unit's assigned regulating capability, or the unit's regulation offer plus the unit's specific after the fact opportunity cost, times its assigned regulating capability. Although most units are paid the clearing price (RMCP) times their assigned regulation MWh, a substantial portion of the RMCP is the opportunity cost calculated during market clearing based on forecast LMP and cost 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 9-3, 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 weighted average offer (excluding opportunity cost) of the marginal unit for the PJM Regulation Market during 2011 was $10.57 per MWh, an increase from the weighted average offer in 2010 of $9.28. Although higher than in 2010, offers remain low compared to prior years as a result of the application of the three pivotal supplier test, which prevents noncompetitive offers from setting price. The weighted average opportunity cost of the marginal unit for the PJM Regulation Market in 2010 was $5.39. In the PJM Regulation Market the marginal unit opportunity cost averaged 34 percent of the RMCP. This is a reduction from the 2010 level of 47 percent.

Figure 9-3 PJM Regulation Market daily weighted average market-clearing price, marginal unit opportunity cost and offer price (Dollars per MWh): Calendar year 2011

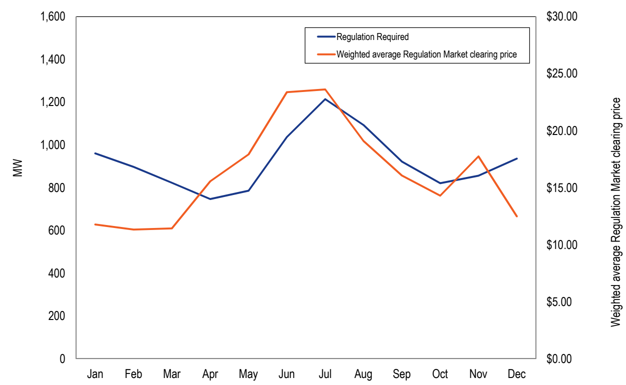


On a shorter term basis, regulation prices follow daily and weekly patterns. The supply of regulation is largest during on-peak hours, between 0600 and 2300 EPT, Monday through Friday.

During 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.

Figure 9-4 shows the level of demand for regulation by month in 2011 and the corresponding level of regulation price.

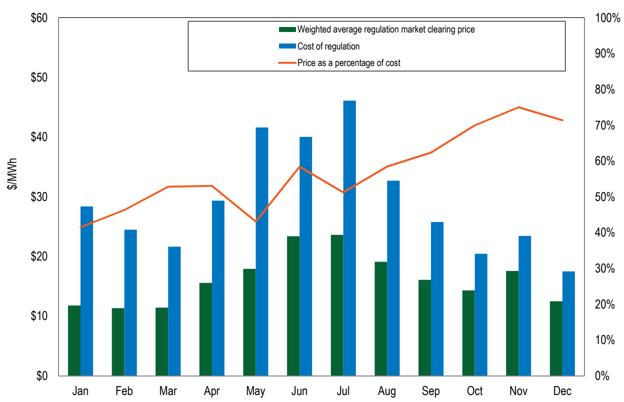
Figure 9-4 Monthly average regulation demand (required) vs. price: Calendar year 2011



The total cost of regulation per MW exceeds the price per MW because some regulation is procured out of the market, regulation MW actually delivered differs from regulation MW offered and cleared, 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 9-5 compares the regulation total cost per MWh (clearing price plus post market opportunity costs) with the regulation clearing price to show the difference between the per MWh price of regulation and the per MWh total cost of regulation. The results in Figure 9-5 show that a significant portion of the costs of regulation are not incorporated in the Regulation Market clearing price. This discrepancy results in a lack of transparency in the Regulation Market.

PJM may call on resources not otherwise scheduled to run in order to provide regulation, in accordance with PJM's obligation to minimize the total cost of energy, operating reserves, regulation, and other ancillary services. This often increases total regulation costs. If a resource is called on by PJM for the purpose of providing regulation, the resource is guaranteed recovery of regulation lost opportunity costs as well as start-up, no-load, and energy costs.

Figure 9-5 Monthly weighted, average regulation cost and price: Calendar year 2011



Total scheduled regulation MWh, total regulation charges, regulation price and regulation cost are listed in Table 9-11.

Table 9-12 provides a comparison of the weighted annual price and cost for PJM Regulation. For 2011, the weighted, average regulation price was $16.21 per MWh. The average regulation cost was $29.28 per MWh. The difference between the Regulation Market price and the actual cost of regulation was slightly greater in 2011 than it was in 2010. In 2011 the market price of regulation was only 55 percent of its actual cost. In 2010 the market price of regulation was 56 percent of its actual cost. 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 and effectively pays a substantial proportion of Regulation Market revenues on an as bid basis rather than on the basis of the clearing price.

Regulation prices were ten percent lower in 2011 than in 2010 and lower than in any year since the current Regulation Market structure was introduced in 2005. Regulation total costs per MW were 7.8 percent lower in 2011 than in 2010. The result was a small increase in the ratio of price to cost. With the exception of 2009, the ratio of price to cost has declined in every year since 2005, and the ratio of price to cost is at its lowest level since 2005.

A key source of the difference between the market clearing price and the cost per MW of regulation results from differences in opportunity cost between the forecast LMP and actual LMP. To address this issue, the MMU recommends that the hourly clearing price for regulation be determined after the close of the hour. All units cleared in the Regulation Market in the hour prior would be paid the market-clearing regulation price based on the actual LMP rather than the forecast LMP. This is expected to result in a net increase in payments to providers of regulation as a result of an increase in the regulation clearing price which more than offsets unit specific reductions in unit specific, post clearing opportunity cost payments. This would improve the transparency of the Regulation Market as the resulting price of regulation would internalize some of the costs currently being collected through uplift and would make the market price more reflective of the actual costs of providing the service.

Table 9-11 Total regulation charges: Calendar year 2011

Month	Scheduled Regulation (MWh)	Total Regulation Charges	Simple Average Regulation Market Clearing Price	Weighted Average Regulation Market Clearing Price	Cost of Regulation
Jan	709,121	$20,116,704	$11.91	$11.77	$28.37
Feb	594,515	$14,551,995	$11.50	$11.33	$24.48
Mar	599,608	$12,967,924	$11.64	$11.42	$21.63
Apr	523,565	$15,361,871	$16.07	$15.56	$29.34
May	566,439	$23,561,565	$18.46	$17.92	$41.60
Jun	691,666	$27,696,820	$23.64	$23.38	$40.04
Jul	810,656	$37,375,988	$22.64	$23.61	$46.11
Aug	803,781	$26,271,979	$19.47	$19.10	$32.69
Sep	662,237	$17,074,805	$16.30	$16.07	$25.78
Oct	608,213	$12,437,431	$14.30	$14.30	$20.45
Nov	637,312	$14,929,690	$18.24	$17.57	$23.43
Dec	685,895	$11,993,503	$12.46	$12.48	$17.49

Table 9-12 Comparison of weighted price and cost for PJM Regulation, August 2005 through December 2011[34]

Year	Simple Average Regulation Market Price	Weighted Regulation Market Price	Regulation Market Cost	Regulation Price as Percentage of Cost
2005	$64.21	$64.03	$77.39	83%
2006	$31.13	$32.69	$44.98	73%
2007	$35.30	$36.86	$52.91	70%
2008	$41.78	$42.09	$64.43	65%
2009	$23.52	$23.56	$29.87	79%
2010	$17.96	$18.08	$32.07	56%
2011	$16.38	$16.21	$29.28	55%

New Developments in the Regulation Market Design

While the current market design satisfies the requirements of regulation, namely that it keep the reportable metrics, CPS1 and BAAL within acceptable limits, a new market design initiative began in 2011 in response to a FERC Order.[35] On October 20, 2011, FERC issued Order No. 755 directing PJM and other ISOs to redesign the regulation market to accommodate fast response resources.[36] The FERC directed PJM and other ISOs to modify their regulation markets so as to make use of and properly compensate a mix of fast and traditional response regulation resources.[37] PJM is currently working with stakeholders to develop market rules that would results in an optimal, least cost combination of fast and traditional resources. This creates market design challenges, which if resolved, could improve the regulation market.

Regulation in PJM has traditionally been defined in terms of MW of capability that can be made available in five minutes and held (regulation up or down) for as long as an hour. Fast regulation resources, typified by batteries and flywheel technologies, are able to reach full capability much faster, but lack the ability to sustain a regulation up or down position for more than a few minutes. The current market design, built around the traditional resources, limited the ability of the new resource set to compete as a source of regulation.

To address the FERC requirements, PJM commissioned a study by KEMA designed to analyze the effectiveness of fast response regulation, in combination with traditional regulation resources, in meeting CPS1 requirements. The study evaluated the substitutability and synergies between fast response and traditional five-minute capability resources in meeting regulation compliance requirements. The results of the study indicated that the rate of substitution, and the overall effectiveness of fast response resources, was dependent upon system conditions and the amount of traditional resources simultaneously supplying regulation. The study indicated that a combination of fast and traditional resources could be more effective in providing for CPS1 compliance than using just traditional resources. PJM

34 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.

35 See *2011 State of the Market Report for PJM*, "Appendix F."

36 Frequency Regulation Compensation in the Organized Wholesale Power Markets, 137 FERC ¶ 61,064 (2011).

37 *Id.*

is currently working with stakeholders to incorporate the results of this study into proposed modifications to the PJM regulation market. At present the plan is to implement changes in a series of phased steps, with Phase 1 expected in late Spring of 2012. It is expected that these changes will include a lower overall regulation requirement, a metric to evaluate the regulation delivered by all types of regulation resources, a process to measure and report regulation performance by resource type compared to the applicable fast (RegD) and slow (RegA) regulation signal, and the goal of reduced cost to acquire the level of required regulation.

Issues in the Regulation Market Design

The MMU has identified several significant issues with the design and implementation of the Regulation Market. These are broad statements of the issues and do not include an exhaustive list of all concerns. The issues address economic efficiency and competitiveness, and transparency.

- The definition of opportunity cost for units providing regulation is not correct. The result is a clearing price not reflective of the actual opportunity cost and therefore not efficient or competitive. 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.
- PJM does not save some data elements that are necessary in order to replicate Regulation Market clearing prices. As a result, the opportunity cost used in the clearing price cannot be calculated and the clearing price cannot be calculated. While it may be possible to recreate data that is not saved, that is not the same as saving the data and making it available.
- It is not clear at what stages in the market clearing process the opportunity cost calculation includes shoulder hour opportunity costs. The documentation should be updated to clarify when shoulder hour opportunity costs are included in the market clearing process.
- The MMU analysis of the Regulation Market following the December 1, 2008, market rule changes resulted in the discovery that a significant number of marginal units whose schedule should have been switched to the lower of the price or cost based offer under the new rule were not switched. The MMU communicated this to PJM. PJM subsequently modified the market clearing process, effective September 9, 2010. The MMU has not been provided up an updated design document for these changes. It is not clear that PJM's approach is a complete fix but it is difficult to evaluate in the absence of documentation.

Table 9-13 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.

Analysis of Regulation Market Changes

There were significant changes made to the Regulation Market effective December 1, 2008. The rule changes are summarized in Table 9-13. The changes were the result of a filing by PJM that reflected a compromise among market participants in the PJM process.[38] The MMU filed comments supporting 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."[39]

As directed by the FERC, the MMU performed an analysis of these Regulation Market rule changes, delivering a report on November 30, 2009.[40]

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 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.

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, more than 100 percent of the average cost of regulation. 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 units.

Table 9-14 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. The impact of the increased margin is 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. The increase in credits paid, of $10,954,411, is a result of the higher offer margin permitted under the new rules.

Change in the Definition of Opportunity Cost

The market clearing price of regulation is a sum of the regulation offer and the lost opportunity cost (LOC), including any applicable shoulder LOC, and in the case of off-line CTs a start-up cost. Offers in the Regulation Market consist of a cost based offer and, optionally, a price-based offer. The December 1, 2008, tariff modifications included a significant change in the definition of LOC. In the Regulation Market the direct offer price is made by the market participant and the opportunity cost 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 opportunity cost is, on average, approximately half the total offer price (Figure 9-3). 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.

Under the prior rules, opportunity cost was defined as the difference between the LMP and the offer on which the unit was dispatched in the energy market. Under the December 1, 2008, tariff modifications, opportunity cost is defined as the difference between the LMP, and the lesser of the available price-based energy schedule or the most expensive available cost-based energy schedule. Thus, for units backing down to provide regulation, the new rules result in higher calculated opportunity costs.

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

38 See Filing initiating Docket No. ER09-13-000 (October 1, 2008).
39 *Id.* at 2.
40 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>.

Table 9-14 Impact of $12 adder to cost based regulation offer: December 2008 through December 2011

Year	Month	Weighted Regulation Market Clearing Price	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%
2010	Jan	$20.66	$20.49	$29,465,392	$125,523	0%
2010	Feb	$16.17	$16.13	$16,640,892	$29,265	0%
2010	Mar	$16.70	$16.57	$14,156,600	$76,654	1%
2010	Apr	$17.26	$17.15	$13,246,951	$57,940	0%
2010	May	$19.16	$18.85	$19,286,137	$168,308	1%
2010	Jun	$19.46	$19.28	$23,333,299	$107,986	0%
2010	Jul	$23.39	$23.49	$34,017,900	($69,252)	-0%
2010	Aug	$21.50	$21.46	$28,928,214	$28,048	0%
2010	Sep	$19.30	$19.20	$19,592,362	$59,153	0%
2010	Oct	$13.57	$13.54	$10,613,185	$15,986	0%
2010	Nov	$11.69	$11.68	$11,930,514	$8,134	0%
2010	Dec	$14.04	$14.03	$25,225,775	$17,454	0%
2011	Jan	$11.77	$10.98	$20,116,696	$45,866	0%
2011	Feb	$11.33	$10.66	$14,551,986	$33,442	0%
2011	Mar	$11.42	$10.51	$12,967,915	$142,190	1%
2011	Apr	$15.56	$14.32	$15,361,860	$136,149	1%
2011	May	$17.92	$16.86	$23,561,554	$55,911	0%
2011	Jun	$23.38	$21.60	$27,696,810	$357,392	1%
2011	Jul	$23.61	$21.75	$37,375,975	$322,741	1%
2011	Aug	$19.10	$17.19	$26,271,969	$277,030	1%
2011	Sep	$16.07	$15.00	$17,074,790	$216,010	1%
2011	Oct	$14.30	$13.34	$12,437,411	$202,659	2%
2011	Nov	$17.57	$14.10	$14,929,802	$1,392,582	9%
2011	Dec	$12.48	$10.78	$11,924,355	$957,833	8%
Total				$728,601,484	$10,954,411	1.5%

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 and consistent manner. The goal is also to ensure that regulation offers are taken in merit order based on their actual marginal costs, including their correctly calculated opportunity cost.

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.

A quantification of the financial impact of this rule is not possible because PJM does not save all of the data used to determine the final opportunity cost and market clearing price.[41]

In addition, the implementation of the December 1, 2008, changes was not done correctly. Had the revised opportunity cost rule been implemented correctly the MMU estimates that the schedule switching of marginal units in the Regulation Market would have occurred in 4,574 hours during the 37 month period of December 2008 through December 2011 of which 2,506, 59.0 percent, would have resulted in higher opportunity costs, and 1,958, 37.7 percent, would have resulted in lower opportunity costs being added to the marginal regulation offer. In the remaining 110 hours the schedule switch would not have affected the opportunity cost calculation of the marginal unit.

As actually implemented by PJM, schedule switching of marginal units occurred in 3070 hours, of which 2,115, 69 percent, had higher than correct opportunity costs and 712 hours, 23 percent, had lower than correct opportunity costs added to the marginal regulation offer. In the remaining 243 hours the schedule switch would not have affected the opportunity cost calculation of the marginal unit.

PJM made a change to the market software (SPREGO) effective September 9, 2010 to address the identified issue with schedule switching.[42]

PJM has begun design work on an MMU requested initiative to make the opportunity cost calculation consistent across all PJM markets. It is expected that this effort will be completed and installed in 2012. If implemented as recommended, this would resolve the opportunity cost issue in the Regulation Market.

Eliminate Offset Against Balancing Operating Reserves Credits

The tariff modifications eliminated 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

41 The MMU has communicated this concern to PJM and been informed that steps are underway to make additional data available to the MMU.

42 See "Minutes," Market Implementation Committee, 11/09/2010, Agenda Item #9, pg. 5. <http://www.pjm.com/~/media/committees-groups/committees/mic/20101109/20101109-minutes.ashx>.

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 reserves 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.

Table 9-15 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 increase in total regulation credits paid, of $3,896,054, is a result of the elimination of the offset against operating reserve credits that result from the new rules.

Regulation Market Summary

The changes in market design increased the payments for regulation service. The impact on the Regulation Market that resulted from the December 1, 2008 rule eliminating the netting of credits against balancing operating reserves was $3,896,054. The impact on the Regulation Market of the December 2008 change increasing the allowable price offer markup from $7.50 to $12 was $10,954,411. These two rule changes increased regulation costs by $14,850,465 over the 37 month period from December 1, 2008 through December 31, 2011.

The dollar impact of changing the lost opportunity cost definition cannot be determined at this time primarily because the necessary data have not been saved by PJM. The rule would likely have changed the price in approximately 16.6 percent of hours between December 1, 2008, and December 31, 2011, (hours in which the marginal unit would have a schedule switch for the LOC calculation) and that in approximately 59 percent of those hours the marginal unit reduced output to regulate, meaning that the corresponding schedule switch would increase lost opportunity cost compared to the correct value. In 37 percent of the hours, the marginal unit increased output to regulate, meaning that the corresponding schedule switch would tend to reduce lost opportunity cost compared to the correct value.

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, 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 prices in the Regulation Market that deviated from the competitive price that would have resulted without these changes.

Synchronized Reserve Market

Market Structure

PJM continued to operate the two synchronized reserve markets it implemented on February 1, 2007: the RFC Synchronized Reserve Zone Market; and the Southern Synchronized Reserve Zone (Dominion) Market. The RFC Synchronized Reserve Zone Market's reliability requirements are set by the Reliability*First* Corporation. PJM sets the synchronized reserve requirement for the RFC Synchronized Reserve Zone as the larger of Reliability*First* Corporation's imposed minimum requirement or the largest contingency on the system. 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 to the PJM Mid-Atlantic Subzone of the RFC. This subzone is defined by the Bedington – Black Oak interface as the RFC Synchronized Reserve Zone including all of AEP, BGE, DPL, JCPL, Met-Ed, PECO, Pepco, PPL, PSEG and parts of AP, AEP, and PENELEC. PJM no longer includes the interface definition in M-11 and reserves the right to modify this model to meet operational and reliability needs.[43] PJM must clear enough Tier 2 synchronized reserve in the Mid-Atlantic Subzone of the RFC Synchronized Reserve Market to ensure that the Mid-Atlantic locational synchronized reserve requirement of 1,300 MW is met, after accounting for available Tier 1 supply. This results in a separate Mid-Atlantic Subzone clearing price.

43 See PJM. "Manual 11: Energy & Ancillary Services Market Operations," Revision 49 (January 1, 2012), p. 67.

Table 9-15 Additional credits paid to regulating units from no longer netting credits above RMCP against operating reserves: December 2008 through December 2011

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	$61,163	$27,426,669	0.2%
2011	Sep	$50,593	$17,050,086	0.3%
2011	Oct	$35,764	$9,542,173	0.4%
2011	Nov	$79,681	$11,030,193	0.7%
2011	Dec	$22,445	$20,271,120	0.1%
Total		$3,896,054	$729,131,461	0.5%

The Southern Synchronized Reserve Zone (Dominion) Market's reliability requirements are set by the Southeastern Electric Reliability Council (SERC).

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.[44] 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 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 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. Sixty 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 market is cleared at least 30 minutes prior to the start of the hour. The Tier 2 market clearing price is equivalent to the 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.[45]

The Synchronized Reserve Market is characterized by structural market power. As a result, the synchronized reserve offer submitted for a unit can be no greater than the unit's incremental operating and maintenance cost plus a $7.50 per MWh margin.[46,47] 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.

In 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 relatively low cost, and their participation in this market lowers overall Synchronized Reserve prices. The ratio of offered and eligible synchronized reserve MW to the administrative synchronized reserve required (1,300 MW) was 1.08 for the Mid-Atlantic Subzone.[48] This is a six percent decrease from 2010 when the ratio was 1.16. Much of the required synchronized reserve is supplied from on-line (Tier 1) synchronized reserve resources. The ratio of eligible synchronized reserve MW to the required Tier 2 MW is much higher. The ratio of offered and eligible synchronized reserve to the required Tier 2 depends on how much Tier 2 synchronized reserve is needed but the median ratio for all cleared Tier 2 hours in 2011 was 2.89 for the Mid-Atlantic Subzone. The ratio of offered and eligible synchronized reserve to the required Tier 2 was 3.00 for the RFC Zone for all hours in which a Tier 2 market was cleared. This is an 11 percent increase from 2010 when the ratio was 2.68. For the RFC Zone the offered and eligible excess supply ratio is determined using the administratively required level of synchronized reserve. The requirement for Tier 2 synchronized reserve is lower than the required reserve level for synchronized

44 See PJM. "Manual 11: Energy & Ancillary Services Market Operations," Revision 49 (January 1, 2012), p. 75.

45 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.

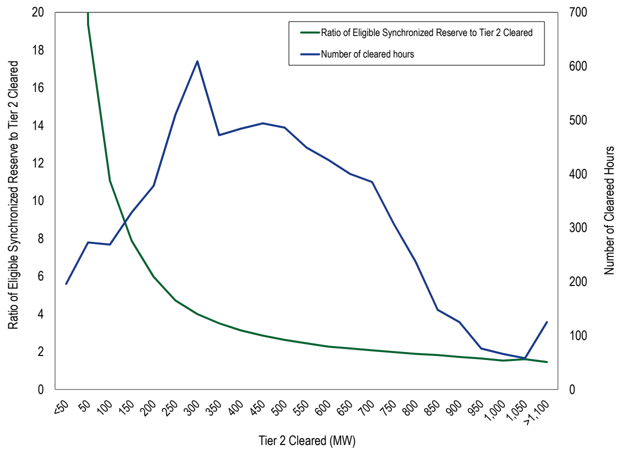
46 See PJM. "Manual 11: Energy & Ancillary Services Market Operations," Revision 49 (January 1, 2012), p. 65.

47 See PJM. "Manual 15: Cost Development Guidelines," Revision 17 (June 1, 2011), p. 36.

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

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

Figure 9-6 Ratio of Eligible Synchronized Reserve to Required Tier 2 for all cleared hours in the Mid-Atlantic Subzone: Calendar year 2011



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 to ensure system reliability and to maintain compliance with applicable NERC and regional reliability organization requirements. RFC and Dominion reserve requirements are determined on at least an annual basis. Mid-Atlantic Subzone requirements are established on a seasonal basis.[49]

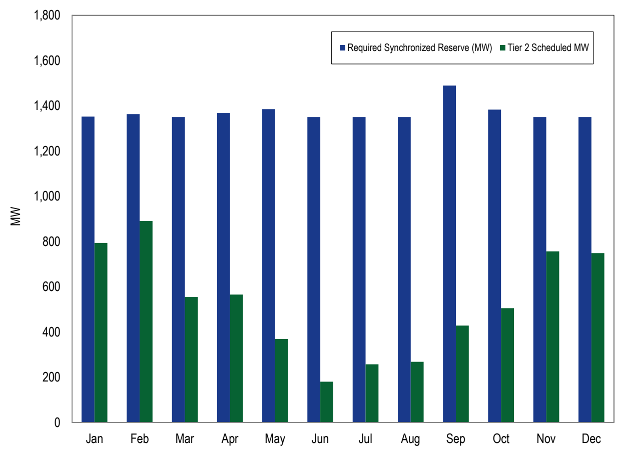
Currently the RFC synchronized reserve requirement is the greater of the ReliabilityFirst Corporation's imposed minimum requirement or the system's largest contingency. The actual synchronized reserve requirement for the RFC Zone was 1,350 MW for all of 2011. For the Mid-Atlantic Subzone the requirement was 1,300 MW for all of 2011 (Ref. Table 9-16).

Table 9-16 Synchronized Reserve Market required MW, RFC Zone and Mid-Atlantic Subzone, December 2008 through December 2011

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	Dec 2011	1,300	Mar 2010	Dec 2011	1,350

Exceptions to this requirement can occur when grid maintenance or outages change the largest contingency. Such a condition occurred for several hours on February 9 and February 10, when the synchronized reserve requirement was set to 1,700 MW (RFC Zone only). Between April 19 and April 20 the requirement was 1,760 MW (Mid-Atlantic Subzone only). For May 5, the requirement was 1,760 MW. Between September 12 and September 26 it was set to 1,700 MW for most hours (RFC Zone only). Between October 26 and October 28 it was set to 1,700 MW for most hours. Figure 9-7 shows the average monthly synchronized reserve required and the average monthly Tier 2 synchronized reserve MW scheduled during 2011 for the RFC Synchronized Reserve Market.

Figure 9-7 RFC Synchronized Reserve Zone monthly average synchronized reserve required vs. Tier 2 scheduled MW: Calendar year 2011



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

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

the amount of Tier 1 synchronized reserve in the west that can be transferred into the east. The 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. From 2007 through mid-March 2009, PJM market operations had estimated this transfer capacity at 70 percent of available RFC Tier 1 not exclusively in the Eastern subzone. However, PJM dispatch frequently observed a more restrictive limitation on transfer capacity in real-time operations on the western interface (Bedington—Black Oak) and needed to add additional synchronized reserve outside of the market solution in order to cover the requirement. This was the source of Added Synchronized Reserve resulting in lost opportunity costs being added to synchronized reserve costs.[50]

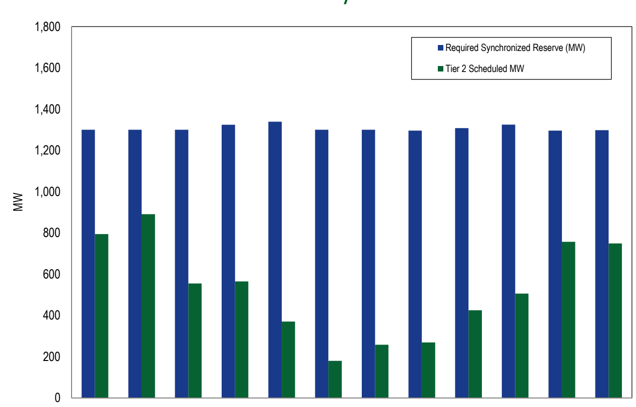
In mid March of 2009, PJM reset the transfer capacity from 70 percent to 15 percent. PJM also changed the transfer interface from Bedington – Black Oak to AP South. As a result, less Tier 1 synchronized reserve was available to the Mid-Atlantic Subzone for the market solution, increasing the amount of Tier 2 that had to be cleared to satisfy the requirement. This also reduced the amount of Tier 2 synchronized reserve that had to be added by PJM dispatch after market.[51] The transfer capacity was further reduced in late December, 2010, to 5 percent.

The integration of the Trans-Allegheny Line (TrAIL) 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. After the implementation of TrAIL, Bedington – Black Oak became the most limiting interface. Prior to the implementation of TrAIL the transfer capacity remained at 5 percent. After TrAil, the MMU observed several changes in the transfer capacity including 20 percent from April 20 through April 28; 10 percent from April 29 through May 19; 30 percent from May 20 through July 22; 5 percent from July 22 through August 1; 30 percent from August 1 through October 10; 50 percent from October 11 through November 14; and 15 percent from November 15 through December 31. The reasons for these changes are not clear and are not documented by PJM.

The MMU determined that these changes may be related to discrepancies between the amount of Tier 1 SPREGO estimates of MW available in the Mid-Atlantic Subzone and the amount actually available during the market hour. When the amount of Tier 1 actually available plus the amount of Tier 2 cleared is less than the required synchronized reserve (1,350 MW), then PJM dispatchers add additional synchronized reserve out of the market.

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 2011, the RFC Synchronized Reserve Zone cleared a Tier 2 Synchronized Reserve Market in less than one 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 only for the Mid-Atlantic Subzone. The Mid-Atlantic Subzone of the RFC Synchronized Reserve Zone cleared a separate Tier 2 market in 83 percent of all hours during 2011. A Tier 2 Synchronized Reserve Market was cleared in the Southern Synchronized Reserve Zone in less than one percent of hours (26 hours) during all of 2011. Figure 9-8 compares the required synchronized reserve MW to the scheduled Tier 2 MW for the Mid-Atlantic Subzone only.

Figure 9-8 RFC Synchronized Reserve Zone, Mid-Atlantic Subzone average hourly synchronized reserve required vs. Tier 2 scheduled: Calendar year 2011



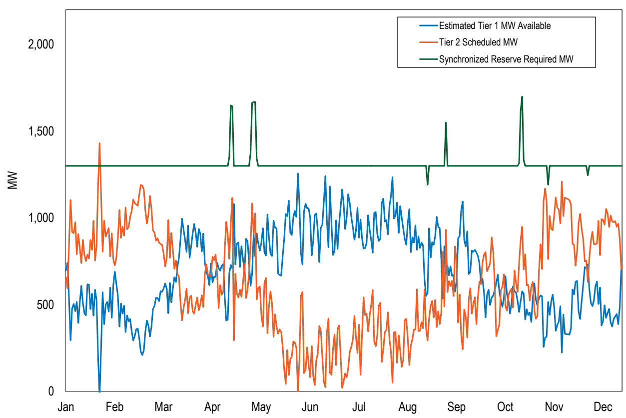
50 See *2007 State of the Market Report for PJM*, Volume II, section 6 Ancillary Service Markets pp. 299, 300. Also *2008 State of the Market Report for PJM*, Volume II, section 6 Ancillary Service Markets, p. 328.

51 See *2009 State of the Market Report for PJM*, Volume II, section 6 Ancillary Service Markets pp. 384, Table 6-14.

The actual synchronized reserve requirement for the Mid-Atlantic Subzone for 2011 was usually 1,300 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 1,760 MW on April 19 and 20, 2011. Throughout 2011, the average synchronized reserve required MW in the Mid-Atlantic Subzone was 1,307 MW. The difference between the level of required synchronized reserve and the level of Tier 2 synchronized reserve scheduled is the amount of Tier 1 synchronized reserve available on the system.

Figure 9-9 shows the relationship among the PJM Mid-Atlantic synchronized reserve required, the estimated Tier 1 available and the amount of Tier 2 synchronized reserve needed to be purchased. The more Tier 1 is available the less Tier 2 is required.

Figure 9-9 RFC Synchronized Reserve Zone, Mid-Atlantic Subzone daily average hourly synchronized reserve required, Tier 2 MW scheduled, and Tier 1 MW estimated: Calendar year 2011



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.[52] The amount of 15 minute quick start reserve available in VACAR is sufficient to make 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. The Southern Synchronized Reserve Zone cleared a Tier 2 market for only 26 hours in 2011.

Market Concentration

The RFC Tier 2 Synchronized Reserve Market was less concentrated in 2011 than it had been in 2010. Nevertheless the RFC Synchronized Reserve Market remains highly concentrated and dominated by a relatively small number of companies. The participation of demand resources in the market continues to have a significant impact on the market solution, resulting in lower prices and less concentration. The HHI for the Mid-Atlantic Subzone of the 2011 RFC cleared Synchronized Reserve Market was 2637, which is defined as "highly concentrated."

The largest hourly market share was 96 percent and 46 percent of all hours had a maximum market share greater than or equal to 40 percent (compared to 68 percent of all hours in 2010). In less than one percent of Mid-Atlantic Subzone hours during which a market was cleared in 2011, a single company had 60 percent or more 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 29 percent (compared to 43 percent in 2010). In other words, a single company sold 29 percent of synchronized reserves on average for all hours in which it had market share over the entire year (Table 9-17).

Table 9-17 Mid-Atlantic Subzone RFC Tier 2 Synchronized Reserve Market's cleared market shares[53]: Calendar year 2011

Company Market Share Rank	Cleared Synchronized Reserve Average Market Share
1	29%
2	25%
3	9%
4	8%
5	7%

In 2011, 63 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 100 percent of all pivotal hours, a second company was

52 See PJM. "Manual 11: Energy & Ancillary Services Market Operations," Revision 49 (January 1, 2012), p. 66.

53 Note that the column "Cleared Synchronized Reserve Average Market Share" includes 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.

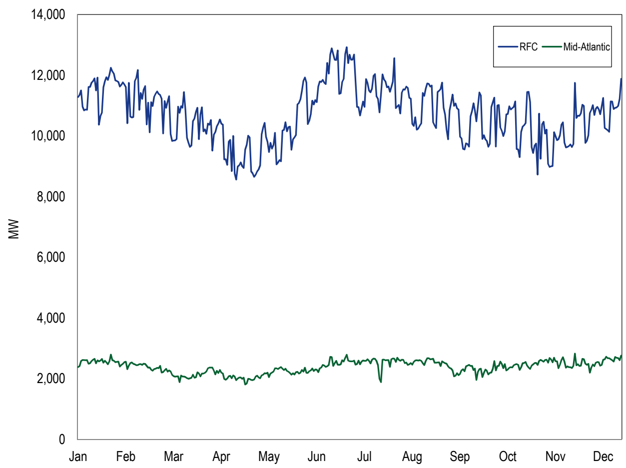
pivotal in 59 percent of all pivotal hours, and a third company was pivotal in 32 percent of all pivotal hours. These results indicate that the Mid-Atlantic Subzone of the RFC Synchronized Reserve Market, the only synchronized reserve market that clears on a regular basis, is not structurally competitive.

Market Conduct

Offers

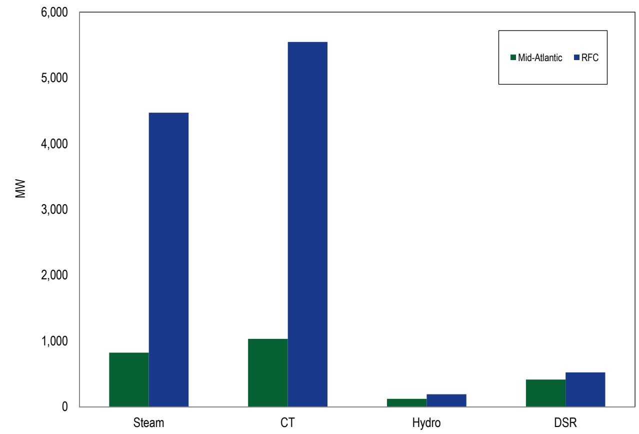
Figure 9-10 shows the daily average hourly offered Tier 2 synchronized reserve MW. For steam units, offered MW are eligible only if the offering unit is running. For that reason, the eligible offer volume shows weekly variability based on off-peak/on-peak operating cycles as well as seasonal variability.

Figure 9-10 Tier 2 synchronized reserve average hourly offer volume (MW): Calendar year 2011



Synchronized reserve is offered by steam, CT, hydroelectric and DSR resources. Figure 9-11 shows average offer MW volume by market and unit type.

Figure 9-11 Average daily Tier 2 synchronized reserve offer by unit type (MW): Calendar year 2011



The contribution of DSR resources to the Synchronized Reserve Market remained significant in 2011. The significance of DSR in the Synchronized Reserve Markets is greater than its eligible offer MW as illustrated in Figure 9-11. In 2011, DSR accounted for 29.3 percent of all cleared Tier 2 synchronized reserves. In 6.6 percent of hours when a synchronized reserve market was cleared all cleared MW was DSR (eight percent in 2010). In the hours when all supply was DSR, the simple average SRMCP was $1.28. The simple average SRMCP for all cleared hours was $9.48 (the simple average SRMCP in 2010 was $8.49). As defined by PJM, demand-side resources may at times be generation that is behind the meter.

Compliance

The MMU has reviewed synchronized reserve non-compliance between 2009 and 2011 and concluded that the incentive/penalty structure is not adequate. 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. The result is that it is possible to provide the service profitably with a very low level of compliance. This behavior does exist in this market. PJM's synchronized reserve penalty structure fails to penalize this behavior adequately. The MMU recommends that the Synchronized Reserve Market non-compliance penalties be restructured to address this issue and provide stronger incentives for compliance.

Synchronized reserve non-compliance has never caused a reliability problem at PJM.

DSR

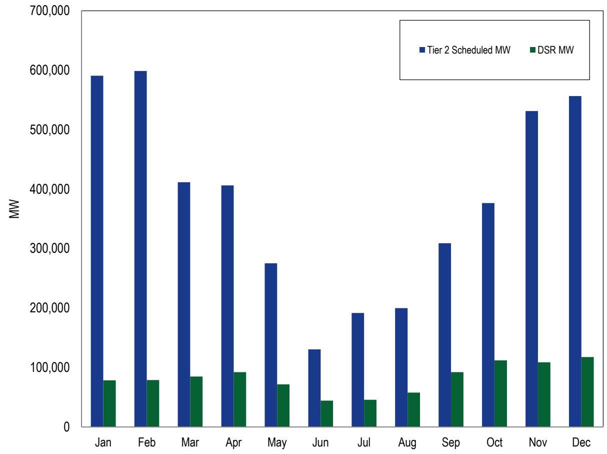
Demand-side resources were permitted to participate in the Synchronized Reserve Markets effective August 2006. DSR continues to have a significant impact on the Synchronized Reserve Market. In 6.6 percent of hours where a synchronized reserve market was cleared in the Mid-Atlantic Subzone of the RFC (see Table 9-18), all cleared synchronized reserve was DSR synchronized reserve. The clearing price for those hours was significantly lower than the average clearing price overall.

Table 9-18 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 2011

Month	Weighted average SRMCP	Weighted average SRMCP when all cleared synchronized reserve is DSR	Percent of cleared hours all synchronized reserve is DSR
Jan	$10.75	$0.10	0.0%
Feb	$10.91	NA	0.0%
Mar	$11.34	$2.04	2.0%
Apr	$16.07	$1.84	10.0%
May	$10.59	$1.71	14.0%
Jun	$13.41	$1.18	10.0%
Jul	$16.99	$0.62	6.0%
Aug	$10.62	$0.78	7.0%
Sep	$10.97	$1.73	15.0%
Oct	$9.65	$1.18	4.0%
Nov	$10.39	$0.71	3.0%
Dec	$10.04	$2.24	1.0%

Figure 9-12 shows total cleared plus self scheduled monthly synchronized reserve MW and cleared plus self scheduled MW for DSR synchronized reserve. Participation of demand response in the Synchronized Reserve Market remained strong in 2011. 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. Furthermore demand resources add some diversity to the supply of synchronized reserve, reducing market concentration.

Figure 9-12 PJM RFC Zone Tier 2 synchronized reserve scheduled MW: Calendar year 2011



Market Performance

Price

Figure 9-13 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 Mid-Atlantic Subzone of the RFC 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 9-13 Required Tier 2 synchronized reserve, Synchronized Reserve Market clearing price, and DSR percent of Tier 2: Calendar year 2011

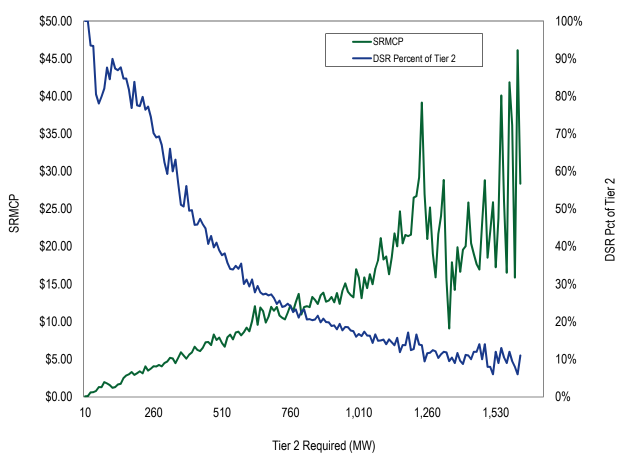


Figure 9-16 shows the weighted, average Tier 2 price and the cost per MW associated with meeting PJM demand for synchronized reserve. The price of Tier 2 synchronized reserve is the Synchronized Reserve Market-clearing price (SRMCP). Resources which provide synchronized reserve are paid the higher of 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.

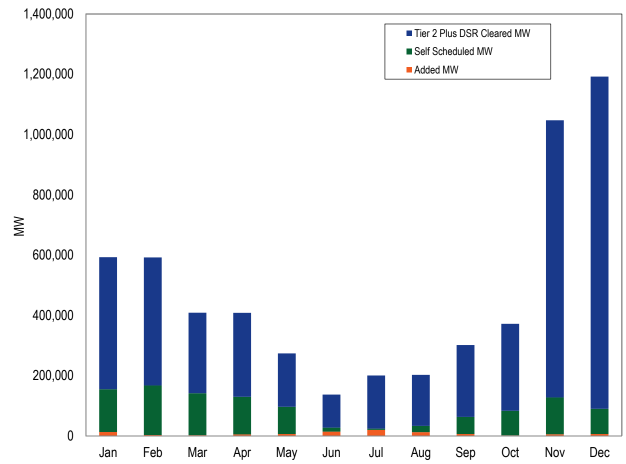
The weighted, average price for synchronized reserve in the PJM Mid-Atlantic Subzone of the RFC Synchronized Reserve Market in 2011 was $11.81 while the corresponding cost of synchronized reserve was $15.48.

The RFC Synchronized Reserve Market cleared as a single market in only 16 hours in all of 2011 with a weighted average $10.07 clearing price.

Price and Cost

A high price to cost ratio is an indicator of an efficient market design, where the costs are the result of the economic solution. A low price to cost ratio is in part a result of out-of-market purchases of Tier 2 synchronized reserve by PJM dispatchers who need the reserves for reliability reasons. The primary reason for the relatively low price to cost ratio is the difference in opportunity cost calculated using the forecast LMP and the actual LMP.

Figure 9-14 Tier 2 synchronized reserve purchases by month for the Mid-Atlantic Subzone: Calendar year 2011



Since the implementation of AC2 (November 7, 2011) PJM has seen an increase in the amount of Tier 2 synchronized reserve purchased. The green portion of Figure 9-14 is higher for the months of November and December, 2011 than in 2010. Although winter months typically require higher levels of Tier 2 synchronized reserve than Spring and Fall, the percentage increase in 2011 is much higher than it had been in 2010.

The difference between the Tier 2 Synchronized Reserve Market price and the cost for Tier 2 synchronized reserve in 2011 is less than in 2010 (Figure 9-16). In the Mid-Atlantic Subzone of the RFC Synchronized Reserve Market for 2011, the cost of Tier 2 synchronized reserves was 31 percent higher than the weighted price. In 2010 this difference was 37 percent.

Figure 9-15 Impact of Tier 2 synchronized reserve added MW to the RFC Synchronized Reserve Zone, Mid-Atlantic Subzone: Calendar year 2011

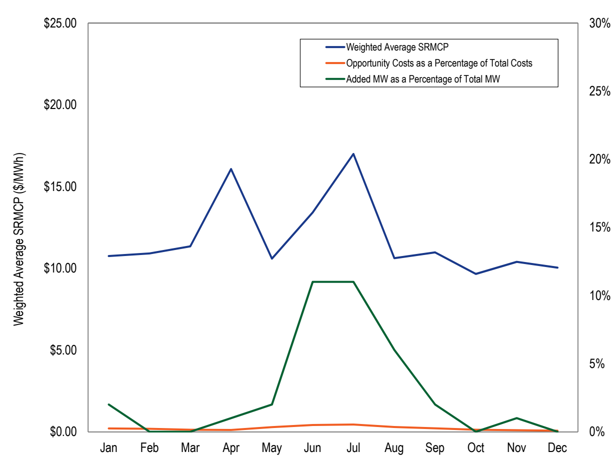
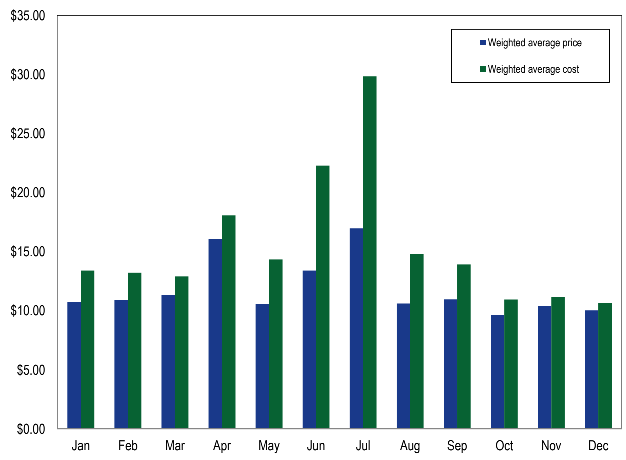


Figure 9-16 Comparison of Mid-Atlantic Subzone Tier 2 synchronized reserve weighted average price and cost (Dollars per MW): Calendar year 2011

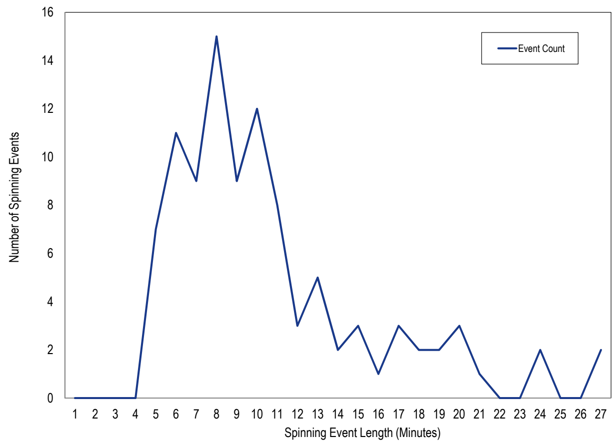


A high price to cost ratio is an indicator of an efficient market design, where the costs are the result of the economic solution. Table 9-19 shows the price and cost history of the Synchronized Reserve Market since 2005. In March of 2009, PJM took steps to reduce the amount of aftermarket added synchronized reserve being added by the dispatchers. As a result, the price to cost ratio increased in 2009.

Synchronized reserve prices were 10.7 percent higher in 2011 than in 2010. Synchronized reserves total costs per MW were 6.9 percent higher in 2011 than in 2010. The total cost of synchronized reserves per MW was 31.1 percent higher than the market clearing price in 2011. The result was a decrease in the ratio of price to cost.

A key source of the difference between the market clearing price and the cost per MW of synchronized reserve results from differences in opportunity cost between the forecast LMP and actual LMP. To address this issue, the MMU recommends that the hourly clearing price for synchronized reserve be determined after the close of the hour. All units cleared in the synchronized reserve market in the hour prior would be paid the market-clearing price based on the actual LMP rather than the forecast LMP.

Figure 9-17 Spinning events duration distribution curve, January 2009 through December 2011



Spinning events (Table 9-20) are situations usually caused by a sudden generation outage or transmission disruption requiring PJM Dispatch to load primary synchronized reserve (spinning reserve).[54] The reserve remains loaded until system balance is recovered. From January 2009 through December 2011 PJM experienced 105 spinning events. This is almost 3 events per month. Spinning events generally last between 7 minutes and twenty minutes with an average length of eleven and a half minutes although several events have lasted longer than thirty minutes.

The need for synchronized (primary) reserve during spinning events is the reason for the Synchronized Reserve Market. Resources that offer and are scheduled in this market are obligated to provide their scheduled synchronized reserve whenever an event happens. When a scheduled resource fails to provide its full amount of synchronized reserve during a spinning event it is penalized.[55]

Market Solution and Actual Dispatch of Ancillary Services

The actual dispatch of ancillary services can and does differ from the market solution at times, as a result of 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.

54 See PJM. "Manual 12, Balancing Operations," Revision 23 (November 16, 2011), pp. 34-35.
55 See PJM. "Manual 11, Energy & Ancillary Serves Market Operations" Revision 49 (January 1, 2012), 4.2.13, p.75.

Table 9-19 Comparison of weighted average price and cost for PJM Synchronized Reserve, 2005 through 2011

Year	Simple Average Synchronized Reserve Market Price	Weighted Average Synchronized Reserve Market Price	Weighted Average Synchronized Reserve Cost	Synchronized Reserve Price as Percent of Cost
2005	$10.89	$13.29	$17.59	76%
2006	$10.67	$14.57	$21.65	67%
2007	$11.57	$11.22	$16.26	69%
2008	$7.76	$10.65	$16.43	65%
2009	$6.58	$7.75	$9.77	79%
2010	$8.49	$10.55	$14.41	73%
2011	$9.48	$11.81	$15.48	76%

Table 9-20 Spinning Events, January 2009 through December 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	SEP-24-2011 15:48	RFC	8
OCT-26-2009 11:05	RFC	13	DEC-16-2010 18:40	Mid-Atlantic	20	SEP-27-2011 14:20	RFC	7
OCT-26-2009 19:55	RFC	8	DEC-17-2010 22:09	Mid-Atlantic	6	SEP-27-2011 16:47	RFC	9
NOV-20-2009 15:30	RFC	8	DEC-29-2010 19:01	Mid-Atlantic	15	OCT-30-2011 22:39	Mid-Atlantic	10
DEC-09-2009 22:34	Mid-Atlantic	34				DEC-15-2011 14:35	Mid-Atlantic	8
DEC-09-2009 22:37	RFCNonMA	31				DEC-21-2011 14:26	RFC	18
DEC-14-2009 11:11	Mid-Atlantic	8						

The market solution software (SPREGO) optimizes regulation and spinning using a theoretical unit dispatch and estimated Tier 1 synchronized reserve based on forecast load. 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 also recommends that dispatchers document all actual unit deselections and the reasons for deselection.

Adequacy

A synchronized reserve deficit occurs when the combination of Tier 1 and Tier 2 synchronized reserve is not adequate to meet the synchronized reserve requirement. Neither PJM Synchronized Reserve Market, nor the Mid-Atlantic subzone of the RFC market experienced deficits in 2011.

Day Ahead Scheduling Reserve (DASR)

The Day-Ahead Scheduling Reserve Market is a market based mechanism for the procurement of supplemental, 30-minute reserves on the PJM System.[56]

On June 1, 2008, PJM introduced the Day-Ahead Scheduling Reserve Market (DASR), as required by the settlement in the RPM case.[57] 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. The DASR 30-minute reserve requirements are determined by the reliability region.[58] In the ReliabilityFirst (RFC) region, reserve requirements are calculated based on historical under-forecasted load rates and generator forced outage rates.[59] Under-forecasted load rates are based on the 80th percentile of a rolling three-year average (November 1 – October 31). For 2011, the load forecast error component of this calculation was 1.87 percent of peak load forecast. This is a 0.03 percent decline from the load forecast error component of the 2010 DASR requirement. 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 2011, the forced outage component of the Day-Ahead Scheduling Reserve was 5.23 percent. This is a 0.25 percent increase from the 2010 forced outage component of the DASR requirement. For 2011 the Day-Ahead Scheduling Reserve for RFC areas of PJM was 7.11 percent times Peak Load Forecast for RFC. This is a 0.23 percent decrease from the 2010 DASR requirement. Dominion Day-Ahead Scheduling Reserve is based on its share of the VACAR Reserve Sharing agreement and is set annually. In 2011 VACAR scheduling reserve was set at 422 MW, an increase of 4 MW from the 2010 VACAR scheduling reserve requirement. 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.

Market Structure

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 2011, the three pivotal supplier test was failed in the DASR Market in a total of 21 hours (less than one percent of all hours, a reduction from 1.3 percent of all hours in 2010).

56 PJM uses the terms "supplemental operating reserves" and "scheduling operating reserves" interchangeably.
57 See, 117 FERC ¶ 61,331 (2006).
58 PJM. "Manual 13, Emergency Requirements," Revision 47 (January 1, 2012), pp. 11-12.
59 PJM. "Manual 10, Pre-Scheduling Operations," Revision 25 (January 1, 2010), p. 17.

Demand side resources do participate in the DASR Market, but remain insignificant. Demand side resources began to offer and clear the DASR market in November 2008. No demand side resources cleared the DASR market in 2011.

In 2011, the required DASR was 7.11 percent of peak load forecast, up from 6.88 percent in 2010.[60] As a result of increased DASR requirements, the DASR MW purchased increased by 7 percent in 2011 over 2010, from 53.2 MMW to 57.0 MMW.

Market Conduct

PJM rules require all units with reserve capability that can be converted into energy within 30 minutes to offer into the DASR Market.[61] Units that do not offer have their offers set to $0/MW.

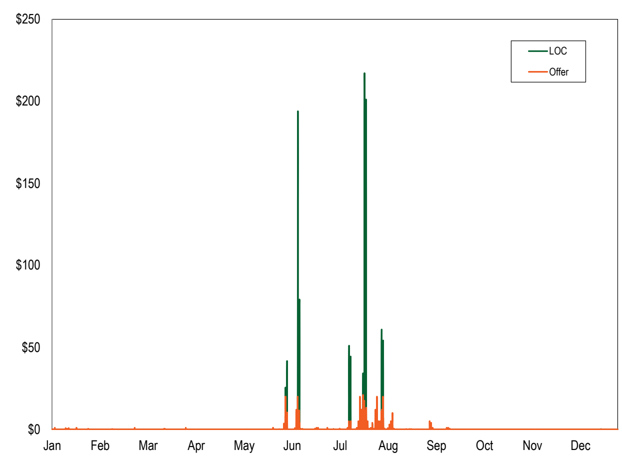
Economic withholding remains an issue in the DASR Market, but the nature of economic withholding in the DASR Market changed in June. The marginal cost of providing DASR is zero. In the first five months of 2011, five percent of units offered at $50 or more and four percent offered at more than $900. Most of these offers were reduced during the month of June but remained at levels exceeding competitive levels. Between June 1, and December 31, 2011, thirteen percent of all units offered DASR at levels above $5, while less than one percent of units offered above $50. Two units offered above $900.

This behavior was limited to a relatively small number of units. Over the full year the impact on DASR prices of excessively high offers was minor as a result of a favorable balance between supply and demand. Of the 89 hours when the DASR clearing price was above $5.00, in 37 hours the price was set by a marginal unit with an offer price greater than $5.00. The MMU recommends that the DASR Market rules be modified to incorporate the application of the three pivotal supplier test in order to address potential market power issues.

Market Performance

For most (97 percent) of hours is 2011 DASR prices are determined entirely by the offer price of the marginal unit with units offering less than $0.03 marginal. Fifty six percent of hours in 2011 cleared at a price of $0.00. This means that most often DASR is available at no cost from the optimized energy solution. At prices above $0.05 however there is usually some re-dispatch required adding LOC to the clearing price. In 2011 there were 8.2 million unit-hours of cleared DASR (including clearing price of $0.00), of which only 5,140 unit-hours (0.06 percent) incurred an LOC. When energy prices get high however (as they did some hours in the summer) and there is less 30 minute reserve available from the energy dispatch, the price of DASR rises rapidly and LOC drives that price almost entirely. Although ninety five percent of hours cleared at $0.05 or less in 2011, the weighted average price of DASR was $0.55 per MW. In 2010, the weighted price of DASR was $0.16 per MW. The maximum clearing price in 2011 was $217.12 per MW on July 21. At prices above $0.05 however there is usually some re-dispatch required adding LOC to the clearing price (Figure 9-18).

Figure 9-18 Hourly components of DASR clearing price: Calendar year 2011



60 See the *2011 State of the Market Report for PJM*, Volume II, Section 9, "Ancillary Services" at Day Ahead Scheduling Reserve (DASR).

61 PJM. "Manual 11, Emergency and Ancillary Services Operations," Revision 49 (January 1, 2012), p. 122.

Table 9-21 PJM Day-Ahead Scheduling Reserve Market MW and clearing prices: Calendar year 2011

Month	Average Required Hourly DASR (MW)	Minimum Clearing Price	Maximum Clearing Price	Weighted Average 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
Oct	5,874	$0.00	$0.04	$0.00	4,370,196	$3,655
Nov	6,067	$0.00	$0.04	$0.00	4,374,307	$6,155
Dec	6,532	$0.00	$0.21	$0.00	4,866,230	$6,181

Black Start Service

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.[62]

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 in their transmission zone following a possible blackout as well as to cover critical load. Individual transmission owners, with PJM, identify the black start units included in each transmission owner's system restoration plan for its zone. PJM defines a minimum critical black start level for each transmission zone.[63] 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 an incentive rate or their revenue requirements (Table 9-22). The black start charges in Table 9-22 for the AEP zone include an estimated $6.5 million of charges that were allocated to customers as operating reserve charges but that were in fact to pay for the operation of ALR black start units.[64]

Table 9-22 Black start yearly zonal charges for network transmission use: Calendar year 2011

ZONE	Network Charges	Black Start Rate ($/MW)
AECO	$485,333	$0.48
AEP	$7,058,952	$0.82
AP	$150,171	$0.05
ATSI	$193,376	$0.18
BGE	$2,143,162	$0.90
ComEd	$3,501,165	$0.47
DAY	$150,068	$0.13
DLCO	$35,936	$0.04
DPL	$438,623	$0.32
JCPL	$498,060	$0.23
Met-Ed	$487,132	$0.49
PECO	$1,045,053	$0.35
PENELEC	$283,555	$0.28
Pepco	$374,447	$0.17
PPL	$145,840	$0.06
PSEG	$3,100,807	$0.84

Formula Rates for Black Start Cost Recovery

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 of these costs (including costs collected pursuant to separately filed and eligible FERC tariffs).[65] 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

62 OATT, Sheet No. 33.01.
63 See PJM. "Manual 36, System Restoration," Revision 15 (August 17, 2011) p. 49.
64 See the *2011 State of the Market Report for PJM*, Volume II, Section 3, "Operating Reserves."

65 The system restoration plan does not necessarily include all of the generating units in PJM capable of providing black start service, but it does include all units that receive payments for black start service from PJM.

to continue providing the service.[66] These provisions established a rolling two-year commitment, appropriate for older units with no requirement for new investment in black start related equipment.

A series of proceedings at the FERC revealed that the cost recovery provisions of Schedule 6A were unsuited for units installing equipment necessary to provide black start service when no such capability previously existed.[67]

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 the cost of substantial capital investments in black start capable resources over a short period 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.

The owners of black start service units had concerns that the provisions in Schedule 6A did not allow them to recover of the costs of new investment in equipment needed to comply with new Critical Infrastructure Protection Standards (CIPS) under development by the NERC.

In late 2007, PJM reactivated the Black Start Service Working Group ("BSSWG") in order to address these issues. Revisions to Schedule 6A developed by the BSSWG were filed with the FERC and approved by order issued May 29, 2009, the Commission approved the reforms.[68]

Some black start service unit owners claimed that they could not use the provisions of Schedule 6A allowing for the recovery of CIPS costs because they could not document non-CIPS related capital costs. The BSSWG developed a compromise proposed by the Market Monitor that allowed the incentive rate formula to be used as a proxy for cost for the first 100 MW for hydroelectric units and 50 MW for CTs and diesel units. By order issued January 13, 2012, the Commission approved the compromise, conditioned on PJM filing to correct certain provisions that allowed for possible double recovery of investment costs, consistent with a protest filed by the MMU.[69] The MMU has continuing concerns that the cost recovery provisions of Schedule 6A are unnecessarily complicated and may prove difficult to appropriately administer.

The MMU has significant concerns about the process for selecting and retaining the units that are included in the black start unit restoration plan. 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 could provide the same service at lower cost.

Black Start Service Procurement

There is no organized market for black start service in PJM and there is unlikely to be a competitive market for black start service as a result of the very local nature of the requirements.

PJM in conjunction with its transmission owners identifies locations where critical black start units are needed, considering each transmission zone separately, and conducts requests for proposals to procure service at those locations. PJM can accept proposals from

66 See PJM filing initiating FERC Docket No. ER02-2651-000 at 4 (September 30, 2002)("2002 Schedule 6A Filing").

67 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. 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.

68 127 FERC ¶ 61,197 (2009).

69 138 FERC ¶ 61,020 (2012).

any party willing and able to provide the service at the required location, but the ability to compete at each location is limited. Separate planning for each transmission zone significantly constrains the definition of locations and reduces flexibility in considering how to restart the grid.[70] No customers or their representatives are involved in this process.

The MMU has concerns that there is a disconnect between a service that is required for system reliability, the balkanized approach to procuring that service, 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.

The principal obstacle is that PJM does not have the authority to develop a 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 rules should be revised to assign responsibility for administering the plan to PJM and allow transmission owners to play an advisory role. This is especially important to address situations where transmission owners have affiliates providing black start service in the PJM region. PJM should administer the plan on a regional basis.

Developing plans for each individual zone prevents or limits consideration of how resources in located in could be used in coordination with resources in a neighboring zone to achieve an efficient and orderly restoration. This approach artificially limits the resources and locations eligible to contribute to the restoration plan.

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.

Procurement of black start service necessarily involves a discussion of price. Currently, that discussion takes the form of a discussion between sellers and PJM, a neutral. The MMU is also a neutral in such discussions. Better balance in discussions about price is needed. An improvement would afford clear representation in the process to those responsible to pay for the service. Schedule 6A is designed to procure black start service as a service incremental to a unit's principal purpose of providing energy and capacity. In some cases, PJM has had to address units providing black start service that requires substantial investment in refurbishment. To date the approach has been to enter bilateral agreements that provide that the unit will recover the full investment needed to remain in service. These agreements provide for owners to retain the higher of cost-based recovery under Schedule 6A or capacity prices. This provision acknowledges that customers should at least receive the capacity value of the unit up to the cost support that they provide through Schedule 6A.

The risk remains that transmission customers in PJM may pay the cost of substantial capital investments in black start capable resources over a short period with no assurance that those resources will continue to provide black start service after the recovery period. Accordingly, the MMU recommends that PJM, FERC, reliability authorities and 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. This recommendation includes continued consideration of reforms to the procurement process and initiating a new effort to assign to PJM responsibility to develop a regional black start restoration plan.

The System Restoration Strategy Task Force (SRSTF) was formed by the MRC and will meet in 2012 to evaluate PJM's restoration plan, but it is not yet clear if the issue of least cost procurement for the entire PJM market will be addressed.

70 A restart is achieved by using smaller self starting units to start larger units, creating disparate energized areas that are gradually merged until the entire grid is energized. Vertically integrated utilities design their restoration plans around the facilities that they control or with which they are familiar. Now that PJM is the grid operator, the range of configurations that could start the system have increased and have the potential to be further and intentionally increased.