

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

¹ 75 FERC ¶ 61,080 (1996).

² See the 2011 State of the Market Report for PJM for a full discussion of Ancillary Service markets and issues.

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 competitive⁴ (See 2011 SOM, Table 9-1)

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 67 percent of the hours in January through March 2012.

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 (See 2011 SOM, Table 9-2)

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 49 percent of the hours in January through March of 2012.
- Participant behavior was evaluated as competitive because the market rules require competitive, cost based offers.

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.

- 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 (See 2011 SOM, Table 9-3)

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 12 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.

Highlights

- The weighted average Regulation Market clearing price, including opportunity cost, for January through March 2012 was \$12.64 per MW.⁶ This was an increase of \$1.13, or 10 percent, from the average price for regulation in January through March 2011. The total cost of regulation decreased by \$8.07 from \$24.83 per MW in January through March 2011, to \$16.76, or 33 percent. In January through March 2012 the weighted Regulation Market clearing price was 75 percent of the total regulation cost per MW, compared to 46 percent of the total regulation cost per MW in January through March 2011.
- The weighted average clearing price for Tier 2 Synchronized Reserve Market in the Mid-Atlantic Subzone was \$6.06 per MW in January through March 2012, a \$4.94 per MW decrease from January through March 2011.⁷ The total cost of synchronized reserves per MWh in January through March 2012 was \$7.76, a 59 percent decrease from the total cost of synchronized reserves (\$13.19) during January through March 2011. The weighted average Synchronized Reserve Market clearing price was 78 percent of the weighted average total cost per MW of synchronized reserve in January through March 2012, down slightly from 83 percent in January through March 2011.
- The weighted DASR market clearing price in January through March 2012 was \$0 per MW. In January through March 2011, the weighted price of DASR was \$0.02 per MW. The average hourly purchased DASR increased by eight percent from 6,145 MW to 6,634 MW reflecting PJM's larger footprint with the integration of Duke on January 1, 2012.
- Black start zonal charges in January through March 2012 ranged from \$0.02 per MW in the ATSI zone to \$1.90 per MW in the AEP zone

⁶ The term "weighted" when applied to clearing prices in the Regulation Market means clearing prices weighted by the MW of cleared regulation.

⁷ The term "weighted" when applied to clearing prices in the Synchronized Reserve Market means clearing prices weighted by the MW of cleared synchronized reserve.

Ancillary Services costs per MW of load: 2001 – 2012

Table 9-4 shows PJM ancillary services costs for January through March 2001 through January through March 2012 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 ReliabilityFirst 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 Load⁸: Q1 2001 through Q1 2012 (See 2011 SOM, Table 9-4)

Year	Regulation	Scheduling, Dispatch, and System Control	Reactive	Synchronized Reserve	Supplementary Operating Reserve
2001	\$0.49	\$0.40	\$0.22	\$0.00	\$0.94
2002	\$0.37	\$0.59	\$0.24	\$0.00	\$0.56
2003	\$0.65	\$0.59	\$0.22	\$0.00	\$0.98
2004	\$0.53	\$0.63	\$0.26	\$0.17	\$0.89
2005	\$0.46	\$0.51	\$0.25	\$0.07	\$0.57
2006	\$0.48	\$0.46	\$0.28	\$0.09	\$0.32
2007	\$0.58	\$0.46	\$0.30	\$0.11	\$0.50
2008	\$0.59	\$0.47	\$0.29	\$0.07	\$0.52
2009	\$0.37	\$0.37	\$0.34	\$0.16	\$0.56
2010	\$0.34	\$0.38	\$0.35	\$0.05	\$0.68
2011	\$0.27	\$0.33	\$0.39	\$0.12	\$0.84
2012	\$0.18	\$0.41	\$0.49	\$0.03	\$0.53

Conclusion

The MMU continues to conclude that the results of the Regulation Market are not competitive.⁹ 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

⁸ Results in this table differ slightly from the results reported previously because accounting load is used in the denominator in this table.

⁹ 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."

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 January through March 2012, 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.

Although 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 rulemaking.¹⁰ 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.¹¹

On March 5, 2012, PJM filed proposed tariff revisions intended to implement Order No. 755.¹² PJM proposed a two-part compensation method, and requested, in order to implement its preferred approach, that the Commission approve its filing to implement tariff revisions for scarcity pricing in compliance with Order No. 719.¹³ A two-part compensation method provides for (i) “a capacity payment, or option payment, for a resource keeping its capacity in reserve in the event that it is needed to provide real-time frequency regulation service” and “a performance payment that reflects the amount of work each resource performs in real-time.”¹⁴ The MMU protested that the Commission should not approve PJM’s filing until PJM completed and filed undeveloped aspects of its proposal.¹⁵ The MMU also protested that PJM’s proposal fails to reflect the incremental cost of providing capability (AReg MW) or the true lost opportunity cost of capability, and, consequently, fails to eliminate the need for after-market make whole payments even if actual real-time opportunity costs are used. On April 19, 2012, the Commission issued an order approving PJM’s scarcity proposal, which the MMU had also protested.¹⁶ An order on PJM’s Order No. 755 compliance proposal is currently pending at the Commission.

Overall, the MMU concludes that the Regulation Market results were not competitive in January through March 2012 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

¹⁰ See 2011 State of the Market Report for PJM, “Appendix F.”

¹¹ *Frequency Regulation Compensation in the Organized Wholesale Power Markets*, 137 FERC ¶ 61,064 (2011) (“Order No. 755”).

¹² PJM filing in Docket No. ER12-1204.

¹³ *Wholesale Competition in Regions with Organized Markets*, Order No. 719, 125 FERC ¶ 61,071 (2008), *order on reh’g*, Order No. 719-A, 128 FERC ¶ 61,059 (2009).

¹⁴ Order No. 755 at PP 197–199.

¹⁵ Protest of the Independent Market Monitor for PJM filed in Docket No. ER12-1204 (March 26, 2012); Answer and Motion for Leave to Answer of the Independent Market Monitor for PJM filed in Docket No. ER12-1204 (April 25, 2012).

¹⁶ 139 FERC ¶ 61,057.

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 January through March 2012. The MMU concludes that the DASR Market results were competitive in January through March 2012.

Regulation Market

The PJM Regulation Market in January through March 2012 continued to be operated as a single market. There have been no structural changes since December 1, 2008.¹⁷

Market Structure

Supply

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. The average hourly regulation capability increased in January through March of 2012, to 9,257 MW from 7,847 MW in the same time period of 2011, primarily as a result of the integration of two new areas into PJM.

Table 9-5 PJM regulation capability, daily offer¹⁸ and hourly eligible: January through March 2012 (See 2011 SOM, Table 9-5)¹⁹

Period	Regulation Capability (MW)	Average Daily Offer (MW)	Percent of Capability Offered	Average Hourly Eligible (MW)	Percent of Capability Eligible
All Hours	9,257	6,878	74%	3,209	35%
Off Peak	9,257			3,032	33%
On Peak	9,257			3,405	37%

The supply of regulation can be impacted by regulating units retiring from service. Table 9-6 shows the impact on the Regulation Market if all units requesting retirement retire through the end of 2015.

Table 9-6 Impact on PJM Regulation Market of currently regulating units scheduled to retire through 2015 (New Table)

Current Regulation Units, Jan-Mar, 2012	Settled MWh, January through March 2012	Units Scheduled To Retire Through 2015	Settled MWh of Units Scheduled To Retire Through 2015	Percent Of January through March, 2012 Regulation MWh Scheduled To Retire Through 2015
225	2,763,249	35	39,390	1.4%

Demand

Demand for regulation does not change with price. The regulation requirement is set by PJM in accordance with NERC control standards, based on reliability objectives and forecast load. 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. Table 9-7 shows the required regulation and its relationship to the supply of regulation.

Table 9-7 PJM Regulation Market required MW and ratio of eligible supply to requirement: January through March 2012 and 2011 (See 2011 SOM, Table 9-6)

Month	Average Required Regulation (MW), Q1 2011	Average Required Regulation (MW), Q1 2012	Ratio of Supply To Requirement, Q1 2011	Ratio of Supply To Requirement, Q1 2012
Jan	960	1,006	3.19	3.35
Feb	897	978	3.06	3.51
Mar	823	875	3.01	3.35
Off Peak	830	883	3.18	3.49
On Peak	964	1,030	3.03	3.31

Market Concentration

Table 9-8 shows Herfindahl-Hirschman Index (HHI) results for the January through March 2012 period. The average HHI of 1611 is classified as “moderately concentrated.”

¹⁷ 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.”

¹⁸ Average Daily Offer MW exclude units that have offers but make themselves unavailable for the day.

¹⁹ Total offer capability is defined as the sum of the maximum daily offer volume for each offering unit during the period, without regard to the actual availability of the resource or to the day on which the maximum was offered.

Table 9-8 PJM cleared regulation HHI: January through March 2012 and 2011 (See 2011 SOM, Table 9-7)

Market Type	Load-weighted		
	Minimum HHI	Average HHI	Maximum HHI
Cleared Regulation, January through March, 2012	814	1611	4429
Cleared Regulation, January through March, 2011	916	1785	3550

Figure 9-1 compares the January through March 2012 HHI distribution curve with distribution curves for the same period of 2011 and 2010.

Figure 9-1 PJM Regulation Market HHI distribution: January through March of 2010, 2011 and 2012 (See 2011 SOM, Figure 9-1)

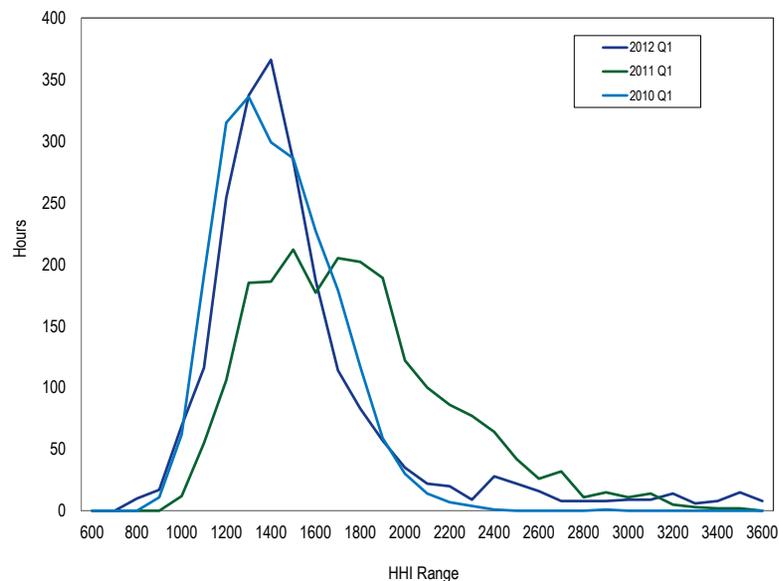


Table 9-9 includes a monthly summary of three pivotal supplier results. In January through March 2012, 67 percent of hours had one or more pivotal suppliers which failed PJM’s three pivotal supplier test. The MMU concludes from these results that the PJM Regulation Market in January through March 2012 was characterized by structural market power in 67 percent of the hours.

Table 9-9 Regulation market monthly three pivotal supplier results: January through March 2010, 2011 and 2012 (See 2011 SOM, Table 9-9)

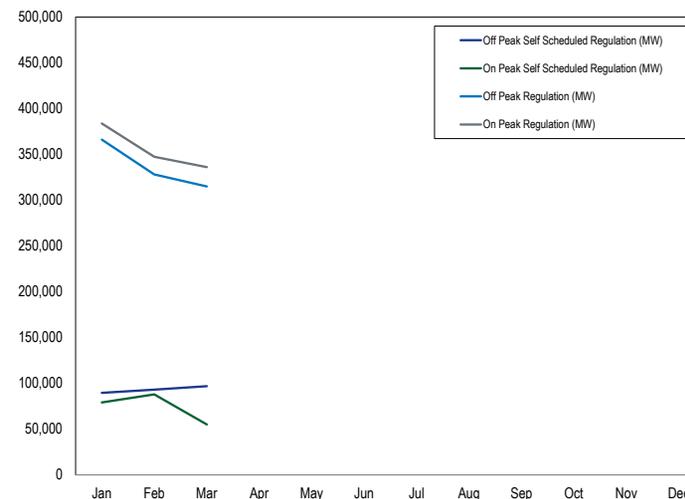
Month	2012		2011		2010	
	Percent of Hours Pivotal	Percent of Hours When Marginal Supplier is Pivotal	Percent of Hours Pivotal	Percent of Hours When Marginal Supplier is Pivotal	Percent of Hours Pivotal	Percent of Hours When Marginal Supplier is Pivotal
Jan	71%	60%	95%	88%	74%	67%
Feb	67%	60%	93%	87%	70%	58%
Mar	64%	52%	94%	89%	83%	73%

Market Conduct

Offers

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 providers bilaterally, or self-schedule regulation to satisfy their obligation (Figure 9-2).²⁰

Figure 9-2 Off peak and on peak regulation levels: January through March 2012 (See 2011 SOM, Figure 9-2)



²⁰ See PJM “Manual 28: Operating Agreement Accounting,” Revision 50, (January 1, 2012); para 4.2, pp 14-15.

Increased self scheduled regulation lowers the requirement for cleared regulation, resulting in fewer MW cleared in the market and lower clearing prices. Of the LSEs' obligation to provide regulation during January through March 2012, 74 percent was purchased in the spot market (79 percent in January through March 2011), 23 percent was self scheduled (18 percent in January through March 2011), and 3 percent was purchased bilaterally (3 percent in January through March 2011). (Table 9-10.)

Table 9-10 Regulation sources: spot market, self-scheduled, bilateral purchases: January through March 2012 (See 2011 SOM, Table 9-10)

Month	Spot Regulation (MW)	Self Scheduled Regulation (MW)	Bilateral Regulation (MW)	Total Regulation (MW)
Jan	553,686	164,806	21,261	739,753
Feb	480,989	175,757	20,456	677,202
Mar	426,032	122,444	17,464	565,940

Demand resources offered and cleared regulation for the first time in November 2011. Since they do not offer energy, demand resources self schedule rather than offer into the market.²¹ The impact of demand response on the Regulation Market has been negligible.

Market Performance

Price

The weighted average regulation market clearing price for January through March, 2012 was \$12.64. 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 the higher of the clearing price, or the unit's regulation offer plus the individual unit's real-time opportunity cost, based on actual LMP.²²

The weighted average offer (excluding opportunity cost) of the marginal unit for the PJM Regulation Market during January through March 2012

was \$9.60 per MWh, an increase from the weighted average offer in January through March 2011 of \$8.81. The weighted average opportunity cost of the marginal unit for the PJM Regulation Market in January through March 2012 was \$2.72. In the PJM Regulation Market the marginal unit opportunity cost averaged 22 percent of the RMCP. This is a small increase from the January through March 2011 level of 19 percent.

Figure 9-3 PJM Regulation Market daily weighted average market-clearing price, marginal unit opportunity cost and offer price (Dollars per MWh): January through March 2012 (See 2011 SOM, Figure 9-3)

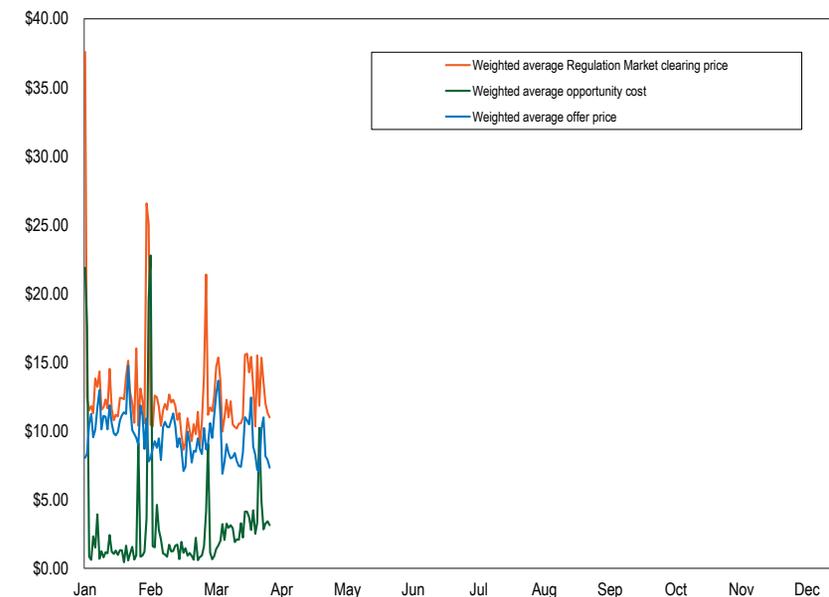


Figure 9-4 shows the level of demand for regulation by month in January through March 2012 and the corresponding level of regulation price.

²¹ The reason for this is that SPREGO might otherwise schedule them for energy which they cannot provide.

²² 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 actual opportunity cost to compensate generators that provide regulation and synchronized reserve.

Figure 9-4 Monthly average regulation demand and price: January through March 2012 (See 2011 SOM, Figure 9-4)

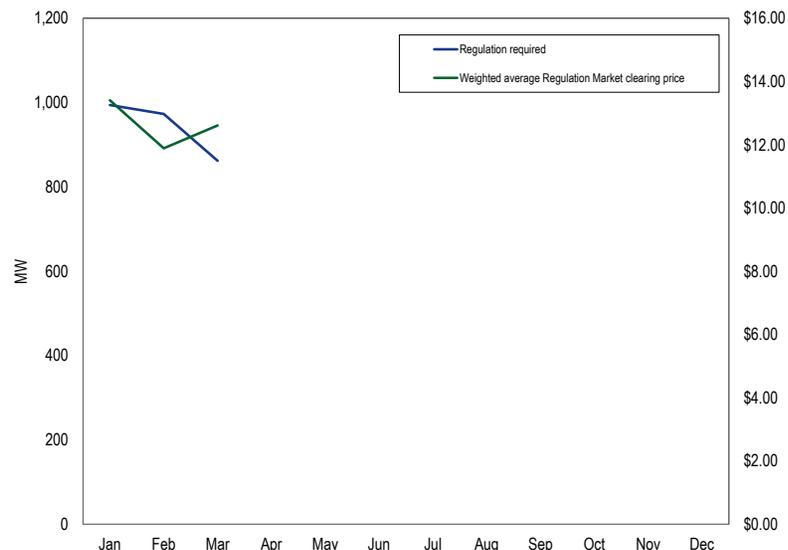
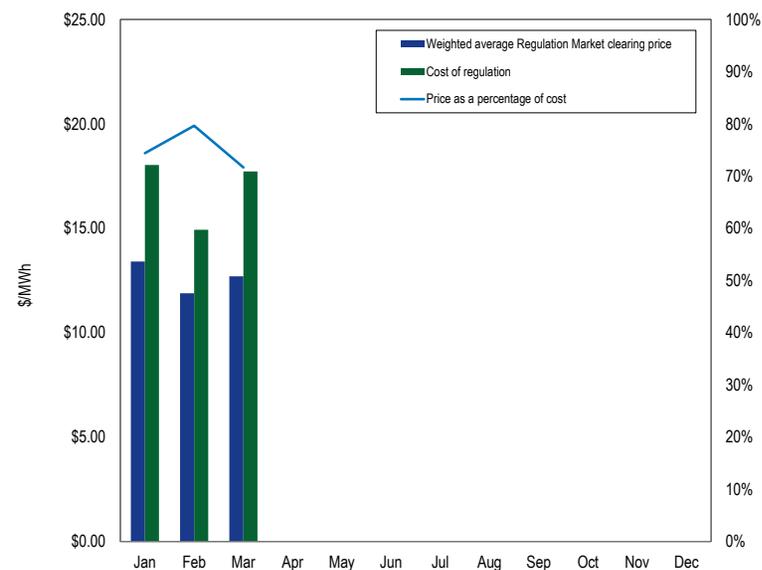


Figure 9-5 compares the regulation total cost per MWh (clearing price plus post market opportunity costs) with the regulation clearing price.

Figure 9-5 Monthly weighted, average regulation cost and price: January through March 2012 (See 2011 SOM, Figure 9-5)



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

Table 9-11 Total regulation charges: January through March 2012 (See 2011 SOM, Table 9-11)

Month	Scheduled Regulation (MWh)	Total Regulation Charges	Simple Average Regulation Market Clearing Price	Weighted Average Regulation Market Price	Cost of Regulation
Jan	739,753	\$13,338,201	\$13.70	\$13.41	\$18.03
Feb	677,202	\$10,107,959	\$12.09	\$11.89	\$14.93
Mar	641,655	\$11,109,763	\$12.54	\$12.61	\$17.31

Table 9-12 provides a comparison of the weighted annual price and cost for PJM Regulation. The difference between the Regulation Market price and the actual cost of regulation was less in January through March 2012 than it was in the same period of 2011.

Table 9-12 Comparison of weighted price and cost for PJM Regulation, August 2005 through March 2012²³ (See 2011 SOM, Table 9-12)

Year	Simple Average Regulation Market Price	Weighted Average Regulation Market Price	Regulation Cost	Regulation Price as a Percentage of Cost
2005	\$59.60	\$64.03	\$77.39	83%
2006	\$27.02	\$32.69	\$44.98	73%
2007	\$31.87	\$36.86	\$52.91	70%
2008	\$27.61	\$42.09	\$64.43	65%
2009	\$22.28	\$23.56	\$29.87	79%
2010	\$18.09	\$18.05	\$30.67	59%
2011	\$11.69	\$11.51	\$24.83	46%
2012	\$12.75	\$12.61	\$16.76	75%

Synchronized Reserve Market

PJM continued to operate the two synchronized reserve markets it implemented on February 1, 2007. The RFC Synchronized Reserve Zone reliability requirements are set by the ReliabilityFirst 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 resulted in a change to the interface defining the Mid-Atlantic subzone of the RFC Synchronized Reserve Market.²⁴ After the implementation of TrAIL, Bedington – Black Oak became the most limiting interface. PJM reserves the right to revise the interface defining the Mid-Atlantic Subzone in accordance with operational and reliability needs.²⁵ From May 20, 2011, through the end of September the percent of Tier 1 synchronized reserve available west of the interface that is 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. From January through March 2012 the transfer capacity has remained at 15 percent. Synchronized reserves added out of market were 3.9 percent of all synchronized reserves in January through March 2012, up from 1.1 percent in January through March 2011.

²³ 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.

²⁴ PJM.com "TrAIL Operational Impacts," <<http://www.pjm.com/~media/committees-groups/committees/oc/20111018/20111018-item-08-trail-operational-impacts.ashx>> (October 2011).

²⁵ See PJM, "Manual 11, Energy and Ancillary Services Market Operations," Revision 49 (January 1, 2012), p. 67.

After-market opportunity cost payments accounted for 22.2 percent of total costs in January through March 2012 compared to 17.1 percent in January through March 2011.

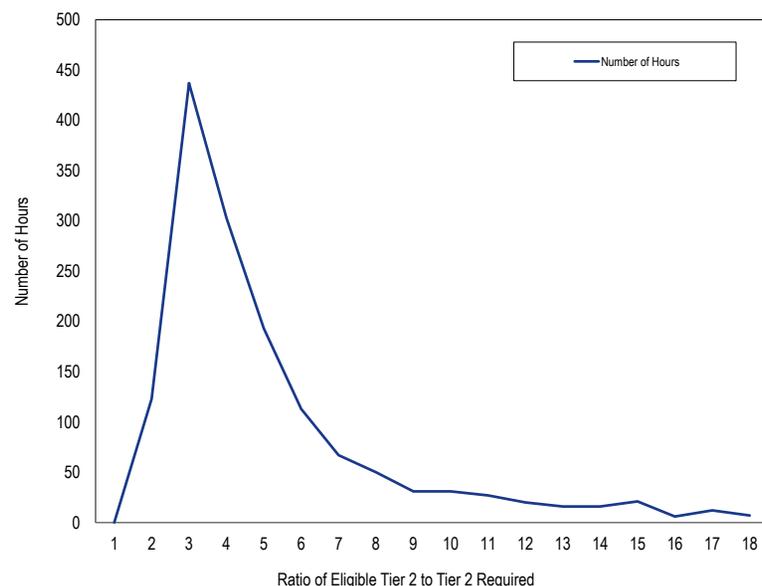
Market Structure

Supply

In January through March 2012 the supply of offered and eligible synchronized reserve was both stable and adequate. The contribution of DSR to the Synchronized Reserve Market remained significant. Demand side resources are relatively low cost, and their participation lowers overall Synchronized Reserve prices. The ratio of offered and eligible synchronized reserve MW to the synchronized reserve required (1,300 MW) was 1.08 for the Mid-Atlantic Subzone.²⁶ 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 January through March 2012 was 3.40 for the Mid-Atlantic Subzone. This is a 10 percent increase from January through March 2011 when the ratio was 3.09. 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. (See Figure 9-6)

²⁶ The Synchronized Reserve Market in the Southern Region cleared in so few hours that related data for that market are not meaningful.

Figure 9-6 Ratio of Eligible Synchronized Reserve to Required Tier 2 for all cleared hours in the Mid-Atlantic Subzone: January through March 2012 (See 2011 SOM, Figure 9-6)



Demand

PJM made no changes to the default hourly required synchronized reserve requirement in January through March 2012.

In January through March 2012, in the Mid-Atlantic Subzone, a Tier 2 synchronized reserve market was cleared in 73 percent of hours compared to 99.9 percent of hours for January through March 2011. In January through March 2012, the average required Tier 2 synchronized reserve (including self scheduled) for all cleared hours was 356 MW. In January through March 2011 the average required Tier 2 synchronized reserve was 742 MW.

Synchronized reserves added out of market were 3.9 percent of all Mid-Atlantic Subzone synchronized reserves in January through March 2012, compared to 1.1 percent in January through March 2011.

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.²⁷

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 January through March 2012. For the Mid-Atlantic Subzone the requirement was 1,300 MW for January through March 2012 (Ref. Table 9-13).

Table 9-13 Synchronized Reserve Market required MW, RFC Zone and Mid-Atlantic Subzone, December 2008 through March 2012 (See 2011 SOM, Table 9-16)

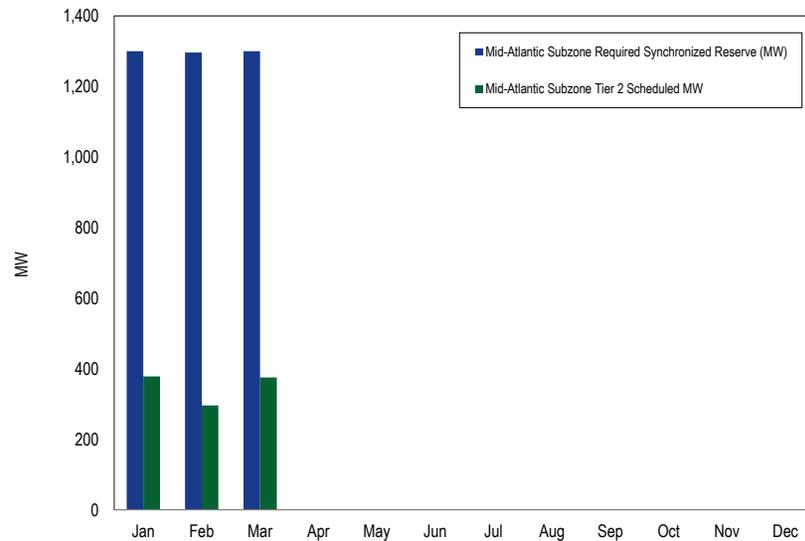
Mid-Atlantic Subzone			RFC Synchronized Reserve Zone		
From Date	To Date	Required MW	From Date	To Date	Required MW
Dec 2008	May 2010	1,150	Dec 2008	Jan 2009	1,305
May 2010	Jul 2010	1,200	Jan 2009	Mar 2010	1,320
Jul 2010	Mar 2012	1,300	Mar 2010	Mar 2012	1,350

Exceptions to this requirement can occur when grid maintenance or outages change the largest contingency. There were no hourly exceptions during January through March 2012. Figure 9-7 shows the average monthly

²⁷ See PJM, "Manual 10: Pre-Scheduling Operations," Revision 25 (January 1, 2010), p. 18.

synchronized reserve required and the average monthly Tier 2 synchronized reserve MW scheduled during January through March 2012 for the RFC Synchronized Reserve Market.

Figure 9-7 Mid-Atlantic Synchronized Reserve Subzone monthly average synchronized reserve required vs. Tier 2 scheduled MW: January through March 2012 (See 2011 SOM, Figure 9-7)

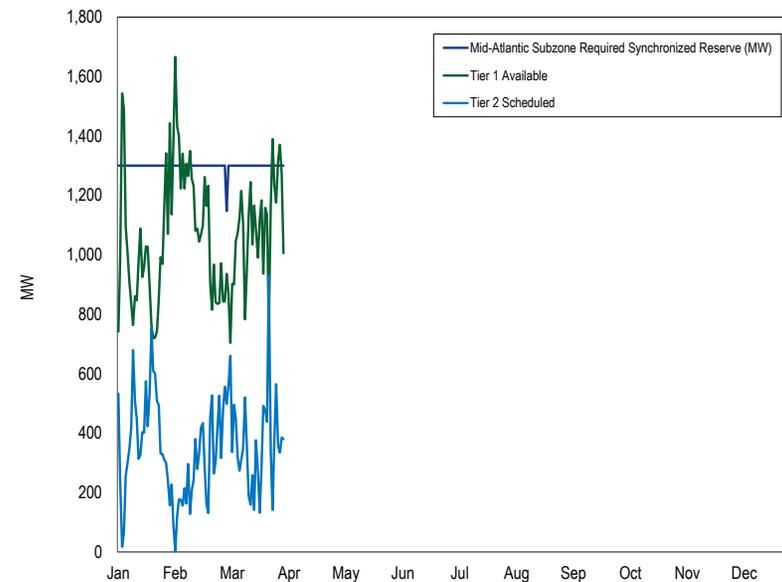


The RFC Synchronized Reserve Zone almost always has enough Tier 1 to cover its synchronized reserve requirement. Available Tier 1 in the western part of the RFC Synchronized Reserve Zone generally exceeds the total synchronized reserve requirement in the west. In January through March 2012, the RFC Synchronized Reserve Zone did not clear a Tier 2 Synchronized Reserve Market in any hour. The Mid-Atlantic Subzone of the RFC Synchronized Reserve Zone cleared a separate Tier 2 market in 73 percent of all hours during January through March 2012. Figure 9-7 compares the required synchronized reserve MW to the scheduled Tier 2 MW for the Mid-Atlantic Subzone.

The actual synchronized reserve requirement for the Mid-Atlantic Subzone for January through March 2012 was always 1,300 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 9-8 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.

Figure 9-8 RFC Synchronized Reserve Zone, Mid-Atlantic Subzone daily average hourly synchronized reserve required, Tier 2 MW scheduled, and Tier 1 MW estimated: January through March 2012 (See 2011 SOM, Figure 9-9)



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.²⁸ The amount of

²⁸ See PJM, "Manual 11: Energy & Ancillary Services Market Operations," Revision 49 (January 1, 2012), p. 66.

15 minute quick start reserve available in VACAR is sufficient to eliminate Tier 2 synchronized reserve demand for most hours. The Southern Synchronized Reserve Zone cleared a Tier 2 market for 26 hours in January through March 2012.

Market Concentration

The RFC Tier 2 Synchronized Reserve Market was less concentrated in January through March 2012 than it had been in the same period of 2011. 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 continued to have a significant impact on the market, resulting in lower prices and less concentration. The HHI for the Mid-Atlantic Subzone of the January through March 2012 RFC cleared Synchronized Reserve Market was 2638, which is defined as “highly concentrated.” The largest hourly market share was 94 percent and 43 percent of all hours had a maximum market share greater than or equal to 40 percent (compared to 46 percent of all hours in January through March 2011).

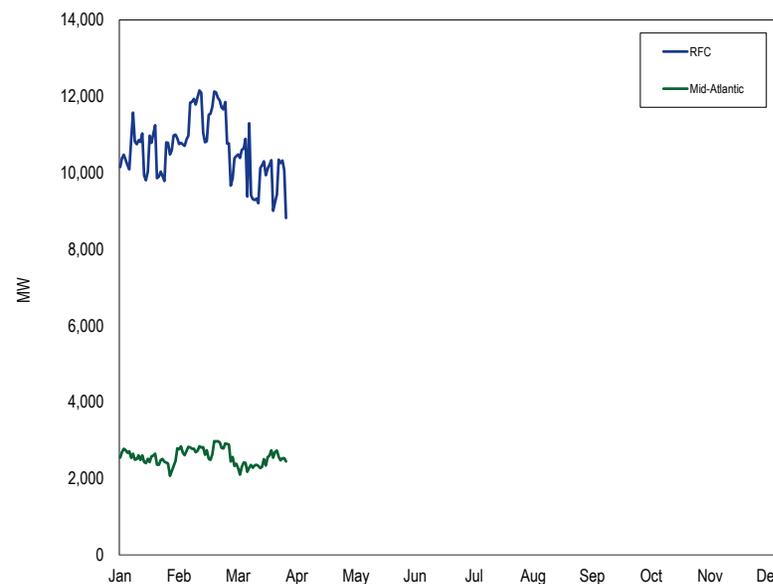
In January through March 2012, 49 percent of hours in the Mid-Atlantic Subzone of the RFC Synchronized Reserve Market failed the three pivotal supplier test. These results indicate that the Mid-Atlantic Subzone of the RFC Synchronized Reserve Market, the only synchronized reserve market that clears on a regular basis, is not structurally competitive.

Market Conduct

Offers

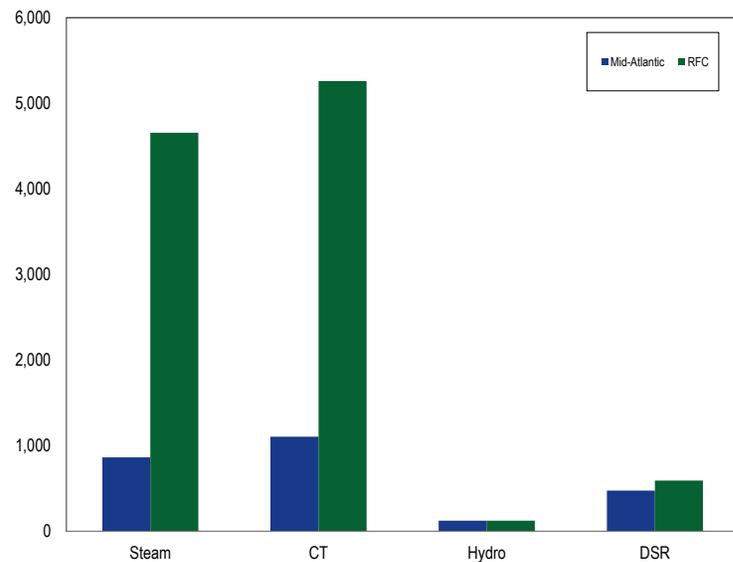
Figure 9-9 shows the daily average hourly offered Tier 2 synchronized reserve MW.

Figure 9-9 Tier 2 synchronized reserve average hourly offer volume (MW): January through March 2012 (See 2011 SOM, Figure 9-10)



Synchronized reserve is offered by steam, CT, hydroelectric and DSR resources. Figure 9-10 shows average offer MW volume by market and unit type.

Figure 9-10 Average daily Tier 2 synchronized reserve offer by unit type (MW): January through March 2012 (See 2011 SOM, Figure 9-11)



DSR

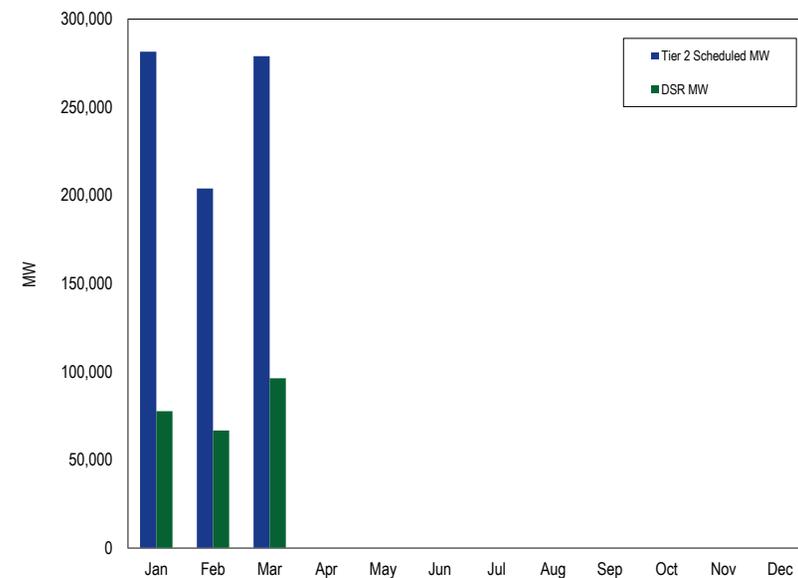
Demand-side resources were permitted to participate in the Synchronized Reserve Markets effective August 2006. DSR continues to have a significant impact on the Synchronized Reserve Market. (Figure 9-10.) In January through March 2012, DSR accounted for 38 percent of all cleared Tier 2 synchronized reserves, compared to 16 percent for the same period in 2011. In 14 percent of hours when a synchronized reserve market was cleared, all cleared MW were DSR compared to one percent in January through March 2011. (See Table 9-14.) In the hours when all supply was DSR, the simple average SRMCP was \$1.63. The simple average SRMCP for all cleared hours was \$4.87 (the simple average SRMCP in January through March 2011 was \$9.76).

Table 9-14 Average RFC SRMCP when all cleared synchronized reserve is DSR, average SRMCP, and percent of all cleared hours that all cleared synchronized reserve is DSR: January through March 2010, 2011, 2012 (See 2011 SOM, Table 9-18)

Year	Month	Weighted Average SRMCP	Weighted Average SRMCP when all cleared synchronized reserve is DSR	Percentage of cleared hours all synchronized reserve is DSR
2010	Jan	\$5.84	\$2.03	4%
2010	Feb	\$5.97	\$0.10	1%
2010	Mar	\$8.45	\$2.03	6%
2011	Jan	\$10.75	\$0.10	0%
2011	Feb	\$10.91	n/a	0%
2011	Mar	\$11.34	\$2.04	2%
2012	Jan	\$6.30	\$1.71	11%
2012	Feb	\$5.47	\$1.78	24%
2012	Mar	\$6.40	\$1.40	6%

Figure 9-11 shows total cleared plus self-scheduled monthly synchronized reserve MW and cleared plus self-scheduled MW for DSR synchronized reserve.

Figure 9-11 PJM RFC Zone Tier 2 synchronized reserve scheduled MW: January through March 2012 (See 2011 SOM, Figure 9-12)



Market Performance

Price

Figure 9-12 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).

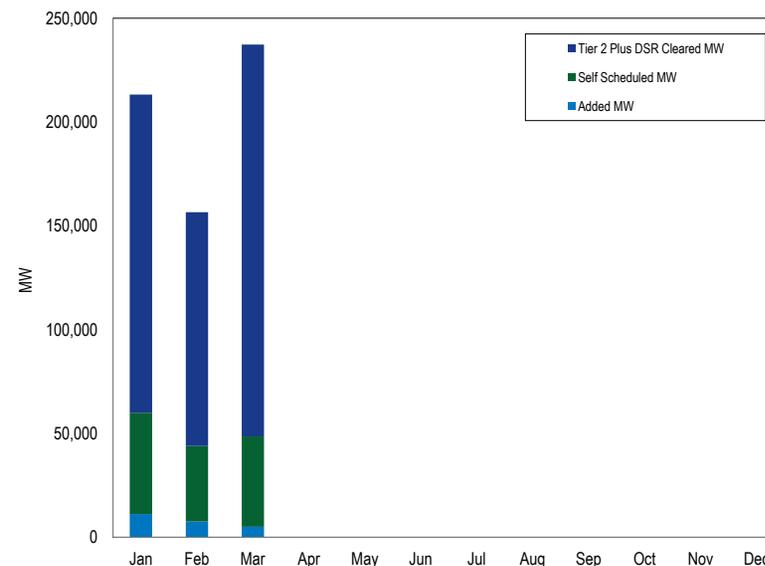
The weighted, average price for synchronized reserve in the PJM Mid-Atlantic Subzone of the RFC Synchronized Reserve Market in January through March 2012 was \$6.06 while the corresponding cost of synchronized reserve was \$7.76.

The RFC Synchronized Reserve requirement was satisfied by Tier 1 in every hour of January through March 2012 so no RFC Synchronized Reserve Market was cleared. The Southern Synchronized Reserve Zone did clear a market in 26 hours of January through March 2012 with a weighted average clearing price of \$11.12.

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. 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. In addition, a low price to cost ratio is in part a result of out of market purchases of Tier 2 synchronized reserve when PJM dispatchers need the reserves for reliability reasons.

Figure 9-12 Tier 2 synchronized reserve purchases by month for the Mid-Atlantic Subzone: January through March 2012 (See 2011 SOM, Figure 9-4)



The difference between the Tier 2 Synchronized Reserve Market price and the cost for Tier 2 synchronized reserve in January through March 2012 was less than in the same period of 2011 (Figure 9-13). In the Mid-Atlantic Subzone of the RFC Synchronized Reserve Market for January through March 2012, the cost of Tier 2 synchronized reserves was 28 percent higher than the weighted price. In January through March 2011 this difference was 21 percent.

Figure 9-13 Impact of Tier 2 synchronized reserve added MW to the RFC Synchronized Reserve Zone, Mid-Atlantic Subzone: January through March 2012 (See 2011 SOM, Figure 9-15)

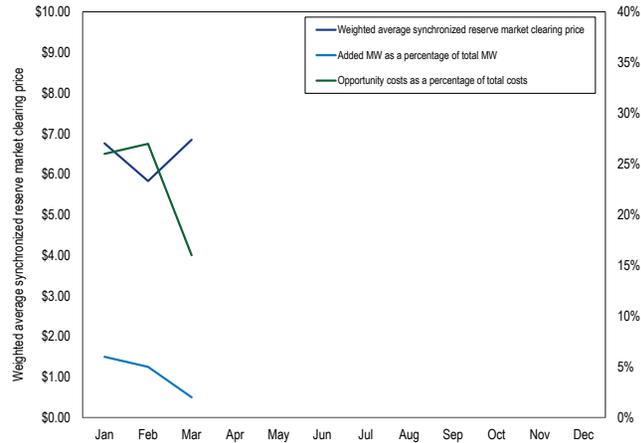


Figure 9-14 Comparison of Mid-Atlantic Subzone Tier 2 synchronized reserve weighted average price and cost (Dollars per MW): January through March 2012 (See 2011 SOM, Figure 9-16)

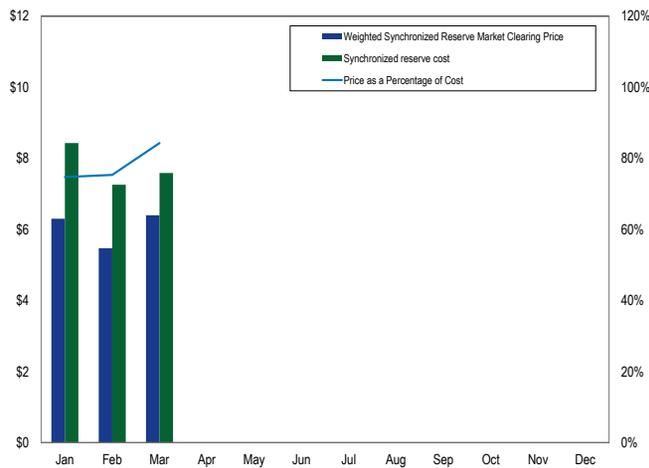


Table 9-15 shows the price and cost history of the Synchronized Reserve Market since 2005.

Table 9-15 Comparison of weighted average price and cost for PJM Synchronized Reserve, January through March, 2005 through 2012 (See 2011 SOM, Table 9-19)

Year	Load Weighted Synchronized Reserve Market Price	Load Weighted Synchronized Reserve Cost	Synchronized Reserve Price as Percent of Cost
2005	\$13.29	\$17.59	76%
2006	\$14.57	\$21.65	67%
2007	\$11.22	\$16.26	69%
2008	\$10.65	\$16.43	65%
2009	\$7.75	\$9.77	79%
2010	\$10.55	\$14.41	73%
2011	\$10.96	\$13.22	83%
2012	\$6.06	\$7.76	78%

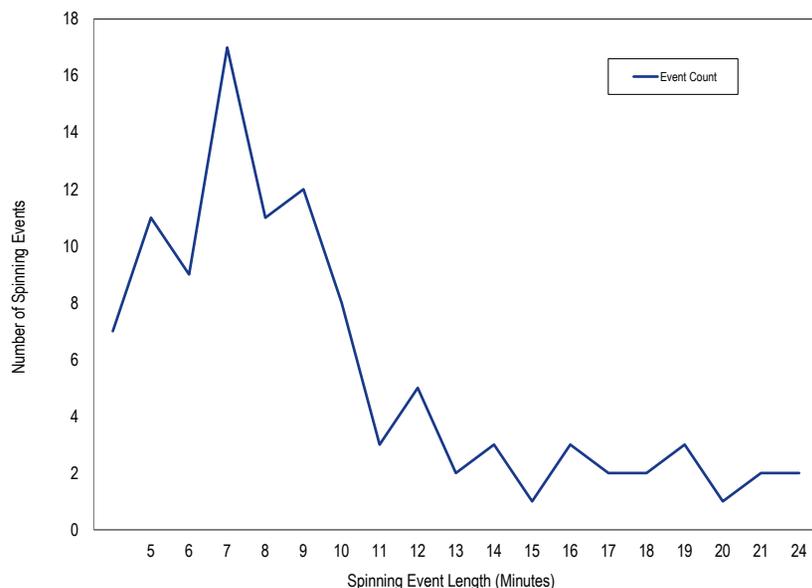
Spinning events (Table 9-16) are usually caused by a sudden generation outage or transmission disruption requiring PJM to load primary synchronized reserve (spinning reserve).²⁹ The reserve remains loaded until system balance is recovered. From January 2009 through March 2012 PJM experienced 109 spinning events. This is almost three 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.

²⁹ See PJM, "Manual 12, Balancing Operations," Revision 23 (November 16, 2011), pp. 34-35.

Table 9-16 Spinning Events, January 2009 through March 2012 (See 2011 SOM, Table 9-20)

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	FEB-09-2011 11:40	Mid-Atlantic	16
JAN-20-2009 17:33	RFC	10	MAR-18-2010 11:02	RFC	27	FEB-13-2011 15:35	Mid-Atlantic	14
JAN-21-2009 11:52	RFC	9	MAR-23-2010 20:14	RFC	13	FEB-24-2011 11:35	Mid-Atlantic	14
FEB-18-2009 18:38	Mid-Atlantic	10	APR-11-2010 13:12	RFC	9	FEB-25-2011 14:12	RFC	10
FEB-19-2009 11:01	RFC	6	APR-28-2010 15:09	Mid-Atlantic	8	MAR-30-2011 19:13	RFC	12
FEB-28-2009 06:19	RFC	5	MAY-11-2010 19:57	Mid-Atlantic	9	APR-02-2011 13:13	Mid-Atlantic	11
MAR-03-2009 05:20	Mid-Atlantic	11	MAY-15-2010 03:03	RFC	6	APR-11-2011 00:28	RFC	6
MAR-05-2009 01:30	Mid-Atlantic	43	MAY-28-2010 04:06	Mid-Atlantic	5	APR-16-2011 22:51	RFC	9
MAR-07-2009 23:22	RFC	11	JUN-15-2010 00:46	RFC	34	APR-21-2011 20:02	Mid-Atlantic	6
MAR-23-2009 23:40	Mid-Atlantic	10	JUN-19-2010 23:49	Mid-Atlantic	9	APR-27-2011 01:22	RFC	8
MAR-23-2009 23:42	RFCNonMA	8	JUN-24-2010 00:56	RFC	15	MAY-02-2011 00:05	Mid-Atlantic	21
MAR-24-2009 13:20	Mid-Atlantic	8	JUN-27-2010 19:33	Mid-Atlantic	15	MAY-12-2011 19:39	RFC	9
MAR-25-2009 02:29	RFC	9	JUL-07-2010 15:20	RFC	8	MAY-26-2011 17:17	Mid-Atlantic	20
MAR-26-2009 13:08	RFC	10	JUL-16-2010 20:45	Mid-Atlantic	19	MAY-27-2011 12:51	RFC	6
MAR-26-2009 18:30	Mid-Atlantic	20	AUG-11-2010 19:09	RFC	17	MAY-29-2011 09:04	RFC	7
APR-24-2009 16:43	RFC	11	AUG-13-2010 23:19	RFC	6	MAY-31-2011 16:36	RFC	27
APR-26-2009 03:04	Mid-Atlantic	5	AUG-16-2010 07:08	RFC	17	JUN-03-2011 14:23	RFC	7
MAY-03-2009 15:07	RFC	10	AUG-16-2010 19:39	Mid-Atlantic	11	JUN-06-2011 22:02	Mid-Atlantic	9
MAY-17-2009 07:41	RFC	5	SEP-15-2010 11:20	RFC	13	JUN-23-2011 23:26	RFC	8
MAY-21-2009 21:37	RFC	13	SEP-22-2010 15:28	Mid-Atlantic	24	JUN-26-2011 22:03	Mid-Atlantic	10
JUN-18-2009 17:39	RFC	12	OCT-05-2010 17:20	RFC	10	JUL-10-2011 11:20	RFC	10
JUN-30-2009 00:17	Mid-Atlantic	8	OCT-16-2010 03:22	Mid-Atlantic	10	JUL-28-2011 18:49	RFC	12
JUL-26-2009 19:07	RFC	18	OCT-16-2010 03:25	RFCNonMA	7	AUG-02-2011 01:08	RFC	6
JUL-31-2009 02:01	RFC	6	OCT-27-2010 10:35	RFC	7	AUG-18-2011 06:45	Mid-Atlantic	6
AUG-15-2009 21:07	RFC	17	OCT-27-2010 12:50	Mid-Atlantic	10	AUG-19-2011 14:49	RFC	5
SEP-08-2009 10:12	Mid-Atlantic	8	NOV-26-2010 14:24	RFC	13	AUG-23-2011 17:52	RFC	7
SEP-29-2009 16:20	RFC	7	NOV-27-2010 11:34	RFC	8	SEP-24-2011 15:48	RFC	8
OCT-01-2009 10:13	RFC	11	DEC-08-2010 01:19	RFC	11	SEP-27-2011 14:20	RFC	7
OCT-18-2009 22:40	Mid-Atlantic	8	DEC-09-2010 20:07	RFC	5	SEP-27-2011 16:47	RFC	9
OCT-26-2009 01:01	RFC	7	DEC-14-2010 12:02	Mid-Atlantic	24	OCT-30-2011 22:39	Mid-Atlantic	10
OCT-26-2009 11:05	RFC	13	DEC-16-2010 18:40	Mid-Atlantic	20	DEC-15-2011 14:35	Mid-Atlantic	8
OCT-26-2009 19:55	RFC	8	DEC-17-2010 22:09	Mid-Atlantic	6	DEC-21-2011 14:26	RFC	18
NOV-20-2009 15:30	RFC	8	DEC-29-2010 19:01	Mid-Atlantic	15	JAN-03-2012 16:51	RFC	9
DEC-09-2009 22:34	Mid-Atlantic	34	JAN-11-2011 15:10	Mid-Atlantic	6	JAN-06-2012 23:25	RFC	8
DEC-09-2009 22:37	RFCNonMA	31	FEB-02-2011 01:21	RFC	5	JAN-23-2012 15:02	Mid-Atlantic	8
DEC-14-2009 11:11	Mid-Atlantic	8	FEB-08-2011 22:41	Mid-Atlantic	11	MAR-02-2012 19:54	RFC	9

Figure 9–15 Spinning events duration distribution curve, January 2009 through March 2012 (See 2011 SOM, Figure 9–17)



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 January through March 2012.

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.³⁰

The DASR 30-minute reserve requirements are determined by the reliability region.³¹ In the Reliability *First* (RFC) region, reserve requirements are calculated based on historical under-forecasted load rates and generator forced outage rates.³² If the DASR Market does not result in procuring adequate scheduling reserves, PJM is required to schedule additional operating reserves.

Market Structure

In January through March 2012, the required DASR was 7.03 percent of peak load forecast, up from 7.11 percent in 2011.³³ DASR MW purchased increased by 9 percent in January through March 2012 over the same period in 2011, from 13.3 MW to 14.5 MW.

In January through March 2012, zero hours failed the three pivotal supplier test. Zero hours failed the pivotal supplier test during the same period in 2011.

Load response resources which are registered in PJM's Economic Load Response and are dispatchable by PJM are also eligible to provide DASR, but remained insignificant. No demand side resources cleared the DASR market in January through March 2012.

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, but any offer price will satisfy the requirement.³⁴ Units that do not offer have their offers set to \$0/MW.

Economic withholding remains an issue in the DASR Market. The marginal cost of providing DASR is zero. Between January and March 2012, twelve percent of all units offered DASR at levels above \$5. The impact on DASR prices of high offers was minor as a result of a favorable balance between supply and demand.

³¹ PJM. "Manual 13, Emergency Requirements," Revision 47 (January 1, 2012), pp. 11–12.

³² PJM. "Manual 10, Pre-Scheduling Operations," Revision 25 (January 1, 2010), p. 17.

³³ See the *2011 State of the Market Report for PJM*, Volume II, Section 9, "Ancillary Services" at Day Ahead Scheduling Reserve (DASR).

³⁴ PJM. "Manual 11, Emergency and Ancillary Services Operations," Revision 49 (January 1, 2012), p. 122.

³⁰ PJM uses the terms "supplemental operating reserves" and "scheduling operating reserves" interchangeably.

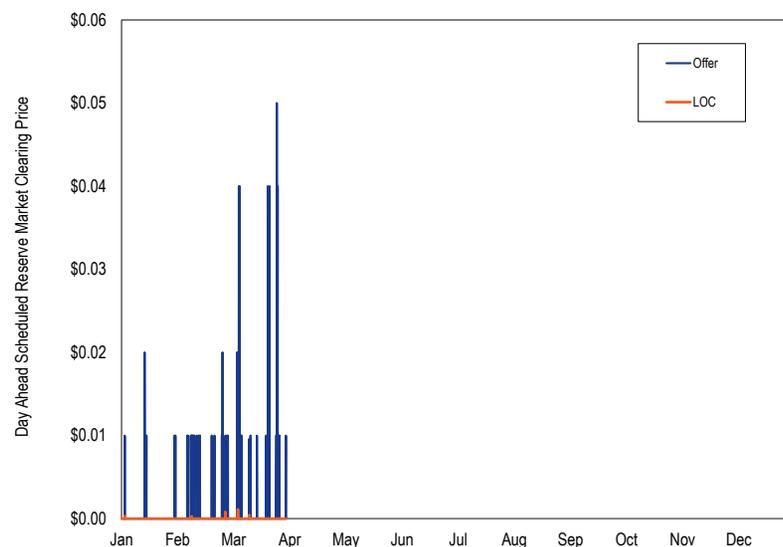
Market Performance

For 96 percent of hours in January through March 2012 DASR cleared at a price of \$0.00. Redispatch was required in only six hours (Figure 9-16).

Table 9-17 PJM Day-Ahead Scheduling Reserve Market MW and clearing prices: January through March 2011 and 2012 (See 2011 SOM, Table 9-21)

Year	Month	Average Required Hourly DASR (MW)	Minimum Clearing Price	Maximum Clearing Price	Weighted Average Clearing Price	Total DASR MW Purchased	Total DASR Credits
2011	Jan	6,536	\$0.00	\$1.00	\$0.03	4,862,520	\$127,837
2011	Feb	6,180	\$0.00	\$1.00	\$0.02	4,152,665	\$61,682
2011	Mar	5,720	\$0.00	\$1.00	\$0.01	4,249,733	\$45,885
2012	Jan	6,944	\$0.00	\$0.02	\$0.00	5,166,216	\$604
2012	Feb	6,777	\$0.00	\$0.02	\$0.00	4,716,710	\$2,037
2012	Mar	6,180	\$0.00	\$0.05	\$0.00	4,591,937	\$5,031

Figure 9-16 Hourly components of DASR clearing price: January through March 2012 (See 2011 SOM, 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 the demonstrated ability of a generating unit with a high operating factor to automatically remain operating at reduced levels when disconnected from the grid.

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.

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 9-18).

In January through March 2012, charges were \$6.11 million. This is 114 percent higher than January through March 2011, when total black start service charges were \$2.86 million. There was substantial zonal variation. Black start zonal charges in January through March 2012 ranged from \$0.02 per MW in the ATSI zone to \$1.90 per MW in the AEP zone.

The increased cost of black start 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 black start resources in the AEP zone that should have been included in black start charges. The black start charges in Table 9-18 for the AEP zone include an estimated \$2.04 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.³⁵

³⁵ See the 2011 State of the Market Report for PJM, Volume II, Section 3, "Operating Reserves."

Table 9-18 Black start yearly zonal charges for network transmission use: January through March 2012³⁶ (See 2011 SOM, Table 9-22)

ZONE	Network Charges	Black Start Rate (\$/MW)
AECO	\$138,751	\$0.51
AEP	\$2,194,032	\$1.90
AP	\$38,529	\$0.05
ATSI	\$19,569	\$0.02
BGE	\$769,776	\$1.17
ComEd	\$1,042,565	\$0.48
DAY	\$39,302	\$0.12
DEOK	\$58,378	\$0.11
DLCO	\$9,621	\$0.04
DPL	\$126,172	\$0.33
JCPL	\$127,840	\$0.21
Met-Ed	\$128,016	\$0.45
PECO	\$299,284	\$0.37
PENELEC	\$86,707	\$0.31
Pepco	\$85,278	\$0.13
PPL	\$34,983	\$0.05
PSEG	\$911,492	\$0.92

³⁶ Network charges for the AEP Zone include an additional \$2.06M that is accounted as operating reserves by PJM but incurred for the purpose of satisfying the black start requirement. This allocation was not included in the black start rates reported for the first quarter of 2011.

