Capacity Market

Each organization serving PJM load must meet its capacity obligations through the PJM Capacity Market, where load serving entities (LSEs) must pay the locational capacity price for their zone. LSEs can also construct generation and offer it into the capacity market, enter into bilateral contracts, develop demand-side resources and Energy Efficiency (EE) resources and offer them into the capacity market, or construct transmission upgrades and offer them into the capacity market.

The Market Monitoring Unit (MMU) analyzed market structure, participant conduct and market performance in the PJM Capacity Market for the first nine months of calendar year 2012, including supply, demand, concentration ratios, pivotal suppliers, volumes, prices, outage rates and reliability.[1]

Table 4-1 The Capacity Market results were competitive (See the 2011 SOM, Table 4-1)

Market Element	Evaluation	Market Design
Market Structure: Aggregate Market	Not Competitive	
Market Structure: Local Market	Not Competitive	
Participant Behavior	Competitive	
Market Performance	Competitive	Mixed

- The aggregate market structure was evaluated as not competitive. The entire PJM region failed the preliminary market structure screen (PMSS), which is conducted by the MMU prior to each Base Residual Auction (BRA), for every planning year for which a BRA has been run to date. For almost all auctions held from 2007 to the present, the PJM region failed the Three Pivotal Supplier Test (TPS), which is conducted at the time of the auction.[2]
- The local market structure was evaluated as not competitive. All modeled Locational Deliverability Areas (LDAs) failed the PMSS, which is conducted by the MMU prior to each Base Residual Auction, for every planning year for which a BRA has been run to date. For almost every auction held, all LDAs have failed the TPS test, which is conducted at the time of the auction.[3]
- Participant behavior was evaluated as competitive. Market power mitigation measures were applied when the Capacity Market Seller failed the market power test for the auction, the submitted sell offer exceeded the defined offer cap, and the submitted sell offer, absent mitigation, would increase the market clearing price. Market power mitigation rules were also applied when the Capacity Market Seller submitted a sell offer for a new resource or uprate that was below the Minimum Offer Price Rule (MOPR) threshold.
- Market performance was evaluated as competitive. Although structural market power exists in the Capacity Market, a competitive outcome resulted from the application of market power mitigation rules.
- Market design was evaluated as mixed because while there are many positive features of the Reliability Pricing Model (RPM) design, there are several features of the RPM design which threaten competitive outcomes. These include the 2.5 percent reduction in demand in Base Residual Auctions and the definition of DR which permits inferior products to substitute for capacity.

Highlights

- During the period January 1, through September 30, 2012, PJM installed capacity increased 4,019.4 MW or 2.2 percent from 178,854.1 MW on January 1 to 182,873.5 MW on September 30. Installed capacity includes net capacity imports and exports and can vary on a daily basis.
- The 2013/2014 RPM Second Incremental Auction and the 2014/2015 RPM First Incremental Auction were conducted in the third quarter of 2012. In the 2013/2014 RPM Second Incremental Auction, the rest of RTO clearing price was $7.01 per MW-day. In the 2014/2015 RPM First Incremental Auction, the rest of RTO clearing price for Annual and Extended Summer Resources was $5.54 per MW-day.

1 The values stated in this report for the RTO and LDAs refer to the aggregate level including all nested LDAs unless otherwise specified. For example, RTO values include the entire PJM market and all LDAs. Rest of RTO values are RTO values net of nested LDA values.
2 In the 2008/2009 RPM Third Incremental Auction, 18 participants in the RTO market passed the TPS test.
3 In the 2012/2013 RPM Base Residual Auction, six participants included in the incremental supply of EMAAC passed the TPS test. In the 2014/2015 RPM Base Residual Auction, seven participants in the incremental supply in MAAC passed the TPS test.

- Capacity in the RPM load management programs was 7,118.5 MW for June 1, 2012 as a result of cleared capacity for Demand Resources and Energy Efficiency Resources in RPM Auctions for the 2012/2013 Delivery Year (9,407.0 MW) less replacement capacity (2,288.5 MW).
- Annual weighted average capacity prices increased from a Capacity Credit Market (CCM) weighted average price of $5.73 per MW-day in 2006 to an RPM weighted-average price of $164.71 per MW-day in 2010 and then declined to $148.33 per MW-day in 2015.
- Combined cycle units ran more often in January through September 2012, than in the same period in 2011, increasing from a 47.1 percent capacity factor in 2011 to a 63.8 percent capacity factor in 2012. Combined cycle units had a higher capacity factor than steam units, for which the capacity factor decreased from 54.0 percent in 2011 to 45.5 percent in January through September 2012.
- The average PJM equivalent demand forced outage rate (EFORd) decreased from 7.6 percent in the first nine months of 2011 to 6.8 percent in the first nine months of 2012.
- The PJM aggregate equivalent availability factor (EAF) increased from 84.9 percent in January through September 2011 to 85.5 percent for the same period in 2012. The equivalent maintenance outage factor (EMOF) increased from 2.8 percent to 3.5 percent, the equivalent planned outage factor (EPOF) decreased from 7.1 percent to 6.3 percent, and the equivalent forced outage factor (EFOF) decreased from 5.3 percent to 4.7 percent (Figure 4-4).

Conclusion

The Capacity Market is, by design, always tight in the sense that total supply is generally only slightly larger than demand. The demand for capacity includes expected peak load plus a reserve margin. Thus, the reliability goal is to have total supply equal to, or slightly above, the demand for capacity. The market may be long at times, but that is not the equilibrium state. Capacity in excess of demand is not sold and, if it does not earn adequate revenues in other markets, will retire. Demand is almost entirely inelastic, because the market rules require loads to purchase their share of the system capacity requirement. The result is that any supplier that owns more capacity than the difference between total supply and the defined demand is pivotal and has market power.

In other words, the market design for capacity leads, almost unavoidably, to structural market power. Given the basic features of market structure in the PJM Capacity Market, including significant market structure issues, inelastic demand, tight supply-demand conditions, the relatively small number of nonaffiliated LSEs and supplier knowledge of aggregate market demand, the MMU concludes that the potential for the exercise of market power continues to be high. Market power is and will remain endemic to the existing structure of the PJM Capacity Market. This is not surprising in that the PJM Capacity Market is the result of a regulatory/administrative decision to require a specified level of reliability and the related decision to require all load serving entities to purchase a share of the capacity required to provide that reliability. It is important to keep these basic facts in mind when designing and evaluating capacity markets. The PJM Capacity Market is unlikely ever to approach a competitive market structure in the absence of a substantial and unlikely structural change that results in much more diversity of ownership.

The analysis of PJM Capacity Markets begins with market structure, which provides the framework for the actual behavior or conduct of market participants. The analysis examines participant behavior within that market structure. In a competitive market structure, market participants are constrained to behave competitively. The analysis examines market performance, measured by price and the relationship between price and marginal cost, that results from the interaction of market structure and participant behavior.

The MMU found serious market structure issues, measured by the three pivotal supplier test results, by market shares and by the Herfindahl-Hirschman Index (HHI), but no exercise of market power in the PJM Capacity Market in the first nine months of 2012. Explicit market power mitigation rules in the RPM construct offset the underlying market structure issues in the PJM Capacity Market under RPM. The PJM Capacity Market results were competitive in the first nine months of 2012.

The MMU has also identified serious market design issues with RPM and the MMU has made specific recommendations to address those issues.[4,5,6,7] In 2011 and 2012, the MMU prepared a number of RPM-related reports and testimony, shown in Table 4-2.

4 See "Analysis of the 2011/2012 RPM Auction Revised" <http://www.monitoringanalytics.com/reports/Reports/2008/20081002-review-of-2011-2012-rpm-auction-revised.pdf> (October 1, 2008).
5 See "Analysis of the 2012/2013 RPM Base Residual Auction" <http://www.monitoringanalytics.com/reports/Reports/2009/Analysis_of_2012_2013_RPM_Base_Residual_Auction_20090806.pdf> (August 6, 2009)
6 See "Analysis of the 2013/2014 RPM Base Residual Auction Revised and Updated" <http://www.monitoringanalytics.com/reports/Reports/2010/Analysis_of_2013_2014_RPM_Base_Residual_Auction_20090920.pdf> (September 20, 2010).
7 See "IMM Response to Maryland PSC re: Reliability Pricing Model and the 2013/2014 Delivery Year Base Residual Auction Results" <http://www.monitoringanalytics.com/reports/Reports/2010/IMM_Response_to_MDPSC_RPM_and_2013-2014_BRA_Results.pdf> (October 4, 2010).

Table 4-2 RPM Related MMU Reports

Date	Name
January 6, 2011	Analysis of the 2011/2012 RPM First Incremental Auction http://www.monitoringanalytics.com/reports/Reports/2011/Analysis_of_2011_2012_RPM_First_Incremental_Auction_20110106.pdf
January 6, 2011	Impact of New Jersey Assembly Bill 3442 on the PJM Capacity Market http://www.monitoringanalytics.com/reports/Reports/2011/NJ_Assembly_3442_Impact_on_PJM_Capacity_Market.pdf
January 14, 2011	Analysis of the 2011/2012 and 2012/2013 ATSI Integration Auctions http://www.monitoringanalytics.com/reports/Reports/2011/Analysis_of_2011_2012_and_2012_2013_ATSI_Integration_Auctions_20110114.pdf
January 28, 2011	Impact of Maryland PSC's Proposed RFP on the PJM Capacity Market http://www.monitoringanalytics.com/reports/Reports/2011/IMM_Comments_to_MDPSC_Case_No_9214_20110128.pdf
February 1, 2011	Preliminary Market Structure Screen results for the 2014/2015 RPM Base Residual Auction http://www.monitoringanalytics.com/reports/Reports/2011/PMSS_Results_20142015_20110201.pdf
March 4, 2011	IMM Comments re MOPR Filing Nos. EL11-20, ER11-2875 http://www.monitoringanalytics.com/reports/Reports/2011/IMM_Comments_EL11-20-000_ER11-2875-000_20110304.pdf
March 21, 2011	IMM Answer and Motion for Leave to Answer re: MOPR Filing Nos. EL11-20, ER11-2875 http://www.monitoringanalytics.com/reports/Reports/2011/IMM_Answer_and_Motion_for_Leave_to_Answer_EL11-20-000_ER11-2875-000_20110321.pdf
June 2, 2011	IMM Protest re: PJM Filing in Response to FERC Order Regarding MOPR No. ER11-2875-002 http://www.monitoringanalytics.com/reports/Reports/2011/IMM_Protest_ER11-2875-002.pdf
June 17, 2011	IMM Comments re: In the Matter of the Board's Investigation of Capacity Procurement and Transmission Planning No. EO11050309 http://www.monitoringanalytics.com/reports/Reports/2011/IMM_Comments_NJ_EO_11050309_20110617.pdf
June 27, 2011	Units Subject to RPM Must Offer Obligation http://www.monitoringanalytics.com/reports/Market_Messages/Messages/IMM_Units_Subject_to_RPM_Must_Offer_Obligation_20110627.pdf
August 29, 2011	Post Technical Conference Comments re: PJM's Minimum Offer Price Rule Nos. ER11-2875-001, 002, and EL11-20-001 http://www.monitoringanalytics.com/reports/Reports/2011/IMM_Post_Technical_Conference_Comments_ER11-2875_20110829.pdf
September 15, 2011	IMM Motion for Leave to Answer and Answer re: MMU Role in MOPR Review No. ER11-2875-002 http://www.monitoringanalytics.com/reports/Reports/2011/IMM_Motion_for_Leave_to_Answer_and_Answer_ER11-2875-002_20110915.pdf
November 22, 2011	Generator Capacity Resources in PJM Region Subject to "Must Offer" Obligatrion for the 2012/2013, 2013/2014 and 2014/2015 Delivery Years http://www.monitoringanalytics.com/reports/Market_Messages/Messages/RPM_Must_Offer_Obligation_20111123.pdf
January 9, 2012	IMM Comments re:MOPR Compliance No. ER11-2875-003 http://www.monitoringanalytics.com/reports/Reports/2012/IMM_Comments_ER11-2875-003_20120109.pdf
January 20, 2012	IMM Testimony re: Review of the Potential Impact of the Proposed Capacity Additions in the State of Maryland's Joint Petition for Approval of Settlement MD PSC Case No. 9271 http://www.monitoringanalytics.com/reports/Reports/2012/IMM_Testimony_MD_PSC_9271.pdf
January 20, 2012	IMM Comments re: Capacity Procurement RFP MD PSC Case No. 9214 http://www.monitoringanalytics.com/reports/Reports/2012/IMM_Comments_MD_PSC_9214.pdf
February 7, 2012	Preliminary Market Structure Screen results for the 2015/2016 RPM Base Residual Auction http://www.monitoringanalytics.com/reports/Reports/2012/PMSS_Results_20152016_20120207.pdf
February 15, 2012	RPM-ACR and RPM Must Offer Obligation FAQs http://www.monitoringanalytics.com/Tools/docs/RPM-ACR_FAQ_RPM_Must_Offer_Obligation_20120215.pdf
February 17, 2012	IMM Motion for Clarification re: Minimum Offer Price Rule Revision Nos.ER11-2871-000, -001 and -002, EL11-20-000 and -001 http://www.monitoringanalytics.com/reports/Reports/2012/IMM_Motion_for_Clarification_ER11-2875_EL-20_20120217.pdf
April 9, 2012	Analysis of the 2014/2015 RPM Base Residual Auction www.monitoringanalytics.com/reports/Reports/2012/Analysis_of_2014_2015_RPM_Base_Residual_Auction_20120409.pdf
May 1, 2012	IMM Complaint and Request for Fast Track Treatment and Shortened Comment Period re Complaint v. Unnamed Participant No. EL12-63 www.monitoringanalytics.com/report/Report/2012/IMM_Complaint_and_Fast_Track_Treatment_and_Shortened_Comment_Period_EL12-63-000_20120501.pdf
May 17, 2012	IMM Notice of Withdrawal re Complaint v. Unnamed Participant No. EL12-63 http://www.monitoringanalytics.com/reports/Reports/2012/IMM_Notice_of_Withdrawal_EL12-63-000_20120517.pdf
July 3, 2012	Generator Capacity Resources in PJM Region Subject to "Must Offer" Obligatrion for the 2013/2014, 2014/2015 and 2015/2016 Delivery Years http://www.monitoringanalytics.com/reports/Market_Messages/Messages/RPM_Must_Offer_Obligation_20120703.pdf
August 10, 2012	IMM Comments re Capacity Portability AD12-16 http://www.monitoringanalytics.com/reports/Reports/2012/IMM_Comments_AD12-16_20120810.pdf
August 20, 2012	IMM and PJM Capacity White Papers on OPSI Issues http://www.monitoringanalytics.com/reports/Reports/2012/IMM_And_PJM_Capacity_White_Papers_On_OPSI_Issues_20120820.pdf
August 29, 2012	Generation Capacity Resources in PJM Region Subject to RPM Must Offer Obligation for 2013/2014, 2014/2015 and 2015/2016 Delivery Years http://www.monitoringanalytics.com/reports/Market_Messages/Messages/RPM_Must_Offer_Obligation_20120829.pdf

Recommendations

- The MMU recommends that the notification requirement for deactivations be extended from 90 days prior to the date of deactivation to 12 months prior to the date of deactivation and that PJM and the MMU be provided 60 days rather than 30 days to complete their reliability and market power analyses. The MMU also recommends that the notification requirement for deactivations be modified to include required notification of six to twelve months prior to an auction in which the unit will not be offered due to deactivation. The purpose of this deadline is to allow adequate time for potential Capacity Market Sellers to offer new capacity in the auction. The currently proposed related deadline of 120 days prior to an RPM Auction for requesting exemption to the RPM Must Offer Obligation is a step in the right direction.[8] All notification recommendations assume that the generation owner has the required knowledge in the defined time frame.
- The MMU recommends that the performance incentives in the RPM Capacity Market design be strengthened.[9]
- The MMU recommends that generation capacity resources be paid on the basis of whether they produce energy when called upon during any of the hours defined as critical. All revenues should be at risk under the peak hour availability charge.
- The MMU recommends that a unit which is not capable of supplying energy consistent with its day-ahead offer should reflect an appropriate outage rather than indicating its availability to supply energy on an emergency basis.
- The MMU recommends that all generation types face the same performance incentives.
- The MMU recommends elimination of the exception related to lack of gas during the winter period for single-fuel, natural gas-fired units.
- The MMU recommends elimination of the exception related to a unit that runs less than 50 hours during the RPM peak period.
- The MMU recommends that PJM eliminate all Out of Management Control (OMC) outages from use in planning or capacity markets.

Installed Capacity

On January 1, 2012, PJM installed capacity was 178,854.1 MW (Table 4-3).[10] Over the next five months, unit retirements, facility reratings plus import and export shifts resulted in PJM installed capacity of 185,243.3 MW on May 31, 2012, an increase of 6,389.2 MW or 3.6 percent over the January 1 level.[11,12] The 6,389.2 MW increase was the result of the integration of the DEOK Zone (3,560.4 MW), a decrease in exports (2,116.5 MW), new generation (1,392.2 MW), an increase in imports (203.0 MW), and capacity modifications (140.0 MW), offset by deactivations (971.0 MW) and derates (51.9 MW).

At the beginning of the new planning year on June 1, 2012, PJM installed capacity was 185,732.9 MW, an increase of 489.6 MW or 0.3 percent over the May 31 level. On September 30, 2012, PJM installed capacity was 182,873.5 MW.

8 In order to make an offer in a BRA, planned generation must be in a generation queue, have completed a Feasibility Study and have a signed Impact Study Agreement. Planned generation must be in the queue at least six months prior to the month of the BRA, or by October 31 of the calendar year preceding the auction, in order to ensure timely completion of the Feasibility Study and Impact Study Agreement. Given these requirements of the queue process, a notification period of nine months prior to the BRA would be required to allow planned generation time to enter the queue in response to a notice of deactivation.

9 For more details on the reasons for these recommendations, see the IMM's White Paper included in: Monitoring Analytics, LLC and PJM Interconnection, LLC, *"Capacity in the PJM Market,"* <http://www.monitoringanalytics.com/reports/Reports/2012/IMM_And_PJM_Capacity_White_Papers_On_OPSI_Issues_20120820.pdf> (August 20, 2012).

10 Percent values shown in Table 4-3 are based on unrounded, underlying data and may differ from calculations based on the rounded values in the tables.

11 The capacity described in this section is the summer installed capacity rating of all PJM generation capacity resources, as entered into the eRPM system, regardless of whether the capacity cleared in the RPM Auctions.

12 Wind resources accounted for 779.6 MW of installed capacity in PJM on June 30, 2012. This value represents approximately 13 percent of wind nameplate capability in PJM. PJM administratively reduces the capabilities of all wind generators to 13 percent of nameplate capacity when determining the system installed capacity because wind resources cannot be assumed to be available on peak and cannot respond to dispatch requests. As data become available, unforced capability of wind resources will be calculated using actual data. There are additional wind resources not reflected in total capacity because they are energy only resources and do not participate in the PJM Capacity Market.

Table 4-3 PJM installed capacity (By fuel source): January 1, May 31, June 1, and September 30, 2012 (See the 2011 SOM, Table 4-3)

	1-Jan-12		31-May-12		1-Jun-12		30-Sep-12	
	MW	Percent	MW	Percent	MW	Percent	MW	Percent
Coal	75,190.4	42.0%	79,311.0	42.8%	79,664.6	42.9%	76,739.2	42.0%
Gas	50,529.3	28.3%	51,940.1	28.0%	52,709.1	28.4%	51,995.2	28.4%
Hydroelectric	8,047.0	4.5%	8,047.0	4.3%	7,879.8	4.2%	7,879.8	4.3%
Nuclear	32,492.6	18.2%	33,085.0	17.9%	33,149.5	17.8%	33,164.9	18.1%
Oil	11,217.3	6.3%	11,494.7	6.2%	10,767.2	5.8%	11,531.7	6.3%
Solar	15.3	0.0%	16.3	0.0%	47.0	0.0%	47.0	0.0%
Solid waste	705.1	0.4%	689.1	0.4%	736.1	0.4%	736.1	0.4%
Wind	657.1	0.4%	660.1	0.4%	779.6	0.4%	779.6	0.4%
Total	178,854.1	100.0%	185,243.3	100.0%	185,732.9	100.0%	182,873.5	100.0%

RPM Capacity Market

The RPM Capacity Market, implemented June 1, 2007, is a forward-looking, annual, locational market, with a must-offer requirement for Existing Generation Capacity Resources and mandatory participation by load, with performance incentives, that includes clear market power mitigation rules and that permits the direct participation of demand-side resources.

Annual base auctions are held in May for delivery years that are three years in the future. Prior to January 31, 2010, First, Second and Third Incremental RPM Auctions were conducted 23, 13 and four months prior to the delivery year. Effective January 31, 2010, First, Second, and Third Incremental Auctions are conducted 20, 10, and three months prior to the delivery year.[13]

Market Structure

Supply

Table 4-4 shows generation capacity additions since the implementation of the Reliability Pricing Model. New generation capacity resources (13,809.3 MW), reactivated generation capacity resources (858.7 MW), uprates to existing generation capacity resources (5,957.0 MW), and the net increase in capacity imports (6,754.6 MW) totals 27,379.6 MW since the implementation of the Reliability Pricing Model.

13 See *PJM Interconnection, L.L.C.*, Letter Order in Docket No. ER10-366-000 (January 22, 2010).

In the 2013/2014 RPM Second Incremental Auction, 1,996.7 MW cleared of the 6,072.9 MW of participant sell offers. In the 2014/2015 RPM First Incremental Auction, 79.4 MW cleared of the 1,508.2 MW cleared of participant sell offers for Limited Resources, 29.0 MW cleared of the 446.5 MW of participant sell offers for Extended Summer Resources, and 4,131.4 MW cleared of the 9,171.6 MW of participant sell offers for Annual Resources.

Table 4-4 RPM generation capacity additions: 2007/2008 through 2015/2016[14] (See 2011 SOM, Table 4-5)

	ICAP (MW)				
Delivery Year	New Generation Capacity Resources	Reactivated Generation Capacity Resources	Uprates to Existing Generation Capacity Resources	Net Increase in Capacity Imports	Total
2007/2008	19.0	47.0	536.0	1,576.6	2,178.6
2008/2009	145.1	131.0	438.1	107.7	821.9
2009/2010	476.3	0.0	793.3	105.0	1,374.6
2010/2011	1,031.5	170.7	876.3	24.1	2,102.6
2011/2012	2,332.5	501.0	896.8	672.6	4,402.9
2012/2013	901.5	0.0	946.6	676.8	2,524.9
2013/2014	1,080.2	0.0	418.2	963.3	2,461.7
2014/2015	1,102.8	9.0	482.5	818.9	2,413.2
2015/2016	6,720.4	0.0	569.2	1,809.6	9,099.2
Total	13,809.3	858.7	5,957.0	6,754.6	27,379.6

Demand

In the 2013/2014 RPM Second Incremental Auction, 5,598.8 MW cleared of the 16,385.8 MW of participant buy bids. In the 2014/2015 RPM First Incremental Auction, 2,781.8 MW cleared of the 4,437.2 MW of participant buy bids for Limited Resources, 116.6 MW cleared of the 943.0 MW of participant buy bids for Extended Summer Resources, and 3,951.4 MW cleared of the 7,850.9 MW of participant buy bids for Annual Resources. Participant buy bids are submitted to cover commitment and compliance shortfalls or because participants wanted to purchase additional capacity.

14 The value for the 2014/2015 net increase in capacity imports has been updated since the *2012 Quarterly State of the Market Report for PJM: January through June.*

Market Concentration

Auction Market Structure

As shown in Table 4-5, all participants in the total PJM market failed the three pivotal supplier (TPS) market structure test in the 2013/2014 RPM Second Incremental Auction and the 2014/2015 RPM First Incremental Auction.[15] The result was that offer caps were applied to all sell offers for resources which were subject to mitigation when the Capacity Market Seller did not pass the test, the submitted sell offer exceeded the defined offer cap, and the submitted sell offer, absent mitigation, increased the market clearing price.[16,17,18]

Table 4-5 presents the results of the TPS test.

15 The market definition used for the TPS test includes all offers with costs less than or equal to 1.50 times the clearing price. See *MMU Technical Reference for PJM Markets*, at "Three Pivotal Supplier Test" for additional discussion.
16 See OATT Attachment DD § 6.5.
17 Prior to November 1, 2009, existing DR and EE resources were subject to market power mitigation in RPM Auctions. See 129 FERC ¶ 61,081 (2009) at P 30.
18 Effective January 31, 2011, the RPM rules related to market power mitigation were changed, including revising the definition for Planned Generation Capacity Resource and creating a new definition for Existing Generation Capacity Resource for purposes of the must-offer requirement and market power mitigation, and treating a proposed increase in the capability of a Generation Capacity Resource the same in terms of mitigation as a Planned Generation Capacity Resource. See 134 FERC ¶ 61,065 (2011).

Table 4-5 RSI results: 2012/2013 through 2015/2016 RPM Auctions[19] (See the 2011 SOM, Table 4-8)

RPM Markets	$RSI_{1\ 1.05}$	RSI_3	Total Participants	Failed RSI_3 Participants
2012/2013 BRA				
RTO	0.84	0.63	98	98
MAAC/SWMAAC	0.77	0.54	15	15
EMAAC/PSEG	0.00	7.03	6	0
PSEG North	0.00	0.00	2	2
DPL South	0.00	0.00	3	3
2012/2013 ATSI FRR Integration Auction				
RTO	0.34	0.10	16	16
2012/2013 First Incremental Auction				
RTO/MAAC/SWMAAC/PSEG/PSEG North/DPL South	0.40	0.60	25	25
EMAAC	0.40	0.00	2	2
2012/2013 Second Incremental Auction				
RTO/MAAC/SWMAAC/PSEG/PSEG North/DPL South	0.62	0.64	33	33
EMAAC	0.00	0.00	2	2
2012/2013 Third Incremental Auction				
RTO/MAAC/EMAAC/SWMAAC/PSEG/PSEG North/DPL South	0.39	0.28	53	53
2013/2014 BRA				
RTO	0.80	0.59	87	87
MAAC/SWMAAC	0.42	0.23	9	9
EMAAC/PSEG/PSEG North/DPL South	0.25	0.00	2	2
Pepco	0.00	0.00	1	1
2013/2014 First Incremental Auction				
RTO/MAAC	0.24	0.28	33	33
EMAAC/PSEG/PSEG North/DPL South	0.34	0.00	3	3
SWMAAC/Pepco	0.00	0.00	0	0
2013/2014 Second Incremental Auction				
RTO	0.44	0.27	32	32
MAAC/SWMAAC/Pepco	0.00	0.00	0	0
EMAAC/PSEG/PSEG North/DPL South	0.00	0.00	0	0
2014/2015 BRA				
RTO	0.76	0.58	93	93
MAAC/SWMAAC/EMAAC/PSEG/DPL South/Pepco	1.40	1.03	7	0
PSEG North	0.00	0.00	1	1
2014/2015 First Incremental Auction				
RTO	0.45	0.14	36	36
MAAC/SWMAAC/EMAAC/PSEG/DPL South/Pepco	0.00	0.00	1	1
PSEG North	0.00	0.00	1	1
2015/2016 BRA				
RTO	0.75	0.57	99	99
MAAC/EMAAC/SWMAAC/PSEG/PSEG North/DPL South/Pepco	0.49	0.63	12	12
ATSI	0.01	0.00	3	3

19 The RSI shown is the lowest RSI in the market.

Locational Deliverability Areas (LDAs)

Under the PJM Tariff, PJM determines, in advance of each BRA, whether defined Locational Deliverability Areas (LDAs) will be modeled in the auction. Effective with the 2012/2013 delivery year, an LDA will be modeled as a potentially constrained LDA for a delivery year if the Capacity Emergency Transfer Limit (CETL) is less than 1.15 times the Capacity Emergency Transfer Objective (CETO), such LDA had a locational price adder in one or more of the three immediately preceding BRAs, or such LDA is determined by PJM in a preliminary analysis to be likely to have a locational price adder based on historic offer price levels. The rules also provide that starting with the 2012/2013 delivery year, EMAAC, SWMAAC, and MAAC LDAs will be modeled as potentially constrained LDAs regardless of the results of the above three tests.[20] In addition, PJM may establish a constrained LDA even if it does not qualify under the above tests if PJM finds that "such is required to achieve an acceptable level of reliability."[21] A reliability requirement, a Variable Resource Requirement (VRR) curve, a Minimum Annual Resource Requirement, and a Minimum Extended Summer Resource Requirement are established for each modeled LDA.

Locational Deliverability Areas are shown in Figure 4-1 and Figure 4-2.

Figure 4-1 PJM Locational Deliverability Areas (See the 2011 SOM, Figure A-3)

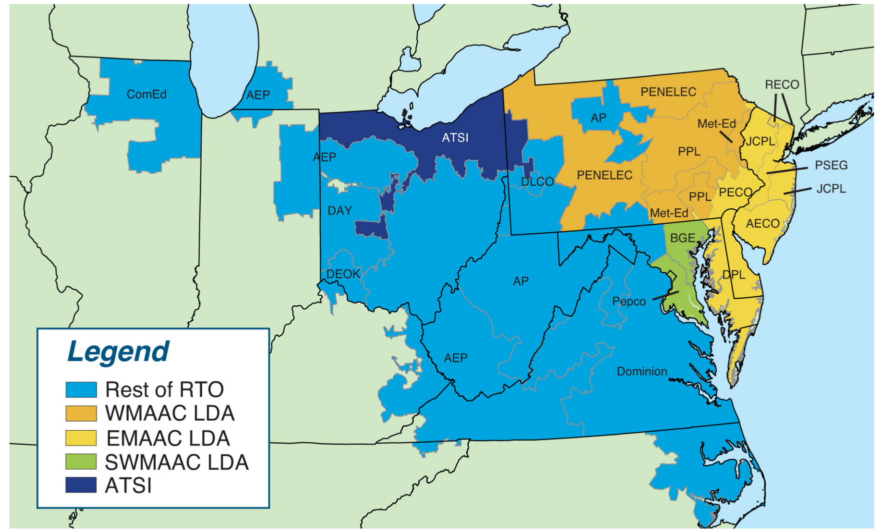
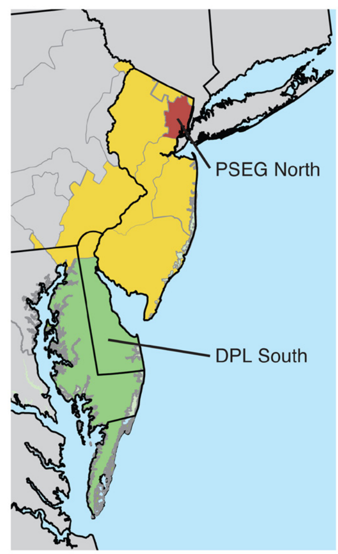


Figure 4-2 PJM RPM EMAAC subzonal LDAs (See the 2011 SOM, Figure A-4)



20 Prior to the 2012/2013 delivery year, an LDA with a CETL less than 1.05 times CETO was modeled as a constrained LDA in RPM. No additional criteria were used in determining modeled LDAs.
21 OATT Attachment DD § 5.10 (a) (ii).

Imports and Exports

Units external to the metered boundaries of PJM can qualify as PJM capacity resources. Generators on the PJM system that do not have a commitment to serve PJM loads in the given delivery year as a result of RPM Auctions, FRR capacity plans, locational UCAP transactions, and/or are not designated as a replacement resource, are eligible to export their capacity outside PJM.[22]

The PJM market rules should not create inappropriate barriers to either the import or export of capacity. The market rules in other balancing authorities should also not create inappropriate barriers to the import or export of capacity. The PJM market rules should ensure that the definition of capacity is enforced including physical deliverability, recallability and the obligation to make competitive offers into the PJM Day-Ahead Energy Market. Physical deliverability is assured by the requirements for firm transmission service. Selling capacity into the PJM capacity market but making energy offers daily of $999 per MWh would not fulfill the requirements of a capacity resource to make a competitive offer, but would constitute economic withholding. This is one of the reasons that the rules governing the obligation to make a competitive offer in the Day-Ahead Energy Market should be clarified for both internal and external resources.

Demand-Side Resources

As shown in Table 4-6 and Table 4-8, capacity in the RPM load management programs was 7,118.5 MW for June 1, 2012 as a result of cleared capacity for Demand Resources and Energy Efficiency Resources in RPM Auctions for the 2012/2013 Delivery Year (9,407.0 MW) less replacement capacity (2,288.5 MW). Table 4-7 shows RPM commitments for DR and EE resources as the result of RPM Auctions prior to adjustments for replacement capacity transactions and certified ILR.

22 OATT Attachment DD § 5.6.6(b).

Table 4-6 RPM load management statistics by LDA: June 1, 2011 to June 1, 2015[23,24] (See the 2011 SOM, Table 4-10)

	UCAP (MW)								
	RTO	MAAC	EMAAC	SWMAAC	DPL South	PSEG	PSEG North	Pepco	ATSI
DR cleared	1,826.6								
EE cleared	76.4								
DR net replacements	(1,052.4)								
EE net replacements	0.2								
ILR	9,032.6								
RPM load management @ 01-Jun-11	9,883.4								
DR cleared	8,740.9	5,193.6	1,971.8	1,794.4	71.0	517.8	97.9		
EE cleared	666.1	253.6	48.1	160.1	0.0	15.9	7.8		
DR net replacements	(2,253.6)	(1,848.6)	(761.5)	(645.5)	(30.6)	(182.9)	10.1		
EE net replacements	(34.9)	(32.4)	(16.2)	(16.5)	0.0	(3.0)	(1.0)		
RPM load management @ 01-Jun-12	7,118.5	3,566.2	1,242.2	1,292.5	40.4	347.8	114.8		
DR cleared	10,458.8	6,297.6	2,702.1	1,788.6	155.4	1,185.0	534.8	661.7	
EE cleared	870.9	269.6	61.3	133.1	6.8	26.2	9.4	56.3	
DR net replacements	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	
EE net replacements	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	
RPM load management @ 01-Jun-13	11,329.7	6,567.2	2,763.4	1,921.7	162.2	1,211.2	544.2	718.0	
DR cleared	14,226.8	7,320.0	2,923.5	2,250.3	220.9	989.5	468.0	908.5	
EE cleared	956.4	276.9	35.2	169.8	8.1	14.9	7.6	51.4	
DR net replacements	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	
EE net replacements	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	
RPM load management @ 01-Jun-14	15,183.2	7,596.9	2,958.7	2,420.1	229.0	1,004.4	475.6	959.9	
DR cleared	14,832.8	6,648.7	2,610.4	2,009.1	86.3	796.1	263.3	867.4	1,763.7
EE cleared	922.5	222.6	42.2	159.4	0.0	10.7	3.1	55.8	44.9
DR net replacements	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
EE net replacements	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
RPM load management @ 01-Jun-15	15,755.3	6,871.3	2,652.6	2,168.5	86.3	806.8	266.4	923.2	1,808.6

23 For delivery years through 2011/2012, certified ILR data were used in the calculation, because the certified ILR data are now available. Effective the 2012/2013 Delivery Year, ILR was eliminated. Starting with the 2012/2013 Delivery Year and also for incremental auctions in the 2011/2012 Delivery Year, the Energy Efficiency (EE) resource type is eligible to be offered in RPM Auctions.

24 The reported DR cleared MW may reflect reductions in the level of committed MW due to relief from Capacity Resource Deficiency Charges. See OATT Attachment DD § 8.4. For the 2012/2013 Delivery Year, relief from charges was granted by PJM for 11.7 MW.

Table 4-7 RPM load management cleared capacity and ILR: 2007/2008 through 2015/2016[25,26,27] (See the 2011 SOM, Table 4-11)

	DR Cleared		EE Cleared		ILR	
Delivery Year	ICAP (MW)	UCAP (MW)	ICAP (MW)	UCAP (MW)	ICAP (MW)	UCAP (MW)
2007/2008	123.5	127.6	0.0	0.0	1,584.6	1,636.3
2008/2009	540.9	559.4	0.0	0.0	3,488.5	3,608.1
2009/2010	864.5	892.9	0.0	0.0	6,273.8	6,481.5
2010/2011	930.9	962.9	0.0	0.0	7,961.3	8,236.4
2011/2012	1,766.0	1,826.6	74.0	76.4	8,730.7	9,032.6
2012/2013	8,429.7	8,740.9	643.4	666.1	0.0	0.0
2013/2014	10,075.3	10,458.8	841.4	870.9	0.0	0.0
2014/2015	13,717.4	14,226.8	923.9	956.4	0.0	0.0
2015/2016	14,303.2	14,832.8	890.8	922.5	0.0	0.0

Table 4-8 RPM load management statistics: June 1, 2007 to June 1, 2015[28,29] (See the 2011 SOM, Table 4-12)

	DR and EE Cleared Plus ILR		DR Net Replacements		EE Net Replacements		Total RPM LM	
	ICAP (MW)	UCAP (MW)	ICAP (MW)	UCAP (MW)	ICAP (MW)	UCAP (MW)	ICAP (MW)	UCAP (MW)
01-Jun-07	1,708.1	1,763.9	0.0	0.0	0.0	0.0	1,708.1	1,763.9
01-Jun-08	4,029.4	4,167.5	(38.7)	(40.0)	0.0	0.0	3,990.7	4,127.5
01-Jun-09	7,138.3	7,374.4	(459.5)	(474.7)	0.0	0.0	6,678.8	6,899.7
01-Jun-10	8,892.2	9,199.3	(499.1)	(516.3)	0.0	0.0	8,393.1	8,683.0
01-Jun-11	10,570.7	10,935.6	(1,017.3)	(1,052.4)	0.2	0.2	9,553.6	9,883.4
01-Jun-12	9,073.1	9,407.0	(2,173.4)	(2,253.6)	(33.7)	(34.9)	6,866.0	7,118.5
01-Jun-13	10,916.7	11,329.7	0.0	0.0	0.0	0.0	10,916.7	11,329.7
01-Jun-14	14,641.3	15,183.2	0.0	0.0	0.0	0.0	14,641.3	15,183.2
01-Jun-15	15,194.0	15,755.3	0.0	0.0	0.0	0.0	15,194.0	15,755.3

Market Conduct

Offer Caps

Market power mitigation measures were applied to Capacity Resources such that the sell offer was set equal to the defined offer cap when the Capacity Market Seller failed the market structure test for the auction, the submitted sell offer exceeded the defined offer cap, and the submitted sell offer, absent mitigation, increased the market clearing price.[30,31,32]

25 For delivery years through 2011/2012, certified ILR data is shown, because the certified ILR data are now available. Effective the 2012/2013 Delivery Year, ILR was eliminated. Starting with the 2012/2013 Delivery Year and also for incremental auctions in the 2011/2012 Delivery Year, the Energy Efficiency (EE) resource type is eligible to be offered in RPM Auctions.

26 FRR committed load management resources are not included in this table.

27 The reported DR cleared MW may reflect reductions in the level of committed MW due to relief from Capacity Resource Deficiency Charges. See OATT Attachment DD § 8.4. For the 2012/2013 Delivery Year, relief from charges was granted by PJM for 11.7 MW.

28 For delivery years through 2011/2012, certified ILR data were used in the calculation, because the certified ILR data are now available. Effective the 2012/2013 Delivery Year, ILR was eliminated. Starting with the 2012/2013 Delivery Year and also for incremental auctions in the 2011/2012 Delivery Year, the Energy Efficiency (EE) resource type is eligible to be offered in RPM Auctions.

29 FRR committed load management resources are not included in this table.

30 See OATT Attachment DD § 6.5.

31 Prior to November 1, 2009, existing DR and EE resources were subject to market power mitigation in RPM Auctions. See 129 FERC ¶ 61,081 (2009) at P 30.

32 Effective January 31, 2011, the RPM rules related to market power mitigation were changed, including revising the definition for Planned Generation Capacity Resource and creating a new definition for Existing Generation Capacity Resource for purposes of the must-offer requirement and market power mitigation, and treating a proposed increase in the capability of a Generation Capacity Resource the same in terms of mitigation as a Planned Generation Capacity Resource. See 134 FERC ¶ 61,065 (2011).

Table 4-9 ACR statistics: Auctions conducted in third quarter, 2012 (See the 2011 SOM, Table 4-14)

	2013/2014 Second Incremental Auction		2014/2015 First Incremental Auction	
Offer Cap/Mitigation Type	Number of Generation Resources	Percent of Generation Resources Offered	Number of Generation Resources	Percent of Generation Resources Offered
Default ACR	55	33.7%	59	31.1%
ACR data input (APIR)	8	4.9%	21	11.1%
ACR data input (non-APIR)	0	0.0%	0	0.0%
Opportunity cost input	4	2.5%	4	2.1%
Default ACR and opportunity cost	0	0.0%	1	0.5%
Offer cap of 1.1 times BRA clearing price elected	NA	NA	NA	NA
Uncapped planned uprate and default ACR	10	6.1%	11	5.8%
Uncapped planned uprate and opportunity cost	0	0.0%	0	0.0%
Uncapped planned uprate and price taker	5	3.1%	4	2.1%
Uncapped planned uprate and 1.1 times BRA clearing price elected	NA	NA	NA	NA
Uncapped planned generation resources	11	6.7%	5	2.6%
Price takers	70	42.9%	85	44.7%
Total Generation Capacity Resources offered	163	100.0%	190	100.0%

Market Performance[33]

As shown in Table 4-10, the rest of RTO clearing price in the 2013/2014 RPM Second Incremental Auction was $7.01 per MW-day, and the rest of RTO clearing price for Annual and Extended Summer Resources in the 2014/2015 RPM First Incremental Auction was $5.54 per MW-day. In the 2014/2015 RPM First Incremental Auction, the PSEG North resource clearing price for Annual and Extended Summer Resources was $410.95 per MW-day and the rest of RTO resource clearing price for Limited Resources was $0.03 per MW-day, the highest and lowest resource clearing prices in RPM history. In the 2014/2015 First Incremental Auction, PJM attempted to procure additional capacity in PSEG North, while PJM attempted to sell capacity in the rest of RTO.

Annual weighted average capacity prices increased from a CCM weighted average price of $5.73 per MW-day in 2006 to an RPM weighted-average price of $164.71 per MW-day in 2010 and then declined to $148.33 per MW-day in 2015. Figure 4-3 presents cleared MW weighted average capacity market prices on a calendar year basis for the entire history of the PJM capacity markets.

Cleared capacity resources across the entire RTO will receive a total of $8.7 million based on the unforced MW cleared and the prices in the 2013/2014 RPM Second Incremental Auction and a total of $35.6 million based on the unforced MW cleared and prices in the 2014/2015 RPM First Incremental Auction.

Table 4-11 shows RPM revenue by resource type for all RPM Auctions held to date with $1.5 billion for new/reactivated generation resources based on the unforced MW cleared and the resource clearing prices.

Table 4-12 shows RPM revenue by calendar year for all RPM Auctions held to date.

33 The MMU provides detailed analyses of market performance in reports for each RPM Auction. See <http://www.monitoringanalytics.com/reports/Reports/2012.shtml>.

Table 4-10 Capacity prices: 2007/2008 through 2015/2016 RPM Auctions (See the 2011 SOM, Table 4-21)

		RPM Clearing Price ($ per MW-day)								
	Product Type	RTO	MAAC	APS	EMAAC	SWMAAC	DPL South	PSEG North	Pepco	ATSI
2007/2008 BRA		$40.80	$40.80	$40.80	$197.67	$188.54	$197.67	$197.67	$188.54	
2008/2009 BRA		$111.92	$111.92	$111.92	$148.80	$210.11	$148.80	$148.80	$210.11	
2008/2009 Third Incremental Auction		$10.00	$10.00	$10.00	$10.00	$223.85	$10.00	$10.00	$223.85	
2009/2010 BRA		$102.04	$191.32	$191.32	$191.32	$237.33	$191.32	$191.32	$237.33	
2009/2010 Third Incremental Auction		$40.00	$86.00	$86.00	$86.00	$86.00	$86.00	$86.00	$86.00	
2010/2011 BRA		$174.29	$174.29	$174.29	$174.29	$174.29	$186.12	$174.29	$174.29	
2010/2011 Third Incremental Auction		$50.00	$50.00	$50.00	$50.00	$50.00	$50.00	$50.00	$50.00	
2011/2012 BRA		$110.00	$110.00	$110.00	$110.00	$110.00	$110.00	$110.00	$110.00	
2011/2012 First Incremental Auction		$55.00	$55.00	$55.00	$55.00	$55.00	$55.00	$55.00	$55.00	
2011/2012 ATSI FRR Integration Auction		$108.89	$108.89	$108.89	$108.89	$108.89	$108.89	$108.89	$108.89	$108.89
2011/2012 Third Incremental Auction		$5.00	$5.00	$5.00	$5.00	$5.00	$5.00	$5.00	$5.00	$5.00
2012/2013 BRA		$16.46	$133.37	$16.46	$139.73	$133.37	$222.30	$185.00	$133.37	
2012/2013 ATSI FRR Integration Auction		$20.46	$20.46	$20.46	$20.46	$20.46	$20.46	$20.46	$20.46	$20.46
2012/2013 First Incremental Auction		$16.46	$16.46	$16.46	$153.67	$16.46	$153.67	$153.67	$16.46	$16.46
2012/2013 Second Incremental Auction		$13.01	$13.01	$13.01	$48.91	$13.01	$48.91	$48.91	$13.01	$13.01
2012/2013 Third Incremental Auction		$2.51	$2.51	$2.51	$2.51	$2.51	$2.51	$2.51	$2.51	$2.51
2013/2014 BRA		$27.73	$226.15	$27.73	$245.00	$226.15	$245.00	$245.00	$247.14	$27.73
2013/2014 First Incremental Auction		$20.00	$20.00	$20.00	$178.85	$54.82	$178.85	$178.85	$54.82	$20.00
2013/2014 Second Incremental Auction		$7.01	$10.00	$7.01	$40.00	$10.00	$40.00	$40.00	$10.00	$7.01
2014/2015 BRA	Limited	$125.47	$125.47	$125.47	$125.47	$125.47	$125.47	$213.97	$125.47	$125.47
2014/2015 BRA	Extended Summer	$125.99	$136.50	$125.99	$136.50	$136.50	$136.50	$225.00	$136.50	$125.99
2014/2015 BRA	Annual	$125.99	$136.50	$125.99	$136.50	$136.50	$136.50	$225.00	$136.50	$125.99
2014/2015 First Incremental Auction	Limited	$0.03	$5.23	$0.03	$5.23	$5.23	$5.23	$399.62	$5.23	$0.03
2014/2015 First Incremental Auction	Extended Summer	$5.54	$16.56	$5.54	$16.56	$16.56	$16.56	$410.95	$16.56	$5.54
2014/2015 First Incremental Auction	Annual	$5.54	$16.56	$5.54	$16.56	$16.56	$16.56	$410.95	$16.56	$5.54
2015/2016 BRA	Limited	$118.54	$150.00	$118.54	$150.00	$150.00	$150.00	$150.00	$150.00	$304.62
2015/2016 BRA	Extended Summer	$136.00	$167.46	$136.00	$167.46	$167.46	$167.46	$167.46	$167.46	$322.08
2015/2016 BRA	Annual	$136.00	$167.46	$136.00	$167.46	$167.46	$167.46	$167.46	$167.46	$357.00

Table 4-11 RPM revenue by type: 2007/2008 through 2015/2016[34,35] (See the 2011 SOM, Table 4-22)

Type	2007/2008	2008/2009	2009/2010	2010/2011	2011/2012	2012/2013	2013/2014	2014/2015	2015/2016	Total
Demand Resources	$5,537,085	$35,349,116	$65,762,003	$60,235,796	$55,795,785	$264,387,897	$554,697,058	$670,147,703	$880,020,384	$2,591,932,826
Energy Efficiency Resources	$0	$0	$0	$0	$139,812	$11,408,552	$21,131,133	$40,247,604	$52,113,238	$125,040,339
Imports	$22,225,980	$60,918,903	$56,517,793	$106,046,871	$185,421,273	$13,260,822	$31,738,568	$178,473,828	$186,311,568	$840,915,605
Coal existing	$1,022,372,301	$1,844,120,476	$2,417,576,805	$2,662,434,386	$1,595,707,479	$1,016,194,603	$1,738,281,395	$1,853,342,698	$2,656,149,396	$16,806,179,541
Coal new/reactivated	$0	$0	$1,854,781	$3,168,069	$28,330,047	$7,568,127	$12,946,883	$56,917,305	$62,882,021	$173,667,234
Gas existing	$1,460,544,471	$1,911,518,321	$2,276,961,764	$2,586,971,699	$1,607,317,731	$1,079,413,451	$1,830,451,475	$1,969,632,253	$2,473,484,871	$17,196,296,036
Gas new/reactivated	$3,472,667	$9,751,112	$30,168,831	$58,065,964	$98,448,693	$76,633,409	$167,340,901	$184,293,676	$527,114,537	$1,155,289,790
Hydroelectric existing	$209,490,444	$287,850,403	$364,742,517	$442,429,815	$278,529,660	$179,117,975	$308,773,557	$328,974,881	$384,329,997	$2,784,239,249
Hydroelectric new/reactivated	$0	$0	$0	$0	$0	$11,397	$25,708	$6,591,114	$14,880,302	$21,508,521
Nuclear existing	$996,085,233	$1,322,601,837	$1,517,723,628	$1,799,258,125	$1,079,386,338	$762,719,550	$1,346,210,480	$1,460,152,259	$1,846,030,461	$12,130,167,912
Nuclear new/reactivated	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Oil existing	$502,172,373	$572,259,505	$715,618,319	$668,505,533	$368,084,004	$423,957,756	$685,582,719	$469,738,966	$562,402,530	$4,968,321,705
Oil new/reactivated	$0	$4,837,523	$5,676,582	$4,339,539	$967,887	$2,772,987	$5,669,955	$3,896,120	$5,166,777	$33,327,370
Solid waste existing	$29,956,764	$33,843,188	$41,243,412	$40,731,606	$25,636,836	$26,840,670	$43,613,120	$34,529,651	$35,405,293	$311,800,540
Solid waste new/reactivated	$0	$0	$523,739	$413,503	$261,690	$316,420	$1,964,565	$1,190,758	$3,324,459	$7,995,134
Solar existing	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Solar new/reactivated	$0	$0	$0	$0	$66,978	$1,246,337	$2,720,170	$3,152,447	$3,403,067	$10,588,999
Wind existing	$430,065	$1,180,153	$2,011,156	$1,819,413	$1,072,929	$812,644	$1,373,205	$1,493,377	$1,768,330	$11,961,271
Wind new/reactivated	$0	$2,917,048	$6,836,827	$15,232,177	$9,919,881	$5,052,036	$13,064,541	$31,173,865	$39,549,396	$123,745,769
Total	$4,252,287,381	$6,087,147,586	$7,503,218,157	$8,449,652,496	$5,335,087,023	$3,871,714,635	$6,765,585,432	$7,293,948,503	$9,734,336,627	$59,292,977,841

Table 4-12 RPM revenue by calendar year: 2007 through 2016[36] (New Table)

Year	Weighted Average RPM Price ($ per MW-day)	Weighted Average Cleared UCAP (MW)	Effective Days	RPM Revenue
2007	$89.78	129,409.2	214	$2,486,310,108
2008	$111.93	130,223.2	366	$5,334,880,241
2009	$142.74	132,772.0	365	$6,917,391,702
2010	$164.71	134,033.9	365	$8,058,113,907
2011	$135.14	134,105.2	365	$6,615,032,130
2012	$89.01	137,684.7	366	$4,485,656,150
2013	$100.22	152,226.6	365	$5,568,395,048
2014	$124.72	155,428.1	365	$7,075,365,425
2015	$148.33	160,866.8	365	$8,709,157,810
2016	$161.62	164,563.9	152	$4,042,675,320

34 A resource classified as "new/reactivated" is a capacity resource addition since the implementation of RPM and is considered "new/reactivated" for its initial offer and all its subsequent offers in RPM Auctions.
35 The results for the ATSI Integration Auctions are not included in this table.
36 The results for the ATSI Integration Auctions are not included in this table.

Figure 4-3 History of capacity prices: Calendar year 1999 through 2015[37] (See the 2011 SOM, Figure 4-1)

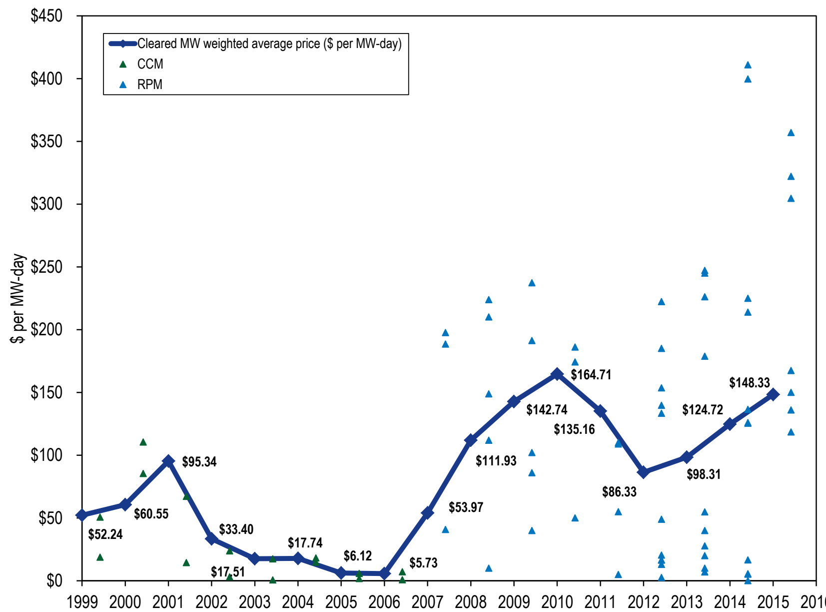


Table 4-13 shows the RPM annual charges to load. For the 2012/2013 planning year, RPM annual charges to load total approximately $3.9 billion.

Table 4-13 RPM cost to load: 2011/2012 through 2015/2016 RPM Auctions[38,39,40] (See the 2011 SOM, Table 4-23)

	Net Load Price ($ per MW-day)	UCAP Obligation (MW)	Annual Charges
2011/2012			
RTO	$116.15	133,815.3	$5,688,608,837
2012/2013			
RTO	$16.74	65,495.4	$400,296,161
MAAC	$133.42	30,107.9	$1,466,181,230
EMAAC	$143.06	19,954.6	$1,041,932,095
DPL	$171.27	4,523.9	$282,806,394
PSEG	$157.73	11,645.3	$670,441,158
2013/2014			
RTO	$28.37	81,517.7	$844,133,053
MAAC	$232.07	14,930.2	$1,264,667,275
EMAAC	$250.12	36,738.0	$3,353,903,318
SWMAAC	$231.08	8,057.0	$679,559,435
Pepco	$244.74	7,653.2	$683,667,039
2014/2015			
RTO	$128.17	82,577.4	$3,863,199,144
MAAC	$137.60	30,833.8	$1,548,586,169
EMAAC	$137.61	20,460.8	$1,027,667,647
DPL	$145.32	4,625.7	$245,357,435
PSEG	$170.24	11,833.5	$735,288,837
2015/2016			
RTO	$134.62	84,948.0	$4,185,534,909
MAAC	$165.78	68,742.2	$4,170,968,816
ATSI	$294.03	14,940.4	$1,607,805,047

37 1999-2006 capacity prices are CCM combined market, weighted average prices. The 2007 capacity price is a combined CCM/RPM weighted average price. The 2008-2015 capacity prices are RPM weighted average prices. The CCM data points plotted are cleared MW weighted average prices for the daily and monthly markets by delivery year. The RPM data points plotted are RPM resource clearing prices.

38 The RPM annual charges are calculated using the rounded, net load prices as posted in the PJM Base Residual Auction results.

39 There is no separate obligation for DPL South as the DPL South LDA is completely contained within the DPL Zone. There is no separate obligation for PSEG North as the PSEG North LDA is completely contained within the PSEG Zone.

40 Prior to the 2009/2010 Delivery Year, the Final UCAP Obligation is determined after the clearing of the Second Incremental Auction. For the 2009/2010 through 2011/2012 Delivery Years, the Final UCAP Obligations are determined after the clearing of the Third Incremental Auction. Effective with the 2012/2013 Delivery Year, the Final UCAP Obligation is determined after the clearing of the final Incremental Auction. Prior to the 2012/2013 Delivery Year, the Final Zonal Capacity Prices are determined after certification of ILR. Effective with the 2012/2013 Delivery Year, the Final Zonal Capacity Prices are determined after the final Incremental Auction. The 2013/2014, 2014/2015, and 2015/2016 Net Load Prices are not finalized. The 2013/2014, 2014/2015, and 2015/2016 Obligation MW are not finalized.

Generator Performance

Generator performance results from the interaction between the physical characteristics of the units and the level of expenditures made to maintain the capability of the units, which in turn is a function of incentives from energy, ancillary services and capacity markets. Generator performance can be measured using indices calculated from historical data. Generator performance indices include those based on total hours in a period (generator performance factors) and those based on hours when units are needed to operate by the system operator (generator forced outage rates).[41]

Capacity Factor

Capacity factor measures the actual output of a power plant over a period of time compared to the potential output of the unit had it been running at full nameplate capacity during that period. Nuclear units typically run at a greater than 90 percent capacity factor. In January through September 2012, nuclear units had a capacity factor of 92.8 percent. Combined cycle units ran more often in January through September 2012 than in the same period in 2011, increasing from a 47.1 percent capacity factor in 2011 to a 63.8 percent capacity factor in 2012. In contrast, the capacity factor for steam units decreased from 54.0 percent in 2011 to 45.5 percent in January through September 2012.

Table 4-14 PJM capacity factor (By unit type (GWh)); January through September 2011 and 2012[42] (See the 2011 SOM, Table 4-24)

	Jan-Sep 2011		Jan-Sep 2012	
Unit Type	Generation (GWh)	Capacity Factor	Generation (GWh)	Capacity Factor
Battery	0.2	1.3%	5.9	3.0%
Combined Cycle	74,481.1	47.1%	108,088.4	63.8%
Combustion Turbine	5,510.2	3.0%	7,273.8	3.7%
Diesel	495.3	18.0%	456.7	15.9%
Diesel (Landfill gas)	629.1	34.9%	913.4	41.2%
Nuclear	195,196.7	91.7%	205,503.9	92.8%
Pumped Storage Hydro	5,460.1	15.2%	5,097.0	14.1%
Run of River Hydro	5,919.8	38.7%	4,671.2	29.5%
Solar	37.9	12.0%	192.7	17.2%
Steam	286,978.5	54.0%	261,413.2	45.5%
Wind	7,924.5	27.2%	8,944.7	25.2%
Total	582,633.3	49.6%	602,560.9	47.9%

Generator Performance Factors

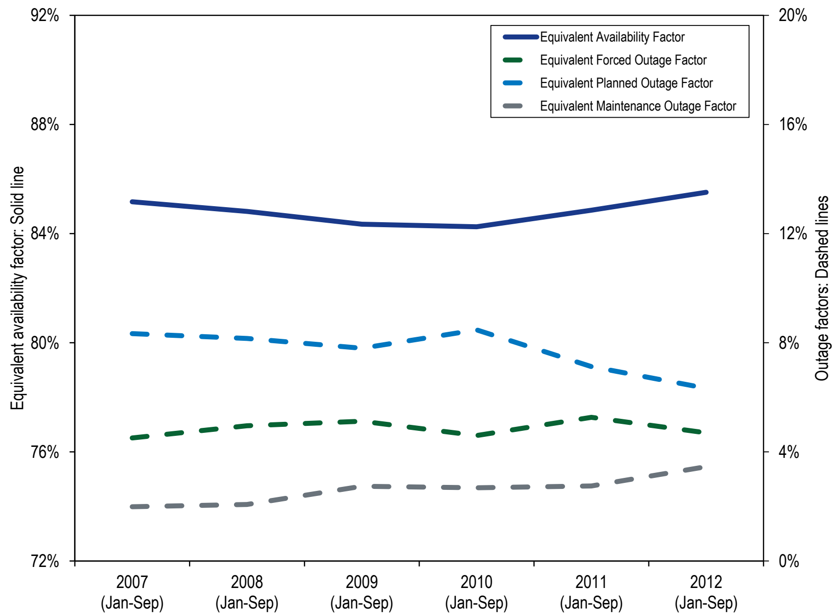
Performance factors include the equivalent availability factor (EAF), the equivalent maintenance outage factor (EMOF), the equivalent planned outage factor (EPOF) and the equivalent forced outage factor (EFOF). These four factors add to 100 percent for any generating unit. The EAF is the proportion of hours in a year when a unit is available to generate at full capacity while the three outage factors include all the hours when a unit is unavailable. The EMOF is the proportion of hours in a year when a unit is unavailable because of maintenance outages and maintenance deratings. The EPOF is the proportion of hours in a year when a unit is unavailable because of planned outages and planned deratings. The EFOF is the proportion of hours in a year when a unit is unavailable because of forced outages and forced deratings.

The PJM aggregate EAF increased from 84.9 percent in January through September 2011, to 85.5 percent for the same period in 2012. The EMOF increased from 2.8 percent to 3.5 percent, the EPOF decreased from 7.1 percent to 6.3 percent, and the EFOF decreased from 5.3 percent to 4.7 percent (Figure 4-4).

41 The generator performance analysis includes all PJM capacity resources for which there are data in the PJM GADS database. This set of capacity resources may include generators in addition to those in the set of generators committed as resources in the RPM.

42 The capacity factors for wind and solar unit types described in this table are based on nameplate capacity values, and are calculated based on when the units come online.

Figure 4-4 PJM equivalent outage and availability factors: Calendar years 2007 to 2012 (See the 2011 SOM, Table 4-1)



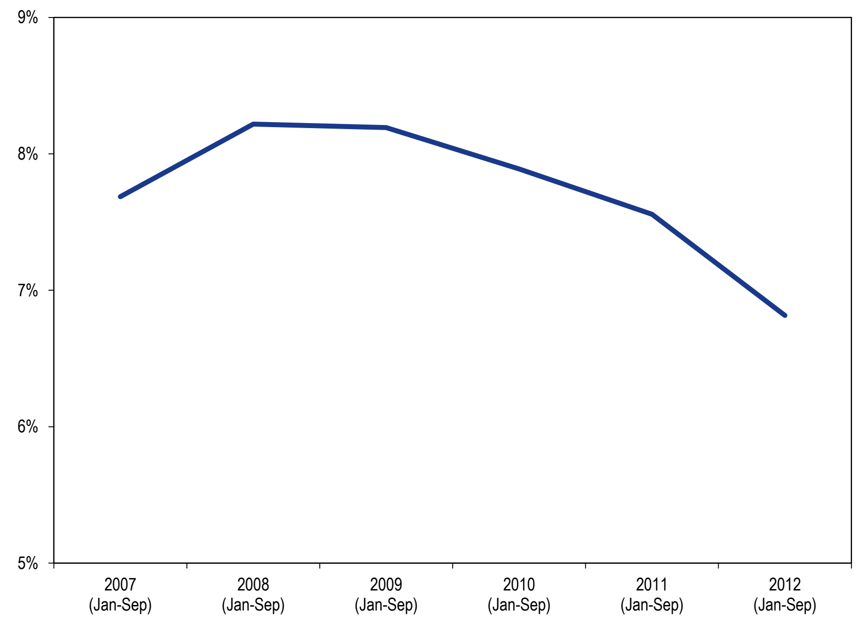
Generator Forced Outage Rates

There are three primary forced outage rate metrics. The most fundamental forced outage rate metric is EFORd. The other forced outage rate metrics either exclude some outages, XEFORd, or exclude some outages and exclude some time periods, EFORp.

The unadjusted forced outage rate of a generating unit is measured as the equivalent demand forced outage rate (EFORd). EFORd is a measure of the probability that a generating unit will fail, either partially or totally, to perform when it is needed to operate. EFORd measures the forced outage rate during periods of demand, and does not include planned or maintenance outages. A period of demand is a period during which a generator is running or needed to run. EFORd calculations use historical performance data, including equivalent forced outage hours,[43] service hours, average forced outage duration, average run time, average time between unit starts, available hours and period hours. The EFORd metric includes all forced outages, regardless of the reason for those outages.

Figure 4-5 shows the average January through September EFORd since 2007 for all units in PJM.

Figure 4-5 Trends in the PJM equivalent demand forced outage rate (EFORd): January through September, 2007 to 2012 (See the 2011 SOM, Figure 4-3)



43 Equivalent forced outage hours are the sum of all forced outage hours in which a generating unit is fully inoperable and all partial forced outage hours in which a generating unit is partially inoperable prorated to represent full hours.

Table 4-15 shows the class average EFORd by unit type.

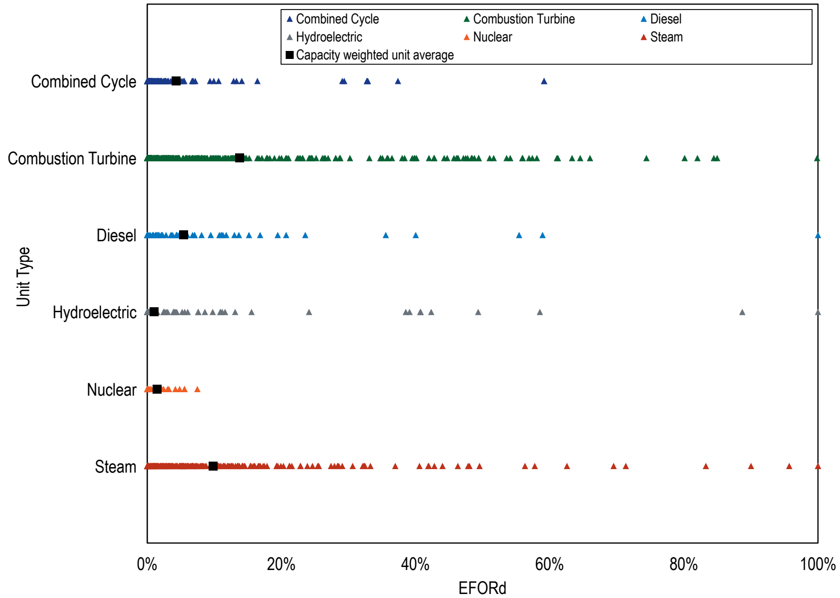
Table 4-15 PJM EFORd data for different unit types: 2007 to 2012 (See the 2011 SOM, Table 4-25)

	2007 (Jan-Sep)	2008 (Jan-Sep)	2009 (Jan-Sep)	2010 (Jan-Sep)	2011 (Jan-Sep)	2012 (Jan-Sep)
Combined Cycle	3.7%	3.4%	5.2%	4.3%	3.0%	3.1%
Combustion Turbine	17.0%	14.2%	10.3%	13.8%	7.1%	6.5%
Diesel	10.7%	10.1%	8.5%	5.5%	9.4%	5.3%
Hydroelectric	2.2%	2.1%	2.3%	1.1%	2.2%	4.0%
Nuclear	1.2%	1.1%	4.0%	1.5%	2.4%	1.5%
Steam	8.7%	10.7%	10.3%	9.8%	11.1%	10.2%
Total	7.7%	8.2%	8.2%	7.9%	7.6%	6.8%

Distribution of EFORd

The average EFORd results do not show the underlying pattern of EFORd rates by unit type. The distribution of EFORd by unit type is shown in Figure 4-6. Each generating unit is represented by a single point, and the capacity weighted unit average is represented by a solid square. Steam and combustion turbine units have the greatest variance of EFORd, while nuclear and combined cycle units have the lowest variance in EFORd values.

Figure 4-6 PJM January through September 2012 distribution of EFORd data by unit type (See the 2011 SOM, Figure 4-4)



Other Forced Outage Rate Metrics

There are two additional primary forced outage rate metrics that play a significant role in PJM markets, XEFORd and EFORp. The XEFORd metric is the EFORd metric adjusted to remove outages that have been defined to be outside management control (OMC). The EFORp metric is the EFORd metric adjusted to remove OMC outages and to reflect unit availability only during the approximately 500 hours defined in the PJM RPM tariff to be the critical load hours.

The PJM capacity market rules use XEFORd to determine the UCAP for generating units. Unforced capacity in the PJM Capacity Market for any individual generating unit is equal to one minus the XEFORd multiplied by the unit ICAP.

All outages, including OMC outages, are included in the EFORd that is used for planning studies that determine the reserve requirement. However, OMC outages are excluded from the calculations of XEFORd, which are used to determine the level of unforced capacity for specific units that must be offered in PJM's Capacity Market.

Thus the PJM Capacity Market creates an incentive to minimize the forced outage rate excluding OMC outages, but not an incentive to minimize the forced outage rate accounting for all forced outages. In fact, because PJM uses XEFORd as the outage metric to define capacity available for sale, the PJM Capacity Market includes an incentive to classify as many forced outages as possible as OMC.

Outages Deemed Outside Management Control

In 2006, NERC created specifications for certain types of outages to be deemed Outside Management Control (OMC).[44] An outage can be classified as an OMC outage only if the outage meets the requirements outlined in Appendix K of the "Generator Availability Data System Data Reporting Instructions." Appendix K of the "Generator Availability Data Systems Data Reporting Instructions" also lists specific cause codes (i.e., codes that are standardized for specific outage causes) that would be considered OMC outages.[45] Not all outages caused by the factors in these specific OMC cause codes are OMC outages. For example, according to the NERC specifications, fuel quality issues (codes 9200 to 9299) may be within the control of the owner or outside management control. Each outage must be considered separately per the NERC directive.

Nothing in NERC's classification of outages requires that PJM exclude OMC outages from the forced outage rate metric used in the Capacity Market. That choice was made by PJM and can be modified without violating any NERC requirements.[46] It is possible to have an OMC outage under the NERC definition, which PJM does not define as OMC for purposes of calculating XEFORd. That is the current PJM practice. The actual implementation of the OMC outages and their impact on XEFORd is and has been within the control of PJM. PJM has chosen to exclude only some of the OMC outages from the XEFORd metric.

At present, PJM does not have a clear, documented, public set of criteria for designating outages as OMC.

All outages, including OMC outages, are included in the EFORd that is used for PJM planning studies that determine the reserve requirement. However, OMC outages are excluded from the calculations used to determine the level of unforced capacity for specific units that must be offered in PJM's Capacity Market. This modified EFORd is termed the XEFORd. Table 4-16 shows OMC forced outages by cause code, as classified by PJM. OMC forced outages account for 6.5 percent of all forced outages. The largest contributor to OMC outages, lack of fuel, is the cause of 69.4 percent of OMC outages and 4.5 percent of all forced outages. The NERC GADS guidelines in Appendix K describe OMC lack of fuel as "lack of fuel where the operator is not in control of contracts, supply lines, or delivery of fuels."

44 Generator Availability Data System Data Reporting Instructions states, "The electric industry in Europe and other parts of the world has made a change to examine losses of generation caused by problems with and outside plant management control... There are a number of outage causes that may prevent the energy coming from a power generating plant from reaching the customer. Some causes are due to the plant operation and equipment while others are outside plant management control. The standard sets a boundary on the generator side of the power station for the determination of equipment outside management control." The Generator Availability Data System Data Reporting Instructions can be found on the NERC website: <http://www.nerc.com/files/GADS_DRI_Complete_Version_010111.pdf>.

45 For a list of these cause codes, see the *Technical Reference for PJM Markets*, at "Generator Performance: NERC OMC Outage Cause Codes" <http://www.monitoringanalytics.com/reports/Technical_References/references.shtml>.

46 It is unclear whether there were member votes taken on this issue.

Table 4-16 OMC Outages: January through September 2012 (See the 2011 SOM, Table 4-30)

OMC Cause Code	% of all Forced Outages
Lack of fuel	4.5%
Switchyard circuit breakers external	0.5%
Other switchyard equipment external	0.3%
Transmission line	0.2%
Transmission system problems other than catastrophes	0.2%
Transmission equipment beyond the 1st substation	0.2%
Storms	0.2%
Lightning	0.1%
Lack of water	0.1%
Transmission equipment at the 1st substation	0.1%
Switchyard system protection devices	0.0%
Switchyard transformers and associated cooling systems	0.0%
Other fuel quality problems	0.0%
Tornados	0.0%
Flood	0.0%
Other miscellaneous external problems	0.0%
Total	6.5%

An outage is an outage, regardless of the cause. Lack of fuel is especially noteworthy because the lack of fuel reasons are arguably not outside the control of management. Virtually any issue with fuel supply can be addressed by additional expenditures. It is significant that some OMC outages are classified as economic. Firm gas contracts could be used in place of interruptible gas contracts. Alternative fuels could be used as a supplement to primary fuels. Improved fuel management practices including additional investment could eliminate wet coal as a reason. Better diversification in supplies could eliminate interruptions from individual suppliers. But regardless of the reason, an outage is an outage. If a particular unit or set of units have outages on a regular basis for one of the OMC reasons, that is a real feature of the units that should be reflected in overall PJM system planning as well as in the economic fundamentals of the capacity market and the capacity market outcomes. Permitting OMC outages to be excluded from the forced outage metric skews the results of the capacity market towards less reliable units and away from more reliable units. This is exactly the wrong incentive. Paying for capacity from units using the EFORd, not the XEFORd, metric would provide a market incentive for unit owners to address all their outage issues in an efficient manner. Pretending that some outages simply do not exist distorts market outcomes. That is exactly the result of using OMC outages to reduce EFORd.[47]

If there were units in a constrained Locational Deliverability Area (LDA) that regularly had a higher rate of OMC outages than other units in the LDA and in PJM, and that cleared in the capacity auctions, the supply and demand in that LDA would be affected. The payments to the high OMC units would be too high and the payments to other units in the LDA would be too low. This market signal, based on the exclusion of OMC outages, favors generating units with high forced outage rates that result from causes classified as OMC, compared to generating units with no OMC outages.

With the OMC rules in place, if a new unit were considering entry into a constrained LDA and had choices about the nature of its fuel supply, the unit would not have an incentive to choose the most reliable fuel source or combination of fuel sources, but simply the cheapest. The OMC outage rules would provide the wrong incentive. While it is up to the generation investor to determine its fuel supply arrangements, the generation investor must also take on the risks associated with its fuel supply decisions rather than being able to shift those risks to other generation owners and to customers, which is exactly what occurs under the OMC rules as currently implemented. This issue is especially critical in a time when almost all incremental conventional generation in PJM is gas fired.

The NYISO does not classify any fuel related outages or derates as OMC under its capacity market rules.[48]

47 For more on this issue, see the IMM's White Paper included in: Monitoring Analytics, LLC and PJM Interconnection, LLC, "Capacity in the PJM Market," <http://www.monitoringanalytics.com/reports/Reports/2012/IMM_And_PJM_Capacity_White_Papers_On_OPSI_Issues_20120820.pdf> (August 20, 2012)

48 See New York Independent System Operator, "Manual 4: Installed Capacity Manual," Version 6.20. (January, 24 2012) <http://www.nyiso.com/public/webdocs/documents/manuals/operations/icap_mnl.pdf>. When a Generator, Energy/Capacity Limited Resource, System Resource, Intermittent Power Resource or Control Area System Resource is forced into an outage by an equipment failure that involves equipment located on the electric network beyond the step-up transformer, and including such step-up transformer, the NYISO shall not treat the outage as a forced outage for purposes of calculating the amount of Unforced Capacity such Installed Capacity Suppliers are qualified to supply in the NYCA. This exception is limited to an equipment failure that involves equipment located on the electric network beyond the generator step-up transformer, and including such step-up transformer on the output side of the Generator, Energy/Capacity Limited Resource, System Resource, Intermittent Power Resource or Control Area System Resource. This exception does not apply to fuel related outages or derates or other cause codes that might be classified as Outside Management Control in the NERC Data reporting Instructions. NYISO only accepts OMC outages for outages at or beyond the step-up transformer.

It is clear that OMC outages defined as lack of fuel should not be identified as OMC and should not be excluded from the calculation of XEFORd and EFORp.

All submitted OMC outages are reviewed by PJM's Resource Adequacy Department. The MMU recommends that PJM review all requests for OMC carefully, develop a clear, transparent set of written public rules governing the designation of outages as OMC and post those guidelines. Any resultant OMC outages may be considered by PJM but should not be reflected in forced outage metrics which affect system planning or market payments to generating units.

The MMU recommends that PJM immediately eliminate lack of fuel as an acceptable basis for an OMC outage. The MMU recommends that PJM eliminate all OMC outages from the calculation of forced outage rates used for any purpose in the PJM Capacity Market after appropriate notice.

Table 4-17 shows the impact of OMC outages on EFORd. The difference is especially noticeable for steam units and combustion turbine units.

Table 4-17 PJM EFORd vs. XEFORd: January through September 2012 (See the 2011 SOM, Table 4-31)

	EFORd	XEFORd	Difference
Combined Cycle	3.1%	3.0%	0.1%
Combustion Turbine	6.5%	5.4%	1.0%
Diesel	5.3%	4.3%	1.0%
Hydroelectric	4.0%	3.8%	0.2%
Nuclear	1.5%	1.5%	0.0%
Steam	10.2%	9.4%	0.7%
Total	6.8%	6.3%	0.5%

Forced Outage Analysis

The MMU analyzed the causes of forced outages for the entire PJM system. The metric used was lost generation, which is the product of the duration of the outage and the size of the outage reduction. Lost generation can be converted into lost system equivalent availability.[49] On a systemwide basis, the resultant lost equivalent availability from the forced outages is equal to the equivalent forced outage factor.

For the nine months January through September 2012, PJM EFOF was 4.7 percent. This means there was 4.7 percent lost availability because of forced outages. Table 4-18 shows that forced outages for boiler tube leaks, at 18.6 percent of the systemwide EFOF, were the largest single contributor to EFOF.

49 For any unit, lost generation can be converted to lost equivalent availability by dividing lost generation by the product of the generating units' capacity and period hours. This can also be done on a systemwide basis.

Table 4-18 Contribution to EFOF by unit type by cause: January through September 2012 (See the 2011 SOM, Table 4-27)

	Combined Cycle	Combustion Turbine	Diesel	Hydroelectric	Nuclear	Steam	System
Boiler Tube Leaks	3.4%	0.0%	0.0%	0.0%	0.0%	23.4%	18.6%
Boiler Piping System	4.3%	0.0%	0.0%	0.0%	0.0%	7.7%	6.4%
Feedwater System	7.4%	0.0%	0.0%	0.0%	1.7%	7.0%	6.1%
Boiler Air and Gas Systems	0.0%	0.0%	0.0%	0.0%	0.0%	7.0%	5.5%
High Pressure Turbine	0.0%	0.0%	0.0%	0.0%	0.0%	6.8%	5.3%
Electrical	6.0%	11.9%	2.9%	8.4%	10.8%	3.8%	5.0%
Miscellaneous (Generator)	5.3%	6.5%	1.7%	66.7%	0.0%	2.8%	4.8%
Economic	0.5%	0.6%	0.9%	4.0%	0.0%	5.7%	4.7%
Reserve Shutdown	3.8%	18.0%	13.5%	2.2%	0.8%	3.0%	4.0%
Boiler Fuel Supply from Bunkers to Boiler	1.3%	0.0%	0.0%	0.0%	0.0%	3.7%	3.0%
Valves	7.7%	0.0%	0.0%	0.0%	1.9%	2.2%	2.3%
Circulating Water Systems	1.3%	0.0%	0.0%	0.0%	10.3%	1.9%	2.1%
Reactor Coolant System	0.0%	0.0%	0.0%	0.0%	41.0%	0.0%	2.1%
Controls	5.2%	0.9%	0.2%	0.2%	4.2%	1.8%	2.0%
Miscellaneous (Steam Turbine)	1.7%	0.0%	0.0%	0.0%	0.3%	2.2%	1.8%
Other Operating Environmental Limitations	1.7%	0.0%	0.0%	0.3%	5.7%	1.8%	1.8%
Condensing System	1.6%	0.0%	0.0%	0.0%	5.0%	1.7%	1.7%
Miscellaneous (Gas Turbine)	3.9%	14.6%	0.0%	0.0%	0.0%	0.0%	1.3%
Precipitators	0.0%	0.0%	0.0%	0.0%	0.0%	1.5%	1.2%
All Other Causes	44.8%	47.4%	80.9%	18.1%	18.4%	16.1%	20.5%
Total	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%

Table 4-19 shows the categories which are included in the economic category.[50] Lack of fuel that is considered Outside Management Control accounted for 95.8 percent of all economic reasons while lack of fuel that was not Outside Management Control accounted for only 1.6 percent.

OMC lack of fuel is described as "Lack of fuel where the operator is not in control of contracts, supply lines, or delivery of fuels".[51] Only a handful of units use other economic problems to describe outages. Other economic problems are not defined by NERC GADS and are best described as economic problems that cannot be classified by the other NERC GADS economic problem cause codes. Lack of water events occur when a hydroelectric plant does not have sufficient fuel (water) to operate.

Table 4-19 Contributions to Economic Outages: January through September 2012 (See the 2011 SOM, Table 4-28)

	Contribution to Economic Reasons
Lack of fuel (OMC)	95.8%
Lack of water (Hydro)	2.3%
Lack of fuel (Non-OMC)	1.6%
Fuel conservation	0.2%
Other economic problems	0.0%
Ground water or other water supply problems	0.0%
Total	100.0%

50 The classification and definitions of these outages are defined by NERC GADS.
51 The classification and definitions of these outages are defined by NERC GADS.

EFORd, XEFORd and EFORp

The equivalent forced outage rate during peak hours (EFORp) is a measure of the probability that a generating unit will fail, either partially or totally, to perform when it is needed to operate during the peak hours of the day in the peak months of January, February, June, July and August. EFORp is calculated using historical performance data and is designed to measure if a unit would have run had the unit not been forced out. Like XEFORd, EFORp excludes OMC outages. PJM systemwide EFORp is a capacity-weighted average of individual unit EFORp.

EFORd, XEFORd and EFORp are designed to measure the rate of forced outages, which are defined as outages that cannot be postponed beyond the end of the next weekend.[52] It is reasonable to expect that units have some degree of control over when to take a forced outage, depending on the underlying cause of the forced outage. If units had no control over the timing of forced outages, outages during peak hours of the peak months would be expected to occur at roughly the same rate as outages during periods of demand throughout the rest of the year. With the exception of nuclear units, EFORp is lower than EFORd, suggesting that units elect to take forced outages during off-peak hours, as much as it is within their control to do so. That is consistent with the incentives created by the PJM Capacity Market.

Table 4-20 shows the capacity-weighted class average of EFORd, XEFORd and EFORp. The impact of OMC outages is especially noticeable in the difference between EFORd and XEFORd for steam units and combustion turbine units.

52 See "Manual 22: Generator Resource Performance Indices," Revision 15 (June 1, 2007), Definitions.

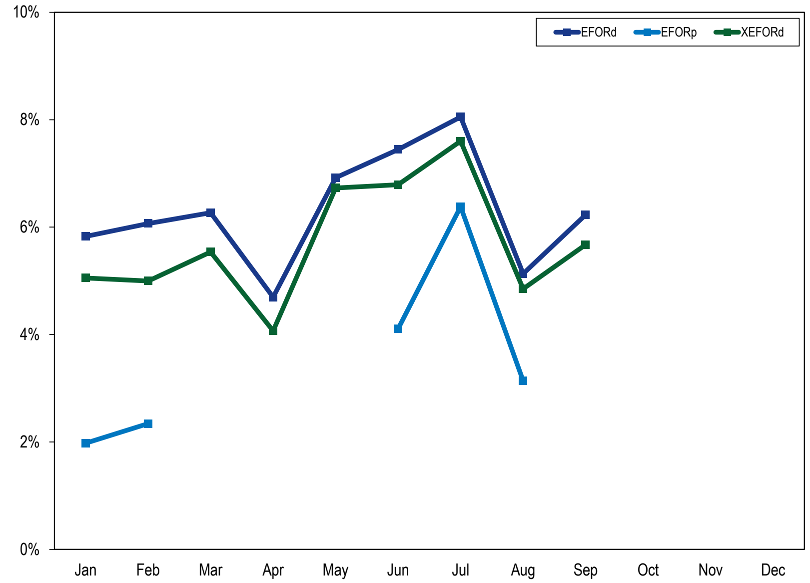
Table 4-20 PJM EFORd, XEFORd and EFORp data by unit type: January through September 2012[53] (See the 2011 SOM, Table 4-35)

	EFORd	XEFORd	EFORp	Difference EFORd and XEFORd	Difference EFORd and EFORp
Combined Cycle	3.1%	3.0%	2.0%	0.1%	1.0%
Combustion Turbine	6.5%	5.4%	2.9%	1.0%	3.6%
Diesel	5.3%	4.3%	2.7%	1.0%	2.6%
Hydroelectric	4.0%	3.8%	4.6%	0.2%	(0.7%)
Nuclear	1.5%	1.5%	1.8%	0.0%	(0.3%)
Steam	10.2%	9.4%	5.7%	0.7%	4.4%
Total	6.8%	6.3%	4.0%	0.5%	2.8%

Performance By Month

On a monthly basis, EFORp values were significantly less than EFORd and XEFORd values as shown in Figure 4-7.

Figure 4-7 PJM EFORd, XEFORd and EFORp: 2012 (See the 2011 SOM, Figure 4-7)



53 EFORp is only calculated for the peak months of January, February, June, July, and August.

On a monthly basis, unit availability as measured by the equivalent availability factor increased during the summer months of June, July and August, primarily due to decreasing planned and maintenance outages, as illustrated in Figure 4-8.

Figure 4-8 PJM monthly generator performance factors: 2012 (See the 2011 SOM, Table 4-8)