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 meet their obligations in the capacity market by constructing generation and offering it into the capacity market, by entering into bilateral contracts, by developing demand-side resources and Energy Efficiency (EE) resources and offering them into the capacity market, or by constructing transmission upgrades and offering 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 three months of calendar year 2012, including supply, demand, concentration ratios, pivotal suppliers, volumes, prices, outage rates and reliability.

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: Local Market	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.[1]
- 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 failed the TPS which is conducted at the time of the auction.[2]
- 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 planned resource 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 a definition of DR which permits inferior products to substitute for capacity.

Highlights

- During the period January 1, through March 31, 2012, PJM installed capacity increased 6,126.6 MW or 3.4 percent from 178,854.1 MW on January 1 to 184,980.7 MW on March 31. Installed capacity includes net capacity imports and exports and can vary on a daily basis.
- The 2012/2013 RPM Third Incremental Auction was run in the first quarter of 2012. In the 2012/2013 RPM Third Incremental Auction, the RTO clearing price was $2.51 per MW-day.
- All LDAs and the entire PJM Region failed the preliminary market structure screen (PMSS) for the 2015/2016 Delivery Year.

1 In the 2008/2009 RPM Third Incremental Auction, 18 participants in the RTO market passed the TPS test.

2 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 8,492.2 MW for June 1, 2012.
- 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 $127.05 per MW-day in 2014.
- Combined cycle units ran more often in January through March 2012, than in the same period in 2011, increasing from a 41.1 percent capacity factor in 2011 to a 63.0 percent capacity factor in 2012. Combined cycle units had a higher capacity factor than steam units, for which the capacity factor decreased from 51.8 percent in 2011 to 39.8 percent in January through March 2012.
- The average PJM equivalent demand forced outage rate (EFORd) decreased from 8.6 percent in the first three months of 2011 to 6.6 percent in the first three months of 2012.
- The PJM aggregate equivalent availability factor (EAF) increased from 85.8 percent in the first three months of 2011 to 86.1 percent in the first three months of 2012. The equivalent maintenance outage factor (EMOF) increased from 2.5 percent to 3.9 percent, the equivalent planned outage factor (EPOF) decreased from 6.4 percent to 5.7 percent, and the equivalent forced outage factor (EFOF) decreased from 5.3 percent to 4.3 percent.

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 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 Capacity Market is unlikely ever to approach the economist's view of 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 three 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 three 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.[3,4,5,6] In 2011 and 2012, the MMU prepared a number of RPM-related reports and testimony, shown in Table 4-2.

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

3 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).
4 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)
5 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).
6 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).

Installed Capacity

On January 1, 2012, PJM installed capacity was 178,854.1 MW (Table 4-3).[7] Over the next three months, unit retirements, facility reratings plus import and export shifts resulted in PJM installed capacity of 184,980.7 MW on March 31, 2012, an increase of 6,126.6 MW or 3.4 percent over the January 1 level.[8,9]

Table 4-3 PJM installed capacity (By fuel source): January 1, January 31, February 29, and March 31, 2012 (See the 2011 SOM, Table 4-3)

	1-Jan-12		31-Jan-12		29-Feb-12		31-Mar-12	
	MW	Percent	MW	Percent	MW	Percent	MW	Percent
Coal	75,190.4	42.0%	80,212.1	43.3%	79,749.1	43.1%	79,749.1	43.1%
Gas	50,529.3	28.3%	51,788.5	27.9%	51,774.8	28.0%	51,774.8	28.0%
Hydroelectric	8,047.0	4.5%	8,047.0	4.3%	8,047.0	4.4%	8,047.0	4.4%
Nuclear	32,492.6	18.2%	32,492.6	17.5%	32,492.6	17.6%	32,534.6	17.6%
Oil	11,217.3	6.3%	11,495.2	6.2%	11,494.7	6.2%	11,494.7	6.2%
Solar	15.3	0.0%	15.3	0.0%	15.3	0.0%	15.3	0.0%
Solid waste	705.1	0.4%	705.1	0.4%	705.1	0.4%	705.1	0.4%
Wind	657.1	0.4%	660.1	0.4%	660.1	0.4%	660.1	0.4%
Total	178,854.1	100.0%	185,415.9	100.0%	184,938.7	100.0%	184,980.7	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.[10]

7 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.

8 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.

9 Wind-based resources accounted for 660.1 MW of installed capacity in PJM on March 31, 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 in place of the 87 percent reduction. There are additional wind resources not reflected in this total because they are energy only resources and do not participate in the PJM Capacity Market.

Market Structure

Supply

Offered MW in the 2012/2013 RPM Third Incremental Auction totaled 5,569.4 MW. Effective with the 2012/2013 delivery year, PJM sell offers and buys bids are submitted in RPM Incremental Auctions as a result of changes in the RTO and LDA reliability requirements and the procurement of the Short-Term Resource Procurement Target. PJM sell offers for the RTO in the 2012/2013 RPM Third Incremental Auction were 2,729.8 MW.

Demand

Participant buy bids in the 2012/2013 RPM Third Incremental Auction totaled 7,459.2 MW. Participant buy bids are submitted to cover short positions due to deratings and EFORd increases or because participants wanted to purchase additional capacity. PJM buy bids for the RTO in the 2012/2013 RPM Third Incremental Auction were 11.6 MW.

Market Concentration

Preliminary Market Structure Screen

Under the terms of the PJM Open Access Transmission Tariff (OATT), the MMU is required to apply the preliminary market structure screen (PMSS) prior to RPM Base Residual Auctions. The results of the PMSS are applicable for all RPM Auctions for the given delivery year. The purpose of the PMSS is to determine whether additional data are needed from owners of capacity resources in the defined areas in order to permit the application of market structure tests defined in the Tariff.

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

Table 4-4 Preliminary market structure screen results: 2011/2012 through 2015/2016 RPM Auctions (See the 2011 SOM, Table 4-7)

RPM Markets	Highest Market Share	HHI	Pivotal Suppliers	Pass/Fail
2011/2012				
RTO	18.0%	855	1	Fail
2012/2013				
RTO	17.4%	853	1	Fail
MAAC	17.6%	1071	1	Fail
EMAAC	32.8%	2057	1	Fail
SWMAAC	50.7%	4338	1	Fail
PSEG	84.3%	7188	1	Fail
PSEG North	90.9%	8287	1	Fail
DPL South	55.0%	3828	1	Fail
2013/2014				
RTO	14.4%	812	1	Fail
MAAC	18.1%	1101	1	Fail
EMAAC	33.0%	1992	1	Fail
SWMAAC	50.9%	4790	1	Fail
PSEG	89.7%	8069	1	Fail
PSEG North	89.5%	8056	1	Fail
DPL South	55.8%	3887	1	Fail
JCPL	28.5%	1731	1	Fail
Pepco	94.5%	8947	1	Fail
2014/2015				
RTO	15.0%	800	1	Fail
MAAC	17.6%	1038	1	Fail
EMAAC	33.1%	1966	1	Fail
SWMAAC	49.4%	4733	1	Fail
PSEG	89.4%	8027	1	Fail
PSEG North	88.2%	7825	1	Fail
DPL South	56.5%	3796	1	Fail
Pepco	94.5%	8955	1	Fail
2015/2016				
RTO	14.3%	763	1	Fail
MAAC	17.5%	1114	1	Fail
EMAAC	32.6%	1904	1	Fail
SWMAAC	51.9%	4745	1	Fail
DPL South	49.2%	3257	1	Fail
PSEG	89.4%	8020	1	Fail
PSEG North	88.0%	7794	1	Fail
Pepco	94.1%	8876	1	Fail
ATSI	75.5%	5881	1	Fail

An LDA or the RTO Region fails the PMSS if any one of the following three screens is failed: the market share of any capacity resource owner exceeds 20 percent; the HHI for all capacity resource owners is 1800 or higher; or there are not more than three jointly pivotal suppliers. As shown in Table 4-4, all defined markets failed the preliminary market structure screen (PMSS) for the 2015/2016 Delivery Year.[11] As a result, all capacity market sellers owning or controlling any generation capacity resource located in the entire PJM Region shall be required to provide the information specified in Section 6.7(b) of Attachment DD of the PJM Open Access Transmission Tariff (OATT).

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 2012/2013 Third Incremental Auction.[12] 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.[13,14,15]

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

11 See "Preliminary Market Structure Screen Results for 2015/2016 RPM Base Residual Auction" (February 7, 2012) <http://www.monitoringanalytics.com/reports/Reports/2012/PMSS_Results_20152016_20120207.pdf>.

12 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.

13 See OATT Attachment DD § 6.5.

14 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.

15 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: 2011/2012 through 2014/2015 RPM Auctions[16] (See the 2011 SOM, Table 4-8)

RPM Markets	$RSI_{1\ 1.05}$	RSI_3	Total Participants	Failed RSI_3 Participants
2011/2012 BRA				
RTO	0.85	0.63	76	76
2011/2012 First Incremental Auction				
RTO	0.86	0.62	30	30
2011/2012 ATSI FRR Integration Auction				
RTO	0.18	0.07	21	21
2011/2012 Third Incremental Auction				
RTO	0.54	0.41	52	52
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 Inremental 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
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

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

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.[17]

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 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 another reason 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 decreased by 1,196.1 MW from 9,688.3 MW on June 1, 2011 to 8,492.2 MW on June 1, 2012. Table 4-7 shows RPM commitments for DR and EE resources as the result of RPM Auctions prior to adjustments for replacement transactions along with certified ILR.

17 OATT Attachment DD § 5.6.6(b).

Table 4-6 RPM load management statistics by LDA: June 1, 2010 to June 1, 2014[18,19,20] (See the 2011 SOM, Table 4-10)

								UCAP (MW)
	RTO	MAAC	EMAAC	SWMAAC	DPL South	PSEG	PSEG North	Pepco
DR cleared	962.9	918.5		520.8	14.9			
DR net replacements	(516.3)	(480.9)		(112.7)	(14.9)			
ILR	8,236.4	3,113.7		655.2	97.2			
RPM load management @ 01-Jun-10	8,683.0	3,551.3		1,063.3	97.2			
DR cleared	1,826.6							
EE cleared	76.4							
DR net replacements	(1,247.5)							
EE net replacements	0.2							
ILR	9,032.6							
RPM load management @ 01-Jun-11	9,688.3							
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	(892.6)	(592.8)	(88.5)	(345.2)	0.0	(5.5)	(4.8)	
EE net replacements	(22.2)	(22.2)	(6.0)	(16.2)	0.0	0.0	0.0	
RPM load management @ 01-Jun-12	8,492.2	4,832.2	1,925.4	1,593.1	71.0	528.2	100.9	
DR cleared	9,802.4	6,005.2	2,588.4	1,650.3	146.1	1,183.8	534.8	547.8
EE cleared	748.6	204.5	55.2	113.5	2.0	25.8	9.2	36.7
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	10,551.0	6,209.7	2,643.6	1,763.8	148.1	1,209.6	544.0	584.5
DR cleared	14,118.4	7,236.8	2,866.8	2,234.4	220.9	964.2	443.3	893.1
EE cleared	822.1	199.6	20.9	161.3	5.0	4.8	0.0	42.9
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	14,940.5	7,436.4	2,887.7	2,395.7	225.9	969.0	443.3	936.0

18 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.

19 For 2010/2011, DPL zonal ILR MW are allocated to the DPL South LDA using the sub-zonal load ratio share (57.72 percent for DPL South).

20 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 2014/2015[21,22,23] (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	8,429.8	8,740.9	643.4	666.1	0.0	0.0
2013/2014	9,487.2	9,802.4	726.3	748.6	0.0	0.0
2014/2015	13,663.8	14,118.4	796.9	822.1	0.0	0.0

Table 4-8 RPM load management statistics: June 1, 2007 to June 1, 2014[24,25] (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)
1-Jun-07	1,708.1	1,763.9	0.0	0.0	0.0	0.0	1,708.1	1,763.9
1-Jun-08	4,029.4	4,167.5	(38.7)	(40.0)	0.0	0.0	3,990.7	4,127.5
1-Jun-09	7,138.3	7,374.4	(459.5)	(474.7)	0.0	0.0	6,678.8	6,899.7
1-Jun-10	8,892.2	9,199.3	(499.1)	(516.3)	0.0	0.0	8,393.1	8,683.0
1-Jun-11	10,570.7	10,935.6	(1,205.8)	(1,247.5)	0.2	0.2	9,365.1	9,688.3
1-Jun-12	9,073.2	9,407.0	(860.8)	(892.6)	(21.4)	(22.2)	8,191.0	8,492.2
1-Jun-13	10,213.5	10,551.0	0.0	0.0	0.0	0.0	10,213.5	10,551.0
1-Jun-14	14,460.7	14,940.5	0.0	0.0	0.0	0.0	14,460.7	14,940.5

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.[26,27,28]

21 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.

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

23 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.

24 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.

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

26 See OATT Attachment DD § 6.5.

27 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.

28 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: 2012/2013 RPM Auctions (See the 2011 SOM, Table 4-14)

	2012/2013 Base Residual Auction		2012/2013 ATSI Integration Auction		2012/2013 First Incremental Auction		2012/2013 Second Incremental Auction		2012/2013 Third Incremental Auction	
Offer Cap/Mitigation Type	Number of Generation Resources	Percent of Generation Resources Offered	Number of Generation Resources	Percent of Generation Resources Offered	Number of Generation Resources	Percent of Generation Resources Offered	Number of Generation Resources	Percent of Generation Resources Offered	Number of Generation Resources	Percent of Generation Resources Offered
Default ACR	465	41.0%	117	67.6%	92	56.8%	80	42.6%	35	11.7%
ACR data input (APIR)	118	10.4%	12	6.9%	14	8.6%	8	4.3%	2	0.7%
ACR data input (non-APIR)	2	0.2%	0	0.0%	0	0.0%	0	0.0%	0	0.0%
Opportunity cost input	8	0.7%	2	1.2%	2	1.2%	0	0.0%	0	0.0%
Default ACR and opportunity cost	14	1.2%	0	0.0%	0	0.0%	0	0.0%	0	0.0%
Offer cap of 1.1 times BRA clearing price elected	NA	NA	26	15.0%	NA	NA	NA	NA	130	43.6%
Uncapped planned uprate and default ACR	NA	NA	NA	NA	NA	NA	3	1.6%	0	0.0%
Uncapped planned uprate and opportunity cost	NA	NA	NA	NA	NA	NA	0	0.0%	0	0.0%
Uncapped planned uprate and price taker	NA	NA	NA	NA	NA	NA	2	1.1%	2	0.7%
Uncapped planned uprate and 1.1 times BRA clearing price elected	NA	NA	NA	NA	NA	NA	NA	NA	1	0.3%
Uncapped planned generation resources	11	1.0%	0	0.0%	17	10.5%	12	6.4%	10	3.4%
Price takers	515	45.5%	16	9.2%	37	22.8%	83	44.1%	118	39.6%
Total Generation Capacity Resources offered	1,133	100.0%	173	100.0%	162	100.0%	188	100.0%	298	100.0%

2012/2013 RPM Third Incremental Auction

As shown in Table 4-9, 298 generation resources submitted offers in the 2012/2013 Third Incremental Auction. Unit-specific offer caps were calculated for two resources (0.7 percent of all generation resources). The MMU calculated offer caps for 37 resources (12.4 percent), of which 35 were based on the technology specific default (proxy) ACR values. Of the 298 generation resources, 131 resources elected offer cap option of 1.1 times the BRA clearing price (44.0 percent), 10 planned generation resources had uncapped offers (3.4 percent), two resources had uncapped planned uprates along with price taker status (0.7 percent), one resource had an uncapped planned uprate along with the 1.1 times the BRA clearing price option for the existing portion (0.3 percent), while the remaining 118 resources were price takers (39.6 percent), of which the offers for 111 resources were zero and the offers for seven resources were set to zero because no data were submitted.

Market Performance[29]

In the 2012/2013 RPM Third Incremental Auction, participant sell offers were 5,569.4 MW, while participant buy bids were 7,459.2 MW. Cleared participant sell offers in the RTO were 2,403.5 MW, while cleared participant buy bids were 4,382.8 MW. Released capacity by PJM were 1,990.9 MW, while procured capacity by PJM were 11.6 MW. As shown in Table 4-10, the RTO clearing price in the 2012/2013 RPM Third Incremental Auction was $2.51 per MW-day.

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 $135.16 per MW-day in 2011 and then declined to $127.05 per MW-day in 2014. Figure 4-1 presents cleared MW weighted average capacity market prices on a calendar year basis for the entire history of the PJM capacity markets.

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

Cleared capacity resources across the entire RTO will receive a total of $2.2 million based on the unforced MW cleared and the prices in the 2012/2013 RPM Third Incremental Auction.

Table 4-11 shows RPM revenue by resource type for all RPM Auctions held to date with over $500 million for new/reactivated resources based on the unforced MW cleared and the resource clearing prices.

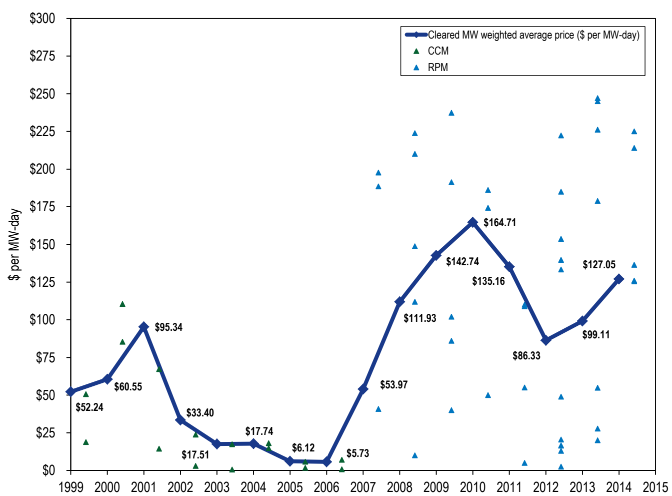
Table 4-10 Capacity prices: 2007/2008 through 2014/2015 RPM Auctions (See the 2011 SOM, Table 4-21)

		RPM Clearing Price ($ per MW-day)							
	Product Type	RTO	MAAC	APS	EMAAC	SWMAAC	DPL South	PSEG North	Pepco
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
2011/2012 Third Incremental Auction		$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
2012/2013 First Incremental Auction		$16.46	$16.46	$16.46	$153.67	$16.46	$153.67	$153.67	$16.46
2012/2013 Second Incremental Auction		$13.01	$13.01	$13.01	$48.91	$13.01	$48.91	$48.91	$13.01
2012/2013 Third Incremental Auction		$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
2013/2014 First Incremental Auction		$20.00	$20.00	$20.00	$178.85	$54.82	$178.85	$178.85	$54.82
2014/2015 BRA	Limited	$125.47	$125.47	$125.47	$125.47	$125.47	$125.47	$213.97	$125.47
2014/2015 BRA	Extended Summer	$125.99	$136.50	$125.99	$136.50	$136.50	$136.50	$225.00	$136.50
2014/2015 BRA	Annual	$125.99	$136.50	$125.99	$136.50	$136.50	$136.50	$225.00	$136.50

Table 4-11 RPM revenue by type: 2007/2008 through 2014/2015[30,31] (See the 2011 SOM, Table 4-22)

Type	2007/2008	2008/2009	2009/2010	2010/2011	2011/2012	2012/2013	2013/2014	2014/2015	Total
Demand Resources	$5,537,085	$35,349,116	$65,762,003	$60,235,796	$55,795,785	$264,387,898	$551,453,434	$666,313,051	$1,704,834,167
Energy Efficiency Resources	$0	$0	$0	$0	$139,812	$11,408,552	$20,680,368	$38,571,074	$70,799,806
Imports	$22,225,980	$60,918,903	$56,517,793	$106,046,871	$185,421,273	$13,260,822	$31,191,272	$178,063,746	$653,646,660
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	$1,736,326,997	$1,827,519,210	$14,122,252,257
Coal new/reactivated	$0	$0	$1,854,781	$3,168,069	$28,330,047	$7,414,940	$12,493,918	$56,917,305	$110,179,060
Gas existing	$1,514,681,896	$1,951,345,311	$2,329,209,917	$2,632,336,161	$1,607,317,731	$1,117,382,927	$1,894,356,673	$2,003,810,846	$15,050,441,462
Gas new/reactivated	$3,472,667	$9,751,112	$30,168,831	$58,065,964	$98,448,693	$76,633,409	$166,414,514	$184,029,455	$626,984,645
Hydroelectric existing	$209,490,444	$287,850,403	$364,742,517	$442,429,815	$278,529,660	$179,117,975	$308,742,213	$328,877,767	$2,399,780,793
Hydroelectric new/reactivated	$0	$0	$0	$0	$0	$11,397	$17,520	$6,591,114	$6,620,031
Nuclear existing	$996,085,233	$1,322,601,837	$1,517,723,628	$1,799,258,125	$1,079,386,338	$762,719,551	$1,346,024,263	$1,459,911,217	$10,283,710,191
Nuclear new/reactivated	$0	$0	$0	$0	$0	$0	$0	$0	$0
Oil existing	$448,034,948	$532,432,515	$663,370,167	$623,141,070	$368,084,004	$385,988,279	$620,740,652	$433,317,895	$4,075,109,531
Oil new/reactivated	$0	$4,837,523	$5,676,582	$4,339,539	$967,887	$2,772,987	$5,669,955	$3,896,120	$28,160,593
Solid waste existing	$29,956,764	$33,843,188	$41,243,412	$40,731,606	$25,636,836	$26,840,670	$43,613,120	$34,529,047	$276,394,643
Solid waste new/reactivated	$0	$0	$523,739	$413,503	$261,690	$469,608	$2,411,690	$1,190,758	$5,270,987
Solar existing	$0	$0	$0	$0	$0	$0	$0	$0	$0
Solar new/reactivated	$0	$0	$0	$0	$66,978	$1,246,337	$2,521,159	$2,371,155	$6,205,629
Wind existing	$430,065	$1,180,153	$2,011,156	$1,819,413	$1,072,929	$812,644	$1,372,110	$1,491,563	$10,190,033
Wind new/reactivated	$0	$2,917,048	$6,836,827	$15,232,177	$9,919,881	$5,052,036	$12,898,748	$30,987,962	$83,844,678
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	$6,756,928,604	$7,258,389,284	$49,514,425,166

Figure 4-1 History of capacity prices: Calendar year 1999 through 2014[32] (See the 2011 SOM, Figure 4-1)



30 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.
31 The results for the ATSI Integrations Auctions are not included in this table.
32 1999-2006 capacity prices are CCM combined market, weighted average prices. The 2007 capacity price is a combined CCM/RPM weighted average price. The 2008-2014 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.

Table 4-12 RPM cost to load: 2011/2012 through 2014/2015 RPM Auctions[33,34,35] (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	$16.73	65,495.4	$399,981,901
MAAC	$133.31	30,107.9	$1,464,999,689
EMAAC	$142.94	19,954.6	$1,041,085,667
DPL	$171.13	4,523.9	$282,576,598
PSEG	$157.60	11,645.3	$669,874,086
2013/2014			
RTO	$27.86	84,109.2	$855,248,034
MAAC	$227.11	15,244.6	$1,263,706,654
EMAAC	$245.32	37,751.5	$3,380,397,528
SWMAAC	$226.15	8,281.8	$683,618,413
Pepco	$239.36	7,861.0	$686,795,004
2014/2015			
RTO	$125.94	84,581.3	$3,888,042,879
MAAC	$135.25	52,277.4	$2,580,741,594
DPL	$142.99	4,615.4	$240,881,412
PSEG	$164.00	12,208.7	$730,811,202

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).[36]

Capacity Factor

Capacity factor measures the actual output of a power plant over a period of time compared to the potential output 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 March 2012, nuclear units had a capacity factor of 96.3 percent. Combined cycle units ran more often in January through March 2012 than in the same period in 2011, going from a 41.1 percent capacity factor in 2011 to a 63.0 percent capacity factor in 2012. Combined cycle units had a higher capacity factor than steam units, for which the capacity factor decreased from 51.8 percent in 2011 to 39.8 percent in January through March 2012. Due to inexpensive natural gas, this trend may continue, as efficient combined cycle units replace coal steam units in the PJM footprint.

Table 4-13 PJM capacity factor (By unit type (GWh)); January through March 2011 and 2012[37,38] (See the 2011 SOM, Table 4-24)

	Jan-Mar 2011		Jan-Mar 2012	
Unit Type	Generation (GWh)	Capacity Factor	Generation (GWh)	Capacity Factor
Battery	0.1	5.1%	0.1	0.1%
Combined Cycle	21,045.3	41.1%	35,691.6	63.0%
Combustion Turbine	500.5	0.8%	557.1	0.8%
Diesel	183.4	17.6%	214.5	19.1%
Diesel (Landfill gas)	168.7	40.2%	277.7	52.6%
Nuclear	65,194.7	95.9%	70,637.4	96.3%
Pumped Storage Hydro	1,652.5	13.9%	1,227.8	10.2%
Run of River Hydro	1,995.2	39.4%	2,130.1	40.4%
Solar	7.0	9.2%	43.9	13.8%
Steam	89,295.8	51.8%	79,543.8	39.8%
Wind	3,363.8	36.0%	4,261.3	37.3%
Total	183,407.0	48.6%	194,585.3	45.6%

33 The RPM annual charges are calculated using the rounded, net load prices as posted in the PJM Base Residual Auction results.
34 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.
35 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 2012/2013, 2013/2014, and 2014/2015 Net Load Prices are not finalized. The 2012/2013, 2013/2014, and 2014/2015 Obligation MW are not finalized.
36 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.
37 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.
38 The capacity factor for solar units in 2011 contains a significantly smaller sample of units than 2012.

Generator Performance Factors

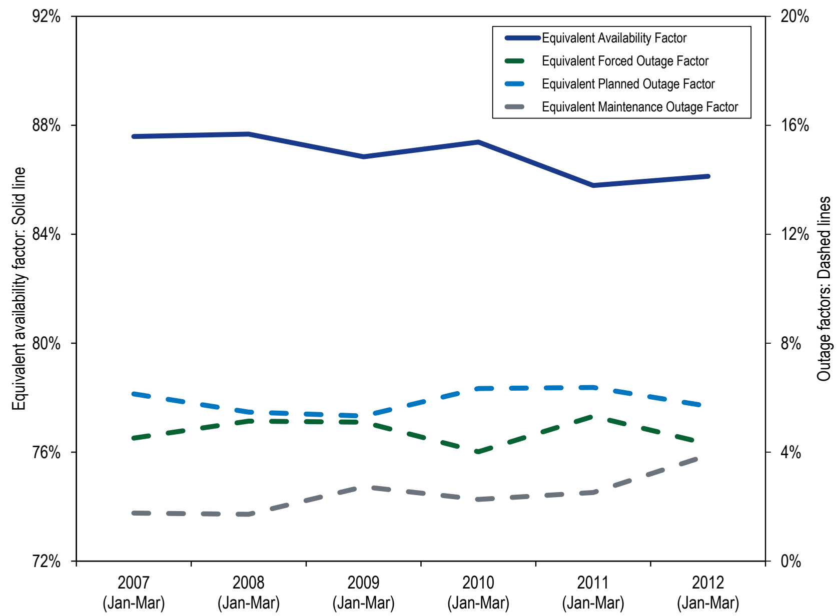
Generator performance factors are based on a defined period, usually a year, and are directly comparable.[39] Performance factors include the equivalent availability factor (EAF), the equivalent maintenance outage factor (EMOF), the equivalent planned outage factor (EPOF) and the equivalent forced outage 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 85.8 percent in January through March 2011 to 86.1 percent in 2012. The EMOF increased from 2.5 percent to 3.9 percent, the EPOF decreased from 6.4 percent to 5.7 percent, and the EFOF decreased from 5.3 percent to 4.3 percent (Figure 4-2).[40]

39 Data from all PJM capacity resources for the years 2007 through 2012 were analyzed.

40 Data are for the three months ending March 31 as downloaded from the PJM GADS database on April 28, 2012. Annual EFORd data presented in state of the market reports may be revised based on data submitted after the publication of the reports as generation owners may submit corrections at any time with permission from PJM GADS administrators.

Figure 4-2 PJM equivalent outage and availability factors: Calendar years 2007 to 2012 (See the 2011 SOM, Figure 4-2)



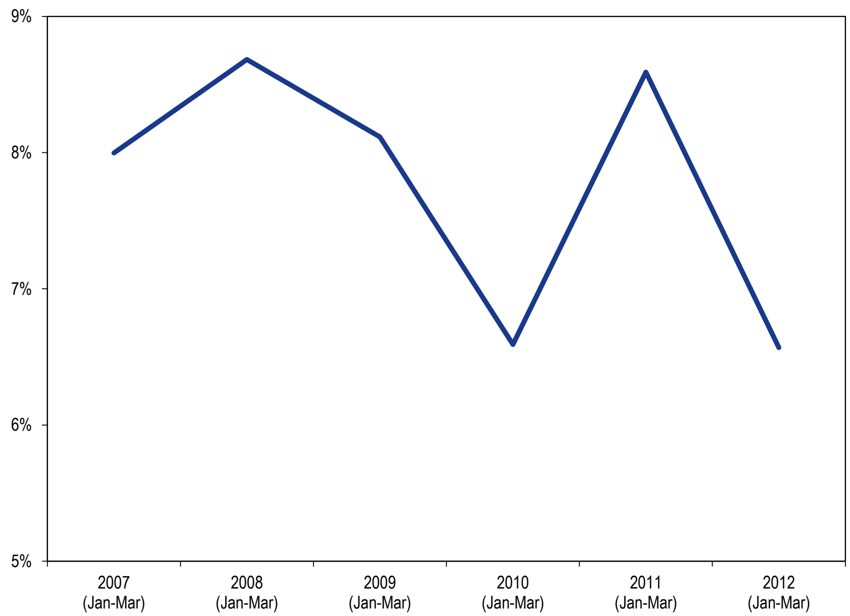
Generator Forced Outage Rates

The equivalent demand forced outage rate (EFORd) (generally referred to as the forced outage rate) 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 is calculated using historical performance data. PJM systemwide EFORd is a capacity-weighted average of individual unit EFORd. Unforced capacity in the PJM Capacity Market for any individual generating unit is equal to one minus the EFORd adjusted to exclude Outside Management Control (OMC) events multiplied by the unit's net dependable summer capability.[41] The PJM Capacity Market creates an incentive to minimize the forced outage rate because the amount of capacity resources available to sell from a unit (unforced capacity) is inversely related to the forced outage rate.

41 EFORd adjusted to exclude Outside Management Control (OMC) events is defined as XEFORd.

EFORd calculations use historical data, including equivalent forced outage hours,[42] service hours, average forced outage duration, average run time, average time between unit starts, available hours and period hours.[43] The average PJM EFORd decreased from 8.6 percent in the three months January through March 2011 to 6.6 percent in the three months January through March 2012. Figure 4-3 shows the average January through March EFORd since 2007 for all units in PJM.

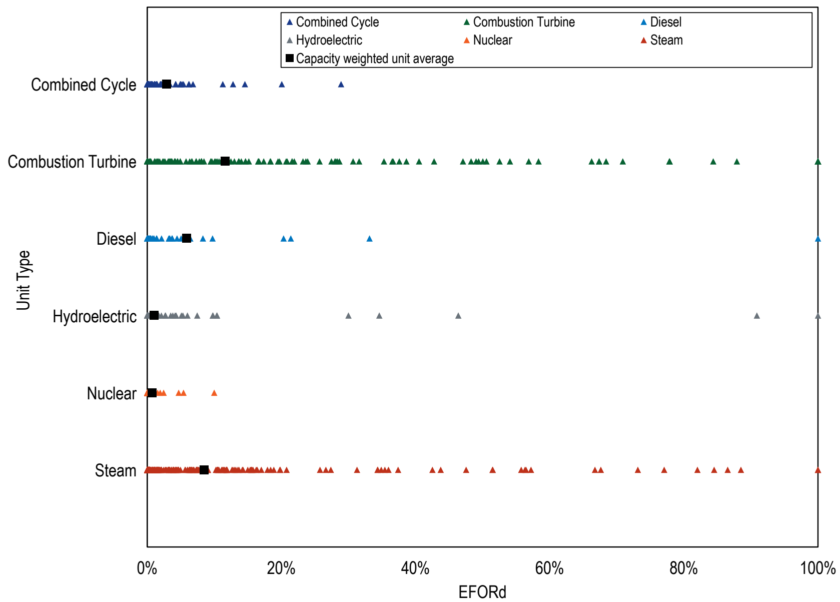
Figure 4-3 Trends in the PJM equivalent demand forced outage rate (EFORd): January through March 2007 to 2012 (See the 2011 SOM, Figure 4-3)



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



42 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.
43 See "Manual 22: Generator Resource Performance Indices," Revision 16 (November 16, 2011), Equations 2 through 5.

Components of EFORd

Table 4-14 PJM EFORd data for different unit types: January through March 2007 to 2012 (See the 2011 SOM, Table 4-25)

	2007 (Jan-Mar)	2008 (Jan-Mar)	2009 (Jan-Mar)	2010 (Jan-Mar)	2011 (Jan-Mar)	2012 (Jan-Mar)
Combined Cycle	6.3%	4.8%	4.9%	2.9%	3.4%	1.9%
Combustion Turbine	20.6%	16.2%	12.8%	11.6%	11.4%	9.4%
Diesel	9.1%	10.1%	8.2%	5.9%	5.0%	2.6%
Hydroelectric	1.9%	2.9%	1.9%	1.0%	2.1%	1.0%
Nuclear	0.4%	1.5%	3.8%	0.7%	1.6%	0.9%
Steam	7.9%	10.4%	9.5%	8.5%	12.1%	9.3%
Total	8.0%	8.7%	8.1%	6.6%	8.6%	6.6%

Table 4-15 shows the contribution of each unit type to the system EFORd, calculated as the total forced MW for the unit type divided by the total capacity of the system.[44] Forced MW for a unit type is the EFORd multiplied by the generator's net dependable summer capability.

Table 4-15 Contribution to EFORd for specific unit types (Percentage points): January through March 2007 to 2012[45] (See the 2011 SOM, Table 4-26)

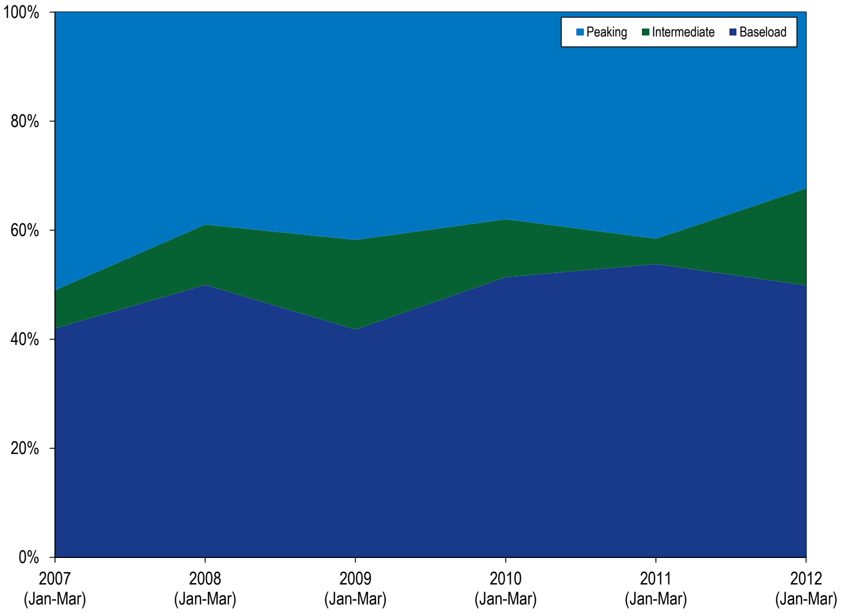
	2007 (Jan-Mar)	2008 (Jan-Mar)	2009 (Jan-Mar)	2010 (Jan-Mar)	2011 (Jan-Mar)	2012 (Jan-Mar)
Combined Cycle	0.7	0.5	0.5	0.3	0.4	0.2
Combustion Turbine	3.3	2.5	2.0	1.9	1.9	1.5
Diesel	0.0	0.0	0.0	0.0	0.0	0.0
Hydroelectric	0.1	0.1	0.1	0.0	0.1	0.0
Nuclear	0.1	0.3	0.7	0.1	0.3	0.2
Steam	3.8	5.2	4.7	4.2	5.9	4.6
Total	8.0	8.7	8.1	6.6	8.6	6.6

Steam units continue to be the largest contributor to overall PJM EFORd.

Duty Cycle and EFORd

In addition to disaggregating system EFORd by unit type, units were categorized by actual duty cycles as baseload, intermediate or peaking to determine the relationship between type of operation and forced outage rates.[46] Figure 4-5 shows the contribution of unit types to system average EFORd.

Figure 4-5 Contribution to EFORd by duty cycle: January through March 2007 to 2012 (See the 2011 SOM, Figure 4-5)



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.[47] On a systemwide basis, the resultant lost equivalent availability from the forced outages is equal to the equivalent forced outage factor.

44 The generating unit types are: combined cycle, combustion turbine, diesel, hydroelectric, nuclear and steam. For all tables, run of river and pumped storage hydroelectric are combined into a single hydroelectric category.

45 Calculated values presented in Section 4, "Capacity Market" at "Generator Performance" are based on unrounded, underlying data and may differ from those derived from the rounded values shown in the tables.

46 Duty cycle is the time the unit is generating divided by the time the unit is available to generate. A baseload unit is defined here as a unit that generates during 50 percent or more of its available hours. An intermediate unit is defined here as a unit that generates during from 10 percent to 50 percent of its available hours. A peaking unit is defined here as a unit that generates during less than 10 percent of its available hours.

47 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.

For the three months January through March 2012, PJM EFOF was 4.3 percent. This means there was 4.3 percent lost availability because of forced outages. Table 4-16 shows that forced outages for boiler tube leaks, at 18.9 percent of the systemwide EFOF, were the largest single contributor to EFOF.

Table 4-16 Contribution to EFOF by unit type by cause: January through March 2012 (See the 2011 SOM, Table 4-27)

	Combined Cycle	Combustion Turbine	Diesel	Hydroelectric	Nuclear	Steam	System
Boiler Tube Leaks	2.4%	0.0%	0.0%	0.0%	0.0%	21.7%	18.9%
Boiler Piping System	1.5%	0.0%	0.0%	0.0%	0.0%	10.6%	9.2%
Economic	0.6%	1.6%	1.6%	0.2%	0.0%	9.8%	8.6%
Electrical	3.2%	15.2%	0.5%	8.6%	30.4%	4.6%	6.1%
High Pressure Turbine	0.0%	0.0%	0.0%	0.0%	0.0%	6.7%	5.8%
Boiler Air and Gas Systems	0.0%	0.0%	0.0%	0.0%	0.0%	6.0%	5.2%
Feedwater System	9.9%	0.0%	0.0%	0.0%	5.6%	5.0%	4.9%
Reserve Shutdown	0.0%	17.5%	4.2%	11.9%	0.0%	4.0%	4.6%
Boiler Fuel Supply from Bunkers to Boiler	0.2%	0.0%	0.0%	0.0%	0.0%	5.0%	4.4%
Precipitators	0.0%	0.0%	0.0%	0.0%	0.0%	3.1%	2.7%
Miscellaneous (Generator)	10.0%	7.5%	0.9%	15.3%	0.0%	1.9%	2.5%
Other Operating Environmental Limitations	0.0%	0.0%	0.0%	0.0%	1.1%	2.8%	2.5%
Slag and Ash Removal	0.0%	0.0%	0.0%	0.0%	0.0%	2.3%	2.0%
Valves	3.9%	0.0%	0.0%	0.0%	0.0%	2.1%	1.9%
Boiler Tube Fireside Slagging or Fouling	0.0%	0.0%	0.0%	0.0%	0.0%	2.0%	1.8%
Controls	8.4%	1.8%	0.0%	1.8%	17.5%	0.9%	1.8%
Cooling System	0.1%	0.0%	4.0%	12.5%	19.8%	0.7%	1.3%
Fuel, Ignition and Combustion Systems	9.6%	13.9%	0.0%	0.0%	0.0%	0.0%	1.1%
Miscellaneous (Steam Turbine)	2.6%	0.0%	0.0%	0.0%	1.4%	1.0%	1.0%
All Other Causes	47.6%	42.6%	88.7%	49.6%	24.2%	9.8%	13.8%
Total	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%

Table 4-17 shows the categories which are included in the economic category.[48] Lack of fuel that is considered Outside Management Control accounted for 97.9 percent of all economic reasons while lack of fuel that was not Outside Management Control accounted for only 2.0 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"[49]. 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.

48 The classification and definitions of these outages are defined by NERC GADS.
49 The classification and definitions of these outages are defined by NERC GADS.

Table 4-17 Contributions to Economic Outages: January through March 2012 (See the 2011 SOM, Table 4-28)

	Contribution to Economic Reasons
Lack of fuel (OMC)	97.9%
Lack of fuel (Non-OMC)	2.0%
Ground water or other water supply problems	0.0%
Lack of water (Hydro)	0.0%
Other economic problems	0.0%
Total	100.0%

Table 4-18 Contribution to EFOF by unit type: January through March 2012 (See the 2011 SOM, Table 4-29)

	EFOF	Contribution to EFOF
Combined Cycle	1.6%	3.0%
Combustion Turbine	2.2%	6.0%
Diesel	3.8%	0.1%
Hydroelectric	0.7%	0.7%
Nuclear	0.7%	3.5%
Steam	6.7%	86.7%
Total	4.0%	100.0%

Outages Deemed Outside Management Control

In 2006, NERC created specifications for certain types of outages to be deemed Outside Management Control (OMC).[50] 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."

50 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/2009_GADS_DRI_Complete_SetVersion_010111.pdf>.

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.[51] Not all outages caused by the factors in these specific OMC cause codes are OMC outages. For example, fuel quality issues (i.e., codes 9200 to 9299) may be within the control of the owner or outside management control. Each outage must be considered per the NERC directive.

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 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 4-19 shows OMC forced outages by cause code. OMC forced outages account for 10.6 percent of all forced outages. The largest contributor to OMC outages, lack of fuel, is the cause of 79.7 percent of OMC outages and 8.4 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." Of the OMC lack of fuel outages in 2012, 79.5 percent of the outages were submitted by units operated by a single owner.

It is questionable whether the OMC outages defined as lack of fuel should be identified as OMC and 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 transparent set of rules governing the designation of outages as OMC and post those guidelines. The MMU also recommends that PJM consider eliminating lack of fuel as an acceptable basis for an OMC outage.

Table 4-19 OMC Outages: January through March 2012 (See the 2011 SOM, Table 4-30)

OMC Cause Code	% of OMC Forced Outages	% of all Forced Outages
Lack of fuel	79.7%	8.4%
Other switchyard equipment external	6.1%	0.6%
Switchyard circuit breakers external	5.4%	0.6%
Transmission line	4.4%	0.5%
Transmission equipment beyond the 1st substation	2.3%	0.2%
Tornados	0.6%	0.1%
Flood	0.5%	0.1%
Transmission system problems other than catastrophes	0.4%	0.0%
Transmission equipment at the 1st substation	0.2%	0.0%
Switchyard transformers and associated cooling systems external	0.2%	0.0%
Lightning	0.1%	0.0%
Switchyard system protection devices external	0.1%	0.0%
Lack of water (hydro)	0.0%	0.0%
Storms (ice, snow, etc)	0.0%	0.0%
Total	100.0%	10.6%

Table 4-20 shows the impact of OMC outages on EFORd for 2012. The difference is especially noticeable for steam units and combustion turbine units. For steam units, the OMC outage reason that resulted in the highest total MW loss in 2012 was lack of fuel. Combustion turbine units have natural gas fuel curtailment outages that were also classified as OMC. If companies' natural gas fuel supply is curtailed because of pipeline issues, the event can be deemed OMC. However, natural gas curtailments caused by lack of firm transportation contracts or arbitraging transportation reservations should not be classified as OMC. In 2012, steam XEFORd was 1.2 percentage points less than EFORd, which translates into a 1,004 MW difference in unforced capacity.

51 For a list of these cause codes, see the *MMU Technical Reference for PJM Markets*, at "Generator Performance: NERC OMC Outage Cause Codes."

Table 4-20 PJM EFORd vs. XEFORd: January through March 2012 (See the 2011 SOM, Table 4-31)

	EFORd	XEFORd	Difference
Combined Cycle	1.9%	1.8%	0.1%
Combustion Turbine	9.4%	6.3%	3.1%
Diesel	2.6%	1.4%	1.2%
Hydroelectric	1.0%	1.0%	0.1%
Nuclear	0.9%	0.9%	0.0%
Steam	9.3%	8.2%	1.2%
Total	6.6%	5.5%	1.1%

Components of 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.

Table 4-21 shows the contribution of each unit type to the system EFORp, calculated as the total forced MW for the unit type divided by the total capacity of the system. Forced MW for a unit type is the EFORp multiplied by the generator's net dependable summer capability.

Table 4-21 Contribution to EFORp by unit type (Percentage points): January through March 2011 to 2012 (See the 2011 SOM, Table 4-32)

	2011 (Jan-Mar)	2012 (Jan-Mar)
Combined Cycle	0.2	0.1
Combustion Turbine	0.4	0.1
Diesel	0.0	0.0
Hydroelectric	0.1	0.1
Nuclear	0.4	0.2
Steam	3.5	1.6
Total	4.7	2.1

Table 4-22 PJM EFORp data by unit type: January through March 2011 to 2012 (See the 2011 SOM, Table 4-33)

	2011 (Jan-Mar)	2012 (Jan-Mar)
Combined Cycle	2.1%	0.8%
Combustion Turbine	2.6%	0.9%
Diesel	1.7%	0.5%
Hydroelectric	2.0%	1.4%
Nuclear	2.3%	0.8%
Steam	7.2%	3.3%
Total	4.7%	2.1%

EFORd, XEFORd and 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. EFORp of nuclear units is slightly higher than EFORd and XEFORd, suggesting that nuclear units have a slightly higher rate of forced outages during the peak months of January, February, June, July and August.

Table 4-23 shows the contribution of each unit type to the system EFORd, XEFORd and EFORp, calculated as the total forced MW for the unit type divided by the total capacity of the system. Table 4-24 shows the capacity-weighted class average of EFORd, XEFORd and EFORp.

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

Table 4-23 Contribution to PJM EFORd, XEFORd and EFORp by unit type: January through March 2012 (See the 2011 SOM, Table 4-34)

	EFORd	XEFORd	EFORp
Combined Cycle	0.2	0.2	0.1
Combustion Turbine	1.5	1.0	0.1
Diesel	0.0	0.0	0.0
Hydroelectric	0.0	0.0	0.1
Nuclear	0.2	0.2	0.2
Steam	4.6	4.1	1.6
Total	6.6	5.5	2.1

Table 4-24 PJM EFORd, XEFORd and EFORp data by unit type: January through March 2012[53] (See the 2011 SOM, Table 4-35)

	EFORd	XEFORd	EFORp	Difference EFORd and XEFORd	Difference EFORd and EFORp
Combined Cycle	1.9%	1.8%	0.8%	0.1%	1.1%
Combustion Turbine	9.4%	6.3%	0.9%	3.1%	8.5%
Diesel	2.6%	1.4%	0.5%	1.2%	2.0%
Hydroelectric	1.0%	1.0%	1.4%	0.1%	(0.4%)
Nuclear	0.9%	0.9%	0.8%	0.0%	0.1%
Steam	9.3%	8.2%	3.3%	1.2%	6.1%
Total	6.6%	5.5%	2.1%	1.1%	4.5%

Comparison of Expected and Actual Performance

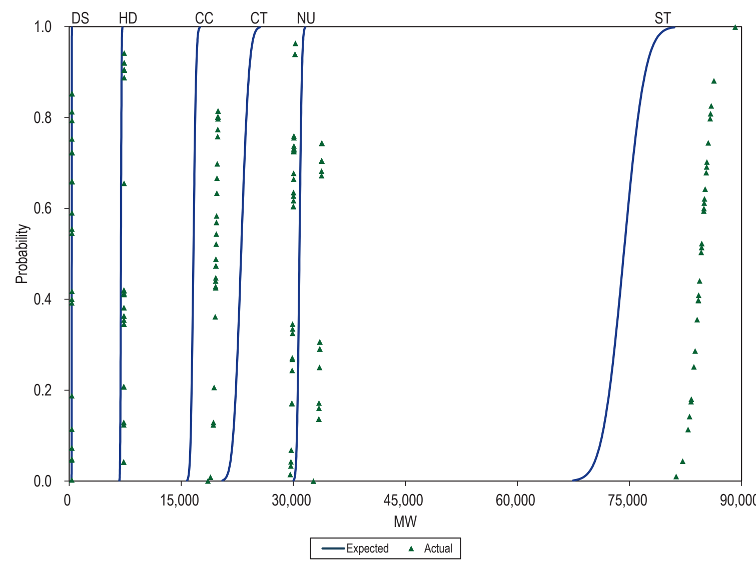
If the unit EFORd were normally distributed and if EFORd based planning assumptions were consistent with actual unit performance, the distribution of actual performance would be identical to a hypothetical normal distribution based on average EFORd performance. There are a limited number of units within each unit type and the distribution of EFORd may not be a normal distribution.

This analysis was performed based on resource-specific EFORd and Summer Net Capability capacity values for the three months ending March 31, 2012.[54] These values were used to estimate a normal distribution for each unit type,[55] which was superimposed on a distribution of actual historical availability for the same resources for the three months ending March 31, 2012.[56] The top thirty load days were selected for each year and the performance of the resources was evaluated for the peak hour of those days, a sample of 30 peak load hours.

Figure 4-6 compares the normal distribution to the actual distribution based on the defined sample.

Overall, generating units performed better during the selected peak hours than would have been expected based on the EFORd statistic. In particular, combustion turbine and steam units tend to have more capacity available during the sampled hours than implied by the EFORd statistic.

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



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

54 See "Manual 21: Rules and Procedures for Determination of Generating Capability," Revision 09 (May 1, 2010), Summer Net Capability.

55 The formulas used to approximate the parameters of the normal distribution are defined as:

$$\text{Mean} = \sum_i \left[MW_i * (1 - EFORd_i) \right]$$

$$\text{Variance} = \sum_i \left[MW_i * MW_i * (1 - EFORd_i) * EFORd_i \right]$$

$$\text{Standard Deviation} = \sqrt{\text{Variance}}$$

56 Availability calculated as net dependable capacity affected only by forced outage and forced derating events. Planned and maintenance events were excluded from this analysis.

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)

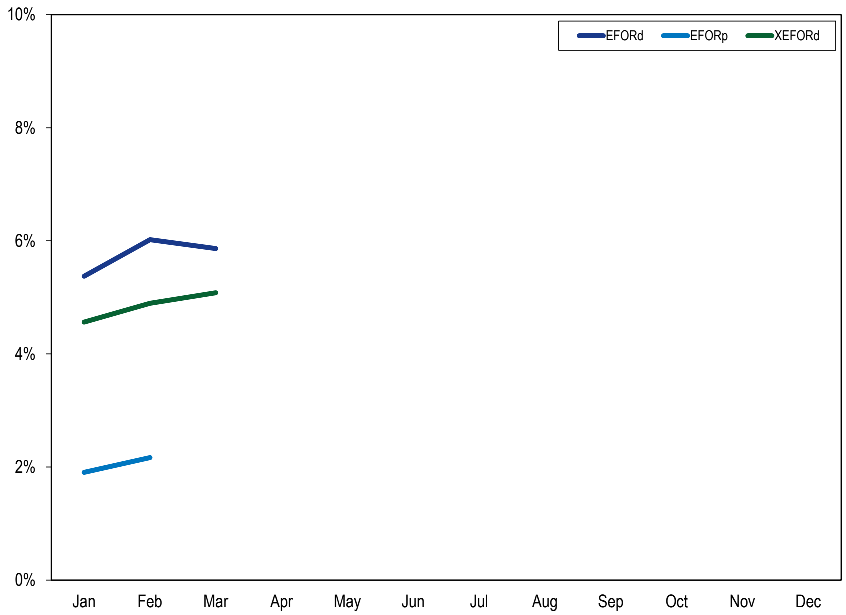


Figure 4-8 PJM monthly generator performance factors: 2012 (See the 2011 SOM, Figure 4-8)