# SECTION 5 – CAPACITY MARKET

Each organization serving PJM load must meet its capacity obligations by acquiring capacity resources through the PJM Capacity Market, where load serving entities (LSEs) must pay the locational capacity price for their zone. LSEs can affect the financial consequences of purchasing capacity 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.

## Overview

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 2010, including supply, demand, concentration ratios, pivotal suppliers, volumes, prices, outage rates and reliability.

### RPM Capacity Market

### Market Design

On June 1, 2007, the Reliability Pricing Model (RPM) Capacity Market design was implemented in the PJM region, replacing the Capacity Credit Market (CCM) design that had been in place since 1999.[1] The RPM design represents a significant change in the structure of the Capacity Market in PJM. The RPM is a forward-looking, annual, locational market, with a must offer requirement for capacity and mandatory participation by load, with performance incentives for generation, that includes clear, market power mitigation rules and that permits the direct participation of demand-side resources.

Under RPM, capacity obligations are annual. Base Residual Auctions (BRA) are held for delivery years that are three years in the future. Effective with the 2012/2013 delivery year, First, Second and Third Incremental Auctions (IA) are held for each delivery year.[2] Prior to the 2012/2013 delivery year, the second incremental auction is conducted if PJM determines than an unforced capacity resource shortage exceeds 100 MW of unforced capacity due to a load forecast increase. Effective January 31, 2010, First, Second, and Third Incremental Auctions are conducted 20, 10, and three months prior to the delivery year.[3] Previously, First, Second, and Third Incremental Auctions were conducted 23, 13, and four months, respectively, prior to the delivery year. Also effective for the 2012/2013 delivery year, a conditional incremental auction may be held if there is a need to procure additional capacity resulting from a delay in a planned large transmission upgrade that was modeled in the BRA for the relevant delivery year.

RPM prices are locational and may vary depending on transmission constraints.[4] Existing generation capable of qualifying as a capacity resource must be offered into RPM Auctions, except for resources owned by entities that elect the fixed resource requirement (FRR) option.  Participation by LSEs is mandatory, except for those entities that elect the FRR option. There is an administratively determined demand curve that defines scarcity pricing levels and that, with the supply curve derived from capacity offers, determines market prices in each BRA. RPM rules provide performance incentives for generation, including the requirement to submit generator outage data and the linking of capacity payments to the level of unforced capacity. Under RPM there are explicit market power mitigation rules that define the must offer requirement, that define structural market power, that define offer caps based on the marginal cost of capacity and that have flexible criteria for competitive offers by new entrants or by entrants that have an incentive to exercise monopsony power. Demand-side resources and Energy Efficiency resources may be offered directly into RPM auctions and receive the clearing price without mitigation.

### Market Structure

- **Supply.** Total internal capacity increased 350.2 MW from 156,968.0 MW on June 1, 2008, to 157,318.2 MW on June 1, 2009.[5] This increase was the result of 439.2 MW of new generation, 74.1 MW of generation uprates, 220.6 MW of demand resource (DR) modifications (mods),

1 The terms *PJM Region*, *RTO Region* and *RTO* are synonymous in the *2010 Quarterly State of the Market Report for PJM: January through March*, Section 5, "Capacity Market" and include all capacity within the PJM footprint.

2 126 FERC ¶ 61,275 (2009).
3 *PJM Interconnection, L.L.C.*, OATT Revisions, Docket No. ER10-366-000 (December 1, 2009).
4 Transmission constraints are local capacity import capability limitations (low capacity emergency transfer limit (CETL) margin over capacity emergency transfer objective (CETO)) caused by transmission facility limitations, voltage limitations or stability limitations.
5 Unless otherwise specified, all volumes are in terms of UCAP.

and a decrease of 383.7 MW due to higher Equivalent Demand Forced Outage Rates (EFORds).

In the 2010/2011, 2011/2012, and 2012/2013 auctions, new generation increased 3,271.9 MW; 651.9 MW came out of retirement and net generation deratings were 2,994.9 MW, for a total of 928.9 MW. DR and EE offers increased 9,409.3 MW through June 1, 2012. A decrease of 890.3 MW was due to higher EFORds. The reclassification of the Duquesne resources as internal added 3,187.2 MW to total internal capacity. The net effect from June 1, 2009, through June 1, 2012, was an increase in total internal capacity of 12,635.1 MW (8.0 percent) from 157,318.2 MW to 169,953.3 MW.

In the 2009/2010 auction, 17 more generating resources made offers than in the 2008/2009 RPM Auction. The increase consisted of 11 new resources (439.2 MW), nine resources that were previously entirely FRR committed (82.5 MW), two less resources exported (698.6 MW), and two fewer resources excused from offering into the auction (37.3 MW) offset by five excused resources (44.5 MW), one less external resource that did not offer (60.4 MW), and one additional resource committed fully to FRR (10.0 MW). The new resources consisted of eight new combustion turbine (CT) resources (380.2 MW), two new diesel resources (9.2 MW) and one new steam resource (49.8 MW).

In the 2010/2011 auction, 11 more generating resources made offers than in the 2009/2010 RPM auction. The increase consisted of 15 new resources (406.9 MW), four reactivated resources (161.7 MW), three that were previously entirely FRR committed (10.9 MW), one less resource excused from offering (3.9 MW), and one less resource entirely exported (39.9 MW), offset by four deactivated resources (59.6 MW), four resources exported from PJM (554.0 MW), three retired resources (348.4 MW), and two resources excused from offering (108.8 MW). The new resources consisted of seven CT resources (270.5 MW), five new wind resources (120.0 MW), three new diesel resources (16.4 MW), and four reactivated resources (165.0 MW).

In the 2011/2012 auction, 21 more generating resources made offers than in the 2010/2011 RPM auction. The increase consisted of 20 new resources (2,203.7 MW), four reactivated resources (486.9 MW), three fewer excused resources (126.3 MW), and one additional resource imported (663.2 MW), offset by five additional resources committed fully to FRR (1.0 MW) and two retired resources (87.3 MW). The new resources consisted of 11 new CT resources (728.7 MW), four new wind resources (75.2 MW), two new steam resources (838.0 MW), one new combined cycle resource (556.5 MW), one new diesel resource (4.2 MW) and one new solar resource (1.1 MW).

In the 2012/2013 auction, eight more generating resources made offers than in the 2011/2012 RPM auction. The net increase of eight resources consisted of 16 new resources (772.5 MW), four resources that were previously entirely FRR committed (13.4 MW), three additional resources imported (276.8 MW), two additional resources resulting from disaggregation of RPM resources, and one resource formerly unoffered (1.9 MW), offset by nine retired resources (1,044.5 MW), four additional resources committed fully to FRR (39.5 MW), four less resources resulting from aggregation of RPM resources, and one less external resource that did not offer (663.2 MW).[6] In addition, there were the following retirements of resources that were either exported or excused in the 2011/2012 BRA: two CT resources (5.3 MW) and three combined cycle resources (297.6 MW). Also, resources that are no longer PJM capacity resources consisted of three CT units (521.5 MW) in the RTO. The new units consisted of six new diesel resources (13.9 MW), four new wind resources (57.9 MW), three new steam units (560.4 MW), and three new CT units (140.3 MW).

- **Demand.** There was a 2,545.5 MW increase in the RPM reliability requirement from 150,934.6 MW on June 1, 2008 to 153,480.1 MW on June 1, 2009. On June 1, 2009, PJM Electric Distribution Companies (EDCs) and their affiliates maintained a 79.6 percent market share of load obligations under RPM, down from 80.1 percent on June 1, 2008.

- **Market Concentration.** For the 2009/2010, 2010/2011, 2011/2012, and 2012/2013 RPM Auctions, all defined markets failed the preliminary market structure screen (PMSS). In the 2009/2010 BRA, 2009/2010 Third IA, 2010/2011 BRA, 2010/2011 Third IA, 2011/2012 BRA, and 2011/2012 First IA all participants in the total PJM market as well as the locational deliverability area (LDA) markets failed the three pivotal supplier (TPS) market structure test. In the 2012/2013 BRA, all participants in the RTO as well as MAAC, PSEG North, and DPL South RPM markets failed the TPS test. Six participants included in the incremental supply of EMAAC passed the test. Offer caps were applied to all sell offers that did not pass the test.

6 Disaggregation and aggregation of RPM resources reflect changes in how units are offered in RPM. For example, multiple units at a plant may be offered as a single unit or multiple units.

- **Imports and Exports.** Net exchange increased 1,688.3 MW from June 1, 2008 to June 1, 2009. Net exchange, which is imports less exports, increased due to an increase in imports of 45.1 MW and a decrease in exports of 1,643.2 MW.

- **Demand-Side and Energy Efficiency Resources.** Under RPM, demand-side resources in the Capacity Market increased by 3,206.9 MW from 4,167.5 MW on June 1, 2008 to 7,374.4 MW on June 1, 2009. Prior to the 2012/2013 delivery year, demand-side resources included DR cleared in the RPM Auctions and certified/forecast interruptible load for reliability (ILR). For delivery years 2012/2013 and beyond, ILR was eliminated and demand-side resources include DR and EE resources.

- **Net Excess.** Net excess increased 3,254.4 MW from 5,011.1 MW on June 1, 2008 to 8,265.5 MW on June 1, 2009.

## Market Conduct

- **2009/2010 RPM Base Residual Auction.** Of the 1,093 generating resources which submitted offers, unit-specific offer caps were calculated for 151 resources (13.8 percent). Offer caps of all kinds were calculated for 550 resources (50.3 percent), of which 377 were based on the technology specific default (proxy) ACR calculated by the MMU.

- **2009/2010 Third Incremental Auction.** Of the 267 generating resources which submitted offers, 255 resources chose the offer cap option of 1.1 times the BRA clearing price (95.5 percent).[7] Unit-specific offer caps were calculated for two resources (0.7 percent). Offer caps of all kinds were calculated for five resources (1.9 percent), of which one was based on the technology specific default (proxy) ACR calculated by the MMU.

- **2010/2011 RPM Base Residual Auction.** Of the 1,104 generating resources which submitted offers, unit-specific offer caps were calculated for 154 resources (13.9 percent). Offer caps of all kinds were calculated for 532 resources (48.1 percent), of which 370 were based on the technology specific default (proxy) ACR calculated by the MMU.

- **2010/2011 Third Incremental Auction.** Of the 303 generating resources which submitted offers, 193 resources chose the offer cap option of 1.1 times the BRA clearing price (63.7 percent). Unit-specific offer caps were calculated for one resource (0.3 percent). Offer caps of all kinds were calculated for nine resources (2.9 percent), of which seven were based on the technology specific default (proxy) ACR calculated by the MMU.

- **2011/2012 RPM Base Residual Auction.** Of the 1,125 generating resources which submitted offers, unit-specific offer caps were calculated for 145 resources (12.9 percent). Offer caps of all kinds were calculated for 472 resources (42.0 percent), of which 303 were based on the technology specific default (proxy) ACR calculated by the MMU.

- **2011/2012 RPM First Incremental Auction.** Of the 129 generating resources which submitted offers, unit-specific offer caps were calculated for 19 resources (14.7 percent). Offer caps of all kinds were calculated for 68 resources (52.8 percent), of which 47 were based on the technology specific default (proxy) ACR calculated by the MMU.

- **2012/2013 RPM Base Residual Auction.**[8] Of the 1,133 generating resources which submitted offers, unit-specific offer caps were calculated for 120 resources (10.6 percent). Offer caps of all kinds were calculated for 607 resources (53.6 percent), of which 479 were based on the technology specific default (proxy) ACR calculated by the MMU.

## Market Performance

### *2009/2010 RPM Base Residual Auction*

- **RTO.** Total internal RTO unforced capacity of 157,318.2 MW includes all generating units and DR that qualified as a PJM capacity resource for the 2009/2010 RPM Base Residual Auction, excludes external units and reflects owners' modifications to installed capacity (ICAP) ratings. After accounting for FRR committed resources and imports, RPM capacity was 136,300.4 MW. The 132,231.8 MW of cleared resources for the entire RTO represented a reserve margin of 17.8 percent, which was 1,784.0 MW greater than the reliability requirement of 130,447.8 MW (installed reserve margin (IRM) of 15.0 percent) and resulted in a clearing price of $102.04 per MW-day.

  Total cleared resources in the RTO were 132,231.8 MW which resulted in a net excess of 8,265.5 MW, an increase of 3,254.4 MW from the net excess of 5,011.1 MW in the 2008/2009 RPM BRA. Certified interruptible load for reliability (ILR) was 6,481.5 MW.

7 124 FERC ¶ 61,140 (2008).

8 For a more detailed analysis of the 2012/2013 RPM Base Residual Auction, see "Analysis of the 2012/2013 RPM Base Residual Auction" (August 6, 2009) <http://www.monitoringanalytics.com/reports/Reports/2009/Analysis_of_2012_2013_RPM_Base_Residual_Auction_20090806.pdf>

Cleared resources across the entire RTO will receive a total of $7.5 billion based on the unforced MW cleared and the prices in the 2009/2010 RPM BRA, an increase of approximately $1.4 billion from the 2008/2009 planning year.

- **MAAC+APS.**[9] Total internal MAAC+APS unforced capacity of 73,012.9 MW includes all generating units and DR that qualified as a PJM capacity resource, excludes external units and reflects owners' modifications to ICAP ratings. Including imports into MAAC+APS, RPM unforced capacity was 73,102.2 MW.[10] Of the 5,764.9 MW of incremental supply, 5,314.7 MW cleared, which resulted in a resource-clearing price of $191.32 per MW-day.

  Total resources in MAAC+APS were 77,488.7 MW, which when combined with certified ILR of 3,081.0 MW resulted in a net excess of 2,666.8 MW (3.4 percent) greater than the reliability requirement of 77,902.9 MW.

- **SWMAAC.** Total internal SWMAAC unforced capacity of 10,345.2 MW includes all generating units and DR that qualified as a PJM capacity resource, excludes external units and reflects owners' modifications to ICAP ratings. There were no imports from outside PJM into SWMAAC. Of the 2,413.7 MW of incremental supply, 2,016.6 cleared, which resulted in a resource-clearing price of $237.33 per MW-day.

  Total resources in SWMAAC were 16,305.6 MW, which when combined with certified ILR of 519.3 MW resulted in a net excess of 506.1 MW (3.1 percent) greater than the reliability requirement of 16,318.8 MW.

#### *2009/2010 RPM Third Incremental Auction*

- **RTO.** There were 3,255.8 MW offered into the Third Incremental Auction while buy bids totaled 2,697.6 MW. Cleared volumes in the RTO were 1,798.4 MW, resulting in an RTO clearing price of $40.00 per MW-day. The 1,457.4 MW of uncleared volumes can be used as replacement capacity or traded bilaterally.

  Cleared resources across the entire RTO will receive a total of $47.7 million based on the unforced MW cleared and the prices in the 2009/2010 RPM Third Incremental Auction.

- **MAAC+APS.** In MAAC+APS, 2,142.3 MW were offered into the auction while buy bids in MAAC+APS totaled 1,953.2 MW. Cleared volumes in MAAC+APS were 1,275.3 MW, resulting in a MAAC+APS clearing price of $86.00 per MW-day. The 867.0 MW of uncleared volumes can be used as replacement capacity or traded bilaterally.

- **SWMAAC.** Although SWMAAC was a constrained LDA in the 2009/2010 BRA, supply and demand curves resulted in a price less than the MAAC+APS clearing price. Supply offers in the incremental auction in SWMAAC (985.1 MW) exceeded SWMAAC demand bids (135.5 MW). The result was that all of SWMAAC supply which cleared received the MAAC+APS clearing price.

### Generator Performance

- **Forced Outage Rates.** Average PJM EFORd decreased from 7.5 percent in 2009 to 6.7 percent in the first three months of 2010. PJM EFORp decreased from 4.0 percent in 2009 to 3.7 percent in the first three months of 2010.[11]

- **Generator Performance Factors.** The PJM aggregate equivalent availability factor increased from 85.7 percent in 2009 to 87.6 percent in the first three months of 2010.

- **Outages Deemed Outside Management Control (OMC).** According to NERC criteria, an outage may be classified as an OMC outage only if the generating unit outage was caused by other than failure of the owning company's equipment or other than the failure of the practices, policies and procedures of the owning company. OMC outages are excluded from the calculation of the forced outage rate, termed the XEFORd, used to calculate the unforced capacity that must be offered in the PJM Capacity Market.

9 MAAC was an acronym for Mid-Atlantic Area Council, EMAAC was an acronym for Eastern Mid-Atlantic Area Council, and SWMAAC was an acronym for Southwestern Mid-Atlantic Area Council. MAAC no longer exists as its role was taken on by Reliabilty*First* Corporation. MAAC, EMAAC and SWMAAC are now regions of PJM.

10 Rules for RPM auctions state that imports are modeled in the unconstrained region of the RTO. See PJM. "Manual 18: PJM Capacity Market," Revision 6 (Effective June 18, 2009), p. 31, <http://www.pjm.com/documents/~/media/documents/manuals/m18.ashx> (1.25 MB). The import MW into MAAC+APS consist of MW under a grandfathered agreement related to Rural Electric Cooperatives (RECs) generation.

11 2009 data is for the 12 months ended December 31, 2009, as downloaded from the PJM GADS database on February 23, 2010. 2010 data is for the period ending March 31, 2010, as downloaded from the PJM GADS database on April 21, 2010. 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.

## Conclusion

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 Herfindahl-Hirschman Index (HHI), but no exercise of market power in the PJM Capacity Market during the first three months of 2010. 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 during the first three months of 2010.

## RPM Capacity Market

### Market Structure

#### *Supply*

***Table 5-1 Internal capacity: June 1, 2008, to June 1, 2012[12] (See 2009 SOM, Table 5-1)***

| | UCAP (MW) | | | | | | |
|---|---|---|---|---|---|---|---|
| | RTO | MAAC+APS | MAAC | EMAAC | SWMAAC | DPL South | PSEG North |
| Total internal capacity @ 01-Jun-08 | 156,968.0 | 72,889.5 | | | 10,777.1 | | |
| New generation | 439.2 | 109.9 | | | 0.0 | | |
| Units out of retirement | 0.0 | 0.0 | | | 0.0 | | |
| Generation capmods | 74.1 | (149.7) | | | (298.2) | | |
| DR mods | 220.6 | 163.2 | | | 42.3 | | |
| Net EFORd effect | (383.7) | 0.0 | | | (176.0) | | |
| | | | | | | | |
| Total internal capacity @ 01-Jun-09 | 157,318.2 | 73,012.9 | | | 10,345.2 | 1,587.0 | |
| New generation | 406.9 | | | | | 0.0 | |
| Units out of retirement | 165.0 | | | | | 0.0 | |
| Generation capmods | 1,085.8 | | | | | (85.5) | |
| DR mods | 43.7 | | | | | 15.7 | |
| Net EFORd effect | 11.3 | | | | | 28.9 | |
| | | | | | | | |
| Total internal capacity @ 01-Jun-10 | 159,030.9 | | | | | 1,546.1 | |
| New generation | 2,203.7 | | | | | | |
| Units out of retirement | 486.9 | | | | | | |
| Generation capmods | (2,567.6) | | | | | | |
| DR mods | 684.4 | | | | | | |
| Net EFORd effect | 44.4 | | | | | | |
| | | | | | | | |
| Total internal capacity @ 01-Jun-11 | 159,882.7 | | 66,329.7 | 32,733.0 | | 1,460.3 | 4,167.5 |
| Reclassification of Duquesne resources | 3,187.2 | | 0.0 | 0.0 | | 0.0 | 0.0 |
| Adjusted internal capacity @ 01-Jun-11 | 163,069.9 | | 66,329.7 | 32,733.0 | | 1,460.3 | 4,167.5 |
| New generation | 661.3 | | 61.9 | 59.7 | | 0.0 | 0.0 |
| Units out of retirement | 0.0 | | 0.0 | 0.0 | | 0.0 | 0.0 |
| Generation capmods | (1,513.1) | | (901.3) | (444.9) | | (31.8) | (509.0) |
| DR mods | 8,028.7 | | 3,829.7 | 1,480.9 | | 64.6 | 67.6 |
| EE mods | 652.5 | | 186.9 | 24.4 | | 0.0 | 0.9 |
| Net EFORd effect | (946.0) | | (503.0) | (185.6) | | 5.8 | 18.3 |
| | | | | | | | |
| Total internal capacity @ 01-Jun-12 | 169,953.3 | | 69,003.9 | 33,667.5 | | 1,498.9 | 3,745.3 |

12 The RTO includes MAAC+APS, EMAAC and SWMAAC. MAAC+APS and MAAC include EMAAC and SWMAAC. EMAAC includes DPL South and PSEG North. Results for only constrained LDAs are shown. Maps of the LDAs can be found in the *2009 State of the Market Report for PJM*, Appendix A, "PJM Geography."

## Demand

*Table 5-2 PJM Capacity Market load obligation served: June 1, 2009 (See 2009 SOM, Table 5-2)*

| | Obligation (MW) | | | | | | | |
|---|---|---|---|---|---|---|---|---|
| | PJM EDCs | PJM EDC Generating Affiliates | PJM EDC Marketing Affiliates | Non-PJM EDC Generating Affiliates | Non-PJM EDC Marketing Affiliates | Non-EDC Generating Affiliates | Non-EDC Marketing Affiliates | Total |
| Obligation | 68,587.1 | 11,994.4 | 26,027.0 | 1,056.0 | 10,452.7 | 517.3 | 15,252.5 | 133,887.0 |
| Percent of total obligation | 51.2% | 9.0% | 19.4% | 0.8% | 7.8% | 0.4% | 11.4% | 100.0% |

## Market Concentration

### Preliminary Market Structure Screen

*Table 5-3 Preliminary market structure screen results: 2009/2010 through 2013/2014 RPM Auctions (See 2009 SOM, Table 5-3)*

| RPM Markets | Highest Market Share | HHI | Pivotal Suppliers | Pass/Fail |
|---|---|---|---|---|
| 2009/2010 | | | | |
| RTO | 18.4% | 853 | 1 | Fail |
| SWMAAC | 51.1% | 4229 | 1 | Fail |
| MAAC+APS | 26.9% | 1627 | 1 | Fail |
| | | | | |
| 2010/2011 | | | | |
| RTO | 18.4% | 853 | 1 | Fail |
| EMAAC | 31.3% | 2053 | 1 | Fail |
| SWMAAC | 51.1% | 4229 | 1 | Fail |
| MAAC+APS | 26.9% | 1627 | 1 | 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 |

### Auction Market Structure

*Table 5-4 RSI results: 2009/2010 through 2012/2013 RPM Auctions[13] (See 2009 SOM, Table 5-4)*

| RPM Markets | RSI[3] | Total Participants | Failed RSI[3] Participants |
|---|---|---|---|
| 2009/2010 BRA | | | |
| RTO | 0.60 | 66 | 66 |
| MAAC+APS | 0.37 | 21 | 21 |
| SWMAAC | 0.00 | 3 | 3 |
| | | | |
| 2009/2010 Third IA | | | |
| RTO | 0.64 | 40 | 40 |
| MAAC+APS | 0.14 | 8 | 8 |
| | | | |
| 2010/2011 BRA | | | |
| RTO | 0.60 | 68 | 68 |
| DPL South | 0.00 | 2 | 2 |
| | | | |
| 2010/2011 Third IA | | | |
| RTO | 0.53 | 47 | 47 |
| | | | |
| 2011/2012 BRA | | | |
| RTO | 0.63 | 76 | 76 |
| | | | |
| 2011/2012 First IA | | | |
| RTO | 0.62 | 30 | 30 |
| | | | |
| 2012/2013 BRA | | | |
| RTO | 0.63 | 98 | 98 |
| MAAC/SWMAAC | 0.54 | 15 | 15 |
| EMAAC/PSEG | 7.03 | 6 | 0 |
| PSEG North | 0.00 | 2 | 2 |
| DPL South | 0.00 | 3 | 3 |

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

## Imports and Exports

*Table 5-5 PJM capacity summary (MW): June 1, 2007, to June 1, 2012[14] (See 2009 SOM, Table 5-5)*

| | 01-Jun-07 | 01-Jun-08 | 01-Jun-09 | 01-Jun-10 | 01-Jun-11 | 01-Jun-12 |
|---|---|---|---|---|---|---|
| Installed capacity (ICAP) | 163,721.1 | 164,444.1 | 166,916.0 | 168,061.5 | 172,666.6 | 181,159.7 |
| Unforced capacity | 154,076.7 | 155,590.2 | 157,628.7 | 158,634.2 | 163,144.3 | 171,147.8 |
| Cleared capacity | 129,409.2 | 129,597.6 | 132,231.8 | 132,190.4 | 132,221.5 | 136,143.5 |
| RPM reliability requirement (pre-FRR) | 148,277.3 | 150,934.6 | 153,480.1 | 156,636.8 | 154,251.1 | 157,488.5 |
| RPM reliability requirement (less FRR) | 125,805.0 | 128,194.6 | 130,447.8 | 132,698.8 | 130,658.7 | 133,732.4 |
| RPM net excess | 5,240.5 | 5,011.1 | 8,265.5 | 1,149.2 | 3,156.6 | 5,754.4 |
| Imports | 2,809.2 | 2,460.3 | 2,505.4 | 2,750.7 | 6,420.0 | 3,831.6 |
| Exports | (3,938.5) | (3,838.1) | (2,194.9) | (3,147.4) | (3,158.4) | (2,637.1) |
| Net exchange | (1,129.3) | (1,377.8) | 310.5 | (396.7) | 3,261.6 | 1,194.5 |
| DR cleared | 127.6 | 536.2 | 892.9 | 939.0 | 1,364.9 | 7,047.2 |
| EE cleared | | | | | | 568.9 |
| ILR | 1,636.3 | 3,608.1 | 6,481.5 | 2,110.5 | 1,593.8 | |
| FRR DR | 445.6 | 452.8 | 423.6 | 452.9 | 452.9 | 488.1 |
| Short-Term Resource Procurement Target | | | | | | 3,343.3 |

14 Prior to the 2012/2013 delivery year, net excess under RPM was calculated as cleared capacity less the reliability requirement plus ILR. For 2008/2009 and 2009/2010, certified ILR was used in the calculation. For 2010/2011, forecast ILR less FRR DR is used in the calculation because PJM forecast ILR including FRR DR for the first four base residual auctions. FRR DR is not subtracted in the calculation for the 2011/2012 auction, because PJM forecast ILR excluding FRR DR for the 2011/2012 BRA. Net excess calculations for auctions prior to 2010/2011 were originally calculated as cleared capacity less the reliability requirement. For delivery years 2012/2013 and beyond, net excess under RPM is calculated as cleared capacity less the reliability requirement plus the Short-Term Resource Procurement Target.

## Demand-Side Resources

**Table 5-6 RPM load management statistics: June 1, 2008 to June 1, 2012[15] (See 2009 SOM, Table 5-6)**

| | UCAP (MW) | | | | | | |
|---|---|---|---|---|---|---|---|
| | RTO | MAAC+APS | MAAC | EMAAC | SWMAAC | DPL South | PSEG North |
| DR cleared | 559.4 | | | 169.0 | 309.2 | | |
| ILR certified | 3,608.1 | | | 622.6 | 219.7 | | |
| RPM load management @ 01-June-2008 | 4,167.5 | | | 791.6 | 528.9 | | |
| | | | | | | | |
| DR cleared | 892.9 | 813.9 | | | 356.3 | | |
| ILR certified | 6,481.5 | 1,055.7 | | | 345.7 | | |
| RPM load management @ 01-June-2009 | 7,374.4 | 1,869.6 | | | 702.0 | | |
| | | | | | | | |
| DR cleared | 962.9 | | | | | 14.9 | |
| ILR forecast - FRR DR | 1,657.6 | | | | | 22.2 | |
| RPM load management @ 01-June-2010 | 2,620.5 | | | | | 37.1 | |
| | | | | | | | |
| DR cleared | 1,364.9 | | | | | | |
| ILR forecast | 1,593.8 | | | | | | |
| RPM load management @ 01-June-2011 | 2,958.7 | | | | | | |
| | | | | | | | |
| DR cleared | 7,047.2 | | 4,723.7 | 1,638.4 | | 64.6 | 67.6 |
| EE cleared | 568.9 | | 179.9 | 20.0 | | 0.0 | 0.9 |
| RPM load management @ 01-June-2012 | 7,616.1 | | 4,903.6 | | | 64.6 | 68.5 |

15 PJM used forecast ILR, including FRR DR, for the first four base residual auctions. For 2008/2009 and 2009/2010, certified ILR data were used in the calculation here because the certified ILR data are now available. For 2010/2011, forecast ILR less FRR DR is used and will continue to be used until certified ILR data are available. PJM used forecast ILR, excluding FRR DR, for the 2011/2012 BRA. Therefore, FRR DR is not subtracted in the calculation here for the 2011/2012 auction. Effective the 2012/2013 delivery year, ILR was eliminated and the Energy Efficiency (EE) resource type was eligible to be offered in RPM auctions.

## Market Conduct

### Offer Caps

**Table 5-7 ACR statistics: 2009/2010 RPM Auctions (See 2009 SOM, Table 5-7)**

| | 2009/2010 BRA | | 2009/2010 Third IA | |
|---|---|---|---|---|
| Calculation Type | Number of Resources | Percent of Generating Resources Offered | Number of Resources | Percent of Generating Resources Offered |
| Default ACR selected | 377 | 34.5% | 1 | 0.4% |
| ACR data input (non-APIR) | 22 | 2.0% | 0 | 0.0% |
| ACR data input (APIR) | 129 | 11.8% | 2 | 0.7% |
| Opportunity cost input | 10 | 0.9% | 2 | 0.7% |
| Transition adder only | 12 | 1.1% | 0 | 0.0% |
| Offer caps calculated | 550 | 50.3% | 5 | 1.9% |
| | | | | |
| Uncapped new units | 3 | 0.3% | 6 | 2.2% |
| | | | | |
| Generators capped at 1.1 times BRA clearing price | NA | | 255 | 95.5% |
| | | | | |
| Generator price takers | 540 | 49.4% | 1 | 0.4% |
| | | | | |
| Generating units offered | 1,093 | 100.0% | 267 | 100.0% |
| Demand resources offered | 38 | | 13 | |
| Total capacity resources offered | 1,131 | | 280 | |

*Table 5-8 ACR statistics: 2010/2011 through 2012/2013 RPM Auctions (See 2009 SOM, Table 5-8)*

| | 2010/2011 BRA | | 2010/2011 Third IA | | 2011/2012 BRA | | 2011/2012 First IA | | 2012/2013 BRA | |
|---|---|---|---|---|---|---|---|---|---|---|
| Calculation Type | Number of Resources | Percent of Generating Resources Offered | Number of Resources | Percent of Generating Resources Offered | Number of Resources | Percent of Generating Resources Offered | Number of Resources | Percent of Generating Resources Offered | Number of Resources | Percent of Generating Resources Offered |
| Default ACR selected | 370 | 33.5% | 7 | 2.3% | 301 | 26.8% | 47 | 36.4% | 476 | 42.0% |
| ACR data input (non-APIR) | 20 | 1.8% | 0 | 0.0% | 12 | 1.1% | 18 | 14.0% | 118 | 10.4% |
| ACR data input (APIR) | 134 | 12.1% | 1 | 0.3% | 133 | 11.8% | 1 | 0.8% | 2 | 0.2% |
| Opportunity cost input | 8 | 0.7% | 1 | 0.3% | 24 | 2.1% | 2 | 1.6% | 8 | 0.7% |
| Default ACR and opportunity cost input | 0 | 0.0% | 0 | 0.0% | 2 | 0.2% | 0 | 0.0% | 3 | 0.3% |
| Offer caps calculated | 532 | 48.1% | 9 | 2.9% | 472 | 42.0% | 68 | 52.8% | 607 | 53.6% |
| | | | | | | | | | | |
| Uncapped new units | 15 | 1.4% | 0 | 0.0% | 20 | 1.8% | 1 | 0.8% | 11 | 1.0% |
| | | | | | | | | | | |
| Generators capped at 1.1 times BRA clearing price | NA | | 193 | 63.7% | NA | | NA | | NA | |
| | | | | | | | | | | |
| Generator price takers | 557 | 50.5% | 101 | 33.4% | 633 | 56.2% | 60 | 46.4% | 515 | 45.4% |
| | | | | | | | | | | |
| Generating units offered | 1,104 | 100.0% | 303 | 100.0% | 1,125 | 100.0% | 129 | 100.0% | 1,133 | 100.0% |
| Demand resources offered | 23 | | 34 | | 37 | | 0 | | 233 | |
| Energy efficiency resources offered | 0 | | 0 | | 0 | | 0 | | 53 | |
| Total capacity resources offered | 1,127 | | 337 | | 1,162 | | 129 | | 1,419 | |

*Table 5-9 APIR statistics: 2009/2010 through 2012/2013 RPM Auctions[16,17,18] (See 2009 SOM, Table 5-9)*

| | | Weighted-Average ($ per MW-day UCAP) | | | | | | |
|---|---|---|---|---|---|---|---|---|
| | | Combined Cycle | Combustion Turbine | Oil or Gas Steam | SubCritical/ SuperCritical Coal | Other | Opportunity Costs | Total |
| 2008/2009 BRA | | | | | | | | |
| Non-APIR units | ACR | $38.81 | $24.59 | $70.24 | $151.50 | $76.66 | | $86.25 |
| | Net revenues | $61.58 | $21.17 | $25.62 | $362.48 | $496.75 | | $184.49 |
| | Offer caps | $17.14 | $13.33 | $45.63 | $9.14 | $4.30 | $106.44 | $20.45 |
| APIR units | ACR | $40.64 | $18.08 | $121.39 | $297.81 | $27.61 | | $129.96 |
| | Net revenues | $99.11 | $19.60 | $20.19 | $202.87 | $15.76 | | $89.95 |
| | Offer caps | $4.70 | $4.60 | $101.20 | $109.96 | $21.85 | | $58.46 |
| | APIR | $0.80 | $4.92 | $28.47 | $131.38 | $15.54 | | $49.29 |
| | Maximum APIR effect | | | | | | | $211.28 |
| | | | | | | | | |
| 2008/2009 Third IA | | | | | | | | |
| Non-APIR units | ACR | $25.17 | $24.46 | $75.38 | $155.14 | $23.56 | | $68.29 |
| | Net revenues | $40.23 | $16.75 | $31.25 | $307.06 | $53.07 | | $105.35 |
| | Offer caps | $12.08 | $14.75 | $46.66 | $24.31 | $8.86 | $149.90 | $39.73 |
| APIR units | ACR | $112.16 | $11.96 | $781.65 | $348.73 | NA | | $350.53 |
| | Net revenues | $256.98 | $18.33 | $1.53 | $141.61 | NA | | $140.94 |
| | Offer caps | $0.00 | $1.29 | $780.12 | $207.12 | NA | | $209.74 |
| | APIR | $0.56 | $2.61 | $199.31 | $126.64 | NA | | $126.82 |
| | Maximum APIR effect | | | | | | | $209.26 |
| | | | | | | | | |
| 2009/2010 BRA | | | | | | | | |
| Non-APIR units | ACR | $37.74 | $26.07 | $80.09 | $159.26 | $84.07 | | $82.66 |
| | Net revenues | $61.97 | $23.08 | $31.92 | $321.88 | $516.72 | | $162.48 |
| | Offer caps | $14.76 | $13.51 | $49.81 | $11.44 | $1.36 | $123.60 | $26.32 |
| APIR units | ACR | $58.12 | $43.83 | $129.59 | $525.98 | $30.71 | | $285.17 |
| | Net revenues | $97.94 | $16.10 | $19.71 | $322.91 | $15.75 | | $172.57 |
| | Offer caps | $17.93 | $30.45 | $109.88 | $164.31 | $22.45 | | $102.07 |
| | APIR | $0.24 | $22.86 | $43.79 | $386.13 | $18.96 | | $195.85 |
| | Maximum APIR effect | | | | | | | $383.79 |
| | | | | | | | | |
| 2010/2011 BRA | | | | | | | | |
| Non-APIR units | ACR | $34.39 | $27.10 | $67.57 | $167.08 | $82.55 | | $80.86 |
| | Net revenues | $96.75 | $18.81 | $15.19 | $302.79 | $391.00 | | $151.31 |
| | Offer caps | $10.13 | $14.12 | $52.38 | $9.67 | $4.53 | $124.60 | $20.98 |
| APIR units | ACR | $61.61 | $49.26 | $152.09 | $654.18 | $34.62 | | $360.27 |
| | Net revenues | $26.84 | $10.32 | $20.94 | $525.48 | $2.07 | | $263.27 |
| | Offer caps | $37.30 | $39.41 | $131.15 | $155.39 | $32.55 | | $110.25 |
| | APIR | $9.87 | $30.93 | $60.54 | $521.16 | $22.42 | | $272.18 |
| | Maximum APIR effect | | | | | | | $577.03 |

16 The weighted-average offer cap can still be positive even when the weighted-average net revenues are higher than the weighted-average ACR due to the offer-cap minimum being zero. On a unit basis, if net revenues are greater than ACR, net revenues in an amount equal to the ACR are used in the calculation and the offer cap is zero.
17 This table has been updated since the MMU RPM Auction reports were posted. The 2010/2011 and 2011/2012 BRA values for Oil and Gas Steam and Sub Critical/Super Critical Coal for resources with an APIR component were updated due to a prior misclassification.
18 Statistics for the 2009/2010 Third IA and the 2010/2011 Third IA are not included as the majority the resources chose the offer cap option of 1.1 times the BRA clearing price.

*Table 5-9 APIR statistics: 2009/2010 through 2012/2013 RPM Auctions (See 2009 SOM, Table 5-9) continued*

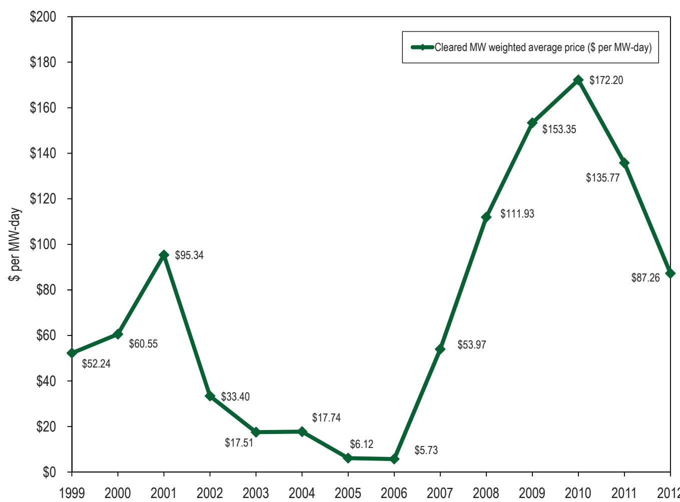
| *(continued)* | | Weighted-Average ($ per MW-day UCAP) | | | | | | |
|---|---|---|---|---|---|---|---|---|
| | | Combined Cycle | Combustion Turbine | Oil or Gas Steam | SubCritical/ SuperCritical Coal | Other | Opportunity Costs | Total |
| Non-APIR units | ACR | $39.52 | $30.17 | $72.20 | $181.52 | $62.54 | | $75.86 |
| | Net revenues | $69.04 | $20.16 | $17.27 | $466.41 | $322.78 | | $173.54 |
| | Offer caps | $11.76 | $16.42 | $62.13 | $7.88 | $11.50 | $182.41 | $45.80 |
| APIR units | ACR | $61.66 | $56.28 | $184.34 | $723.65 | $36.03 | | $424.49 |
| | Net revenues | $78.17 | $10.35 | $19.81 | $531.93 | $2.06 | | $286.80 |
| | Offer caps | $34.69 | $46.18 | $164.54 | $203.41 | $33.97 | | $147.77 |
| | APIR | $11.82 | $37.28 | $91.30 | $578.47 | $24.68 | | $324.58 |
| | Maximum APIR effect | | | | | | | $523.26 |
| | | | | | | | | |
| 2011/2012 First IA | | | | | | | | |
| Non-APIR units | ACR | $54.15 | $29.43 | $71.79 | $284.63 | $30.04 | | $169.77 |
| | Net revenues | $220.31 | $44.98 | $10.25 | $298.96 | $0.07 | | $195.83 |
| | Offer caps | $2.66 | $2.64 | $61.54 | $150.63 | $29.97 | $136.01 | $78.56 |
| APIR units | ACR | $220.20 | $152.28 | $194.25 | $583.59 | NA | | $326.57 |
| | Net revenues | $81.72 | $6.94 | $23.64 | $328.71 | NA | | $128.90 |
| | Offer caps | $138.48 | $145.34 | $170.62 | $254.88 | NA | | $197.67 |
| | APIR | $220.19 | $120.84 | $82.87 | $324.31 | NA | | $170.61 |
| | Maximum APIR effect | | | | | | | $468.26 |
| | | | | | | | | |
| 2012/2013 BRA | | | | | | | | |
| Non-APIR units | ACR | $41.84 | $32.61 | $75.47 | $207.54 | $57.18 | | $110.84 |
| | Net revenues | $91.67 | $35.29 | $7.51 | $396.82 | $257.96 | | $208.65 |
| | Offer caps | $5.28 | $14.40 | $67.96 | $11.31 | $15.63 | $136.48 | $21.55 |
| APIR units | ACR | $218.10 | $49.83 | $177.52 | $715.10 | NA | | $464.65 |
| | Net revenues | $98.97 | $15.62 | $3.62 | $508.00 | NA | | $302.04 |
| | Offer caps | $119.12 | $34.96 | $173.89 | $215.38 | NA | | $167.62 |
| | APIR | $218.10 | $26.59 | $89.08 | $559.97 | NA | | $351.74 |
| | Maximum APIR effect | | | | | | | $1,155.57 |

## Market Performance

*Table 5-10 Capacity prices: 2007/2008 through 2012/2013 RPM Auctions (See 2009 SOM, Table 5-10)*

| | RPM Clearing Price ($ per MW-day) | | | | | | |
|---|---|---|---|---|---|---|---|
| | RTO | MAAC+ APS | MAAC | EMAAC | SWMAAC | DPL South | PSEG North |
| 2007/2008 BRA | $40.80 | | | $197.67 | $188.54 | | |
| 2008/2009 BRA | $111.92 | | | $148.80 | $210.11 | | |
| 2008/2009 Third IA | $10.00 | | | | $223.85 | | |
| 2009/2010 BRA | $102.04 | $191.32 | | | $237.33 | | |
| 2009/2010 Third IA | $40.00 | $86.00 | | | | | |
| 2010/2011 BRA | $174.29 | | | | | $186.12 | |
| 2010/2011 Third IA | $50.00 | | | | | | |
| 2011/2012 BRA | $110.00 | | | | | | |
| 2011/2012 First IA | $55.00 | | | | | | |
| 2011/2012 ATSI FRR Integration Auction | $108.89 | | | | | | |
| 2012/2013 BRA | $16.46 | | $133.37 | $139.73 | | $222.30 | $185.00 |
| 2012/2013 ATSI FRR Integration Auction | $20.46 | | | | | | |

*Figure 5-1 History of capacity prices: Calendar year 1999 through 2012[19] (See 2009 SOM, Figure 5-1)*




19 1999-2006 capacity prices are CCM combined market, weighted average prices. The 2007 capacity price is a combined CCM/RPM weighted average price. The 2008-2012 capacity prices are RPM weighted average prices.

*Table 5-11 RPM cost to load: 2009/2010 through 2012/2013 RPM Auctions[20,21,22] (See 2009 SOM, Table 5-11)*

| | Net Load Price ($ per MW-day) | UCAP Obligation (MW) | Annual Charges |
|---|---|---|---|
| 2009/2010 BRA | | | |
| RTO | $104.82 | 56,696.9 | $2,169,117,837 |
| MAAC+APS | $193.78 | 60,984.3 | $4,313,445,473 |
| SWMAAC | $224.86 | 16,205.7 | $1,330,043,812 |
| | | | |
| 2010/2011 BRA | | | |
| RTO | $183.05 | 129,340.6 | $8,641,666,369 |
| DPL | $187.24 | 4,507.5 | $308,053,731 |
| | | | |
| 2011/2012 BRA | | | |
| RTO | $110.04 | 133,815.3 | $5,389,363,034 |
| | | | |
| 2012/2013 BRA | | | |
| RTO | $16.46 | 69,648.3 | $418,440,022 |
| MAAC | $129.63 | 31,338.7 | $1,482,789,024 |
| EMAAC | $135.18 | 21,171.5 | $1,044,616,630 |
| DPL | $162.99 | 4,685.6 | $278,752,670 |
| PSEG | $149.65 | 12,642.7 | $690,572,720 |

20 The annual charges are calculated using the rounded, net load prices as posted in the PJM Base Residual Auction results.
21 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.
22 Prior to the 2009/2010 delivery year, the Final UCAP Obligation is determined after the clearing of the Second IA. For the 2009/2010 through 2011/2012 delivery years, the Final UCAP Obligations are determined after the clearing of the Third IA. 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 2010/2011 Net Load Prices are not finalized. The 2011/2012 and 2012/2013 Net Load Prices and Obligation MW are not finalized.

## 2009/2010 RPM Base Residual Auction

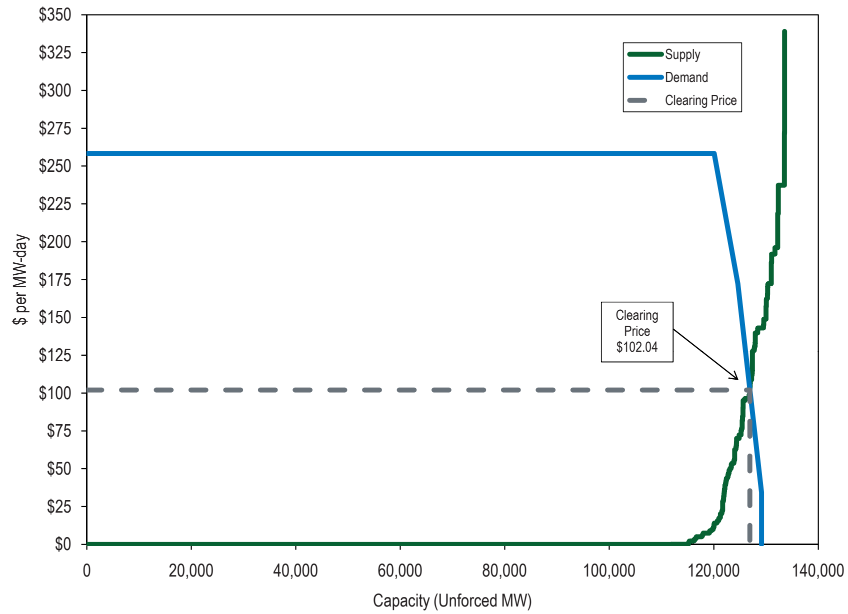
### RTO

*Table 5-12 RTO offer statistics: 2009/2010 RPM Base Residual Auction[23] (See 2009 SOM, Table 5-12)*

| | ICAP (MW) | UCAP (MW) | Percent of Available ICAP | Percent of Available UCAP |
|---|---|---|---|---|
| Total Internal RTO Capacity (Gen and DR) | 166,639.7 | 157,318.2 | | |
| FRR | (25,316.2) | (23,523.2) | | |
| Imports | 2,652.5 | 2,505.4 | | |
| RPM Capacity | 143,976.0 | 136,300.4 | | |
| | | | | |
| Exports | (2,376.2) | (2,194.9) | | |
| FRR Optional | (552.5) | (450.2) | | |
| Excused | (136.8) | (104.3) | | |
| Available | 140,910.5 | 133,551.0 | 100.0% | 100.0% |
| | | | | |
| Generation Offered | 140,003.6 | 132,614.2 | 99.4% | 99.3% |
| DR Offered | 906.9 | 936.8 | 0.6% | 0.7% |
| Total Offered | 140,910.5 | 133,551.0 | 100.0% | 100.0% |
| | | | | |
| Unoffered | 0.0 | 0.0 | 0.0% | 0.0% |
| | | | | |
| Cleared in RTO | 133,859.0 | 126,917.1 | 95.0% | 95.0% |
| Cleared in LDAs | 5,594.4 | 5,314.7 | 4.0% | 4.0% |
| Total Cleared | 139,453.4 | 132,231.8 | 99.0% | 99.0% |
| | | | | |
| Uncleared in RTO | 895.5 | 869.0 | 0.6% | 0.7% |
| Uncleared in LDAs | 561.6 | 450.2 | 0.4% | 0.3% |
| Total Uncleared | 1,457.1 | 1,319.2 | 1.0% | 1.0% |
| | | | | |
| Reliability Requirement | | 130,447.8 | | |
| | | | | |
| Total Cleared | | 132,231.8 | | |
| | | | | |
| ILR Certified | | 6,481.5 | | |
| | | | | |
| RPM Net Excess/(Deficit) | | 8,265.5 | | |
| | | | | |
| Resource Clearing Price ($ per MW-day) | | $102.04 | A | |
| Final Zonal Capacity Price ($ per MW-day) | | $104.82 | B | |
| Final Zonal CTR Credit Rate ($ per MW-day) | | $0.00 | C | |
| Final Zonal ILR Price ($ per MW-day) | | $102.04 | A-C | |
| Net Load Price ($ per MW-day) | | $104.82 | B-C | |

23 Prices are only for those generating units outside of MAAC+APS and SWMAAC.

*Figure 5-2 RTO market supply/demand curves: 2009/2010 RPM Base Residual Auction[24] (See 2009 SOM, Figure 5-2)*



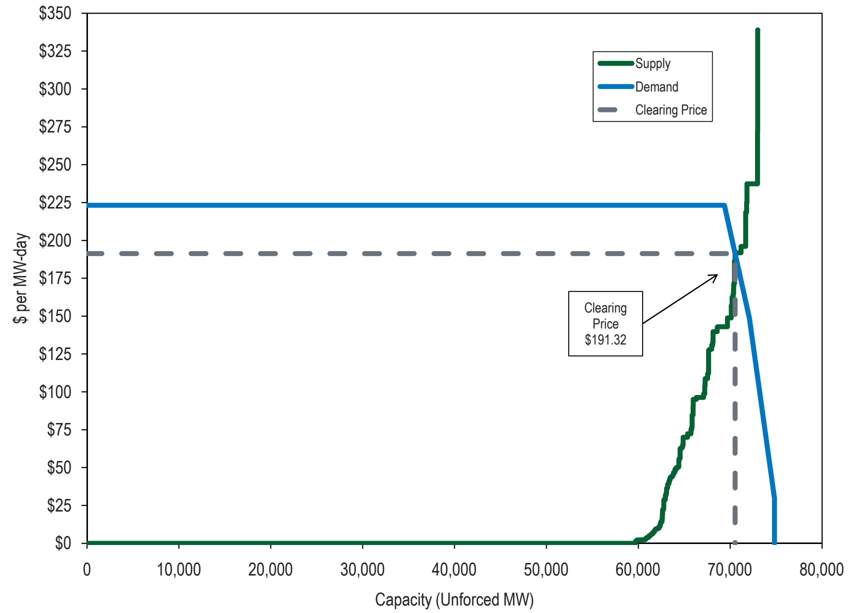

24 The supply curve includes all supply offers at the lower of offer price or offer cap. The demand curve excludes incremental demand which cleared in MAAC+APS and SWMAAC.

### MAAC+APS

*Table 5-13 MAAC+APS offer statistics: 2009/2010 RPM Base Residual Auction (See 2009 SOM, Table 5-13)*

| | ICAP (MW) | UCAP (MW) | Percent of Available ICAP | Percent of Available UCAP |
|---|---|---|---|---|
| Total Internal MAAC+APS Capacity (Gen and DR) | 77,870.6 | 73,012.9 | | |
| Imports | 89.3 | 89.3 | | |
| RPM Capacity | 77,959.9 | 73,102.2 | | |
| | | | | |
| Exports | 0.0 | 0.0 | | |
| Excused | (136.8) | (104.3) | | |
| Available | 77,823.1 | 72,997.9 | 100.0% | 100.0% |
| | | | | |
| Generation Offered | 77,028.6 | 72,177.3 | 99.0% | 98.9% |
| DR Offered | 794.5 | 820.6 | 1.0% | 1.1% |
| Total Offered | 77,823.1 | 72,997.9 | 100.0% | 100.0% |
| | | | | |
| Unoffered | 0.0 | 0.0 | 0.0% | 0.0% |
| | | | | |
| Cleared in RTO | 71,667.1 | 67,233.0 | 92.1% | 92.1% |
| Cleared in LDAs | 5,594.4 | 5,314.7 | 7.2% | 7.3% |
| Total Cleared | 77,261.5 | 72,547.7 | 99.3% | 99.4% |
| | | | | |
| Uncleared | 561.6 | 450.2 | 0.7% | 0.6% |
| | | | | |
| Reliability Requirement | | 77,902.9 | | |
| | | | | |
| Total Cleared | | 72,547.7 | | |
| CETL | | 4,941.0 | | |
| Total Resources | | 77,488.7 | | |
| | | | | |
| ILR Certified | | 3,081.0 | | |
| | | | | |
| RPM Net Excess/(Deficit) | | 2,666.8 | | |
| | | | | |
| Resource Clearing Price ($ per MW-day) | | $191.32 | A | |
| Final Zonal Capacity Price ($ per MW-day) | | $196.54 | B | |
| Final Zonal CTR Credit Rate ($ per MW-day) | | $2.77 | C | |
| Final Zonal ILR Price ($ per MW-day) | | $188.55 | A-C | |
| Net Load Price ($ per MW-day) | | $193.77 | B-C | |

*Figure 5-3 MAAC+APS supply/demand curves: 2009/2010 RPM Base Residual Auction[25] (See 2009 SOM, Figure 5-3)*



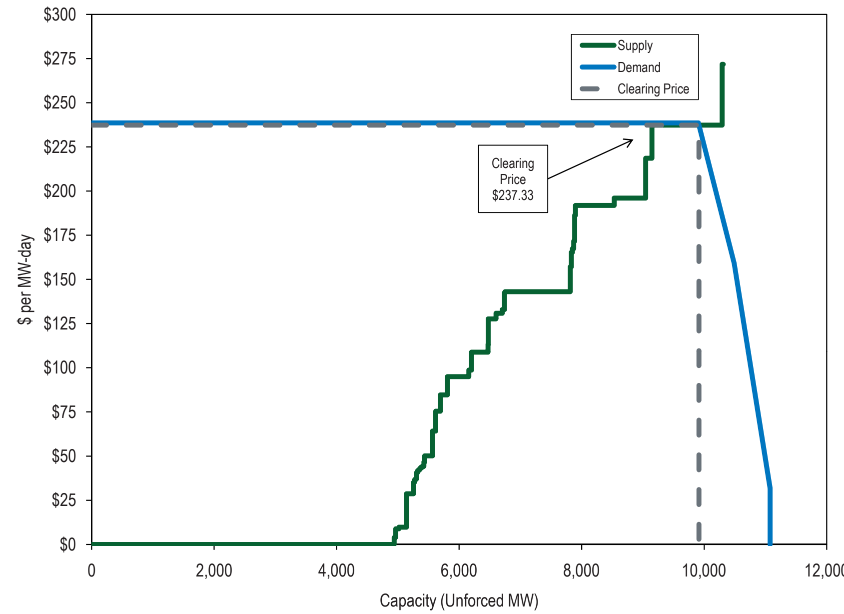

25 The supply curve includes all supply offers at the lower of offer price or offer cap. The demand curve excludes incremental demand which cleared in SWMAAC.

### SWMAAC

*Table 5-14 SWMAAC offer statistics: 2009/2010 RPM Base Residual Auction (See 2009 SOM, Table 5-14)*

| | ICAP (MW) | UCAP (MW) | Percent of Available ICAP | Percent of Available UCAP |
|---|---|---|---|---|
| Total Internal SWMAAC Capacity (Gen and DR) | 11,448.6 | 10,345.2 | | |
| Imports | 0.0 | 0.0 | | |
| RPM Capacity | 11,448.6 | 10,345.2 | | |
| | | | | |
| Exports | 0.0 | 0.0 | | |
| Excused | (37.0) | (33.5) | | |
| Available | 11,411.6 | 10,311.7 | 100.0% | 100.0% |
| | | | | |
| Generation Offered | 11,066.7 | 9,955.4 | 97.0% | 96.5% |
| DR Offered | 344.9 | 356.3 | 3.0% | 3.5% |
| Total Offered | 11,411.6 | 10,311.7 | 100.0% | 100.0% |
| | | | | |
| Unoffered | 0.0 | 0.0 | 0.0% | 0.0% |
| | | | | |
| Cleared in RTO | 7,001.2 | 6,202.3 | 61.4% | 60.1% |
| Cleared in MAAC+APS | 1,784.3 | 1,695.7 | 15.6% | 16.4% |
| Cleared in LDA | 2,146.2 | 2,016.6 | 18.8% | 19.6% |
| Total Cleared | 10,931.7 | 9,914.6 | 95.8% | 96.1% |
| | | | | |
| Uncleared | 479.9 | 397.1 | 4.2% | 3.9% |
| | | | | |
| Reliability Requirement | | 16,318.8 | | |
| | | | | |
| Total Cleared | | 9,914.6 | | |
| CETL | | 6,391.0 | | |
| Total Resources | | 16,305.6 | | |
| | | | | |
| ILR Certified | | 519.3 | | |
| | | | | |
| RPM Net Excess/(Deficit) | | 506.1 | | |
| | | | | |
| Resource Clearing Price ($ per MW-day) | | $237.33 | A | |
| Final Zonal Capacity Price ($ per MW-day) | | $243.80 | B | |
| Final Zonal CTR Credit Rate ($ per MW-day) | | $19.21 | C | |
| Final Zonal ILR Price ($ per MW-day) | | $218.12 | A-C | |
| Final Net Load Price ($ per MW-day) | | $224.59 | B-C | |

*Figure 5-4 SWMAAC supply/demand curves: 2009/2010 RPM Base Residual Auction (See 2009 SOM, Figure 5-4)*



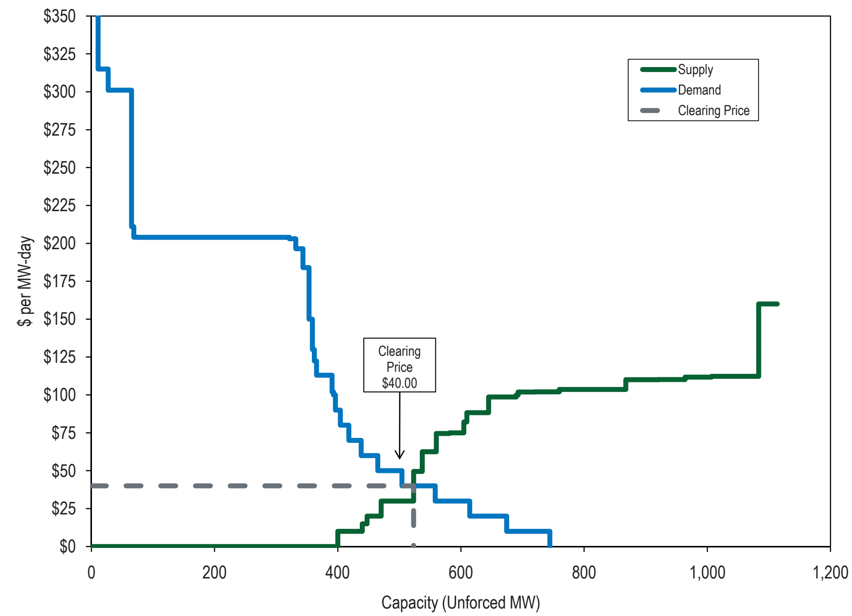
## 2009/2010 RPM Third Incremental Auction

### RTO

*Table 5-15 RTO offer statistics: 2009/2010 RPM Third Incremental Auction (See 2009 SOM, Table 5-15)*

| | Offered (Supply) | | Bid (Demand) |
|---|---|---|---|
| | ICAP (MW) | UCAP (MW) | UCAP (MW) |
| Generation | 2,918.7 | 2,724.4 | |
| DR | 514.6 | 531.4 | |
| Total | 3,433.3 | 3,255.8 | 2,697.6 |
| | | | |
| Cleared in RTO | 539.9 | 523.1 | 523.1 |
| Cleared in MAAC+APS | 1,364.1 | 1,275.3 | 1,275.3 |
| Total cleared | 1,904.0 | 1,798.4 | 1,798.4 |
| | | | |
| Uncleared in RTO | 589.6 | 590.4 | 221.3 |
| Uncleared in MAAC+APS | 939.7 | 867.0 | 677.9 |
| Total uncleared | 1,529.3 | 1,457.4 | 899.2 |
| | | | |
| Resource clearing price ($ per MW-day) | $40.00 | | |

*Figure 5-5 RTO supply/demand curves: 2009/2010 RPM Third Incremental Auction[26,27] (See 2009 SOM, Figure 5-5)*



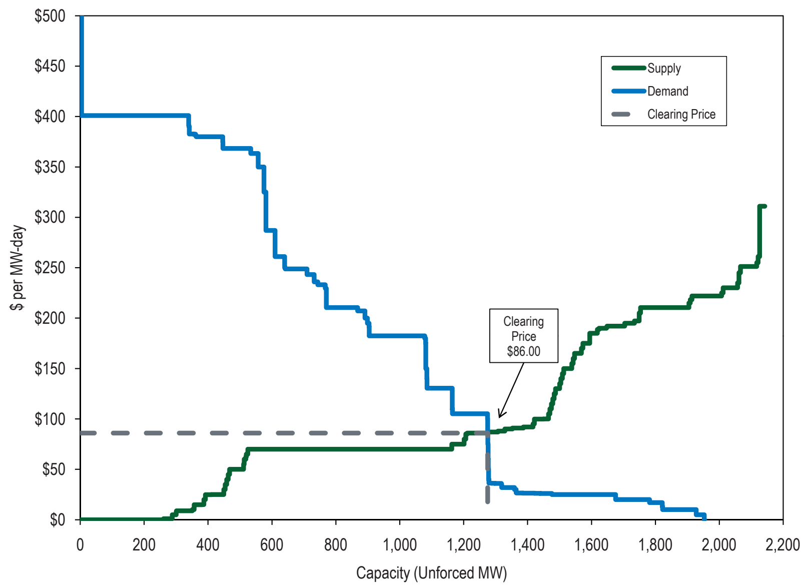

26 The supply curve includes all supply offers at the lower of offer price or offer cap.
27 For ease of viewing, the graph was truncated at $350 per MW-day and does not show a buy bid of approximately $1,000 per MW-day.

### MAAC+APS

**Table 5-16 MAAC+APS offer statistics: 2009/2010 RPM Third Incremental Auction (See 2009 SOM, Table 5-16)**

| | Offered (Supply) | | Bid (Demand) |
|---|---|---|---|
| | ICAP (MW) | UCAP (MW) | UCAP (MW) |
| Generation | 2,043.3 | 1,873.3 | |
| DR | 260.5 | 269.0 | |
| Total | 2,303.8 | 2,142.3 | 1,953.2 |
| | | | |
| Cleared in RTO | 487.3 | 462.9 | |
| Cleared in MAAC+APS | 876.8 | 812.4 | |
| Total cleared | 1,364.1 | 1,275.3 | 1,275.3 |
| | | | |
| Uncleared | 939.7 | 867.0 | 677.9 |
| | | | |
| Resource clearing price ($ per MW-day) | $86.00 | | |

**Figure 5-6 MAAC+APS supply/demand curves: 2009/2010 RPM Third Incremental Auction[28] (See 2009 SOM, Figure 5-6)**

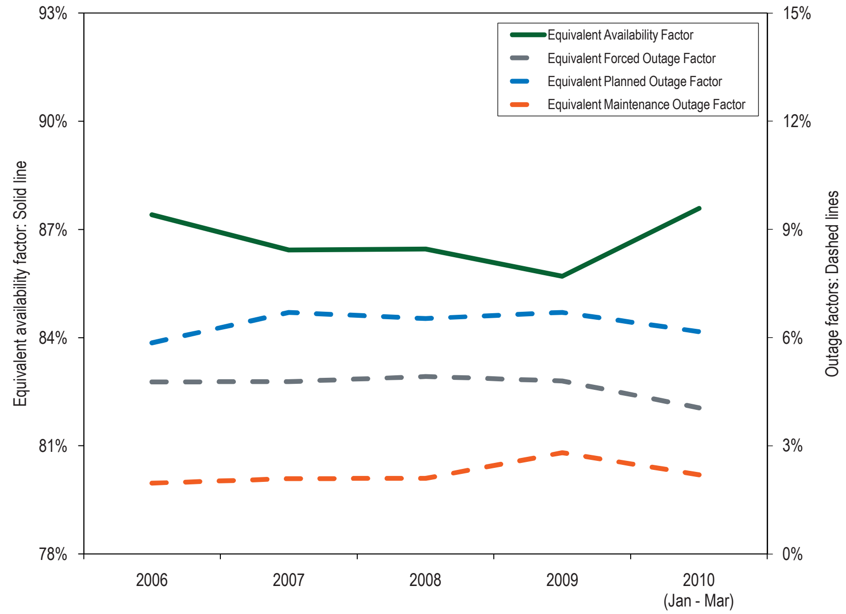



28 The supply curve includes all supply offers at the lower of offer price or offer cap.

## Generator Performance

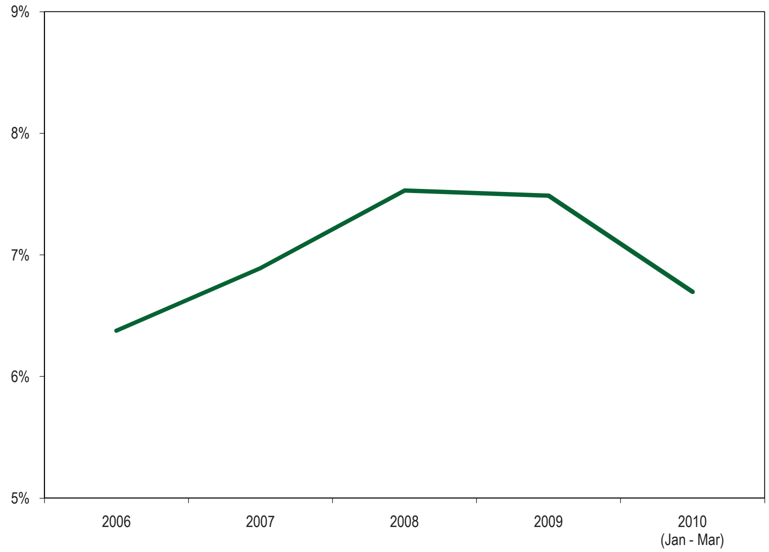
### Generator Performance Factors

**Figure 5-7 PJM equivalent outage and availability factors: Calendar years 2006 to 2010 (January through March) (See 2009 SOM, Figure 5-7)**



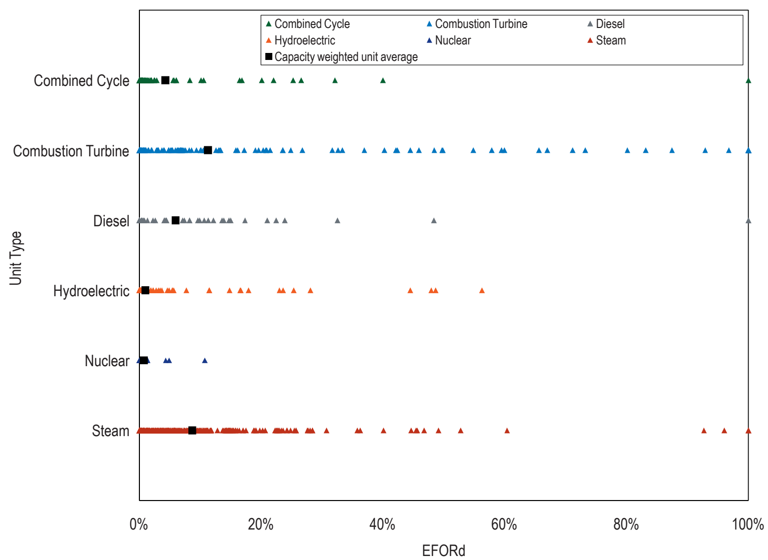
## Generator Forced Outage Rates

*Figure 5-8 Trends in the PJM equivalent demand forced outage rate (EFORd): Calendar years 2006 to 2010 (January through March) (See 2009 SOM, Figure 5-8)*




## Distribution of EFORd

*Figure 5-9 PJM 2010 (January through March) Distribution of EFORd data by unit type (See 2009 SOM, Figure 5-9)*




## Components of EFORd

*Table 5-17 Five-year PJM EFORd data comparison to NERC five-year average for different unit types: Calendar years 2006 to 2010 (January through March) (See 2009 SOM, Table 5-17)*

| | 2006 | 2007 | 2008 | 2009 | 2010 (Jan - Mar) |
|---|---|---|---|---|---|
| Combined Cycle | 4.2% | 3.4% | 3.4% | 3.8% | 4.2% |
| Combustion Turbine | 9.3% | 11.0% | 11.0% | 9.8% | 11.3% |
| Diesel | 13.1% | 12.0% | 11.4% | 10.2% | 5.9% |
| Hydroelectric | 1.9% | 2.1% | 2.0% | 3.2% | 1.0% |
| Nuclear | 1.4% | 1.4% | 1.9% | 4.1% | 0.7% |
| Steam | 8.2% | 9.1% | 10.1% | 9.3% | 8.7% |
| Total | 6.4% | 6.9% | 7.5% | 7.5% | 6.7% |

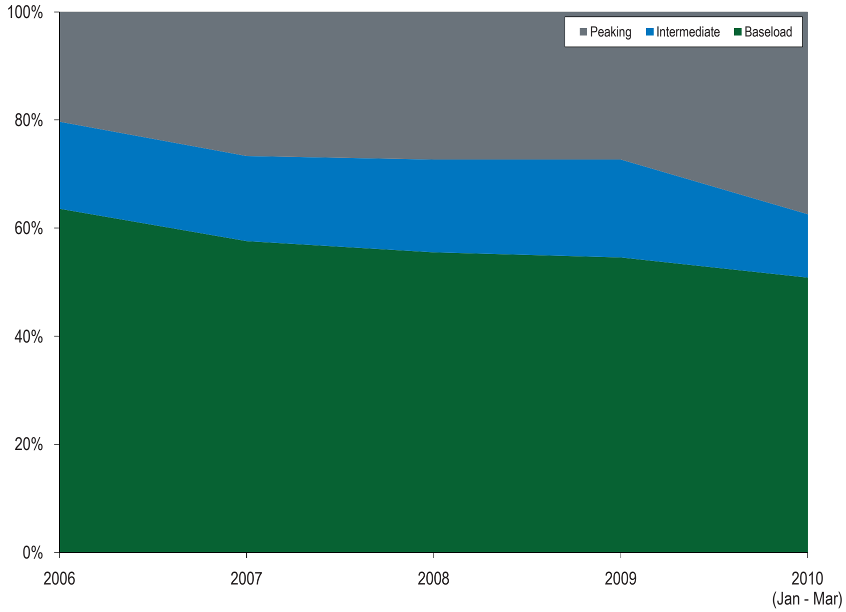
*Table 5-18 Contribution to EFORd for specific unit types (Percentage points): Calendar years 2006 to 2010 (January through March)[29] (See 2009 SOM, Table 5-18)*

| | 2006 | 2007 | 2008 | 2009 | 2010 (Jan - Mar) | Change in 2010 from 2009 |
|---|---|---|---|---|---|---|
| Combined Cycle | 0.5 | 0.5 | 0.5 | 0.5 | 0.5 | 0.0 |
| Combustion Turbine | 1.4 | 1.7 | 1.7 | 1.5 | 1.7 | 0.2 |
| Diesel | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | (0.0) |
| Hydroelectric | 0.1 | 0.1 | 0.1 | 0.1 | 0.0 | (0.1) |
| Nuclear | 0.3 | 0.3 | 0.4 | 0.8 | 0.1 | (0.6) |
| Steam | 4.0 | 4.4 | 5.0 | 4.6 | 4.2 | (0.3) |
| Total | 6.4 | 6.9 | 7.5 | 7.5 | 6.7 | (0.8) |

29 Calculated values presented in Section 5, "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.

## Duty Cycle and EFORd

*Figure 5-10 Contribution to EFORd by duty cycle: Calendar years 2006 to 2010 (January through March) (See 2009 SOM, Figure 5-10)*




## Forced Outage Analysis

*Table 5-19 Outage cause contribution to PJM EFOF: Calendar year 2010 (January through March) (See 2009 SOM, Table 5-19)*

| | Percentage Point Contribution to EFOF | Contribution to EFOF |
|---|---|---|
| Boiler Tube Leaks | 1.10 | 22.9% |
| Economic | 0.80 | 16.6% |
| Boiler Air and Gas Systems | 0.30 | 6.3% |
| Electrical | 0.28 | 5.8% |
| Fuel Quality | 0.21 | 4.3% |
| Boiler Fuel Supply from Bunkers to Boiler | 0.17 | 3.6% |
| Exciter | 0.13 | 2.7% |
| Boiler Tube Fireside Slagging or Fouling | 0.12 | 2.5% |
| Generator | 0.12 | 2.5% |
| Stack Emission | 0.12 | 2.4% |
| Feedwater System | 0.11 | 2.3% |
| Inlet Air System and Compressors | 0.09 | 1.8% |
| Cooling System | 0.08 | 1.6% |
| Boiler Piping System | 0.08 | 1.6% |
| Low Pressure Turbine | 0.07 | 1.5% |
| Circulating Water Systems | 0.07 | 1.4% |
| Controls | 0.06 | 1.2% |
| Fuel, Ignition and Combustion Systems | 0.06 | 1.1% |
| Precipitators | 0.05 | 1.1% |
| All Other Causes | 0.80 | 16.7% |
| Total | 4.80 | 100.0% |

*Table 5-20 Contributions to Economic Outages: 2010 (January through March) (See 2009 SOM, Table 5-20)*

| | Contribution to Economic Reasons |
|---|---|
| Lack of Fuel (OMC) | 74.2% |
| Other Economic Problems | 18.7% |
| Lack of Fuel (Non-OMC) | 6.9% |
| Fuel Conservation | 0.3% |
| Lack of Water (Hydro) | 0.0% |
| Total | 100.0% |

*Table 5-21 Contribution to EFOF by unit type for the most prevalent causes: Calendar year 2010 (January through March) (See 2009 SOM, Table 5-21)*

| | Combined Cycle | Combustion Turbine | Diesel | Hydroelectric | Nuclear | Steam | System |
|---|---|---|---|---|---|---|---|
| Boiler Tube Leaks | 0.8% | 0.0% | 0.0% | 0.0% | 0.0% | 28.2% | 22.9% |
| Low Pressure Turbine | 0.0% | 0.0% | 0.0% | 0.0% | 17.3% | 1.2% | 1.5% |
| Economic | 1.9% | 35.1% | 0.4% | 0.2% | 0.0% | 16.4% | 16.6% |
| Electrical | 0.8% | 26.9% | 0.4% | 17.8% | 44.5% | 2.3% | 5.8% |
| Boiler Air and Gas Systems | 0.1% | 0.0% | 0.0% | 0.0% | 0.0% | 7.8% | 6.3% |
| Generator | 32.2% | 0.2% | 0.3% | 0.1% | 0.0% | 0.6% | 2.5% |
| Boiler Fuel Supply from Bunkers to Boiler | 0.1% | 0.0% | 0.0% | 0.0% | 0.0% | 4.4% | 3.6% |
| Fuel Quality | 0.6% | 0.0% | 3.1% | 0.0% | 0.0% | 5.2% | 4.3% |
| Stack Emission | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 3.0% | 2.4% |
| Boiler Piping System | 0.3% | 0.0% | 0.0% | 0.0% | 0.0% | 1.9% | 1.6% |
| Controls | 0.2% | 0.8% | 0.3% | 9.9% | 0.0% | 1.3% | 1.2% |
| High Pressure Turbine | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 0.7% | 0.6% |
| Feedwater System | 1.0% | 0.0% | 0.0% | 0.0% | 12.3% | 2.3% | 2.3% |
| Performance | 0.9% | 0.8% | 0.0% | 1.2% | 0.0% | 0.6% | 0.6% |
| Condensing System | 0.1% | 0.0% | 0.0% | 0.0% | 0.4% | 1.3% | 1.0% |
| Inlet Air System and Compressors | 20.6% | 6.4% | 0.0% | 0.0% | 0.0% | 0.0% | 1.8% |
| Boiler Tube Fireside Slagging or Fouling | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% | 3.1% | 2.5% |
| Valve | 1.8% | 0.0% | 0.0% | 0.0% | 0.0% | 1.2% | 1.1% |
| Miscellaneous (Generator) | 2.1% | 3.2% | 0.3% | 11.3% | 0.0% | 0.6% | 0.9% |
| All Other Causes | 36.5% | 26.6% | 95.3% | 59.5% | 25.4% | 17.8% | 20.4% |
| Total | 100.0% | 100.0% | 100.0% | 100.0% | 100.0% | 100.0% | 100.0% |

*Table 5-22 Contribution to EFOF by unit type: Calendar year 2010 (January through March) (See 2009 SOM, Table 5-22)*

| | EFOF | Contribution to EFOF |
|---|---|---|
| Combined Cycle | 2.0% | 6.1% |
| Combustion Turbine | 2.3% | 8.9% |
| Diesel | 3.8% | 0.2% |
| Hydroelectric | 0.7% | 0.7% |
| Nuclear | 0.7% | 2.9% |
| Steam | 6.7% | 81.2% |
| Total | 4.0% | 100.0% |

## Outages Deemed Outside Management Control

*Table 5-23 PJM EFORd vs. XEFORd: Calendar year 2010 (January through March) (See 2009 SOM, Table 5-23)*

| | 2010 EFORd | 2010 XEFORd | Difference |
|---|---|---|---|
| Combined Cycle | 4.2% | 4.2% | 0.0% |
| Combustion Turbine | 11.3% | 7.6% | 3.7% |
| Diesel | 5.9% | 3.8% | 2.2% |
| Hydroelectric | 1.0% | 0.6% | 0.3% |
| Nuclear | 0.7% | 0.7% | 0.0% |
| Steam | 8.7% | 7.2% | 1.5% |
| Total | 6.7% | 5.4% | 1.3% |

## Components of EFORp

*Table 5-24 Contribution to EFORp by unit type (Percentage points): Calendar years 2009 to 2010 (January through March) (See 2009 SOM, Table 5-24)*

| | 2009 | 2010 (Jan - Mar) |
|---|---|---|
| Combined Cycle | 0.4 | 0.2 |
| Combustion Turbine | 0.4 | 0.4 |
| Diesel | 0.0 | 0.0 |
| Hydroelectric | 0.1 | 0.0 |
| Nuclear | 0.8 | 0.2 |
| Steam | 2.3 | 2.9 |
| Total | 4.0 | 3.7 |

*Table 5-25 PJM EFORp data by unit type: Calendar years 2009 to 2010 (January through March) (See 2009 SOM, Table 5-25)*

| | 2009 | 2010 (Jan - Mar) |
|---|---|---|
| Combined Cycle | 2.9% | 1.9% |
| Combustion Turbine | 2.5% | 2.4% |
| Diesel | 5.3% | 3.7% |
| Hydroelectric | 2.9% | 0.5% |
| Nuclear | 4.3% | 1.0% |
| Steam | 4.7% | 6.0% |
| Total | 4.0% | 3.7% |

## EFORd, XEFORd and EFORp

**Table 5-26 Contribution to PJM EFORd, XEFORd and EFORp by unit type: Calendar year 2010 (January through March) (See 2009 SOM, Table 5-26)**

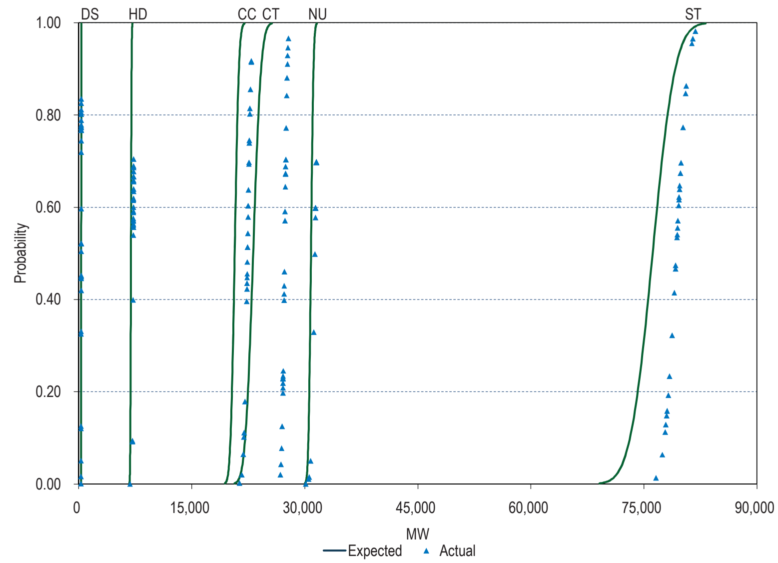
| | EFORd | XEFORd | EFORp |
|---|---|---|---|
| Combined Cycle | 0.5 | 0.5 | 0.2 |
| Combustion Turbine | 1.7 | 1.2 | 0.4 |
| Diesel | 0.0 | 0.0 | 0.0 |
| Hydroelectric | 0.0 | 0.0 | 0.0 |
| Nuclear | 0.1 | 0.1 | 0.2 |
| Steam | 4.2 | 3.5 | 2.9 |
| Total | 6.7 | 5.4 | 3.7 |

**Table 5-27 PJM EFORd, XEFORd and EFORp data by unit type: Calendar year 2010 (January through March) (See 2009 SOM, Table 5-27)**

| | EFORd | XEFORd | EFORp |
|---|---|---|---|
| Combined Cycle | 4.2% | 4.2% | 1.9% |
| Combustion Turbine | 11.3% | 7.6% | 2.4% |
| Diesel | 5.9% | 3.8% | 3.7% |
| Hydroelectric | 1.0% | 0.6% | 0.5% |
| Nuclear | 0.7% | 0.7% | 1.0% |
| Steam | 8.7% | 7.2% | 6.0% |
| Total | 6.7% | 5.4% | 3.7% |

## Comparison of Expected and Actual Performance

**Figure 5-11 PJM 2010 (January through March) distribution of EFORd data by unit type (See 2009 SOM, Figure 5-11)**




## Performance During Peak Months

**Figure 5-12 PJM peak month data: 2010 (See 2009 SOM, Figure 5-12)**

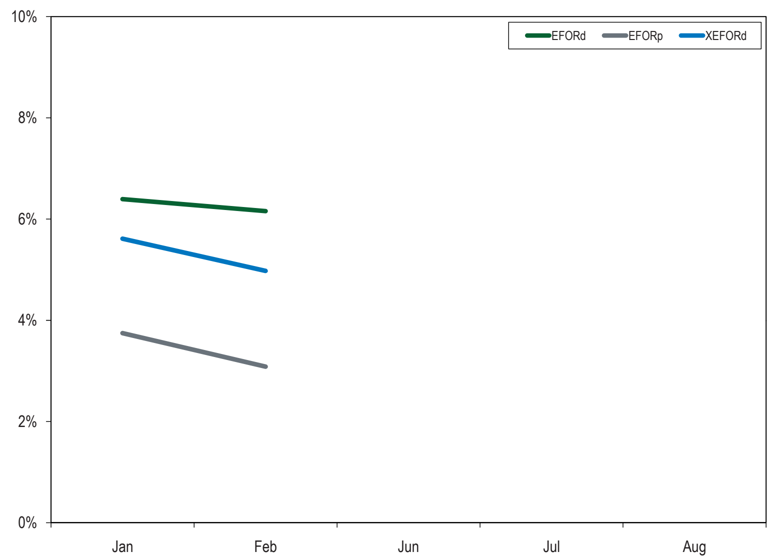


*Figure 5-13 PJM peak month generator performance factors: 2010 (See 2009 SOM, Figure 5-13)*