Market Monitoring Unit

# Analysis of the
# 2008 – 2009 RPM Auction
# Revised

PJM Market Monitoring Unit

July 3, 2008

## Introduction

This report, prepared by the PJM Market Monitoring Unit (MMU), reviews the functioning of the second Reliability Pricing Model (RPM) auction (for the 2008-2009 delivery year) and responds to questions raised by PJM members about that auction. The MMU will prepare a similar report for each RPM auction.

The MMU verified the reasonableness of offer data and calculated the derived offer caps based on submitted data, calculated unit net revenues, verified capacity exports, verified the reasons for MW not offered, verified the maximum EFORd rates used, verified EFORd offer segments, verified clearing prices based on the demand curves and verified that the market structure tests were applied correctly. All participants in the RPM auction failed the market structure tests with the result that offer caps were applied to all sellers. Based on these facts, the MMU concludes that the results of the 2008-2009 RPM auction were competitive.

## Preliminary Market Structure Screen (PMSS)

Under the terms of the PJM Tariff, the MMU is required to apply the preliminary market structure screen (PMSS) prior to RPM auctions.[1] 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 MMU to apply the market structure tests defined in the Tariff. For each locational deliverability area (LDA) and the PJM Region, the PMSS is based on: (1) the unforced capacity available for the delivery year from generation capacity resources located in such area; and (2) the LDA's reliability requirement and the PJM reliability requirement.[2]

An LDA or the regional transmission organization (RTO) Region fails the PMSS if any one of the following three screens is failed: (1) the market share of any capacity resource owner exceeds 20 percent; (2) the Herfindahl-Hirschman Index (HHI) for all capacity

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1 See PJM Open Access Transmission Tariff (OATT), "Attachment DD: Reliability Pricing Model," Original Sheet No. 605 (Effective June 1, 2007), section 6.3 (a) i.

2 The terms "PJM Region," "RTO Region" and "RTO" are synonymous in this report and include all capacity within the PJM footprint.

resource owners is 1800 or higher; or (3) there are not more than three jointly pivotal suppliers.[3] Capacity resource owners who own or control generation in the area that fails the PMSS are required to provide avoidable cost rate (ACR) data to the MMU.[4]

Consistent with the requirements of the Tariff, the MMU applied the PMSS two months prior to the 2008-2009 RPM auction. As shown in Table 1, all three defined areas failed the PMSS. The RTO Region passed the market share and HHI screens, but failed the three pivotal supplier screen. The Eastern Mid-Atlantic Area Council (EMAAC) LDA and Southwestern Mid-Atlantic Area Council (SWMAAC) LDA failed all three screens. Each of the three areas also failed the two pivotal supplier test and the one pivotal supplier test, using the same market definition applied with the three pivotal supplier test. As a result, capacity resource owners were required to submit ACR data to the MMU for resources for which they intended to submit non-zero sell offers unless certain other conditions were met.[5] Specified types of units in areas outside the two constrained LDAs were provisionally exempted from providing such data based on the assumption that these units would not affect the clearing price.[6]

**Table 1 Preliminary Market Structure Screen results: 2008-2009[7]**

| RPM Markets | Highest Market Share | HHI | Pivotal Suppliers | Pass/Fail |
|---|---|---|---|---|
| RTO | 18.5% | 879 | 1 | Fail |
| EMAAC | 33.1% | 2180 | 1 | Fail |
| SWMAAC | 47.5% | 4290 | 1 | Fail |

3 See PJM Open Access Transmission Tariff (OATT), "Attachment DD: Reliability Pricing Model," Original Sheet No. 605 (Effective June 1, 2007), section 6.3 (a) ii.

4 See PJM Open Access Transmission Tariff (OATT), "Attachment DD: Reliability Pricing Model," First Revised Sheets No. 609-612 (Effective June 20, 2007). The required data are defined at section 6.7.

5 See PJM Open Access Transmission Tariff (OATT), "Attachment DD: Reliability Pricing Model," First Revised Sheet No. 610 (Effective June 20, 2007), section 6.7 (c).

6 Attachment A provides the referenced MMU letter regarding provisional exemptions from the data requirement.

7 The RTO includes EMAAC and SWMAAC.

## *Offer Caps*

The defined capacity resource owners were required to submit ACR data to the MMU by six weeks prior to the 2008-2009 RPM auction. If a capacity resource owner failed the market power test for the auction, avoidable costs were used to calculate offer caps for that owner's resources.

Avoidable costs are the costs that a generation owner would not incur if the generating unit did not operate for one year, in particular the delivery year.[8] In effect, avoidable costs are the costs that a generation owner would not incur if the generating unit were mothballed for the year. In the calculation of avoidable costs, there is no presumption that the unit would retire as the alternative to operating, although that possibility could be reflected if the owner documented that retirement was the alternative. Avoidable costs also include annual capital recovery associated with investments required to maintain a unit as a capacity resource. Avoidable costs are defined to be net of net revenues from all other PJM markets and unit-specific bilateral contracts. The specific components of avoidable costs are defined in the PJM Tariff.

Capacity resource owners could provide ACR data by providing their own unit-specific data, by selecting the default ACR values, by submitting an opportunity cost for a possible export, by inputting a transition adder or by using permitted combinations of these options. The default ACR values were calculated by the MMU based on available unit data and posted to the PJM Web site in order to provide an alternative for owners that did not wish to calculate unit-specific ACR values or who believed that the default ACR values exceeded their unit-specific ACR values. The opportunity cost option allows resource owners to input a documented export opportunity cost as the offer for the unit. If the relevant RPM market clears above the opportunity cost, the unit's capacity is sold in the RPM market. If the opportunity cost is greater than the clearing price, the unit's capacity does not clear in the RPM market and it is available for export. The transition

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8 See PJM Open Access Transmission Tariff (OATT), "Attachment DD: Reliability Pricing Model," Original Sheet No. 617 (Effective June 1, 2007), section 6.8 (b).

adder was added to the offer cap, if appropriate, regardless of the offer-cap calculation method.[9]

As shown in Table 2, 1,076 generating units submitted offers as compared to 1,061 generating units offered in the 2007-2008 RPM auction.[10] The increase of 15 units included four new wind units (60.9 MW), three new diesel units (23.3 MW) and two units (112.6 MW) which came out of retirement while the remaining six units were the result of a reclassification of external units.[11, 12] There were 23 DR resources offered compared to 15 DR resources offered in the 2007-2008 RPM auction.[13] Unit-specific offer caps were calculated for 117 units (10.9 percent). Owners submitted unit-specific cost data and net revenue data for these units and the MMU calculated the unit-specific offer caps based on that data. Offer caps of all kinds were used by 567 units (52.7 percent), of which 399 were the default ("proxy") offer caps calculated and posted by the MMU. Of the 1,076 generating units, the remaining 509 units were price takers, of which the offers for 472 units were zero and the offers for 37 units were set to zero because no data were submitted. The transition adder was part of the offers on 255 units, of which offers on 43 units included only the transition adder. The transition adder had no impact on the clearing prices.

As shown in Table 3, of the 1,076 generating units which submitted offers, 79 (7.3 percent) included an Avoidable Project Investment Recovery Rate (APIR) component.

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9 The transition adder, which is added to the calculated offer cap, is $10.00 per MW-day for delivery years 2007-2008 and 2008-2009 and $7.50 per MW-day for delivery years 2009-2010. It can be applied only up to 3,000 MW of unforced capacity per owner, only in unconstrained markets and only by those parent companies which own no more than 10,000 MW of unforced capacity in PJM.

10 In the report on the 2007-2008 RPM auction, total units offered were incorrectly reported as 1,090 units. The correct number was 1,076 units, comprised of 1,061 generating units offered and 15 DR resources offered.

11 Certain external hydro units were allocated from the LDA level to the zonal level, resulting in an increased unit count.

12 Unless otherwise specified, all volumes are in terms of UCAP.

13 Some resources had multiple associated offers.

The APIR component added $27.28 per MW-day on average to the UCAP ACR value of these units. On a UCAP weighted average basis the APIR component added $49.29 per MW-day to the ACR value of these units. The default ACR values include an average APIR of $0.91 per MW-day. The maximum effect ($211.28 per MW-day) is the maximum amount by which an offer cap was increased by APIR. This value is less than the maximum APIR ($283.09 per MW-day) due to the net revenue offset to ACR plus APIR.

**Table 2 ACR statistics: 2008-2009 RPM auction**

| Calculation Type | Number of Units | Percent of Generating Units Offered |
|---|---|---|
| Default ACR Selected | 399 | 37.1% |
| ACR Data Input | 117 | 10.9% |
| Opportunity Cost Input | 8 | 0.7% |
| Transition Adder Only | 43 | 4.0% |
| Offer Caps Calculated | 567 | 52.7% |
| | | |
| Generator Price Takers | 509 | 47.3% |
| | | |
| Generating Units Offered | 1,076 | 100.0% |
| Demand Resources Offered | 23 | |
| Total Capacity Resources Offered | 1,099 | |

**Table 3 APIR statistics: 2008-2009 RPM auction**

| | $ per MW-day UCAP |
|---|---|
| Average APIR | $27.28 |
| UCAP Weighted Average APIR | $49.29 |
| Maximum APIR | $283.09 |
| Maximum APIR Effect | $211.28 |
| Offers Caps with APIR | 79 |

## *RPM Auction Results*

### MMU Methodology

The MMU reviewed the following inputs to and results of the 2008-2009 RPM auction: [14]

- **Offer Cap –** Verified that the avoidable costs, opportunity costs and net revenues used to calculate offer caps were reasonable and properly documented;
- **Net Revenues –** Calculated actual unit-specific net revenue from PJM energy and ancillary service markets for each PJM capacity resource for the period from 2001 through 2006;
- **Exported Resources –** Verified that capacity resources exported from PJM had firm external contracts or made documented opportunity cost offers;
- **Excused Resources –** Verified the specific reasons that capacity resources were excused from offering into the auction;
- **Maximum EFORd –** Verified that the maximum equivalent demand forced outage rate (EFORd) used in base offer segments was the one-year EFORd ending September 30, 2006;
- **EFORd Offer Segment –** Verified that the EFORd offer segments were calculated per the tariff. A total of 1,711.1 MW were included in EFORd offer segments as compared to 811.9 MW included in the 2007-2008 RPM auction;
- **Clearing Prices –** Verified that the auction clearing prices were accurate, based on submitted offers and the Variable Resource Requirement (VRR) curves;
- **Market Structure Test –** Verified that the market power test was properly defined using the three pivotal supplier (TPS) test, that offer caps were properly applied and that the TPS test results were accurate.

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[14] All volumes and prices are in terms of unforced capacity (UCAP), which is calculated as installed capacity (ICAP) times (1-EFORd). The equivalent demand forced outage rate (EFORd) values in this report are the EFORd values used in the 2008-2009 RPM auction. They can be no greater than the EFORd for the 12 months ending September 30, 2006.

## Market Structure Tests

As shown in Table 4, all participants in the total PJM market as well as both LDA RPM markets failed the TPS test. The result was that offer caps were applied to all sell offers. Only those participants that fail the market power test are subject to offer capping. The RTO market includes all supply which cleared at or below the unconstrained clearing price. The LDA markets include the incremental supply inside the LDAs which was required to meet the demand for capacity in each LDA and which cleared at a price higher than the unconstrained price.

Table 4 presents the results of the TPS test using the Residual Supplier Index ($RSI_x$) as the metric.[15] A generation owner or owners are pivotal if the capacity of the owners' generation facilities is needed to meet the demand for capacity. The $RSI_x$ is a general measure that can be used with any number of pivotal suppliers. The subscript denotes the number of pivotal suppliers included in the test. If the $RSI_x$ is less than 1.0, the supply owned by the specific generation owner, or owners, is needed to meet market demand and the generation owners are pivotal suppliers with a significant ability to influence market prices. If the $RSI_x$ is greater than 1.0, the supply of the specific generation owner or owners is not needed to meet market demand and those generation owners have a reduced ability to unilaterally influence market price. For example, ninety-five percent of participants in the RTO market failed the one pivotal supplier test using a market definition that includes all offers with costs less than or equal to 1.05 times the clearing price.[16]

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15 See *2006 State of the Market Report* (March 8, 2007), Appendix J, "Three Pivotal Supplier Test" for additional discussion on the TPS test.

16 The market definition used for the TPS test includes all offers with costs less than or equal to 1.50 times the clearing price. The appropriate market definition to use for the one pivotal supplier test includes all offers with costs less than or equal to 1.05 times the clearing price. See *2006 State of the Market Report* (March 8, 2007), Appendix J, "Three Pivotal Supplier Test" for additional discussion.

**Table 4 RSI results: 2008-2009 RPM auction**[17]

| | $RSI_{1\ 1.05}$ | $RSI_2$ | $RSI_3$ |
|---|---|---|---|
| RTO | 0.82 | 0.69 | 0.61 |
| EMAAC | 1.10 | 0.79 | 0.25 |
| SWMAAC | 0.32 | 0.14 | 0.00 |

## RTO

Table 5 shows total RTO offer data for the 2008-2009 RPM auction, which includes the EMAAC and SWMAAC LDAs. Total internal RTO unforced capacity increased 1,762.0 MW from 155,206.0 MW in the 2007-2008 RPM auction to 156,968.0 MW due to new generation (84.2 MW), units which came out of retirement (112.6 MW), capacity upgrades to existing generation and increases in demand resources, net of unit retirements (79.8 MW) and derations to existing generation and demand capacity resources. Of the 1,762.0 MW increase in total internal RTO unforced capacity, 818.5 MW were due to voluntary reductions in sell offer EFORds in the 2008-2009 auction. Of the remaining 943.5 MW, 348.2 MW (about 34 percent) were generation and 595.3 MW (about 66 percent) were DR. This value includes all generating units and demand resources (DR) that qualified as a PJM capacity resource for the 2008-2009 auction, excluding external units, and also includes owners' modifications to installed capacity ratings (Table 6) which are permitted under the PJM Reliability Assurance Agreement (RAA) and associated manuals.[18] The installed capacity (ICAP) of a unit may only be reduced through a capacity modification (capmod) if the capacity owner does not intend to restore the reduced capability by the end of the planning period following the

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17 The RTO includes EMAAC and SWMAAC. The reported $RSI_x$ results are the lowest calculated for each market and test.

18 See "Reliability Assurance Agreement among Load-Serving Entities in the PJM Region," (June 1, 2007) (Accessed July 19, 2007) <http://www.pjm.com/documents/ downloads/ agreements/ raa.pdf> (1.92 MB).

planning period in question.[19] Otherwise the owner must take an outage, as appropriate, if the owner cannot provide energy consistent with the ICAP of the unit.

Multiple owners submitted both positive and negative capacity modifications, with a net RTO increase of 926.7 MW of ICAP and 943.5 MW of UCAP (Table 6). Capmod increases and decreases were the result of owner reevaluation of the capabilities of their generation and demand resources, at least partially in response to the incentives and penalties contained in RPM. After accounting for fixed resource requirement (FRR), committed resources and for imports, RPM capacity was 136,237.3 MW as compared to 135,092.6 MW in the 2007-2008 RPM auction.[20] FRR volumes increased by 268.4 MW and imports decreased by 348.9 MW. RPM capacity was reduced by exports of 3,838.1 MW[21] and 188.5 MW which were excused from the RPM must-offer requirement as a result of environmental regulations (151.0 MW), generation moving behind the meter (17.3 MW), non-utility generator (NUG) ownership questions (17.7 MW) and other factors (2.5 MW). Exports decreased 100.4 MW and excused volumes decreased 81.8 MW from the 2007-2008 RPM auction. Subtracting 330.1 MW of FRR optional volumes not offered, an increase of 294.3 MW in FRR MW not offered from the 2007-2008 RPM auction, resulted in 131,880.6 MW that were available to be offered into the auction, an increase of 1,032.6 MW.[22] After accounting for the above, all capacity resources were offered into the RPM auction.

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19 See "PJM Manual 21: Rules and Procedures for Determination of Generating Capability," Revision 04 (August 15, 2005), p. 8 <http://www.pjm.com/ contributions/pjm-manuals/pdf/m21.pdf> (228 KB). The manual states "the end of the next planning period."

20 The FRR alternative allows an LSE, subject to certain conditions, to avoid direct participation in the RPM auctions. The LSE is required to submit a FRR capacity plan to satisfy the unforced capacity obligation for all load in its service area.

21 If all of the exports had been offered into the auction at $0.00 per MW-day, the clearing price would have been approximately $56.00 per MW-day.

22 FRR entities are allowed to offer into the RPM auction excess volumes above their FRR quantities, subject to a sales cap amount. The 330.1 MW are excess volumes included in the sales cap amount which were not offered into the auction.

The downward sloping demand curve resulted in more capacity clearing in the market than the reliability requirement. As shown in Table 5, the 129,597.6 MW of cleared resources for the entire RTO, which represented a reserve margin of 17.5 percent, resulted in net excess of 1,403.0 MW greater than the reliability requirement of 128,194.6 MW (IRM of 15.0 percent).[23] [24] [25] Net excess decreased 2,201.2 MW from the net excess of 3,604.2 MW in the 2007–2008 RPM auction. This decrease resulted from the increase in the reliability requirement and the associated shift in the demand curve. The ILR forecast less FRR demand response increased 2.7 MW from 1,660.9 MW in the 2007-2008 auction to 1,663.6 MW. As shown in Figure 1, the downward sloping demand curve resulted in a price of $111.92 per MW-day. If the demand curve had been vertical at the reliability requirement, as shown in Figure 2, the clearing price would have been approximately $39.00 per MW-day.

Table 7 shows the composition of the offers on the steeply sloped portion of the RTO supply curve from $12.00 per MW-day up to and including $150.00 per MW-day. Almost two thirds of the offers on this section of the supply curve were for oil/gas steam units and combustion turbines, both with APIR. The last offer to clear was a DR offer.

As shown in Figure 3, the RTO clearing price increased from $40.80 per MW-day in the 2007–2008 auction to $111.92 per MW-day in the 2008–2009 auction. While offered volumes (supply) increased by 1,036.9 MW from 130,843.7 MW to 131,880.6 MW, the reliability requirement, from which the demand curve is developed, increased by 2,389.6 MW from 125,805.0 MW to 128,194.6 MW.[26] The increase in the reliability requirement, which was due to an increase in the preliminary forecast peak load, shifted the demand

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23 The reserve margin of 17.5 percent was calculated by subtracting DR and ILR from the peak load. If DR and ILR were counted as resources in the calculation, then the reserve margin would be 17.3 percent.

24 The RTO reliability requirement, which is after FRR adjustments, is plotted on the VRR curve as the reliability requirement less the ILR forecast obligation plus any FRR DR.

25 Net excess is defined as the cleared volumes less the reliability requirement.

26 The demand curve is based on three points, which are ratios of the installed reserve margin (IRM =15.0%) times the reliability requirement, less the forecast RTO ILR obligation. For the three points, the ratios are 1.12/1.15, 1.16/1.15 and 1.20/1.15.

curve to the right and resulted in a significant increase in the clearing price because the demand curve intersected the steeply sloped portion of the supply curve.[27]

Figure 4 shows how changes in supply, demand and CETL contributed to the increase in the RTO clearing price from $40.80 per MW-day in the 2007-2008 auction to $111.92 per MW-day in the 2008-2009 auction. Higher sell offers contributed approximately $6.00 per MW-day (Point A) to the increase. In other words, if the demand curve had remained unchanged from the 2007-2008 auction, the clearing price would have been approximately $47.00 per MW-day. Increased demand (Point B) had the greatest impact ($41.00 per MW-day). In other words, if the supply curve had remained unchanged from the 2007-2008 auction, the clearing price would have been approximately $110.00 per MW-day. The approximately $24.00 per MW-day increase from Point B to the 2008-2009 clearing price of $111.92 per MW-day was the result of a net increase in CETL (2.085.0 MW increase in EMAAC and 89.0 decrease in SWMAAC) which resulted in increased demand in the RTO market.

As shown in Table 5, the preliminary net load price that LSEs will pay is $111.92 per MW-day in the RTO area not included in the constrained LDAs. This value is the preliminary zonal capacity price. The final zonal capacity price will be calculated three months before the delivery year when the resource clearing price is adjusted for differences between the certified interruptible load for reliability (ILR) for the delivery year and the forecasted RTO ILR obligation.

Figure 5 shows that the RTO would have cleared at approximately $125.00 per MW-day compared to $70.00 per MW-day in the 2007-2008 auction if there had been no constraints and the RTO had cleared as a single market with the downward sloping demand curve. In both cases, these prices are greater than the clearing prices for the unconstrained part of the RTO (the RTO market), but less than the clearing prices for the constrained LDAs.

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27 See "Planning Period Parameters" (July 25, 2007) <http://www.pjm.com/markets/rpm/downloads/planning-period-parameters.xls> (36.5 KB).

**Table 5  RTO offer statistics: 2008-2009 RPM auction[28]**

| | ICAP (MW) | UCAP (MW) | Percent of Available ICAP | Percent of Available UCAP |
|---|---|---|---|---|
| Total Internal RTO Capacity (Gen and DR) | 166,037.9 | 156,968.0 | | |
| FRR | (24,953.5) | (23,191.0) | | |
| Imports | 2,612.0 | 2,460.3 | | |
| RPM Capacity | 143,696.4 | 136,237.3 | | |
| | | | | |
| Exports | (4,205.8) | (3,838.1) | | |
| FRR Optional | (356.7) | (330.1) | | |
| Excused | (365.3) | (188.5) | | |
| Available | 138,768.6 | 131,880.6 | 100.0% | 100.0% |
| | | | | |
| Generation Offered | 138,076.7 | 131,164.8 | 99.5% | 99.5% |
| DR Offered | 691.9 | 715.8 | 0.5% | 0.5% |
| Total Offered | 138,768.6 | 131,880.6 | 100.0% | 100.0% |
| | | | | |
| Unoffered | 0.0 | 0.0 | 0.0% | 0.0% |
| | | | | |
| Cleared in RTO | 135,613.1 | 128,910.6 | 97.8% | 97.8% |
| Cleared in LDAs | 743.6 | 687.0 | 0.5% | 0.5% |
| Total Cleared | 136,356.7 | 129,597.6 | 98.3% | 98.3% |
| | | | | |
| Uncleared in RTO | 1,185.1 | 1,130.0 | 0.8% | 0.8% |
| Uncleared in LDAs | 1,226.8 | 1,153.0 | 0.9% | 0.9% |
| Total Uncleared | 2,411.9 | 2,283.0 | 1.7% | 1.7% |
| | | | | |
| Reliability Requirement | | 128,194.6 | | |
| | | | | |
| Total Cleared | | 129,597.6 | | |
| | | | | |
| Net Excess/(Deficit) | | 1,403.0 | | |
| | | | | |
| ILR Forecast - FRR DR | | 1,663.6 | | |
| | | | | |
| Resource Clearing Price ($ per MW-day) | | $111.92 | A | |
| Preliminary Zonal Capacity Price ($ per MW-day) | | $111.92 | B | |
| Final Zonal CTR Credit Rate ($ per MW-day) | | $0.00 | C | |
| Final Zonal ILR Price ($ per MW-day) | | $111.92 | A-C | |
| Preliminary Net Load Price ($ per MW-day) | | $111.92 | B-C | |

28 Prices are only for those generating units outside of EMAAC and SWMAAC.

**Table 6 Capacity modifications: 2008-2009 RPM auction[29]**

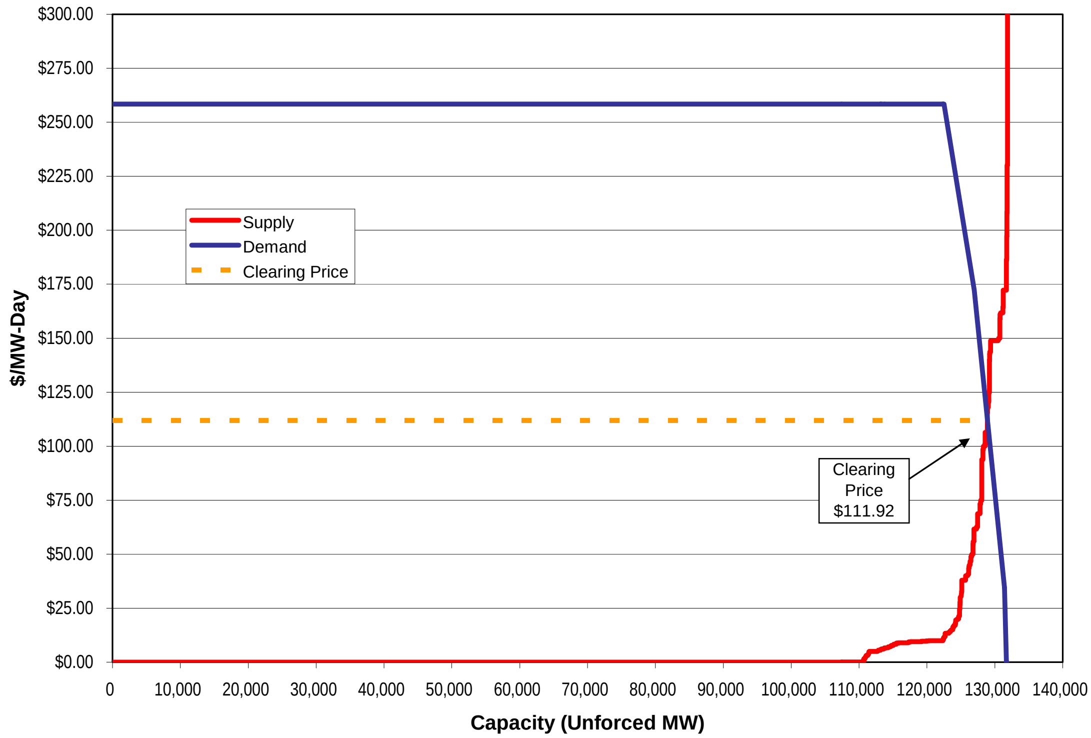
| | ICAP (MW) | | | UCAP (MW) | | |
|---|---|---|---|---|---|---|
| | RTO | EMAAC | SWMAAC | RTO | EMAAC | SWMAAC |
| Generation Increases | 717.7 | 293.4 | 52.0 | 677.1 | 265.3 | 51.7 |
| Generation Decreases | (365.7) | (51.6) | (14.0) | (328.9) | (46.8) | (12.8) |
| Generation Net Increase/(Decrease) | 352.0 | 241.8 | 38.0 | 348.2 | 218.5 | 38.9 |
| | | | | | | |
| DR Increases | 609.1 | 315.2 | 287.6 | 630.7 | 326.0 | 297.5 |
| DR Decreases | (34.4) | (26.5) | (3.1) | (35.4) | (27.3) | (3.2) |
| Net DR Increase/(Decrease) | 574.7 | 288.7 | 284.5 | 595.3 | 298.7 | 294.3 |
| | | | | | | |
| Net Capacity Resource Increase/(Decrease) | 926.7 | 530.5 | 322.5 | 943.5 | 517.2 | 333.2 |

**Table 7 Offers between $12.00 and $150.00 on RTO supply curve: 2008-2009 RPM auction**

| Offer/Technology Type | UCAP (MW) | Percent of Offers |
|---|---|---|
| DR | 248.5 | 3.1% |
| EFORd Offer Segment | 750.1 | 9.3% |
| Oil/Gas Steam | 2,888.3 | 35.5% |
| Combustion Turbine | 2,389.1 | 29.5% |
| Combined Cycle | 635.3 | 7.8% |
| Subcritical Coal | 583.7 | 7.2% |
| Supercritical Coal | 524.7 | 6.5% |
| Pumped Storage | 80.6 | 1.0% |
| Diesel | 7.9 | 0.1% |
| Total | 8,108.2 | 100.0% |

29 Only capmods that had a start date after June 1, 2007 and on or before June 1, 2008 are included.

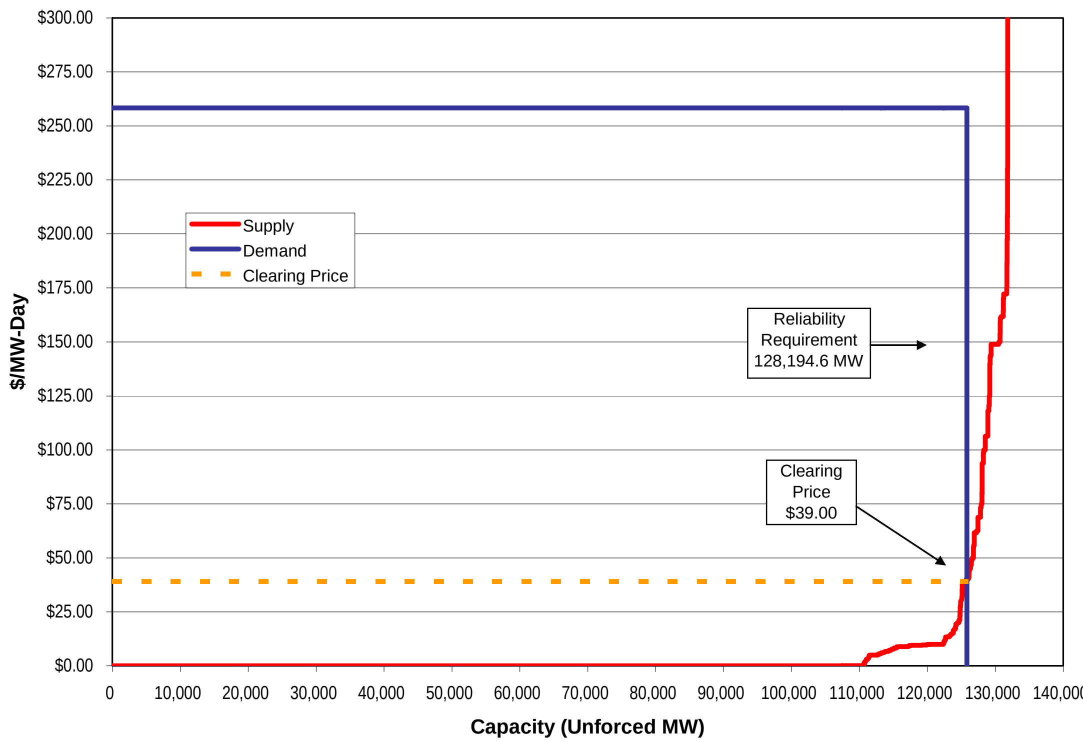
**Figure 1 RTO market supply/demand curves: 2008-2009 RPM auction[30, 31]**




30 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 EMAAC and SWMAAC.

31 For ease of viewing, the graph was truncated at $300.00 per MW-day and does not show an uncleared offer of approximately $800.00 per MW-day.

**Figure 2 PJM RTO supply/demand curves at reliability requirement: 2008-2009 RPM auction**[32, 33, 34]

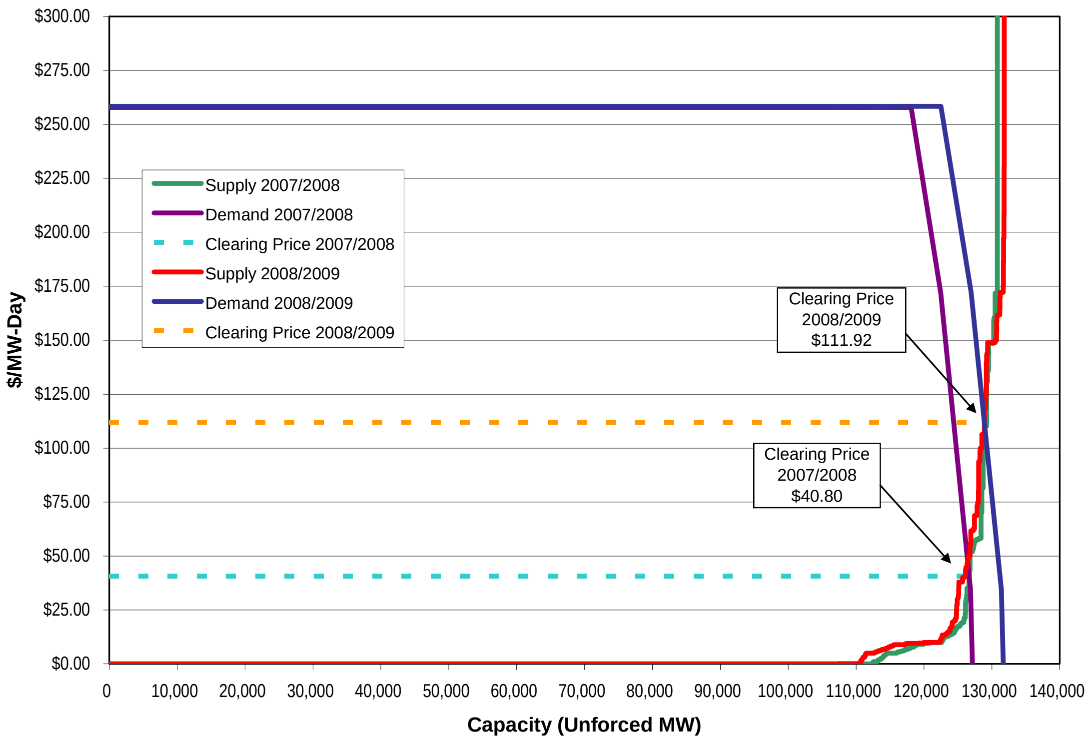



32 The supply curve includes all supply offers at the lower of offer price or offer cap. The demand curve includes all demand in the entire RTO, including EMAAC and SWMAAC.

33 For ease of viewing, the supply curve was truncated at $300.00 per MW-day and does not show an uncleared offer of approximately $800.00 per MW-day.

34 The reliability requirement is plotted on the VRR curve as the reliability requirement less the ILR forecast obligation.

## Figure 3 RTO market supply/demand curves: 2007-2008 and 2008-2009 RPM auctions[35, 36]

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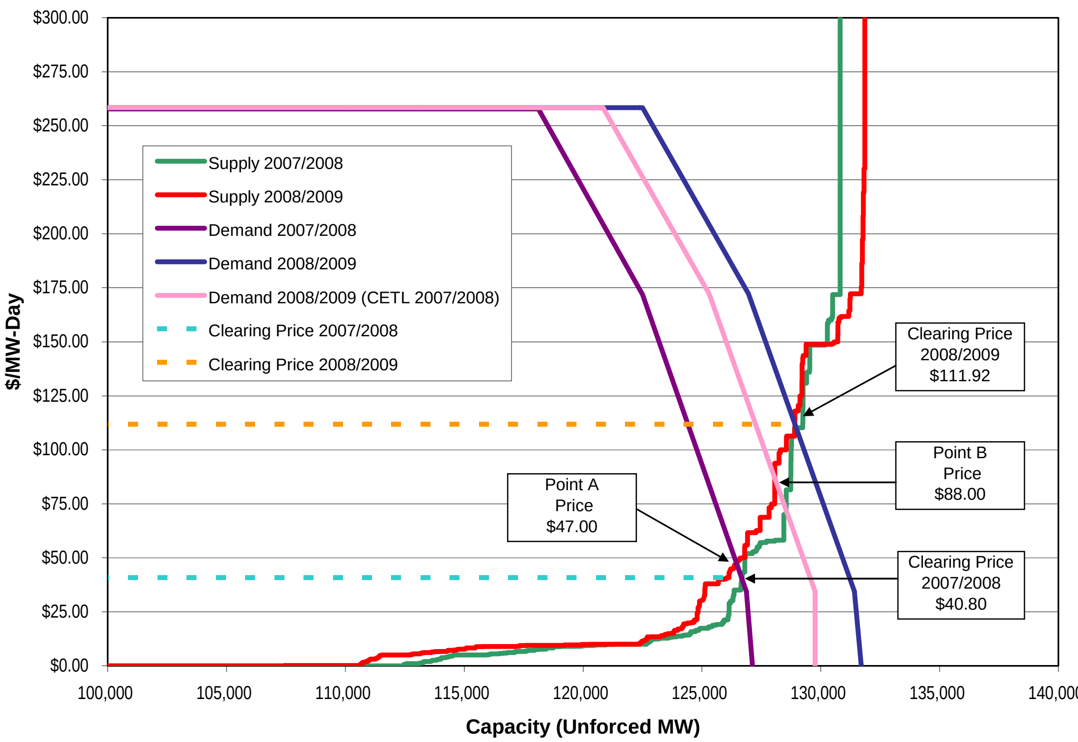
35 The supply curve includes all supply offers at the lower of offer price or offer cap. The demand curve excludes incremental demand which cleared in EMAAC and SWMAAC.

36 For ease of viewing, the graph was truncated at $300.00 per MW-day and does not show an uncleared offer of approximately $800.00 per MW-day.

**Figure 4 RTO market supply/demand curves: 2007-2008 and 2008-2009 RPM auctions**[37, 38]

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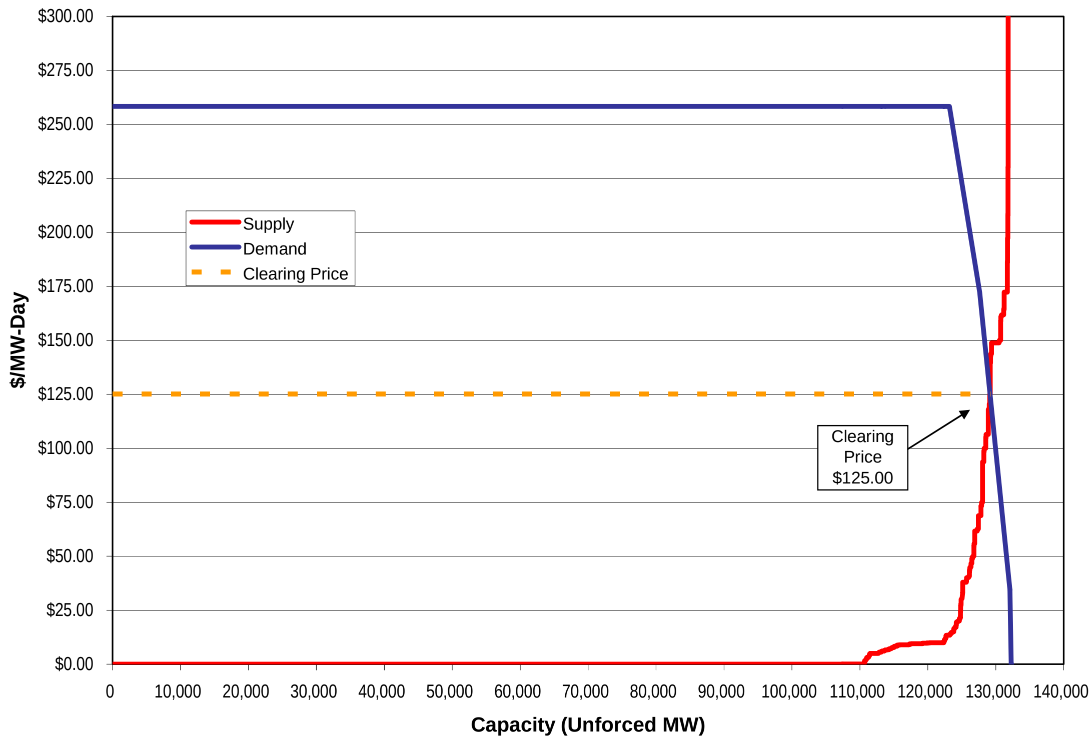
[37] The supply curve includes all supply offers at the lower of offer price or offer cap. The demand curve excludes incremental demand which cleared in EMAAC and SWMAAC.

[38] For ease of viewing, the graph was truncated at $300.00 per MW-day and does not show an uncleared offer of approximately $800.00 per MW-day.

**Figure 5 PJM RTO supply/demand curves: 2008-2009 RPM auction[39, 40]**




## Eastern MAAC (EMAAC)

Table 8 shows total EMAAC offer data for the 2008-2009 RPM auction. Total internal EMAAC UCAP, which includes all generating units and demand resources that qualified as a PJM capacity resource, excluding external units, and also includes owners' modifications to ICAP ratings (Table 6), increased 554.0 MW from 30,825.1 MW in the 2007-2008 auction to 31,379.1 MW. This increase was due to units which came out of retirement (112.6 MW), upgrades to existing generation and increases in demand resources, net of derations to existing generation and demand capacity resources. Multiple owners submitted both positive and negative capacity modifications, which resulted in a net increase of 530.0 MW of ICAP and 517.2 MW of UCAP in EMAAC. Of

39 The supply curve includes all supply offers at the lower of offer price or offer cap. The demand curve includes all demand in the entire RTO, including EMAAC and SWMAAC.

40 For ease of viewing, the supply curve was truncated at $300.00 per MW-day and does not show an uncleared offer of approximately $800.00 per MW-day.

the 554.0 MW increase in total internal EMAAC unforced capacity, 36.8 MW were due to lower sell offer EFORds being used in the 2008-2009 auction. Of the remaining 517.2 MW increase in unforced capacity, 281.5 MW (about 42 percent) were generation and 298.7 MW (about 58 percent) were DR. Including imports of 17.6 MW into EMAAC, RPM capacity was 31,396.7 MW. This amount was reduced by 17.3 MW which were excused from the RPM must-offer requirement as a result of generation moving behind the meter, resulting in 31,379.4 MW of UCAP that were available to be offered into the auction, an increase of 551.7 MW. After accounting for the above exception, all capacity resources were offered into the RPM auction, with offered volumes increasing by 552.2 MW from 30,827.2 MW to 31,379.4 MW.

Of the 30,231.3 MW cleared in EMAAC, which was a decrease of 566.5 MW from the 2007-2008 auction, 28,829.9 MW were cleared in the RTO before EMAAC became constrained. Once the constraint was binding, based on the 7,930.0 MW capacity emergency transfer limit (CETL) value, only the incremental supply located in EMAAC was available to meet the incremental demand in the LDA. Of the 1,549.5 MW of incremental supply, 401.4 MW cleared, which resulted in a resource clearing price of $148.80 per MW-day, as shown in Figure 6. The price was determined by the intersection of the incremental supply and demand curves. On the horizontal section of the supply curve, 1,098.3 MW were offered at the net CONE price of $148.80 per MW-day. Of this amount, 660.6 MW were base offers with APIR from existing generation and 437.7 MW were EFORd offer segments. The 1,148.1 MW of uncleared volumes, which increased 1,118.7 MW from 29.4 MW, were the result of offer prices which exceeded the clearing price. Offers with APIR accounted for 690.0 MW of the uncleared volumes while uncleared demand side offers totaled 174.7 MW.

As shown in Table 8, total resources available to EMAAC were 38,161.3 MW, which was 270.6 MW (0.7 percent) greater than the reliability requirement of 37,890.7 MW. The ILR forecast increased 0.8 MW from 395.3 MW in the 2007-2008 auction to 396.1 MW. If the demand curve had been vertical at the incremental reliability requirement with the same maximum price as for the downward sloping demand curve in Figure 6, the clearing price would have been $117.98 per MW-day, as shown in Figure 7.

As shown in Figure 8, the 2008-2009 clearing price decreased $48.87 per MW-day from $197.67 per MW-day in the 2007–2008 auction. A 2,085.0 MW increase in the CETL (capacity import capability) from 5,845.0 MW to 7,930.0 MW due to transmission upgrades scheduled to be in service prior to the 2008-2009 delivery year allowed more capacity from outside of EMAAC to be imported into the LDA before it constrained, thereby lowering the clearing price. The increase in CETL resulted in a smaller demand that had to be met by resources in the LDA as well as a smaller supply of capacity remaining after the RTO market cleared. The increase in CETL and associated shifts in the demand and supply curves more than offset the increase in the reliability requirement (demand) of 654.0 MW from 37,236.7 MW to 37,890.7 MW, which was due to an increase in the preliminary peak load forecast.[41]

As shown in Table 8, the preliminary net load price that LSEs will pay is $143.51 per MW-day. This value is the preliminary zonal capacity price ($148.80 per MW-day) less the final capacity transfer right (CTR) credit rate ($5.29 per MW-day). The final zonal capacity price will be calculated three months before the delivery year when the resource clearing price is adjusted for differences between the certified interruptible load for reliability (ILR) for the delivery year and the forecasted RTO ILR obligation. The CTR MW value allocated to load in an LDA is the LDA UCAP obligation less the cleared generation internal to the LDA less the ILR forecast for the LDA. This MW value is multiplied by the locational price adder for the LDA to arrive at the economic value of the CTRs allocated to the load in the LDA. This value is then divided by the LDA UCAP obligation to arrive at the final CTR credit rate for the LDA. The final CTR credit rate is an allocation of the economic value of transmission import capability that exists in constrained LDAs and serves to offset a portion of the locational price adder charged to load in constrained LDAs. The CTR credit is not based on the total CETL, the total MW of capacity from outside the LDA that helps meet the LDA obligation, because the load in the LDA must pay for the capacity obligation at the clearing price and not for the capacity deliverable to the LDA.

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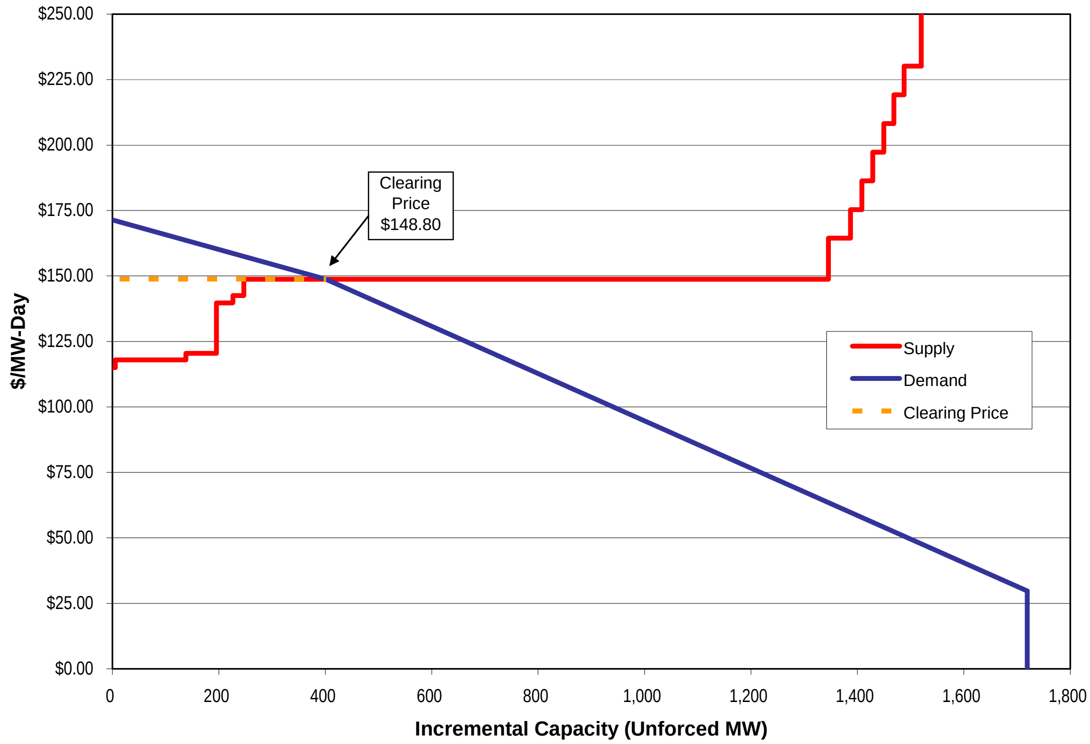
41 See "Planning Period Parameters" (July 25, 2007) <http://www.pjm.com/markets/rpm/downloads/planning-period-parameters.xls> (36.5 KB).

**Table 8 EMAAC offer statistics: 2008-2009 RPM auction**

| | ICAP (MW) | UCAP (MW) | Percent of Available ICAP | Percent of Available UCAP |
|---|---|---|---|---|
| Total Internal EMAAC Capacity (Gen and DR) | 33,472.8 | 31,379.1 | | |
| Imports | 17.6 | 17.6 | | |
| RPM Capacity | 33,490.4 | 31,396.7 | | |
| | | | | |
| Exports | 0.0 | 0.0 | | |
| Excused | (18.1) | (17.3) | | |
| Available | 33,472.3 | 31,379.4 | 100.0% | 100.0% |
| | | | | |
| Generation Offered | 33,140.3 | 31,036.0 | 99.0% | 98.9% |
| DR Offered | 332.0 | 343.4 | 1.0% | 1.1% |
| Total Offered | 33,472.3 | 31,379.4 | 100.0% | 100.0% |
| | | | | |
| Unoffered | 0.0 | 0.0 | 0.0% | 0.0% |
| | | | | |
| Cleared in RTO | 31,797.7 | 29,829.9 | 94.9% | 95.0% |
| Cleared in LDA | 452.5 | 401.4 | 1.4% | 1.3% |
| Total Cleared | 32,250.2 | 30,231.3 | 96.3% | 96.3% |
| | | | | |
| Uncleared | 1,222.1 | 1,148.1 | 3.7% | 3.7% |
| | | | | |
| Reliability Requirement | | 37,890.7 | | |
| | | | | |
| Total Cleared | | 30,231.3 | | |
| CETL | | 7,930.0 | | |
| Total Resources | | 38,161.3 | | |
| | | | | |
| Net Excess/(Deficit) | | 270.6 | | |
| | | | | |
| ILR Forecast | | 396.1 | | |
| | | | | |
| Resource Clearing Price ($ per MW-day) | | $148.80 | A | |
| Preliminary Zonal Capacity Price ($ per MW-day) | | $148.80 | B | |
| Final Zonal CTR Credit Rate ($ per MW-day) | | $5.29 | C | |
| Final Zonal ILR Price ($ per MW-day) | | $143.51 | A-C | |
| Preliminary Net Load Price ($ per MW-day) | | $143.51 | B-C | |

**Figure 6 EMAAC incremental supply/demand curves: 2008-2009 RPM auction[42, 43]**

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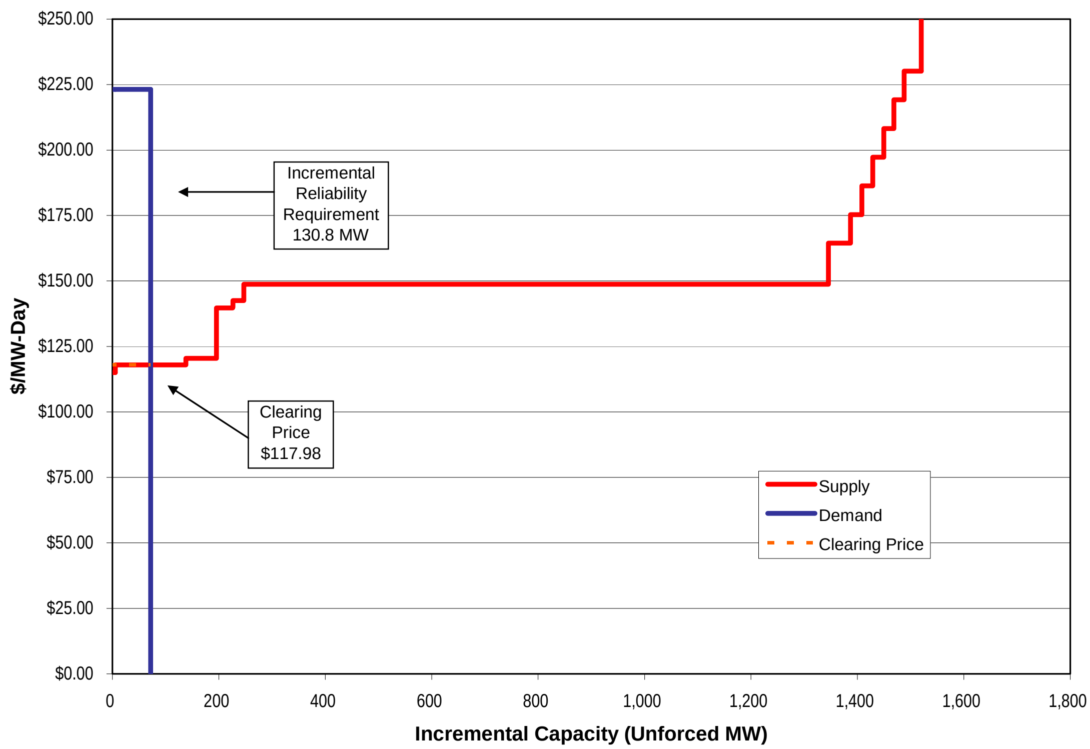
42 The supply curve includes all supply offers at the lower of offer price or offer cap.

43 The supply curve was truncated at $250.00 per MW-day and does not show an uncleared offer of approximately $800.00 per MW-day.

**Figure 7 EMAAC incremental supply/demand curves at reliability requirement: 2008-2009 RPM auction[44, 45, 46]**

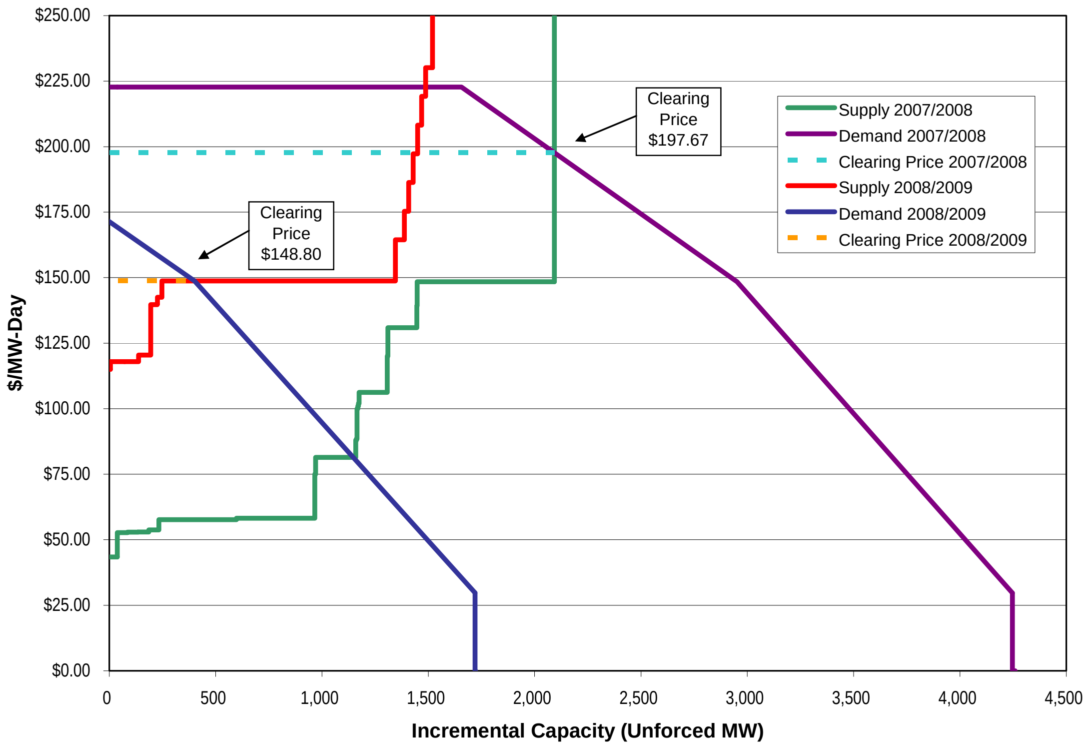



44 The supply curve includes all supply offers at the lower of offer price or offer cap.

45 For ease of viewing, the graph was truncated at $250.00 per MW-day and does not show an uncleared offer of approximately $800.00 per MW-day.

46 The reliability requirement is plotted on the VRR curve as the reliability requirement less the ILR forecast obligation.

**Figure 8 EMAAC incremental supply/demand curves: 2007-2008 and 2008-2009 RPM auctions**[47, 48]




## Southwestern MAAC (SWMAAC)

Table 9 shows total SWMAAC offer data for the 2008-2009 RPM auction. Total internal SWMAAC UCAP, which includes all generating units and demand resources that qualified as a PJM capacity resource, excluding external units, and also includes owners' modifications to ICAP ratings (Table 6), increased 424.9 MW from 10,352.2 MW in the 2007-2008 auction to 10,777.1 MW. This increase was due to upgrades to existing generation and increases in demand resources, net of derations to existing generation and demand capacity resources. Multiple owners submitted both positive and negative capacity modifications, which resulted in a net increase of 322.5 MW of ICAP and 424.9

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

48 For ease of viewing, the graph was truncated at $250.00 per MW-day and does not show an uncleared offer of approximately $800.00 per MW-day.

MW of UCAP in SWMAAC. Of the 424.9 MW increase in total internal SWMAAC unforced capacity, 91.7 MW were due to lower sell offer EFORds being used in the 2008-2009 auction. Of the remaining 333.2 MW increase in unforced capacity, 38.9 MW (about 12 percent) were generation and 294.3 MW (about 88 percent) were DR. Since there were no imports from outside PJM into SWMAAC, RPM capacity was 10,777.1 MW. This amount was reduced by 151.0 MW which were excused from the RPM must-offer requirement as a result of environmental regulations, resulting in 10,626.1 MW of UCAP that were available to be offered into the auction, an increase of 424.9 MW. After accounting for the above exception, all capacity resources were offered into the RPM auction, with offered volumes increasing by 424.9 MW from 10,201.2 MW to 10,626.1 MW.

Of the 10,621.2 MW cleared in SWMAAC, which was an increase of 420.0 MW from the 2007-2008 auction, 10,335.6 MW were cleared in the RTO before SWMAAC became constrained. Once the constraint was binding, based on the 5,610.0 CETL value, only the incremental supply in SWMAAC was available to meet the incremental demand in the LDA. Of the 290.5 MW of incremental supply, 285.6 MW cleared, which resulted in a resource clearing price of $210.11 per MW-day, as shown in Figure 9. The price was determined by the intersection of the incremental supply and demand curves. All of the volumes offered around the net CONE price of $159.02 per MW-day were EFORd offer segments.

As shown Table 9, total resources available to SWMAAC were 16,231.2 MW, which was 330.7 MW (2.0 percent) less than the reliability requirement of 16,561.9 MW. The ILR forecast increased 0.6 MW from 345.6 MW in the 2007-2008 auction to 346.2 MW. If the demand curve had been vertical at the incremental reliability requirement with the same maximum price as for the downward sloping demand curve in Figure 9, the clearing price would have been $238.53 per MW-day, as shown in Figure 10.

The 4.9 MW of uncleared volumes, which increased 4.9 MW from no uncleared volumes, were the result of offer prices which exceeded the clearing price. As shown in Figure 11, the 2008-2009 clearing price increased $21.57 per MW-day from $188.54 per MW-day in the 2007–2008 auction. A combination of factors led to an increase in the clearing price. The RTO market cleared at a higher price which meant fewer resources available within SWMAAC to meet demand that could not be met via imports. CETL decreased by 89.0 MW (capacity import capability) from 5,699.0 MW to 5,610.0 MW, which allowed less capacity to be imported into SWMAAC. The reliability requirement (demand) increased by 486.6 MW, due to an increase in the preliminary peak load forecast, from 16,561.9 MW to 16,075.3 MW.[49]

As shown in Table 9, the preliminary net load price that LSEs will pay is $180.58 per MW-day. This value is the preliminary zonal capacity price ($210.11 per MW-day) less the final CTR credit rate ($29.53 per MW-day). The final zonal capacity price will be calculated three months before the delivery year when the resource clearing price is adjusted for differences between the certified interruptible load for reliability (ILR) for the delivery year and the forecasted RTO ILR obligation. The CTR MW value allocated to load in an LDA is the LDA UCAP obligation less the cleared generation internal to the LDA less the ILR forecast for the LDA. This MW value is multiplied by the locational price adder for the LDA to arrive at the economic value of the CTRs allocated to the load in the LDA. This value is then divided by the LDA UCAP obligation to arrive at the final CTR credit rate for the LDA. The final CTR credit rate is an allocation of the economic value of transmission import capability that exists in constrained LDAs and serves to offset a portion of the locational price adder charged to load in constrained LDAs. The CTR credit is not based on the total CETL, the total MW of capacity from outside the LDA that helps meet the LDA obligation, because the load in the LDA must pay for the capacity obligation at the clearing price and not for capacity deliverable to the LDA.

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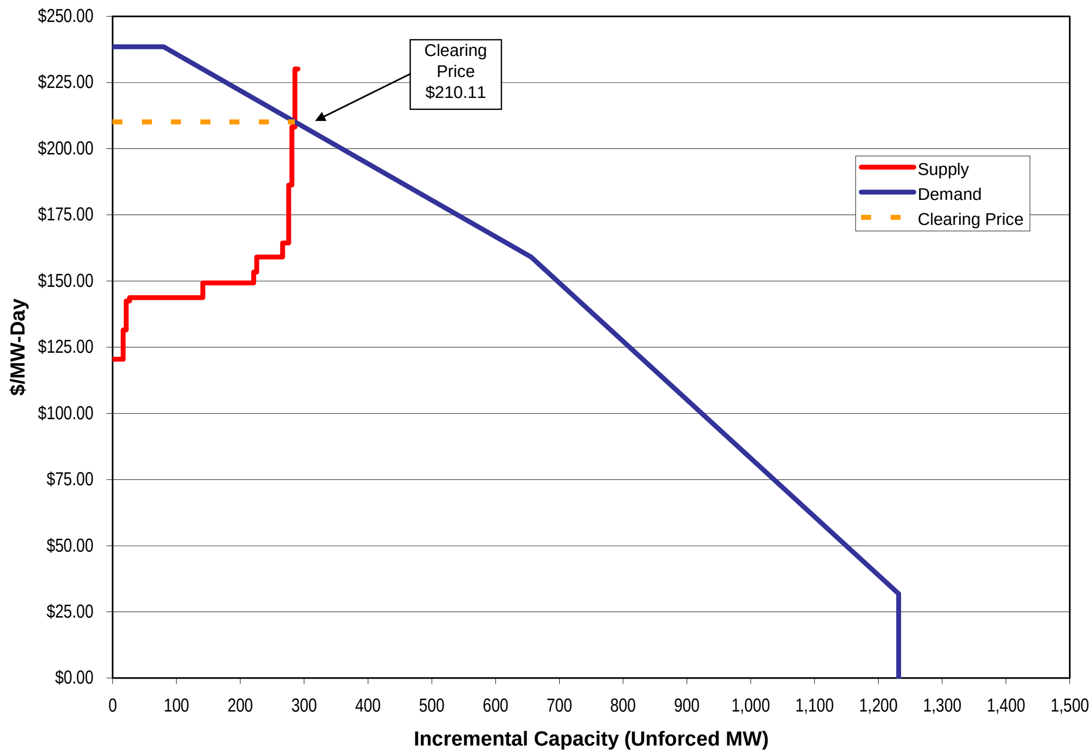
49 See "Planning Period Parameters" (July 25, 2007) <http://www.pjm.com/markets/rpm/downloads/planning-period-parameters.xls> (36.5 KB).

**Table 9 SWMAAC offer statistics: 2008-2009 RPM auction**

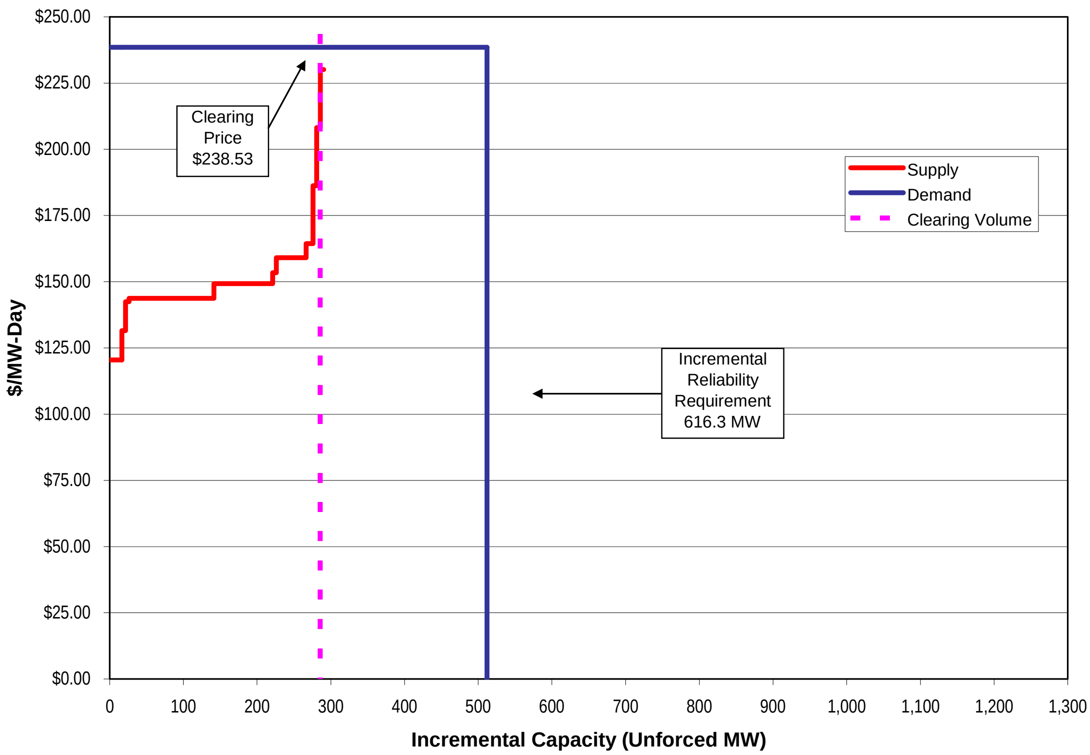
| | ICAP (MW) | UCAP (MW) | Percent of Available ICAP | Percent of Available UCAP |
|---|---|---|---|---|
| Total Internal SWMAAC Capacity (Gen and DR) | 11,868.6 | 10,777.1 | | |
| Imports | 0.0 | 0.0 | | |
| RPM Capacity | 11,868.6 | 10,777.1 | | |
| | | | | |
| Exports | 0.0 | 0.0 | | |
| Excused | (316.0) | (151.0) | | |
| Available | 11,552.6 | 10,626.1 | 100.0% | 100.0% |
| | | | | |
| Generation Offered | 11,249.1 | 10,312.0 | 97.4% | 97.0% |
| DR Offered | 303.5 | 314.1 | 2.6% | 3.0% |
| Total Offered | 11,552.6 | 10,626.1 | 100.0% | 100.0% |
| | | | | |
| Unoffered | 0.0 | 0.0 | 0.0% | 0.0% |
| | | | | |
| Cleared in RTO | 11,256.8 | 10,335.6 | 97.5% | 97.3% |
| Cleared in LDA | 291.1 | 285.6 | 2.5% | 2.7% |
| Total Cleared | 11,547.9 | 10,621.2 | 100.0% | 100.0% |
| | | | | |
| Uncleared | 4.7 | 4.9 | 0.0% | 0.0% |
| | | | | |
| Reliability Requirement | | 16,561.9 | | |
| | | | | |
| Total Cleared | | 10,621.2 | | |
| CETL | | 5,610.0 | | |
| Total Resources | | 16,231.2 | | |
| | | | | |
| Net Excess/(Deficit) | | (330.7) | | |
| | | | | |
| ILR Forecast | | 346.2 | | |
| | | | | |
| Resource Clearing Price ($ per MW-day) | | $210.11 | A | |
| Preliminary Zonal Capacity Price ($ per MW-day) | | $210.11 | B | |
| Final Zonal CTR Credit Rate ($ per MW-day) | | $29.53 | C | |
| Final Zonal ILR Price ($ per MW-day) | | $180.58 | A-C | |
| Preliminary Net Load Price ($ per MW-day) | | $180.58 | B-C | |

**Figure 9  SWMAAC incremental supply/demand curves: 2008-2009 RPM auction[50]**




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

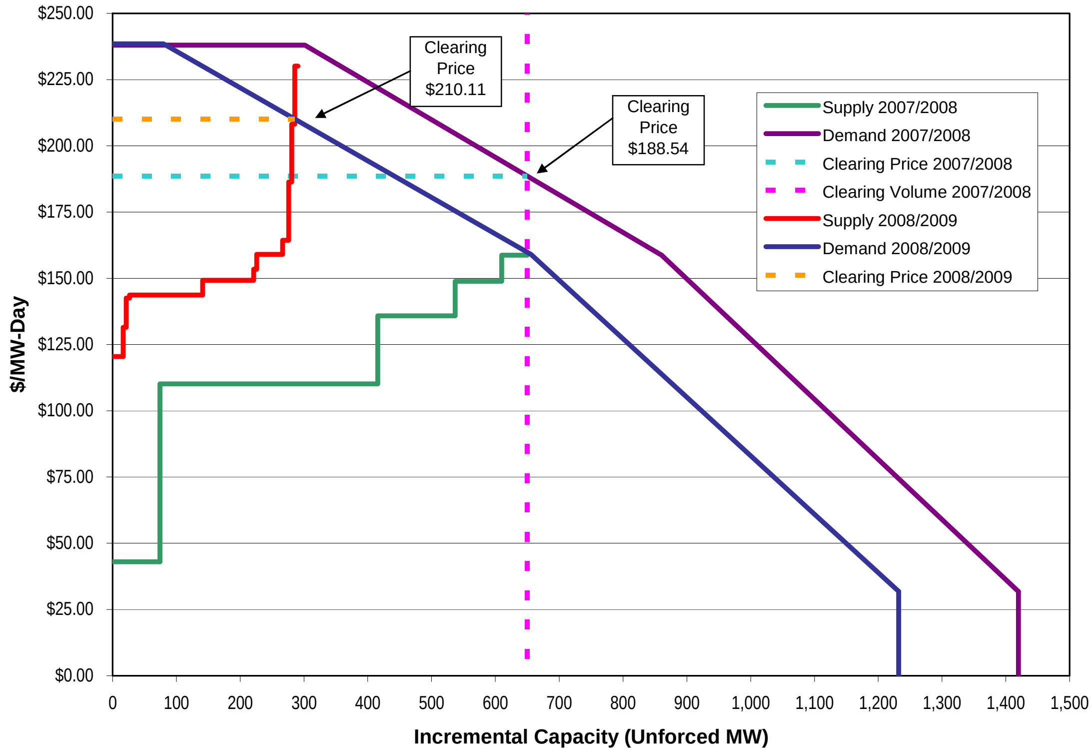
**Figure 10 SWMAAC incremental supply/demand curves at reliability requirement: 2008-2009 RPM auction[51, 52]**




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

52 The reliability requirement is plotted on the VRR curve as the reliability requirement less the ILR forecast obligation.

**Figure 11 SWMMAC incremental supply/demand curves: 2007-2008 and 2008-2009 RPM auctions[53, 54]**




## Load Management (LM)

Effective June 1, 2007, the PJM Active Load Management (ALM) program was replaced by the PJM Load Management (LM) program. Under ALM, providers had received a MW credit which offset their capacity obligation. With the introduction of LM, qualifying load management resources can be offered into the auction as a capacity resource and receive the resource clearing price, or can they can be offered outside of the auction and receive the final zonal ILR price.

The LM program introduced two RPM-related products:

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

54 For ease of viewing, the graph was truncated at $250.00 per MW-day and does not show an uncleared offer of approximately $800.00 per MW-day.

- **Demand Resource (DR) –** Capacity load resource that is offered into an RPM auction as capacity and receives the relevant LDA or RTO resource clearing price; and

- **Interruptible Load for Reliability (ILR) –** Capacity load resource that is not offered into the RPM auction, but receives the final zonal ILR price determined after the close of the auction.

As shown in Table 10, the LM program provided 2,825.7 MW, which is a combination of DR offered into the RPM auction and forecast ILR for the 2008–2009 delivery year. DR offers increased 588.2 MW from 127.6 MW in the 2007-2008 auction. ILR will be certified three months before the delivery year.

**Table 10 Load management statistics: 2008-2009 RPM auction**[55]

| | UCAP (MW) | | |
|---|---|---|---|
| | RTO | EMAAC | SWMAAC |
| DR Offered | 715.8 | 343.4 | 314.1 |
| ILR Forecast | 2,109.9 | 396.1 | 346.2 |
| Total Load Management | 2,825.7 | 739.5 | 660.3 |

There are a number of other differences between PJM's ALM program and the LM program that replaced it.

There is a difference in certification timing. Under the ALM program, customers could be nominated at any time prior to the day that ALM was called upon by PJM. Under RPM, DR resources must be offered into the auction for the delivery year in which they will participate while ILR resources must be certified by a published deadline which is after the base auction for the delivery year and at least three months prior to the delivery year in which they will participate.

Differences exist in the way compliance and settlement are handled. Under the ALM program, all data was input into eCapacity, and ALM providers received a levelized MW credit for the October-May period which resulted in ALM providers avoiding the purchase of capacity. Under RPM, DR and ILR are certified and event compliance data

55 RTO includes EMAAC and SWMAAC.

are submitted in LoadResponse, which is part of PJM's eSuite. Under RPM, DR and ILR settlement rates are set prior to the delivery year and do not change. DR resources offer into an RPM base residual auction and receive the auction clearing price while ILR will be certified and receive the final zonal ILR price (see Table 8 for example).

## CETO/CETL[56]

Since the ability to import energy and capacity into LDAs may be limited by the existing transmission capability, a load deliverability analysis is conducted for each LDA.[57] The first step in this process is to determine the transmission import requirement into an LDA, called the Capacity Emergency Transfer Objective (CETO). This value, expressed in unforced megawatts, is the transmission import capability required for each LDA to meet the area reliability criterion of loss of load expectation of one occurrence in 25 years when the LDA is experiencing a localized capacity emergency.

The second step is to determine the transmission import limit for an LDA, called the Capacity Emergency Transfer Limit (CETL), which is also expressed in unforced megawatts. The CETL is the ability of the transmission system to deliver energy into the LDA when it is experiencing the localized capacity emergency used in the CETO calculation.

If CETL is less than CETO, transmission upgrades are planned under the Regional Transmission Expansion Planning Process (RTEPP). However, if transmission upgrades cannot be built prior to a delivery year to increase the CETL value, locational constraints could result under RPM, causing locational price differences.[58]

An LDA with CETL less than 1.05 times CETO is modeled as a constrained LDA in RPM. An LDA may also be modeled as a constrained LDA even if CETL is more than

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56 See "PJM Manual 14B: Generation and Transmission Interconnection Planning, Attachment E: PJM Deliverability Methods," Revision 10 (March 1, 2007), <http://www.pjm.com/contributions/pjm-manuals/pdf/m14b-redline.pdf >.

57 Manual 14B indicates that all "electrically cohesive load areas" are tested.

58 See "PJM Manual 18: PJM Capacity Market," Revision 0 (Effective June 1, 2007), p. 12, <http://www.pjm.com/contributions/pjm-manuals/pdf/m18.pdf> (604 KB).

1.05 times CETO if there are other reliability concerns. A reliability requirement and a variable resource requirement curve will be established for each constrained LDA.