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 developing demand-side resources and offering them into the capacity market, or 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 calendar year 2008, including supply, demand, concentration ratios, pivotal suppliers, volumes, prices, outage rates and reliability.

RPM Capacity Market

Market Design

On June 1, 2007, the RPM Capacity Market design was implemented in the PJM region, replacing the CCM Capacity Market 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. First, Second and Third Incremental RPM Auctions may be held for each delivery year, occurring 23, 13 and four months, respectively, prior to the delivery year. RPM prices are locational and may vary depending on transmission constraints.[2] Existing generation capable of qualifying as a capacity resource must be offered into RPM Auctions, except for the fixed resource requirement (FRR) option. Under RPM, participation by LSEs is mandatory, except for the FRR option. Under RPM, 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. Under RPM there are performance incentives for generation. 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 do not limit prices offered by new entrants. Under RPM, demand-side resources may be offered directly into RPM auctions and receive the clearing price.

1 The terms *PJM Region*, *RTO Region* and *RTO* are synonymous in the *2008 State of the Market Report*, Volume II, Section 5, "Capacity Market" and include all capacity within the PJM footprint.

2 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.

Market Structure

- **Supply.** Total internal capacity increased 1,762.0 MW from 155,206.0 MW on June 1, 2007, to 156,968.0 MW on June 1, 2008.[3] This increase was the result of 89.4 MW of new generation, 112.6 MW from resources which came out of retirement, and 146.2 MW from generation uprates. DR offers increased 595.3 MW. Improvements in the net equivalent demand forced outage rate (EFORd) effect added 818.5 MW.

  In the 2009/2010, 2010/2011 and 2011/2012 auctions, new generation increased 3,049.8 MW; 651.9 MW came out of retirement and net generation deratings were 1,407.7 MW, for a total of 2,294.0 MW. DR offers increased 948.7 MW through June 1, 2011 offset in part by 328.0 MW from higher EFORds. The net effect from June 1, 2008, through June 1, 2011, was an increase in total internal capacity of 2,914.7 MW (1.9 percent) from 156,968.0 MW to 159,882.7 MW.

  In the 2008/2009 auction, 15 more generating resources made offers than in the 2007/2008 RPM Auction. The increase included five new wind resources (66.1 MW), three new diesel resources (23.3 MW) and two resources (112.6 MW) which came out of retirement while the remaining five resources were the result of a reclassification of external resources.

  In the 2009/2010 auction, 17 more generating resources made offers than in the 2008/2009 RPM Auction. The increase included eight new combustion turbine (CT) resources (380.2 MW), two new diesel resources (9.2 MW) and one new steam resource (49.8 MW) while the remaining six resources included more resources imported, fewer resources exported, a decrease in resources excused from offering into the auction and fewer resources removed from the auction under the fixed resource requirement (FRR) option.

  In the 2010/2011 auction, 11 more generating resources made offers than in the 2009/2010 RPM auction. The net increase of 11 resources consisted of 15 new resources, four reactivated resources and three resources from the FRR participant, offset by three retired resources, four deactivated resources, three resources exported from PJM and one resource excused from offering. There were seven new CT resources (270.5 MW), three new diesel resources (16.4 MW), five new wind resources (120.0 MW) and four reactivated resources (165.0 MW) for a total of 19 resources. There were three resources that retired (358.3 MW), four resources that were deactivated (52.9 MW) and an additional three resources exported out of PJM (521.5 MW) for a total of 10 resources.

  In the 2011/2012 auction, 21 more generating resources made offers than in the 2010/2011 RPM auction. The net increase of 21 resources 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 FRR resources (64.2 MW) and two retired resources (85.8 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).

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

- **Demand.** There was a 2,657.3 MW increase in the RPM reliability requirement from 148,277.3 MW on June 1, 2007 to 150,934.6 MW on June 1, 2008. On June 1, 2008, PJM EDCs and their affiliates maintained an 80.1 percent market share of load obligations under RPM, up from 77.5 percent on June 1, 2007.

- **Market Concentration.** For the 2008/2009, 2009/2010, 2010/2011, and 2011/2012 RPM Auctions, all defined markets failed the preliminary market structure screen (PMSS). In each BRA 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. The result was that offer caps were applied to all sell offers in all auctions. In the 2008/2009 Third Incremental Auction, 22 of 40 participants in the RTO/EMAAC RPM market and all three participants in the SWMAAC RPM market failed the market structure test. Offer caps were applied to those sellers that failed the test.

- **Imports and Exports.** Net exchange decreased 248.5 MW from June 1, 2007 to June 1, 2008. Net exchange, which is imports less exports, decreased due to a decrease in exports of 100.4 MW and a larger decrease in imports of 348.9 MW.

- **Demand-Side Resources.** Under RPM, demand-side resources in the Capacity Market, a combination of DR cleared in the RPM Auctions and certified/forecast interruptible load for reliability (ILR), increased by 2,403.6 MW from 1,763.9 MW on June 1, 2007 to 4,167.5 MW on June 1, 2008.

- **Net Excess.** Net excess decreased 229.42 MW from 5,240.5 MW on June 1, 2007 to 5,011.1 MW on June 1, 2008.

Market Conduct

- **2008/2009 RPM Base Residual Auction.** Of the 1,076 generating resources which submitted offers, unit-specific offer caps were calculated for 117 resources (10.9 percent). Offer caps of all kinds were calculated for 567 resources (52.7 percent), of which 399 were based on the technology specific default (proxy) ACR posted by the MMU.

- **2008/2009 RPM Third Incremental Auction.** Of the 327 generating resources which submitted offers, unit-specific offer caps were calculated for 24 resources (7.3 percent). Offer caps of all kinds calculated for 170 resources (51.9 percent), of which 123 were based on the technology specific default (proxy) ACR posted by the MMU.

- **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 posted 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 posted 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 301 were based on the technology specific default (proxy) ACR posted by the MMU.

Market Performance

2008/2009 RPM Base Residual Auction

- **RTO.** Total internal RTO unforced capacity of 156,968.0 MW includes all generating units and DR that qualified as a PJM capacity resource for the 2008/2009 RPM base residual auction, excludes external units and reflects owners' modifications to installed capacity (ICAP) ratings. Including FRR, committed resources and imports, RPM capacity was 136.237.3 MW. The 129,597.6 MW of cleared resources for the entire RTO represented a reserve margin of 17.5 percent, which was 1,403.0 MW greater than the reliability requirement of 128,194.6 MW (installed reserve margin (IRM) of 15.0 percent) and resulted in a clearing price of $111.92 per MW-day.

  Total cleared resources in the RTO were 129,597.6 MW which resulted in a net excess of 5,011.1 MW, a decrease of 229.4 MW from the net excess of 5,240.5 MW in the 2007/2008 RPM base residual auction. Certified interruptible load for reliability (ILR) was 3,608.1 MW.

  Cleared resources across the entire RTO will receive a total of $6.1 billion based on the unforced MW cleared and the prices in the 2008/2009 RPM BRA, an increase of approximately $1.8 billion from the 2007/2008 planning year.

- **EMAAC.**[4] Total internal EMAAC unforced capacity of 31,379.1 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 EMAAC, RPM unforced capacity was 31,396.7 MW. 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.

  Total resources in EMAAC were 38,161.3 MW, which when combined with certified ILR of 622.6 MW resulted in a net excess of 893.2 MW (2.3 percent) greater than the reliability requirement of 37,890.7 MW.

- **SWMAAC.** Total internal SWMAAC unforced capacity of 10,777.1 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 290.5 MW of incremental supply, 285.6 cleared, which resulted in a resource-clearing price of $210.11 per MW-day.

4 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. EMAAC and SWMAAC are now regions of PJM.

Total resources in SWMAAC were 16,231.2 MW, which when combined with certified ILR of 219.7 MW resulted in a net deficit of 111.0 MW (0.7 percent) less than the reliability requirement of 16,561.9 MW.

2008/2009 RPM Third Incremental Auction

- **RTO.** There were 2,339.4 MW offered into the Third Incremental Auction while buy bids totaled 2,251.8 MW. Cleared volumes in the RTO were 1,011.6 MW, resulting in an RTO clearing price of $10.00 per MW-day. The price was set by the transition adder. The 1,307.2 MW of uncleared volumes can be used as replacement capacity or traded bilaterally.

  Cleared resources across the entire RTO will receive a total of $5.4 million based on the unforced MW cleared and the prices in the 2008/2009 RPM Third Incremental Auction.

- **EMAAC.** Although EMAAC was a constrained LDA in the 2008/2009 BRA, supply and demand curves resulted in a price less than the RTO clearing price. Supply offers in the incremental auction in EMAAC (1,142.8 MW) exceeded EMAAC demand bids (191.0 MW). The result was that all of EMAAC supply which cleared received the RTO clearing price.

- **SWMAAC.** In SWMAAC, 20.6 MW were offered into the auction while buy bids in SWMAAC totaled 237.5 MW. SWMAAC was a constrained LDA for the 2008/2009 delivery year, so the 20.6 MW was the only supply available to meet SWMAAC demand. Since supply was less than demand, the price was set by a vertical extension of the supply curve to meet demand, resulting in a clearing price of $223.85 per MW-day.

Generator Performance

- **Forced Outage Rates.** The average PJM EFORd decreased from 7.3 percent in 2005 to 6.4 percent in 2005 and 2006 and increased to 6.8 percent in 2007 and 7.4 percent in 2008.[5] The increase in EFORd from 2007 to 2008 was the result of increased forced outage rates for steam and nuclear generating units. The forced outage rates are for the entire PJM footprint.

- **Outages Outside of Management Control (OMC).** PJM permits units to use a forced outage rate (XEFORd) for purposes of selling unforced capacity in the Capacity Market, calculated using outages that are designated outside management control. The MMU questions whether the use of the OMC outage designation in this manner is reasonable, particularly given that most of the OMC outages are based on lack of fuel. A forced outage is a forced outage, from the perspective of system reliability, regardless of the cause.

5 Data are for the 12 months ended December 31, 2008, as downloaded from the PJM GADS database on January 23, 2009. 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

Market Design

The wholesale power markets, in order to be viable, must be competitive and they must provide adequate revenues to ensure an incentive to invest in new capacity. A wholesale energy market will not consistently produce competitive results in the absence of local market power mitigation rules. This is the result, not of a fundamental flaw in the market design, but of the fact that transmission constraints in a network create local markets where there is structural market power. A wholesale energy market will not consistently result in adequate revenues in the absence of a carefully designed and comprehensive approach to scarcity pricing. This is a result, not of offer capping, but of the fundamentals of wholesale power markets which must carry excess capacity in order to meet externally imposed reliability rules.

Scarcity revenues to generation owners can come entirely from energy markets or they can come from a combination of energy and capacity markets. The RPM design reflects the recognition that the energy markets, by themselves and in the absence of a carefully designed expansion of scarcity pricing, will not result in adequate revenues. The RPM design provides an alternate method for collecting scarcity revenues. The revenues in the capacity market are scarcity revenues.

If the revenues collected in the RPM market are adequate, it is not essential that a scarcity pricing mechanism exist in the energy market. Nonetheless, it would be preferable to also have a scarcity pricing mechanism in the energy market because it provides direct, market-based incentives to load and generation, as long as it is designed to ensure that scarcity revenues directly offset RPM revenues. This hybrid approach would include both a capacity market and scarcity pricing in the energy market.

The definition of the capacity product is central to refining the market rules governing the sale and purchase of capacity. The current definition of capacity includes several components: the obligation to offer the energy of the unit into the day ahead market; the obligation to permit PJM to recall the energy from the unit under emergency procedures; the obligation to provide outage data to PJM; the obligation to provide energy during the defined high demand hours each year; and the obligation that the energy output from the resource be deliverable to load in PJM.

The most critical of these components of the definition of capacity is the obligation to offer the energy of the unit into the day ahead market. If buyers are to pay the high prices associated with RPM, it must be clear what they are buying and what the obligations of the sellers are. The fundamental energy market design should assure all market participants that the outcomes are competitive. This works to the ultimate advantage of all market participants including existing and prospective load and existing and prospective generation. The market rules should explicitly require that offers into the day ahead energy market be competitive, where competitive is defined to be the short run marginal cost of the units. The short run marginal cost should reflect opportunity cost when and where appropriate.

An offer that exceeds short run marginal cost is not a competitive offer in the day ahead energy market. Such an offer assumes the need to exercise market power to ensure revenue adequacy. An offer to provide energy only in an emergency is not a competitive offer in the day ahead energy market. A unit which is not capable of supplying energy consistent with its day-ahead offer should reflect an appropriate outage rather than indicating its availability to supply energy.

Capacity market design should reflect the fact that the capacity market is a mechanism for the collection of scarcity revenues and thus reflect the incentive structure of energy markets to the maximum extent possible. For example, if a generation unit does not produce power during a high price hour, it receives no revenues from the energy market. It does not receive some revenues simply for existing, it receives zero revenues. The reason that the unit does not produce energy is not relevant. It does not receive revenues if it does not produce energy even if the reason for non performance is outside management's control. That is the basic performance incentive structure of energy markets. The same performance incentive structure should be replicated in capacity market design. If a unit that is a capacity resource does not produce energy during the hours defined as critical, it will receive no energy revenues for those hours. If a unit defined as a capacity resource does not produce energy during any of the hours defined as critical, it should receive no capacity revenues. This approach to performance is also consistent with the reduction or elimination of administrative penalties associated with failure to meet capacity tests, for example.

A hybrid market design can provide scarcity revenues both via scarcity pricing in the energy market and via the capacity market. However, if there is scarcity pricing in the energy market, the market design must ensure that units receiving scarcity revenues in the capacity market do not also receive scarcity revenues in the energy market. This would be double payment of scarcity revenues. This offset must reflect the actual scarcity revenues and not those reflected in forward curves or forecasts, or those reflected in results from prior years. Scarcity revenues are episodic and unlikely to be fully reflected in historical data or in forward curves, even if such curves were based on a liquid market three years forward, which they are not, and reflected locational results, which they do not. The most straightforward way to ensure that such double payment does not occur would be to ensure that capacity resources do not receive scarcity revenues in the energy market in the first place. The settlements process can remove any scarcity revenues from payments to capacity resources and eliminate the need for a complex, uncertain, after the fact procedure for offsetting scarcity revenues in the capacity market.

Market Power

The RPM Capacity Market design explicitly addresses the underlying issues of ensuring that competitive prices can reflect local scarcity while not relying on the exercise of market power to achieve the design objective and explicitly limiting the exercise of market power.

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

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

RPM has explicit market power mitigation rules designed to permit competitive, locational capacity prices while limiting the exercise of market power. The RPM construct is consistent with the appropriate market design objectives of permitting competitive prices to reflect local scarcity conditions while explicitly limiting market power. The RPM Capacity Market design provides that competitive prices can reflect locational scarcity while not relying on the exercise of market power to achieve that design objective by limiting the exercise of market power via the application of the three pivotal supplier test.

Competitive prices are the lowest possible prices, consistent with the resource costs. But, competitive prices are not necessarily low prices. In the Capacity Market, it is essential that the cost of new entry (CONE) be based on the actual resource costs of bringing a new capacity resource into service. If RPM is to provide appropriate incentives for new entry, the marginal price signal must reflect the actual cost of new entry.

The existence of a capacity market that links payments for capacity to the level of unforced capacity and therefore to the forced outage rate creates an incentive to improve forced outage rates. The performance incentives are stronger in the RPM Capacity Market design although they need further strengthening. The Energy Market also provides incentives for improved performance with somewhat different characteristics. Generators want to maximize their sales of energy when prices are high and if they are successful, this will also result in lower forced outage rates. Well designed scarcity pricing could also provide strong, complementary incentives for reduced outages during high load periods. It would be preferable to rely on strong market-based incentives for capacity resource performance rather than the current structure of penalties, which has its own incentive effects.

Results

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, but no exercise of market power in the PJM Capacity Market in 2008. 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 2008.

RPM Capacity Market

Market Design

The RPM Capacity Market design was implemented effective June 1, 2007. RPM 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.

The first four base RPM Auctions comprised the RPM transition period.[6] After this transition period, annual base auctions are held in May for delivery years that are three years in the future. First, Second and Third Incremental RPM Auctions may be held for each delivery year, occurring 23, 13 and four months prior to the delivery year. In 2008, the 2010/2011 BRA was held in January and the 2011/2012 BRA was held in May.[7] A Third Incremental Auction was held in January 2008 for the delivery year 2008/2009.

Market Structure

Supply

As shown in Table 5-1, total internal capacity increased 1,762.0 MW from 155,206.0 MW on June 1, 2007, to 156,968.0 MW on June 1, 2008. This increase was the result of 89.4 MW of new generation, 112.6 MW from resources which came out of retirement, and 146.2 MW from generation uprates. DR offers increased 595.3 MW. The net EFORd effect was 818.5 MW.

In the 2009/2010, 2010/2011 and 2011/2012 auctions, new generation increased 3,049.8 MW; 651.9 MW were brought out of retirement and net generation deratings were 1,407.7 MW, for a total of 2,294.0 MW. DR offers increased 948.7 MW through June 1, 2011 offset in part by 328.0 MW from higher EFORds. The net effect from June 1, 2008, through June 1, 2011, was an increase in total internal capacity of 2,914.7 MW (1.9 percent) from 156,968.0 MW to 159,882.7 MW.

As shown in Table 5-1 and Table 5-7, in the 2008/2009 RPM Auction, the increase of 15 RPM resources included five new wind resources (66.1 MW), three new diesel resources (23.3 MW) and two resources (112.6 MW) which came out of retirement while the remaining five resources

6 For more detailed analysis of the RPM Auctions, see: "Analysis of the 2007/2008 RPM Auction" (August 16, 2007); "Analysis of the 2008/2009 RPM Auction" (November 30, 2007); "Analysis of the 2008/2009 Third Incremental RPM Auction" (June 23, 2008); "Analysis of the 2009/2010 RPM Auction" (November 30, 2007); "Analysis of the 2010-2011 RPM Auction" (May 6, 2008); "Analysis of the 2011/2012 RPM Auction" (September 12, 2008) (Accessed February 20, 2009) <http://www.monitoringanalytics.com/reports/Reports/2008.shtml>.

7 Delivery years are from June 1 through May 31. The 2008/2009 delivery year runs from June 1, 2008, through May 31, 2009.

were the result of a reclassification of external resources.[8] There were 23 DR resources offered compared to 15 DR resources offered in the 2007/2008 RPM Auction.[9]

As also shown in Table 5-1 and Table 5-8, in the 2009/2010 RPM Auction, the increase of 17 RPM resources included eight new CT resources (380.2 MW), two new diesel resources (9.2 MW) and one new steam resource (49.8 MW) while the remaining increase of six resources was the result of a combination of more resources imported, less resources exported, a decrease in resources excused from offering into the auction and fewer resources removed from the auction under the FRR option. There were 38 DR resources offered compared to 23 DR resources offered in the 2008/2009 RPM Auction.

As shown in Table 5-1 and Table 5-8, in the 2010/2011 auction, the increase of 11 RPM resources consisted of 15 new resources, four reactivated resources and three resources from the FRR participant, offset by three retired resources, four deactivated resources, three resources exported from PJM and one resource excused from offering. There were seven new CT resources (270.5 MW), three new diesel resources (16.4 MW), five new wind resources (120.0 MW) and four reactivated resources (165.0 MW) for a total of 19 resources. There were three resources that retired (358.3 MW), four resources that were deactivated (52.9 MW) and an additional three resources exported out of PJM (521.5 MW) for a total of 10 resources. There were 23 demand resources (DR) offered compared to 38 DR resources offered in the 2009/2010 RPM auction.

As also shown in Table 5-1 and Table 5-8, in the 2011/2012 auction, the increase of 21 resources 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 FRR resources (64.2 MW) and two retired resources (85.8 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). There were 37 demand resources (DR) offered compared to 23 DR resources offered in the 2010/2011 RPM auction.

8 Certain external hydroelectric units were allocated from the LDA level to the zonal level, resulting in an increased unit count.
9 Some generation and DR resources had multiple associated offers.

Table 5-1 Internal capacity: June 1, 2007, through May 31, 2011[10]

	UCAP (MW)				
	RTO	EMAAC	SWMAAC	MAAC+APS	DPL-South
Total internal capacity @ 01-Jun-07	155,206.0	30,825.1	10,352.2		
New generation	89.4	0.0	0.0		
Units out of retirement	112.6	112.6	0.0		
Generation capmods	146.2	105.9	38.9		
DR mods	595.3	298.7	294.3		
Net EFORd effect	818.5	36.8	91.7		
Total internal capacity @ 01-Jun-08	156,968.0	31,379.1	10,777.1	72,889.5	
New generation	439.2		0.0	109.9	
Units out of retirement	0.0		0.0	0.0	
Generation capmods	74.1		(298.2)	(149.7)	
DR mods	220.6		42.3	163.2	
Net EFORd effect	(383.7)		(176.0)	0.0	
Total internal capacity @ 01-Jun-09	157,318.2		10,345.2	73,012.9	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				
Reclassification of Duquesne units	3,009.5				
Adjusted internal capacity @ 01-Jun-11	162,892.2				

10 The RTO includes MAAC+APS, EMAAC and SWMAAC. MAAC+APS includes EMAAC and SWMAAC. In the 2009/2010 RPM Auction, EMAAC was not constrained, so results for it are not shown. Maps of the LDAs can be found in the *2008 State of the Market Report*, Appendix A, "PJM Geography."

Demand

There was a 2,657.3 MW increase in the RPM reliability requirement from 148,277.3 MW on June 1, 2007, to 150,934.6 MW on June 1, 2008. This increase resulted from a higher peak-load forecast.

The MMU analyzed market sectors in the PJM Capacity Market to determine how they met their load obligations. The Capacity Market was divided into the following sectors:

- **PJM EDC.** EDCs with a franchise service territory within the PJM footprint. This sector includes traditional utilities, electric cooperatives, municipalities and power agencies.
- **PJM EDC Generating Affiliate.** Affiliate companies of PJM EDCs that own generating resources.
- **PJM EDC Marketing Affiliate.** Affiliate companies of PJM EDCs that sell power and have load obligations in PJM, but do not own generating resources.
- **Non-PJM EDC.** EDCs with franchise service territories outside the PJM footprint.
- **Non-PJM EDC Generating Affiliate.** Affiliate companies of non-PJM EDCs that own generating resources.
- **Non-PJM EDC Marketing Affiliate.** Affiliate companies of non-PJM EDCs that sell power and have load obligations in PJM, but do not own generating resources.
- **Non-EDC Generating Affiliate.** Affiliate companies of non-EDCs that own generating resources.
- **Non-EDC Marketing Affiliate.** Affiliate companies of non-EDCs that sell power and have load obligations in PJM, but do not own generating resources.

On June 1, 2008, PJM EDCs and their affiliates maintained a large market share of load obligations under RPM, together totaling 80.1 percent (Table 5-2), up from 77.5 percent on June 1, 2007. The combined market share of LSEs not affiliated with any EDC and of non-PJM EDC affiliates was 19.9 percent, down from 22.5 percent on June 1, 2007. Obligation is defined as cleared MW plus ILR forecast obligations.

Table 5-2 PJM Capacity Market load obligation served: June 1, 2008

	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	63,390.7	17,884.1	23,910.3	1,211.4	9,668.5	199.5	14,990.2	131,254.6
Percent of total obligation	48.3%	13.6%	18.2%	0.9%	7.4%	0.2%	11.4%	100.0%

Market Concentration

Preliminary Market Structure Screen

Under the terms of the PJM Tariff, the MMU is required to apply the PMSS prior to RPM BRA Auctions.[11] The results of the PMSS are applicable for the First, Second, and Third Incremental Auctions for a given delivery year.[12] 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.

An LDA or the RTO Region fails the PMSS if any one of the following three screens is failed: the market share of any capacity resource owner exceeds 20 percent; the HHI for all capacity resource owners is 1800 or higher; or there are not more than three jointly pivotal suppliers.[13]

As shown in Table 5-3, all defined markets failed the PMSS. As a result, capacity resource owners were required to submit avoidable cost rate (ACR) data to the MMU for resources for which they intended to submit nonzero sell offers unless certain other conditions were met.[14]

11 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.
12 See PJM. "Open Access Transmission Tariff (OATT)," "Attachment DD: Reliability Pricing Model," Original Sheet No. 605 (Effective June 1, 2007), section 5.11 (b) i.
13 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.
14 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).

Table 5-3 Preliminary market structure screen results: 2008/2009 through 2011/2012 RPM Auctions

RPM Markets	Highest Market Share	HHI	Pivotal Suppliers	Pass/Fail
2008/2009				
RTO	18.5%	879	1	Fail
EMAAC	33.1%	2180	1	Fail
SWMAAC	47.5%	4290	1	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

Auction Market Structure

As shown in Table 5-4, all participants in the total PJM market as well as the LDA RPM markets failed the TPS test in each BRA auction.[15] The result was that offer caps were applied to all sell offers. In the 2008/2009 Third Incremental Auction, 22 of 40 participants in the RTO/EMAAC RPM market and all three participants in the SWMAAC RPM market failed the market structure test. Some participants passed the test in the incremental auction as a result of the substantially different structure of incremental supply. Offer caps were applied to those sellers that failed the test. The RTO market includes all supply which cleared at or below the unconstrained clearing price. The LDA markets include the incremental supply in 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.

15 The market definition used for the TPS test includes all offers with costs less than or equal to 1.50 times the clearing price. See the *2008 State of the Market Report*, Appendix L, "Three Pivotal Supplier Test" for additional discussion.

Table 5-4 RSI results: 2008/2009 through 2011/2012 RPM Auctions

RPM Markets	RSI_3	Total Participants	Failed RSI_3 Participants
2008/2009 BRA			
RTO	0.61	65	65
EMAAC	0.25	10	10
SWMAAC	0.00	3	3
2008/2009 Third IA			
RTO/EMAAC	0.87	40	22
SWMAAC	0.00	3	3
2009/2010 BRA			
RTO	0.60	66	66
MAAC+APS	0.37	21	21
SWMAAC	0.00	3	3
2010/2011 BRA			
RTO	0.60	68	68
DPL-South	0.00	2	2
2011/2012 BRA			
RTO	0.63	76	76

Imports and Exports

As shown in Table 5-5, net exchange decreased 248.5 MW from June 1, 2007 to June 1, 2008. Net exchange, which is imports less exports, decreased due to a decrease in exports of 100.4 MW and a larger decrease in imports of 348.9 MW.

Table 5-5 PJM capacity summary (MW): June1, 2007, through May 31, 2011[16]

	01-Jun-07	01-Jun-08	01-Jun-09	01-Jun-10	01-Jun-11
Installed capacity (ICAP)	163,721.1	164,444.1	166,916.0	168,061.5	172,666.6
Unforced capacity	154,076.7	155,590.2	157,628.7	158,634.2	163,144.3
Cleared capacity	129,409.2	129,597.6	132,231.8	132,190.4	132,221.5
RPM reliability requirement (pre-FRR)	148,277.3	150,934.6	153,480.1	156,636.8	154,251.1
RPM reliability requirement (less FRR)	125,805.0	128,194.6	130,447.8	132,698.8	130,658.7
RPM net excess	5,240.5	5,011.1	3,403.3	1,149.2	3,156.6
Imports	2,809.2	2,460.3	2,505.4	2,750.7	6,420.0
Exports	(3,938.5)	(3,838.1)	(2,194.9)	(3,147.4)	(3,158.4)
Net exchange	(1,129.3)	(1,377.8)	310.5	(396.7)	3,261.6
DR cleared	127.6	536.2	892.9	939.0	1,364.9
ILR	1,636.3	3,608.1	2,107.5	2,110.5	1,593.8
FRR DR	445.6	452.8	488.2	452.9	452.9

Demand-Side Resources

Under the PJM load management (LM) program, qualifying load management resources can be offered into RPM Auctions as capacity resources and receive the clearing price, or they can be offered outside of the auction and receive the final, zonal ILR price.

The LM program introduced two RPM-related products. DR resources are load resources that are offered into an RPM Auction as capacity and receive the relevant LDA or RTO clearing price. ILR resources are load resources that are not offered into the RPM Auction, but receive the final, zonal ILR price determined after the close of the second incremental auction.

Under RPM, DR resources must be offered into the auction for the delivery year during which they will participate while ILR resources must be certified by a published deadline which is after the Base Residual Auction for the delivery year but at least three months prior to the delivery year during which they will participate.

As shown in Table 5-6, capacity in the RPM load management programs, which is a combination of DR cleared in the RPM Auctions and certified/forecast ILR, increased by 2,403.6 MW from 1,763.9 MW on June 1, 2007 to 4,167.5 MW on June 1, 2008. Final ILR is certified three months before the delivery year and it may differ from the ILR forecast.

16 FRR DR values have been revised since the *2007 State of the Market Report* was posted.

Table 5-6 RPM load management statistics: June 1, 2007 through May 31, 2011[17]

	UCAP (MW)				
	RTO	EMAAC	SWMAAC	MAAC+APS	DPL-South
DR cleared	127.6	44.7	19.7		
ILR certified	1,636.3	387.0	273.4		
RPM load management @ 01-June-2007	1,763.9	431.7	293.1		
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		356.3	813.9	
ILR forecast - FRR DR	1,619.3		345.7	1,055.7	
RPM load management @ 01-June-2009	2,512.2		702.0	1,869.6	
DR cleared	939.0				14.9
ILR forecast - FRR DR	1,657.6				22.2
RPM load management @ 01-June-2010	2,596.6				37.1
DR cleared	1,364.9				
ILR forecast	1,593.8				
RPM load management @ 01-June-2011	2,958.7				

Market Conduct

Offer Caps

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.[18] 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. This component of avoidable costs is termed the avoidable project investment recovery rate (APIR). Avoidable costs are the defined costs less net revenues from all other PJM

17 PJM used forecast ILR, including FRR DR, for the first four base residual auctions. For 2007/2008 and 2008/2009, certified ILR data were used in the calculation here because the certified ILR data are now available. For 2009/2010 and 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.

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

markets and from 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 calculated by the MMU, by submitting an opportunity cost for a possible export, by inputting a transition adder or by using combinations of these options. The opportunity cost option for exports allows resource owners to input a documented export price as the opportunity cost 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 adder was added to the offer cap, if appropriate, regardless of the offer-cap calculation method.[19]

Table 5-7 ACR statistics: 2008/2009 RPM Auctions

	2008/2009 BRA		2008/2009 Third IA	
Calculation Type	Number of Resources	Percent of Generating Resources Offered	Number of Resources	Percent of Generating Resources Offered
Default ACR selected	399	37.1%	123	37.6%
ACR data input (non-APIR)	37	3.4%	8	2.4%
ACR data input (APIR)	80	7.4%	16	4.9%
Opportunity cost input	8	0.7%	3	0.9%
Transition adder only	43	4.0%	20	6.1%
Offer caps calculated	567	52.6%	170	51.9%
Uncapped new units	0	0.0%	3	0.9%
Generator price takers	509	47.4%	154	47.2%
Generating units offered	1,076	100.0%	327	100.0%
Demand resources offered	23		9	
Total capacity resources offered	1,099		336	

19 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 year 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.

Table 5-8 ACR statistics: 2009/2010 through 2011/2012 RPM Base Residual Auctions

	2009/2010 BRA		2010/2011 BRA		2011/2012 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
Default ACR selected	377	34.5%	370	33.5%	301	26.8%
ACR data input (non-APIR)	22	2.0%	20	1.8%	12	1.1%
ACR data input (APIR)	129	11.8%	134	12.1%	133	11.8%
Opportunity cost input	10	0.9%	8	0.7%	26	2.3%
Transition adder only	12	1.1%	N/A		N/A	
Offer caps calculated	550	50.3%	532	48.1%	472	42.0%
Uncapped new units	3	0.3%	15	1.4%	20	1.8%
Generator price takers	540	49.4%	557	50.5%	633	56.2%
Generating units offered	1,093	100.0%	1,104	100.0%	1,125	100.0%
Demand resources offered	38		23		37	
Total capacity resources offered	1,131		1,127		1,162	

Table 5-9 APIR statistics: 2008/2009 through 2011/2012 RPM Auctions[20,21]

		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	$28.56	$23.93	$60.76	$149.73	$41.06		$71.67
	Net revenues	$27.74	$17.21	$16.20	$353.71	$355.75		$127.86
	Offer caps	$20.75	$14.99	$52.02	$12.82	$9.37	$162.37	$27.31
APIR units	ACR	$112.16	$10.18	$142.97	$341.45	NA		$259.45
	Net revenues	$251.21	$15.58	$22.34	$177.77	NA		$136.18
	Offer caps	NA	$1.63	$120.62	$163.68	NA		$132.74
	APIR	$0.56	$2.55	$33.44	$165.40	NA		$113.75
	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	$290.64	$630.85	$34.62		$360.27
	Net revenues	$26.84	$10.32	$83.61	$535.68	$2.07		$263.27
	Offer caps	$37.30	$39.41	$207.04	$123.85	$32.55		$110.25
	APIR	$9.87	$30.93	$198.78	$494.87	$22.42		$272.18
	Maximum APIR effect							$577.03
2011/2012 BRA								
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	$307.18	$709.11	$36.03		$424.49
	Net revenues	$78.17	$10.35	$82.14	$542.90	$2.06		$286.80
	Offer caps	$34.69	$46.18	$225.04	$178.79	$33.97		$147.77
	APIR	$11.82	$37.28	$213.50	$560.20	$24.68		$324.58
	Maximum APIR effect							$523.26

20 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.

21 This table has been updated since the MMU RPM Auction reports were posted.

2008/2009 RPM Base Residual Auction

As shown in Table 5-7, 1,076 generating resources submitted offers into the 2008/2009 RPM BRA as compared to the 1,061 generating resources offered in the 2007/2008 RPMBRA. Unit-specific offer caps were calculated for 117 resources (10.8 percent). Offer caps of all kinds were calculated for 567 resources (52.6 percent), of which 399 were based on the technology specific default (proxy) ACR posted by the MMU. Of the 1,076 generating resources, the remaining 509 resources were price takers, of which the offers for 472 resources were zero and the offers for 37 resources were set to zero because no data were submitted. The transition adder was part of the offers on 255 resources, of which offers on 43 resources included only the transition adder. The transition adder had no impact on the clearing prices.

Of the 1,076 generating resources which submitted offers, 80 (7.4 percent) included an APIR component. (See Table 5-7.) As shown in Table 5-9, the weighted averages for resources with APIR for ACR ($129.96 per MW-day) and offer caps ($58.46 per MW-day) were higher than the ACR ($86.25 per MW-day) and offer caps ($20.45 per MW-day) for resources without an APIR component, including resources for which the default value was selected. The APIR component added $49.29 per MW-day to the ACR value of the APIR resources.[22] The default ACR values include an average APIR of $0.91 per MW-day. The highest APIR for a technology ($131.38 per MW-day) was for subcritical/supercritical coal resources. The maximum APIR effect ($211.28 per MW-day) is the maximum amount by which an offer cap was increased by APIR.

2008/2009 RPM Third Incremental Auction

As shown in Table 5-7, 327 generating resources and nine demand resources submitted offers in the 2008/2009 RPM Third Incremental Auction. Unit-specific offer caps were calculated for 24 resources (7.3 percent). Offer caps of all kinds were calculated for 170 resources (51.9 percent), of which 123 (37.6 percent) were based on the technology specific default (proxy) ACR posted by the MMU. Three new generation resources had uncapped offers while the remaining 154 generation resources were price takers. The transition adder was part of the offers on 90 resources, of which offers on 20 resources included only the transition adder. All of the 14 resources which were marginal at $10.00 per MW-day had the transition adder as their offer caps.

Of the 327 generating resources which submitted offers, 16 (4.9 percent) included an APIR component. (See Table 5-7.) As shown in Table 5-9, the weighted-averages for resources with APIR for ACR ($259.45 per MW-day) and offer caps ($132.74 per MW-day) were higher than the ACR ($71.67 per MW-day) and offer caps ($27.31 per MW-day) for resources without an APIR component, including resources for which the default value was selected. The APIR component added $113.75 per MW-day to the ACR value of the APIR resources. The default ACR values include an average APIR of $0.91 per MW-day. The highest APIR for a technology ($165.40 per MW-day) was for subcritical/supercritical coal resources. The maximum APIR effect ($209.26 per MW-day) is the maximum amount by which an offer cap was increased by APIR.

22 Of the 80 units which had an APIR component, 77 units had current year capital dollars submitted of $421.1 million on 7,234.9 MW UCAP. Three units had APIR based on the inclusion of 2007/2008 capital projects.

2009/2010 RPM Base Residual Auction

As shown in Table 5-8, 1,093 generating resources submitted offers in the 2009/2010 RPM Auction as compared to 1,076 generating resources offered in the 2008/2009 RPM Auction. 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 posted by the MMU. Three new generation resources had uncapped offers while the remaining 540 generation resources were price takers, of which the offers for 514 resources were zero and the offers for 26 resources were set to zero because no data were submitted.[23] The transition adder was part of the offers on 206 resources, of which offers on 12 resources included only the transition adder. The transition adder had no impact on the clearing prices.

Of the 1,093 generating resources which submitted offers, 129 (11.8 percent) included an APIR component. (See Table 5-8.) As shown in Table 5-9, the weighted-averages for resources with APIR for ACR ($285.17 per MW-day) and offer caps ($102.07 per MW-day) were higher than the ACR ($82.66 per MW-day) and offer caps ($26.32 per MW-day) for resources without an APIR component, including resources for which the default value was selected. The APIR component added $195.85 per MW-day to the ACR value of the APIR resources.[24] The default ACR values include an average APIR of $0.91 per MW-day. The highest APIR for a technology ($386.13 per MW-day) was for subcritical/supercritical coal resources. The maximum APIR effect ($383.79 per MW-day) is the maximum amount by which an offer cap was increased by APIR.

2010/2011 RPM Base Residual Auction

As shown in Table 5-8, 1,104 generating resources submitted offers in the 2010/2011 RPM Auction as compared to 1,093 generating resources offered in the 2009/2010 RPM Auction. Unit-specific offer caps were calculated for 154 resources (13.9 percent) including 134 resources (12.1 percent) with an APIR component and 20 resources (1.8 percent) without an APIR component. Offer caps of all kinds were calculated for 532 resources (48.1 percent), of which 370 (33.5 percent) were based on the technology specific default (proxy) ACR posted by the MMU. There were 15 new generation resources with uncapped offers while the remaining 557 generation resources were price takers, of which the offers for 546 resources were zero and the offers for 11 resources were set to zero because no data were submitted.[25]

Of the 1,104 generating resources which submitted offers, 134 (12.1 percent) included an APIR component. (See Table 5-8.) As shown in Table 5-9, the weighted-averages for resources with APIR for ACR ($360.27 per MW-day) and offer caps ($110.25 per MW-day) were higher than the ACR ($80.86 per MW-day) and offer caps ($20.98 per MW-day) for resources without an APIR component, including resources for which the default value was selected. The APIR component added $272.18 per MW-day to the ACR value of the APIR resources.[26] The default ACR values include an average APIR of $0.91 per MW-day. The highest APIR for a technology ($494.87 per

23 Generally, planned units are not subject to mitigation. The seven other planned units submitted zero price offers. See PJM "Open Access Transmission Tariff (OATT)," "Attachment DD: Reliability Pricing Model," Original Sheet No. 617 (Effective June 1, 2007), section 6.5 (a) ii.

24 Of the 129 units which had an APIR component, 109 units had current year capital dollars submitted of $2.5 billion on 14,519.2 MW UCAP. Twenty units had APIR based on the inclusion of 2007/2008 and 2008/2009 capital projects.

25 Planned units are subject to mitigation only under specific circumstances defined in the tariff. Some of the uncapped planned units submitted zero price offers.

26 The 134 units which had an APIR component submitted $1.5 billion for capital projects associated with 12,645.3 MW UCAP.

MW-day) was for subcritical/supercritical coal resources. The maximum APIR effect ($577.03 per MW-day) is the maximum amount by which an offer cap was increased by APIR.

2011/2012 RPM Base Residual Auction

As shown in Table 5-8, 1,125 generating resources submitted offers in the 2011/2012 RPM Auction as compared to 1,104 generating resources offered in the 2010/2011 RPM Auction. Unit-specific offer caps were calculated for 145 resources (12.9 percent of all generating resources offered) including 133 resources (11.8 percent) with an APIR component and 12 resources (1.1 percent) without an APIR component. Offer caps of all kinds were calculated for 472 resources (42.0 percent), of which 301 (26.8 percent) were based on the technology specific default (proxy) ACR posted by the MMU. There were 20 new generation resources with uncapped offers while the remaining 633 generation resources were price takers, of which the offers for 578 resources were zero and the offers for 55 resources were set to zero because no data were submitted.[27]

Of the 1,125 generating resources which submitted offers, 133 (11.8 percent) included an APIR component. (See Table 5-8.) As shown in Table 5-9, the weighted-averages for resources with APIR for ACR ($424.49 per MW-day) and offer caps ($147.77 per MW-day) were higher than the ACR ($75.86 per MW-day) and offer caps ($45.80 per MW-day) for resources without an APIR component, including resources for which the defaults ACR value was selected. The APIR component added $324.58 per MW-day to the ACR value of the APIR resources.[28] The default ACR values include an average APIR of $0.91 per MW-day. The highest APIR for a technology ($560.20 per MW-day) was for subcritical/supercritical coal resources. The maximum APIR effect ($523.26 per MW-day) is the maximum amount by which an offer cap was increased by APIR.

Market Performance

Prices for capacity increased from $40.80 per MW-day for the RTO for the 2007/2008 BRA to a high of $237.33 per MW-day (SWMAAC) for the 2009/2010 BRA. (See Table 5-10.)

Annual weighted average capacity prices increased from a CCM/RPM combined, weighted average price of $5.73 per MW-day in 2006 to an RPM weighted-average price of $173.15 per MW-day in 2010 and then declined to $136.62 per MW-day in 2011. Figure 5-1 presents capacity market prices on a calendar year basis for the entire history of the PJM capacity markets.

As Table 5-5 shows, net excess decreased 229.42 MW from 5,240.5 MW on June 1, 2007, to 5,011.1 MW on June 1, 2008, because of a 2,657.3 MW increase in the RPM reliability requirement from 148,277.3 MW to 150,934.6 MW.[29] This increase was caused by a higher peak-load forecast and was partially offset by an increase of 1,513.5 MW in unforced capacity from 154,076.7 MW on June 1, 2007, to 155,590.2 MW on June 1, 2008.[30] The increase in unforced capacity was the result

27 Planned units are subject to mitigation only under specific circumstances defined in the tariff. Some of the 20 uncapped planned units submitted zero price offers.

28 The 133 units which had an APIR component submitted $613.8 million for capital projects associated with 8,813.7 MW UCAP.

29 Net excess under RPM is calculated as cleared capacity less the reliability requirement plus ILR. For 2007/2008 and 2008/2009, certified ILR was used in the calculation. For 2009/2010 and 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.

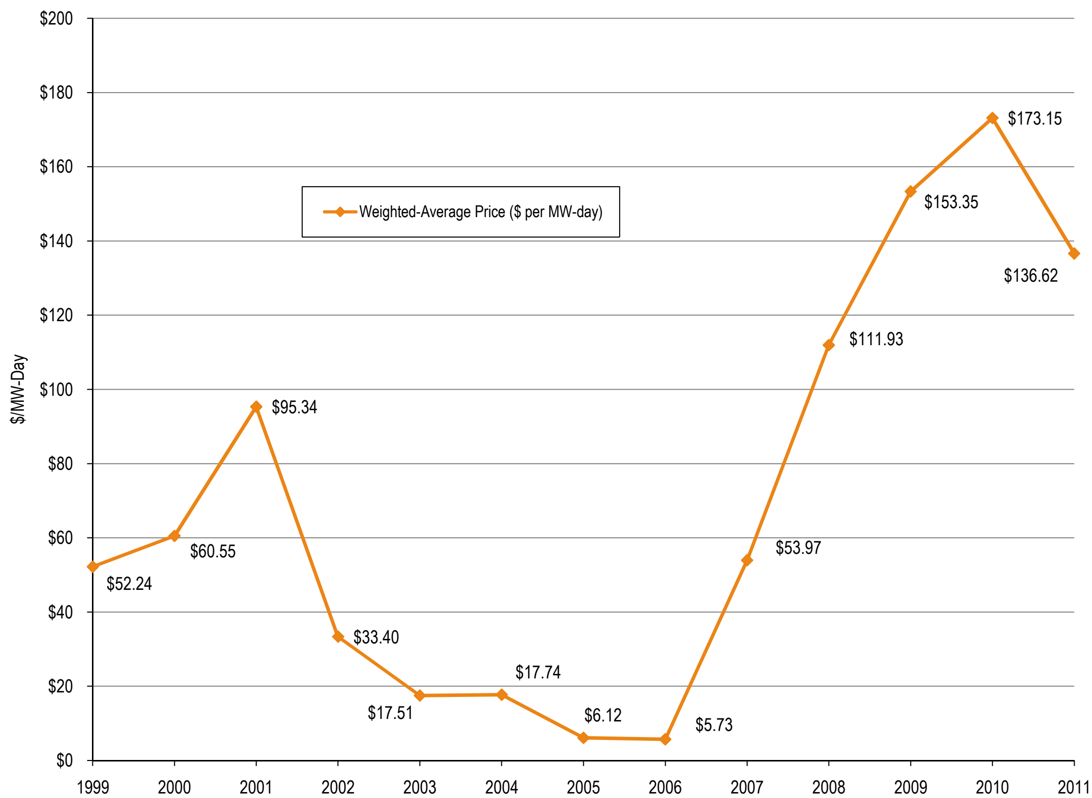
30 Unforced capacity is defined as the UCAP value of iron in the ground plus the UCAP value of imports less the UCAP value of exports.

of a decrease in exports of 100.4 MW plus a 1,762 MW growth in total internal capacity (Table 5-1), both of which were partially offset by a decrease in imports of 348.9 MW.

Table 5-10 Capacity prices: 2007/2008 through 2011/2012 RPM Auctions

	RPM Clearing Price ($ per MW-day)				
	RTO	EMAAC	SWMAAC	MAAC+APS	DPL-South
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		$237.33	$191.32	
2010/2011 BRA	$174.29				$178.27
2011/2012 BRA	$110.00				

Figure 5-1 History of capacity prices: Calendar year 1999 through 2011[31,32]



31 1999-2006 capacity prices are CCM combined market, weighted average prices. The 2007 capacity price is a combined CCM/RPM weighted average price. The 2008-2011 capacity prices are RPM weighted average prices.

32 The calculation of the 2007 weighted average price has been revised since the value in the *2007 State of the Market Report* was posted.

Table 5-11 RPM cost to load: 2008/2009 through 2011/2012 RPM Auctions[33,34,35]

	Net Load Price ($/MW-Day)	UCAP Obligation (MW)	Annual Charges
2008/2009 BRA			
RTO	$113.22	79,814.6	$3,298,362,289
EMAAC	$145.24	35,755.4	$1,895,486,718
SWMAAC	$183.03	15,684.6	$1,047,824,603
2009/2010 BRA			
RTO	$102.04	57,520.9	$2,142,342,912
MAAC+APS	$188.55	60,399.9	$4,156,766,418
SWMAAC	$218.12	15,966.1	$1,271,121,892
2010/2011 BRA			
RTO	$174.29	129,253.2	$8,222,552,183
DPL	$178.27	4,595.0	$298,989,987
2011/2012 BRA			
RTO	$110.04	133,815.3	$5,389,363,034

Table 5-11 shows the RPM annual charges to load. For the 2008/2009 planning year, annual charges totaled approximately $6.2 billion.

2008/2009 RPM Base Residual Auction

Cleared capacity resources across the entire RTO will receive a total of $6.1 billion based on the unforced MW cleared and the prices in the 2008/2009 BRA.

RTO

Table 5-12 shows total RTO offer data for the 2008/2009 RPM Auction, which includes the EMAAC and SWMAAC LDAs. Total internal RTO unforced capacity of 156,968.0 MW includes all generating units and DR that qualified as a PJM capacity resource for the 2008/2009 RPM Auction, excluding external units, and also includes owners' modifications to installed capacity ratings which are permitted under the PJM Reliability Assurance Agreement (RAA) and associated manuals.[36]

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

34 There is no separate obligation for DPL-South as the DPL-South LDA is completely contained within the DPL Zone.

35 The Final UCAP Obligation is determined after the clearing of the second incremental auction. If a second incremental auction is not held, the final UCAP Obligation is equal to the Base UCAP Obligation. The Final Zonal Capacity Prices are determined after certification of ILR. The 2009/2010, 2010/2010 and 2011/2012 Net Load Prices are not finalized. The 2010/2011 and 2011/2012 Obligation MW are not finalized.

36 See "Reliability Assurance Agreement among Load-Serving Entities in the PJM Region" (June 1, 2007) (Accessed February 3, 2009) <http://www.pjm.com/documents/agreements/~/media/documents/agreements/raa.ashx> (1.92 MB).

After accounting for FRR committed resources and for imports, RPM capacity was 136,237.3 MW.[37] This amount was reduced by exports of 3,838.1 MW[38] 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). Subtracting 330.1 MW of FRR optional volumes not offered, resulted in 131,880.6 MW that were available to be offered into the auction.[39] Offered volumes included 1,711.1 MW of EFORd offer segments. All capacity resources were offered into the RPM Auction. Four new wind resources (60.9 MW), three new diesel resources (23.3 MW) and two resources (112.6 MW) which came out of retirement were offered into the auction.

The downward sloping demand curve resulted in more capacity cleared in the market than the reliability requirement. The 129,597.6 unforced MW of cleared resources for the entire RTO represented a reserve margin of 17.5 percent, which was 1,403.0 MW greater than the reliability requirement of 128,194.6 MW (IRM of 15.0 percent).[40,41,42] As shown in Figure 5-2, the downward sloping demand curve resulted in a price of $111.92 per MW-day. Net excess was 5,011.1 MW, which was a decrease of 229.4 MW from the net excess of 5,240.5 MW in the 2007/2008 RPM Auction. (See Table 5-5.) This decrease was mainly because of an increase in the RTO load forecast of 2,385.0 MW from 137,421.0 MW to 139,806.0 MW effective June 1, 2008. Certified ILR was 3,608.1 MW.

As shown in Table 5-12, the net load price that LSEs will pay is $113.22 per MW-day in the RTO area not included in the constrained LDAs. This value is the final zonal capacity price. The final zonal capacity price is the resource-clearing price adjusted for differences between the certified ILR for the delivery year and the forecasted RTO ILR obligation.

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

38 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.

39 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.

40 Both the reserve margin calculation and IRM include FRR resources and FRR load and are on an ICAP basis.

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

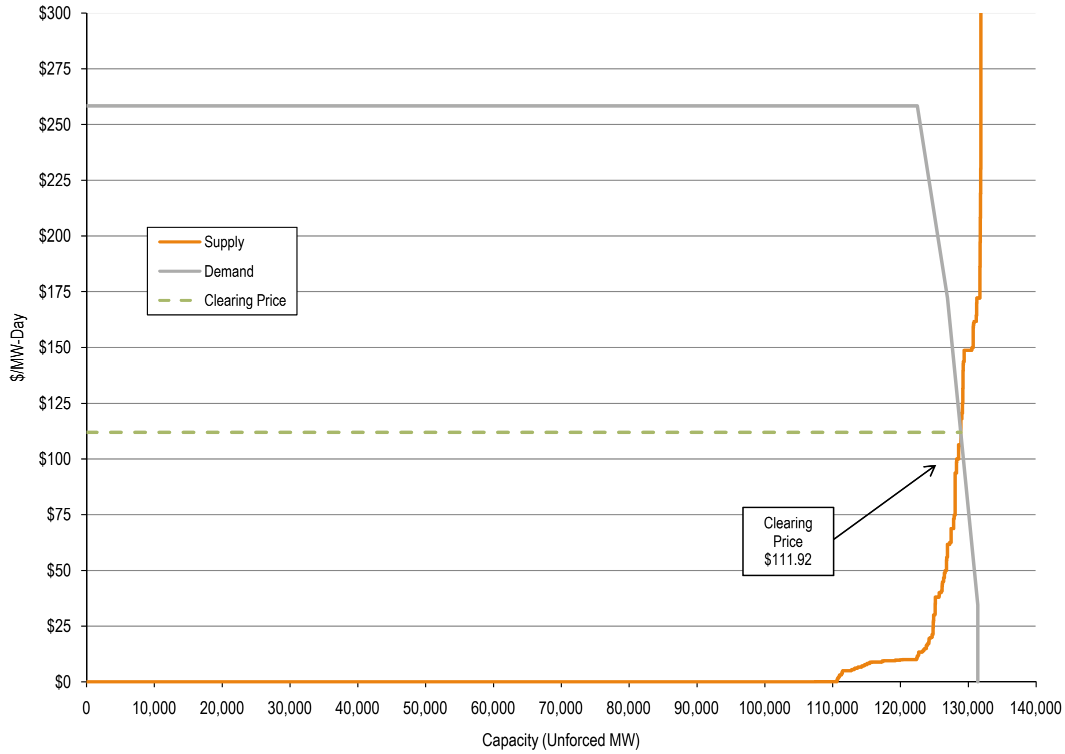
42 The demand curve UCAP quantities are based on three points, which are ratios of the installed reserve margin (IRM =15.0 percent) times the reliability requirement, less the forecast RTO ILR obligation. For the three points, the ratios are 1.12/1.15, 1.16/1.15 and 1.20/1.15. For these three points the UCAP prices are based on factors multiplied by net cost of net entry (CONE) divided by one minus the pool-wide EFORd. Net CONE is defined as CONE minus the energy and ancillary service revenue offset (E&AS). For the three points, the factors are 1.5, 1.0 and 0.2. For 2008/2009, CONE was $197.83 per MW-day and E&AS was $36.12 MW-day.

Table 5-12 RTO offer statistics: 2008/2009 RPM Base Residual Auction[43]

	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		
ILR Certified		3,608.1		
RPM Net Excess/(Deficit)		5,011.1		
Resource Clearing Price ($ per MW-day)		$111.92	A	
Final Zonal Capacity Price ($ per MW-day)		$113.22	B	
Final Zonal CTR Credit Rate ($ per MW-day)		$0.00	C	
Final Zonal ILR Price ($ per MW-day)		$111.92	A-C	
Net Load Price ($ per MW-day)		$113.22	B-C	

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

Figure 5-2 RTO market supply/demand curves: 2008/2009 RPM Base Residual Auction[44,45]



EMAAC

Table 5-13 shows total EMAAC offer data for the 2008/2009 RPM Auction. Total internal EMAAC unforced capacity of 31,396.7 MW includes all generating units and DR that qualified as a PJM capacity resource, excluding external units, and also includes owners' modifications to ICAP ratings. Including imports of 17.6 MW into EMAAC, RPM unforced 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 that were available to be offered into the auction. All capacity resources were offered into the RPM Auction.

Of the 30,231.3 MW cleared in EMAAC, 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 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 5-3. The price was determined by the intersection of the incremental supply and demand curves. The uncleared MW were the result of offer prices which exceeded the demand curve.

44 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.
45 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.

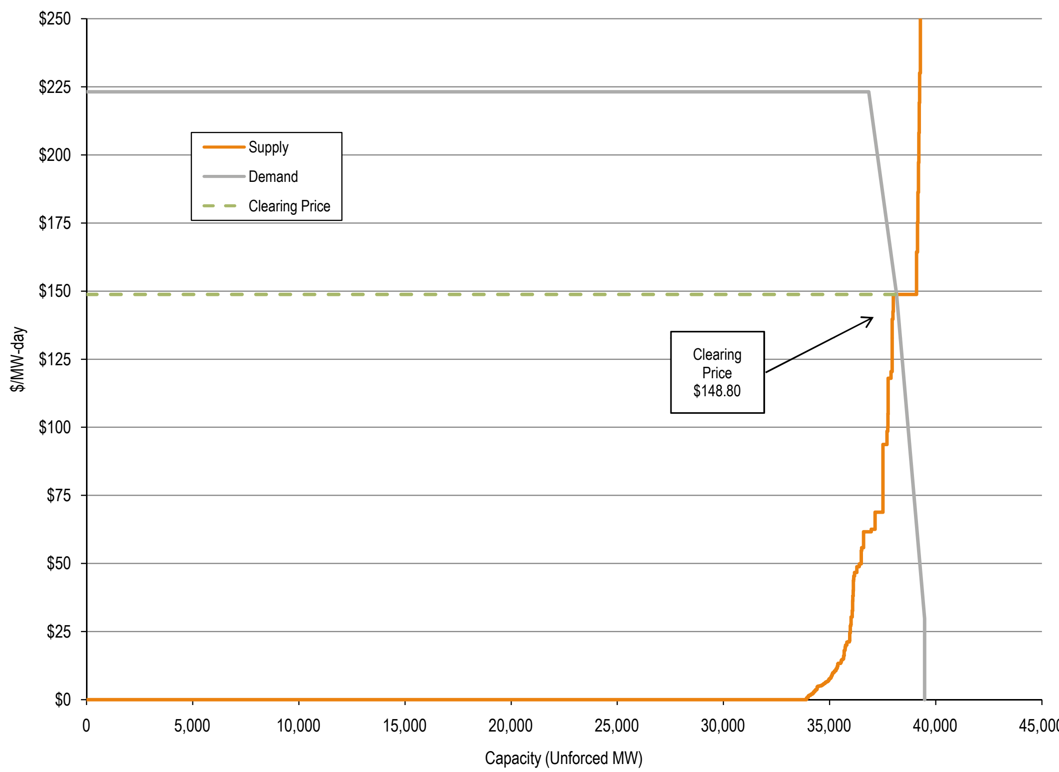
Total resources in EMAAC were 38,161.3 MW, which when combined with certified ILR of 622.6 MW resulted in a net excess of 893.2 MW (2.3 percent) greater than the reliability requirement of 37,890.7 MW.

As shown in Table 5-13, the net load price that LSEs will pay is $145.24 per MW-day. This value is the final zonal capacity price ($150.53 per MW-day) less the final CTR credit rate ($5.29 per MW-day). 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.

Table 5-13 EMAAC offer statistics: 2008/2009 RPM Base Residual 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		
ILR Certified		622.6		
RPM Net Excess/(Deficit)		893.2		
Resource Clearing Price ($ per MW-day)		$148.80	A	
Final Zonal Capacity Price ($ per MW-day)		$150.53	B	
Final Zonal CTR Credit Rate ($ per MW-day)		$5.29	C	
Final Zonal ILR Price ($ per MW-day)		$143.51	A-C	
Net Load Price ($ per MW-day)		$145.24	B-C	

Figure 5-3 EMAAC supply/demand curves: 2008/2009 RPM Base Residual Auction[46]



SWMAAC

Table 5-14 shows total SWMAAC offer data for the 2008/2009 RPM Auction. Total internal SWMAAC unforced capacity of 10,777.1 MW includes all generating units and DR that qualified as a PJM capacity resource, excluding external units, and also includes owners' modifications to ICAP ratings. Since there were no imports from outside PJM into SWMAAC, RPM unforced 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 that were available to be offered into the auction. All capacity resources were offered into the RPM Auction.

Of the 10,621.2 MW cleared in SWMAAC, 10,335.6 MW had 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 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. (See Figure 5-4.)

Total resources in SWMAAC were 16,231.2 MW, which when combined with certified ILR of 219.7 MW resulted in a net deficit of 111.0 MW (.7 percent) less than the reliability requirement of 16,561.9 MW.

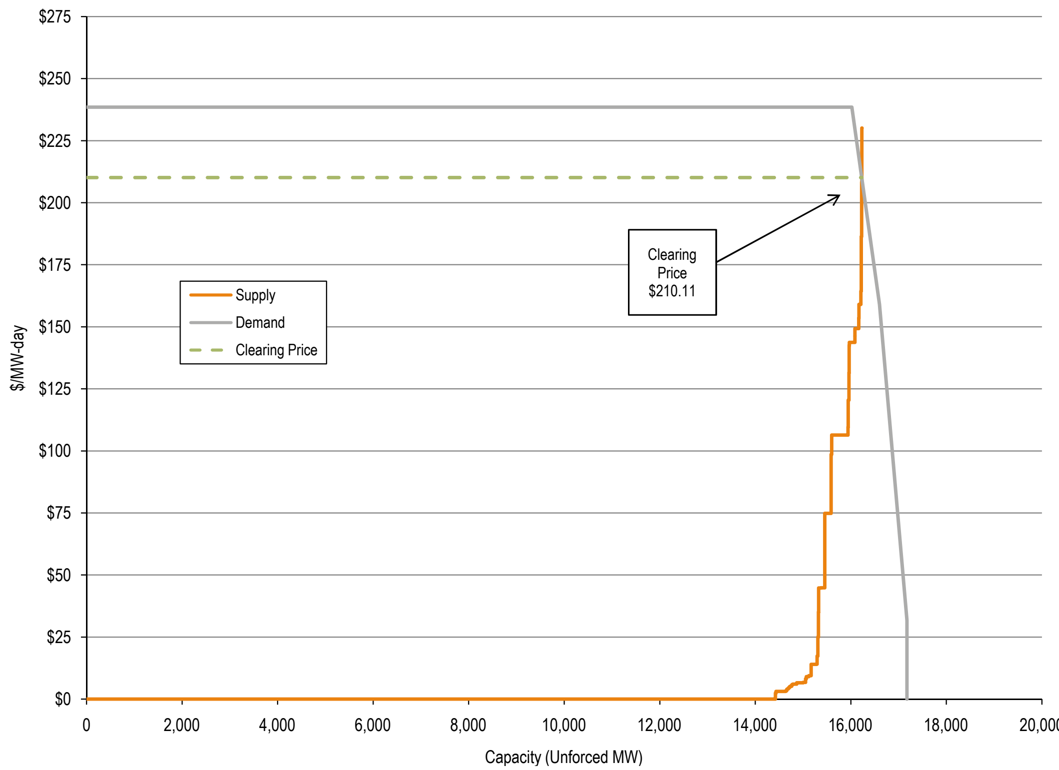
46 The supply curve was truncated at $250.00 per MW-day and does not show an uncleared offer of approximately $800.00 per MW-day.

As shown in Table 5-14, the net load price that LSEs will pay is $183.03 per MW-day. This value is the final zonal capacity price ($212.56 per MW-day) less the final CTR credit rate ($29.53 per MW-day).

Table 5-14 SWMAAC offer statistics: 2008/2009 RPM Base Residual 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		
ILR Certified		219.7		
RPM Net Excess/(Deficit)		(111.0)		
Resource Clearing Price ($ per MW-day)		$210.11	A	
Final Zonal Capacity Price ($ per MW-day)		$212.56	B	
Final Zonal CTR Credit Rate ($ per MW-day)		$29.53	C	
Final Zonal ILR Price ($ per MW-day)		$180.58	A-C	
Final Net Load Price ($ per MW-day)		$183.03	B-C	

Figure 5-4 SWMAAC supply/demand curves: 2008/2009 RPM Base Residual Auction



2008/2009 RPM Third Incremental Auction

Under RPM, the Third Incremental Auction, which is held in January prior to the start of the delivery year, allows capacity resource owners to buy and sell capacity to accommodate adjustments to participants' resource positions as a result of resource retirements, cancellations, delays or changes in a resource's EFORd. The demand curve in the Third Incremental Auction is entirely a function of demand bids. There is no administrative market demand curve.

Cleared resources across the entire RTO will receive a total of $5.4 million based on the unforced MW cleared and the prices in the 2008/2009 RPM Third Incremental Auction.

RTO

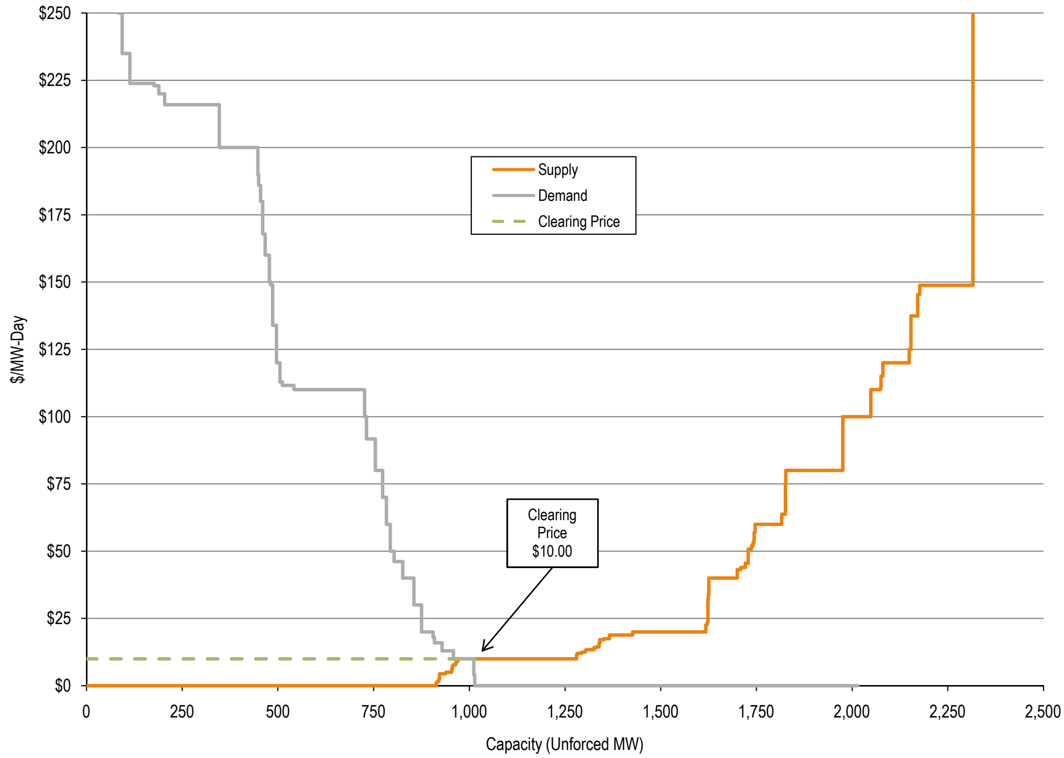
Table 5-15 shows total RTO offer and bid data for the 2008/2009 RPM Third Incremental Auction. There were 2,339.4 MW offered into the incremental auction while buy bids totaled 2,251.8 MW. The offered volumes came from uncleared offers from the 2008/2009 BRA (2,283.0 MW), three new resources (64.6 MW), four reactivated resources (166.9 MW), nine new DR resources (22.8 MW), net derates to existing DR resources (-179.2 MW), net derates to existing generating resources (-171.7 MW) and higher UCAP values due to improved EFORds (153.0 MW). Of the 904.3 MW with zero price offers, 872.2 MW had zero price offer caps. Buy bids were submitted to cover short positions due to deratings and EFORd increases or because participants wished to purchase additional capacity. No EFORd offer segments were permitted in this auction because the delivery year EFORds were known for this auction and the EFORd risk was therefore zero. Cleared volumes in the RTO were 1,011.6 MW, resulting in an RTO clearing price of $10.00 per MW-day (See Figure 5-5.) The price was set by the transition adder. The RTO clearing price in the 2008/2009 BRA was $111.92 per MW-day. The 1,307.2 MW of uncleared volumes can be used as replacement volumes or traded bilaterally.

Although EMAAC was constrained in the 2008/2009 BRA, supply offers in the incremental auction in EMAAC (1,142.8 MW) exceeded EMAAC demand bids (191.0 MW). The offered volumes came from uncleared offers from the 2008/2009 BRA (1,148.1 MW), one new resource (5.2 MW), three reactivated resources (9.7 MW), net derates to existing DR resources (-174.4 MW), net uprates to existing resources (66.5 MW) and higher UCAP values due to improved EFORds (87.7 MW). Supply and demand resulted in a price less than the RTO clearing price. The result was that all of EMAAC supply which cleared received the RTO clearing price.

Table 5-15 RTO offer statistics: 2008/2009 RPM Third Incremental Auction

	Offered (Supply)		Bid (Demand)
	ICAP (MW)	UCAP (MW)	UCAP (MW)
Generation	2,468.3	2,316.2	
DR	22.6	23.2	
Total	2,490.9	2,339.4	2,251.8
Cleared in RTO	1,046.4	1,011.6	1,011.6
Cleared in SWMAAC	0.0	0.0	0.0
Total cleared	1,046.4	1,011.6	1,011.6
Uncleared in RTO	1,444.5	1,327.8	1,240.2
Uncleared in SWMAAC	0.0	0.0	0.0
Total uncleared	1,444.5	1,327.8	1,240.2
Resource clearing price ($ per MW-day)	$10.00		

Figure 5-5 RTO supply/demand curves: 2008/2009 RPM Third Incremental Auction



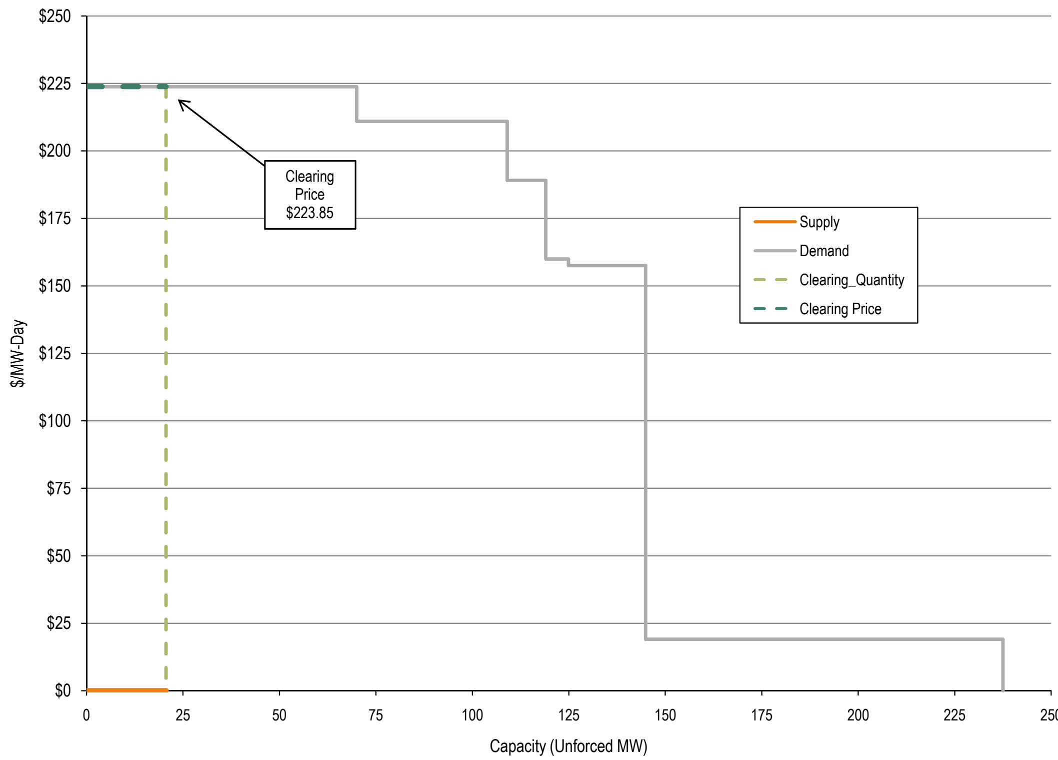
SWMAAC

Table 5-16 shows total SWMAAC offer and bid data for the 2008/2009 RPM Third Incremental Auction. There were 20.6 MW in SWMAAC offered into the auction while buy bids in SWMAAC totaled 237.5 MW. Except for 0.1 MW of new DR, the offered volumes came from capacity modifications (14.6 MW) and higher UCAP values due to improved EFORds (5.9 MW). SWMAAC was a constrained LDA for the 2008/2009 delivery year, so the only supply which could meet the demand was the 20.6 MW in SWMAAC. Since these offered volumes were less than buy bids, the price was set by a vertical extension of the supply curve to meet demand, resulting in a clearing price of $223.85 per MW-day. (See Figure 5-6.) The SWMAAC clearing price in the 2008/2009 BRA was $210.11 per MW-day.

Table 5-16 SWMAAC offer statistics: 2008/2009 RPM Third Incremental Auction

	Offered (Supply)		Bid (Demand)
	ICAP (MW)	UCAP (MW)	UCAP (MW)
Generation	22.9	20.5	
DR	0.1	0.1	
Total	23.0	20.6	237.5
Cleared in RTO	0.0	0.0	0.0
Cleared in SWMAAC	23.0	20.6	20.6
Total cleared	23.0	20.6	20.6
Uncleared	0.0	0.0	216.9
Resource clearing price ($ per MW-day)	$223.85		

Figure 5-6 SWMAAC supply/demand curves: 2008/2009 RPM Third Incremental Auction



Generator Performance

Generator performance results from the interaction between the physical nature of the units and the level of expenditures made to maintain the capability of the units, which in turn is a function of incentives from energy, ancillary services and capacity markets. Generator performance can be measured using indices calculated from historical data. Generator performance indices include those based on total hours in a period (generator performance factors) and those based on hours when units are needed to operate by the system operator (generator forced outage rates).[47]

Generator Performance Factors

Generator performance factors are based on a defined period, usually a year, and are directly comparable.[48] Performance factors include the equivalent availability factor (EAF), the equivalent maintenance outage factor (EMOF), the equivalent planned outage factor (EPOF) and the equivalent forced outage factor (EFOF). These four factors add to 100 percent for any generating unit. The EAF is the proportion of hours in a year when a unit is available to generate at full capacity while the three outage factors include all the hours when a unit is unavailable. The EMOF is the proportion of hours in a year when a unit is unavailable because of maintenance outages and maintenance deratings. The EPOF is the proportion of hours in a year when a unit is unavailable because of planned outages and planned deratings. The EFOF is the proportion of hours in a year when a unit is unavailable because of forced outages and forced deratings.

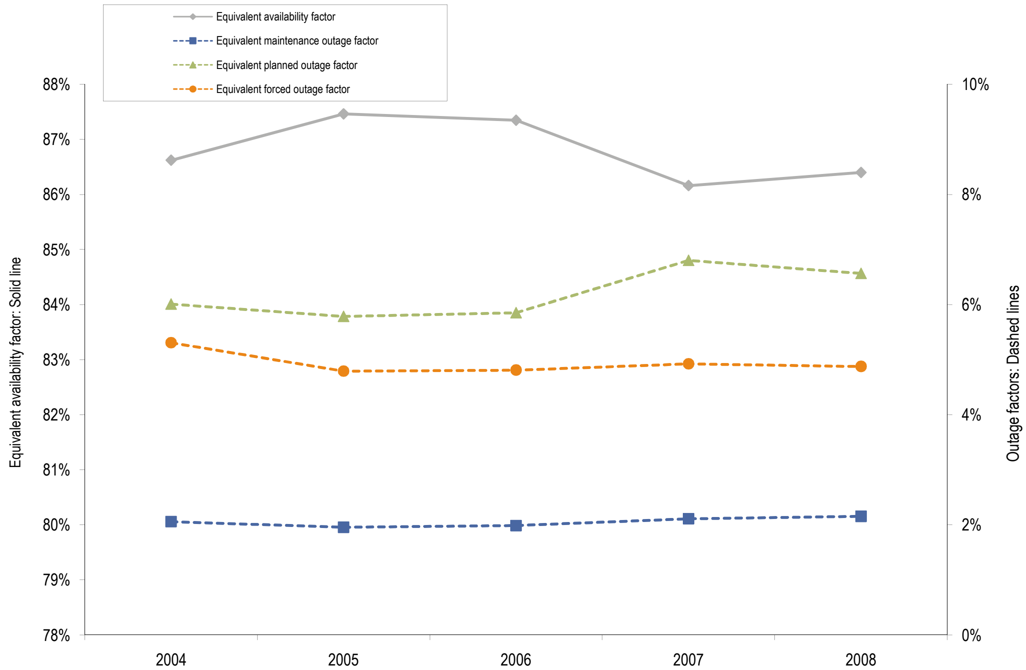
The PJM aggregate EAF increased from 86.2 percent in 2007 to 86.4 percent in 2008. The EFOF decreased 0.047 percentage points from 2007, to 4.877 percent while the EPOF decreased by about 0.237 percentage points to 6.567 and the EMOF increased 0.045 percentage points to 2.155.[49] (See Figure 5-7.)

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

48 Data from all PJM capacity resources for the years 2004 through 2008 were analyzed.

49 The performance factor data include all units from PJM. Results for prior years may be different from previous reports as corrections can be made at any time with permission from the PJM GADS administrators. Data are for 12 months ended December 31, 2008, as downloaded from the PJM GADS database on January 23, 2009.

Figure 5-7 PJM equivalent outage and availability factors: Calendar years 2004 to 2008



Generator Forced Outage Rates

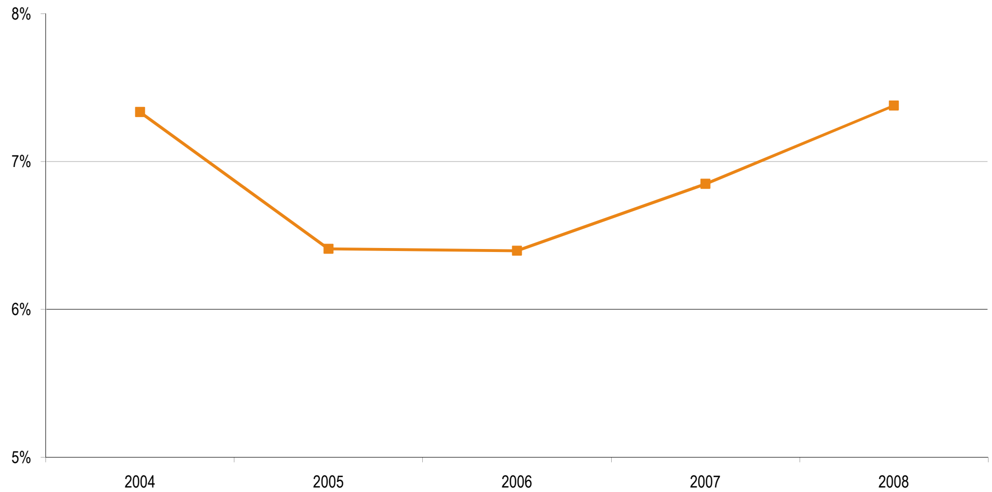
The equivalent demand forced outage rate (EFORd) (generally referred to as the forced outage rate) is a measure of the probability that a generating unit will fail, either partially or totally, to perform when it is needed to operate. EFORd is calculated using historical performance data. PJM systemwide EFORd is a capacity-weighted average of individual unit EFORd. Unforced capacity for any individual generating unit is equal to one minus the EFORd multiplied by the unit's net dependable summer capability. The PJM Capacity Market creates an incentive to minimize the forced outage rate because the amount of capacity resources available to sell from a unit (unforced capacity) is inversely related to the forced outage rate.

EFORd calculations use historical data, including equivalent forced outage hours,[50] service hours, average forced outage duration, average run time, average time between unit starts, available hours and period hours.[51] The average PJM EFORd decreased from 7.3 percent in 2005 to 6.4 percent in 2005 and 2006 and increased to 6.8 percent in 2007 and 7.4 percent in 2008.[3] The increase in EFORd from 2007 to 2008 was the result of increased forced outage rates for steam and nuclear generating units. Figure 5-8 shows the average EFORd since 2004 for all units in PJM.

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

51 See PJM. "Manual 22: Generator Resource Performance Indices," Revision 15 (June 1, 2007), Equations 2 through 5.

Figure 5-8 Trends in the PJM equivalent demand forced outage rate (EFORd): Calendar years 2004 to 2008



Components of Change in EFORd

Table 5-17 shows the contribution of each unit type to the system EFORd, calculated as the total forced MW for the unit type divided by the total capacity of the system.[52] Forced MW for a unit type is the EFORd multiplied by the generator's net dependable summer capability.

Table 5-17 Contribution to EFORd for specific unit types (Percentage points): Calendar years 2004 to 2008[53]

	2004	2005	2006	2007	2008	Change in 2008 from 2007
Combined cycle	0.5	0.6	0.5	0.4	0.4	0.0
Combustion turbine	1.3	1.3	1.4	1.6	1.5	(0.1)
Diesel	0.0	0.0	0.0	0.0	0.0	0.0
Hydroelectric	0.2	0.1	0.1	0.1	0.1	0.0
Nuclear	0.6	0.3	0.3	0.2	0.4	0.2
Steam	4.7	4.1	4.1	4.4	4.9	0.5
Total	7.3	6.4	6.4	6.8	7.4	0.6

The increase in overall PJM EFORd of 0.6 percentage points (a 7.7 percent increase) between 2007 and 2008 resulted from poorer performance of steam and nuclear units (313 and 32 generating units respectively) which accounted for 0.5 and 0.2 percentage points of the overall increase, or 117%, while improved performance of combustion turbines offset the increase by -0.1 percentage points.

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

53 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.

Of the 1,189 generating units in the EFORd analysis during calendar year 2008, 431 units had decreased EFORds, 387 units had increased EFORds and the remaining 371 units had unchanged EFORds.[54] If the 431 units with lower forced outage rates had not experienced rates lower than the average, the 2008 EFORd would have been 9.7 percent, 31 percent higher than the actual overall EFORd of 7.4.

Changes in outage rates by unit type and changes in capacity by unit type combined to produce the observed impacts on system EFORd. Since total capability from fossil steam units remained relatively constant from year to year, the increased forced outage rates for this unit type was the reason for its contribution to the increased system EFORd.

Table 5-18 shows the relative contributions of EFORd and capacity to EFORd levels by unit type and for the system. The contribution of steam units to the increased system EFORd was the result of increased steam unit EFORd (112.0 percent of the steam contribution) which was offset by lower capacity levels for steam units (-12.0 percent). The contribution of nuclear units to the increased system EFORd was the result of increased nuclear unit EFORd (95.8 percent of the nuclear contribution) and of increased capacity levels for nuclear units (4.2 percent). Overall, 117.2 percent of the increase in EFORd from 2007 to 2008 was the result of increased EFORd for nuclear and steam units types, offset by decreased EFORd for combustion turbines and changes in the mix of capacity by unit type.

Table 5-18 Percent change in contribution to EFORd (Unit type): 2008 compared to 2007

	Contribution Change Due to Capacity	Contribution Change Due to EFORd
Combined cycle	31.9%	68.1%
Combustion turbine	42.5%	57.5%
Diesel	14.2%	85.8%
Hydroelectric	(24.6%)	124.6%
Nuclear	4.2%	95.8%
Steam	(12.0%)	112.0%
All unit types	(17.2%)	117.2%

54 A single unit may include more than one set of generator terminals aggregated as a single generator.

Table 5-19 compares 2008 PJM EFORd data by unit type to the five-year North American Electric Reliability Council (NERC) average EFORd data for corresponding unit types. The 2008 PJM forced outage rates for combined cycle, hydroelectric and nuclear units were below the NERC five-year averages. The 2008 PJM EFORd for combustion turbine, diesel and fossil steam units exceeded the NERC averages.[55]

Table 5-19 Five-year PJM EFORd data comparison to NERC five-year average for different unit types: Calendar years 2004 to 2008

	PJM EFORd					NERC EFORd
	2004	2005	2006	2007	2008	2003 to 2007 Average
Combined cycle	5.2%	5.0%	4.3%	3.5%	3.4%	0.0%
Combustion turbine	9.0%	8.9%	9.4%	11.1%	10.9%	8.9%/8.3%
Diesel	8.9%	14.0%	13.2%	11.8%	9.6%	0.0%
Hydroelectric	3.9%	2.5%	1.9%	2.3%	2.4%	0.0%
Nuclear	3.2%	1.6%	1.4%	1.3%	1.9%	0.0%
Steam	9.2%	8.1%	8.2%	8.8%	9.8%	0.0%
Overall	7.3%	6.4%	6.4%	6.8%	7.4%	NA

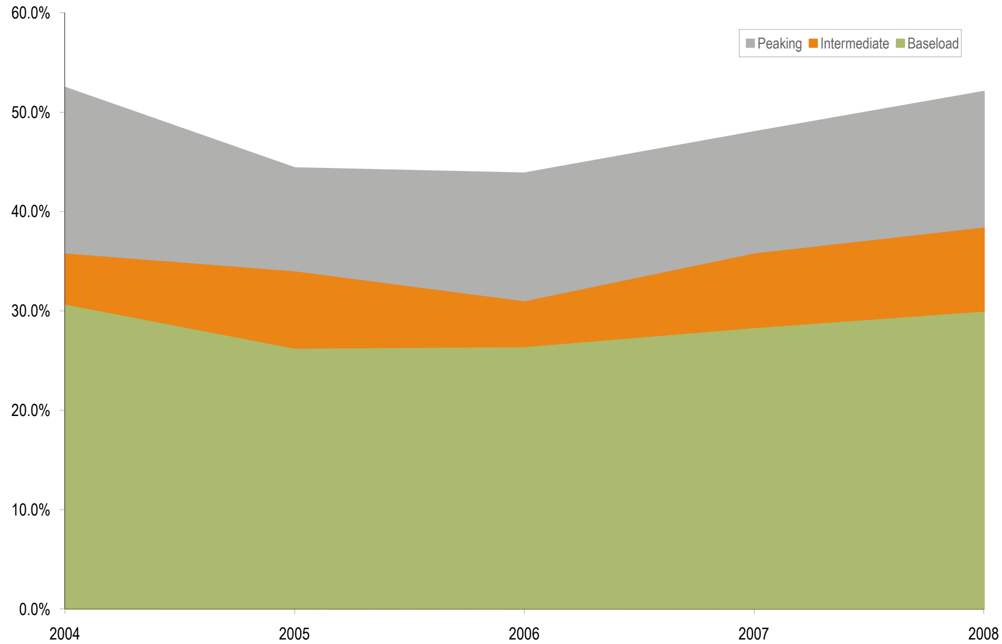
Duty Cycle and EFORd

In addition to disaggregating system EFORd by unit type, units were categorized by actual duty cycles as baseload, intermediate or peaking to determine the relationship between type of operation and forced outage rates.[56] Figure 5-9 shows the contribution of unit types to system average EFORd. In 2008, of 21,323 total MW of combined-cycle units, approximately 6,497 MW are in baseload classes, 11,555 MW in the intermediate, and 3,271 MW are in peaking classes. Of the 24,157 total MW of combustion turbine units, approximately 533 MW are in baseload classes, 1,589 MW in the intermediate, and 22,036 MW are in peaking classes.

55 NERC defines combustion turbines in two categories: jet engines and gas turbines. Their EFORd for the 2003 to 2007 period are 8.9 percent and 8.3 percent, respectively, per NERC's GADS "2003-2007 Generating Unit Statistical Brochure - Units Reporting Events" <http://www.nerc.com/files/2003-2007%20Generating%20Unit%20Statistical%20Brochure%20-%20Units%20Reporting%20Events.zip> (32 KB). Also, the NERC average for fossil steam units is a unit-year-weighted value for all units reporting. The PJM values are weighted by capability for each calendar year.

56 Duty cycle is the time the unit is generating divided by the time the unit is available to generate. A baseload unit is defined as a unit that generates during 50 percent or more of its available hours. An intermediate unit is defined as a unit that generates during from 10 percent to 50 percent of its available hours. A peaking unit is defined as a unit that generates during less than 10 percent of its available hours. These terms were defined for the purposes of this analysis.

Figure 5-9 Contribution to EFORd by duty cycle: Calendar years 2004 to 2008



Forced Outage Analysis

The MMU analyzed the causes of forced outages for the entire PJM system. The metric used was lost generation, which is the product of the duration of the outage and the size of the outage reduction. Lost generation can be converted into lost system equivalent availability.[57] On a systemwide basis, the resultant lost equivalent availability from the forced outages is equal to the equivalent forced outage factor.

The PJM EAF for 2008 was 86.4 percent; the corresponding EMOF and EPOF were 2.2 percent and 6.6 percent, respectively. As a result, the 2008 PJM EFOF was 4.9 percent. This means 4.9 percent lost availability because of forced outages.

The major reasons for this lost equivalent availability are listed in Table 5-20.

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

Table 5-20 Outage cause contribution to PJM EFOF: Calendar year 2008

	Percentage Point Contribution to EFOF	Contribution to EFOF
Boiler Tube Leaks	0.96	19.7%
Economic	0.60	12.4%
Low Pressure Turbine	0.29	6.0%
Boiler Air and Gas Systems	0.23	4.8%
Boiler Fuel Supply from Bunkers to Boiler	0.21	4.4%
Feedwater System	0.16	3.3%
Miscellaneous (Generator)	0.16	3.2%
Stack Emission	0.15	3.0%
Fuel Quality	0.13	2.7%
Circulating Water Systems	0.12	2.4%
Electrical	0.12	2.4%
Miscellaneous (Steam Turbine)	0.08	1.7%
Performance	0.08	1.7%
Miscellaneous (Jet Engine)	0.08	1.7%
High Pressure Turbine	0.08	1.6%
Controls	0.07	1.5%
Condensing System	0.07	1.4%
Wet Scrubbers	0.07	1.4%
Generator	0.06	1.3%
All other causes	1.14	23.4%
PJM EFOF 2008	4.86	100.0%

Table 5-20 shows that boiler tube leaks, at 19.7 percent of the systemwide EFOF, were the largest single contributor to EFOF. Forced outages because of boiler tube leaks reduced system equivalent availability by 0.96 percentage points. Economic reasons caused the second largest reduction to equivalent availability by 0.60 percentage points. Low pressure turbine problems caused the third largest reduction to equivalent availability by 0.29 percentage points, or 6.0 percent of the systemwide EFOF.

Table 5-21 shows the categories which are included in the economic category.[58] Lack of fuel that is considered out of management control accounted for 96.0 percent of all economic reasons while the lack of fuel that was not out of management control accounted for only 1.1 percent. Lack of water (hydro) was included in the lack of fuel (OMC) calculation.

Table 5-21 Contributions to Economic Outages: 2008

	Contribution to Economic Reasons
Lack of Fuel (OMC)	95.9%
Core Coastdown (Nuclear)	2.1%
Lack of Fuel (Non-OMC)	1.1%
Fuel Conservation	0.5%
Other Economic Problems	0.4%
Lack of Water (Hydro)	0.1%

Table 5-22 Contribution to EFOF by unit type for the most prevalent causes: Calendar year 2008

	Combined Cycle	Combustion Turbine	Diesel	Hydroelectric	Nuclear	Steam	System
Boiler Tube Leaks	2.9%	0.0%	0.0%	0.0%	0.0%	26.1%	19.7%
Economic	1.1%	14.1%	4.1%	1.3%	3.3%	14.6%	12.4%
Low Pressure Turbine	0.0%	0.0%	0.0%	0.0%	58.2%	1.9%	6.0%
Boiler Air and Gas Systems	0.8%	0.0%	0.0%	0.0%	0.0%	6.3%	4.8%
Boiler Fuel Supply from Bunkers to Boiler	0.3%	0.0%	0.0%	0.0%	0.0%	5.9%	4.4%
Feedwater System	2.9%	0.0%	0.0%	0.0%	6.9%	3.4%	3.3%
Miscellaneous (Generator)	14.7%	9.6%	0.5%	33.9%	1.6%	1.0%	3.2%
Stack Emission	0.1%	0.2%	0.0%	0.0%	0.0%	4.0%	3.0%
Fuel Quality	1.1%	0.1%	9.3%	0.0%	0.0%	3.5%	2.7%
Circulating Water Systems	6.6%	0.0%	0.0%	0.0%	1.0%	2.4%	2.4%
Electrical	5.0%	5.6%	2.2%	3.4%	0.8%	1.9%	2.4%
Miscellaneous (Steam Turbine)	3.3%	0.0%	0.0%	0.0%	2.6%	1.6%	1.7%
Performance	2.4%	7.1%	1.2%	14.2%	3.4%	0.8%	1.7%
Miscellaneous (Jet Engine)	0.0%	21.0%	0.0%	0.0%	0.0%	0.0%	1.7%
High Pressure Turbine	4.2%	0.0%	0.0%	0.0%	0.1%	1.7%	1.6%
Controls	1.5%	0.9%	1.4%	6.2%	1.1%	1.6%	1.5%
Condensing System	1.4%	0.0%	0.0%	0.0%	2.0%	1.5%	1.4%
Wet Scrubbers	0.0%	0.0%	0.0%	0.0%	0.0%	1.9%	1.4%
Generator	7.4%	3.0%	0.8%	0.5%	0.0%	0.5%	1.3%

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

Table 5-22 shows the major causes of EFOF by unit type. Boiler tube leaks caused 26.1 percent of the EFOF for fossil steam units. Low pressure turbine problems caused 58.2 percent of the EFOF for nuclear units. Miscellaneous (generator) outages caused 33.9 percent of the EFOF for hydroelectric units. Some miscellaneous generator outages include outages caused by problems with the generator's output breaker, the generator's main leads, or other miscellaneous generator problems.[12]

Table 5-23 Contribution to EFOF by unit type: Calendar year 2008

	EFOF	Contribution to EFOF
Combined cycle	3.4%	8.6%
Combustion turbine	2.7%	7.9%
Diesel	7.3%	0.3%
Hydroelectric	2.0%	0.7%
Nuclear	2.0%	7.8%
Steam	7.3%	74.7%
PJM systemwide	4.9%	100.0%

The contribution to systemwide EFOF by a generator or group of generators is a function of duty cycle, EFORd and share of the systemwide capacity mix. For example, fossil steam units have the largest share (about 49.8 percent) of the capacity mix,[59] have a high duty cycle and in 2008 had an EFORd of 9.8 percent which yields a 74.7 percent contribution to PJM systemwide EFOF. Nuclear units also have a high duty cycle; their share of the PJM systemwide capacity mix is about 18.4 percent and in 2008 they had a 1.9 percent EFORd which yields a 7.8 percent contribution to PJM systemwide EFOF. By using the values in Table 5-23 and Table 5-22 one can determine how much the individual unit types' causes contributed to PJM systemwide EFOF. For instance the value for boiler tube leaks in Table 5-22 multiplied by the contribution value in Table 5-23 for the same unit type will yield the percent contribution to the PJM systemwide EFOF for that outage cause.

59 See the *2008 State of the Market Report*, Volume II, Section 3, "Energy Market, Part 2," "Existing and Planned Generation," at Table 3-37, " Existing PJM capacity 2008 (By zone and unit type (MW))."

Outages Deemed Outside Management Control

In 2006, NERC created specifications for certain types of outages to be deemed outside management control (OMC) in response to the system disturbance of August 14, 2003.[60] NERC specified, in its January 2006 update to the "Generator Availability Data System Data Reporting Instructions,"[61] in Appendix K,[62] that each OMC outage must be carefully considered as to its cause and nature. An outage can 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. Appendix K of the "Generator Availability Data Systems Data Reporting Instructions" lists specific cause codes (i.e., codes that are standardized for specific outage causes) that would be considered OMC outages.[63] Not all outages caused by the factors in these specific OMC cause codes are OMC outages. For example, fuel quality issues (i.e., codes 9200 to 9299) may be within the control of the owner or outside management control. Each outage must be considered per the NERC directive. In 2007, PJM removed the OMC designation from all of the fuel quality codes with the exception of 9250, "low Btu coal" since only that code had both an OMC and non-OMC code (i.e., 9250, OMC code for "low Btu coal"; 9251, non-OMC code for "low Btu coal"). After analyzing the data for these outages types, it was found that in 2006, of 17 companies that used either of these cause codes, only three had used both the OMC and non-OMC cause codes. In other words, 14 companies exclusively used the OMC cause code. In 2007, however, of 39 companies that used either of the OMC and non-OMC fuel quality cause codes, only one company exclusively used the OMC cause code. Finally, in 2008, of those same 39 companies that used either OMC and non-OMC fuel quality cause codes, no company exclusively used the OMC cause code. In 2006, approximately 51 percent of the lost generation because of "low Btu coal" was deemed OMC by the generation owners. In 2007, 6 percent of the lost generation because of "low Btu coal" was deemed OMC and in 2008, 12 percent of the lost generation because of "low Btu coal" was deemed OMC. It is not clear why some companies, in 2006, exclusively used the OMC cause codes and did not use the non-OMC cause code for "low Btu coal." In 2007 and 2008, companies seem to have used the non-OMC and OMC cause codes for fuel quality more carefully. It is a reasonable expectation that companies would monitor coal quality stringently and reject noncompliant shipments. It is also possible that these outages are a function of issues with generating plant equipment. PJM should scrutinize OMC outages for low Btu coal carefully.

All outages, including OMC outages, are included in the EFORd that is used for planning studies that determine the reserve requirement. However, OMC outages are excluded from the calculations used to determine the level of unforced capacity for specific units and thus the amount of unforced capacity for sale in Capacity Markets. This modified EFORd is termed the XEFORd. All submitted OMC outages are reviewed by PJM's Capacity Adequacy Department. Table 5-24 shows the impact of OMC outages on EFORd for 2008. The difference is especially noticeable for steam units and combustion turbine units. For steam units, the OMC outage reason that resulted in the highest total MW loss in 2008 was lack of fuel. Although not sub-categorized in the table shown below, most of the difference in the steam XEFORd compared to EFORd is from petroleum-fired steam units

60 NERC had always provided cause codes for outages that were caused by external forces. However, as a result of the system disturbance on August 14, 2003, NERC specifically created outage specifications for outages that were "outside management control."

61 The "Generator Availability Data System Data Reporting Instructions" can be found on the NERC Web site: <http://www.nerc.com/files/2009 GADS DRI Complete Set.pdf> (4.9 MB).

62 The "Generator Availability Data System Data Reporting Instructions," Appendix K can be found on the NERC Web site: <http://www.nerc.com/files/Appendix K Outside Plant Management Control.pdf> (161 KB).

63 For a list of these cause codes, see the *2008 State of the Market Report*, Volume II, Appendix E, "Capacity Market."

and not coal-fired plants. Combustion turbine units have natural gas fuel curtailment outages that are also deemed as OMC. If companies' natural gas fuel supply is curtailed because of pipeline issues, the event can be deemed OMC. However, natural gas curtailments caused by lack of firm transportation contracts or arbitraging transportation reservations should not be classified as OMC. In 2008, XEFORd was 1.3 percentage points less than EFORd, which translates into a 2,155 MW difference in unforced capacity.

Table 5-24 PJM EFORd vs. XEFORd: Calendar year 2008

	2008 EFORd	2008 XEFORd	Difference
Combined cycle	3.4%	3.3%	0.1%
Combustion turbine	10.9%	7.4%	3.5%
Diesel	9.6%	9.0%	0.6%
Hydroelectric	2.4%	1.7%	0.7%
Nuclear	1.9%	1.9%	0.0%
Steam	9.8%	8.5%	1.4%
Overall	7.4%	6.1%	1.3%