SECTION 5 – CAPACITY MARKET

Each organization serving PJM load must own or acquire capacity resources to meet its capacity obligations. Load-serving entities (LSEs) can acquire capacity resources by entering into bilateral agreements, by participating in the PJM-operated Capacity Credit Market (CCM) or by constructing generation. LSEs can reduce their capacity obligations by participating in relevant demand-side response programs. Collectively, all arrangements by which LSEs acquire capacity are known as the Capacity Market.[1]

The PJM Capacity Credit Market[2] provides mechanisms to balance supply of and demand for capacity unmet by the bilateral market or self-supply. The PJM Capacity Credit Market consists of the Daily, Interval,[3] Monthly and Multimonthly CCM. The PJM CCM is intended to provide a transparent, market-based mechanism for retail LSEs to acquire the capacity resources needed to meet their capacity obligations and to sell capacity resources when no longer needed to serve load. The PJM Daily CCM permits LSEs to match capacity resources with short-term shifts in retail load while the Interval, Monthly and Multimonthly CCMs provide mechanisms to match longer-term obligations with capacity resources.

In June 2007, it is expected that the current capacity market construct will be replaced with the Reliability Pricing Model (RPM) capacity market construct.

Analysis of 2006 market results requires comparison to prior years. During calendar years 2004 and 2005, PJM integrated five new control zones. When making comparisons to 2004 and 2005, the *2006 State of the Market Report* refers to three phases in calendar year 2004 and two phases in 2005 that correspond to those integrations.[4]

From June 2004 through May 2005, a separate ComEd capacity credit market had operated under PJM rules, but with capacity obligations and capabilities measured in installed MW. That changed on June 1, 2005, when all ComEd capacity markets became fully integrated into the PJM capacity marketplace. To analyze PJM Capacity Market performance during 2006 as compared to 2005, the *2006 State of the Market Report* limits the relevant 2005 period to the one that started on June 1, 2005, and ended on December 31, 2005, when all capacity became measured by unforced MW. The report refers to it as the 2005 ComEd post capacity integration (PCI) period (i.e., the 2005 ComEd PCI period).[5]

1 See *2006 State of the Market Report,* Volume II, Appendix K, "Glossary," for definitions of PJM Capacity Credit Market terms.

2 All PJM Capacity Market values (capacities) are in terms of unforced MW.

3 PJM defines three intervals for its Capacity Market. The first interval extends for five months and runs from January through May. The second interval extends for four months and runs from June through September. The third interval extends for three months and runs from October through December.

4 For additional information on PJM's footprint and the definition of these phases, see *2006 State of the Market Report,* Volume II, Appendix A, "PJM Geography."

5 For further information on the ComEd PCI period, see *2006 State of the Market Report,* Volume II, Appendix E, "Capacity Market."

Overview

Market Structure

- **Supply.** Unforced capacity remained relatively constant in the PJM CCM in 2006 compared to the 2005 ComEd PCI period. Average unforced capacity decreased by 298 MW or 0.2 percent to 152,482 MW. Capacity resources exceeded capacity obligations every day by an average of 9,531 MW, a decrease of 466 MW from the average net excess of 9,997 MW for the 2005 ComEd PCI period.

- **Demand.** Unforced obligations remained relatively constant in the PJM CCM in 2006 compared to the 2005 ComEd PCI period. Average load obligations increased by 168 MW or 0.1 percent to 142,951 MW. PJM electricity distribution companies (EDCs) and their affiliates maintained a large market share of load obligations in the PJM CCM in 2006, together averaging 87.6 percent, down slightly from 88.5 percent for the 2005 ComEd PCI period.

- **Market Concentration.** Structural analysis of the PJM CCM found that, on average, the Daily CCM exhibited moderate concentration levels while the Monthly and Multimonthly CCM exhibited high concentration levels during 2006. The highest market share for any entity in one daily auction was 44.9 percent, while the highest average daily market share for any entity across all of the daily auctions was 28.8 percent. Of 365 daily auctions, 82 (22.5 percent) had a Herfindahl-Hirschman Index (HHI) greater than 1800. HHIs for the longer-term Monthly and Multimonthly CCM averaged 3611, with a maximum of 10000 and a minimum of 1691 (three firms with equal market shares would result in an HHI of 3333). The highest market share for any entity in one monthly/multimonthly auction was 100.0 percent, while the highest average market share for any entity across all of the monthly/multimonthly auctions was 30.5 percent. All but one of the 65 monthly/multimonthly auctions (98.5 percent) had an HHI greater than 1800. The PJM CCM accounted for 6.4 percent of total capacity obligations. The PJM Market Monitoring Unit (MMU) also analyzed ownership in the PJM Capacity Market as a whole in order to develop a more complete assessment of market structure for capacity. Ownership in the PJM Capacity Market exhibited low concentration levels throughout the year, with HHIs at 925 on January 1 and December 31. The highest market share declined from 16.7 percent to 16.4 percent. There was a single pivotal supplier throughout the year, with four individual suppliers who were each pivotal on a stand-alone basis.

- **External and Internal Capacity Transactions.** In 2006, imports averaged 3,093 MW, which was a decrease of 904 MW or 22.6 percent from the 2005 ComEd PCI period average of 3,997 MW. Exports averaged 4,958 MW, which was a decrease of 74 MW or 1.5 percent from the 2005 ComEd PCI period average of 5,032 MW. Average net exchange decreased 830 or 80.2 percent to -1,865 MW from the 2005 ComEd PCI period average of -1,035 MW. Internal bilateral transactions averaged 160,952 MW, which was an increase of 4,581 MW or 2.9 percent from the 156,371 MW average for the 2005 ComEd PCI period.

- **Active Load Management (ALM).** In 2006, ALM credits in the PJM CCM averaged 1,828 MW, down 214 MW (10.5 percent) from 2,042 MW in the 2005 ComEd PCI period.

Market Performance

- **CCM Volumes and Prices.** During 2006, total PJM CCM transactions averaged 9,118 MW (6.4 percent of obligation), which was 2,113 MW higher than the 2005 ComEd PCI period average of 7,005 MW (4.9 percent of obligation). Total PJM CCM prices averaged $5.73 per MW-day, which was $0.46 per MW-day higher than the 2005 ComEd PCI period average of $5.27 per MW-day. Daily CCM volume declined from 2.5 percent of average obligation in 2000 to 2.1 percent in 2006. Monthly and multimonthly CCM volume increased from 3.0 percent of obligation in 2000 to 4.3 percent of average obligation in 2006. CCM prices increased from 1999 through 2001 and have declined and remained relatively stable since 2001 with the exception of the summers of 2004 and 2006 and the first few days of January 2006.

Generator Performance

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. These incentives are somewhat attenuated in the current capacity market design. 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. If they are successful, this will also result in lower forced outage rates. The design of the RPM provides additional incentives for reduced outages during high-load periods and scarcity pricing could also provide strong, complementary incentives for reduced outages during high-load periods.

From 2002 to 2004, the average PJM equivalent demand forced outage rate (EFORd) increased, from 5.4 percent in 2002 to 6.7 percent in 2003 and 7.3 percent in 2004.[6] In 2005, the average PJM EFORd decreased to 6.6 percent and again decreased in 2006 to 6.4 percent. The decrease in EFORd from 2005 to 2006 was the result of decreased forced outage rates across all unit types with the exception of steam and diesel generators. These forced outage rates are for the entire PJM Control Area.[7]

Conclusion

Perhaps the most important fact about the PJM Capacity Market is that it will change significantly in 2007 as the result of the implementation of the RPM capacity market design. The conclusions here are based both on the details of the capacity market structure, conduct and performance under the existing market designs and on the underlying facts about the ownership structure of capacity and the obligations of load. While the detailed conclusions apply primarily to the existing capacity market design, there are significant conclusions that apply to any capacity market design.

The MMU analyzed market structure and market performance in the PJM Capacity Market for calendar year 2006, including supply, demand, concentration ratios, pivotal suppliers, volumes, prices, outage rates and reliability. 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

6 As a general matter, the annual EFORd data presented in state of the market reports may be revised based on final data submitted after the publication of the reports.

7 In some cases, data for the AEP, DAY, DLCO, Dominion and ComEd Control Zones may be incomplete for the years 2002 and 2003. Only data that have been reported to PJM were used.

nonaffiliated LSEs, the capacity-deficiency penalty structure facing LSEs, supplier knowledge of the penalty structure and supplier knowledge of aggregate market demand if not individual LSE demand, the MMU concludes that the potential for the exercise of market power continues to be high. Market power is endemic to the existing structure of the PJM Capacity Market.

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. This is the case for the existing capacity market design as well as for the RPM. 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. 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. 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. In PJM, in 2006, the excess supply was 9,531 MW. There were four individual suppliers who were each larger than 9,531 MW and who were, therefore, each pivotal on a stand-alone basis. In other words, the market design for capacity leads, almost unavoidably, to structural market power. 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. But, 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.[8]

The analysis of capacity markets begins with market structure, which provides the framework for the actual behavior or conduct of market participants. The analysis also examines participant behavior in the context of market structure. In a competitive market structure, market participants are constrained to behave competitively. In a competitive market structure, competitive behavior is profit maximizing behavior. Finally, the analysis examines market performance results. The actual performance of the market, measured by price and the relationship between price and marginal cost, results from the interaction of these elements. For example, at times market participants behave in a competitive manner even within a noncompetitive market structure. This may result from the relationship between supply and demand and the degree to which one or more suppliers are singly or jointly pivotal. This may result from the short-run, net position of individual suppliers with structural market power. This may also result from a conscious choice by market participants to behave in a competitive manner based on perceived regulatory scrutiny or other reasons, even when the market structure itself does not constrain behavior.

8 The market could be competitive if there were many more suppliers and all were relatively small compared to the size of the market and the level of excess capacity, but this is unlikely to occur.

The MMU found serious market structure issues, but no exercise of market power in the PJM Capacity Market. The behavior of market participants in the context of the market structure and the supply and demand fundamentals offset these market structure issues in the PJM Capacity Market in 2006. The PJM Capacity Market results were competitive during 2006.

The new RPM capacity market design represents a significant advance over the current capacity market design because RPM has explicit market power mitigation rules designed to permit competitive, locational capacity prices while limiting the exercise of market power. The RPM construct appears consistent with the appropriate market design objectives of permitting competitive prices to reflect local scarcity conditions while explicitly limiting market power. The MMU recommends the implementation of the rules included in PJM's filed RPM Tariff to stimulate competition, to provide direct incentives for performance, to provide locational price signals, to provide forward auctions to permit competition from new entrants and to incorporate explicit market power mitigation rules. The RPM capacity market design explicitly provides that competitive prices can reflect local scarcity while not relying on the exercise of market power to achieve that design objective and explicitly limits the exercise of market power via the application of the three pivotal supplier test.

Market Structure

The MMU analyzed sources of supply of and demand for capacity, market concentration in the PJM CCM and the PJM Capacity Market, internal and external bilateral capacity transactions and ALM activity.

Supply

System net excess capacity can be determined using unforced capacity, capacity obligation, the sum of members' excesses and the sum of members' deficiencies. Table 5-1 and Figure 5-1 present these data for 2006.[9] Unforced capacity includes capacity imports and exports. Net excess is the net pool position, calculated by subtracting total capacity obligation from total capacity resources. Since total capacity obligation includes expected total load plus a reserve margin, a pool net excess position of zero is consistent with established reliability objectives.

The amount of capacity resources in PJM on any day reflects the addition of new resources, the retirement of old resources and the importing or exporting of capacity resources. These daily changes are functions of market forces. The total pool capacity obligation is set annually via an administrative process. During 2006, unforced capacity and obligations remained relatively constant in the PJM Capacity Market as compared to the 2005 ComEd PCI period.[10] Average unforced capacity decreased by 298 MW from 152,780 MW to 152,482 MW, a decrease of 0.2 percent. Average load obligations increased 168 MW or 0.1 percent from 142,783 MW to 142,951 MW. During this period, capacity resources exceeded capacity obligations in PJM on every day and the daily average net excess was 9,531 MW (6.7 percent of average obligation), a decrease of 466 MW from the average net excess of 9,997 MW for the 2005 ComEd PCI period (7.0 percent of average obligation).

9 These data are posted on a monthly basis at www.pjm.com under the PJM Market Monitoring Unit link.

10 Data for this period are presented in the *2006 State of the Market Report,* Volume II, Appendix E, "Capacity Market."

Table 5-1 PJM capacity summary (MW): Calendar year 2006

	Mean	Standard Deviation	Minimum	Maximum
Installed Capacity	162,571	349	162,008	163,097
Unforced Capacity	152,482	186	152,176	152,887
Obligation	142,951	121	142,461	143,152
Sum of Excess	9,531	205	9,037	10,047
Sum of Deficiency	0	0	0	0
Net Excess	9,531	205	9,037	10,047
Imports	3,093	201	2,769	3,333
Exports	4,958	404	4,401	5,668
Net Exchange	(1,865)	560	(2,616)	(1,114)
Unit-Specific Transactions	15,548	504	14,694	16,044
Capacity Credit Transactions	145,404	3,742	140,345	155,060
Internal Bilateral Transactions	160,952	3,543	155,750	170,680
Daily Capacity Credits	3,013	332	2,268	3,962
Monthly Capacity Credits	1,572	382	996	2,067
Multimonthly Capacity Credits	4,533	1,154	2,484	5,783
All Capacity Credits	9,118	1,424	7,103	11,720
ALM Credits	1,828	180	1,642	2,042

Figure 5-1 Capacity obligation for the PJM Capacity Market: Calendar year 2006

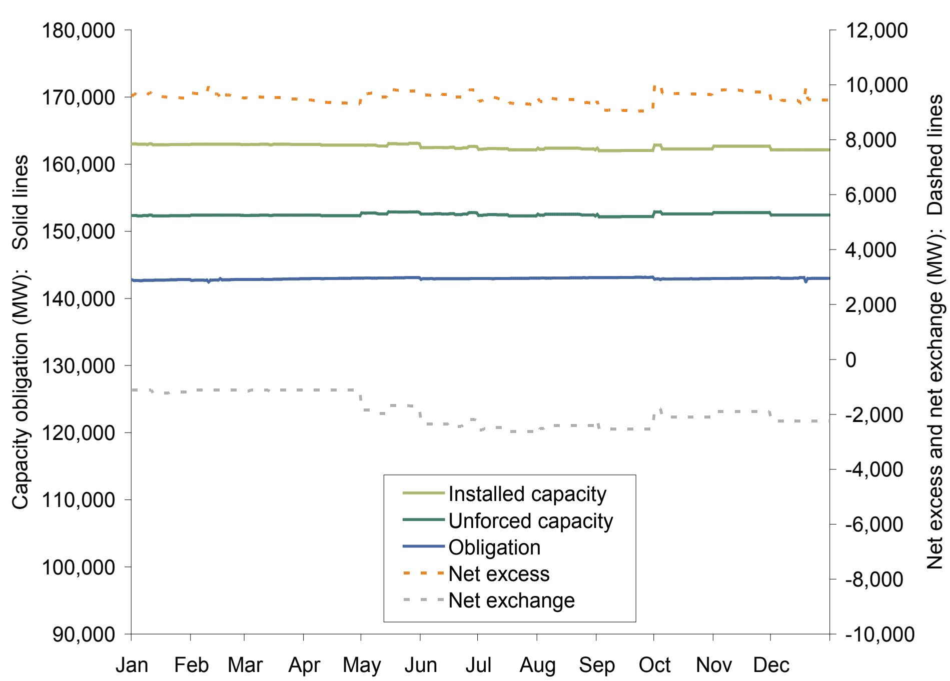
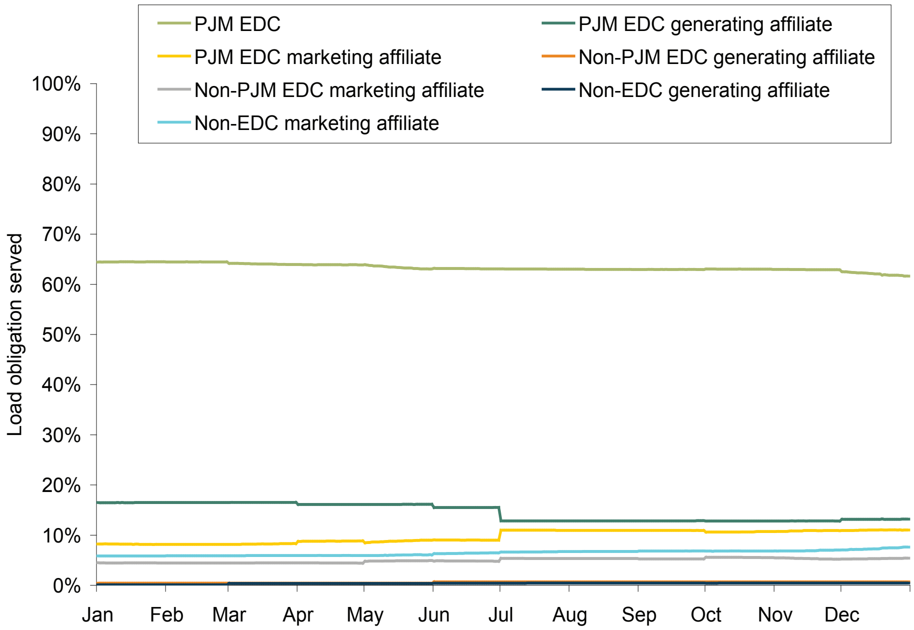


Figure 5-2 PJM Capacity Market load obligation served (Percent): Calendar year 2006



Demand

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.

During 2006, PJM EDCs and their affiliates maintained a large market share of load obligations in the PJM Capacity Market, together averaging 87.6 percent (See Figure 5-2 and Table 5-2.), down slightly from 88.5 percent for the 2005 ComEd PCI period. The combined market share of LSEs not affiliated with any EDC and of non-PJM EDC affiliates averaged 12.4 percent, up from 11.5 percent for the 2005 ComEd PCI period.

Load-serving entities can meet their load obligations through self-supply,[11] the PJM CCM or bilateral contracts with third parties. As shown in Table 5-3, Table 5-4 and Table 5-5, reliance on these options varied by market sector.[12] During 2006, PJM EDCs, some of which still owned generating assets (although as a whole not enough to meet their load obligations), self-supplied an average of 56.7 percent of their load obligations with their remaining obligations being supplied through bilateral contracts with third parties (45.8 percent) and the PJM CCM (-0.1 percent). The self-supply percentage is up from the 2005 ComEd PCI period value of 56.0 percent, while the bilateral contract percentage also increased from 45.6 percent for the 2005 ComEd PCI period. In 2006, entities in this sector, on average, purchased more capacity credits in the PJM CCM or through bilateral contracts with third parties than were required to meet their obligation, resulting in an average net excess of 2,171 MW (2.4 percent of obligation) as compared to a 2005 ComEd PCI period average net excess of 2,268 MW (2.1 percent of obligation) for this sector.

In the 2005 ComEd PCI period and in 2006, all generating affiliate sectors owned more capacity than their load obligations, were net capacity credit sellers in either the PJM CCM or through bilateral contracts and remained in higher net excess positions as a percentage of load obligations than the other sectors. All marketing affiliates, each of which was a net capacity credit buyer in either the PJM CCM or through bilateral contracts, bought slightly more capacity credits than required to meet their obligation and were in lower net excess positions than the other sectors in both periods. Volumes and percentages of load obligations for self-supply, the CCM and bilateral contracts for all generating affiliate and marketing affiliate sectors were approximately the same for the 2005 ComEd PCI period and for 2006.

11 Self-supply is defined as the unforced MW of the units owned by an entity.

12 Negative values in the “Capacity Credit Market” and in the “Net Bilateral Contracts” columns mean that a sector sold more capacity credits than it purchased for the relevant time period. A positive number means that a sector purchased more capacity credits than it sold for the relevant time period.

Table 5-2 PJM capacity market load obligation served: Calendar year 2006

	Average 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
Jan	92,037	23,520	11,694	606	6,374	144	8,361	142,736
Feb	92,032	23,553	11,653	606	6,336	157	8,419	142,756
Mar	91,519	23,617	11,763	606	6,372	534	8,453	142,864
Apr	91,367	23,029	12,580	606	6,369	534	8,488	142,973
May	90,688	23,075	12,586	607	6,963	534	8,607	143,060
Jun	90,230	22,162	12,877	1,005	6,923	610	9,131	142,938
Jul	90,138	18,361	15,693	1,006	7,649	616	9,515	142,978
Aug	90,104	18,375	15,673	1,006	7,630	618	9,651	143,057
Sep	90,115	18,400	15,663	1,006	7,548	618	9,771	143,121
Oct	90,069	18,319	15,200	1,003	7,951	617	9,754	142,913
Nov	90,010	18,345	15,521	1,004	7,624	621	9,881	143,006
Dec	88,767	18,825	15,726	1,005	7,597	626	10,454	143,000
Average	90,580	20,779	13,901	840	7,118	521	9,212	142,951
Percent of Total Obligation	63.4%	14.5%	9.7%	0.6%	5.0%	0.4%	6.4%	100.0%

Table 5-3 PJM capacity market load obligation served by PJM EDCs and affiliates: Calendar year 2006

	PJM EDCs					PJM EDC Generating Affiliates					PJM EDC Marketing Affiliates				
	Self-Supply (MW)	CCM (MW)	Net Bilateral Contracts (MW)	Obligation (MW)	Net Excess (MW)	Self-Supply (MW)	CCM (MW)	Net Bilateral Contracts (MW)	Obligation (MW)	Net Excess (MW)	Self-Supply (MW)	CCM (MW)	Net Bilateral Contracts (MW)	Obligation (MW)	Net Excess (MW)
Jan	51,307	471	42,673	92,037	2,414	65,614	(1,547)	(40,034)	23,520	513	0	1,382	10,573	11,694	261
Feb	51,318	489	42,746	92,032	2,521	65,614	(1,789)	(40,128)	23,553	144	0	1,421	10,515	11,653	283
Mar	51,341	(12)	42,736	91,519	2,546	65,581	(2,127)	(39,617)	23,617	220	0	1,430	10,587	11,763	254
Apr	51,340	(104)	42,612	91,367	2,481	65,582	(1,827)	(40,137)	23,029	589	0	1,437	11,358	12,580	215
May	51,340	(66)	42,364	90,688	2,950	66,692	(2,815)	(40,048)	23,075	754	0	1,868	10,955	12,586	237
Jun	51,450	1	40,245	90,230	1,466	66,974	(1,556)	(40,383)	22,162	2,873	0	3,083	10,269	12,877	475
Jul	51,471	(257)	40,956	90,138	2,032	66,979	(1,774)	(43,970)	18,361	2,874	0	3,651	12,115	15,693	73
Aug	51,481	48	40,368	90,104	1,793	66,954	(2,164)	(43,680)	18,375	2,735	0	3,587	12,167	15,673	81
Sep	51,458	(150)	40,568	90,115	1,761	66,788	(1,791)	(43,753)	18,400	2,844	0	3,519	12,250	15,663	106
Oct	51,255	(234)	40,859	90,069	1,811	66,974	(2,702)	(43,146)	18,319	2,807	0	3,640	11,674	15,200	114
Nov	51,255	(338)	40,954	90,010	1,861	66,974	(2,314)	(43,467)	18,345	2,848	0	3,611	12,036	15,521	126
Dec	51,255	(358)	40,298	88,767	2,428	66,619	(2,326)	(43,233)	18,825	2,235	0	3,713	12,260	15,726	247
Average	51,356	(46)	41,441	90,580	2,171	66,451	(2,065)	(41,812)	20,779	1,795	0	2,703	11,403	13,901	205
Percent of Total Obligation	56.7%	(0.1%)	45.8%	102.4%	2.4%	319.8%	(9.9%)	(201.2%)	108.7%	8.7%	0.0%	19.4%	82.0%	101.4%	1.4%

Table 5-4 PJM capacity market load obligation served by non-PJM EDC affiliates: Calendar year 2006

	Non-PJM EDC Generating Affiliates					Non-PJM EDC Marketing Affiliates				
	Self-Supply (MW)	CCM (MW)	Net Bilateral Contracts (MW)	Obligation (MW)	Net Excess (MW)	Self-Supply (MW)	CCM (MW)	Net Bilateral Contracts (MW)	Obligation (MW)	Net Excess (MW)
Jan	12,908	(316)	(11,021)	606	965	0	660	6,720	6,374	1,006
Feb	12,908	(285)	(11,076)	606	941	0	626	6,720	6,336	1,010
Mar	12,908	(34)	(11,355)	606	913	0	755	6,780	6,372	1,163
Apr	12,908	(141)	(11,201)	606	960	0	822	6,725	6,369	1,178
May	12,908	(69)	(11,480)	607	752	0	1,107	6,386	6,963	530
Jun	12,862	(535)	(10,892)	1,005	430	0	792	6,403	6,923	272
Jul	12,862	(512)	(10,653)	1,006	691	0	1,031	6,882	7,649	264
Aug	12,862	(487)	(10,659)	1,006	710	0	854	7,129	7,630	353
Sep	12,538	(783)	(10,104)	1,006	645	0	878	6,827	7,548	157
Oct	12,625	(231)	(10,544)	1,003	847	0	971	7,218	7,951	238
Nov	12,625	(228)	(10,490)	1,004	903	0	641	7,253	7,624	270
Dec	12,625	(231)	(10,460)	1,005	929	0	1,165	6,725	7,597	293
Average	12,795	(320)	(10,828)	840	807	0	861	6,815	7,118	558
Percent of Total Obligation	1,523.0%	(38.1%)	(1,288.9%)	196.0%	96.0%	0.0%	12.1%	95.7%	107.8%	7.8%

Table 5-5 PJM capacity market load obligation served by non-EDC affiliates: Calendar year 2006

	Non-EDC Generating Affiliates					Non-EDC Marketing Affiliates				
	Self-Supply (MW)	CCM (MW)	Net Bilateral Contracts (MW)	Obligation (MW)	Net Excess (MW)	Self-Supply (MW)	CCM (MW)	Net Bilateral Contracts (MW)	Obligation (MW)	Net Excess (MW)
Jan	23,671	(727)	(18,666)	144	4,134	0	76	8,581	8,361	296
Feb	23,684	(955)	(18,586)	157	3,986	0	493	8,690	8,419	764
Mar	23,683	(587)	(18,731)	534	3,831	0	575	8,473	8,453	595
Apr	23,634	(701)	(18,882)	534	3,517	0	514	8,406	8,488	432
May	23,617	(806)	(18,568)	534	3,709	0	782	8,614	8,607	789
Jun	23,647	(1,223)	(18,426)	610	3,388	0	(562)	10,456	9,131	763
Jul	23,624	(1,352)	(18,250)	616	3,406	0	(787)	10,365	9,515	63
Aug	23,613	(1,361)	(18,256)	618	3,378	0	(476)	10,510	9,651	383
Sep	23,927	(1,202)	(18,933)	618	3,174	0	(470)	10,628	9,771	387
Oct	23,825	(1,107)	(18,671)	617	3,430	0	(336)	10,556	9,754	466
Nov	23,826	(1,028)	(18,828)	621	3,349	0	(343)	10,649	9,881	425
Dec	24,181	(1,604)	(18,968)	626	2,983	0	(358)	11,138	10,454	326
Average	23,745	(1,055)	(18,646)	521	3,523	0	(77)	9,761	9,212	472
Percent of Total Obligation	4,555.0%	(202.5%)	(3,577.0%)	775.5%	675.5%	0.0%	(0.8%)	106.0%	105.2%	5.2%

Market Concentration

Market concentration is assessed using market shares, concentration ratios and residual supply indices as measures. Concentration ratios are a summary measure of market share, a key element of market structure.[13] The residual supply index (RSI) is a measure of the extent to which one or more generation owners are pivotal suppliers in a market.

High Herfindahl-Hirschman Index (HHI) concentration ratios mean that a comparatively small number of sellers dominates a market, while low concentration ratios mean that a larger number of sellers shares market sales more equally. Concentration measures must be applied carefully in assessing the competitiveness of markets. Low aggregate market concentration ratios do not establish that a market is competitive, that market participants cannot exercise market power or that concentration is not high in particular geographic market areas. High aggregate market concentration ratios do, however, indicate an increased potential for market participants to exercise market power.

The RSI measure recognizes that market shares and concentration ratios do not measure the extent to which an owner's generation facilities are pivotal to meeting demand. A generation owner or owners are pivotal if the capacity of the owners' generation facilities is needed to meet the demand for capacity. When a generation owner or owners are pivotal, they have the ability to affect market price, regardless of market share. In effect, they have a monopoly position at the margin. The RSI is a general measure that can be used with any number of pivotal suppliers. An RSI greater than 1.0 for three generation owners is a reasonable benchmark for a competitive market structure but does not guarantee that there is no market power, while an RSI less than 1.0 for three or fewer generation owners clearly indicates a significant ability to exercise market power. If the RSI is greater than 1.0, the supply of the specific generation owner or owners is not needed to meet market demand and those generation owners have a reduced ability to unilaterally influence market price. If the RSI is less than 1.0, the supply owned by the specific generation owner, or owners, is needed to meet market demand and the generation owners are pivotal suppliers with a significant ability to influence market prices.[14]

The MMU calculated HHI and RSI metrics for the PJM Capacity Credit Market and for the PJM Capacity Market during calendar year 2006.

Capacity Credit Market

The HHI analysis indicates that, on average, the PJM CCM in 2006 exhibited moderate levels of concentration in the Daily CCM and high levels of concentration in the Monthly and Multimonthly CCM.[15] As shown in Table 5-6, HHIs for the Daily CCM averaged 1576 during this period, with a maximum of 2635 and a minimum of 867 (four firms with equal market shares would result in an HHI of 2500).[16] The highest market share for any entity in one daily auction was 44.9 percent, while the highest average daily market share for

13 See *2006 State of the Market Report*, Volume II, Section 2, "Energy Market, Part 1," for a more detailed discussion of concentration ratios and the HHI and of the calculation of the residual supply index.

14 For additional information on the three pivotal supplier test and its calculation, see *2006 State of the Market Report*, Volume II, Appendix J, "Three Pivotal Supplier Test."

15 The HHI calculations use capacity cleared in each respective auction. This is consistent with the appropriate definition of the market. In prior state of the market reports, HHI calculations used total capacity offered in each respective auction. In general, the calculated HHIs in 2006 are higher using cleared capacity than offered capacity.

16 PJM CCM results are reported by the time period during which the auction was run and not by the time period to which the auction applies.

any entity across all of the daily auctions was 28.8 percent.[17] Of 365 daily auctions, 82 (22.5 percent) had an HHI greater than 1800. HHIs for the longer-term Monthly and Multimonthly CCM averaged 3611, with a maximum of 10000 and a minimum of 1691 (three firms with equal market shares would result in an HHI of 3333). The highest market share for any entity in one monthly/multimonthly auction was 100.0 percent, while the highest average market share for any entity across all of the monthly/multimonthly auctions was 30.5 percent. All but one of the 65 monthly/multimonthly auctions (98.5 percent) had an HHI greater than 1800.

Table 5-6 PJM CCM HHI: Calendar year 2006

	Daily Market HHI	Monthly and Multimonthly Market HHI
Average	1576	3611
Minimum	867	1691
Maximum	2635	10000
Highest Market Share (One Auction)	44.9%	100.0%
Highest Market Share (All Auctions)	28.8%	30.5%
# Auctions	365	65
# Auctions with HHI >1800	82	64
% Auctions with HHI >1800	22.5%	98.5%

The RSI analysis indicates that there were significant market structure issues in both the Daily CCM and the Monthly and Multimonthly CCM for 2006.[18] Table 5-7 shows RSI values for the daily CCM auctions and the monthly and multimonthly CCM auctions. The RSI results for the Daily CCM indicate that all daily auctions had three or fewer jointly pivotal suppliers. The average three pivotal supplier RSI level for calendar year 2006 was 0.50, while one supplier was individually pivotal in 329 of the 365 daily auctions (90.1 percent). The RSI results for the Monthly and Multimonthly CCM indicate that all of the auctions had three or fewer jointly pivotal suppliers. The average three pivotal supplier RSI was 0.17, while one supplier was individually pivotal in 64 of the 65 monthly auctions (98.5 percent).

17 The market share for an entity across all auctions is calculated as the average market share for the entity for all 365 daily auctions or all 65 monthly and multimonthly auctions. For auctions in which an entity did not participate or clear, the entity was assigned a zero market share in the calculation of the multi-auction market share.

18 The RSI calculations use a market definition that includes those offers with offer prices less than or equal to 150 percent of the capacity market-clearing price for the relevant market. This is consistent with the appropriate definition of competitive offers. In prior state of the market reports, RSI calculations for the capacity market included all offers. In general, use of a threshold for competitive offers reduced calculated 2006 RSI values and increased the number of 2006 auctions with three or fewer pivotal suppliers when compared to calculations that assume all offers are competitive.

Table 5-7 PJM CCM three pivotal supplier residual supply index (RSI): Calendar year 2006 [19]

	Daily Market RSI_3	Monthly and Multimonthly Market RSI_3
Average	0.50	0.17
Minimum	0.26	0.00
Maximum	0.90	0.54
# Auctions	365	65
# Auctions with = 1 Pivotal Supplier	329	64
% Auctions with = 1 Pivotal Supplier	90.1%	98.5%
# Auctions with <= 3 Pivotal Suppliers	365	65
% Auctions with <= 3 Pivotal Suppliers	100.0%	100.0%

Capacity Market

The market structure analyses presented above focus on the operation of the PJM CCM which included only 6.4 percent of total capacity obligations traded in PJM-operated markets in 2006. To provide a more complete assessment of competition in the PJM Capacity Market, the MMU also analyzed total capacity without regard to whether it was sold in the PJM-operated market, through bilateral agreements or self-supplied.

The market structure in the aggregate PJM Capacity Market is shown for the beginning of each interval (January 1, June 1 and October 1) and for December 31 in Table 5-8.

Total capacity ownership was at low concentration levels throughout the year, with HHIs at 925 on January 1 and December 31.[20] The highest market share declined from 16.7 percent to 16.4 percent. There was a single pivotal supplier throughout the year, with four individual suppliers who were each pivotal on a stand-alone basis. In other words, the capacity owned by any of these individually pivotal suppliers was required in order to meet the total demand for capacity (capacity obligation) in PJM.

The market defined by total capacity exhibits significant market structure issues, measured by the pivotal supplier results.[21] As a general matter, the results of the three pivotal supplier test can differ from the results of the HHI and market share tests and total capacity illustrates that situation. As in this case, the three pivotal supplier test can show the existence of structural market power when the HHI is less than 2500, and the maximum market share is less than 20 percent. The three pivotal supplier test can also show the absence of market power when the HHI is greater than 2500, and the maximum market share is greater than 20 percent. The three pivotal supplier test is more accurate than the HHI and market share tests because it focuses on the relationship between demand and the most significant aspect of the ownership structure of supply available to meet it.

19 RSI_x is the residual supply index, using "x" pivotal suppliers.

20 The aggregate PJM Capacity Market is not a formal market as there is no single clearing price, but includes all capacity in the PJM footprint. The measures of market structure include all capacity as there is no market-clearing price or quantity. These measures of market structure are descriptive of the overall patterns of capacity ownership in the PJM footprint.

21 See *2006 State of the Market Report*, Volume II, Appendix J, "Three Pivotal Supplier Test."

Table 5-8 PJM capacity: Calendar year 2006

	01-Jan	01-Jun	01-Oct	31-Dec
Unforced Capacity (MW)	152,349	152,581	152,887	152,440
Obligation (MW)	142,772	142,864	142,896	142,992
HHI	925	930	928	925
Highest Market Share	16.7%	16.4%	16.4%	16.4%
RSI_1	0.89	0.89	0.89	0.89
RSI_3	0.58	0.59	0.59	0.58
Pivotal Suppliers	1	1	1	1

External and Internal Capacity Transactions

PJM capacity resources may be traded bilaterally within PJM and between PJM and external markets.

External Capacity Transactions

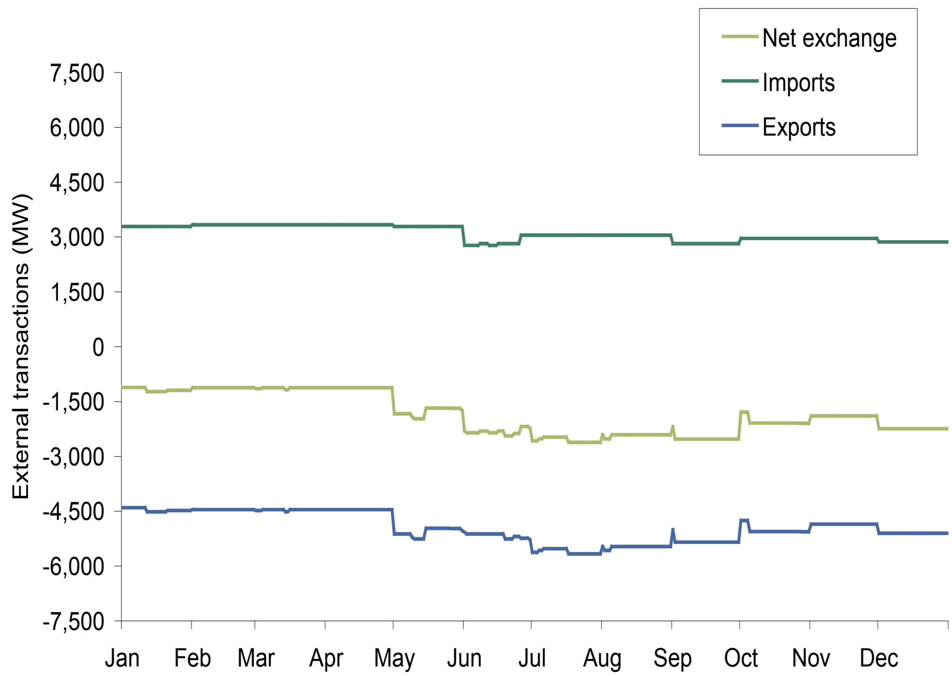
External bilateral transactions include imports of capacity resources from other control areas and exports of capacity resources to control areas outside of PJM.[22] Net exchange is equal to imports less exports.

As shown in Table 5-1 and Figure 5-3, Capacity Market participants' external bilateral purchases (i.e., imports) of capacity resources were relatively flat in 2006, averaging 3,093 MW, which was a decrease of 904 MW or 22.6 percent from the average of 3,997 MW for the 2005 ComEd PCI period.

During 2006, an average of 4,958 MW of capacity resources was exported from the PJM Capacity Market, which was a decrease of 74 MW or 1.5 percent from the average of 5,032 MW for the 2005 ComEd PCI period. The result was an average net exchange of -1,865 MW of capacity resources for 2006, which was a decrease of 830 MW or 80.2 percent from the average net exchange of -1,035 MW for the 2005 ComEd PCI period.

22 The sink (destination) of exports cannot be identified since these data are not required from member companies.

Figure 5-3 External PJM Capacity Market transactions: Calendar year 2006



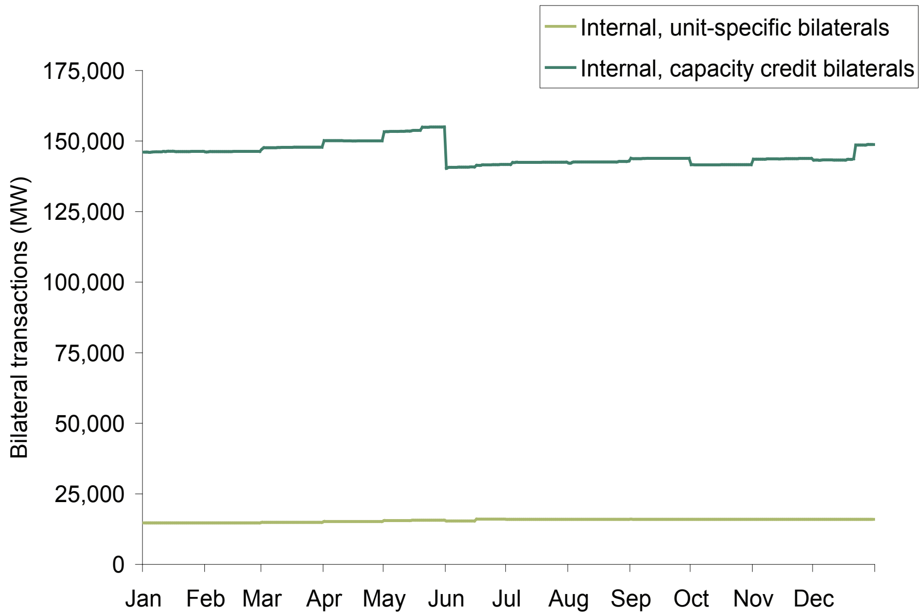
Internal Bilateral Transactions

Internal bilateral transactions are agreements between two parties to buy and sell capacity credits within PJM, but outside of the PJM Capacity Credit Market.[23] Unit-specific transactions are for capacity credits from a specific generating unit while capacity credit transactions are for non unit-specific capacity credits. Both types of transactions may be repeated multiple times among parties, for the same units or credits, with the result that transaction volume can exceed obligation.

During 2006, internal, unit-specific transactions for the PJM Capacity Market averaged 15,548 MW, which was a decrease of 2,806 MW or 15.3 percent from the average of 18,354 MW for the ComEd PCI period. (See Table 5-1 and Figure 5-4.) Internal capacity credit transactions in 2006 averaged 145,404 MW, which was an increase of 7,387 MW or 5.4 percent from the average of 138,017 MW for the 2005 ComEd PCI period. Total internal bilateral transactions in 2006 averaged 160,952 MW, an increase of 4,581 MW or 2.9 percent from the 156,371 MW average for the 2005 ComEd PCI period.

23 As of December 31, 2006, only volumes from internal bilateral transactions were reported to PJM. Pricing data were not required from member companies.

Figure 5-4 Internal bilateral PJM Capacity Market transactions: Calendar year 2006



Active Load Management (ALM) Credits

Active load management (ALM) reflects the ability of individual customers, under contract with their LSE, to reduce specified amounts of load during an emergency. ALM credits, measured in MW of curtailable load, reduce LSE capacity obligations and thus the total PJM capacity obligation.[24]

During 2006, ALM credits in the PJM Capacity Market averaged 1,828 MW, down 214 MW (10.5 percent) from 2,042 MW in the 2005 ComEd PCI period. (See Table 5-1.)

Market Performance

Capacity Credit Market Volumes and Prices

During 2006, PJM operated the Daily, Monthly and Multimonthly CCM. Figure 5-5 and Table 5-12 show prices and volumes for 2006 in PJM's Daily and longer-term CCM. (Also see Table 5-13.) The Daily CCM averaged 3,013 MW of transactions, representing 2.1 percent of the period's 142,951 MW average daily capacity obligation. The average transaction volume for 2006 was 1,408 MW greater than the 2005 ComEd PCI period average of 1,605 MW, which had been 1.1 percent of the 142,783 MW average capacity obligations for the period. The Monthly and Multimonthly CCM averaged 6,105 MW of transactions, which was 4.3 percent of the average daily capacity obligations for 2006 and 705 MW higher than the 2005 ComEd PCI period average of 5,400 MW, which was 3.8 percent of the average capacity obligations for the

24 ALM capacity credits reduce capacity obligations throughout the year. The fixed ALM value for non-summer months (October through May) is calculated by PJM based upon daily values of nominated ALM in the PJM eCapacity system for the summer months.

period. Thus, on average, the CCM accounted for 6.4 percent of all average daily capacity obligations in 2006.

The volume-weighted, average price for 2006 was $1.92 per MW-day in the Daily CCM and $7.60 per MW-day in the Monthly and Multimonthly CCM. The volume-weighted, average price for the entire CCM was $5.73 per MW-day.[25] Prices in the Daily CCM during 2006 were $1.69 higher than the 2005 ComEd PCI period price of $0.23. Prices in the Monthly and Multimonthly CCM were $0.83 higher than the 2005 ComEd PCI period price of $6.77.

As shown in Table 5-9, in the January 1, 2006, Daily CCM prices increased to $79.00 per MW-day from $0.02 per MW-day on December 31, 2005, primarily because of a shift in lower-priced capacity from the daily market to the bilateral market and to a shift in demand from the monthly to the daily market. Although capacity offered into the market increased by 452 MW from December 31 to January 1 and the percentage of available capacity offered into the market increased from 47.3 percent to 50.5 percent, lower-priced offers from capacity sellers were replaced by higher-priced offers from other sellers. In addition, demand also increased by 957 MW from the previous day because of decreased bilateral purchases and decreased purchases in the Monthly and Multimonthly CCM. Prices remained at this level through January 3 because the auctions for the first three days of January had all been run on Friday, December 30, 2005. Daily auctions for Saturday, Sunday and Monday are always run on the preceding Friday, and Tuesday was also run on this day because Monday, January 2, was a PJM holiday. Prices decreased to $50.00 per MW-day on January 4 as capacity owners responded to the higher prices by offering more capacity into the market and reducing their offer prices. Prices eventually fell to $1.00 per MW-day on January 12 and remained near this level throughout the rest of the month.

As shown in Table 5-10, in the July 1, 2006, Daily CCM prices increased to $13.19 per MW-day from $0.10 per MW-day on June 30, 2006, primarily because of a decrease in the amount of low-priced capacity offered and an increase in demand. Capacity offered into the market decreased by 1,009 MW from June 30 to July 1 as several lower-price suppliers shifted to either bilateral sales or higher-priced offers in the Monthly and Multimonthly CCM. In addition, the available capacity not offered into the daily market increased by 877 MW. Demand increased by 201 MW from the previous day because of decreased bilateral purchases. Prices remained at this level through July 5 in part because the auctions for the first three days of July had all been run on Friday, June 30. Daily auctions for Saturday, Sunday and Monday are always run on the preceding Friday. Tuesday was July 4, a PJM holiday, so auctions for July 4 and July 5 were run on Monday, July 3.

On July 7 capacity owners responded to the higher prices by offering more capacity into the market, causing the decrease in prices to $2.50 per MW-day. Offered volumes increased by 417 MW from July 1 to July 7, as some suppliers offered into the daily market part of their net excess that had not been previously offered. Prices rose to $5.00 per MW-day on July 10 and remained near this level for the rest of the month as supply and demand remained relatively stable.

25 Graph and average price data are all in terms of unforced capacity. Capacity credits are, by definition, in terms of unforced capacity.

As shown in Table 5-11 and Table 5-12, Monthly and Multimonthly CCM prices increased in June. The June monthly market price increased as a result of higher offer prices. June multimonthly prices increased because of an increase in demand that resulted from shifts from bilateral contracts to the multimonthly market. Multimonthly CCM prices declined over the remainder of the year as supply and demand came more into balance but still remained higher than January through May.

Table 5-9 Daily available capacity vs. offered capacity: December 31, 2005, to January 12, 2006

	Available Capacity (MW)	Capacity Offered (MW)	Capacity Not Offered (MW)	Percent Offered	Percent Not Offered	Clearing Price ($/MW-day)	Capacity Bid (MW)	Capacity Cleared (MW)
31-Dec-05	12,874	6,084	6,790	47.3%	52.7%	$0.02	2,434	2,434
1-Jan-06	12,967	6,536	6,431	50.5%	49.5%	$79.00	3,391	3,362
2-Jan-06	13,050	6,588	6,462	50.6%	49.4%	$79.00	3,383	3,354
3-Jan-06	13,052	6,594	6,458	50.6%	49.4%	$79.00	3,387	3,358
4-Jan-06	12,982	9,555	3,427	73.6%	26.4%	$50.00	3,359	3,359
5-Jan-06	12,953	9,078	3,875	70.1%	29.9%	$30.00	3,305	3,305
6-Jan-06	12,896	9,466	3,430	73.4%	26.6%	$5.00	3,247	3,247
7-Jan-06	12,966	10,137	2,829	78.2%	21.8%	$3.50	3,300	3,300
8-Jan-06	12,966	10,006	2,960	77.2%	22.8%	$5.00	3,300	3,300
9-Jan-06	12,921	10,009	2,912	77.5%	22.5%	$5.00	3,291	3,291
10-Jan-06	13,013	9,485	3,528	72.9%	27.1%	$2.00	3,295	3,295
11-Jan-06	12,901	9,635	3,266	74.7%	25.3%	$1.05	3,194	3,194
12-Jan-06	12,785	9,440	3,345	73.8%	26.2%	$1.00	3,191	3,191

Table 5-10 Daily available capacity vs. offered capacity: June 30, 2006, to July 12, 2006

	Available Capacity (MW)	Capacity Offered (MW)	Capacity Not Offered (MW)	Percent Offered	Percent Not Offered	Clearing Price ($/MW-day)	Capacity Bid (MW)	Capacity Cleared (MW)
30-Jun-06	13,167	10,705	2,462	81.3%	18.7%	$0.10	3,414	3,414
1-Jul-06	13,035	9,696	3,339	74.4%	25.6%	$13.19	3,615	3,615
2-Jul-06	13,035	9,696	3,339	74.4%	25.6%	$13.19	3,615	3,615
3-Jul-06	13,059	9,693	3,366	74.2%	25.8%	$13.19	3,636	3,636
4-Jul-06	12,737	8,935	3,802	70.2%	29.8%	$13.19	3,258	3,258
5-Jul-06	12,741	9,403	3,338	73.8%	26.2%	$13.19	3,265	3,265
6-Jul-06	12,699	9,788	2,911	77.1%	22.9%	$10.00	3,174	3,174
7-Jul-06	12,791	10,113	2,678	79.1%	20.9%	$2.50	3,258	3,258
8-Jul-06	12,786	9,612	3,174	75.2%	24.8%	$1.24	3,245	3,245
9-Jul-06	12,786	9,612	3,174	75.2%	24.8%	$1.24	3,245	3,245
10-Jul-06	12,801	9,616	3,185	75.1%	24.9%	$5.00	3,265	3,265
11-Jul-06	12,781	10,059	2,722	78.7%	21.3%	$5.00	3,279	3,279
12-Jul-06	12,777	10,052	2,725	78.7%	21.3%	$5.00	3,287	3,287

Table 5-11 Monthly and multimonthly capacity volumes and prices: May to July 2006

	Daily Average (MW)						Weighted-Average Price ($ per MW-day)		
	Monthly Market Purchases	MultiMonthly Market Purchases	Monthly Market Offered	Monthly Market Bid	MultiMonthly Market Offered	MultiMonthly Market Bid	Monthly Clearing Price	MultiMonthly Clearing Price	Combined Clearing Price
May	1,636	3,540	1,357	1,038	1,258	1,315	$1.11	$4.61	$3.50
Jun	1,695	5,509	1,440	1,524	1,778	2,754	$22.08	$12.27	$14.58
Jul	1,678	5,641	2,146	1,098	898	1,429	$1.81	$12.06	$9.71

Figure 5-5 PJM Daily and Monthly/Multimonthly CCM performance: Calendar year 2006

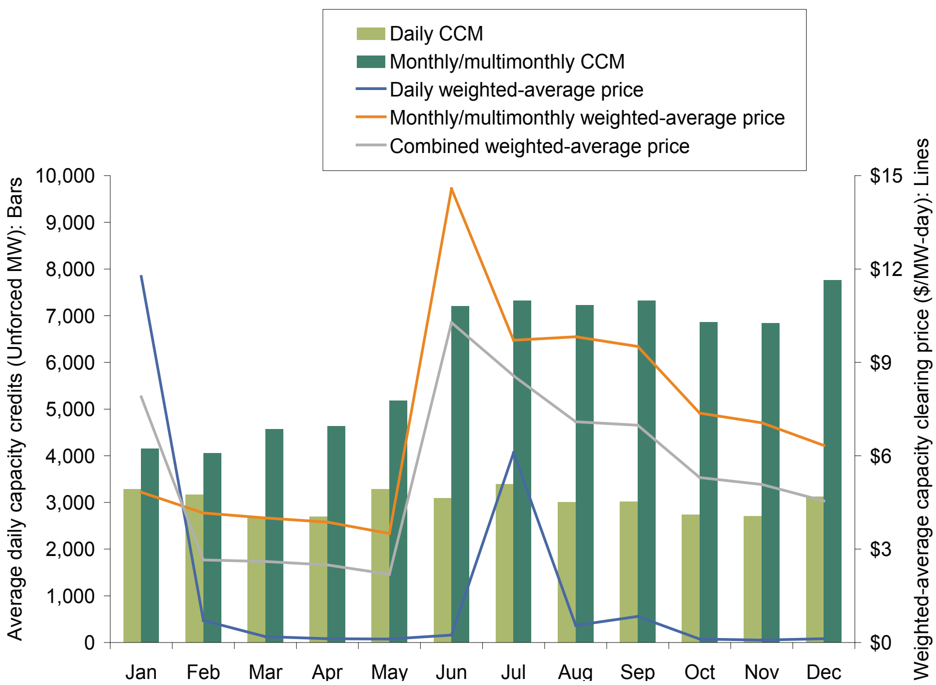


Table 5-12 PJM Capacity Credit Market: Calendar year 2006

	Average Daily Capacity Credits (MW)			Weighted-Average Price ($ per MW-day)		
	Daily CCM	Monthly and Multimonthly CCM	Combined Markets	Daily CCM	Monthly and Multimonthly CCM	Combined Markets
Jan	3,286	4,153	7,439	$11.76	$4.83	$7.89
Feb	3,163	4,058	7,221	$0.71	$4.16	$2.65
Mar	2,662	4,567	7,229	$0.19	$4.00	$2.60
Apr	2,698	4,630	7,328	$0.12	$3.87	$2.49
May	3,278	5,176	8,454	$0.11	$3.50	$2.19
Jun	3,090	7,204	10,294	$0.24	$14.58	$10.28
Jul	3,391	7,319	10,710	$6.10	$9.71	$8.57
Aug	3,007	7,223	10,230	$0.55	$9.82	$7.09
Sep	3,019	7,322	10,341	$0.84	$9.51	$6.98
Oct	2,732	6,859	9,591	$0.11	$7.37	$5.30
Nov	2,702	6,842	9,544	$0.08	$7.06	$5.08
Dec	3,121	7,758	10,879	$0.12	$6.33	$4.55
2006	3,013	6,105	9,118	$1.92	$7.60	$5.73

Calendar Years 1999 through 2006

Figure 5-6 and Table 5-13 show prices and volumes in PJM's Daily and longer-term CCM from June 1999 through December 2006.[26] Since the interval system was introduced in July 2001, overall volume in the CCM has increased; prices have declined and remained relatively stable with the exception of the summer of 2004 and capacity obligations have almost tripled. The share of load obligation traded in both the Daily CCM and in the Monthly and Multimonthly CCM has increased. Daily CCM volume increased from 1.5 percent of average obligation in 2001 to 2.1 percent in 2006. Monthly and multimonthly CCM volume increased from 2.2 percent of obligation in 2001 to 4.3 percent of average obligation in 2006.

26 After June 1, 1999, the PJM Capacity Credit Market was based on unforced capacity. Before this date, the market had been based on installed capacity.

Figure 5-6 PJM Daily and Monthly/Multimonthly CCM performance: June 1999 to December 2006

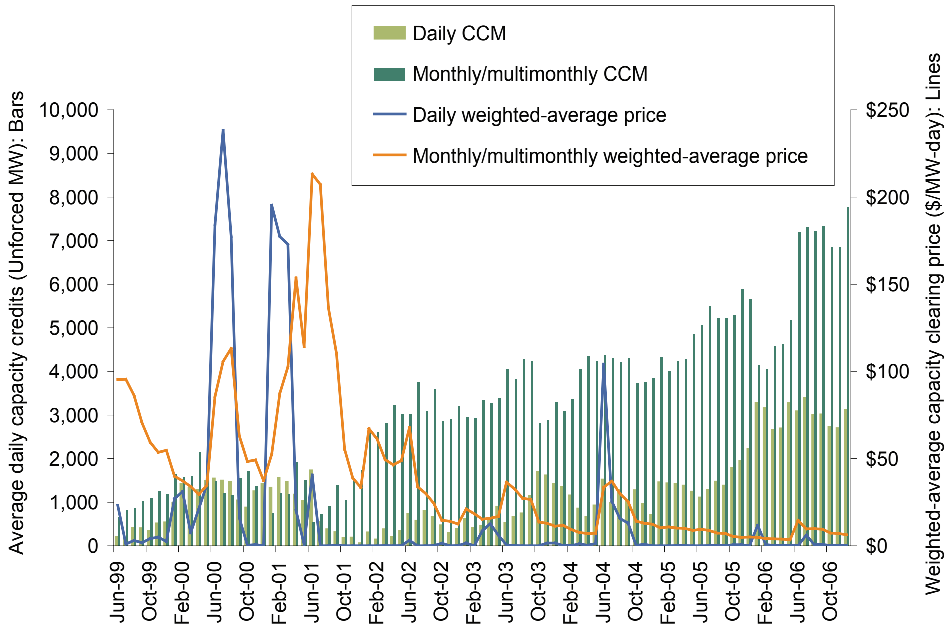


Table 5-13 PJM Capacity Credit Market: Calendar years 1999 to 2006

	Average Daily Capacity Credits						Weighted-Average Price ($ per MW-day)		
	Daily CCM (MW)	Percent of Obligation	Monthly and Multimonthly CCM (MW)	Percent of Obligation	Combined Markets (MW)	Percent of Obligation	Daily CCM	Monthly and Multimonthly CCM	Combined Markets
1999	374	0.7%	981	1.9%	1,355	2.6%	$4.69	$70.36	$52.24
2000	1,304	2.5%	1,561	3.0%	2,865	5.4%	$69.39	$53.16	$60.55
2001	829	1.5%	1,197	2.2%	2,026	3.7%	$87.98	$100.43	$95.34
2002	450	0.8%	3,066	5.3%	3,516	6.1%	$0.59	$38.21	$33.40
2003	907	1.4%	3,436	5.2%	4,343	6.6%	$2.14	$21.57	$17.51
2004	1,062	1.4%	3,966	5.1%	5,028	6.5%	$17.21	$17.88	$17.74
2005	1,516	1.2%	4,968	3.9%	6,484	5.1%	$0.15	$7.94	$6.12
2006	3,013	2.1%	6,105	4.3%	9,118	6.4%	$1.92	$7.60	$5.73

Generator Performance

Generator performance is a function of incentives from energy and capacity markets as well as the physical nature of the units and the level of expenditures made to maintain the capability of the units. 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). In prior state of the market reports, the generator performance analysis was based solely on the capacity resources in the PJM Mid-Atlantic Region and the AP Control Zone. The generator performance analysis for the *2006 State of the Market Report* includes all PJM capacity resources for which there are data in the PJM GADS database.

Generator Performance Factors

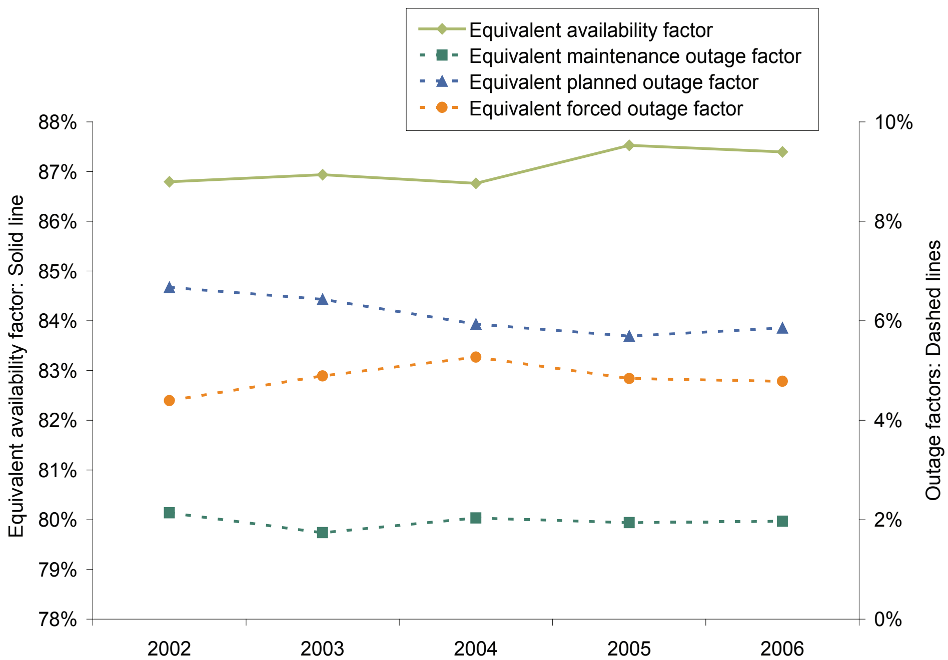
Generator performance factors are based on a defined period, usually a year, and are directly comparable.[27] Performance factors include the equivalent availability factor (EAF), the equivalent maintenance outage factor (EMOF), the equivalent planned outage factor (EPOF) and the equivalent forced outage 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 decreased from 87.6 percent in 2005 to 87.4 percent in 2006. The EFOF decreased by 0.1 percentage points from 2005 to 2006 while the EPOF increased by about 0.2 percentage points and the EMOF did not change. [28] (See Figure 5-7.)

27 Data from all PJM capacity resources for the years 2002 through 2006 were analyzed. In the *2005 State of the Market Report*, data from only the PJM Mid-Atlantic Region and the AP Control Zone for the years 1994 through 2005 were analyzed.

28 The performance factor data include all units from the PJM Control Area. Data for the year 2006 may be incomplete as of the download date as corrections can be made at anytime with permission from the PJM GADS administrators. Data are for 12 months ended December 31, 2006, as downloaded from the PJM GADS database on January 23, 2007.

Figure 5-7 PJM equivalent outage and availability factors: Calendar years 2002 to 2006



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. 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[29] calculations use historical data, including equivalent forced outage hours,[30] service hours, average forced outage duration, average run time, average time between unit starts, available hours and period hours.[31] Between 2002 and 2004, the average PJM EFORd increased from 5.4 percent in 2002 to 6.7 percent in 2003 and 7.3 percent in 2004 before it decreased to 6.6 percent in 2005 and 6.4 percent in 2006.[32] Figure 5-8 shows the average EFORd since 2002 for all units in the PJM Control Area.

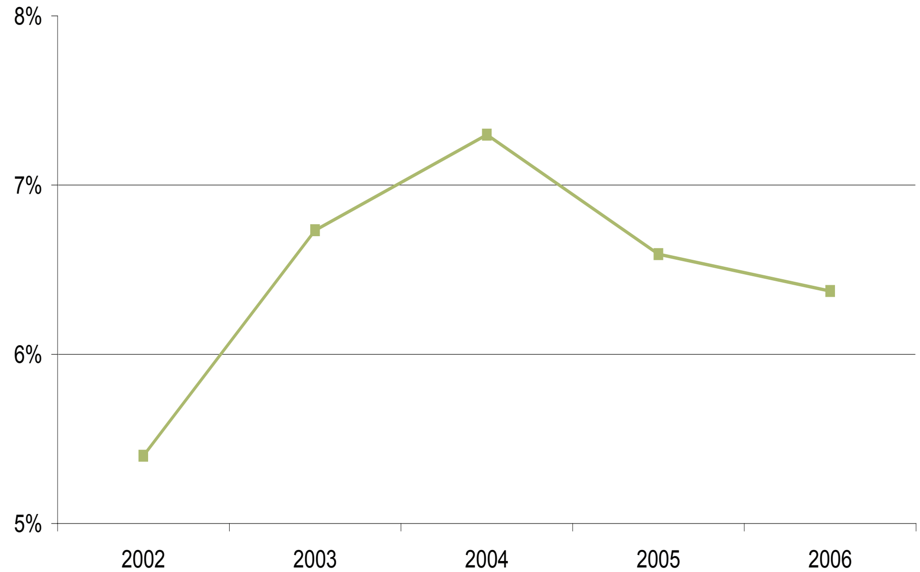
29 EFORd was calculated using all units that have participated in the PJM Capacity Market. Data for these units are contained in the PJM eGADS database. PJM systemwide EFORd is a capacity-weighted average of individual unit EFORd.

30 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.

31 See PJM "Manual 22: Generator Resource Performance Indices," Revision 14 (June 1, 2005), Equation 8.

32 Data are for the 12 months ended December 31, 2006, as downloaded from the PJM GADS database on January 23, 2007. Data for the year 2006 may be incomplete as of the download date as corrections can be made at anytime with permission from the PJM GADS administrators.

Figure 5-8 Trends in the PJM equivalent demand forced outage rate (EFORd): Calendar years 2002 to 2006 [33]



Components of Change in EFORd

Table 5-14 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.[34] Forced MW for a unit type is the EFORd multiplied by the generator's net dependable summer capability.

33 Data for 2002 and 2003 are incomplete for some units in newly integrated areas. Available information supports the conclusion that there is no significant impact on the results of the analysis.

34 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.

Table 5-14 Contribution to EFORd for specific unit types (Percentage points): Calendar years 2002 to 2006

	2002	2003	2004	2005	2006	Change in 2006 from 2005
Combined Cycle	0.2	0.4	0.6	0.7	0.5	(0.2)
Combustion Turbine	0.5	1.1	1.3	1.5	1.4	(0.1)
Diesel	0.0	0.0	0.0	0.0	0.0	0.0
Hydroelectric	0.1	0.1	0.2	0.1	0.1	0.0
Nuclear	0.4	0.6	0.6	0.3	0.3	0.0
Steam	4.2	4.5	4.6	4.0	4.1	0.1
Total	5.4	6.7	7.3	6.6	6.4	(0.2)

The decrease in overall PJM Control Area EFORd of 0.2 percentage points (a 3.0 percent decline) between 2005 and 2006 resulted primarily from better performance of combustion turbine units (501 generating units), combined-cycle units (103 generating units) and nuclear units (32 generating units) which together accounted for 0.3 of the 0.2 percentage point overall decrease.[35] This decrease was partially offset by the decline in the performance of fossil steam units (316 generating units) Fossil steam units accounted for an increase of 0.1 percentage points in the overall total.

Of the 1,231 generating units in the EFORd analysis, during calendar year 2006, 498 units had decreased EFORds, 443 units had increased EFORds and the remaining 290 units had unchanged EFORds. Had the 498 units with lower forced outage rates not experienced rates lower than the average, the 2006 EFORd would have been 8.3 percent.

Changes in outage rates by unit type and changes in capacity by unit type combined to produce the observed impacts on the system EFORd. Since total capability from both combustion turbine and combined-cycle units remained nearly the same from year to year, the decreased forced outage rates for these unit types was the reason for their contribution to the decreased system EFORd.

Table 5-15 shows the relative contributions of EFORd and capacity to EFORd levels by unit type and for the system. Approximately 24 percent of the contribution of combustion turbine units to the decreased system EFORd was the result of reduced combustion turbine capacity while 76 percent of the contribution of combustion turbine units to the decreased system EFORd was the result of lower EFORd levels for combustion turbines. Approximately minus 9 percent of the contribution of combined-cycle units to the decreased system EFORd was the result of increased combined-cycle capacity while 109 percent of the contribution of combined-cycle units to the decreased system EFORd was the result of lower EFORd levels for combined-cycle units. Overall, 75 percent of the decrease in EFORd from 2005 to 2006 was the result of decreased EFORd for specific unit types while the balance was the result of the change in the mix of capacity by unit type.

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

Table 5-15 Percent change in contribution to EFORd (Unit type): 2006 compared to 2005

	Contribution Change Due to Capacity	Contribution Change Due to EFORd
Combined Cycle	(9.0%)	109.0%
Combustion Turbine	23.8%	76.2%
Diesel	138.0%	(38.0%)
Hydroelectric	15.2%	84.8%
Nuclear	0.0%	100.0%
Steam	(98.0%)	198.0%
All Unit Types	24.6%	75.4%

Table 5-16 Five-year PJM EFORd data comparison to NERC five-year average for different unit types: Calendar years 2002 to 2006

	2002	2003	2004	2005	2006	NERC 2001 to 2005
Combined Cycle	4.7%	5.4%	5.5%	5.4%	4.1%	NA
Combustion Turbine	4.0%	8.2%	8.6%	9.7%	9.1%	9.4%/10.3%
Diesel	6.0%	7.0%	7.9%	13.8%	13.5%	13.5%
Hydroelectric	1.1%	2.2%	3.9%	2.6%	1.9%	3.9%
Nuclear	2.0%	3.2%	3.2%	1.6%	1.4%	4.2%
Steam	7.4%	8.2%	9.1%	8.0%	8.2%	6.4%
Overall	5.4%	6.7%	7.3%	6.6%	6.4%	NA

Table 5-16 compares PJM EFORd data by unit type to North American Electric Reliability Council (NERC) data for corresponding unit types.[36] NERC has not published average EFORd for combined-cycle units because the new calculations for combined-cycle blocks are not ready and have not been tested.[37] The 2006 PJM forced outage rates for combustion turbines, for hydroelectric units and for nuclear units were below the NERC five-year average. The 2006 PJM EFORd for diesel units was at the NERC average. The 2006 PJM EFORd for fossil steam units exceeded the NERC average.[38]

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.[39] Figure 5-9 shows the increased contribution of peaking units to system average EFORd

36 The PJM data include all combustion turbines as a single unit type.

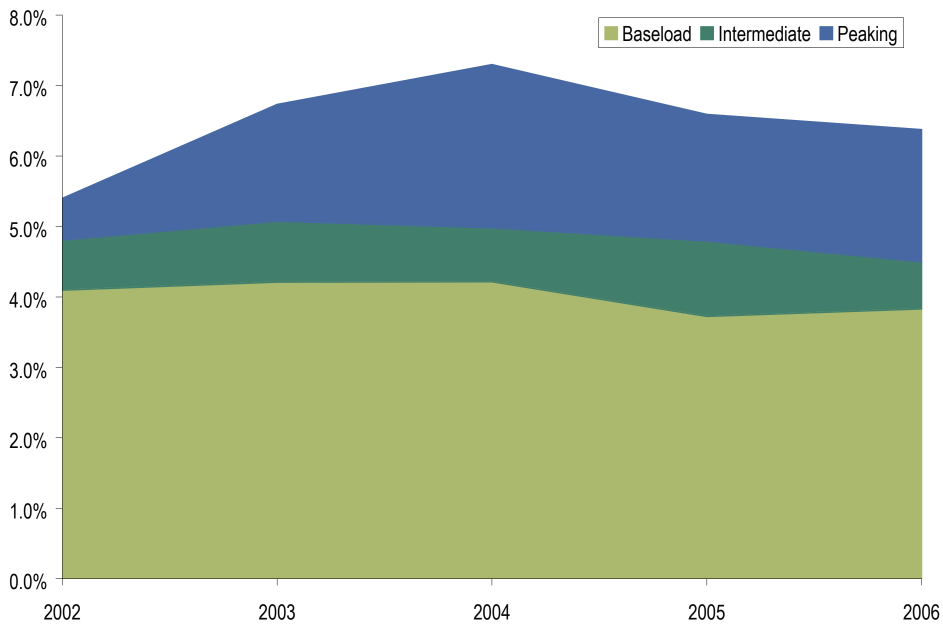
37 Combined-cycle blocks consist of one or more combustion turbines and one or more heat recovery steam generators. The configuration may vary for each individual combined-cycle unit.

38 NERC defines combustion turbines in two categories: jet engines and gas turbines. Their EFORd for the 2001 to 2005 period are 9.4 percent and 10.3 percent, respectively, per NERC's GADS "2001-2005 Generating Unit Statistical Brochure - Units Reporting Events" <ftp://www.nerc.com/pub/sys/all_updl/gads/gar/2001-2005%20Generating-Unit-Statiistical-Brochure-units%20reporting%20events.zip > (28 KB). Also, the NERC average for fossil steam units is a unit-year-weighted value for all units reporting. The PJM Control Area values are weighted by capability for each calendar year.

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

beginning in 2002 through 2004 that, while it decreased slightly in 2005, has remained higher than in 2002. In 2006, of 22,600 MW of combined-cycle units, approximately 20,700 MW are in the intermediate (18,100 MW) and peaking (2,600 MW) classes. Of 27,200 MW of combustion turbine units approximately 26,700 MW are in the intermediate (1,900 MW) and peaking (24,800 MW) classes.

Figure 5-9 Contribution to EFORd by duty cycle: Calendar years 2002 to 2006



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.[40] 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 2006 was 87.4 percent; the corresponding EMOF and EPOF were 2.0 percent and 5.8 percent, respectively. As a result, the 2006 PJM EFOF was 4.8 percent. This means 4.8 percent lost availability because of forced outages.

40 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.

The major reasons for this lost equivalent availability can be found in Table 5-17.

Table 5-17 Outage cause contribution to PJM EFOF: Calendar year 2006

	Percentage Point Contribution to EFOF	Contribution to EFOF
Boiler Tube Leaks	1.12	23.4%
Performance	0.38	8.0%
Boiler Fuel Supply	0.26	5.4%
Electrical	0.23	4.9%
Miscellaneous (Jet Engine)	0.20	4.1%
Boiler Air and Gas Systems	0.18	3.8%
Feedwater System	0.16	3.4%
Auxiliary Systems	0.12	2.5%
Stack Emission	0.11	2.4%
High Pressure Turbine	0.10	2.1%
Controls	0.10	2.1%
Miscellaneous (Generator)	0.09	1.9%
Boiler Piping System	0.09	1.8%
Generator	0.09	1.8%
Boiler Overhaul and Inspections	0.08	1.7%
Valves	0.08	1.6%
Condensing System	0.08	1.6%
Fuel Quality	0.07	1.5%
Reactor Coolant System	0.07	1.5%
All Other Causes	1.17	24.5%
PJM EFOF 2006	4.78	100.0%

Table 5-17 shows that boiler tube leaks, at 23.4 percent of the systemwide EFOF, were the largest contributor to EFOF. Forced outages because of boiler tube leaks reduced system equivalent availability by 1.12 percentage points. Performance caused the second largest reduction to equivalent availability by 0.38 percentage points. Almost all of this reduction was attributable to failing, in whole or in part, PJM seasonal capacity verification tests which require an outage until the problem is solved or the generator takes a capacity derating.

Table 5-18 Contribution to EFOF by unit type for the most prevalent causes: Calendar year 2006

	Combined Cycle	Combustion Turbine	Diesel	Hydroelectric	Nuclear	Steam	System
Boiler Tube Leaks	0.0%	0.0%	0.0%	0.0%	0.0%	33.0%	23.4%
Performance	40.7%	14.6%	15.3%	11.0%	4.4%	3.0%	8.0%
Boiler Fuel Supply	8.3%	0.0%	0.0%	0.0%	0.0%	6.7%	5.4%
Electrical	1.3%	7.1%	0.4%	2.4%	0.1%	5.3%	4.9%
Miscellaneous (Jet Engine)	0.0%	30.0%	0.0%	0.0%	0.0%	0.0%	4.1%
Boiler Air and Gas Systems	0.0%	0.0%	0.0%	0.0%	0.0%	5.3%	3.8%
Feedwater System	1.3%	0.0%	0.0%	0.0%	0.8%	4.6%	3.4%
Auxiliary Systems	4.9%	11.0%	0.0%	0.1%	2.0%	0.6%	2.5%
Stack Emission	0.0%	0.6%	0.0%	0.0%	0.0%	3.3%	2.4%
High Pressure Turbine	1.7%	0.0%	0.0%	0.0%	0.0%	2.8%	2.1%
Controls	1.2%	1.5%	0.0%	2.8%	13.6%	1.6%	2.1%
Miscellaneous (Generator)	3.8%	0.6%	16.2%	37.7%	2.3%	1.1%	1.9%
Boiler Piping System	1.5%	0.0%	0.0%	0.0%	0.0%	2.3%	1.8%
Generator	0.0%	2.1%	1.3%	2.8%	0.1%	2.0%	1.8%
Boiler Overhaul and Inspections	0.0%	0.0%	0.0%	0.0%	0.0%	2.4%	1.7%
Valves	0.3%	0.0%	0.0%	0.0%	2.4%	2.1%	1.6%
Condensing System	0.6%	0.0%	0.0%	0.0%	6.9%	1.7%	1.6%
Fuel Quality	0.6%	0.1%	0.3%	0.0%	0.0%	2.0%	1.5%
Reactor Coolant System	0.0%	0.0%	0.0%	0.0%	29.7%	0.0%	1.5%

Table 5-18 shows the major causes of EFOF by unit type. Boiler tube leaks caused 33.0 percent of the EFOF for fossil steam units. Reactor cooling system problems were the cause of 29.7 percent of the lost availability because of forced outages of nuclear units.

Table 5-19 Contribution to EFOF by unit type: Calendar year 2006

	EFOF	Contribution to EFOF
Combined Cycle	3.1%	8.3%
Combustion Turbine	4.3%	13.8%
Diesel	10.5%	0.5%
Hydroelectric	1.3%	1.4%
Nuclear	1.3%	5.0%
Steam	6.8%	71.0%
PJM Systemwide	4.8%	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 48 percent) of the capacity mix,[41] have a high duty cycle and in 2006 had an EFORd of 8.2 percent which yields a 71.0 percent contribution to EFOF. Nuclear units also have a high duty cycle; their share of the PJM systemwide capacity mix is about 18 percent and in 2006 they had a 1.4 percent EFORd which yields a 5.0 percent contribution to PJM systemwide EFOF. By using the values in Table 5-19 and Table 5-18 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 5-18 multiplied by the contribution value in Table 5-19 for the same unit type will yield the percent contribution to the PJM systemwide EFOF for that outage cause.

Outages Deemed Outside Management Control

In 2006, NERC created specifications for certain types of outages that should be deemed outside management control (OMC) in response to the system disturbance of August 14, 2003.[42] NERC specifies, in its January 2006 update to the "Generator Availability Data System Data Reporting Instructions,"[43] in Appendix K,[44] 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 (codes that are standardized for specific outage causes) that would be considered OMC outages.[45] Not all outages caused by the factors in these specific OMC cause codes are OMC outages. For example, fuel quality issues (codes 9200 to 9299) may be within the control of the owner or outside management control. Each outage must be considered per the NERC directive.

All outages, including OMC outages, are included in the EFORd that is used for planning studies that determine the reserve requirement. However, OMC outages will be 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 will be reviewed by PJM's Capacity Adequacy Department. Table 5-20 shows the impact of OMC outages on EFORd for 2006. The difference is especially noticeable for peaking units (combustion turbines and diesels). This 0.38 percentage point decrease in EFORd translates to a 600 MW increase in unforced capacity.

41 See Table 3-26, "PJM capacity (By fuel source)," *2006 State of the Market Report*, Volume II, Section 3, "Energy Market, Part 2," at "Existing and Planned Generation."

42 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."

43 The "Generator Availability Data System Data Reporting Instructions" can be found on the NERC Web site: <ftp://www.nerc.com/pub/sys/all_updl/gads/dri/2007GADS_DRI.pdf> (4.9 MB).

44 The "Generator Availability Data System Data Reporting Instructions," Appendix K can be found on the NERC Web site: <ftp://www.nerc.com/pub/sys/all_updl/gads/dri/Appendix-K-Outside-Plant-Management-Control.pdf> (161 KB).

45 For a list of these cause codes, see *2006 State of the Market Report*, Volume II, Appendix E, "Capacity Market."

Table 5-20 PJM EFORd vs. XEFORd: Calendar year 2006

	2006 EFORd	2006 XEFORd	Difference
Combined Cycle	4.12%	3.93%	(0.19%)
Combustion Turbine	9.09%	7.42%	(1.67%)
Diesel	13.49%	11.72%	(1.77%)
Hydroelectric	1.94%	1.77%	(0.17%)
Nuclear	1.43%	1.32%	(0.11%)
Steam	8.25%	8.10%	(0.15%)
Overall	6.37%	5.99%	(0.38%)