Section 2 – Energy Market

The PJM Energy Market comprises all types of energy transactions, including the sale or purchase of energy in PJM's Day-Ahead and Real-Time Balancing Markets, bilateral and forward markets and self-supply. Energy transactions analyzed in this report include those in the PJM Day-Ahead and Real-Time Energy Markets. These markets provide key benchmarks against which market participants may measure results of other transaction types. The PJM Market Monitoring Unit (MMU) analyzed measures of energy market structure and performance for 2003, including market size, concentration, residual supplier index, price-cost markup, net revenue and prices. The MMU concludes that, despite ongoing concerns about market structure, the PJM Day-Ahead and Real-Time Balancing Market results were competitive in 2003.

OVERVIEW

Market Structure

- **Market Size.** During the 12-month period from October 1, 2002, to September 30, 2003, approximately 5,000 MW of new generation plus 300 MW of upgrades to existing generation were added in PJM.[1] These increases were offset, in part, by the derating of 100 MW of generation and the retirement of 100 MW of existing facilities. The new generation was entirely gas-fired, with most of it based on combined-cycle technology. Upgrades to existing generation included approximately 150 MW in hydroelectric, 100 MW in gas-fired and 50 MW in nuclear facilities. During this same period, approximately 100 MW of gas-fired generation was derated and another 100 MW of gas-fired generation was retired. The net result of the addition of new combined-cycle units was a flattening of the middle portion of the PJM aggregate supply curve. As Table 2-1 shows, the PJM system peak load in 2003 was approximately 2,300 MW less than it had been in 2002.

- **Ownership Concentration.** Concentration ratios are a summary measure of market share, a key element of market structure. High concentration ratios indicate comparatively smaller numbers of sellers dominating a market, while low concentration ratios suggest larger numbers of sellers splitting market sales more equally. Analysis of the PJM Energy Market indicates moderate market concentration overall, but high levels of concentration in the intermediate and peaking segments of the supply curve. Further, specific geographic areas of PJM exhibit moderate to high concentration that may be problematic when transmission constraints exist. No evidence exists, however, that market power was exercised in these areas during 2003, primarily because of generators' obligations to serve load. If those obligations were to change, significant market-power-related risk would exist.

- **Pivotal Suppliers.** A generation owner is pivotal if the output of the owner's generation facilities is required in order to meet market demand. When a generation owner is pivotal, it has the ability to affect market price. The residual supply index (RSI) is a measure of the extent to which generation owners are pivotal suppliers. When the RSI is less than 1.00, a generation owner is pivotal. The RSI results are consistent with the conclusion that the PJM Energy Market results were competitive in both 2002 and 2003, with an average RSI of 1.57 and 1.66, respectively. In 2003, a generation owner in the PJM Energy Market was pivotal for only six hours, less than 0.1 percent of all hours during the year. This represents a reduction in pivotal hours from 2002, when a generation owner was pivotal in the Energy Market for 87 hours, or approximately 1 percent of all hours.

- **Demand-Side Response (DSR).** Markets require both a supply side and a demand side to function effectively. The demand side of the wholesale energy market is severely underdeveloped. This underdevelopment is one of the basic reasons for maintaining an offer cap in PJM and other wholesale power markets. Total demand-side resources available in PJM during 2003 were 1,207 MW of active load management, 659 MW from the Emergency Load-Response Program and 724 MW from the Economic Load-Response Program. There were 445 MW enrolled in both the Load-Response Program and in active load management. The 4,918 MW in total DSR resources, including additional programs reported by PJM customers in response to a survey, were approximately 8.0 percent of peak demand.

1 This period was used to reflect capacity additions made through the summer.

Market Performance

- **Price-Cost Markup.** Price-cost markups are a measure of market power. The price-cost markup index is defined here as the difference between price and marginal cost, divided by price, which is load-weighted to account for congestion and normalized. Overall, data on the price-cost markup are consistent with the conclusion that PJM Energy Market results were reasonably competitive in 2003.

- **Net Revenue.** Net revenue is an indicator of generation investment profitability, and thus is a measure of overall market performance as well as a measure of incentives to add generation to serve PJM Markets. Net revenue quantifies the contribution to capital cost received by generators from PJM Energy, Capacity and Ancillary Service Markets and from the provision of black start and reactive services. In 2003, the net revenue stream would not have covered the fixed costs of peaking units with operating costs between $70 and $75 per MWh which ran during all profitable hours.[2]

- **Energy Market Prices.** PJM's locational marginal prices (LMPs) reflect market structure and the conduct of individual participants. Price level is a good, general indicator of market performance, although the number of factors influencing the overall level of prices means it must be analyzed carefully. For example, overall average prices subsume congestion and price differences over time.

  PJM average prices increased from 2002 to 2003. The simple, hourly average system LMP was 35.2 percent higher in 2003 than in 2002, $38.27 per MWh versus $28.30 per MWh. When hourly load levels are reflected, the load-weighted LMP of $41.23 per MWh in 2003 was 30.5 percent higher than in 2002. However, when increased fuel costs are accounted for, the fuel-cost-adjusted, load-weighted, average LMP was 9.5 percent lower in 2003 than in 2002, $28.60 per MWh compared to $31.60 per MWh.

  PJM average real-time energy market prices increased in 2003 over 2002 for several reasons, including significantly increased fuel costs and higher levels of demand during the first quarter of 2003. These changed fundamentals led to higher prices during normal system conditions. PJM did not experience extreme demand conditions during 2003. While LMPs were higher overall, LMP exceeded $150 per MWh for only 11 hours during all of 2003 and was greater than $200 per MWh for only one hour with a maximum of $210.83 per MWh.

The Energy Market results for 2003 reflected supply-demand fundamentals. While Energy Market results were competitive, analysis of the Energy Market has identified a number of concerns regarding market structure that could affect competitive market results when markets are tighter, including:

- The relatively high levels of concentration in the intermediate and peaking portions of the aggregate supply curve;
- The relatively high levels of concentration in markets defined by transmission constraints; and
- The relatively high levels of concentration in the ownership of marginal units.

Mitigation

- **Offer-Capping Statistics**. PJM rules limiting exercise of market power provide that PJM can offer-cap units when they would otherwise have the ability to exercise local market power. Offer-capping levels have declined since 2001. Offer-capping does not have a significant, negative impact on unit net revenues.

2 The $70 to $75 per MWh variable operating cost reflects 2003 average natural gas costs and the heat rate of a new peaking unit.

Market Structure

Market Size

During the June to September 2003 summer period, PJM Energy Markets received a maximum of 76,900 MW in offers, including generation and real-time net transactions. This was an increase of 4,800 MW over 2002. This 4,800 MW is comprised of a net addition of 5,000 MW of generation combined with an average reduction of 100 MW of real-time hydroelectric generation and an average decrease of 100 MW of real-time net transaction flow.[3] PJM did not establish a new record for peak demand in 2003. As Table 2-1 shows, PJM's all-time peak of 63,762 MW was set on August 14, 2002, for the hour ending 1600. The 2003 peak of 61,500 MW was set on August 22, 2003, for the hour ending 1600.

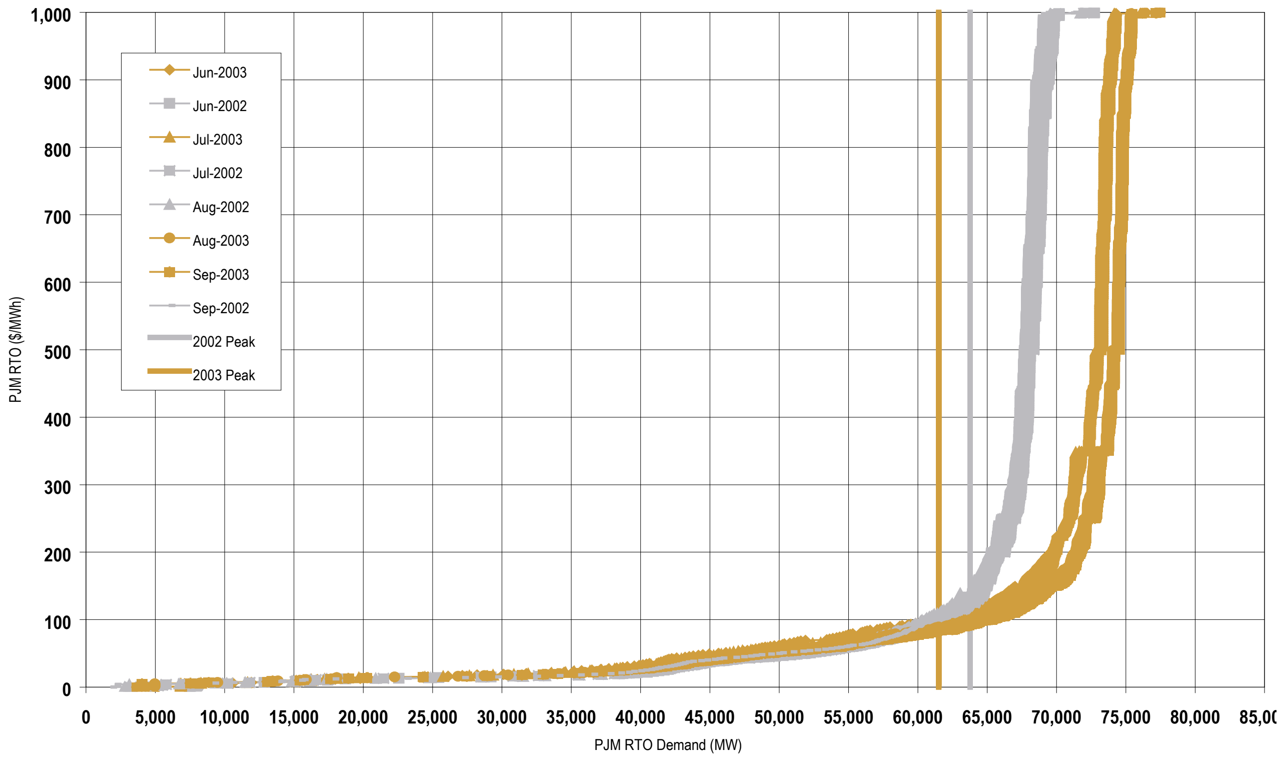
Table 2-1 Peak PJM Demand Days: 2001, 2002 and 2003

	22-Aug-03	14-Aug-02	9-Aug-01
Peak Demand (MW)	61,500	63,762	62,232
Maximum Daily LMP ($ per MWh)	$95.11	$445.30	$932.30
Average PJM LMP ($ per MWh)	$58.47	$88.00	$387.70
Average Peak PJM LMP ($ per MWh)	$65.89	$122.30	$559.40
Average Off Peak PJM LMP ($ per MWh)	$43.61	$19.20	$44.20

Price levels in 2003 were a function of market fundamentals, including lower peak demand levels and net additions to the aggregate Energy Market supply curve through new construction and upgrades to existing facilities. New generation additions and upgrades to existing units in PJM resulted in a net addition of approximately 5,000 MW of generation, after retirements and reductions in capacity. The shape of the aggregate supply curve was also changed by the new generation and its fuel mix. The result was that the midportion of the aggregate supply curve was extended (Figure 2-1). About 80 percent of the new generation was gas-fired combined-cycle, about 10 percent was gas-fired combustion turbine and the remaining 10 percent involved net upgrades to existing nuclear, hydroelectric and combustion turbines.

3 These increases in generation are calculated from October 1, 2002, through September 30, 2003, to reflect the summer to summer increase in generation.

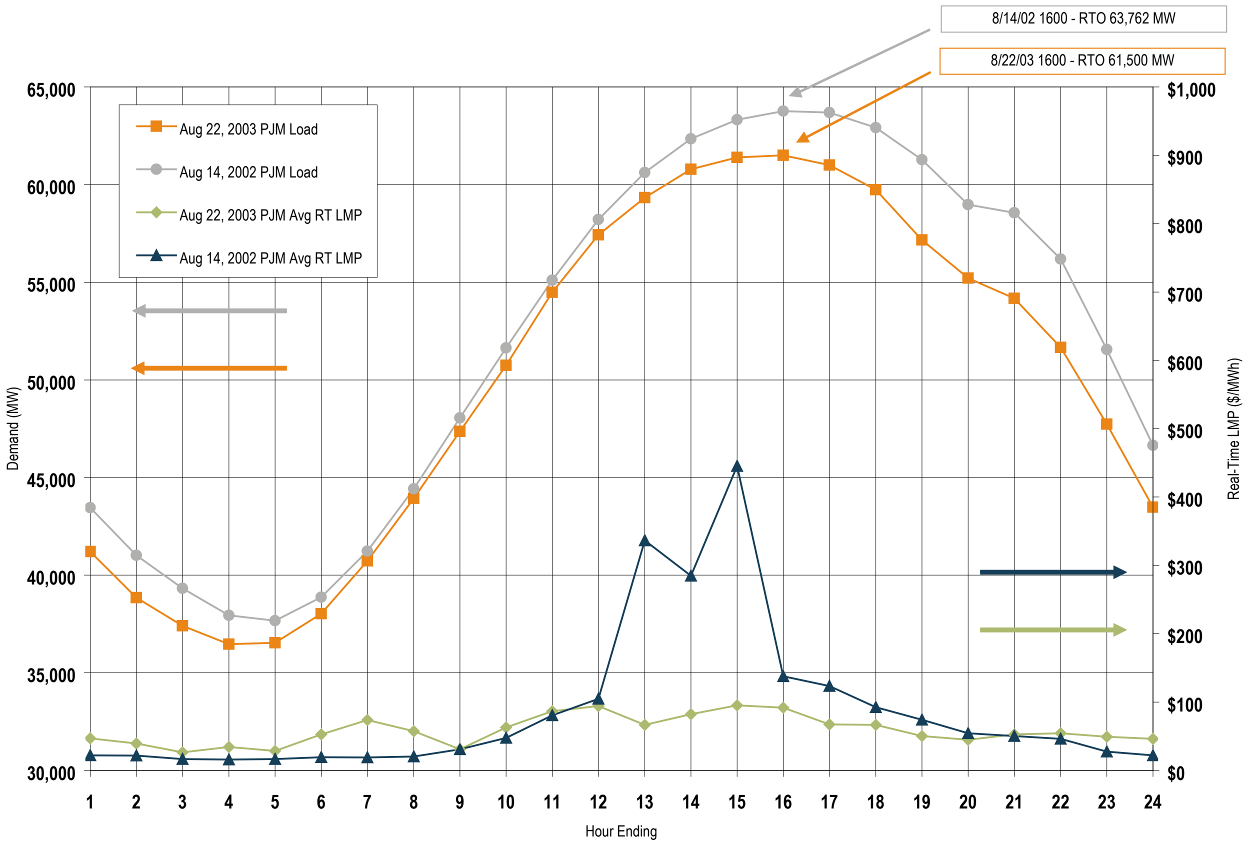
Figure 2-1 Average PJM Aggregate Supply Curves: June to September 2002 and 2003



During the summer of 2003, the demand curve intersected the supply curve at a lower price level than would have occurred with less additional generation or a different mix of additional generation (Figure 2-1).

Figure 2-2 compares the hourly load and prices for the peak-load days in 2003 and 2002. As expected, prices for the peak-load day in 2003 were lower than for the peak-load day in 2002. Average PJM LMP never exceeded $100 during the 2003 peak-load day, with $95 being the highest PJM average LMP; however, the $100 level was exceeded for six hours on the peak day in 2002, with $445 being the highest average LMP for the day.

Figure 2-2 PJM Peak Load Comparison: Friday, August 22, 2003, and Wednesday, August 14, 2002



Market Concentration

Concentration in the PJM Energy Market during 2003 was moderate overall, but high in the intermediate and peaking segments of the supply curve. High concentration levels, particularly in the peaking segment, increase the probability that a generation owner will be pivotal during high demand periods. A pivotal supplier provides output that is required to meet load.[4] Further, specific areas of PJM exhibit moderate to high concentration ratios that may be problematic when transmission constraints exist. No evidence suggests that market power was exercised in these areas during 2003 primarily because of generation owners' obligations to serve load. If those obligations were to change, however, significant market power-related risk would exist.

Concentration ratios are a summary measure of market share, a key element of market structure. High concentration ratios indicate that comparatively small numbers of sellers dominate a market; low concentration ratios mean larger numbers of sellers split market sales more equally. The best tests of market competitiveness are direct tests of the conduct and performance of individual participants and their impact on price. The price-cost markup index is one such test and direct examination of offer behavior by individual market participants is another. Low aggregate market concentration ratios establish neither that a market is competitive nor that participants are unable to exercise market power. High concentration ratios do, however, indicate an increased potential for participants to exercise market power.

Despite their significant limitations, concentration ratios provide useful information on market structure. The concentration ratio used here is the Herfindahl-Hirschman Index (HHI), calculated by summing the squares of the market share percentages of all firms in a market. Hourly PJM Energy Market HHIs were calculated based on the real-time energy output of generators located in PJM, adjusted for hourly net imports (Table 2-2). The installed capacity HHIs were calculated based on the installed capacity of PJM generating resources, adjusted for aggregate import capability (Table 2-3).

4 See the RSI calculations below for a direct measure of whether generation owners were pivotal.

Actual net imports and import capability were incorporated in the hourly energy market and installed capacity HHI calculations because imports are a source of competition for generation located in PJM. Energy can be imported into PJM under most conditions. The hourly HHI was calculated by combining all export and import transactions from each market participant with its generation output from each hour. A market participant's market share increases with imports and decreases with exports.[5] The maximum installed HHI was calculated by assigning all import capability to the market participant with the largest market share; the minimum installed HHI was determined by assigning import capability to five nonaffiliated market participants and the overall average is the average of the two.

For both hourly and installed HHIs, generators were aggregated by ownership and, in the case of affiliated companies, by parent organization. Hourly and installed HHIs were also calculated for baseload, intermediate and peaking segments of generation supply. Hourly energy market HHIs by supply curve segment were calculated based on hourly energy market shares, unadjusted for imports, while installed capacity HHIs by segment were calculated on an installed capacity basis, also unadjusted for import capability.

In addition to the aggregate PJM calculations, HHIs were calculated for selected transmission-constrained areas of PJM to provide an indication of the level of concentration that exists when specific areas within PJM are isolated from the larger PJM Market by transmission constraints.

The "Merger Policy Statement" of the United States Federal Energy Regulatory Commission (FERC)[6] states that a market can be broadly characterized as:

- **Unconcentrated.** Market HHI below 1000 - equivalent to 10 firms with equal market shares;
- **Moderately Concentrated.** Market HHI between 1000 and 1800; and
- **Highly Concentrated.** Market HHI greater than 1800 - equivalent to between five and six firms with equal market shares.

HHI Results

Calculations for installed and hourly HHI indicate that by the FERC standards the PJM Energy Market during 2003 was moderately concentrated (Table 2-2). Overall market concentration varied from 947 to 1593 based on the hourly Energy Market measure and from 908 to 1053 based on the installed capacity measure.

Table 2-2 PJM Hourly Energy Market HHI: 2003

	Minimum	Average	Maximum
Hourly	947	1213	1593

Table 2-3 PJM Installed Capacity HHI: 2003

	Minimum	Average	Maximum
Installed	908	981	1053

5 The method differs from that used in prior "State of the Market" reports. The hourly 2003 calculation reflects actual, company-specific net imports on an hourly basis while in prior years a range of net import ownership was imputed to develop a maximum and minimum HHI level.

6 77 FERC ¶ 61,263, "Inquiry Concerning the Commission's Merger Policy Under the Federal Power Act: Policy Statement," Order No. 592, pages 64-70.

Table 2-4 and Table 2-5 include HHI values for capacity and energy measures by supply curve segment, including base, intermediate and peaking plants. The hourly measure indicates that, on average, intermediate and peaking segments of the supply curve are highly concentrated, while the installed measure indicates that, on average, all segments are moderately concentrated. For both hourly and installed measures, HHIs are calculated for facilities located in PJM; imports are not accounted for.

Table 2-4 PJM Hourly Energy Market HHI by Segment: 2003

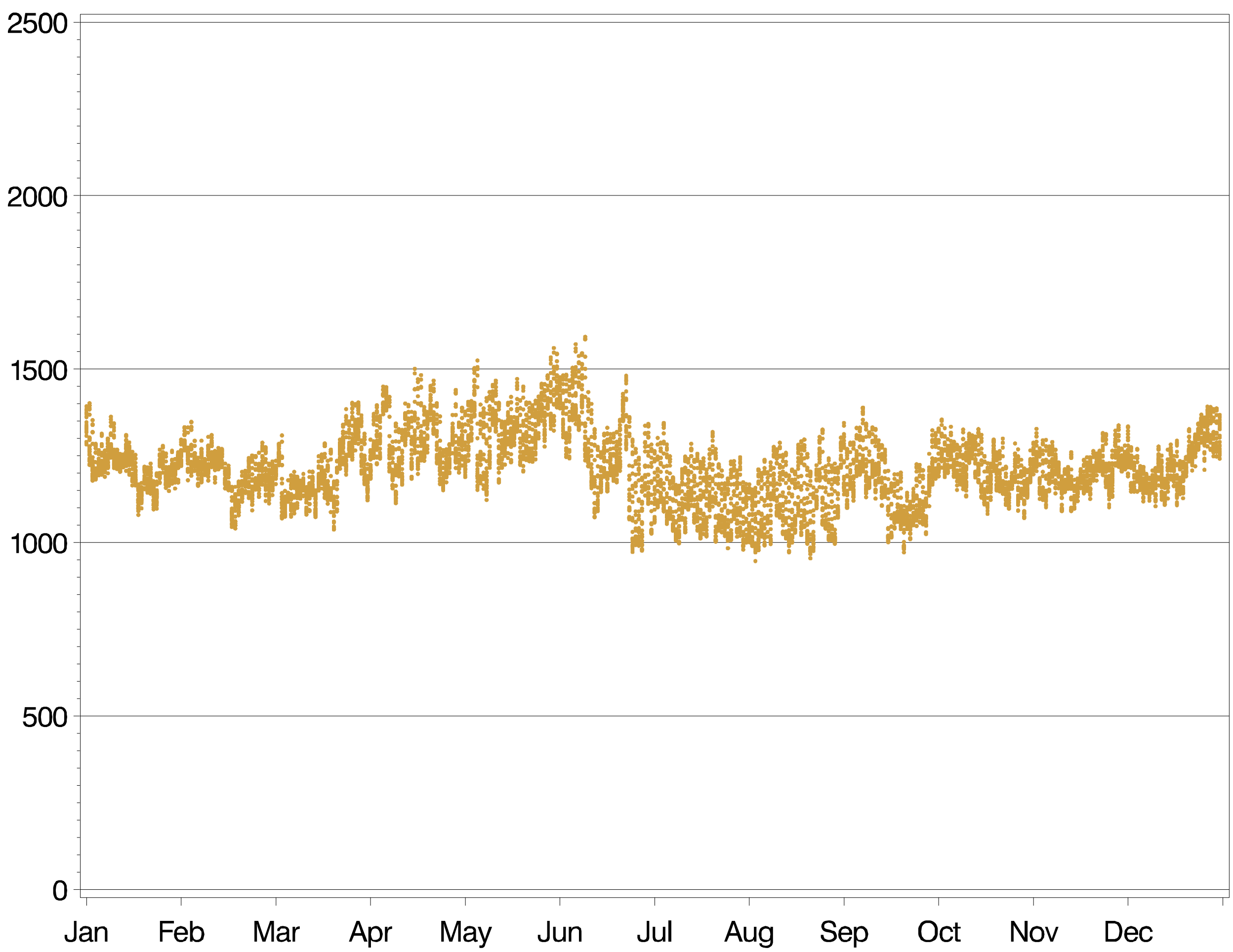
	Base	Intermediate	Peak
Maximum	1705	5772	9854
Average	1333	2055	4948
Minimum	1135	861	865

Table 2-5 PJM Installed Capacity HHI by Segment: 2003

	Base	Intermediate	Peak
HHI	1198	1037	1211

Figure 2-3 presents detailed hourly HHI results for the PJM Energy Market summarized in Table 2-2.

Figure 2-3 PJM Hourly Energy Market HHI: 2003



Local Market Concentration and Frequent Congestion

Eight PJM subareas showed high local market concentration and frequent congestion in 2002 or 2003: Northern PSEG (PSN), Northcentral PSEG (PSNC), eastern PJM, Delmarva Peninsula, Cedar subarea, Metropolitan Edison Company (Met-Ed) west, Erie and Towanda.

- **Northern PSEG (PSN)**: In 2003, congestion increased from 250 hours in 2002 to 1,059 hours, with 55 percent of all congestion occurring during on-peak periods. This increase was primarily caused by congestion on the Roseland-Cedar Grove 230 kV line, which contributed to 68 percent of all congestion in the area. An outage of the Linden-Goethals 230 kV line and generation dispatch patterns in the Public Service Electric and Gas Company (PSEG) zone were the main causes for this constraint. The Roseland-Cedar Grove constraint isolated approximately 4,500 MW of load and caused high market concentration, with an average HHI of 6500. Minimum and maximum HHIs were 4300 and 8900.

- **Northcentral PSEG (PSNC)**: In 2003, congestion increased from 459 hours in 2002 to 688 hours, with 75 percent of all congestion occurring during on-peak periods. Two constraints accounted for the majority of congestion in the area: the Edison-Meadow Road 138 kV line and the Branchburg-Readington 230 kV line. Congestion on Branchburg-Readington was attributable to area transmission outages, while congestion on Edison-Meadow Road was attributable to generation dispatch patterns in the Public Service Electric and Gas Company (PSEG) zone. These lines were congested 266 hours and 242 hours, respectively. These constraints isolated approximately 600 MW and 6,500 MW of load, respectively. Congestion caused average HHIs to range from 7000 to 7800. Minimum and maximum HHIs range from 4500 to 7000 and 8500 to 10000.

- **Eastern PJM**: During 2003, congestion on the Eastern Interface increased to 203 hours from 54 hours in 2002. Sixty-five percent of all congestion occurred during on-peak hours. The Eastern Interface isolated approximately 50 percent of total PJM system load. Eastern PJM had an average HHI of 1935, with a minimum HHI of 1300 and a maximum HHI of 2500.

- **Delmarva Peninsula**. Continued transmission improvements have reduced the occurrence of individual constraints in this area. Overall, congestion fell from 792 hours in 2002 to 522 hours in 2003. Seventy-five percent of all congestion occurred during on-peak periods. Notably, not one constraint occurred for more than 100 hours in 2003. In comparison, four constraints occurred for 100 hours or more in 2002. The Hallwood-Oak Hall 138 kV line was constrained 286 hours in 2002, but only six hours in 2003. Similarly, the Cheswold 138/69 kV transformer, the Indian River 230/138 kV transformer and the Church 230/69 kV transformer were all down from 263, 113 and 130 hours in 2002, to 77, 81 and 0 hours in 2003. Across these constraints, isolated load varied from 70 MW for the Hallwood-Oak Hall 138 kV line and Cheswold 138/69 kV transformer, to approximately 1,000 MW for the Indian River 230/138 kV transformer. Market concentration remained high during these constraints, with average HHIs ranging from 4675 to 5475. Minimum and maximum HHIs ranged from 900 to 1200 and from 8200 to 10000, respectively.

- **Cedar Subarea**. In 2003, the Cedar subarea in the Atlantic City Electric Company (AECO) zone continued to be frequently constrained. Two constraints accounted for most of the congestion in the area, which was slightly down from 786 hours in 2002, to 638 hours in 2003. Sixty-seven percent of all congestion was during on-peak periods. The Cedar interface and the Cedar-Motts 69 kV line were constrained for 396 hours and 245 hours, respectively. The Cedar-Motts 69 kV line occurred less frequently in 2003, down from 537 hours in 2002, but the Cedar interface increased from 166 hours in 2002. These two constraints isolated approximately 100 MW of load and caused the average HHI to be 6000. The minimum and maximum HHIs were 2000 and 10000.

- **Met-Ed West**. In 2003, the Met-Ed west subarea was constrained 253 hours, down from 570 hours in 2002. Ninety-six percent of all congestion in the area occurred during on-peak periods. Primarily two constraints contributed to congestion in the area: the Jackson 230/115 kV transformer, constrained 45 hours in 2003, down from 235 hours in 2002 and the Yorkana 230/115 kV transformer, constrained 149 hours, down from 186 hours in 2002. Congestion on these transformers can be attributed to the Hunterstown 500/230 kV transformer outage, which occurred in August of 2002 and continued until August of 2003.[7] These two constraints isolated approximately 1,000 MW of load and caused high market concentration, with an average HHI of 4461. Minimum and maximum HHIs were 1075 and 7850, respectively.

- **The Erie Subarea**. In 2003, the Erie subarea, located in the northwest area of the Pennsylvania Electric Company (PENELEC) zone, was constrained 324 hours, of which 42 percent occurred during on-peak periods. This was approximately a 70 percent decrease from 2002 when congestion occurred for 1,054 hours. In March 2003, congestion in the area was greatly reduced by the addition of a second Erie West 345/115 kV transformer which eliminated the occurrence of the Erie West 345/115 kV transformer constraint. Prior to the new addition, congestion from this constraint occurred for 182 hours in the first quarter of 2003 and then for no hours during the rest of the year. This was a significant decrease from a total of 900 hours in 2002. The Erie West constraint isolated approximately 800 MW of load and caused the average HHI to be 5400. The minimum and maximum HHIs were 1100 and 9800, respectively.

- **The Towanda Subarea**. In 2003, the Towanda subarea, located in the northeast area of the PENELEC zone, was constrained 490 hours, of which 29 percent occurred during on-peak periods. This was a decrease from 844 hours in 2002. However, in 2003, congestion on the North Meshoppen 230/115 kV transformer doubled from 221 hours in 2002, to 442 hours. As a result, during 2003, a second transformer and series reactors were installed at North Meshoppen to alleviate this congestion. In 2002, the Towanda interface had significant congestion attributable to area transmission outages and to its use to control congestion on the North Meshoppen transformer. These two constraints isolated approximately 500 MW of load and caused the average HHI to be 5400. Minimum and maximum HHIs were 1000 and 10000, respectively.

Pivotal Suppliers

In addition to the aggregate PJM and local market HHI calculations used to measure market concentration, the residual supply index (RSI) is a measure of the extent to which generation owners are pivotal suppliers in the PJM Energy Market. A generation owner is pivotal if the output of the owner's generation facilities is needed to meet demand. When a generation owner is pivotal, it has the ability to affect market price. For a given level of market demand, the RSI compares the market supply net of an individual generation owner's supply to the market demand. The RSI for generation owner "i" is $[(Supply_m - Supply_i)/(Demand_m)]$, where $Supply_m$ is total supply in the energy market including net imports.[8] $Supply_i$ is the supply owned by the individual generation owner "i" and $Demand_m$ is total market demand. If the RSI is greater than 1.00, the supply of the specific generation owner is not needed to meet market demand and that generation owner has a reduced ability to influence market price. If the RSI is less than 1.00, the supply owned by the specific generation owner is needed to meet market demand and the generation owner is a pivotal supplier with a greater ability to influence prices.

RSI was calculated hourly for every generation owner. The overall PJM Energy Market RSI is the minimum RSI for each hour, equal to the RSI for the largest generation owner in each hour (Table 2-6). The RSI was also calculated for the largest two generation owners together and the largest three generation owners together in order to determine the extent to which two or three suppliers were jointly pivotal. These results are reported in Table 2-7 and Table 2-8.

7 See Section 6, "Congestion," for a more in-depth discussion of Met-Ed congestion and this particular outage.
8 Total supply in the Energy Market is the sum of all offers to provide energy.

RSI Results

The RSI results reported in Table 2-6 are consistent with the conclusion that PJM Energy Market results were competitive in both 2002 and 2003, with an average hourly RSI of 1.57 and 1.66, respectively.[9] In 2003, a generation owner in the PJM Energy Market was pivotal for only six hours, less than 0.1 percent of all hours during the year. This represents a reduction in pivotal hours from 2002, when a generation owner was pivotal in the Energy Market for 87 hours, or approximately 1 percent of all hours. During the hours when a single generation owner was pivotal in the Energy Market in 2002 and 2003, demand averaged 60,000 MW. This indicates that, as the PJM Energy Market reaches a demand close to its peak of approximately 63,000 MW, one or more large market suppliers is likely to be pivotal and to have the ability to influence prices. The reduction in hours when a generation owner was pivotal between 2002 and 2003 resulted primarily from a reduction in high load hours. PJM load exceeded 60,000 MW for only 12 hours during 2003, but exceeded 60,000 MW for 83 hours in 2002.

Table 2-6 PJM RSI Statistics: 2002-2003

Year	Number of Hours RSI < 1.10	Number of Hours RSI < 1.00	Percent of Hours in Year RSI < 1.00	Average RSI	Minimum RSI
2003	91	6	0.07%	1.66	0.99
2002	339	87	0.99%	1.57	0.91

Table 2-7 shows RSI results for the top two generation owners together.

Table 2-7 PJM Top-Two Supplier RSI Statistics: 2002-2003

Year	Number of Hours RSI < 1.10	Number of Hours RSI < 1.00	Percent of Hours in Year RSI < 1.00	Average RSI	Minimum RSI
2003	822	299	3.41%	1.40	0.83
2002	1,784	748	8.54%	1.29	0.71

Table 2-8 shows RSI results for the top-three generation owners together.

Table 2-8 PJM Top-Three Supplier RSI Statistics: 2002-2003

Year	Number of Hours RSI < 1.10	Number of Hours RSI < 1.00	Percent of Hours in Year RSI < 1.00	Average RSI	Minimum RSI
2003	2,881	1,448	16.53%	1.20	0.70
2002	4,904	3,000	34.25%	1.09	0.52

9 While there is no defined RSI threshold, the California Independent System Operator (CAISO) has used an energy market RSI value exceeding 1.20 -1.50 as an indicator of a reasonably competitive market.

Figure 2-4 shows the comparison of the RSI duration curves in 2002 and 2003. The curve shows the improvement in 2003 with a decreased number of hours having an RSI index below 1.0.

Figure 2-4 PJM RSI Index Duration Curve: 2002-2003

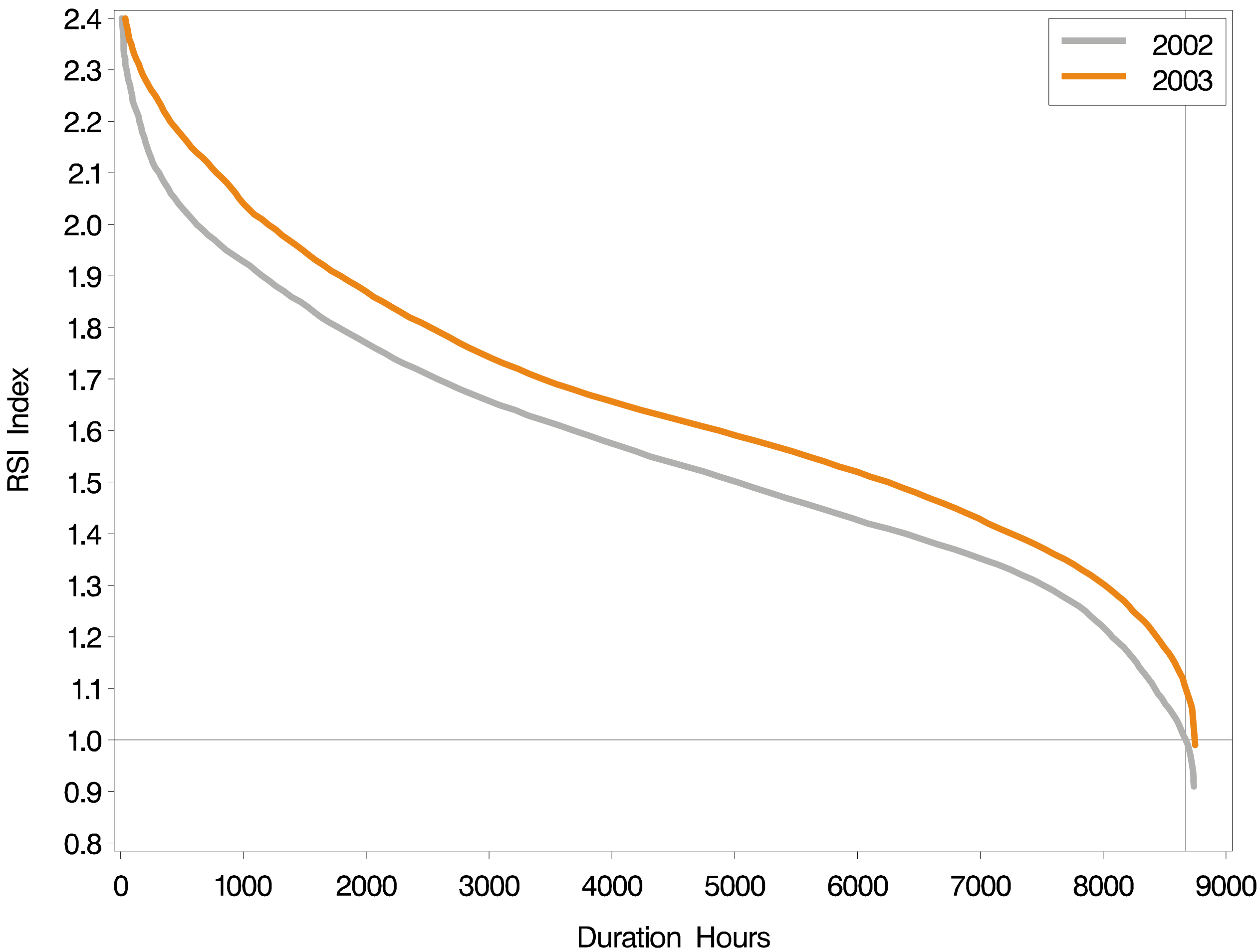
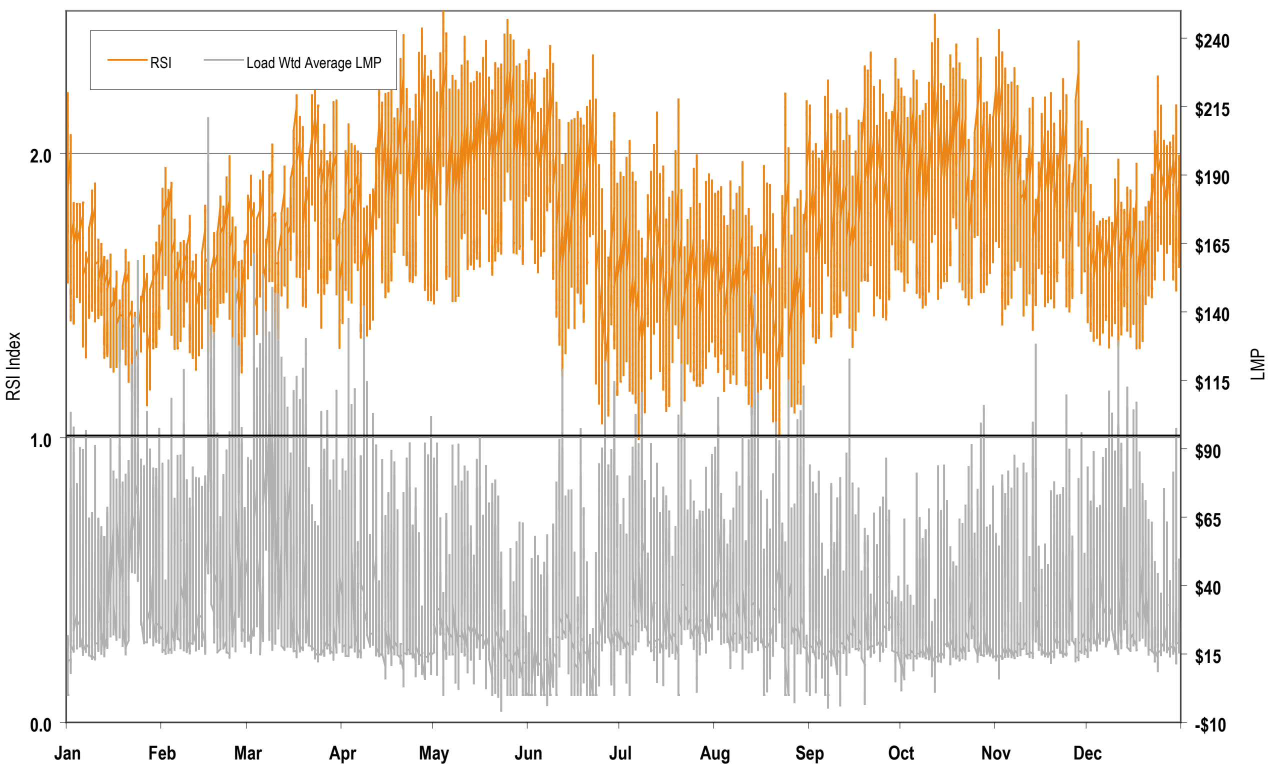


Figure 2-5 shows that there was no strong correlation between RSI and LMP.

Figure 2-5 PJM Hourly RSI and Average LMP: 2003



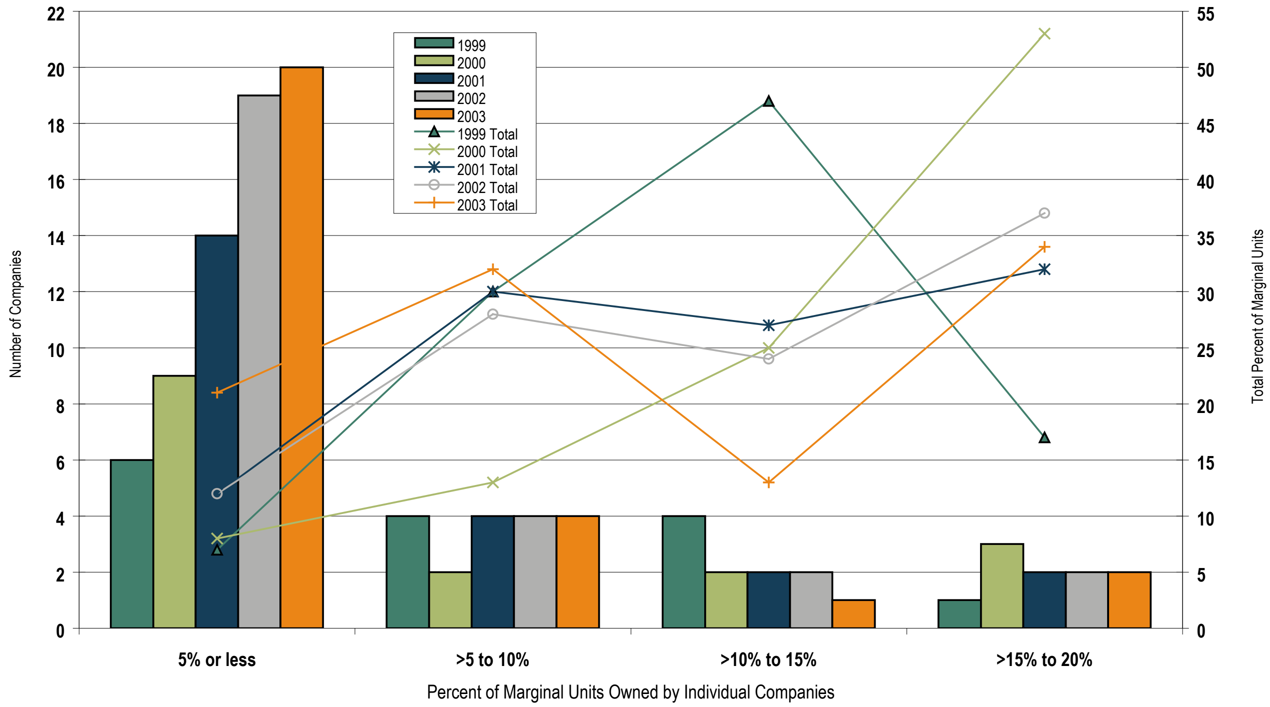
Ownership of Marginal Units

Figure 2-6 shows ownership distribution for marginal units.[10] The bars show all units that were on the margin for one or more five-minute intervals during the specified year. In 2003, two companies each owned 15 to 20 percent of the marginal units, while one other company owned 10 to 15 percent of the marginal units. The figure's "2003 Total" line shows that the two companies that each separately owned from 15 to 20 percent of the marginal units, together owned the marginal unit in just under 35 percent of the five-minute intervals. This is close to the 2002 result. In 2002, four companies individually owned the marginal unit in more than 10 percent of the intervals and together owned the marginal unit in about 60 percent of the intervals. By comparison, in 2003 the four companies with the highest share of marginal units together owned the marginal unit in about 55 percent of the intervals. The top seven companies owned the marginal unit in about 80 percent of the intervals. In 2002, the top eight companies owned about 90 percent of the marginal units; in 2001, the top four companies owned about 60 percent of the marginal units; in 2000, the top five companies owned about 80 percent of the marginal units; in 1999, the top five companies owned more than 60 percent of the marginal units.

Together with data on HHIs by supply curve segment, distribution of ownership of marginal units causes further concern about the structure of the Energy Market.

10 The calculation method was refined for 2003 to better account for marginal units owned by more than one company.

Figure 2-6 Ownership of Marginal Units



Offer-Capping

PJM has clear rules for limiting exercise of local market power. These rules are set out in the PJM Operating Agreement, Schedule 1, Section 6.4.2. The local market power rules provide that PJM shall cap the offers of units when conditions on the transmission system and the absence of sufficient competition in the area defined by the transmission constraint put units in a position to exercise local market power. The rules governing the exercise of local market power recognize that units in certain areas of the system would be in a position to extract monopoly profits but for these rules.

The basic facts of offer-capping for local market power are that:

- Units are offer-capped only if they must be dispatched out of economic order;
- The offer cap is generally the marginal cost of the unit plus 10 percent; and
- Offer-capped units receive the higher of their offer cap or the market price

Figure 2-7 through Figure 2-14 present data on the frequency of offer-capping, by month, for the past three years.

Offer-capping has declined since 2001, the first year for which data are presented. Conditions in specific subareas of PJM have affected the overall frequency of offer-capping. In 2001, constraints associated with construction of transmission system upgrades on the Delmarva Peninsula resulted in more frequent offer-capping. As the transmission projects were completed, congestion decreased significantly because of both the transmission improvements and the ending of maintenance outages. The combined effect of these factors was the decrease in offer-capped hours per MW in 2002. In 2001, there were 37,251 unit-hours of offer-capped operation, compared with 25,421 in 2002 and 18,809 in 2003.

Figure 2-7 Average Real-Time Offer-Capped Units (by Month)

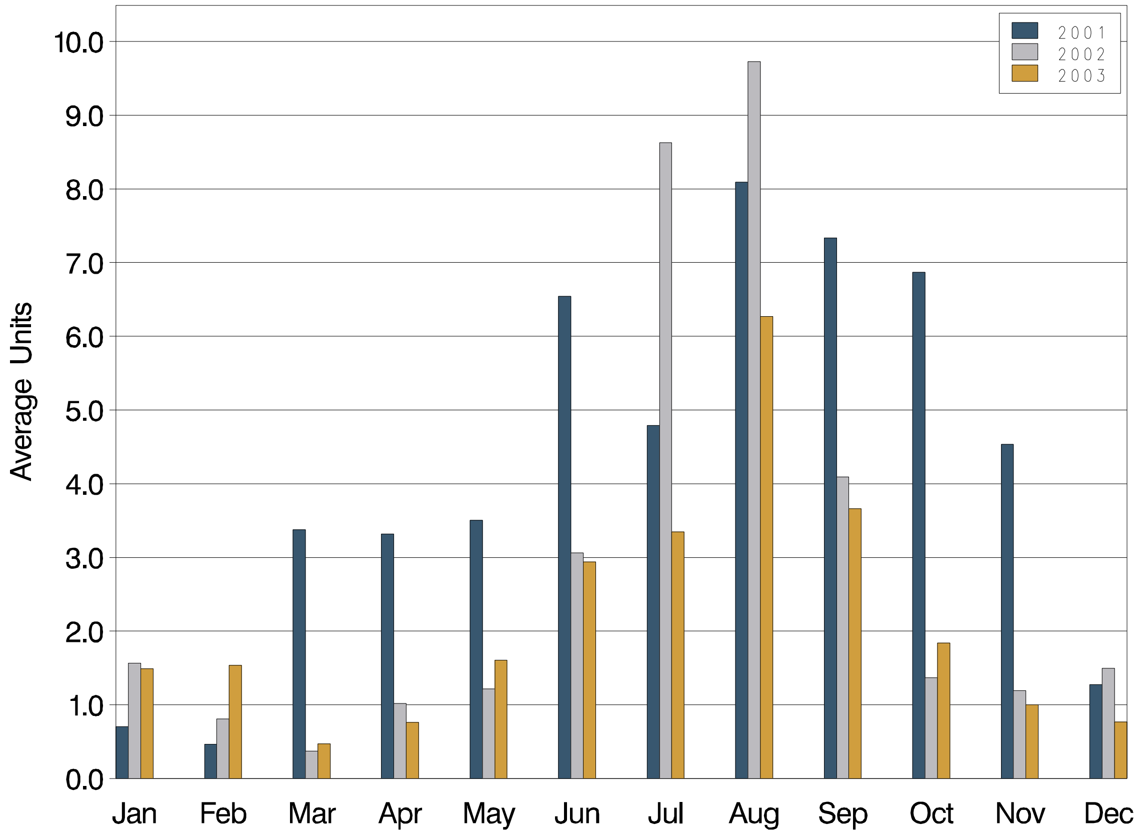


Figure 2-8 Percent of Real-Time Offer-Capped Unit Hours versus Bidding Units (by Month)

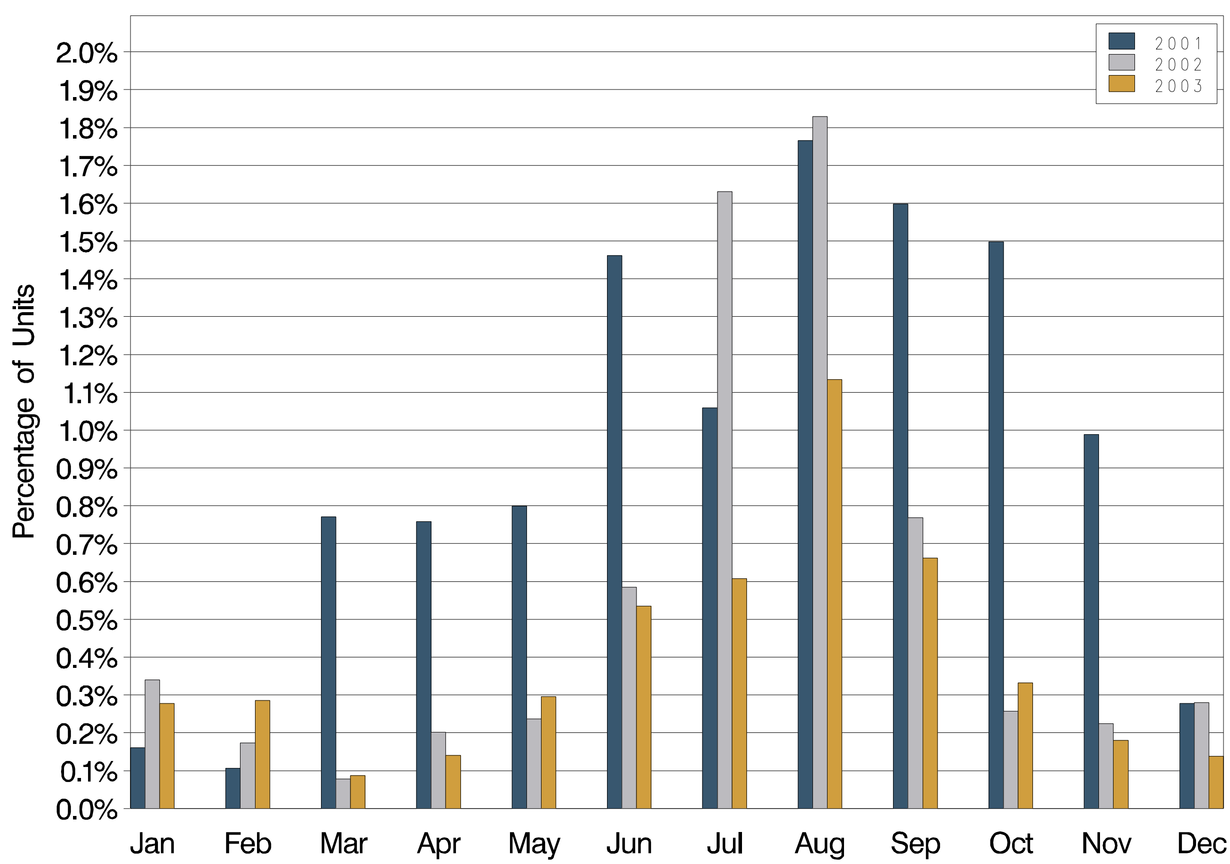


Figure 2-9 Average Real-Time Offer-Capped MW (by Month)

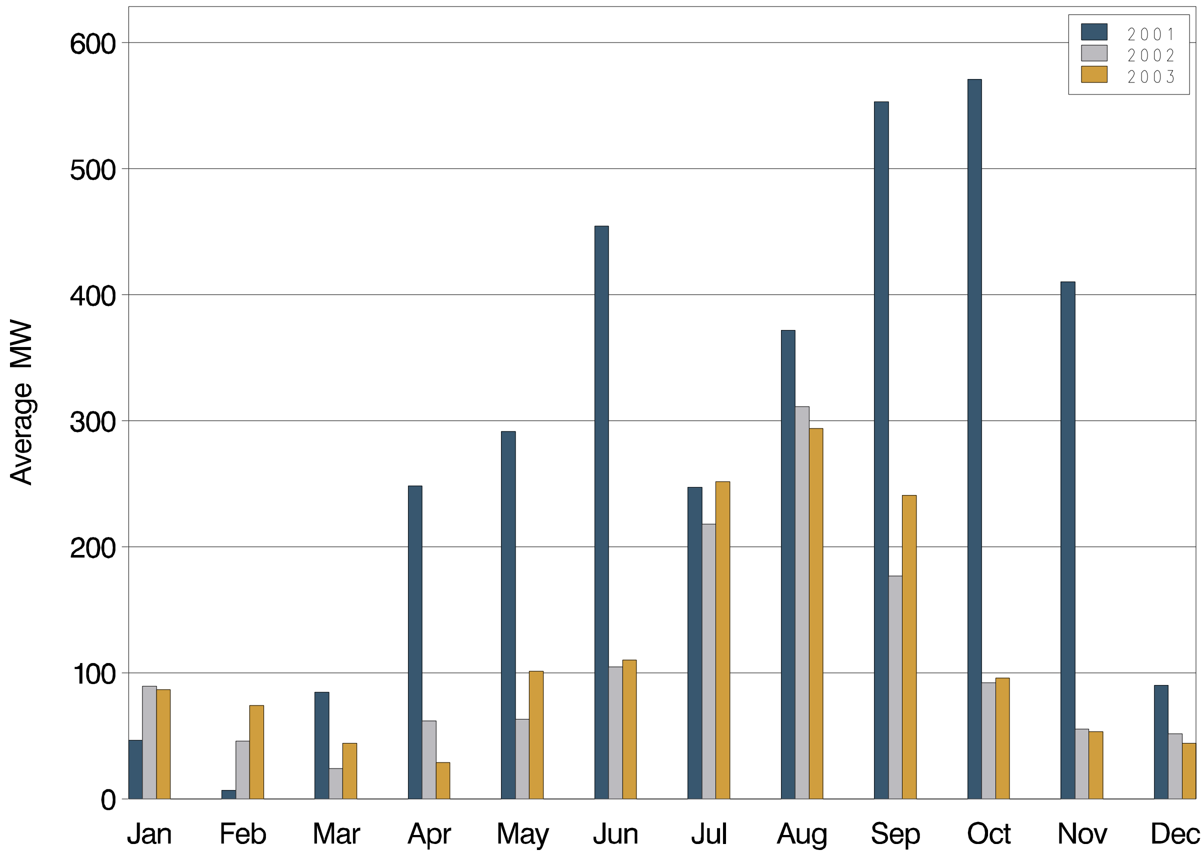


Figure 2-10 Percent of Real-Time Offer-Capped MW (by Month)

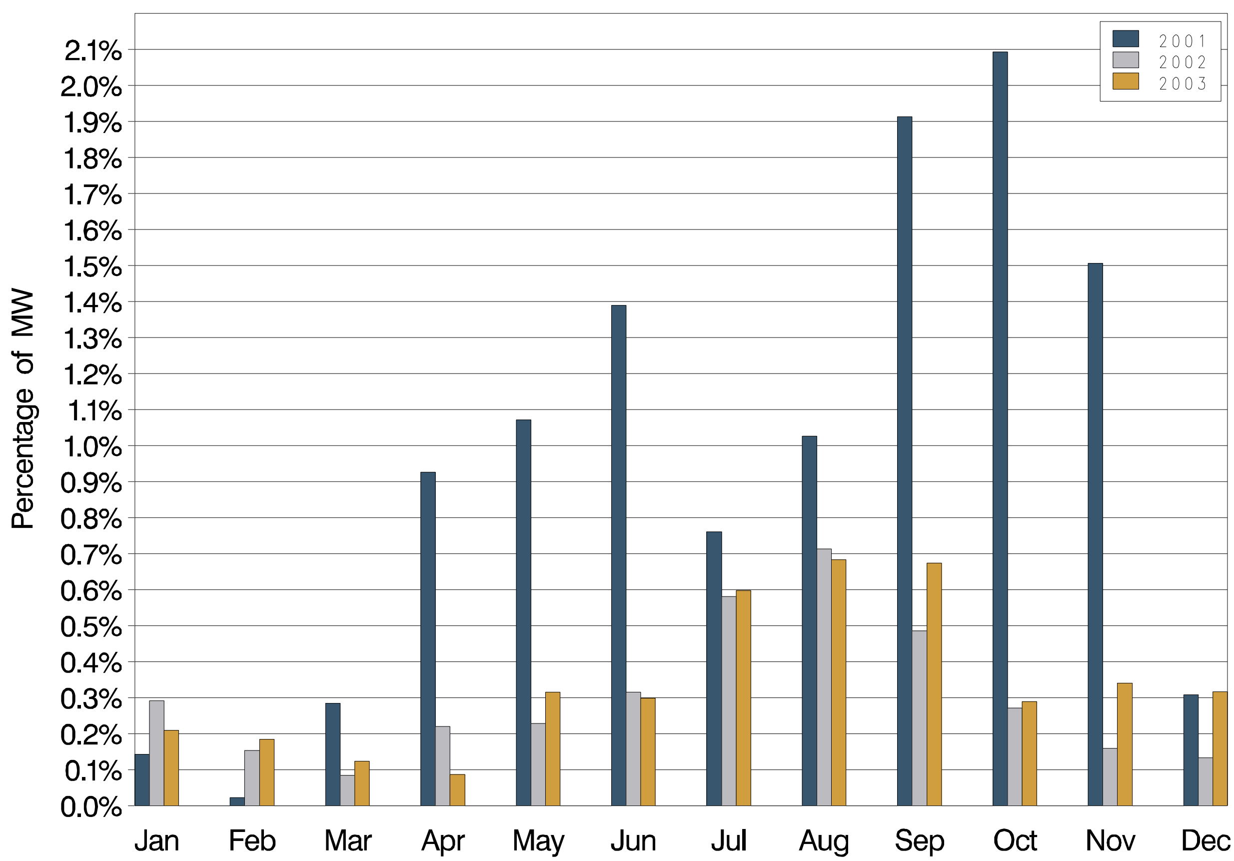


Figure 2-11 Average Day-Ahead Offer-Capped Units (by Month)

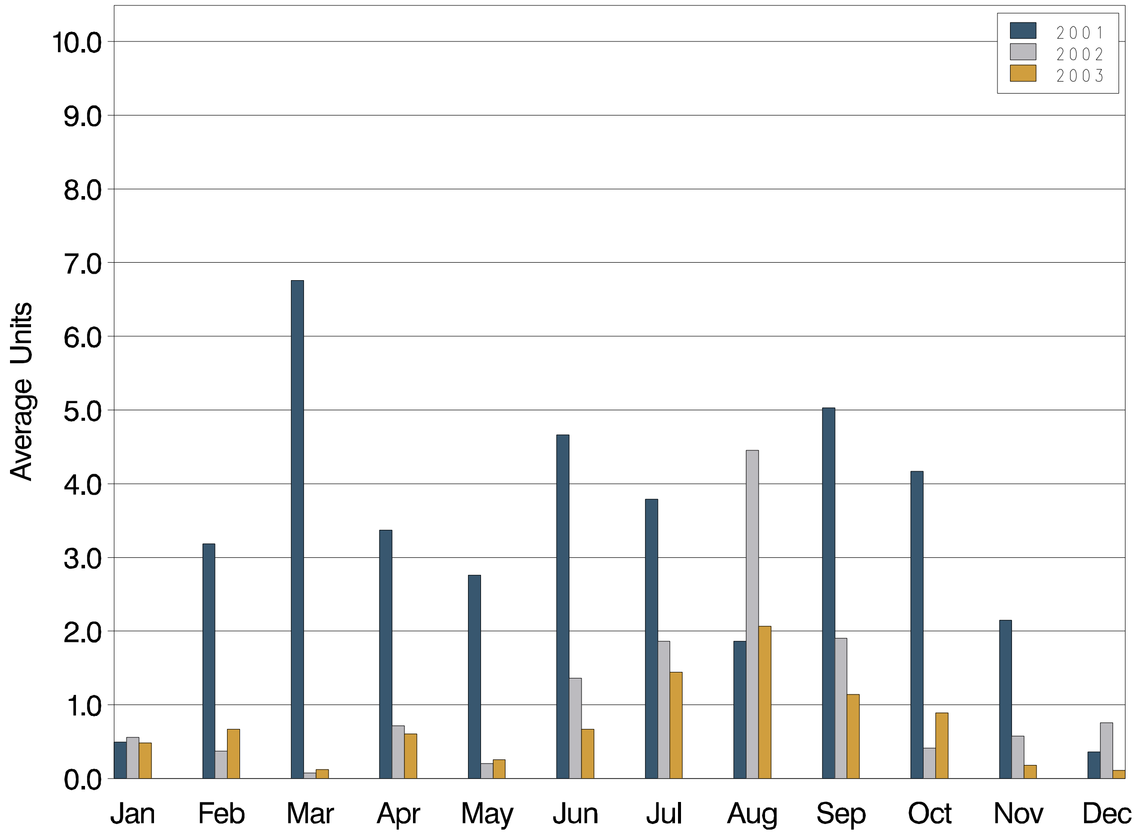


Figure 2-12 Percent of Day-Ahead Offer-Capped Unit Hours versus Bidding Units (by Month)

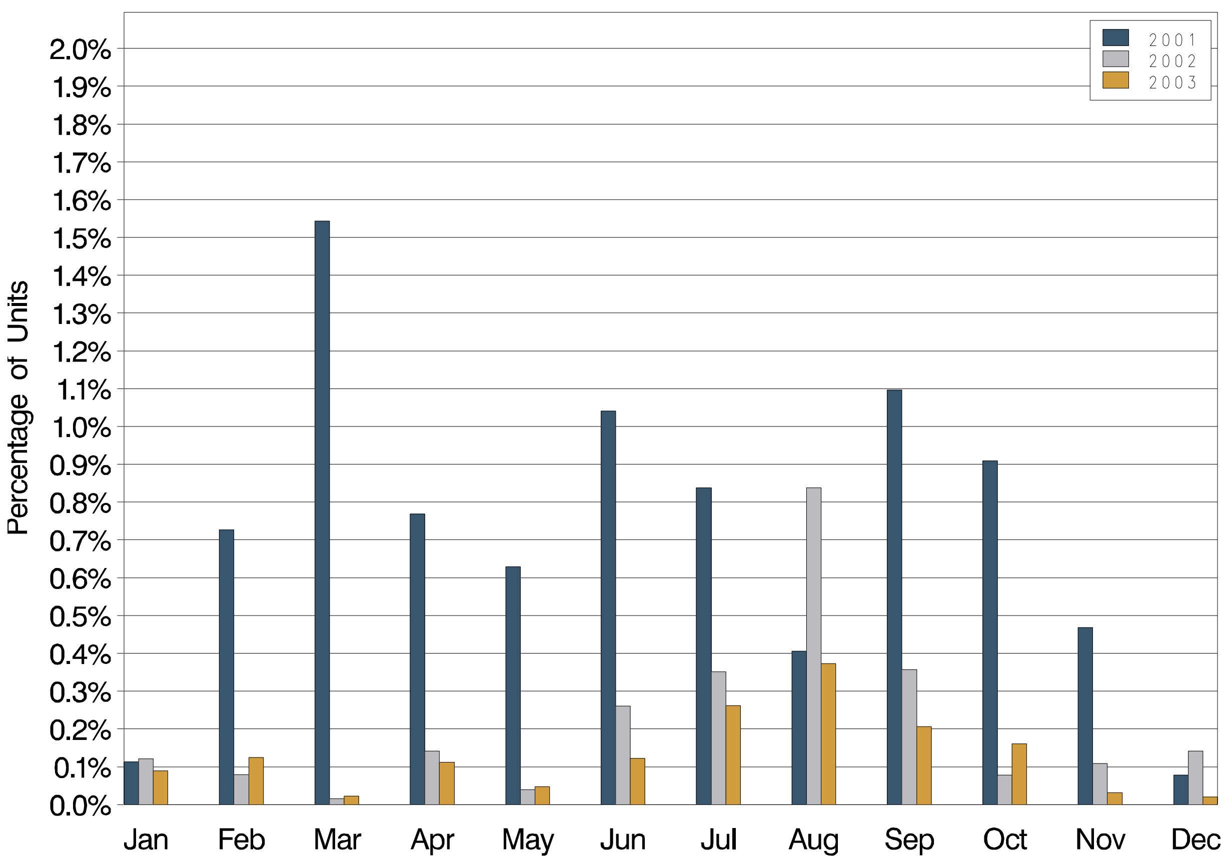


Figure 2-13 Average Day-Ahead Offer-Capped MW (by Month)

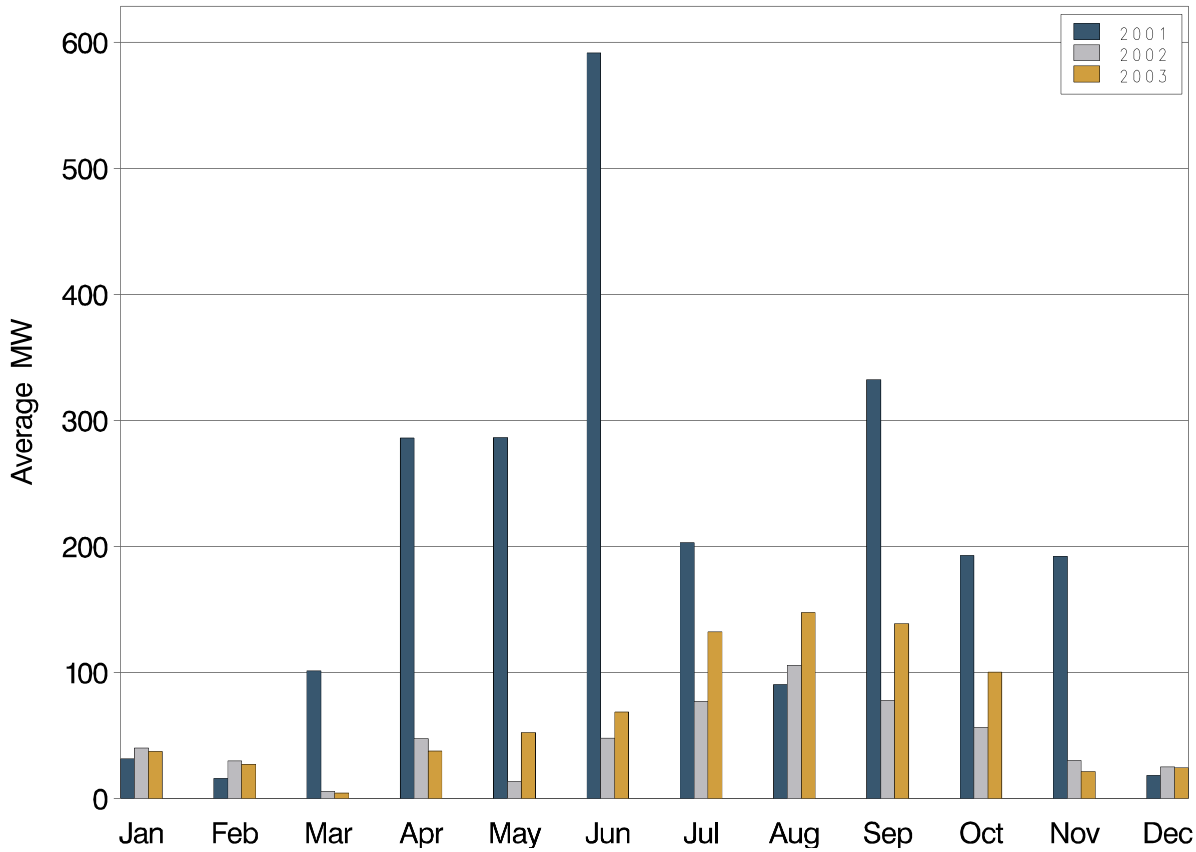
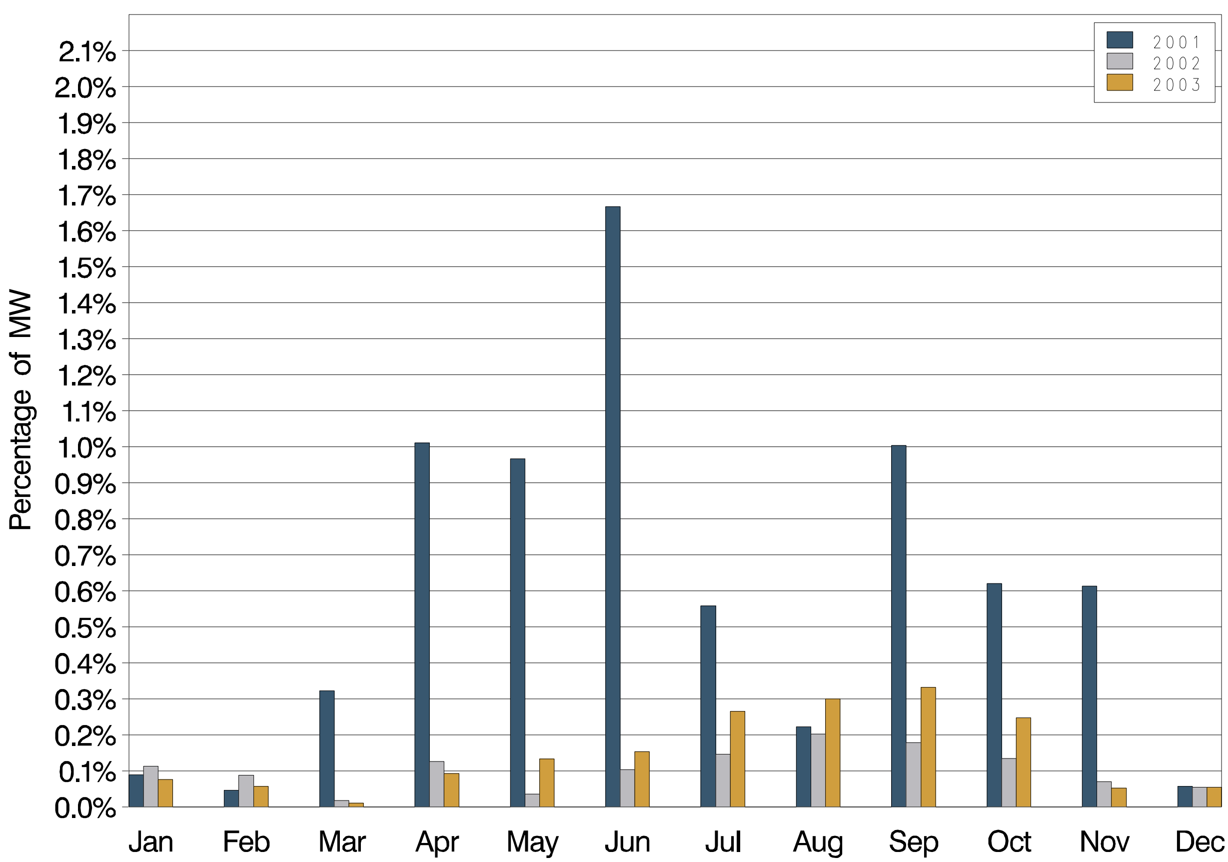


Figure 2-14 Percent of Day-Ahead Offer-Capped MW (by Month)



The following tables show the number of generation units that met the criteria of both offer-capped run hours and percentage of run hours that were offer-capped for the year indicated. For example, in 2001 three units were both offer-capped for more than 80 percent of their run hours and had at least 300 offer-capped run hours.

Table 2-9 2001 Offer-Capped Statistics

Percentage of Offer-Capped Run Hours	2001 Minimum Offer-Capped Hours					
	500	400	300	200	100	1
90%	0	0	2	2	3	3
80%	0	0	3	3	6	9
75%	0	1	4	4	9	14
50%	1	2	5	6	12	31
25%	13	16	19	20	28	72
10%	18	21	24	27	39	117

Table 2-10 2002 Offer-Capped Statistics

Percentage of Offer-Capped Run Hours	2002 Minimum Offer-Capped Hours					
	500	400	300	200	100	1
90%	2	2	3	6	6	6
80%	4	4	8	15	19	19
75%	4	4	8	16	25	25
50%	4	5	17	26	38	53
25%	6	7	19	28	52	124
10%	6	8	20	29	61	170

Table 2-11 2003 Offer-Capped Statistics

Percentage of Offer-Capped Run Hours	2003 Minimum Offer-Capped Hours					
	500	400	300	200	100	1
90%	0	0	0	0	1	2
80%	0	1	1	2	3	11
75%	1	2	2	5	9	18
50%	1	2	2	11	23	51
25%	5	9	11	20	35	97
10%	6	10	12	23	49	153

As a general matter, offer-capping did not result in financial harm to the affected units. Frequently offer-capped units received net revenues that were close to those received by units not offer-capped or that were offer-capped, but for significantly fewer hours. The extent offer-capped units had relatively low net revenues in 2003 was the result of overall market conditions and not offer-capping. In fact, offer-capping can, at times, result in higher revenues for offer-capped units than other comparable units because the offer-capped units operate when market conditions result in comparable units not operating.

Market Performance

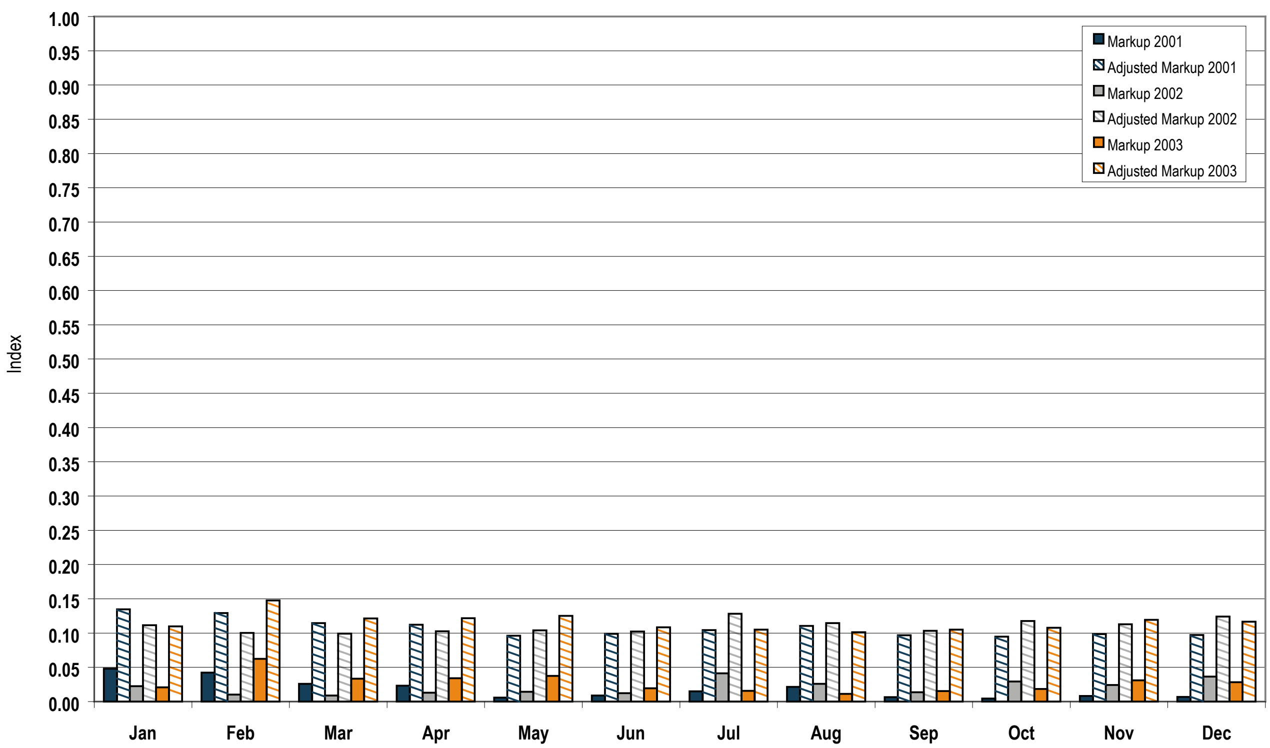
Price-Cost Markup Index

The price-cost markup index is a measure of market power. The goal of the markup analysis is to estimate the difference between the observed market price and the competitive market price.

The price-cost markup index is defined here as the difference between price (*P*) and marginal cost (*MC*), divided by price, where price is determined by the offer of the marginal unit and marginal cost is from the highest marginal cost unit operating (The markup index = $(P - MC)/P$. It is load-weighted to account for congestion and then normalized.) This markup index measure can vary from -1.00, when price is less than marginal cost to 1.00 when price is higher than marginal cost[11] (Figure 2-15).

PJM has data on price and cost offers for every unit in PJM if its construction began before July 9, 1996. The markup index can thus be calculated directly for any time period. The markup index is calculated for the marginal unit or units in every five-minute period. The marginal unit is the unit that sets LMP in the five-minute interval. There are multiple marginal units when congestion exists. Congestion is accounted for by weighting the markup index for each of the multiple marginal units, in a five-minute interval with congestion, by the load that pays the price determined by that marginal unit.[12] The resulting markups are adjusted so that the markup index compares the price offer for the marginal unit to the cost corresponding to the output of the highest marginal cost unit operating, rather than to the marginal cost of the marginal unit.

Figure 2-15 Average Monthly Load-Weighted Markup Indices



11 The value of the index can be less than zero if a unit offers its output at less than marginal cost. This is not implausible because units in PJM may provide a cost curve equal to cost plus 10 percent. Thus the index can be negative if the marginal unit's offer price is between cost and cost plus 10 percent.

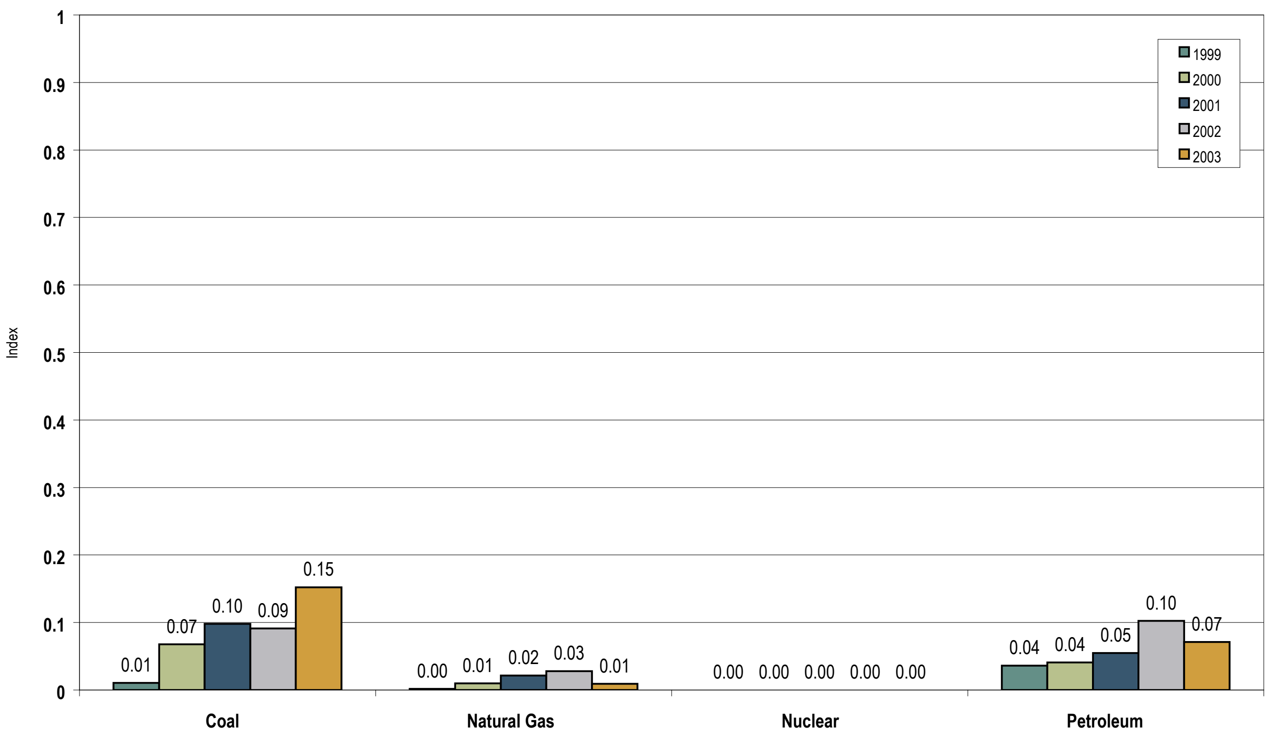
12 For example, if a marginal unit with a markup index of 0.50 set the LMP for 3,000 MW of load in an interval and a second marginal unit with a markup index of 0.01 set the LMP for 27,000 MW of load, the weighted-average markup index for the interval would be 0.06.

Figure 2-15 shows the average monthly markup index. The average markup index was 0.03 in 2003, with a maximum markup index of 0.06 in February and a minimum markup index of 0.01 in August. Generators in PJM are permitted to provide cost-based offers that include a 10 percent markup over marginal cost. Since a significant number of generators have increased their cost bids by this 10 percent, the calculated markup index is likely to be low. The adjusted markup index in Figure 2-15 assumes that all unit owners include a 10 percent markup over cost. Given this assumption, the average 2003 markup index was 0.12, with a maximum index of 0.15 in February and a minimum index of 0.10 in several other months.[13]

The markup index calculation is based on the marginal production cost of the highest marginal cost operating unit and could overstate the actual markup because it does not include the marginal cost of the next most expensive unit, an appropriate scarcity rent, if any, or an opportunity cost, if any, as a cost component. Thus, if the marginal unit is a combustion turbine (CT) with a price offer equal to $500 per MWh and the highest marginal cost of an operating unit is $130 per MWh, the observed price-cost markup index would be 0.74 [(500-130)/500]. If, however, the unit can export power and the real-time price in the external control area is $500 per MWh, then the appropriately calculated markup index would actually be zero.

To understand the dynamics underlying observed markups, the MMU analyzed marginal units in more detail, including fuel type, plant type and ownership. Figure 2-16 shows the average, unit-specific markup by fuel type. The unit markup index [(*P-MC*)/*P*] is calculated using price and marginal cost for the specific unit of the identified fuel type that is marginal during any five-minute interval and normalized. During 2003, units using coal and petroleum showed the highest unit markup indices averaging 0.15 and 0.07, respectively.[14]

Figure 2-16 Average Markup Index by Type of Fuel



13 The 10 percent markup is permitted, in part, to account for inaccuracies in marginal cost calculations. Thus, the correct markup index lies between the adjusted and unadjusted index values.

14 The primary fuels contained in the miscellaneous category include methane, petroleum coke, refuse, refinery gas, waste coal, wood and wood waste.

Figure 2-17 shows the “Type of Fuel Used by Marginal Units.” Between 2002 and 2003, the share of coal decreased from 55 to 53 percent; the share of natural gas increased from 23 to 28 percent; the share of nuclear units remained steady and the share of petroleum decreased from 21 to 17 percent.

Figure 2-17 Type of Fuel Used by Marginal Units

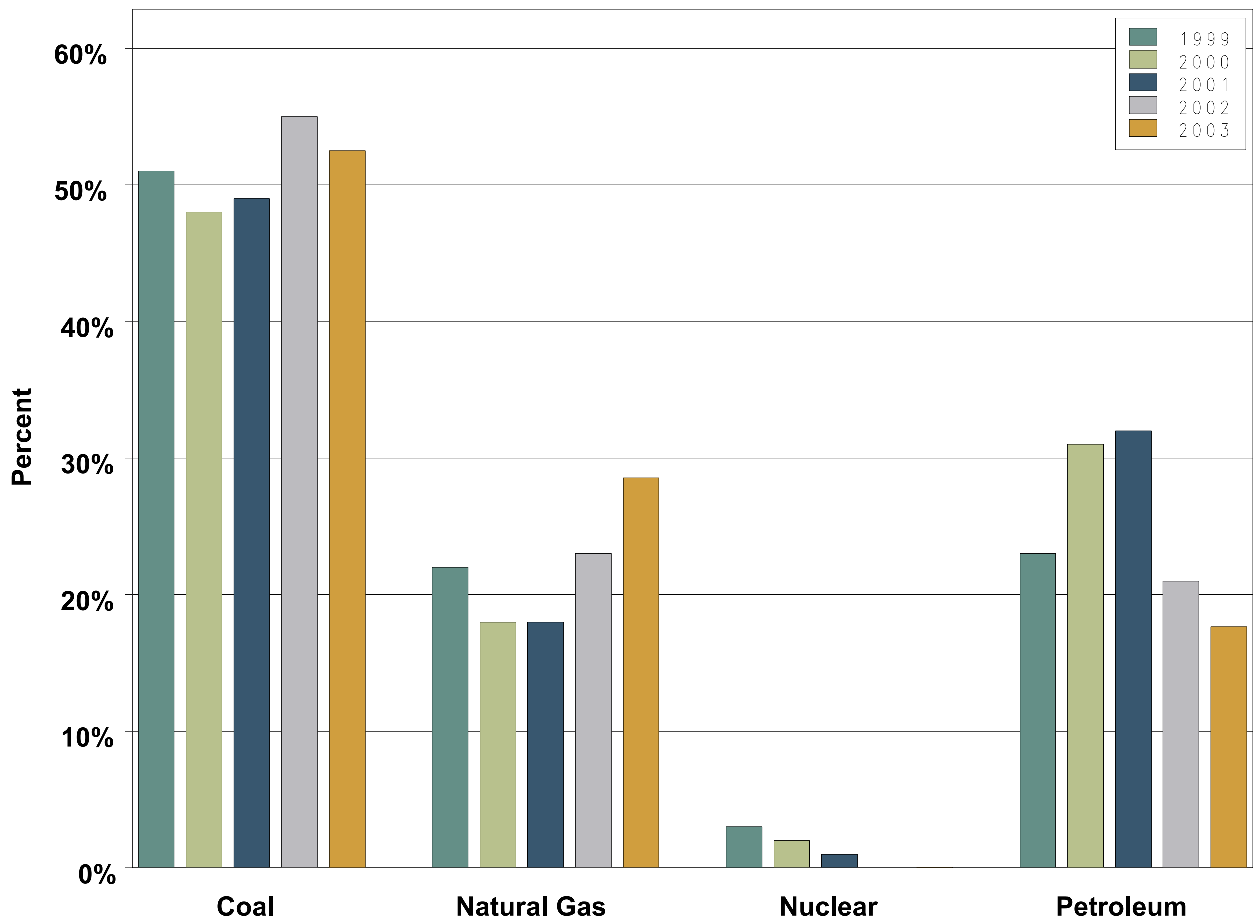


Figure 2-18 shows the type of units on the margin from 1999 to 2003. During 2003, the marginal unit was a CT 22 percent of the time and a steam unit 77 percent of the time.

Figure 2-18 Type of Marginal Unit

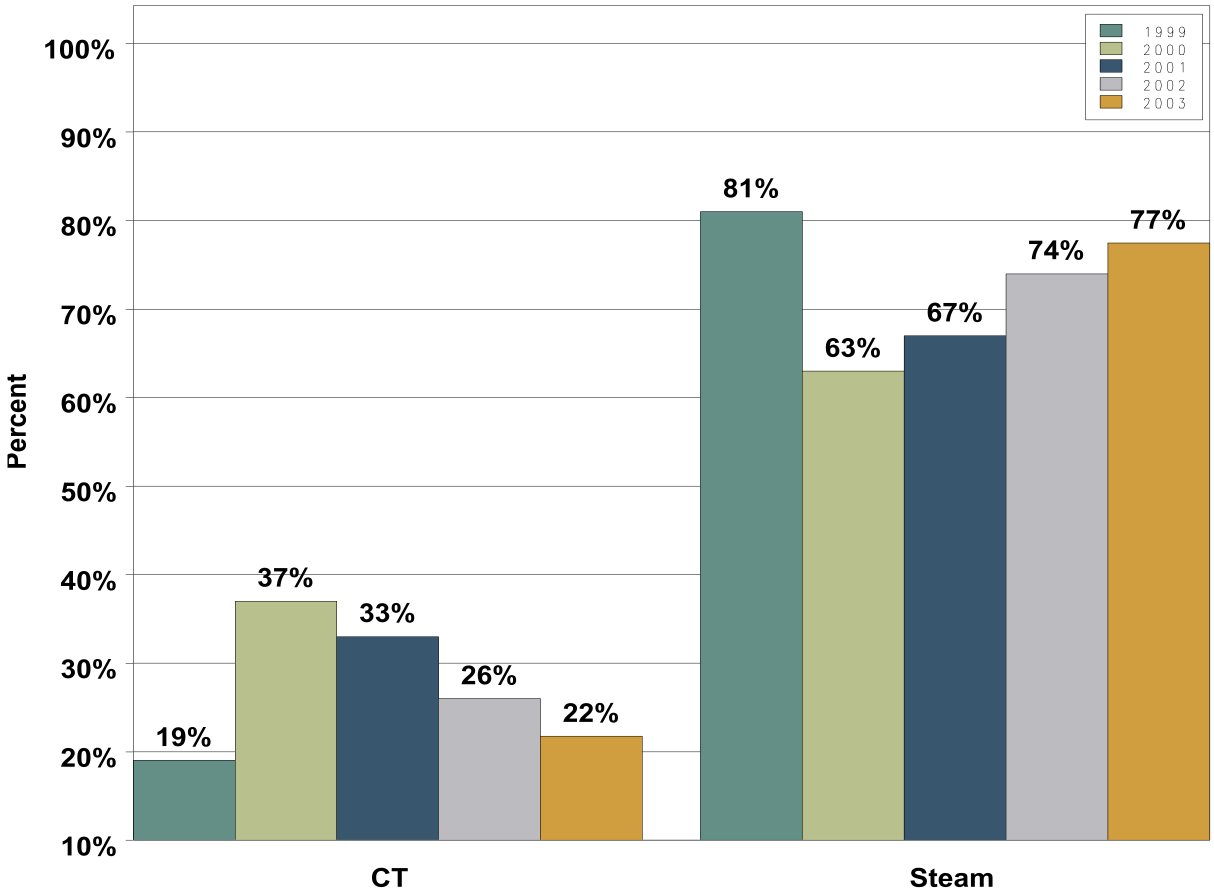
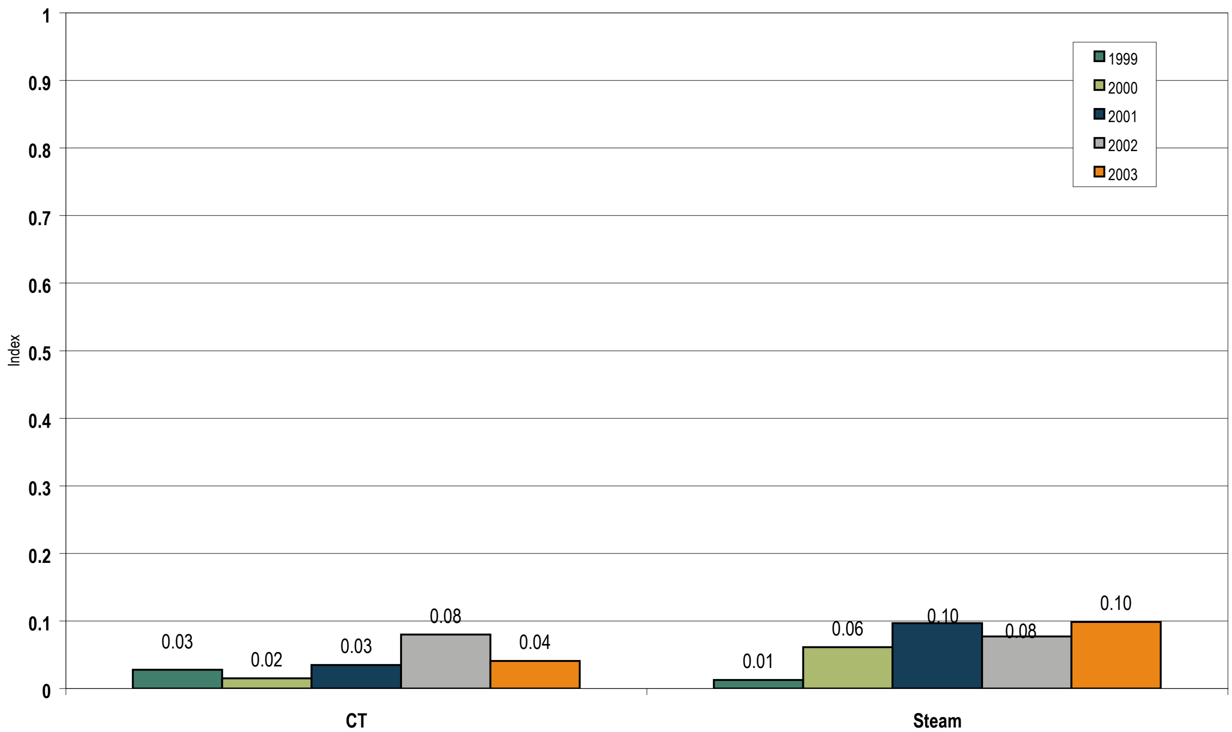


Figure 2-19 shows average markup index by unit type. The average annual markup index diverged somewhat for steam units and CTs. The average annual index decreased for CTs to 4 percent in 2003 from 8 percent in 2002 and increased for steam units to 10 percent from 8 percent in 2002.

Figure 2-19 Average Markup Index by Type of Unit



Overall, the index results presented here are consistent with the conclusion that the Energy Market results were competitive in 2003.

Net Revenue

Net revenue is an indicator of generation investment profitability, and thus is a measure of overall market performance as well as a measure of incentives to add generation to serve PJM Markets. Net revenue quantifies the contribution to capital cost received by generators from PJM Energy, Capacity and Ancillary Service Markets and from the provision of black start and reactive services. Although generators receive operating reserve payments as a revenue stream, these payments are not included here because the analysis is based on perfect economic dispatch in the PJM model.[15] Gross energy market revenue is the product of market price and generation output. Gross revenue less variable cost equals net revenue, and Table 2-12 through Table 2-16 illustrate the relationship between net revenue and generation variable cost.

In other words, net revenue is the amount that remains from gross sales revenue, after variable costs, to cover fixed costs, including a return on investment, depreciation, taxes and fixed operations and maintenance expenses.

15 Perfect economic dispatch means that the unit is assumed to be operating whenever hourly LMP exceeds marginal cost and not to be operating whenever LMP is less than marginal cost. Under the PJM model, operating reserve payments compensate generation owners when units operate at PJM's request when LMP is less than marginal cost. The PJM model also ensures that generators are compensated for start-up and no-load costs when they are dispatched based on marginal costs (i.e., theoretical dispatch) or on their offer price.

Table 2-12 Net Revenues in 1999 by Marginal Cost of Unit

	Economic Dispatch Marginal Cost Net Revenue Streams ($ per Installed MW-Year) 1999			
Marginal Cost	Energy Net Revenue	Capacity Revenue	Ancillary Revenue	Total Net Revenue
$10	$152,087	$20,469	$3,444	$176,000
$20	$94,690	$20,469	$3,444	$118,603
$30	$72,489	$20,469	$3,444	$96,402
$40	$62,367	$20,469	$3,444	$86,280
$50	$57,080	$20,469	$3,444	$80,993
$60	$54,132	$20,469	$3,444	$78,045
$70	$52,259	$20,469	$3,444	$76,173
$80	$50,959	$20,469	$3,444	$74,872
$90	$49,840	$20,469	$3,444	$73,753
$100	$48,818	$20,469	$3,444	$72,732
$110	$47,863	$20,469	$3,444	$71,776
$120	$46,926	$20,469	$3,444	$70,839
$130	$46,007	$20,469	$3,444	$69,920
$140	$45,114	$20,469	$3,444	$69,027
$150	$44,228	$20,469	$3,444	$68,141
$160	$43,374	$20,469	$3,444	$67,287
$170	$42,523	$20,469	$3,444	$66,436
$180	$41,685	$20,469	$3,444	$65,598
$190	$40,856	$20,469	$3,444	$64,769
$200	$40,036	$20,469	$3,444	$63,949

Table 2-13 Net Revenues in 2000 by Marginal Cost of Unit

	Economic Dispatch Marginal Cost Net Revenue Streams ($ per Installed MW-Year) 2000			
Marginal Cost	Energy Net Revenue	Capacity Revenue	Ancillary Revenue	Total Net Revenue
$10	$150,774	$23,308	$4,594	$178,676
$20	$89,418	$23,308	$4,594	$117,320
$30	$59,776	$23,308	$4,594	$87,679
$40	$39,519	$23,308	$4,594	$67,421
$50	$25,752	$23,308	$4,594	$53,654
$60	$16,888	$23,308	$4,594	$44,790
$70	$11,750	$23,308	$4,594	$39,652
$80	$8,586	$23,308	$4,594	$36,488
$90	$6,700	$23,308	$4,594	$34,602
$100	$5,640	$23,308	$4,594	$33,542
$110	$4,930	$23,308	$4,594	$32,832
$120	$4,385	$23,308	$4,594	$32,287
$130	$3,958	$23,308	$4,594	$31,860
$140	$3,609	$23,308	$4,594	$31,511
$150	$3,317	$23,308	$4,594	$31,219
$160	$3,102	$23,308	$4,594	$31,004
$170	$2,923	$23,308	$4,594	$30,825
$180	$2,768	$23,308	$4,594	$30,670
$190	$2,623	$23,308	$4,594	$30,525
$200	$2,488	$23,308	$4,594	$30,390

Table 2-14 Net Revenues in 2001 by Marginal Cost of Unit

	Economic Dispatch Marginal Cost Net Revenue Streams ($ per Installed MW-Year) 2001			
Marginal Cost	Energy Net Revenue	Capacity Revenue	Ancillary Revenue	Total Net Revenue
$10	$186,887	$36,700	$3,823	$227,411
$20	$116,116	$36,700	$3,823	$156,639
$30	$78,368	$36,700	$3,823	$118,891
$40	$56,055	$36,700	$3,823	$96,578
$50	$42,006	$36,700	$3,823	$82,529
$60	$33,340	$36,700	$3,823	$73,863
$70	$27,926	$36,700	$3,823	$68,450
$80	$24,389	$36,700	$3,823	$64,912
$90	$22,080	$36,700	$3,823	$62,603
$100	$20,521	$36,700	$3,823	$61,044
$110	$19,375	$36,700	$3,823	$59,899
$120	$18,480	$36,700	$3,823	$59,003
$130	$17,716	$36,700	$3,823	$58,239
$140	$17,030	$36,700	$3,823	$57,553
$150	$16,421	$36,700	$3,823	$56,944
$160	$15,884	$36,700	$3,823	$56,407
$170	$15,395	$36,700	$3,823	$55,919
$180	$14,944	$36,700	$3,823	$55,467
$190	$14,542	$36,700	$3,823	$55,065
$200	$14,162	$36,700	$3,823	$54,685

Table 2-15 Net Revenues in 2002 by Marginal Cost of Unit

	Economic Dispatch Marginal Cost Net Revenue Streams ($ per Installed MW-Year)			
	2002			
Marginal Cost	Energy Net Revenue	Capacity Revenue	Ancillary Revenue	Total Net Revenue
$10	$153,620	$11,601	$3,915	$169,135
$20	$85,661	$11,601	$3,915	$101,177
$30	$51,898	$11,601	$3,915	$67,414
$40	$31,650	$11,601	$3,915	$47,166
$50	$19,776	$11,601	$3,915	$35,292
$60	$13,101	$11,601	$3,915	$28,617
$70	$9,080	$11,601	$3,915	$24,596
$80	$6,623	$11,601	$3,915	$22,139
$90	$5,079	$11,601	$3,915	$20,594
$100	$4,109	$11,601	$3,915	$19,625
$110	$3,507	$11,601	$3,915	$19,023
$120	$3,063	$11,601	$3,915	$18,579
$130	$2,758	$11,601	$3,915	$18,274
$140	$2,501	$11,601	$3,915	$18,017
$150	$2,287	$11,601	$3,915	$17,803
$160	$2,115	$11,601	$3,915	$17,631
$170	$1,970	$11,601	$3,915	$17,486
$180	$1,828	$11,601	$3,915	$17,344
$190	$1,700	$11,601	$3,915	$17,216
$200	$1,607	$11,601	$3,915	$17,123

Table 2-16 Net Revenues in 2003 by Marginal Cost of Unit

	Economic Dispatch Marginal Cost Net Revenue Streams ($ per Installed MW-Year) 2003			
Marginal Cost	Energy Net Revenue	Capacity Revenue	Ancillary Revenue	Total Net Revenue
$10	$213,211	$5,936	$3,880	$223,027
$20	$147,516	$5,936	$3,880	$157,333
$30	$101,922	$5,936	$3,880	$111,738
$40	$68,531	$5,936	$3,880	$78,347
$50	$44,150	$5,936	$3,880	$53,966
$60	$27,810	$5,936	$3,880	$37,626
$70	$17,097	$5,936	$3,880	$26,914
$80	$10,205	$5,936	$3,880	$20,021
$90	$6,079	$5,936	$3,880	$15,896
$100	$3,697	$5,936	$3,880	$13,513
$110	$2,226	$5,936	$3,880	$12,042
$120	$1,305	$5,936	$3,880	$11,121
$130	$722	$5,936	$3,880	$10,538
$140	$387	$5,936	$3,880	$10,203
$150	$218	$5,936	$3,880	$10,034
$160	$141	$5,936	$3,880	$9,958
$170	$94	$5,936	$3,880	$9,910
$180	$51	$5,936	$3,880	$9,867
$190	$23	$5,936	$3,880	$9,840
$200	$10	$5,936	$3,880	$9,826

In a perfectly competitive, energy-only market in long-run equilibrium, net revenue from the energy market would be expected to equal the total of all fixed costs for the marginal unit, including a competitive return on investment. The PJM Capacity, Energy and Ancillary Service Markets are all sources of revenue to cover fixed costs of generators, as are payments for the provision of black start and reactive services. Thus, in a perfectly competitive market in long-run equilibrium, with energy, capacity and ancillary service payments, net revenue from all sources would be expected to equal the fixed costs of generation for the marginal unit. Net revenue is a measure of whether generators are receiving competitive returns on invested capital and of whether market prices are high enough to encourage entry of new capacity.

The approach to the theoretical net revenue calculation has been modified in this report in several ways from prior “State of the Market” reports. This altered approach has been applied to each year from 1999 through 2003 to create a consistent set of results. The modifications to the net revenue analysis include the use of forced outage rates, elimination of operating reserve revenues and inclusion of ancillary service revenues from the provision of reactive and black start services. Use of forced outage rates reduces net revenues because it assumes that units are not available to run even when it was profitable to operate. Elimination of operating reserve revenues also reduces net revenues. The inclusion of ancillary service revenues from reactive and black start services increases net revenues.

Net revenue calculations presented in Table 2-12 through Table 2-16 reflect net revenues from Energy, Capacity and Ancillary Service Markets and from the provision of black start and reactive services during the study years 1999 to 2003. The tables illustrate the dollars per installed MW-year that would have been received by a unit in PJM if it had operated whenever system price exceeded the identified marginal cost levels in dollars per MWh adjusted for outages. The net revenue calculations reflect a forced outage rate equal to the actual PJM system forced outage rate for each study year. For example, during 2003, if a unit had marginal costs (fuel plus variable operations and maintenance expense) equal to $30 per MWh, it had an incentive to operate whenever LMP exceeded $30 per MWh. If such a unit had operated during all profitable hours in 2003, it would have received $111,738 per MW in net revenue from all sources, with the Energy Market contributing $101,922, the Capacity Market contributing $5,936 and ancillary service revenues contributing $3,880.

The net revenue data are approximate measures, generally representing an upper bound of the markets' direct contribution to generator fixed costs. The net revenue curve does not take account of operating constraints that may affect the actual net revenues of individual plants. For example, for a typical summer weekday, a six-hour hot status notification plus start-up time for a combined-cycle steam plant could prevent a unit from running during two profitable hours in the afternoon peak and two more profitable hours in the evening peak, separated by four unprofitable hours. A combustion turbine with a limit of one start per day would also not be available for both an afternoon and an evening peak. As another example, ramp limitations might prevent a unit from starting and ramping up to full output in time to operate for all profitable hours.

In addition, the net revenue measure accounts for neither the profitability of a portfolio of generation assets nor the contribution to fixed costs from the option value of physical units, which can be considerable.

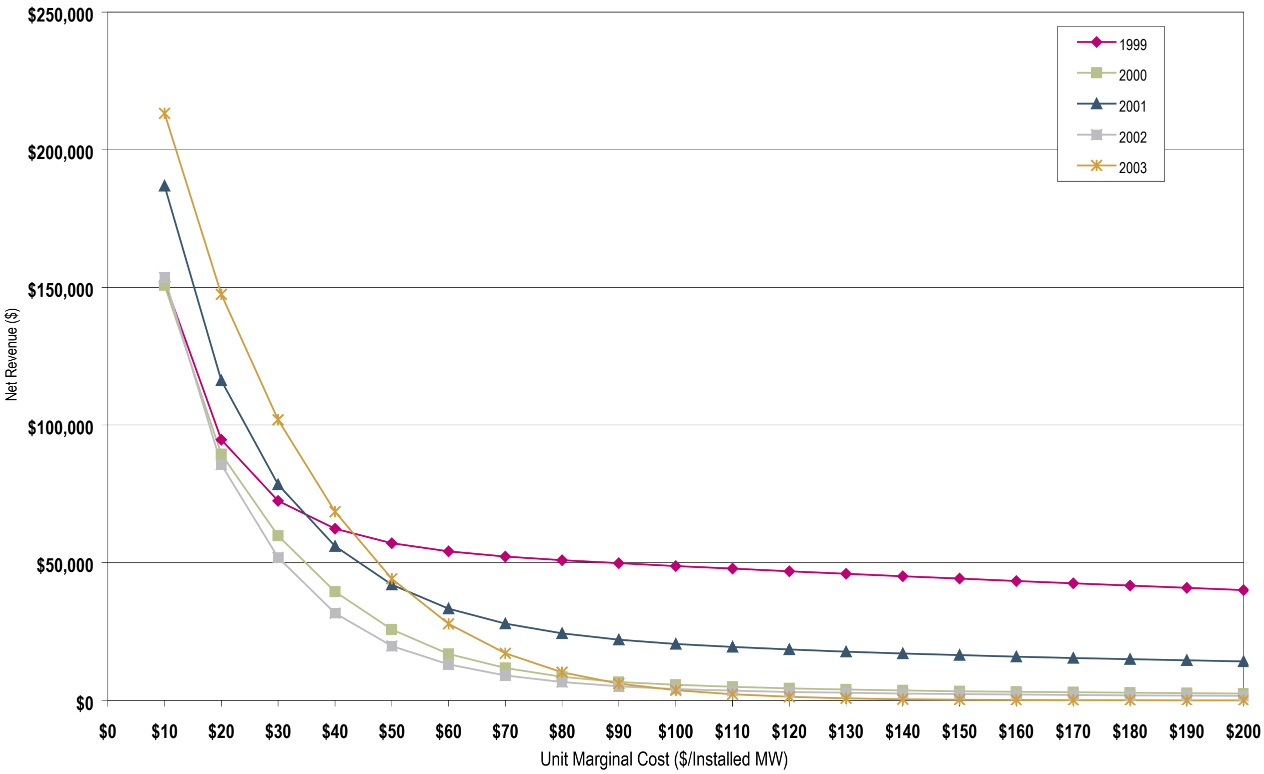
Energy Market Net Revenue

As Figure 2-20 illustrates, the energy market net revenue curve was higher in 2003 for units with marginal costs equal to or less than $40 and lower for those with marginal costs above $100 than for any year from 1999 through 2002. As a result, units with low marginal costs were more profitable in 2003 than in prior years. If a unit with marginal costs of $30 per MWh had operated during all hours when the LMP exceeded $30 per MWh, it would have received about $72,000 per installed MW in net energy revenue in 1999, about $60,000 in 2000, about $78,000 in 2001, about $52,000 in 2002 and about $102,000 in 2003.

The large increase in energy revenue for 2003 compared to earlier years results from a change in LMP frequency distribution. In 1999, the frequency of LMP equal to or less than $30 was 83 percent and of LMP equal to or less than $20 was 60 percent. In 2000, the frequencies were 71 percent and 54 percent, respectively; in 2001, the frequencies were 66 percent and 39 percent, respectively; in 2002, the frequencies were 70 percent and 45 percent, respectively and in 2003, the frequencies were 49 percent and 27 percent, respectively. Consequently, there were more hours with LMPs above $30 in 2003 than in any year since the introduction of PJM Markets.

The 2003 load-weighted LMP averaged $41.23 per MWh compared to $31.60 in 2002, $36.65 in 2001, $30.72 in 2000 and $34.06 in 1999. In contrast to earlier years, however, 2003 did not have any price spikes. In 2003 LMP exceeded $200 for only one hour, compared to nine hours in 2002, 40 hours in 2001, 15 hours in 2000 and 86 hours in 1999. As a result, units with high marginal costs were not as profitable in 2003 as in prior years. In 1999, if a unit with marginal costs of $100 per MWh had operated during all hours when LMP exceeded $100 per MWh, it would have received about $49,000 per installed MW in net energy revenue versus about $6,000 in 2000, about $21,000 in 2001, about $4,000 in 2002 and less than $4,000 in 2003.

Figure 2-20 PJM Energy Market Net Revenue: 1999, 2000, 2001, 2002 and 2003



Differences in the shape and position of net energy revenue curves for the five years result from different distributions of energy market prices. These differences illustrate the significance of a relatively small number of high-priced hours to the profitability of high marginal cost units. Although average prices in 2000 were approximately equal to average prices in 1999, hourly average prices in 2000 were actually higher than hourly average prices in 1999 for all intervals except hours 1200 through 1800, when 1999 prices significantly exceeded those in 2000. These peak hours included intervals when 1999 prices spiked to more than $900 per MWh for a limited number of hours. The 91 hours in 1999 when prices exceeded $150 per MWh and the 43 hours when prices exceeded $800 per MWh generally occurred during these peak intervals. These periods were responsible for the shape of the 1999 net revenue curve. In 2000, there were only 27 hours when prices exceeded $150 per MWh and only one hour when prices exceeded $800 per MWh. The limited number of high-priced hours in 2000 resulted in lower net revenue for units operating at marginal costs above $30 per MWh. In 2003, LMP exceeded $150 for only 11 hours compared to 20 hours in 2002, and during only one hour in 2003 did prices exceed $200, reaching a maximum of $211. In 2002, prices had been above $200 for nine hours and had reached a maximum of $791. Conversely, price was less than $10 for 241 hours in 2003 compared to 195 hours in 2002.

Capacity Market Net Revenue

In addition to energy-related revenue, generators receive revenues for capacity. In 2003, PJM capacity resources received a weighted-average payment from the PJM Capacity Credit Markets of $17.51 per MW-day, or $5,936 per MW of installed capacity for the year. The 2003 results represent a significant reduction from the 2002 Capacity Market revenues of $33.40 per MW-day or $11,601 per installed MW of capacity. The PJM Mid-Atlantic and PJM Western Regions had different Capacity Market designs from April 1, 2002 (the date of the PJM Western Region's integration), until June 1, 2003 (the date of the PJM Western Region Capacity Market's merger with the Mid-Atlantic Region Capacity Market). However, since there was no effective market in the Western Region, its capacity market prices did not represent market-clearing value transactions. The capacity value used in the net revenue calculations is the Mid-Atlantic market value through May 31, 2003, and the integrated PJM market value thereafter.[16]

Ancillary Service and Operating Reserve Net Revenue

Under the terms of the PJM tariff, generators also receive revenues for providing ancillary services, including those from the Spinning Reserve and Regulation Markets and from black start and reactive services. Aggregate ancillary revenues were $3,880 per installed MW-year in 2003 versus $3,915 per installed MW-year in 2002.

Although not included in the theoretical net revenue analysis above based on the assumption of perfect economic dispatch, generators also received operating reserve revenues from both the Day-Ahead and Balancing Energy Markets. Operating reserve payments were about $3,500 per installed MW-year in 2003 and $3,000 per installed MW-year in 2002. These payments, in part, ensure that generators are guaranteed accepted bid revenues from units scheduled by PJM, including the payment of start-up and no-load costs.

New Entrant Combustion Turbine/Combined-Cycle Net Revenue

An analysis of the theoretical net revenues available for a new combustion turbine (CT) or combined-cycle (CC) market entrant was performed to calculate the potential net revenues available. This calculation represents the upper bound of net revenue since it assumes perfect economic dispatch. For analysis purposes, the CT and CC heat rates were 10,500 Btu per kWh and 7,000 Btu per kWh, respectively, with a variable operations and maintenance (VOM) expense of $3 per MWh for the CT and $1 per MWh for the CC plant. The heat rate and VOM estimates were established by utilizing data from original equipment manufacturers (OEM) and available market data. The burner tip fuel cost was determined by utilizing the published Platt's commodity daily cash price for natural gas with a basis adjustment to account for transportation costs. Forced outage rates of 2.5 percent and 5.4 percent for the CT and CC, respectively, were used in this analysis. These outage rates are based upon OEM estimates for new facilities. Operating reserve payments are not included since the analysis represents perfect economic dispatch where marginal cost is equal to or less than system average LMP and, therefore, no operating reserve payments would be necessary. The summary of the potential net revenue streams for 1999 to 2003 are shown in Table 2-17 for a new CT and a new CC, both burning natural gas. These net revenue figures do not take account of operating constraints. For example, for a typical summer weekday, a six-hour hot status notification plus start-up time could prevent a unit from running during two profitable hours in the afternoon peak and two more profitable hours in the evening peak, separated by four unprofitable hours, or a combustion turbine with a limit of one start per day might not be available for the evening peak from the above example. As another example, ramp limitations might prevent a unit from starting and ramping up to full output in time to operate for all profitable hours.

16 See Section 4, "Capacity Markets," for further details.

Table 2-17 New Entrant Combustion Turbine and Combined-Cycle Plant Theoretical Net Revenues

Economic Dispatch Generic CT and CC Net Revenue Streams ($ per Installed MW - Year) Gas-Fired								
Year	CT Energy	CC Energy	Capacity	Ancillary	CT Total	CC Total	CT Run Hours	CC Run Hours
2003	$15,380	$53,743	$5,936	$3,880	$25,196	$63,559	964	2,791
2002	$27,626	$57,148	$11,601	$3,915	$43,142	$72,664	1,383	3,206
2001	$44,481	$74,831	$36,700	$3,823	$85,004	$115,354	1,373	3,507
2000	$19,876	$45,236	$23,308	$4,594	$47,779	$73,138	926	2,201
1999	$73,480	$97,603	$20,469	$3,444	$97,393	$121,516	1,415	4,199

Table 2-18 Burner Tip Average Fuel Price in PJM (in Dollars per MBtu)

Average Burner Tip Fuel Price (Dollars per Mbtu)	
Year	Natural Gas
2003	$6.45
2002	$3.81
2001	$4.52
2000	$5.18
1999	$2.62

Total Net Revenue

To put the net revenue results in perspective, the average gas cost in PJM in 2003 was about $6.45 per MBtu (Table 2-18) and the corresponding variable cost for a new combustion turbine was, on average, between $70 and $75 per MWh.[17] On average, the corresponding variable cost for a new combined-cycle unit was between $45 and $50 per MWh.[18] According to OEM and available market data, annual fixed costs for a new CT averaged approximately $68,000 per MW-year from 1999 to 2003 while a new CC plant averaged approximately $78,000 per MW-year over the same period.[19] Current annual fixed costs for a CT are somewhat higher than the CDR calculations of such costs of about $63,000 per MW-year.[20] The capacity costs of a new CT constructed in New England in 2001 was recently estimated to be $73,800 per MW-year.[21]

In 2003, net revenues from the Energy Market, the Capacity Market and ancillary services for a new entrant CT were approximately $25,200 and the associated operating costs were between $75 and $80 per MWh. These figures are based on a heat rate of 10,500 Btu per kWh, daily delivered natural gas prices that averaged $6.45 per MBtu and a variable operations and maintenance (VOM) rate of $3 per MWh. The net revenue stream would not have covered the fixed costs of peaking units with operating costs between $75 and $80 per MWh which ran during all profitable hours.

17 The analysis used the daily gas costs and associated production cost for CTs and CCs.

18 The key variables are fuel cost and heat rate.

19 The fixed costs in 2003 were somewhat less. The fixed costs for a CT were $65,600 and the fixed costs for a CC were $76,400

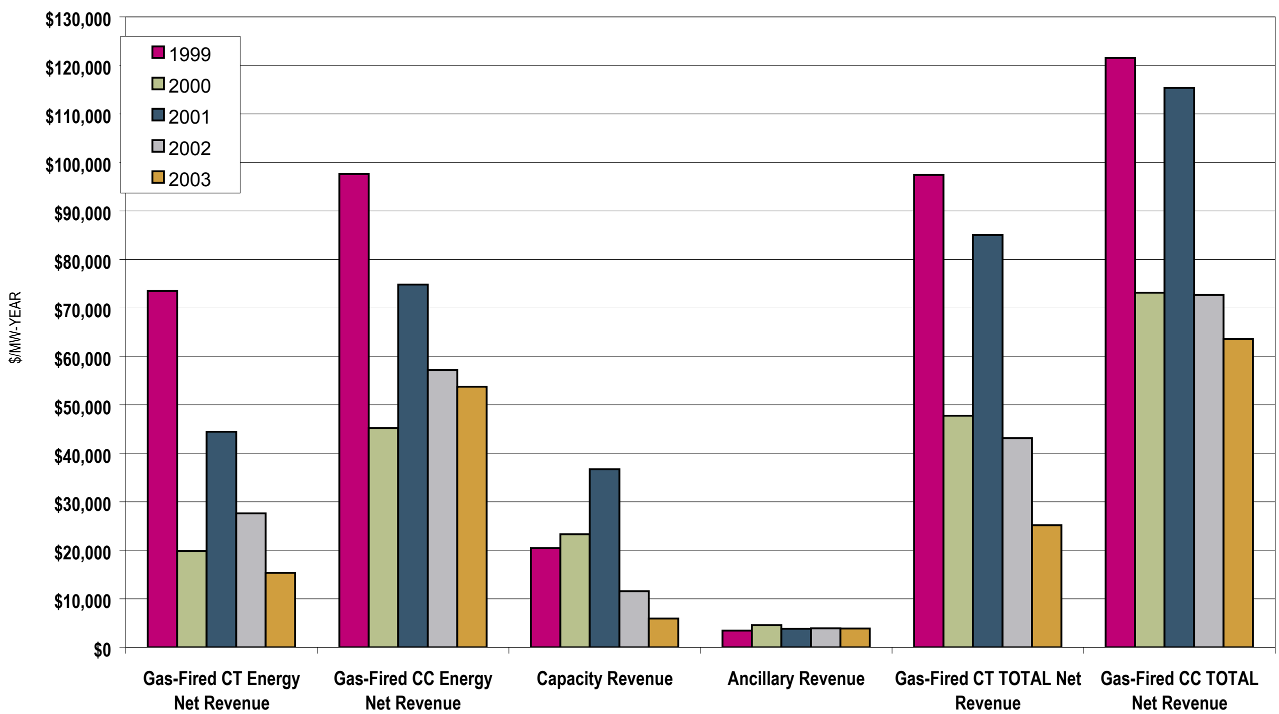
20 The CDR was designed to reflect the annual fixed costs of a CT in PJM and the annual fixed costs of the associated transmission investment, including a return on investment, depreciation and fixed operation and maintenance expense. The CDR also includes, as an offset, an energy credit of about $4,500 per MW-year designed to reflect the difference between the PJM dispatch rate and CT costs during the hours when the CTs run. The CDR was calculated in 1997. Thus the annual fixed cost of a CT in PJM, per CDR calculations, is about $63,000 per MW-year.

21 Acumen, Inc., "Final Report to ISO New England," December 10, 2001.

For a new entrant CC, the 2003 net revenue stream was approximately $63,600 and the associated operating costs were between $45 and $50 per MWh. These figures are based on a heat rate of 7,000 Btu per kWh, daily delivered natural gas prices that averaged $6.45 per MBtu and a variable operations and maintenance (VOM) rate of $1 per MWh. As with the case with the new entrant CT, this net revenue stream would not have covered the fixed costs of a CC plant with operating costs between $45 and $50 per MWh which ran during all profitable hours.

In 1999 and 2001 the calculated theoretical net revenue as shown in Table 2-17 for CT and CC plants was sufficient to cover the average fixed costs of $68,000 per installed MW-year and $78,000 per installed MW-year, respectively, while there was a revenue shortfall for 2000, 2002 and 2003. Five-year theoretical net revenue averaged $59,700 per installed MW-year for new entrant CT plants and $89,200 per MW-year for new entrant CC plants. Therefore, under theoretical conditions over the five-year period, net revenue was not adequate to cover CT fixed costs, but was more than adequate to cover the fixed costs of new entrant CC plants. The conclusion regarding both CT and CC plants depends on the actual fixed costs of such plants. While the net revenue calculations accurately reflect the stated assumptions, to the extent that annual fixed costs are higher than the estimate used here, the conclusion may be affected.

Figure 2-21 Theoretical New Entrant Combustion Turbine and Combined-Cycle Plant Yearly Net Revenue



Although it can be expected that in the long run, in a competitive market, net revenues from all sources will cover the fixed costs of investing in new generating resources, including a return on investment, actual results may vary from year to year. Revenues from the Capacity Market and the provision of ancillary services clearly vary from unit to unit, depending on particular capacity market transactions and the provision of specific ancillary services. The MMU's analysis of 2003 net revenues indicates that the fixed costs of a marginal unit were not fully covered. The data lead to the conclusion that generators' net revenues were less than the fixed costs of generation and that this shortfall emerged from lower, less volatile energy market prices and lower capacity market prices.

Net revenues provide an incentive to build new generation to serve PJM Markets. While these incentives operate with a significant lag time and are based on expectations of future net revenue, the amount of planned new generation in PJM reflects the market's perception of the incentives provided by the combination of revenues from the PJM Energy, Capacity and Ancillary Service Markets. At the end of 2003, about 15,200 MW of capacity were in generation request queues for construction through 2008 (Figure 2-22), compared to an average installed capacity of 71,473 MW in 2003. Although it is clear that not all of this generation will be completed, PJM is steadily adding capacity. Figure 2-23 shows the level of capacity that is in service and the level that has been withdrawn from the queues.

Figure 2-22 Queued Capacity by In-Service Date

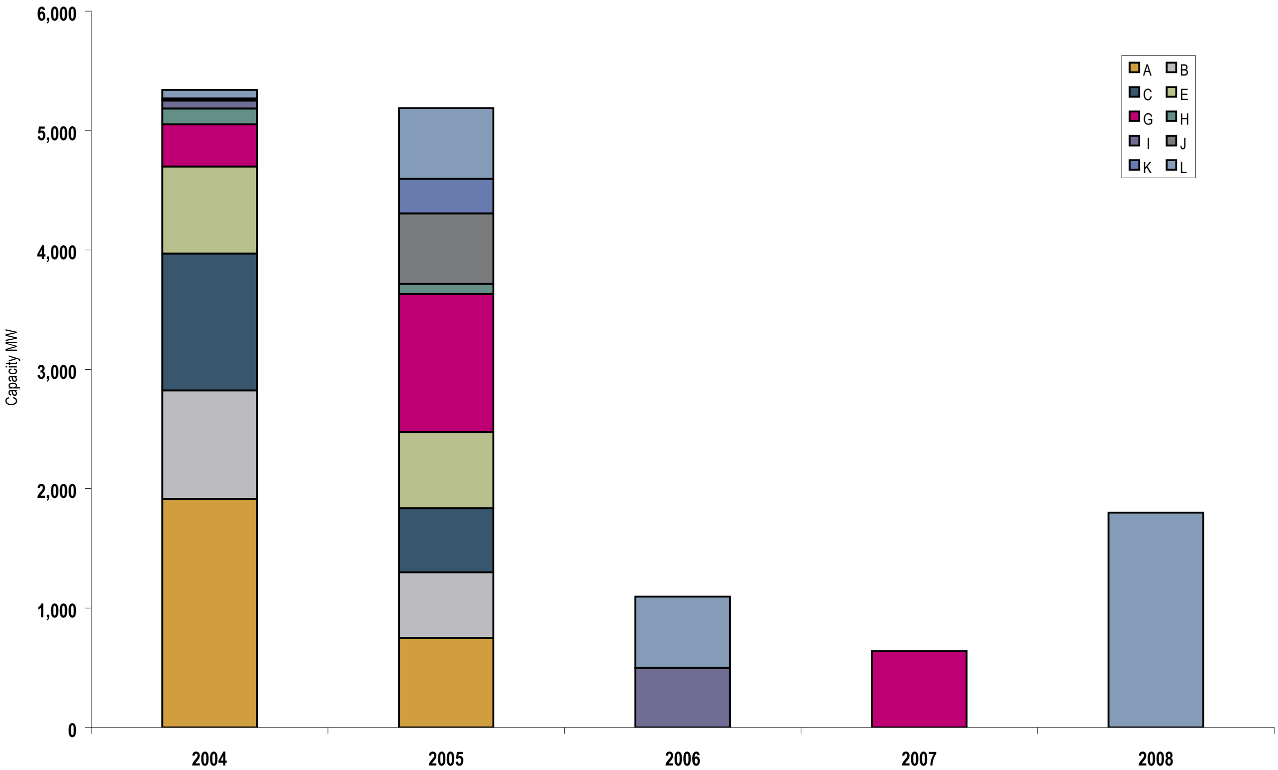
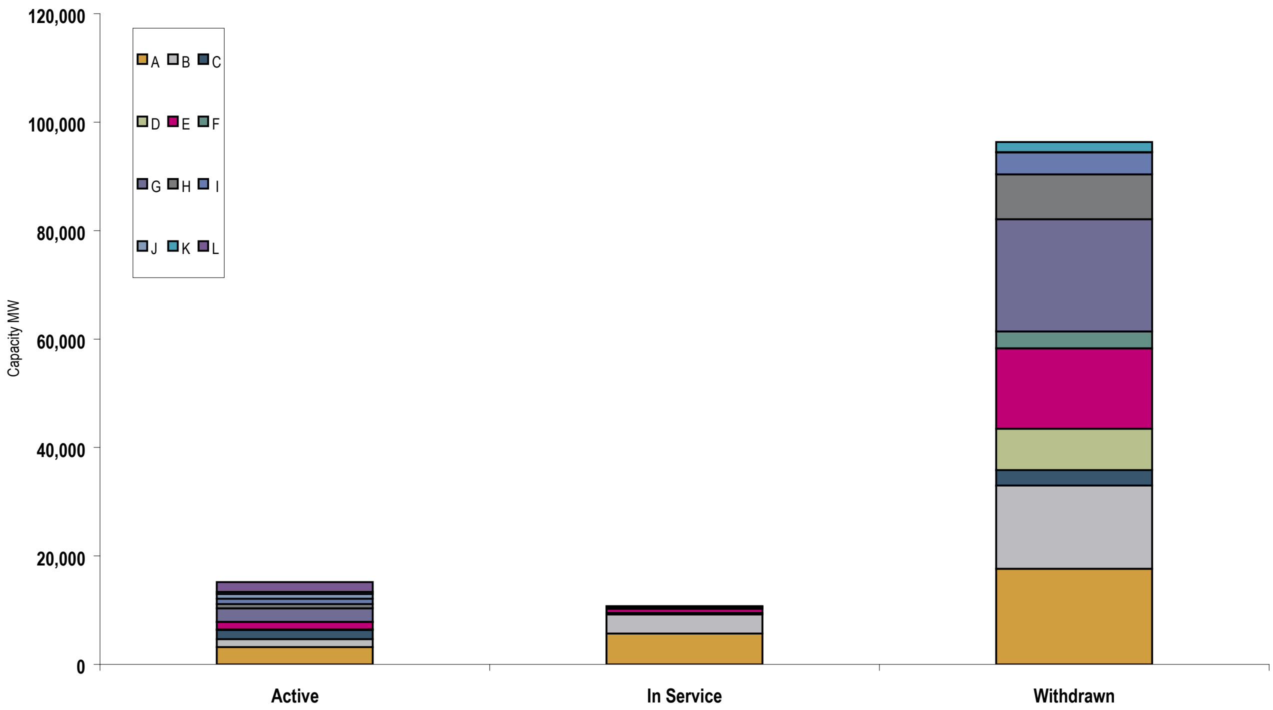


Figure 2-23 New Capacity in PJM Queues through December 31, 2003



Operating Reserve Payments

Operating reserve payments are made to resource owners under specified conditions in order to ensure that units are not required to operate for PJM at a loss. These payments provide an incentive to generation owners to offer their energy to the PJM Market at marginal cost and to operate their units at the direction of PJM dispatchers. If a unit is selected to operate in the PJM Day-Ahead Market on the basis of its offer and the revenues in the Energy Market are insufficient to cover all the components of that unit's offer, including start-up and no-load offers, operating reserve payments ensure that all costs offer components are covered[22].

Table 2-19 shows total operating reserve payments from 1999 through 2003. A number of significant market changes have occurred during this period. Energy Markets clearing on the basis of market-based generator offers were initiated on April 1, 1999. Thus the 1999 operating reserve total includes operating reserve payments for three months based on generators' marginal cost-based offers and for nine months based on generators' market-based offers. The Day-Ahead Market opened on June 1, 2000. Thus operating reserve payments for 1999 and the first five months of 2000 include only operating reserve payments made in the Balancing Market. Beginning on June 1, 2000, operating reserve payments include both day-ahead and balancing operating reserve payments. As Table 2-19 shows, between 2001, the first full year of two settlement operation, and 2002, operating reserve payments declined by about $62 million, or 25 percent. Between 2002 and 2003, operating reserve payments rose by approximately $85 million or 45 percent. Table 2-19 also shows the ratio of total operating reserve payments to the total value of PJM market billings. Over the last five years, the operating reserve payments ranged from a low of 3.0 percent in 1999 to a high of 7.5 percent in 2001; they were 4.0 percent in both 2002 and 2003.

Table 2-19 Total Day-Ahead and Balancing Operating Reserve Payments

	PJM Day-Ahead and Balancing Operating Reserve Payments	
Year	Annual Payment	Annual Payment Change
2003	$274,489,178	45.1%
2002	$189,114,344	-24.8%
2001	$251,583,885	71.3%
2000	$146,841,525	172.5%
1999	$53,886,408	----

Table 2-20 shows day-ahead and balancing operating reserve total payments and payments per MWh. Per MWh rates are calculated for each full year after the introduction of the Day-Ahead Market. The day-ahead billing determinant (denominator of the day-ahead rate) is the sum of the day-ahead demand plus accepted decrement bids plus exports. The balancing market billing determinant is the sum of the load, generation and transaction deviations from the Day-Ahead Market. In this context, transaction deviations include deviations that result from cleared virtual bids or offers from the Day-Ahead Market that were not subsequently delivered in the Balancing Market. The day-ahead operating reserve rate was lower in 2003 than in 2001 and the real-time operating reserve rate was higher in 2003 than in 2001.

22 Operating reserve payments are also made for pool-scheduled energy transactions, for generating units operating as condensers not for spinning reserves, for the cancellation of pool-scheduled resources, for units backed down for reliability reasons and for units providing quick start reserves.

Table 2-20 Day-Ahead and Balancing Operating Reserve Rates

Year	Annual Payment	Annual Payment Change	Operating Reserves as a Percent of Total PJM Billing
2003	$274,489,178	45.1%	4.0%
2002	$189,114,344	-24.8%	4.0%
2001	$251,583,885	71.3%	7.5%
2000	$146,841,525	172.5%	6.5%
1999	$53,886,408	----	3.0%

For each year from 2001 to 2003, total day-ahead and balancing operating reserve payments for the top-10 generating units were compared to the system total. As Table 2-21 shows, in 2001 the top-10 units represented 46.6 percent of total operating reserve payments. For 2002, the percentage dropped to 32.0 percent. For 2003, payments to the top-10 units represented 39.2 percent of total operating reserve payments. A relatively small number of generation owners accounted for a substantial proportion of total operating reserve payments in each year from 2001 through 2003.

Table 2-21 Top-10 Operating Reserve Revenue Units

	Percent of System Total		
	2003	2002	2001
Top Units	39.2%	32.0%	46.6%

A unit is eligible to receive operating reserve payments when it is selected by PJM in the Day-Ahead Energy Market and when its corresponding revenues are not sufficient to cover its offer value. In addition, if a generator is scheduled for operation in the Balancing Market and it operates as directed by PJM dispatchers, it is eligible to receive operating reserve payments when its corresponding revenues are not sufficient to cover its offer. The operating reserve payments act as a revenue guarantee for generators in order to provide an additional incentive to participate in the voluntary PJM scheduling and dispatch process.

The level of operating reserves payments made to specific units depends on the offer level of the units, unit operating parameters and the decisions made by PJM operators when scheduling generation in excess of demand.

To determine the contribution that unit price offers in excess of cost make to operating reserve payments, the MMU performed a markup analysis of the top-10 units. It calculated the markup using the formula [(Price – Cost)/Price] at the relevant operating point on the supply curve for each unit. As Table 2-22 shows, the markup for the top-10 units averaged 0.03 in 2001, 0.11 in 2002 and 0.17 in 2003. The markup for the top-10 units weights individual unit markup by generator output when operating reserves are paid. The markup rose from 2001 through 2003 despite a decline in the share of operating reserves paid to the top-10 units over that period. The increased markup resulted from higher company and unit-specific markups combined with increased hours during which PJM dispatched the higher markup units out of merit order. In 2001, the top-10 units had price offers much closer to their respective cost offers. As a comparison, the PJM system overall weighted-average markup was 0.02 in 2001, 0.02 in 2002 and 0.03 in 2003.

Table 2-22 Top-10 Operating Reserve Revenue Units' Markup

	Markup		
	2003	2002	2001
Top Units	0.17	0.11	0.03

Operating reserve payments also result from unit-specific operating parameters. For example, if a unit is needed by PJM for reliability purposes and if that unit, with a price offer equal to its cost offer, has only one permitted start per day, or has a 24-hour minimum run time and a minimum shutdown or long start time, then it receives higher operating reserve payments than if those operating parameters were not in place. Restrictive operating parameters can interact with unit-specific markups to increase operating reserve payments to units.

Operating reserve payments ultimately result from decisions of PJM operators to keep units operating even though the hourly LMP is less than their offer price, including the energy offer, start-up offer and no-load offer. These PJM decisions also interact with the level of the markup and the operating parameters to affect operating reserve payments to units.

The MMU will continue to examine the various factors underlying operating reserve payments. The reasons that a relatively small number of generation owners account for a substantial proportion of total operating reserve payments will be examined. The role of unit-specific, price-cost markups will be examined. The role of restrictive operating parameters will be examined. Finally, the role of PJM operations in contributing to overall operating reserve payment levels and to operating reserve payments to the top-10 units will be examined to ensure that PJM is operating in an efficient manner. The MMU will also examine the other rules governing operating reserve payments, including the requirement that they be based on a 24-hour average of LMP revenues and offers.

Load and LMP

Energy Market Prices

The conduct of individual market entities within a market structure is reflected in market prices. The overall level of prices is a good general indicator of market performance, although overall price results must be interpreted carefully because of the multiple factors that affect them.[23]

Prices are a key outcome of markets. Prices vary across hours, days and years for multiple reasons. Price is an indicator of the level of competition in a market although individual prices are not always easy to interpret. In a competitive market in long-run equilibrium, prices are directly related to the cost of the marginal unit required to serve load. The markup index is a direct measure of that relationship. LMP is a broader indicator of the level of competition. While PJM has experienced price spikes, these have been limited in duration and, in general, prices in PJM have been well below the marginal cost of the highest cost unit installed on the system. The pattern of prices within days and across months and years illustrates how prices are directly related to demand conditions and thus illustrates the potential significance of price elasticity of demand in affecting price.

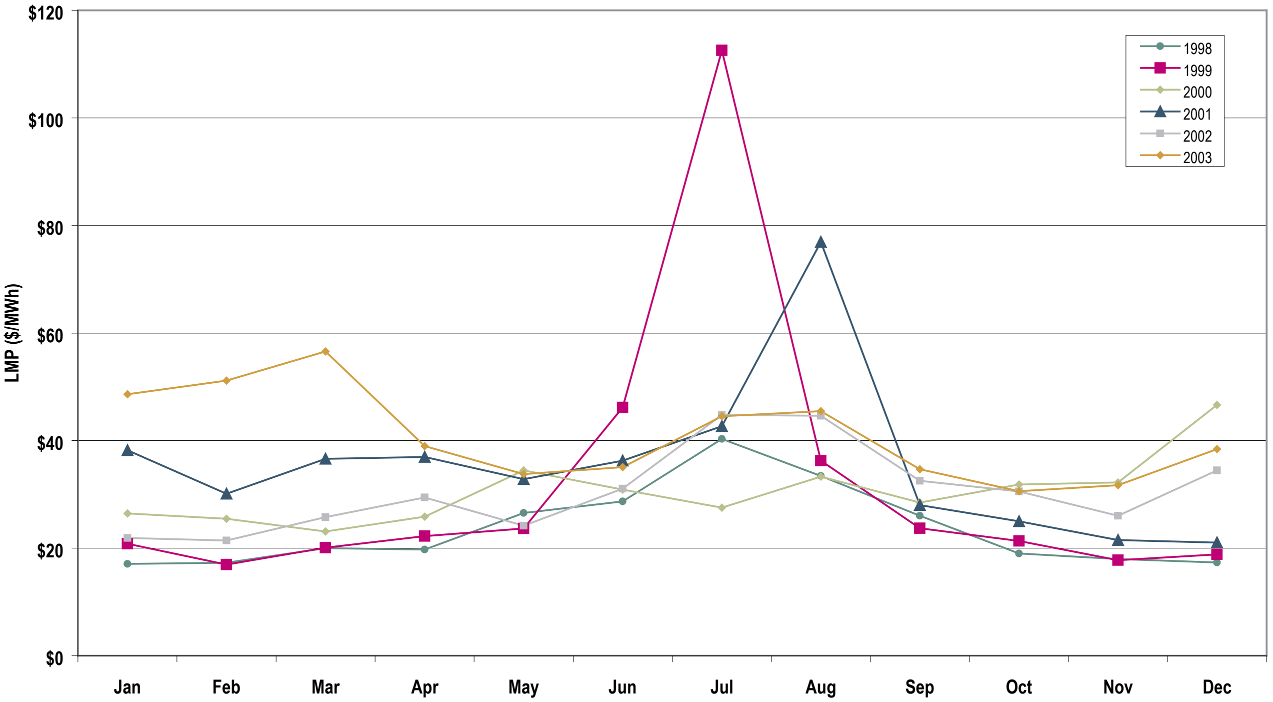
Real-Time Energy Market Prices

PJM real-time energy market prices increased in 2003. The simple hourly average system LMP[24] was 35.2 percent higher in 2003 than in 2002, $38.27 per MWh versus $28.30 per MWh. The average LMP in 2003 was higher than in all previous years since the introduction of markets in PJM. When hourly load levels are reflected, the load-weighted LMP of $41.23 per MWh in 2003 was 30.5 percent higher than in 2002, 12.5 percent higher than in 2001 and 34.2 percent higher than in 2000. The load-weighted result reflects the fact that market participants typically purchase more energy during high-priced periods and that peak-period prices are generally higher. In 2003, summer peak loads and prices were lower than in 2002, and in 2003 the highest prices occurred in the winter period. When increased fuel costs are accounted for, the fuel-cost-adjusted, load-weighted average LMP in 2003 was 9.5 percent lower than in 2002, $28.60 per MWh compared to $31.60 per MWh. Thus, after accounting for both the actual pattern of loads and the increased costs of fuel, average prices in PJM were 9.5 percent lower in 2003 than in 2002.

The annual increase in PJM system average LMP was significantly affected by prices in the first quarter. Prices in the first quarter of 2003 were much higher than in the first quarter of 2002. In the first quarter of 2003, average load-weighted, real-time LMP was $29.09 per MWh higher, or 127 percent, than during the comparable 2002 period. Load-weighted average LMP was $51.92 per MWh in the first quarter of 2003 and $23.02 per MWh in the first quarter of 2002 (Figure 2-24). As an illustration of the impact of first quarter results, if the first quarter 2003 LMPs had been the same as first quarter 2002 LMPs, the annual load-weighted LMP for 2003 would have been $34.44 per MWh (the actual was $41.23), or 9 percent higher than in 2002 (the actual increase was 30.5 percent).

23 See Appendix C, "Energy Market," for methodological background and detailed price data and comparisons.
24 The simple average system LMP is the average of the hourly LMP in each hour without any weighting.

Figure 2-24 Monthly Load-Weighted Average LMP (by Year)



Two principal factors contributed to the higher first quarter LMPs:

- **Marginal Fuel Prices.** A combination of higher natural gas prices and an increase in the proportion of hours that natural gas served as the marginal fuel contributed to higher first quarter prices. Natural gas prices increased 200 percent on average during the first quarter of 2003 as compared to the first quarter of 2002.

  Figure 2-25 shows average typical daily natural gas prices for units within PJM.[25] The price of No. 6 fuel oil also increased nearly 100 percent during the first quarter of 2003. Higher fuel costs have an impact on LMP only when units burning those fuels are on the margin. In the first quarter of 2003, in conjunction with the fuel price increases, units burning the more expensive fuels were on the margin, and thus set LMP more frequently. Units burning natural gas were on the margin 27 percent of the time in the first quarter of 2003, about twice as frequently as the 14 percent they had been on the margin during the same period in 2002. Oil burning units were on the margin nearly three times as frequently in the first quarter 2003 as in 2002, 17 percent and 6 percent, respectively. Correspondingly, the percentage of time that coal units were marginal decreased from 79 percent in 2002 to 55 percent in 2003. The cost of fuels affects the shape of the supply curve. The interaction of demand with that supply curve determines market prices.[26] Units burning natural gas and oil were on the margin more frequently in the first quarter of 2003 than in the first quarter of 2002 because demand for electricity was higher.

- **Demand.** On average, for all of 2003, load increased 5 percent over the 2002 load. However, load for the PJM Mid-Atlantic Region was nearly 10 percent higher in the first quarter of 2003 than in the first quarter of 2002. For the remainder of the year, load was nearly 2.5 percent less overall in 2003 than 2002 (Figure 2-26). As an illustration, if the first quarter 2003 load had been the same as the first quarter 2002 load, then overall average load for 2003 would have been 1.9 percent less than in 2002. Demand for electricity is a function of the weather. The winter period of 2002 (December 2001 through February 2002) was one of the warmest on record. In contrast, temperatures during the winter of 2003 (December 2002 through February 2003) were below normal. According to the National Climactic Data Center, average temperatures in the Northeast were nearly 13 degrees cooler in January 2003 than in January 2002, nine degrees cooler in February 2003 than in February 2002 and about the same in March for both years.

25 Natural gas prices are the average of the daily cash price for Transco, Z6, non-New York and Texas Eastern, M-3.
26 .Analysis of unit outage data showed no differences between the first quarter of 2003 and the first quarter of 2002.

Figure 2-25 Natural Gas Cash Prices

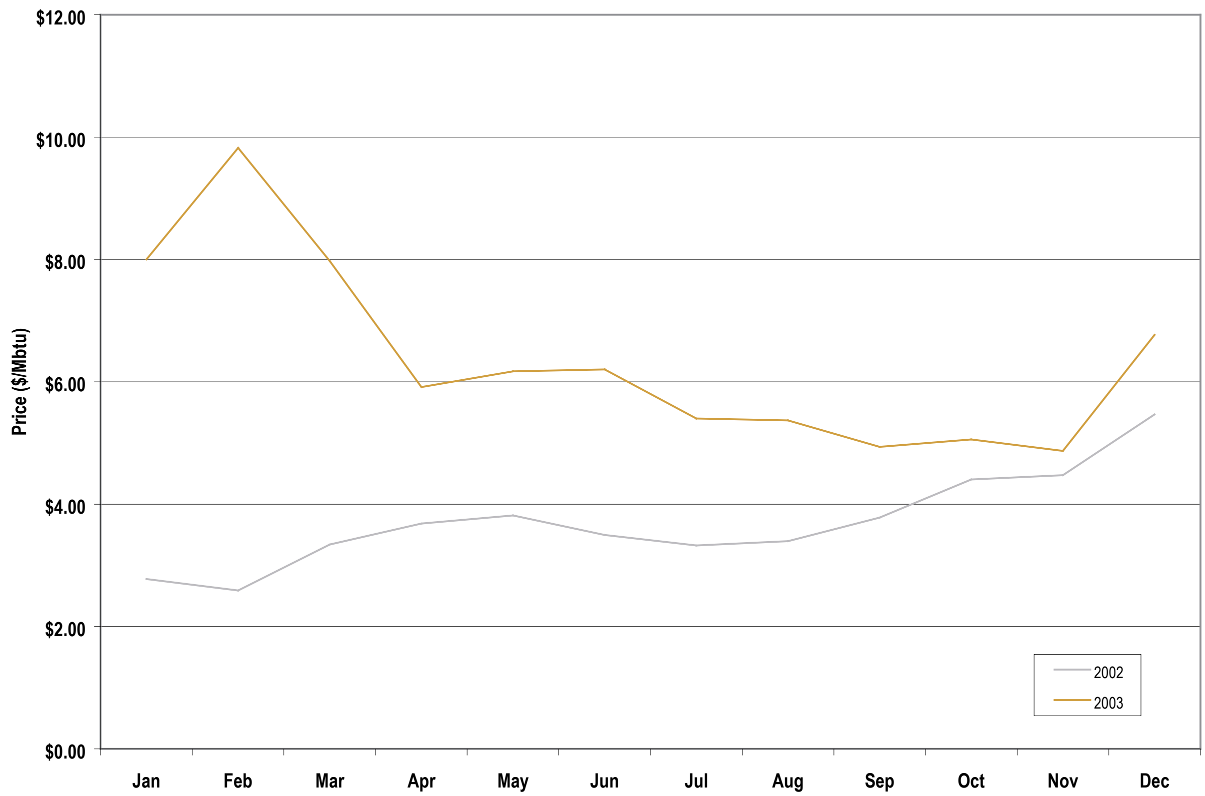
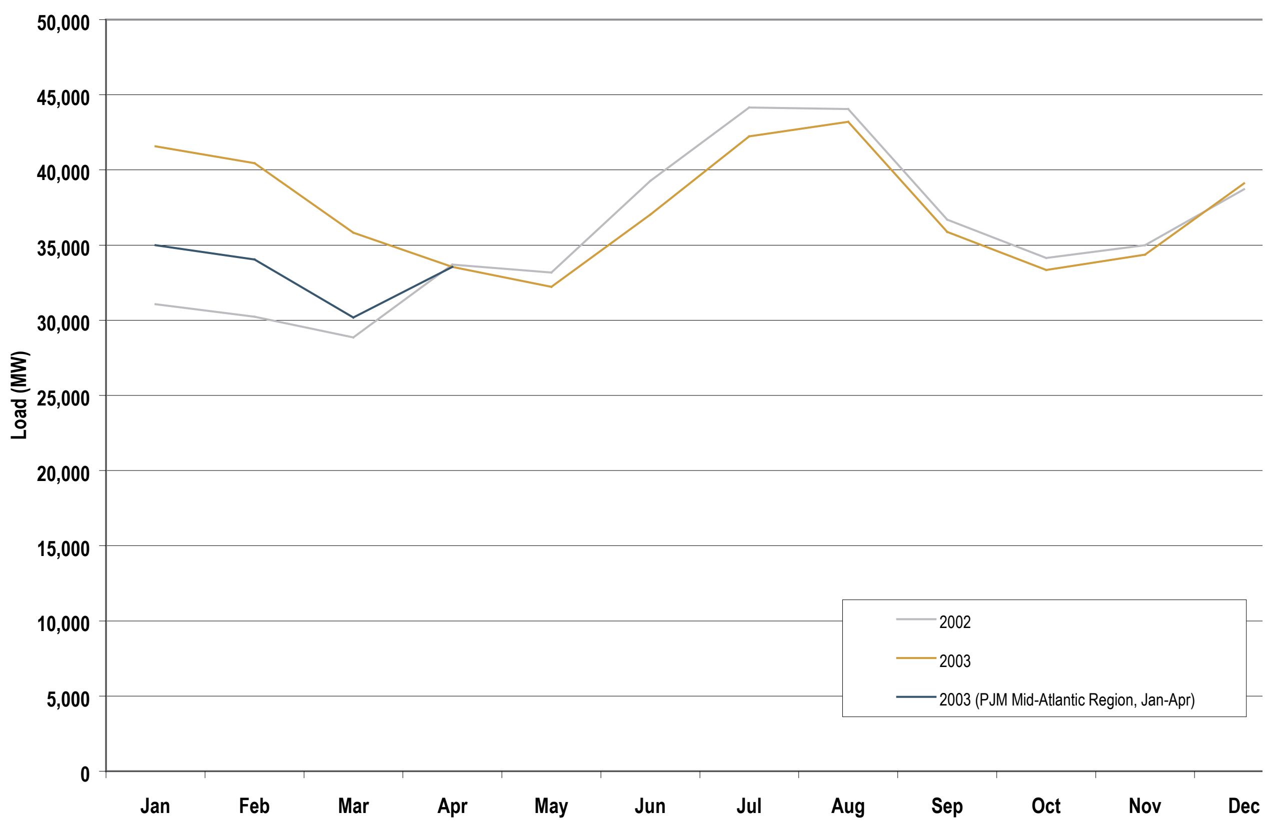


Figure 2-26 PJM Average Monthly Load



Average Hourly, System Unweighted LMP

At $38.27 per MWh, the average hourly, system unweighted LMP for 2003 was 35.2 percent higher than for 2002 (Table 2-23).[27]

Table 2-23 PJM Average Hourly Locational Marginal Prices (in Dollars per MWh)

	Locational Marginal Prices (LMP)			Year-to-Year Percent Change		
	Average	Median	Standard Deviation	Average LMP	Median LMP	Standard Deviation
2003	$38.27	$30.79	$24.71	35.2%	46.0%	10.3%
2002	$28.30	$21.08	$22.40	-12.6%	-8.3%	-50.6%
2001	$32.38	$22.98	$45.30	15.1%	20.3%	76.3%
2000	$28.14	$19.11	$25.69	-0.6%	6.9%	-64.5%
1999	$28.32	$17.88	$72.41	30.4%	7.7%	130.2%
1998	$21.72	$16.60	$31.45			

Price Duration

For 2003, prices were above $150 per MWh for only 11 hours, with the maximum LMP of $210 per MWh occurring on February 26.

While prices during most hours generally reflect the interaction of demand and energy offers, prices on high load days may reflect a combination of market power and scarcity. In 2002, however, the additional capacity provided by the PJM Western Region and new capacity built in the rest of PJM caused a downward shift in the supply curve and a shifting to the right of the upward sloping portion of the supply curve. In 2003, the shape of the supply curve remained generally the same as in 2002, with the exception of the first quarter of the year. In the first quarter, the flat portion of the curve shifted higher because of the rise in fuel costs. As in 2002, the shape of the supply curve combined with the level of demand meant that there were relatively few hours when scarcity existed or when there was an opportunity to exercise market power

Figure 2-27 compares the PJM system price duration curves for 1998, 1999, 2000, 2001, 2002 and 2003. A price duration curve shows the percent of hours that LMP was at or below a given price for the year. Figure 2-27 shows relatively little difference in LMPs for nearly 70 percent of the hours in each of the previous five years. The 2003 price duration curve shows higher prices for 2003 over a substantial portion of the curve. Figure 2-28 compares price duration curves for hours above the 95th percentile. Figure 2-28 shows that in all years, prices generally exceeded $100 per MWh between 1 and 2 percent of the hours. In 2003, despite overall higher LMPs, the price duration curve remained relatively flat in comparison to previous years, with LMPs never reaching higher than $210 per MWh.

Figure 2-27 and Figure 2-28 show that LMP exceeded $900 per MWh in 1998, 1999 and 2001. For 1998 and 1999, prices were greater than $900 per MWh for a total of 35 hours during the hot summer months. In 2001, prices rose to more than $900 per MWh for 10 hours during the week of August 6 when a new peak demand was set. Prices in 2002 never exceeded $800 per MWh, exceeded $700 per MWh for only one hour and exceeded $150 per MWh for 20 hours. Prices in 2003 exceeded $200 per MWh for only one hour and exceeded $150 per MWh for a total of 11 hours.

27 Hourly statistics were calculated from hourly integrated, PJM system LMPs and MCPs for January to March 1998. MCP is the single market-clearing price calculated by PJM prior to implementation of LMP.

Figure 2-27 PJM Price Duration Curves – Real-Time Market: 1998 - 2003

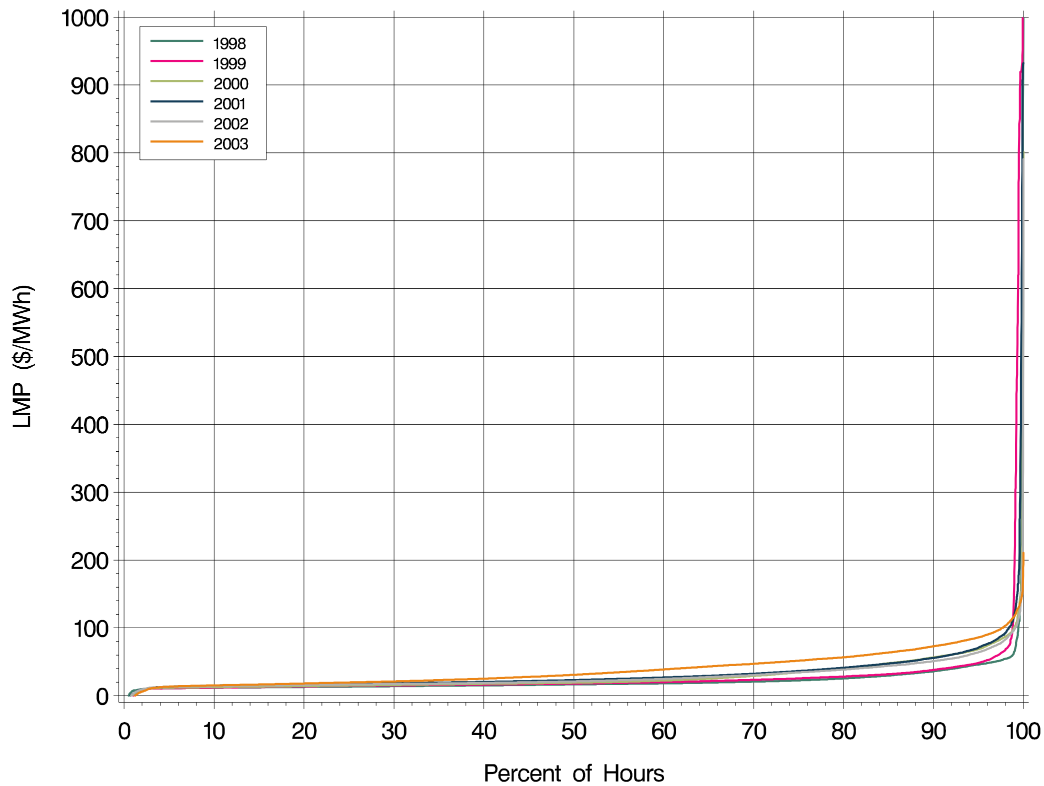
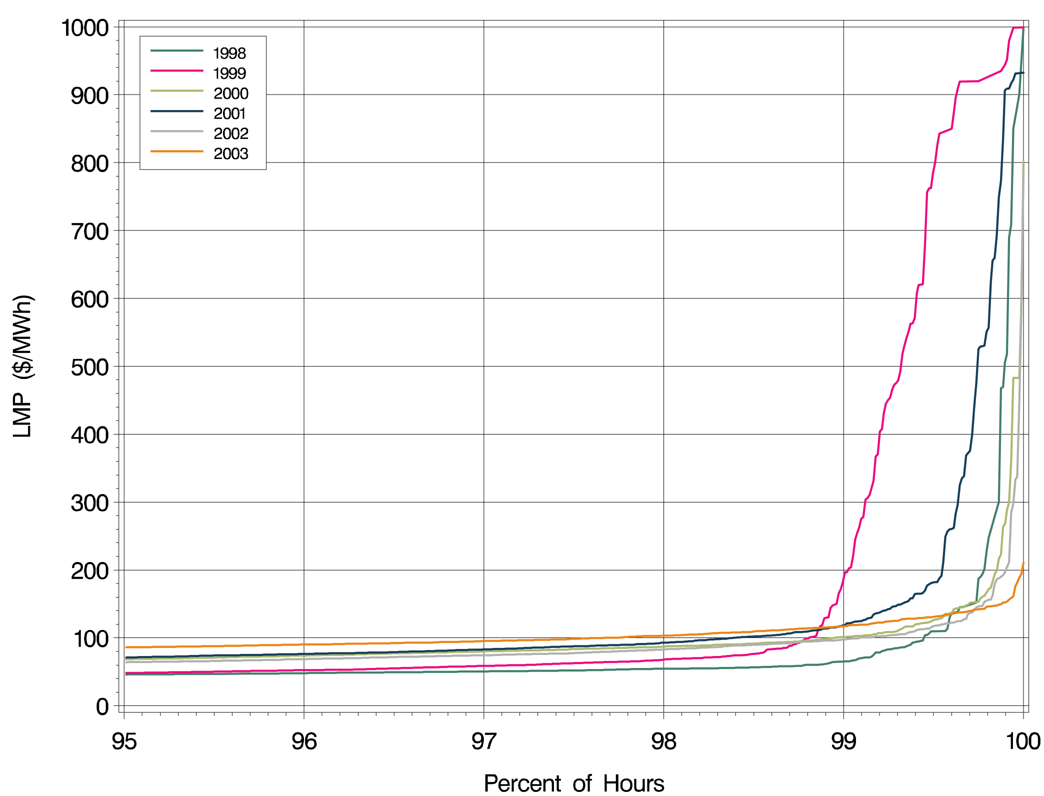


Figure 2-28 PJM Price Duration Curves – Real-Time Market – Hours above the 95th Percentile: 1998 - 2003



Load

Table 2-24 presents summary load statistics for the six-year period 1998 to 2003. The average load of 37,395 MW in 2003 was 5.2 percent higher than in 2002, reflecting colder than usual temperatures in the first quarter of 2003. In the first quarter of 2003, load for the PJM Mid-Atlantic Region was nearly 10 percent higher than in the first quarter of 2002. For the remainder of the year, however, PJM load was about 2.5 percent less in 2003 than in 2002[28] (Figure 2-26). The variability of load, as measured by the standard deviation, was lower in 2003 than in 2002.[29]

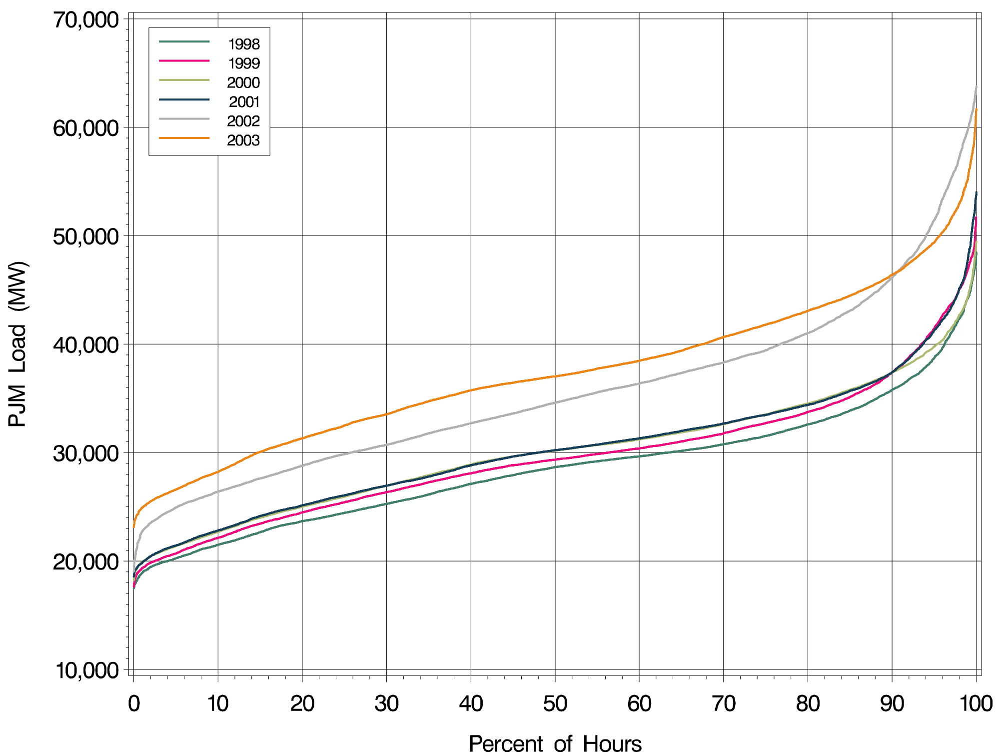
Table 2-24 PJM Load (in MW)

	PJM Load			Year-to-Year Percent Change		
	Average	Median	Standard Deviation	Average Load	Median Load	Standard Deviation
2003	37,395	37,029	6,834	5.2%	7.0%	-14.0%
2002	35,551	34,596	7,942	17.3%	14.5%	35.2%
2001	30,297	30,219	5,873	0.6%	0.2%	6.2%
2000	30,113	30,170	5,529	1.6%	2.8%	-7.2%
1999	29,640	29,341	5,956	3.7%	2.4%	8.1%
1998	28,577	28,653	5,512			

Load Duration

Figure 2-29 shows load duration curves for 1998, 1999, 2000, 2001, 2002 and 2003. A load duration curve shows the percent of hours when load was at or below a given level for the year. The 2003 load duration curve reflects the first full year of PJM Western Region load and lies above load duration curves for all years with the exception of the approximately 10 percent of the high-load hours in 2002 which had also included PJM Western Region load as well as higher summer load conditions.

Figure 2-29 PJM Hourly Load Duration Curve: 1998 - 2003



28 The PJM Western Region was added on April 1, 2002. The load comparison for the first quarter of 2003 is for PJM Mid-Atlantic Region load only. The comparison for the last three quarters of the year is for the PJM system. The average for the full year 2003 includes the additional load from the PJM Western Region during the first quarter. The table shows the actual 2002 and actual 2003 loads.

29 See Appendix C, "Energy Market," for additional load frequency details, including on-peak and off-peak loads.

Load-Weighted LMP

Market participants typically purchase more energy during high-priced periods as higher demand results in higher prices. As a result, when hourly load levels are reflected, the 2003 average hourly load-weighted LMP was about 8 percent higher than the simple average LMP.

Load-weighted LMP reflects the average LMP paid for actual MWh generated and consumed during a year. Hourly LMP is weighted by the total MW of load in each hour to derive load-weighted LMP.

As Table 2-25 shows, 2003 load-weighted LMP rose to $41.23 per MWh, 30.5 percent higher than in 2002, 12.5 percent higher than in 2001 and 34.2 percent higher than in 2000.[30]

Table 2-25 PJM Load-Weighted, Average LMP (in Dollars per MWh)

	Load-Weighted Average LMP			Year-to-Year Percent Change		
	Average	Median	Standard Deviation	Average LMP	Median LMP	Standard Deviation
2003	$41.23	$34.95	$25.40	30.5%	49.3%	-5.0%
2002	$31.60	$23.41	$26.74	-13.8%	-6.7%	-53.3%
2001	$36.65	$25.08	$57.26	19.3%	22.3%	101.8%
2000	$30.72	$20.51	$28.38	-9.8%	7.8%	-69.0%
1999	$34.06	$19.02	$91.49	41.0%	8.1%	132.9%
1998	$24.16	$17.60	$39.29			

Fuel Cost and Price

Changes in LMP can result from changes in unit costs. Fuel costs comprise the bulk of marginal costs for most generating units. To account for differences in fuel cost between 2002 and 2003, the 2003 load-weighted LMP was adjusted to reflect the change in price of fuels used by the marginal units and the change in marginal MW generated by each fuel type.[31]

Table 2-26 compares 2003 load-weighted, fuel-cost-adjusted, average LMP to 2002 load-weighted, average LMP.[32] After adjustment for fuel price changes, load-weighted, average LMP in 2003 was 9.5 percent lower than in 2002. If fuel prices for both years had been the same, the 2003 load-weighted LMP would have been $28.60 per MWh instead of $41.23 per MWh. This means that, but for the increases in fuel costs, LMP would have been lower in 2003 than in 2002. The fact that higher fuel prices were reflected in higher Energy Market prices is consistent with the functioning of a competitive market.

Table 2-26 PJM Load-Weighted, Fuel-Cost-Adjusted LMP (in Dollars per MWh)

	2003	2002	Percent Change
Average LMP	$28.60	$31.60	-9.5%
Median LMP	$24.40	$23.41	4.2%
Standard Deviation	$16.94	$26.74	-36.6%

30 See Appendix C, “Energy Market,” for peak and off-peak load-weighted LMP details.

31 See Appendix C, “Energy Market,” for fuel cost adjustment method.

32 Note that the base of the comparison is the simple load-weighted average LMP. This comparison is for these two years only and cannot be extended to multiple years.

Day-Ahead Energy Market LMP

When the PJM Day-Ahead Energy Market was introduced on June 1, 2000, it was expected that competition would cause prices in the Day-Ahead and Real-Time Energy Markets to converge. As the following tables and graphs show, day-ahead prices and real-time prices have converged. Day-ahead prices were higher than real-time prices by $0.45 per MWh on average during 2003. During 2002, day-ahead prices were $0.16 per MWh higher than real-time prices. In 2001, day-ahead prices were $0.37 per MWh higher than real-time prices, and in 2000, day-ahead prices were $1.61 per MWh higher than real-time prices.

Figure 2-30 shows 2003 price duration curves for the two markets, while Figure 2-31 shows 2003 price duration curves for hours above the 95th percentile. The two figures show that real-time and day-ahead prices were almost coincident for the lowest priced 20 percent of the hours and again during the 60 to 80 percent range, with some alteration in the pattern over the course of the hours. Real-time prices were slightly higher for the remaining 20 percent of the hours while the difference increased in the highest priced 1 percent of the hours.

Figure 2-30 PJM Price Duration Curves -- Real-Time and Day-Ahead Energy Markets: 2003

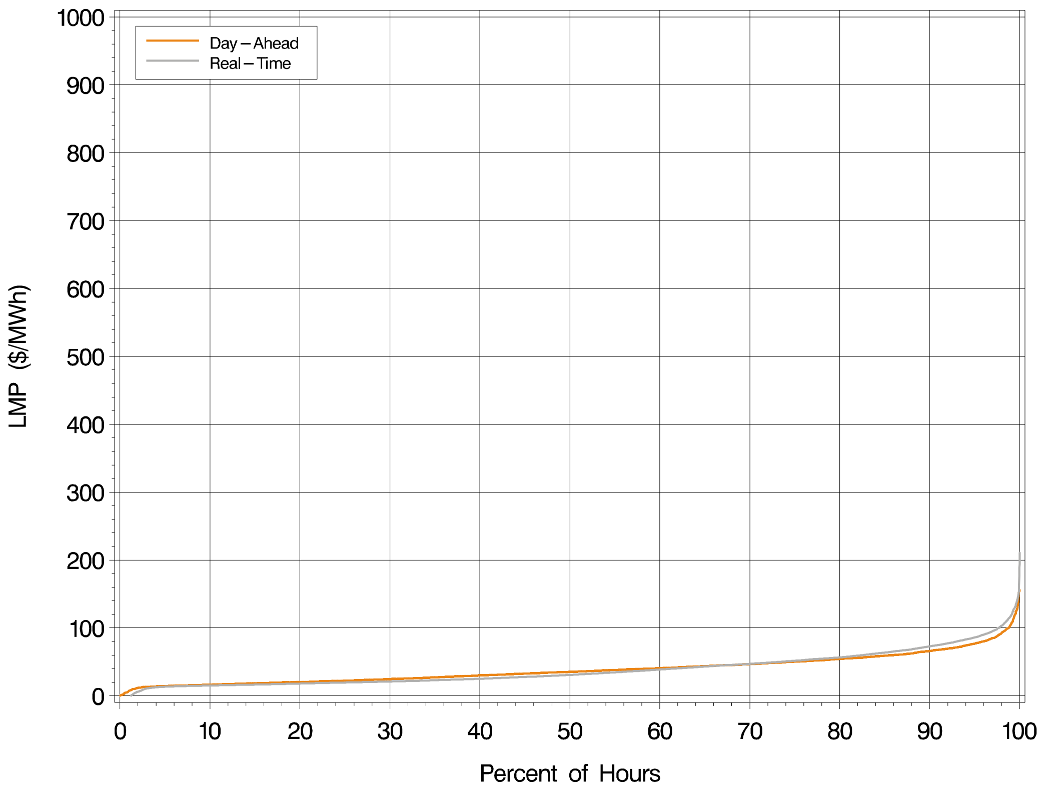


Figure 2-31 PJM Price Duration Curves -- Real-Time and Day-Ahead Energy Markets – Hours above the 95th Percentile: 2003

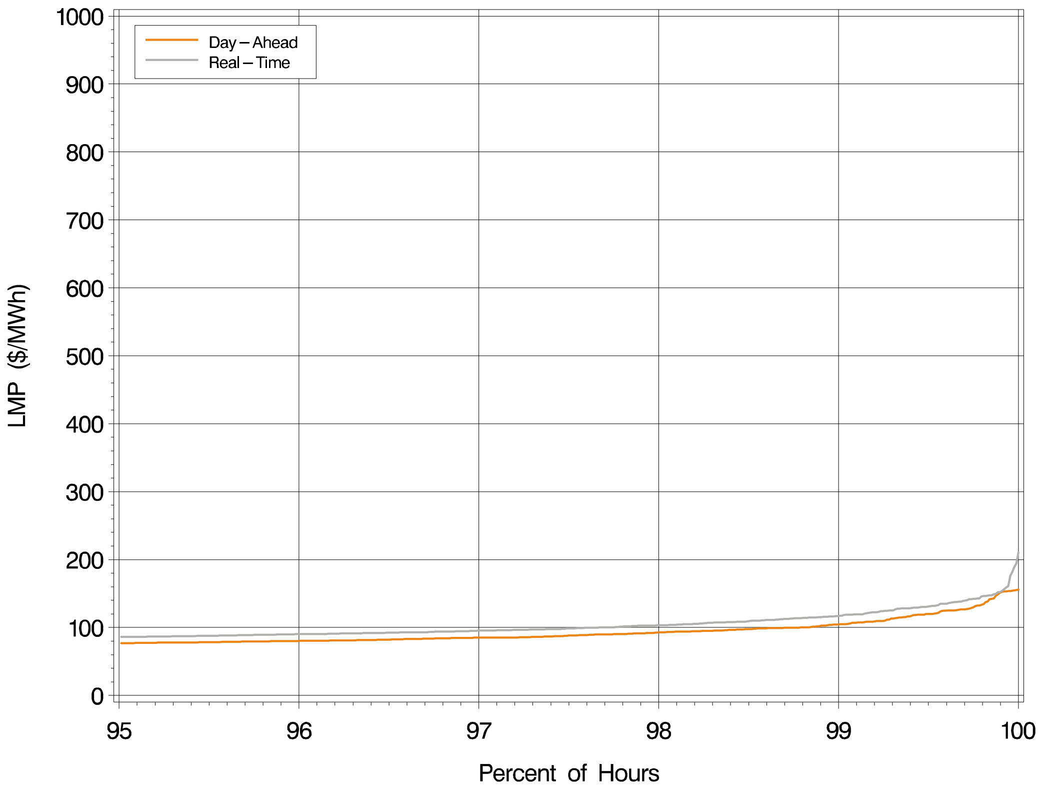


Figure 2-32 compares average hourly day-ahead and real-time LMP for 2003. Although the average difference between the Day-Ahead and Real-Time Markets was only $0.45 per MWh for the entire year, Figure 2-32 shows considerable variation, both positive and negative, between day-ahead and real-time prices, especially during the first quarter of the year. Figure 2-33 shows the average hourly levels of real-time and day-ahead LMP.[33]

33 See Appendix C, "Energy Market," for more details on the frequency distribution of prices.

Figure 2-32 Hourly Real-Time LMP minus Day-Ahead LMP: 2003

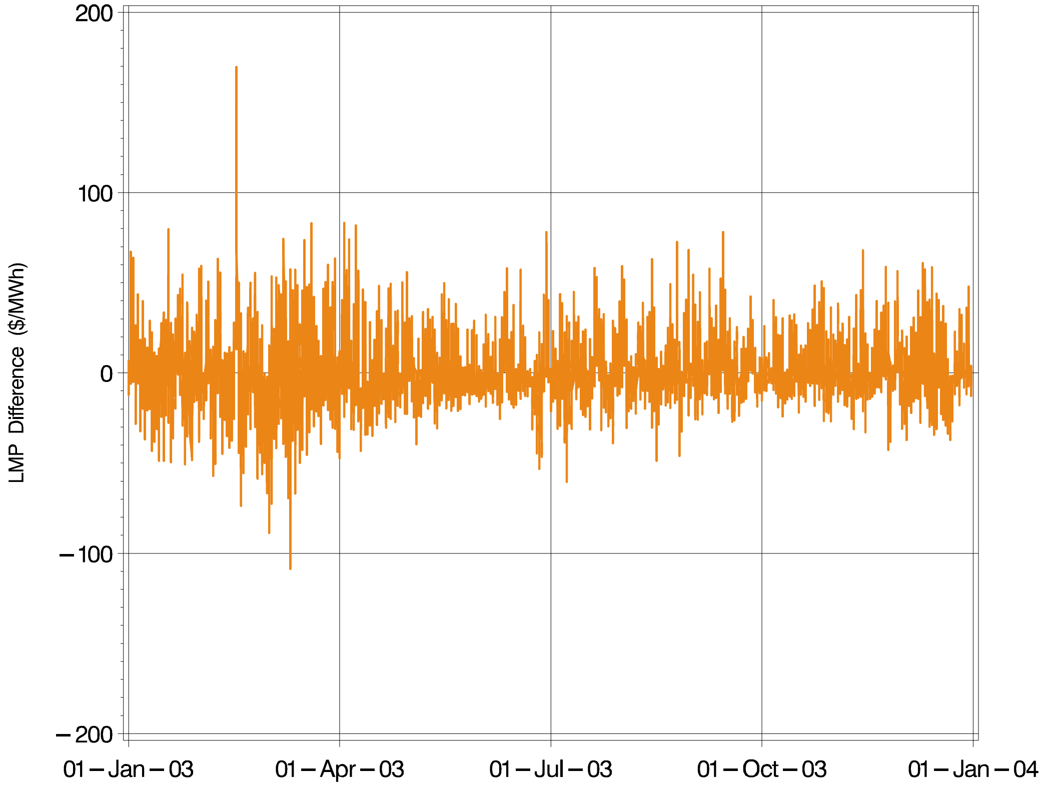


Figure 2-33 PJM Average Hourly System LMP

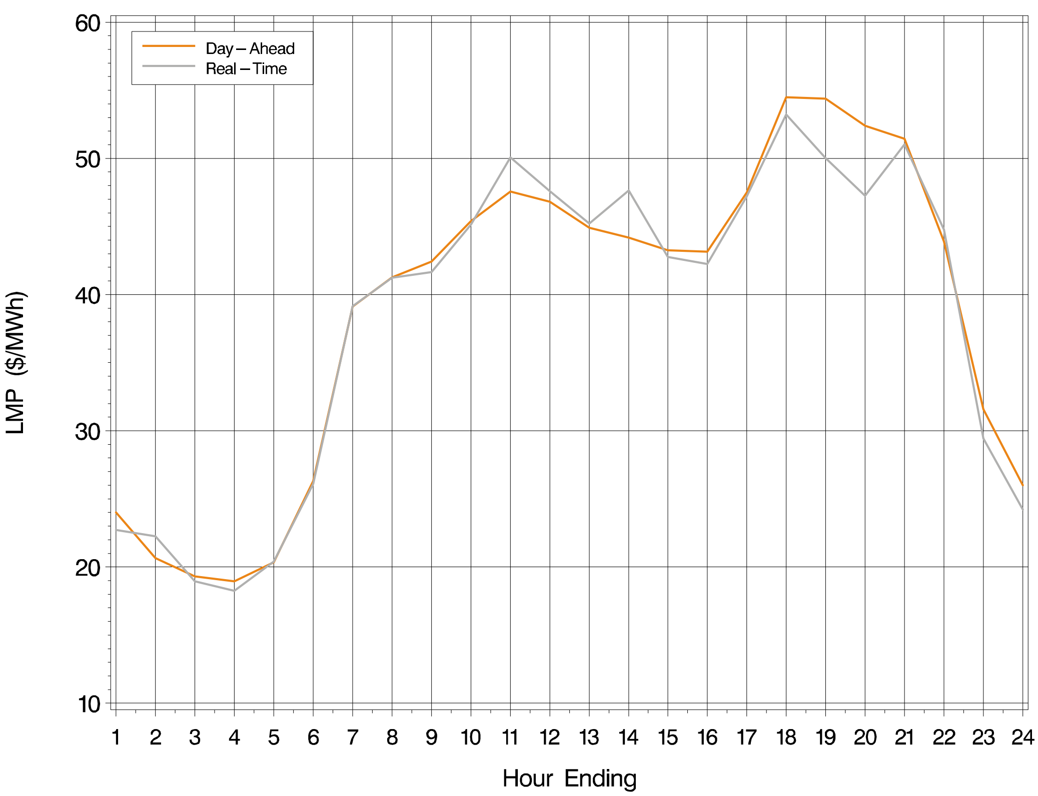


Table 2-27 presents summary statistics for the two markets. Average LMP in the Day-Ahead Energy Market was $0.45 per MWh or 1.2 percent higher than average LMP in the Real-Time Energy Market. The day-ahead median LMP was 14.4 percent higher than real-time LMP, reflecting an average difference of $4.43 per MWh. Consistent with the price duration curve, price dispersion in the Real-Time Energy Market was 15.7 percent greater than in the Day-Ahead Energy Market, with an average difference in standard deviation between the two markets of $3.87 per MWh.[34]

Table 2-27 Comparison of Real-Time and Day-Ahead 2003 Market LMP (in Dollars per MWh)

	Day-Ahead	Real-Time	Difference	Difference as Percent Real-Time
Average LMP	$38.72	$38.27	-$0.45	-1.2%
Median LMP	$35.21	$30.79	-$4.43	-14.4%
Standard Deviation	$20.84	$24.71	$3.87	15.7%

Day-Ahead and Real-Time Generation

Real-time generation is the actual production of electricity during the operating day.

In the Day-Ahead Energy Market[35], three types of financially binding commitments for generation are made and cleared:

- **Self-Scheduled.** Units submitted as a fixed block of MW that must be run, or as a minimum amount of MW that must run plus a dispatchable component above the minimum.

- **Generator Offers.** Schedules of MW offered and the corresponding offer price.

- **Increment Offers.** Financial offers to supply specified amounts of MW at or above a given price.

Figure 2-34 shows average hourly values of day-ahead generation, day-ahead generation plus increment offers and real-time generation for 2003. Day-ahead generation is all generator offers cleared in the Day-Ahead Energy Market. During 2003, real-time generation was always higher than day-ahead generation. If, however, increment offers were added to day-ahead generation, total day-ahead MW offers would have always exceeded real-time generation.

34 See Appendix C, "Energy Market" for more details on the frequency distribution of prices.

35 All referencees to day-ahead generation and increment offers in the "Day-Ahead and Real-Time Generation" portion of the "Energy Market" section of this report are presented in cleared MW amounts.

Figure 2-34 2003 Average Hourly Values for Real-Time and Day-Ahead Generation

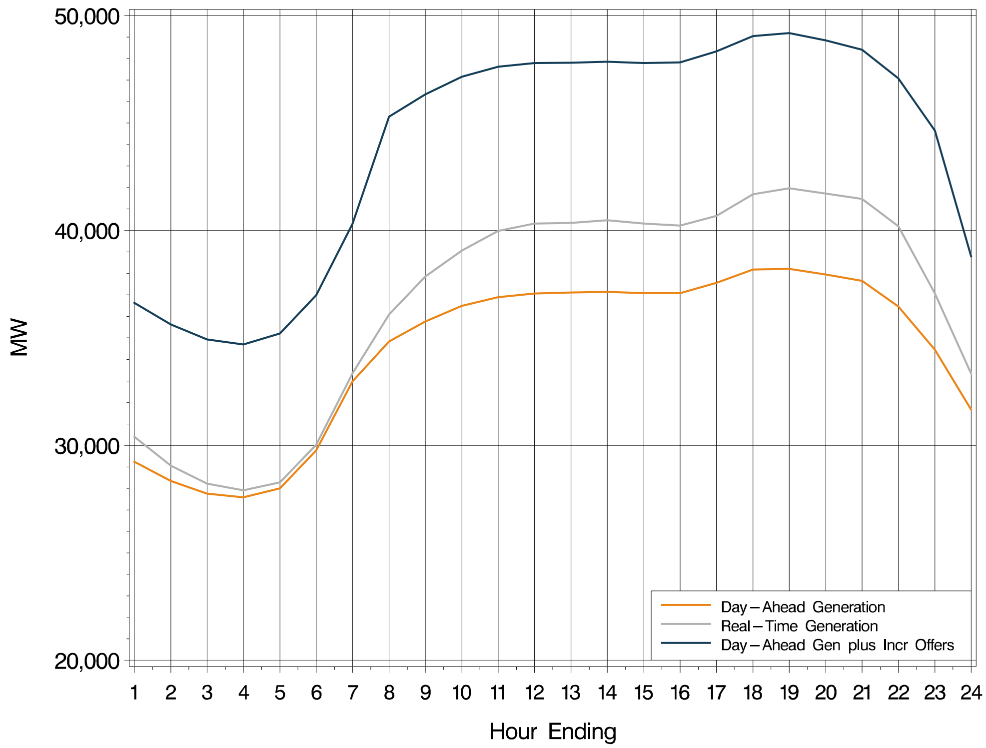


Table 2-28 presents summary statistics for 2003 day-ahead and real-time generation and the average differences between them. Day-ahead generation averaged 2,282 MW less than real-time generation. The sum of day-ahead generation offers and increment offers was 7,255 MW higher than real-time generation.

Table 2-28 2003 Day-Ahead and Real-Time Generation (in MW)

	Day-Ahead		Real-Time	Average Difference	
	Generation	Increment Offers	Generation	Generation	Generation plus Increment Offers
Average MW	34,389	9,537	36,672	-2,282	7,255
Median MW	34,297	9,007	36,580	-2,283	6,723
Standard Deviation	5,938	2,565	7,485	-1,547	1,018

Table 2-29 demonstrates that during 2003 differences between the sum of the two types of day-ahead generation offers and real-time generation were greatest during peak hours.

Table 2-29 shows the average MW offer values in the PJM Day-Ahead and Real-Time Markets during the off-peak and on-peak hours, while Table 2-30 shows the average differences between day-ahead generation and increment offers and real-time generation during both the off-peak and on-peak hours. Day-ahead generation was less than real-time generation in both periods. The average difference between day-ahead and real-time generation during off-peak hours was 1,216 MW, and the average difference during peak hours was 3,505 MW. The sum of day-ahead generation and increment offers exceeded real-time generation during both periods. During off-peak hours, day-ahead generation plus increment offers averaged 6,361 MW more than real-time generation; and during peak hours, day-ahead generation plus increment offers averaged 8,280 MW more than real-time generation.

Table 2-29 2003 Day-Ahead and Real-Time On-Peak and Off-Peak Generation (in MW)

	Day-Ahead				Real-Time	
	Off-Peak Generation	On-Peak Generation	Off-Peak Increment Offers	On-Peak Increment Offers	Off-Peak Generation	On-Peak Generation
Average MW	31,220	38,024	7,578	11,785	32,436	41,529
Median MW	30,816	37,017	7,589	11,607	31,755	40,214
Standard Deviation	5,029	4,688	1,080	1,826	6,166	5,702

Table 2-30 Average 2003 Differences between Day-Ahead and Real-Time Markets (in MW)

	Off-Peak		On-Peak	
	Generation	Generation Plus Increment Offers	Generation	Generation Plus Increment Offers
Average MW Difference	-1,216	6,361	-3,505	8,280
Median MW Difference	-939	6,650	-3,197	8,410

Day-Ahead and Real-Time Load

Real-time load is the actual load on the system during the operating day. In the Day-Ahead Energy Market, three types of financially binding bids are made:

- **Fixed-Demand Bids.** Bids to purchase a defined MW level of energy, regardless of LMP.
- **Price-Sensitive Bids.** Bids to purchase a defined MW level of energy only up to a specified LMP, above which the load bid is zero.
- **Decrement Bids.** Financial bids to purchases a defined MW level of energy up to a specified LMP, above which the bid is zero. Decrement bids are financial bids that can be submitted by any market participant.

Figure 2-35 shows the average 2003 hourly values of day-ahead load, fixed-demand, price-sensitive load, decrement bids and total day-ahead and real-time load (total day-ahead load is the sum of the three demand components).

Figure 2-35 2003 Average Hourly Values for Real-Time and Day-Ahead Loads

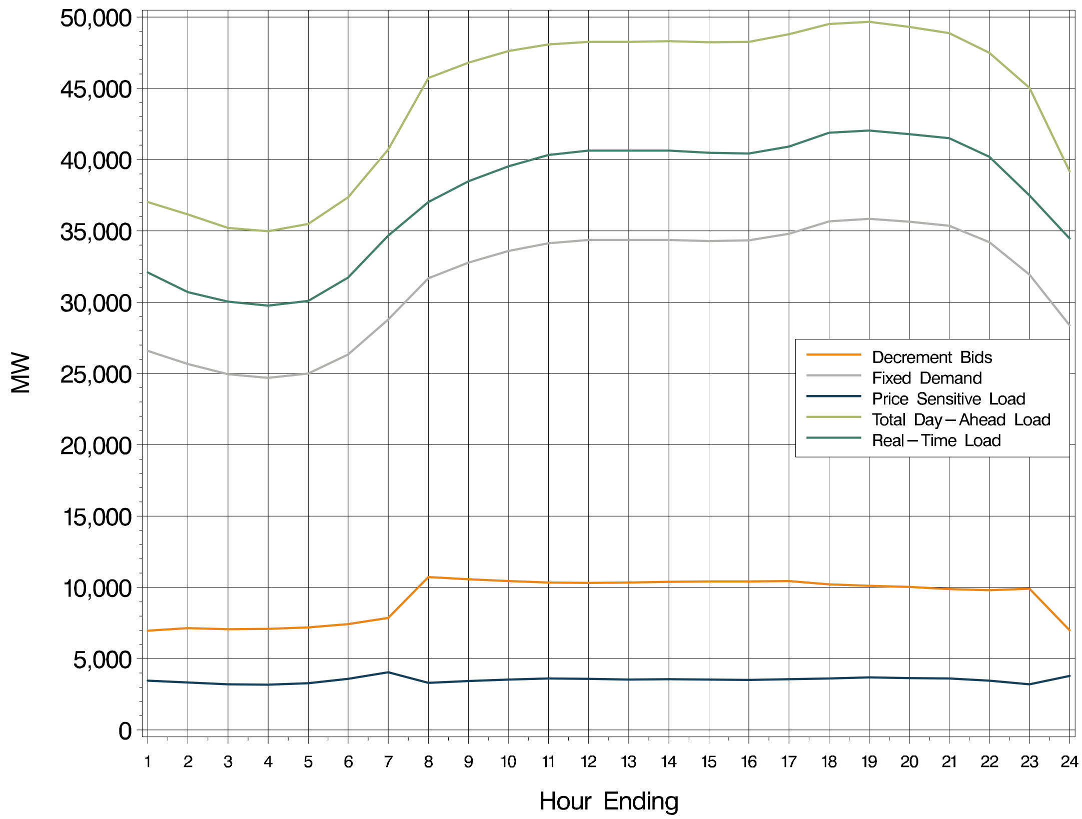


Table 2-31 presents summary statistics for 2003 day-ahead load components, total day-ahead load, real-time load and the average difference between total day-ahead load and total real-time load.

As Figure 2-35 and Table 2-31 show, during 2003 total day-ahead load was higher than real-time load by an average of 6,947 MW. The table also shows that, at 71 percent, fixed demand was the largest component of day-ahead load. At 8 percent, price-sensitive load was the smallest component, with cleared decrement bids accounting for the remaining 21 percent of day-ahead load.

Table 2-31 2003 Day-Ahead and Real-Time Load (in MW)

	Day-Ahead				Real-Time	
	Fixed Demand	Price Sensitive	Decrement Bids	Total Load	Total Load	Average Difference
Average MW	31,569	3,517	9,253	44,340	37,393	6,947
Median MW	31,606	3,511	9,101	44,368	37,028	7,340
Standard Deviation	6,002	871	2,173	7,883	6,835	1,048

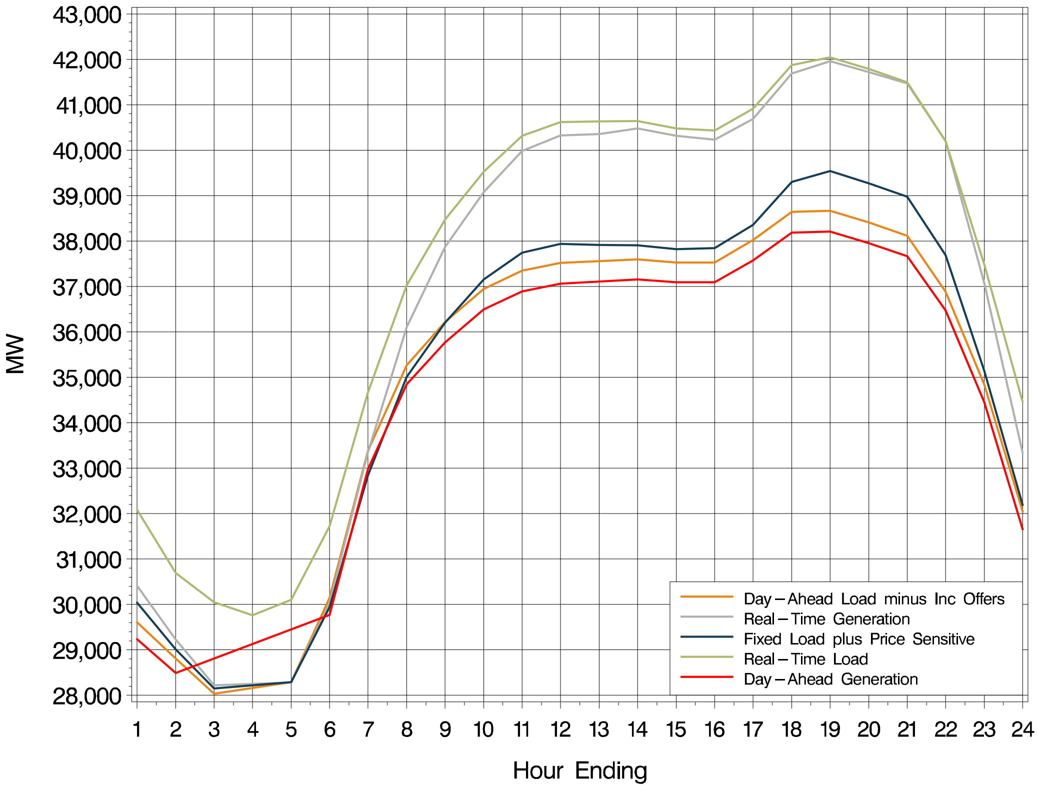
As Figure 2-35 shows, except for price-sensitive demand, day-ahead load components increased during on-peak hours as did real-time load. Table 2-32 shows the average load MW values in the Day-Ahead and Real-Time Markets for 2003 during the off-peak and on-peak hours. During 2003, real-time load was always higher than fixed-demand load plus price-sensitive load in the Day-Ahead Market. If, however, decrement bids were included, then the day-ahead load would have always exceeded real-time load and total day-ahead load would have been higher than real-time load during both off-peak and on-peak hours. The average difference during off-peak hours was 5,592 MW, while the average difference during on-peak hours was 8,502 MW. The percentage of day-ahead load comprised by each of the components was similar during the two periods. At 71 percent, fixed demand accounted for the largest percentage of day-ahead load during both the off-peak and on-peak periods. Price-sensitive load, at 9 and 7 percent, respectively, accounted for the smallest percentage during both periods while decrement bids accounted for 20 percent and 22 percent, respectively.

Table 2-32 2003 Day-Ahead and Real-Time Load During On-Peak and Off-Peak Hours (in MW)

	Day-Ahead								Real-Time	
	Off-Peak				On-Peak				Off-Peak	On-Peak
	Fixed Demand	Price Sensitive	Dec Bids	Total Load	Fixed Demand	Price Sensitive	Dec Bids	Total Load	Total Load	Total Load
Average	27,799	3,688	7,697	39,183	35,896	3,322	11,039	50,257	33,591	41,755
Median	27,264	3,670	7,581	38,866	35,044	3,358	10,972	48,673	32,970	40,802
Standard Deviation	4,473	838	1,323	5,441	4,401	867	1,471	5,826	5,547	5,424

Figure 2-36 shows day-ahead and real-time load and generation for 2003. For this analysis, increment offers were subtracted from total day-ahead load. Since increment offers look like generation, their subtraction from day-ahead load provides an estimate of day-ahead generation that would have had to be turned on to meet the load.

Figure 2-36 2003 Real-Time and Day-Ahead Load and Generation: Average Hourly Values



Impact of August 2003 Power Disturbance on LMP

A major electricity outage occurred on August 14, 2003, a few minutes after 4 p.m. EDT in large areas in the Northeast and Midwest United States as well as in Canada. It has been estimated that 50 million people were affected.

PJM was serving approximately 61,200 MW of load at the time of the disturbance. PJM experienced a sustained loss of load of approximately 4,500 MW. About 4,100 MW of the load loss occurred in northeastern New Jersey with the remaining 400 MW of load loss occurring in northwestern Pennsylvania. In addition, 56 generating units tripped off line as a result of the disturbance.

During this time period, however, the PJM Energy Market remained competitive, and there was no discernable impact on LMP during or after the event. Bidding also remained competitive.

Demand-Side Response (DSR)

Markets require both a supply side and a demand side to function effectively. The demand side of wholesale energy markets is severely underdeveloped. This underdevelopment is one of the basic reasons for maintaining an offer cap in PJM and in other wholesale power markets. It is widely recognized that wholesale energy markets will work better when a significant level of potential demand-side response is available in the market. The PJM demand-side programs should be understood as one part of a transition mechanism to a fully functional demand side of its Energy Market.

A functional demand side of the energy market does not mean that all customers will curtail usage at specified levels of price. A fully functional demand side of the energy market does mean that all or most customers, or their designated proxies, will have the ability to see real-time prices, will have the ability to react to real-time prices in real time and will have the ability to receive the direct benefits or costs of changes in real-time energy usage. If these conditions are met, customers can decide for themselves the relationship between the value and price of power for particular activities from operating a production plant to running a commercial building to smaller scale retail and residential applications. The true goal of demand-side programs is to ensure that customers have the capabilities required to make informed decisions about energy consumption. Customers can and will make investments in demand-side management technologies based on their own evaluations of those tradeoffs.

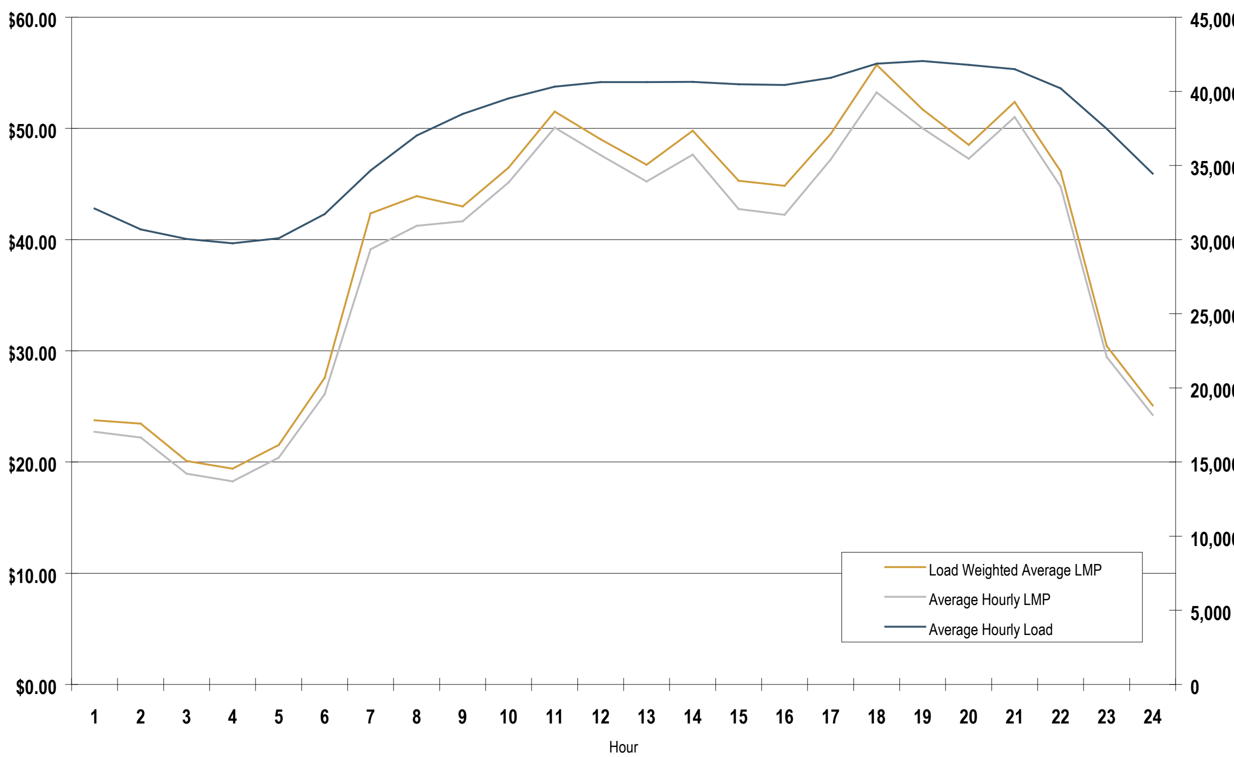
A functional demand side of wholesale energy markets does not necessarily mean that prices will be lower than they otherwise would be. A functional demand side of these markets does mean that customers will have the ability to make decisions about levels of power consumption based both on the value of the uses of the power and the actual cost of that power.

A functional demand side of the wholesale energy market will also tend to induce more competitive behavior among suppliers and to limit the ability to exercise market power. If customers have the essential tools to respond to prices, then suppliers will have the incentive to deliver power on a cost-effective basis, consistent with customers' evaluations.

The PJM Economic Load-Response Program provides a PJM-managed accounting mechanism that requires payment of the real savings that result from load reductions to the load-reducing customer. Such a mechanism is required because of the complex interaction between the wholesale market and the incentive and regulatory structures faced by both load-serving entities (LSEs) and customers. The broader goal of the Economic Program is to transition to a structure where customers do not require mandated payments, but where they either see and react to market signals or enter into contracts with intermediaries to provide that service. Even as currently structured, the Economic Program represents a minimal and relatively efficient intervention into the markets.

The pattern of prices within days and across months illustrates that prices are directly related to demand. The fact that price is a direct function of load (Figure 2-37) illustrates the potential significance of price elasticity of demand in affecting price. The potential for load to respond to changes in price is a critical component of a competitive market which remains as yet undeveloped in the wholesale energy market.

Figure 2-37 PJM Average Hourly LMP and System Load: 2003



On February 14, 2002, the PJM Members Committee (MC) approved a permanent Emergency Load-Response Program. On March 1, 2002, PJM filed amendments to the PJM Open Access Transmission Tariff (PJM Tariff) and to the Amended and Restated Operating Agreement (PJM Operating Agreement) to establish a permanent Emergency Load-Response Program (Emergency Program). By order dated April 30, 2002, the FERC approved the Emergency Program effective June 1, 2002, but set a sunset date for it of December 1, 2004.

Similarly, on March 15, 2002, PJM submitted filing amendments to the PJM Tariff and PJM Operating Agreement to establish a multiyear Economic Load-Response Program (Economic Program). On May 31, 2002, the FERC accepted the Economic Program, effective June 1, 2002. Like the Emergency Program, the Economic Program is effective until December 1, 2004.

Emergency Program

There was only one emergency event during the summer of 2003 (August 15), and this event was a locational emergency. On this day, a total of 47 MWh were reduced over an 11-hour period. The maximum hourly reduction in the Emergency Program was 6 MW.

Economic Program

As measured by total MW enrolled in the program and actual MWh response under it, the Economic Program has grown significantly in the two years since its 2001 inception. In 2003, there were a total of 724 MW registered in the Economic Program, an increase of 115 percent from 337 MW in 2002 which was, in turn, an increase of about 400 percent over the 65 MW enrolled in 2001. The level of load reductions in the Economic Program increased from 50 MWh in 2001 to 6,462 MWh in 2002 to 14,678 MWh in 2003.[35] Consistent with lower LMPs, payments per MWh have decreased 58 percent from 2001 to 2002, and decreased 61 percent from 2002 to 2003. The MWh of actual load reductions per MW enrolled in the Economic Program increased from 2001 to 2002 and was relatively constant between 2002 and 2003.

35 Load reductions are measured by multiplying hourly MW reductions by the hours in which they occur. Thus a 1 MW reduction for one hour is 1 MWh. A 1 MW reduction in one hour and a 3 MW reduction in a second hour is 4 MWh.

During the summer of 2003, load levels were somewhat lower than during the summer of 2002, and the combination of milder weather plus changes in supply and demand conditions resulted in lower prices. Using actual demand reductions and real-time supply curves, the MMU estimated that the price impact of the Economic Program was approximately $1 per MWh in 2003.

The maximum hourly load reduction attributable to the Economic Program was about 82 MW in 2003. Based on the real-time supply curves for a representative day during the summer of 2003 and the summer peak load, a reduction of 1,000 MW would have resulted in a $10 reduction in LMP and a reduction of 2,000 MW would have resulted in a $15 reduction in LMP. LMPs were lower during the summer of 2003 based on supply-demand fundamentals, and the potential price impacts of load reductions were also attenuated by supply-demand fundamentals. This is demonstrated by the aggregate supply curve for the summer of 2003 (Figure 2-37).

Non-hourly Metered Program

PJM created the non-hourly metered program as part of an effort to extend participation in the demand side of the market to smaller customers that generally lack hourly meters. PJM's non-hourly metered program serves as a pilot program for such customers, if they or their representatives propose an alternate method for measuring load reduction. Such measurement methods are approved by PJM on a case by case basis, and participants are otherwise subject to the rules and procedures governing the load-response program in which the customer has enrolled.

To provide sufficient opportunities to all non-hourly metered customers, PJM suggested an increase in the 25 MW limit. At its April 16, 2003, meeting the PJM Energy Market Committee supported an increase in the aggregate MW limit, expanding it to 100 MW. PJM's Members Committee approved the change at its May 1, 2003, meeting endorsing the revisions to the PJM Open Access Transmission Tariff. These changes were accepted by the FERC on June 27, 2003.[36]

In 2003, one customer (with about 45,000 retail customers) participated in the non-hourly metered program for about 131 separate hourly reductions, totaling about 1,816 MWh and averaging about 14 MW per hour. The expansion of the aggregate MW limit allowed for a maximum hourly reduction of 43 MW in the non-hourly metered program.

Customer Demand-Side Response Programs

In evaluating the level of DSR activity, it is important to include not just the activity that occurs in direct response to PJM programs, but also other types of DSR activity. Both state public utility commission policies on retail competition and the programs of individual LSEs have had a significant impact on DSR activity. It has been difficult to acquire meaningful data on these phenomena. To address this issue, in July 2003 PJM conducted a survey of LSEs to obtain information about price-responsive tariffs as well as load-response programs offered at the retail level by either electric distribution companies or competitive electric suppliers.

The July 2003 PJM survey revealed that there is substantial load in PJM that is exposed to real-time prices because of actions by state public utility commissions. In addition, LSEs in the PJM footprint operate their own DSR programs that are completely independent of those operated by PJM.

The survey results identified 3,122 MW of load that pays real-time prices. These retail customers pay real-time prices as the result of tariffs approved by state public utility commissions in New Jersey and Maryland. Of the 3,122 MW of load, 1,978 MW or about 63 percent of the total, currently purchases electricity directly at an hourly LMP rate plus an adder. This load has chosen to pay LMP rates rather than to enter into a contract with a competitive supplier. The remaining 1,144 MW or 37 percent represents retail customers who have shifted the risk of managing real-time price volatility to a competitive supplier.

36 103 FERC 61,365 (June 27, 2003).

The survey also identified a total of about 500 MW enrolled in independent DSR programs. Of the total, 193 MW or 39 percent were included in price-responsive load programs or pilot programs, 73 MW or 15 percent participated in interruptible load programs and 235 MW or 47 percent of load is currently participating in emergency load-response programs of electric distribution companies.

The July 2003 PJM survey revealed that significant DSR activity has resulted from actions of state public utility commissions as they have implemented policies governing retail competition. The primary result has been that more load is directly exposed to real-time prices. This is a critical prerequisite to an effective demand side of the wholesale energy markets. In addition, individual LSEs have implemented independent DSR programs that parallel PJM programs in basic design and that have resulted in additional DSR activity.

DSR Program Summary Data

Summary data for Demand-Side Response programs in the PJM service area are presented in Table 2-33. The programs include the PJM Emergency Load-Response Program, the PJM Economic Load-Response Program, the PJM Active Load Management Program (ALM) net of ALM resources participating directly in other PJM demand-side programs and additional programs reported by PJM customers in response to a survey.[37]

Table 2-33 2003 Demand-Side Response Program

PJM Programs	MW Registered
PJM Economic Load-Response Program	724
PJM Emergency Load-Response Program	659
PJM Active Load-Management Resources	1,207
PJM ALM Resources Included in Load-Response Program	(445)
Total PJM Programs	2,145
Additional Programs Reported By Customers in PJM Survey	
Direct Customer Purchases Based on LMP Signals	1,978
Competitive Contracts in NJ and MD	1,144
Independent	
Price-Responsive Load or Pilot Programs	193
Interruptible Load Programs	73
Emergency Load-Response Programs of EDCs	235
Total Independent	501
Total Additional Programs	3,623
Partial Summer Load Participation	(850)
Net Load, Including Survey Responses	**4,918**

37 The table reflects the fact that the survey includes 850 MW associated with retail customers that left their DSR program in mid-summer. The "partial summer load reduction" row of the table reflects that this was subtracted from relevant participation as it was not present for the entire summer of 2003. After accounting for this reduction, there was a total of 4,918 MW of demand-side resources in the PJM service area in the summer of 2003.