2004 State of the Market

Market Monitoring Unit

March 8, 2005

print: 03.07.05

PREFACE

The Market Monitoring Unit of the PJM Interconnection publishes an annual state of the market report that assesses the state of competition in each market operated by PJM, identifies specific market issues and recommends potential enhancements to improve the competitiveness and efficiency of the markets.

The *2004 State of the Market Report* is the seventh such annual report. This report is submitted to the Board of Managers of the PJM Interconnection, L.L.C. pursuant to the PJM Open Access Transmission Tariff, Attachment M (Market Monitoring Plan):

> "The Market Monitoring Unit shall prepare and submit to the PJM Board and, if appropriate, to the PJM Members Committee, periodic (and if required, *ad hoc*) reports on the state of competition within, and the efficiency of, the PJM Market."

The Market Monitoring Unit is submitting this report simultaneously to the United States Federal Energy Regulatory Commission (FERC) per the Commission's Order in PJM Interconnection, L.L.C., 96 FERC ¶61,061 (2001):

> "The Commission has the statutory responsibility to ensure that public utilities selling in competitive bulk power markets do not engage in market power abuse and also to ensure that markets within the Commission's jurisdiction are free of design flaws and market power abuse. To that end, the Commission will expect to receive the reports and analyses of an RTO's [regional transmission organization's] market monitor at the same time they are submitted to the RTO."

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INTRODUCTION

The PJM Interconnection operates a centrally dispatched, competitive wholesale electricity market comprising generating capacity of approximately 144,000 megawatts (MW) and about 330 market buyers, sellers and traders of electricity in a region including more than 45.3 million people in all or parts of Delaware, Illinois, Indiana, Kentucky, Maryland, Michigan, New Jersey, Ohio, Pennsylvania, Tennessee, Virginia, West Virginia and the District of Columbia.[1] PJM grew substantially in 2004 as the result of the integrations of new members from Illinois, Indiana, Kentucky, Michigan, Ohio and Tennessee. [2]

PJM Market Overview

PJM operates the Day-Ahead Energy Market, the Real-Time Energy Market, the Daily Capacity Market, the Interval, Monthly and Multimonthly Capacity Markets, the Regulation Market, the Spinning Reserve Market and the Annual and Monthly Auction Markets in Financial Transmission Rights (FTRs).

PJM introduced nodal energy pricing with market-clearing prices based on offers at cost on April 1, 1998, and nodal market-clearing prices based on competitive offers on April 1, 1999. Daily Capacity Markets were introduced on January 1, 1999, and Monthly and Multimonthly Capacity Markets were introduced in mid-1999. PJM implemented an auction-based FTR Market on May 1, 1999. It implemented the Day-Ahead Energy Market and the Regulation Market on June 1, 2000. PJM modified regulation market design and added a market in spinning reserve on December 1, 2002. PJM introduced an Auction Revenue Rights (ARR) allocation process and an associated Annual FTR Auction effective June 1, 2003.[3]

1 See Appendix A, "PJM Service Territory," for map.
2 In 2003, PJM operated a centrally dispatched, competitive wholesale electricity market comprising generating capacity of more than 76,000 MW and about 250 market buyers, sellers and traders of electricity in a region including more than 25 million people in all or parts of Delaware, Maryland, New Jersey, Ohio, Pennsylvania, Virginia, West Virginia and the District of Columbia.
3 See also Appendix B, "PJM Market Milestones."

Conclusions

In the *2004 State of the Market Report*, the calendar year is divided into three phases, corresponding to market integration dates.

- **Phase 1.** The four-month period from January 1 through April 30, 2004, during which PJM was comprised of 12 control zones.[4] Eleven of these comprised the Mid-Atlantic Region while the remaining control zone comprised the PJM Western Region.

- **Phase 2.** The five-month period from May 1 through September 30, 2004, during which PJM was comprised of the Mid-Atlantic Region, the AP Control Zone and the Commonwealth Edison Company Control Area (ComEd).[5]

- **Phase 3.** The three-month period from October 1 through December 31, 2004, during which PJM was comprised of the Phase 2 elements plus the American Electric Power Control Zone (AEP) and The Dayton Power & Light Company Control Zone (DAY). The ComEd Control Area became the ComEd Control Zone on October 1.

This report assesses the competitiveness of the Markets managed by PJM during 2004, including market structure, participant behavior and market performance. This report gives special attention to the market structure and market performance of PJM during each of the three phases of integration that occurred in 2004. This report was prepared by and reflects the analysis of PJM's independent Market Monitoring Unit (MMU).

The MMU concludes that in 2004:

- The Energy Market results were competitive;

- The PJM Capacity Market results were competitive. The ComEd Capacity Market results were reasonably competitive;

- The Regulation Markets results were competitive both where market-based offers and cost-based offers set market prices;

- The Spinning Reserve Markets (markets were cleared on cost-based offers) results were competitive; and

- The FTR Auction Market results were competitive.

4 Control zones and control areas are geographic areas that customarily bear the name of a large utility service provider working within their boundaries. The nomenclature applies to the geographic area, not to any single company.
5 During the five-month period May 1, 2004, through September 30, 2004, the ComEd Control Zone (ComEd), as it is currently known, was called the Northern Illinois Control Area (NICA).

The MMU also concludes:

- Market power in the Capacity Markets remains a serious concern given the structural issues of high levels of supplier concentration, frequent occurrences of pivotal suppliers and extreme inelasticity of demand. Market power is endemic to the structure of PJM Capacity Markets. Smaller locational markets will amplify the market power issue and any redesign of Capacity Markets must address market power;

- The Ancillary Service Markets in PJM are not structurally competitive, with the exception of the Regulation Market in the PJM Mid-Atlantic Region, as they are characterized by high levels of supplier concentration, frequent occurrences of pivotal suppliers and inelastic demand. Ancillary Service Markets currently operating on the basis of market-clearing, cost-based offers should continue on a cost basis until market structure analysis indicates that competitive conditions warrant the introduction of market-based offers; and

- Market structure issues in the PJM Energy Markets have been offset to date by a combination of high levels of supply, moderate demand and competitive participant behavior.

Recommendations

The MMU recommends the retention of key market rules and certain enhancements to those rules that are required for continued competitive results in PJM Markets and for continued improvements in the functioning of PJM Markets. These include:

- Enhancements of the PJM Capacity Market design to stimulate competition, to provide locational price signals and to incorporate explicit market power mitigation rules;

- Modification of PJM's rules governing operating reserve payments to generators both to reduce gaming incentives and to ensure that compensation is consistent with incentives for efficient market outcomes;

- Modification of rules governing the reporting and verification of unit outages to ensure consistency with actual unit conditions, accurate assessments of system conditions and incentives for efficient market outcomes;

- Retention of the $1,000 per MWh offer cap in the PJM Energy Market and other rules that limit incentives to exercise market power;

- Retention and continued enhancement of local market power mitigation rules to prevent the exercise of local market power while ensuring appropriate economic signals when investment is required;

- Continued development of an integrated approach to economic planning that evaluates the costs and benefits of identified alternative investments in areas where investments in transmission expansion, generation or demand-side resources would relieve congestion both in Energy and Capacity Markets, especially where that congestion may enhance generator market power and where such investments support competition;

- Evaluation of additional actions to increase demand-side responsiveness to price in both Energy and Capacity Markets and of actions to address institutional issues which may inhibit the evolution of demand-side price response; and

- Based on the experience of the MMU during its sixth year and its analysis of the PJM Markets, the MMU recognizes the need to continue to make the market monitoring function well-organized, well-defined and clear to market participants. The MMU recommends that the role of the market monitoring function be reviewed and further clarified if necessary and that the Market Monitoring Plan be analyzed and modified if necessary to make the market monitoring function well-defined and clear to all market participants.

Energy Market

Energy Market Design

In PJM, market participants wishing to buy and sell energy have multiple options. Market participants decide whether to meet their energy needs through self-supply, bilateral purchases from generation owners or market intermediaries, through the Day-Ahead Energy Market or the Real-Time Energy Market. Energy purchases can be made over any timeframe from instantaneous Real-Time Energy Market purchases to long-term bilateral contracts. Purchases may be made from generation located within or outside PJM. Market participants also decide whether and how to sell the output of their generation assets. Generation owners can sell their output within PJM or externally and can use generation to meet their own loads, to sell into the spot market or to sell bilaterally. Generation owners can sell their output over any timeframe from instantaneous Real-Time Energy Market sales to long-term bilateral arrangements. Market participants can use increment and decrement bids in the Day-Ahead Energy Market to hedge positions or to arbitrage expected price differences between markets.

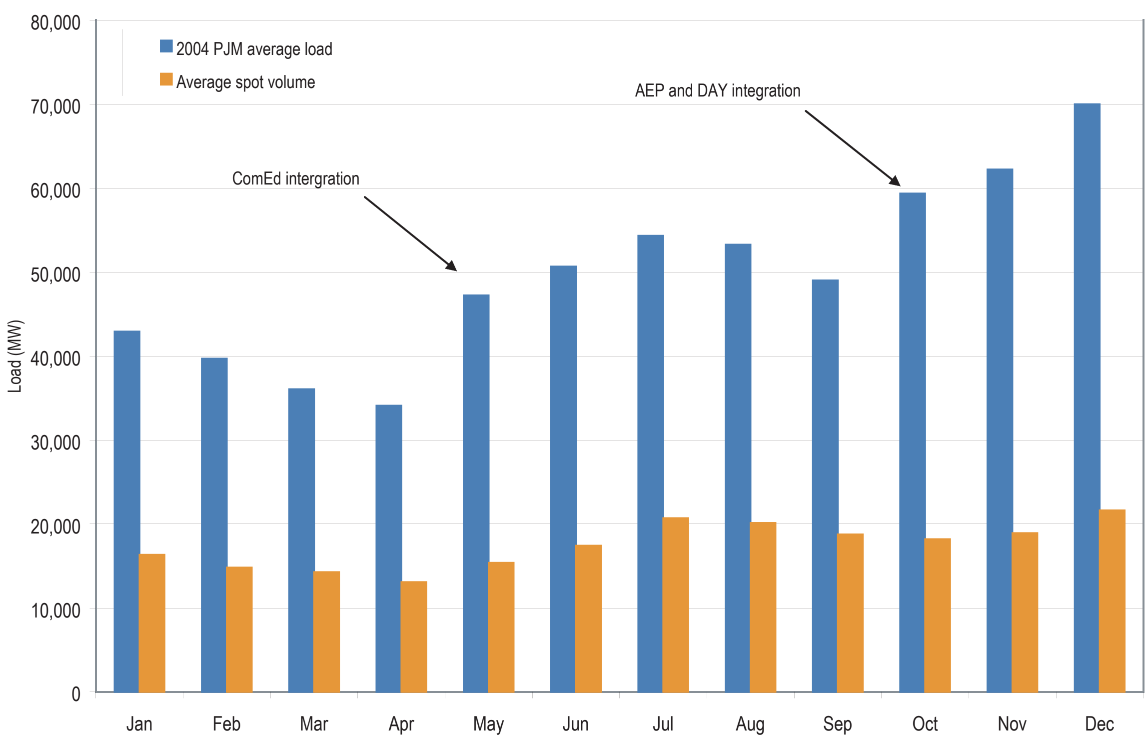
The PJM Energy Market comprises all types of energy transactions, including the sale or purchase of energy in PJM's Day-Ahead and Real-Time Energy Markets, bilateral and forward markets and self-supply. Energy transactions analyzed in this report include those in the PJM Day-Ahead and Real-Time Energy Markets. These markets provide key benchmarks against which market participants may measure results of other transaction types. For PJM, 2004 was a time of significant growth with three control zones being integrated into PJM Markets. The MMU analysis of the Energy Market treats these new zones as part of existing markets as of the date of integration.

The MMU analyzed measures of energy market structure, participant behavior and market performance for 2004, including supply and demand conditions, market concentration, residual supplier index, price-cost markup, net revenue and prices. The performance of demand-side response programs was also evaluated. The MMU concludes that, despite concerns about market structure, the PJM Day-Ahead and Real-Time Energy Market results were competitive in 2004.

In 2004, Real-Time Energy Market activity averaged 19,668 MW during peak periods and 15,567 MW during off-peak periods, or 35 percent of average loads for all hours. (See Figure 1-1.) In 2004, Day-Ahead Energy Market activity averaged 17,618 MW on peak and 13,956 MW off peak, or 26 percent of average total Day-Ahead loads for all hours. Both Real-Time and Day-Ahead Energy Market transactions are referred to as spot market activity because they are transactions made in a short-term market. The alternatives to such spot market transactions are self-supply and bilateral arrangements. The fact that transactions occur in the Real-Time and Day-Ahead Energy Markets does not necessarily mean that participants are exposed to the related short-term prices. Longer term bilateral contracts can and do clear through the PJM Energy Markets. A significant proportion of the spot market activity represents such underlying bilateral contracts.

Total Real-Time Energy Market activity increased by 21.5 percent on peak and 9.8 percent off peak over 2003 levels. Total real-time load also grew in 2004 and as a result spot market activity as a proportion of load in the Real-Time Energy Market decreased from 40 percent in 2003 to 35 percent in 2004. Total Day-Ahead Energy Market activity increased by 22.4 percent on peak and 8.3 percent off peak over 2003 levels. Total day-ahead load also grew in 2004 and as a result spot market activity as a proportion of load in the Day-Ahead Energy Market decreased from 31 percent in 2003 to 26 percent in 2004.

Figure 1-1 - PJM average hourly load and spot market volume: Calendar year 2004



Overview

Market Structure

- **Supply.** During the June to September 2004 summer period, PJM Energy Markets received a maximum of 109,600 MW in supply offers, net of real-time imports or exports. The 2004 net supply offers represented an approximately 29,800 MW increase compared to the comparable 2003 summer period. The increase in 2004 was comprised of 29,342 MW from the Phase 2 ComEd Control Area integration and of 500 MW from a net increase in capacity from the Mid-Atlantic Region and the AP Control Zone.

- **Demand.** The PJM system peak load in 2004 was 77,887 MW, a coincident summer peak load reflecting the Mid-Atlantic Region, the AP Control Zone and the ComEd Control Area.[6] The PJM peak load in 2003 of 61,499 MW occurred prior to the integration of the ComEd Control Area. If the 2003 peak load were adjusted to include the ComEd Control Area for comparison purposes, the 2003 peak load of the combined area would have been 81,992 MW.[7] As Phase 3 integrations occurred too late to be relevant to the 2004 summer peak, they were excluded from this analysis.

- **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 mean larger numbers of sellers splitting market sales more equally. High concentration ratios indicate an increased potential for participants to exercise market power, although low concentration ratios do not mean that a market is competitive or that participants cannot exercise market power. Analysis of the PJM Energy Market indicates moderate market concentration overall. Further, analyses of supply curve segments indicate moderate concentration in the baseload segment, but high concentration in the intermediate and peaking segments. Analysis also indicates that the ComEd Control Area was highly concentrated overall and in each segment of the supply curve. Several other geographic areas of PJM exhibited moderate to high levels of concentration when transmission constraints defined local markets. No evidence exists, however, that market power was exercised in these areas during 2004, both because of generator obligations to serve load and because of PJM's rules limiting the exercise of local market power.

- **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, that owner has market power. The residual supply index (RSI) is a measure of the extent to which generation owners are pivotal suppliers. Like concentration ratios, the RSI is an indicator of market structure. When the RSI is less than 1.00, a generation owner is pivotal. As with concentration ratios, the RSI is not a bright line test. While an RSI less than 1.00 clearly indicates market power, an RSI greater than 1.00 does not guarantee that there is no market power. As an example, suppliers can be jointly pivotal. The RSI results are consistent with the conclusion that the PJM Energy Market results were competitive in both 2003 and 2004, with an average RSI of 1.66 and 1.64, respectively. In 2004, a generation owner in the PJM Energy Market was pivotal for only eight hours, less than 0.1 percent of all hours during the year. This

6 For the purpose of the 2004 State of the Market Report, all hours are presented and all hourly data are analyzed using Eastern Prevailing Time (EPT). See Appendix H, "Glossary," for a definition of EPT and its relationship to Eastern Standard Time (EST) and Eastern Daylight Time (EDT).
7 This calculated 2003 peak load of the combined area was a total system coincident peak load and occurred on a different day and hour than the 2003 peak load for PJM.

represents a slight increase in pivotal hours from 2003, when a generation owner was pivotal in the Energy Market for six hours, also less than 0.1 percent of all hours during the year.

- **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 response resources available in PJM during the nine-month period ended September 30, 2004, were 1,806 MW from active load management, 1,385 MW from the Emergency Load-Response Program and 724 MW from the Economic Load-Response Program. There were 317 MW enrolled in both the Load-Response Program and in active load management. The 11,562 MW in total DSR resources, including additional programs reported by PJM customers in response to a survey, were approximately 15 percent of PJM's peak demand.

Market Performance

- **Price-Cost Markup.** Price-cost markups are a measure of market power. The price-cost markup reflects both participant behavior and the resultant market performance. The price-cost markup index is defined here as the difference between price and marginal cost, divided by price for the marginal units in the PJM Energy Market. The MMU has expanded and refined the analysis of markup measures. Overall, data on the price-cost markup are consistent with the conclusion that PJM Energy Market results were reasonably competitive in 2004.

- **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 all PJM Markets. The net revenue calculation has been refined from the 2003 State of the Market Report. Improvements include reflection of environmental costs, unit class-specific, forced-outage factors, annual planned outages, the hourly effects of ambient and cooling water temperature on plant performance and unforced capacity, the reactive revenue requirements for each plant class approved by the United States Federal Energy Regulatory Commission (FERC) and the addition of analysis for a new entrant pulverized coal plant. Alternate dispatch scenarios were also analyzed. In 2004, the perfect economic dispatch net revenues would not have covered the first year fixed costs of a new entrant combustion turbine (CT) with variable costs between $75 and $80 per MWh, a combined-cycle plant (CC) with variable costs between $50 and $55 per MWh or a pulverized coal plant (CP) with variable costs between $25 and $30 per MWh operating for all profitable hours.[8]

- **Energy Market Prices.** PJM's locational marginal prices (LMPs) are a direct measure of market performance. 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.

8 The costs reflect the new entry variable costs for each plant type, including the 2004 average natural gas costs for the CT and CC plants and the 2004 average coal costs for the CP plant.

PJM average prices increased from 2003 to 2004. The simple, hourly average system LMP was 10.8 percent higher in 2004 than in 2003, $42.40 per MWh versus $38.27 per MWh. When hourly load levels are reflected, the load-weighted LMP of $44.34 per MWh in 2004 was 7.5 percent higher than in 2003. When increased fuel costs are accounted for, the fuel-cost-adjusted, load-weighted, average LMP was 4.2 percent lower in 2004 than in 2003, $39.49 per MWh compared to $41.23 per MWh.

PJM average real-time energy market prices increased in 2004 over 2003 for several reasons, including, but not limited to, significantly increased fuel costs for the marginal units. PJM did not experience extreme demand conditions during 2004. While average prices increased in 2004, the PJM system price was above $150 per MWh for only five hours, with the maximum LMP of $180.12 per MWh occurring on December 20, 2004, during the hour ending 0900 Eastern Prevailing Time (EPT).

Energy Market results for 2004 reflect supply-demand fundamentals. While the existing structure of the Energy Market does not guarantee competitive outcomes, actual market performance results were reasonably competitive in 2004 because the market was relatively long and demand was moderate. Given the structure of the Energy Market, tighter markets or a change in participant behavior are potential sources of concern in the Energy Market.

Mitigation

- **Offer Capping Statistics.** PJM rules provide that PJM offer caps units whenever they would otherwise have the ability to exercise local market power. Offer capping levels increased slightly in 2004 because of congestion and a larger service territory, but remained low overall. Offer capping does not have a significant, negative impact on unit net revenues.

Interchange Transactions

The integration of several service territories into the PJM regional transmission organization (RTO) during 2004 resulted in significant changes to its external interfaces. These interfaces are the seams between PJM and other regions. PJM market participants import energy from, and export energy to, external regions on a continuous basis. Such transactions may fulfill long-term or short-term bilateral contracts or take advantage of price differentials.

Overview

Interchange Transaction Activity

- **Aggregate Imports and Exports**

  Phase 1. During the four months ended April 30, 2004, PJM was a net importer of power, averaging 1.8 million MWh of net interchange[9] (positive value indicates import, negative value indicates export) per month, or 0.9 million MWh more per month than for the same period in 2003. The 2004 period's average monthly gross import volume of 3.0 million MWh also

9 Net interchange is gross import volume less gross export volume. Thus, positive net interchange is equivalent to positive net imports and negative net interchange is equivalent to positive net exports.

represented an increase from the 2.6 million MWh experienced in 2003. Gross exports decreased by 600,000 MWh per month in 2004 compared to 2003, averaging 1.1 million MWh in 2004 versus 1.7 million MWh in 2003.

Phase 2. During the five months ended September 30, 2004, PJM, including the ComEd Control Area, became a net exporter of power. Monthly average net interchange was -1.1 million MWh. Gross monthly import volumes averaged 2.8 million MWh while gross monthly exports averaged 3.9 million MWh.

Phase 3. During the three months ended December 31, 2004, PJM, including the AEP and DAY Control Zones, continued to be a net exporter of power. Monthly average net interchange was -1.3 million MWh. Gross monthly import volumes averaged 4.3 million MWh while gross monthly exports averaged 5.6 million MWh.

- **Interface Imports and Exports**[10]

Phase 1. During Phase 1, net imports at two interfaces accounted for 94 percent of total net imports. Net imports at PJM's interface with the AEP control area (PJM/AEP) were 44 percent and at its interface with the FirstEnergy control area (PJM/FE) were 50 percent of total net imports. Net exports occurred only at the PJM interface with the New York Independent System Operator (PJM/NYIS). Five interfaces were active during Phase 1.

Phase 2. During Phase 2, PJM became a net exporter of energy. PJM's largest exporting interface was AEP Northern Illinois (PJM/AEPNI); it carried 44 percent of the net export volume. Nine other interfaces were net exporters. The largest net importing interface was PJM/FE which carried 49 percent of the net import volume while PJM/AEPPJM carried 38 percent. The number of interfaces in Phase 2 rose to 14.

Phase 3. During Phase 3, PJM continued to be a net exporter of energy. The two largest net exporting interfaces totaled 43 percent of the total net exporting volume: PJM/NYIS at 22 percent and PJM/Michigan Electric Coordinated System (PJM/MECS) with 21 percent. Ninety-two percent of the net import volume was carried on three interfaces: PJM/Illinois Power (PJM/IP) carried 33 percent, PJM/Ohio Valley Electric Corporation (OVEC) carried 30 percent and PJM/FE carried 29 percent of the volume. The number of interfaces increased to 22 during Phase 3.

- **Modified Interfaces and Pricing Points**

New Interfaces. Integration of the ComEd Control Area into PJM on May 1, 2004, introduced new interfaces. The number of external interfaces increased from five to 14. The subsequent integration of the AEP and DAY Control Zones on October 1, 2004, significantly enlarged the boundaries of PJM and the number of interfaces grew from 14 to 22.

New Pricing Points. During Phase 2, integration of the ComEd Control Area, with its accompanying interfaces, required new pricing points. The physical configuration and the potential for power schedules, but not physical power flows, to bypass a control area required

10 Interfaces are named after adjacent control areas. As is true of the control areas themselves, this naming convention does not imply anything about any company operating within the control areas.

pricing points that recognized the location of generation and the path of power flows. The result was that PJM increased the number of pricing points from six in Phase 1, to 23 in Phase 2. The subsequent integration of the AEP and DAY Control Zones in Phase 3 reduced the potential for loop flows and simplified the pricing point issue. The number of pricing points was reduced to nine. The issue of potential control zone bypass was virtually eliminated with the result that fewer pricing points are now needed to account for transactions with neighboring control areas and the generators located there or in external, non-contiguous control areas.[11]

Interchange Transaction Issues

- **Fewer PJM TLRs.** The number of transmission loading relief procedures (TLRs) issued by PJM declined after the integration of the AEP and DAY Control Zones. The integration meant that PJM could redispatch generating units to relieve constraints on facilities in the newly integrated areas where PJM had previously relied on TLRs for constraint control. The result was a drop in the number of TLRs called by PJM, particularly in the AEP Control Zone.

- **Midwest Independent System Operator (ISO).** The "Joint Operating Agreement between the Midwest Independent Transmission System Operator, Inc. and PJM Interconnection, L.L.C." (JOA)[12] provides for relief of constraints on certain coordinated flowgates. PJM redispatches generation to aid in providing this relief.

- **Actual Versus Scheduled Power Flows.** Loop flow is one reason that actual and scheduled flows may not match at a particular interface. Loop flow can arise from transactions scheduled into, out of or around the PJM system on contract paths that do not correspond to the actual physical paths that the energy takes. Even when energy is scheduled on a path consistent with its expected actual flow, other loop flows can cause some of the energy to flow on another path. Outside of PJM's LMP-based Energy Market, energy is scheduled and paid for based on contract path despite the fact that the associated actual energy deliveries flow on the path of least resistance. For example, loop flow can result when a transaction is scheduled between two external control areas and some, or all, of the actual flows occur at PJM interfaces. Loop flow can also result when transactions are scheduled into or out of PJM on one interface, but actually flow on another. Although PJM's total scheduled and actual flows were approximately equal in 2004, they were often not equal for each individual interface. PJM's method of defining pricing points is designed to provide price signals consistent with the actual power flows and thus to minimize the incentive to create loop flow.

- **Transactions and PJM Area Control Error (ACE).** An important function performed by PJM is to balance load and generation on a continuous basis. ACE is the metric used to measure that balance. One component in the measurement of ACE is the flow into and out of PJM that results from external transactions. The other component is frequency error. When ACE deviates significantly from zero in either direction, certain measures are used to correct it. Regulation is the primary tool dispatchers use to control ACE.[13]

- **PJM and New York Transaction Issues.** During 2004, the relationship between prices at the PJM/NYIS interface and at the New York Independent System Operator (NYISO) PJM proxy

11 See Appendix D, "Interchange Transactions" for a more detailed discussion of interface pricing issues.
12 See Joint Operating Agreement (JOA) between the Midwest ISO and PJM (December 30, 2003) <http://www.pjm.com/documents/downloads/agreements/joa-complete.pdf> (906 KB).
13 See Appendix F, "Ancillary Service Markets."

bus appeared to reflect economic fundamentals. The relationship between interface price differentials and power flows between PJM and the NYISO also continued to appear to reflect economic fundamentals. As in 2003, however, both continued to be affected by differences in institutional and operating practices between PJM and NYISO.

Capacity Markets

Each organization serving PJM load must own or acquire capacity resources to meet its respective capacity obligations. Load-serving entities (LSEs) can acquire capacity resources by entering into bilateral agreements, by participating in the PJM-operated Capacity Credit Market or by constructing generation. Collectively, all arrangements by which LSEs acquire capacity are known as the Capacity Market.[14]

The PJM Capacity Credit Market[15] and the ComEd Capacity Credit Market[16] provide mechanisms to balance supply of and demand for capacity unmet by the bilateral market or self-supply. The PJM Capacity Credit Market consists of the Daily, Interval,[17] Monthly and Multimonthly Capacity Credit Markets. The ComEd Capacity Credit Market consists of Interval, Monthly and Multimonthly Capacity Credit Markets. Each Capacity Credit Market is intended to provide a transparent, market-based mechanism for competitive retail LSEs to acquire the capacity resources needed to meet their capacity obligations and to sell capacity resources when no longer needed to serve load. The PJM Daily Capacity Credit Market permits LSEs to match capacity resources with short-term shifts in retail load while Interval, Monthly and Multimonthly Capacity Credit Markets provide mechanisms to match longer term obligations with capacity resources.

During Phase 1, PJM operated one Capacity Market for the Mid-Atlantic Region and the AP Control Zone. That market remained intact during Phase 2 when a separate Capacity Credit Market was created and became effective on June 1, 2004, for the ComEd Control Area. During the first month of the Phase 2 period, the Commonwealth Edison Company satisfied the area's requirements under the guidance of PJM. [18]

During Phase 3, the AEP and DAY Control Zones were integrated into the PJM Capacity Market that operated for all zones except ComEd, which continued to operate based on a separate set of PJM rules.

The calendar year ended with PJM operating two Capacity Markets. The PJM Capacity Market (or simply PJM) was comprised of the 11 control zones of the Mid-Atlantic Region, the AP Control Zone and the newer AEP and DAY Control Zones. The ComEd Capacity Market was comprised solely of the ComEd Control Zone. These two Capacity Markets are scheduled to be combined into a single Capacity Market effective June 1, 2005. [19]

Overview

The MMU analyzed key measures of PJM Capacity Market and of ComEd Capacity Market structure and performance for 2004, including concentration ratios, prices, outage rates and reliability. The MMU found serious market structure issues, but no exercise of market power during 2004.

14 See Appendix H, "Glossary," for definitions of PJM Capacity Credit Market terms.
15 All PJM Capacity Market values (capacities) are in terms of unforced MW.
16 All ComEd Capacity Market values (capacities) are in terms of installed MW.
17 PJM defines three intervals for its Capacity Markets. The first interval extends for five months and runs from January through May. The second interval extends for four months and runs from June through September. The third interval extends for three months and runs from October through December.
18 "Schedule 17, Capacity Adequacy Standards and Procedures for the Commonwealth Edison Zone during the Interim Period," "PJM West Reliability Assurance Agreement Among Load-Serving Entities in the PJM West Region" (December 20, 2004), pp. 48C – 48D, Section L.
19 For purposes of the "Capacity Section" and its Appendix, these markets are identified as the PJM Capacity Market (or PJM) and the ComEd Control Zone Capacity Market, the ComEd Capacity Market (or ComEd). These markets are referred to collectively as the Capacity Markets for the RTO.

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

The PJM Capacity Market results were competitive during 2004. The ComEd Capacity Market results were reasonably competitive in 2004. Market power remains a serious concern for the MMU in both Capacity Markets based on market structure conditions in those markets.

Market Structure

The PJM Capacity Market

Ownership Concentration

- **Phases 1 and 2.** Structural analysis of the PJM Capacity Credit Market found that its short-term markets exhibited moderate concentration while its long-term markets exhibited high concentration levels during the period January through September 2004.

- **Phase 3.** Structural analysis of the PJM Capacity Credit Market found that its short-term markets exhibited moderate concentration while its long-term markets exhibited high concentration levels during the period October through December 2004.

Demand

- **Phases 1 and 2.** During January through September 2004, electricity distribution companies (EDCs) and their affiliates accounted for 76 percent of the PJM Capacity Markets' load obligations.

- **Phase 3.** During October through December 2004, EDCs and their affiliates accounted for 80 percent of the PJM Capacity Markets' load obligations.

Supply and Demand

- **Phases 1 and 2.** During the first and second intervals of 2004, installed capacity, unforced capacity and obligations grew in the PJM Capacity Market. Compared to the same period of 2003,[20] average installed capacity increased by 7,781 MW or 11.1 percent to 77,673 MW,

20 The AP Control Zone obligations were met under an available capacity construct prior to the second interval of 2003 and, therefore, not included in these values.

while average unforced capacity rose by 6,267 MW or 9.5 percent to 72,415 MW. Average load obligations climbed by 6,502 MW or 10.1 percent to 70,797 MW, or 1,618 MW less than average unforced capacity. Overall capacity credit market transactions increased by more than 20.0 percent during the first and second intervals. Daily capacity credit market volume increased by 60.1 percent, while monthly and multimonthly capacity credit market volume increased by 63.1 percent and 0.7 percent, respectively.

- **Phase 3.** During the third interval of 2004, installed capacity, unforced capacity and obligations increased with the integration of the AEP and DAY Control Zones into the PJM Capacity Market. Average installed capacity increased to 116,770 MW. Average unforced capacity rose to 108,422 MW. Average load obligation climbed to 98,906 MW. Compared to the first two intervals, the overall capacity credit market volume in the third interval decreased by nearly 7.0 percent. Daily capacity credit market volume decreased by 9.3 percent, while monthly capacity credit market volume decreased by 29.6 percent and multimonthly capacity credit market volume increased by 2.3 percent.

The ComEd Capacity Market

Ownership Concentration

- **Phases 2 and 3 (June through December 2004).** Structural analysis of the ComEd Capacity Credit Market found that its long-term markets exhibited high levels of concentration from June 1 of Phase 2, through Phase 3, 2004.

Demand

- **Phases 2 and 3 (June through December 2004).** During the seven-month period ended December 31, 2004, EDCs accounted for 86 percent of the load obligation in the ComEd Capacity Market.

Supply and Demand

- **Phases 2 and 3 (June through December 2004).** During the seven-month period ended December 31, 2004, capacity resources exceeded capacity obligations in the ComEd Capacity Market every month, resulting in an average net excess of 5,672 MW for the period.

Market Performance

The PJM Capacity Market

Capacity Credit Market Volumes

- **Phases 1 and 2.** During the first interval of 2004, PJM Capacity Credit Markets experienced moderate activity. On average 994 MW traded in the Daily Market. Trades in the Monthly and Multimonthly Markets averaged 1,199 MW and 2,619 MW, respectively.[21]

21 Unless otherwise noted, all volume measures in the Capacity Market Section are in MW-days.

During the second interval of 2004, activity in the PJM Capacity Credit Markets increased. On average 1,203 MW traded in the Daily Market. Trades in the Monthly and Multimonthly Markets averaged 971 MW and 3,325 MW, respectively.

- **Phase 3.** With the Phase 3 integration of the AEP and DAY Control Zones into PJM, Capacity Credit Markets experienced slightly less activity. An average 986 MW traded in the Daily Market. Trades in the Monthly and Multimonthly Markets averaged 773 MW and 3,002 MW, respectively.

Capacity Credit Market Prices

- **Phases 1 and 2.** During the first interval of 2004, PJM daily capacity credit market prices were low, averaging $0.51 per MW-day. Prices in the Monthly and Multimonthly Markets declined slightly over the period from $11.72 per MW-day in January to $7.26 per MW-day in May, averaging $8.38 per MW-day for the first interval.

  During the second interval of 2004, daily capacity credit market prices were higher, averaging $44.79 per MW-day. The daily capacity credit market price peaked in June 2004 at $110.61 per MW-day. Prices in the Monthly and Multimonthly Markets increased in June and then decreased over the remainder of the period from $33.60 per MW-day in June to $25.39 per MW-day in September, averaging $31.53 per MW-day for the second interval.

- **Phase 3.** During the third interval of 2004, daily capacity credit market prices were low, averaging $0.40 per MW-day. Prices in the Monthly and Multimonthly Capacity Markets declined slightly over the interval from $14.19 per MW-day in October to $12.36 per MW-day in December, averaging $13.17 per MW-day for the third interval.

The ComEd Capacity Market

Capacity Credit Market Volumes

- **Phases 2 and 3.** The ComEd monthly and multimonthly capacity credit market volumes averaged 1,299 MW, or about 6 percent of the average capacity obligation for the seven months ended December 31, 2004.

Capacity Credit Market Prices

- **Phases 2 and 3.** Volume-weighted average prices in the ComEd Capacity Credit Market ranged from a low of $24.17 per MW-day in December 2004, to a high of $32.26 per MW-day in July.

Generator Performance

From 1996 to 2001, the average, PJM equivalent demand forced outage rate (EFORd) trended downward, reaching 4.8 percent in 2001, but then increased to 5.2 percent in 2002 and 7.0[22] percent in 2003. In 2004, the average PJM EFORd continued its upward trend, reaching 8.0 percent.

22 The 2003 EFORd reported in the 2003 State of the Market Report was 7.1 percent. Final EFORd data were not available until after the publication of the report. The 2004 EFORd reported here will also be revised based on final data submitted after the publication of the report.

Approximately half the increase in EFORd from 2003 to 2004 was the result of increased forced outage rates of fossil steam units, while the balance of the increase was the result of increased forced outage rates of combustion turbine, nuclear and hydroelectric units. These forced outage rates are for the PJM Mid-Atlantic Region and the AP Control Zone only. The forced outage rate in 2004 was 7.9 percent for all zones within the PJM Capacity Market (including the AEP, DAY and ComEd Control Zones).[23]

Conclusion

Given the basic features of market structure in both the PJM and ComEd Capacity Markets, including high levels of concentration, the relatively small number of nonaffiliated LSEs, the capacity-deficiency penalty structure facing LSEs, supplier knowledge of the penalty structure and supplier knowledge of aggregate market demand if not individual LSE demand, the MMU concludes that the likelihood of the exercise of market power is high. These structural conditions are more severe in the ComEd Capacity Market than in the PJM Capacity Market. Market power is endemic to the structure of PJM Capacity Markets. Supply and demand fundamentals offset these market structure issues in the PJM Capacity Market in 2004, producing competitive results in the PJM Capacity Market and reasonably competitive results in the ComEd Capacity Market.

Ancillary Service Markets

The FERC defined six ancillary services in Order 888: 1) scheduling, system control and dispatch service; 2) reactive supply and voltage control from generation sources service; 3) regulation and frequency response service; 4) energy imbalance service; 5) operating reserve - spinning reserve service; and 6) operating reserve - supplemental reserve service.[24] Of these, PJM currently provides regulation and spinning through market-based mechanisms. PJM also provides energy imbalance service through the Real-Time Energy Market. PJM provides the remaining ancillary services on a cost basis.

Regulation matches generation with very short-term changes in load by moving the output of selected generators up and down via an automatic control signal.[25] Regulation is provided, independent of economic signal, by generators with a short-term response capability (less than five minutes). Longer term deviations between system load and generation are met via primary and secondary reserves and generation responses to economic signals. Spinning reserve is a form of primary reserve. To provide spinning a generator must be synchronized to the system and capable of providing output within 10 minutes.

Both the Regulation and Spinning Reserve Markets are cleared on a real-time basis. A unit can be selected for either spinning reserve or regulation or neither, but it cannot be selected for both. The Spinning Reserve and Regulation Markets are cleared simultaneously and cooptimized with the Energy Market to minimize the cost of the combined products.

PJM does not provide a market for reactive power, but does ensure its adequacy through member requirements and scheduling.[26] Generation owners are paid according to the FERC-approved reactive revenue requirements. Charges are allocated to network customers based on their percentage of load, as well as to point-to-point customers based on their monthly peak usage.

23 In some cases the data for the AEP, DAY and ComEd Control Zones may be incomplete for the year 2004 and as such, only data that have been reported to PJM were used.
24 75 FERC ¶ 61,080 (1996).
25 Regulation is used to help control the area control error (ACE). See Appendix F, "Ancillary Service Markets," for a full definition and discussion of ACE.
26 See "PJM Manual for Scheduling Operations, M-11," Revision 22 (October 19, 2004), p. 71.

In Phase 1 of 2004, PJM operated two Regulation Markets: one for the Mid-Atlantic Region and a second for the AP Control Zone. For Phase 2 a third market was added for the ComEd Control Area. For Phase 3, PJM operated two Regulation Markets, one for the Mid-Atlantic Region and one for the Western Region now comprised of the AP, ComEd, AEP and DAY Control Zones.

In Phase 1, PJM operated two Spinning Reserve Markets: one for the Mid-Atlantic Region and a second for the AP Control Zone. For Phase 2, a third market was added for the ComEd Control Area. For Phase 3, PJM operated three Spinning Reserve Markets in three spinning zones: the PJM Mid-Atlantic Region spinning zone, the ComEd spinning zone and the AP-AEP-DAY spinning zone.

Overview

The MMU has reviewed structure, conduct and performance indicators for the identified Regulation Markets and the Spinning Reserve Markets. The MMU concludes that the markets functioned effectively, except for the Regulation Market in the Phase 2 ComEd regulation zone, and produced competitive results during calendar year 2004, in every case including ComEd. The issue in the ComEd regulation zone was inadequate available supply of regulation during some hours. Clearing prices in the ComEd Regulation Market were consistent with a competitive outcome as the market was cleared on the basis of cost-based offers.

Before the Phase 2 integration of ComEd and the Phase 3 integrations of the AEP and DAY Control Zones, PJM operated separate Regulation Markets and the Spinning Reserve Markets in the PJM Mid-Atlantic Region and in the AP Control Zone.[27] The market analysis treats each Regulation Market and each Spinning Reserve Market separately for these periods.

The structure of each of the Regulation and Spinning Reserve Markets has been evaluated and the MMU has concluded that, with the exception of the Regulation Market in the PJM Mid-Atlantic Region, these markets are not structurally competitive as they are characterized by high levels of supplier concentration and inelastic demand. As a result, these Ancillary Service Markets are operated as markets with market-clearing prices and with offers based on the marginal cost of producing the service plus a margin. The conduct of market participants within these market structures has been consistent with competition, and the market performance results have been competitive.

The Regulation Market in the PJM Mid-Atlantic Region was cleared based on participants' price offers during Phases 1, 2 and 3. All suppliers were paid the market-clearing price, which is a function of the supply curve and PJM-defined demand. The supply curve is offered MW and their associated offer price, which is a combination of unit-specific offers plus opportunity cost (OC)[28] as calculated by PJM. The Regulation Market in the AP Control Zone during Phases 1 and 2 was cleared on cost-based offers because, given a single regulation supplier, the market was not structurally competitive. The price of regulation in the AP Control Zone was based on unit-specific, cost-based offers plus unit-specific opportunity cost. The Regulation Market in the ComEd Control Area during Phase 2 was cleared on cost-based offers as the market was not structurally competitive. The cost-based regulation offer prices are defined to be the unit-specific incremental cost of providing regulation plus a margin of $7.50 per MWh plus opportunity cost calculated by PJM.

27 The PJM Mid-Atlantic Region is in the Mid-Atlantic Area Council (MAAC) region of the North American Electric Reliability Council (NERC), the AP, AEP and DAY Control Zones of the PJM Western Region are in the East Central Area Reliability Council (ECAR) NERC region, and the ComEd Control Zone is in the Mid-America Interconnected Network, Inc. (MAIN) NERC region. MAAC, ECAR and MAIN have different reliability requirements for the two services. These requirements are documented in the business rules for each market, located in the "PJM Manual for Scheduling Operations, M-11" (October 19, 2004).

28 As used here, the term "opportunity cost" (OC) refers to the estimated lost opportunity cost (LOC) that PJM uses to create a supply curve on an hour-ahead basis. The term, "lost opportunity cost," refers to opportunity costs included in payments to generation owners.

The geographic scope of the Regulation Market was redefined for Phase 3 as two Regulation Markets, one for the Mid-Atlantic Region and one for the Western Region comprised of the AP, ComEd, AEP and DAY Control Zones. In Phase 3, the PJM Western Region's Regulation Market was cleared on cost-based offers as the market was not structurally competitive.

During 2004, the Spinning Reserve Markets in the PJM Mid-Atlantic Region and in the ComEd spinning zone were cleared based on cost-based offers because these markets were determined to be not structurally competitive. The cost-based offers for spinning reserve include incremental cost plus a margin and opportunity cost. The price of spinning in the AP Control Zone was based on unit-specific cost-based offers. Prices for spinning in the PJM Mid-Atlantic Region and the ComEd spinning zone were market-clearing prices determined by supply and PJM-defined demand. The cost-based spinning offers are defined to be the unit-specific incremental cost of providing spinning reserve plus a margin of $7.50 per MWh plus opportunity cost calculated by PJM.

Regulation Market Structure

- **Concentration of Ownership.** During 2004, the PJM Mid-Atlantic Region's Regulation Market had an average Herfindahl-Hirschman Index (HHI) of 1608 which is classified as "moderately concentrated."[29, 30] Less than 1 percent of the hours had a single pivotal supplier. During Phases 1 and 2 of the year, there was only one supplier of regulation in the Western Region. In Phase 2, the ComEd Control Area was a separate Regulation Market with an average HHI of 5817, meaning that the market was highly concentrated. In Phase 3, the AP, ComEd, AEP and DAY Control Zones became a single Regulation Market, with an average HHI of 3426. In Phase 3, ownership of regulation in the PJM Western Region's Regulation Market was highly concentrated. There was a single pivotal supplier in 56 percent of the hours.

Regulation Market Performance

- **Price.** The average price per MWh associated with meeting PJM's demand for regulation during 2004 remained about the same as it had been in 2003, approximately $42.75 per MWh. The average cost per MWh in the AP regulation zone during Phases 1 and 2 was $33.71 per MWh, an increase of 34 percent.

  The average price per MWh for regulation in the ComEd Control Area during Phase 2 was $39.22. Intraday regulation prices varied widely in the ComEd Control Area primarily because of insufficient regulation capacity during times of minimum generation and times when the requirement was 300 MW.

  For the PJM Western Region regulation zone during Phase 3, the average price per MWh for regulation was $18.36.

- **Availability.** The supply of regulation in the PJM Mid-Atlantic Region was both stable and adequate, with a 2.90 average ratio of hourly regulation supply offered to the hourly regulation requirement. This average ratio was 1.68 for the ComEd Control Area's Phase 2 Regulation Market and 2.12 for the Western Region's Phase 3 Regulation Market.

29 See Section 2, "Energy Market" for a more complete discussion of concentration ratios and the Herfindahl-Hirschman Index (HHI).
30 The HHIs reported in this summary are based on regulation capacity that is both offered to the market and is eligible to provide regulation.

While the average ratio of hourly regulation supply offered to the hourly regulation requirement was 1.68, the situation was more complicated in the ComEd Control Area during Phase 2. Regulation capacity was always adequate in the sense that the total reported capability was adequate.[31] However, there was inadequate regulation that was both offered and eligible to participate in the market on an hourly basis to meet the on-peak requirement of 300 MW during May, June and July. This situation was alleviated in August after the regulation certification of additional generating units.

Spinning Reserve Market Structure

- **Concentration of Ownership.** In 2004, market concentration was high in the Tier 2 Spinning Reserve Market. The average spinning market HHI for the PJM Mid-Atlantic Region throughout 2004 was approximately 3100. During Phases 1 and 2 of the year, the AP Control Zone had only one supplier of spinning reserve. During Phases 2 and 3, the Spinning Reserve Market in the ComEd spinning zone had only two suppliers and an HHI of approximately 8181. During Phase 3, the AP-AEP-DAY spinning zone had an HHI of 5648. [32]

Spinning Reserve Market Performance

- **Price.** Average price associated with meeting the PJM system demand for spinning reserve throughout 2004 was about $14.86 per MW, a $0.66 per MW decrease from 2003. The average price in the AP Control Zone for Phases 1 and 2 was $33.37 per MW for a 27 percent increase compared to 2003. This increase was caused by higher fuel costs in the AP Control Zone and was reflected in the cost-based bids of the units. The average price for spinning reserve in the ComEd spinning zone during Phases 2 and 3 was $17.21. The average price for spinning in the AP-AEP-DAY spinning zone during Phase 3 was $12.24.

Congestion

Congestion occurs when available, low-cost energy cannot be delivered to all loads because of limited transmission capabilities. When the least cost available energy cannot be delivered to load in a transmission-constrained area, higher cost units must be dispatched in this constrained area to meet that load.[33] The result is that the price of energy in the constrained area is higher than elsewhere because of the transmission limitations. LMPs reflect the price of the lowest cost resources available to meet loads, taking into account actual delivery constraints imposed by the transmission system. Thus LMP is an efficient way of pricing energy supply when transmission constraints exist. Congestion reflects this efficient pricing.

As PJM integrated new transmission zones during 2004, the patterns of congestion changed, reflecting additional transmission and generation resources with new cost structures, load requirements and transmission system characteristics.

31 See "Regulation Capacity, Daily Availability, Hourly Supply and Price," in Appendix F, "Ancillary Service Markets," for a definition of capacity, availability and supply.
32 This portion of the Spinning Reserve Market ended the calendar year comprised of the AP, AEP and DAY Control Zones. For clarity, it is referred to herein as the AP-AEP-DAY spinning zone.
33 This is referred to as dispatching units out of economic merit order. Economic merit order is the order of all generator offers from lowest to highest cost. Congestion occurs when loadings on transmission facilities mean that the next unit in merit order cannot be used and that a higher cost unit must be used in its place.

Overview

- **Total Congestion.** Congestion costs have ranged from 6 to 9 percent of PJM annual total billings since 2000. Congestion costs increased from 7 percent of total billings in calendar year 2003 to 9 percent of total billings in calendar year 2004, a 28 percent increase. Total congestion costs were $808 million in calendar year 2004, a 62 percent increase from $499 million in calendar year 2003. The total PJM billing for 2004 was approximately $8.7 billion, a 26 percent increase over the approximately $6.9 billion billed in 2003.

- **Hedged Congestion.** Although some months had congestion credit deficiencies, excess congestion charges collected in other months offset all but $16 million of the deficiencies for the 17-month planning period that ended May 31, 2004.[34] This means that FTRs were paid at 98 percent of the target allocation level for that period. FTRs through December 31, 2004, of the planning period ending May 31, 2005, have been paid at 97 percent of the target allocation level.

- **Monthly Congestion.** Differences in monthly congestion costs continued to be substantial. In 2004, these differences were driven by varying load and energy import levels, different patterns of generation, weather-induced changes in demand and variations in congestion frequency on constraints affecting large portions of PJM load.

- **Zonal Congestion.** To provide an approximate indication of the geographic dispersion of congestion costs, LMP differentials were calculated for control zones in the PJM Mid-Atlantic and Western Regions as they existed at year end. The data show new overall congestion patterns during calendar year 2004.

- **Congested Facilities.** Congestion frequency increased in calendar year 2004 as compared to 2003. During 2004, there were 11,205 congestion-event hours as compared to 9,711 congestion-event hours during 2003. Included in the 2004 total are 2,512 congestion-event hours associated with the Pathway that existed during Phase 2. The Pathway, which was comprised of transmission service reservations through AEP, linked the PJM and the ComEd Control Areas. The management of Pathway constraints through redispatch procedures and reductions in capability limits from TLRs effectively regulated west-to-east flow into PJM. As a result of this limiting behavior, facilities prone to congestion because of west-to-east flow through PJM saw a reduction in loading and thus experienced lower congestion frequency in 2004. This characteristic, combined with a relatively mild summer season, tended to reduce facility loadings in PJM's Mid-Atlantic Region and further contributed to reduced congestion. Excluding Pathway congestion, interfaces, transformers and lines experienced overall decreases in congested hours during 2004 as compared to 2003.

- **Local Congestion.** In calendar year 2004, the PSEG Control Zone experienced 1,784 congestion-event hours, the most of any control zone, but only a 2 percent increase over the 1,751 congestion-event hours the PSEG Control Zone had experienced in 2003. On March 17, 2004, PSEG significantly reduced the emergency and normal ratings of the Branchburg

34 PJM accounts for congestion costs and the FTRs and related financial instruments intended to hedge them on a planning period basis. Normally, the planning period will be 12 months long and run from June 1 to May 31 of the following year. For the transition from a calendar to a planning year, the planning period was 17 months long, running from January 1, 2003, until May 31, 2004.

number 1 and number 2 transformers because of a deteriorating condition identified during an inspection. The result was a large increase in congestion-event hours on the Branchburg 500/230 kV transformers. However, a combined decrease of 1,044 congestion-event hours attributable to the Branchburg-Readington 230 kV, Edison-Meadow Road 138 kV and Cedar Grove-Roseland 230 kV facilities, offset the 1,005 hours of congestion on the Branchburg transformers. The Branchburg transformer constraint affected prices across a large geographic area. Prices were increased by this constraint in the PSEG, JCPL and AECO zones, while prices in the remainder of PJM experienced downward pressure as a result of congestion on this facility. The Erie West and North Meshoppen transformers experienced 624 fewer hours of congestion during 2004 and drove the 67 percent reduction in congestion frequency in the PENELEC Control Zone. The DPL Control Zone showed a continued decrease in congestion-event hours of operation, resulting from completion of transmission reinforcements in the southern part of the territory.

- **Post-Contingency Congestion Management Program.** During calendar year 2003, PJM developed, tested and implemented a protocol resulting in less frequent out of merit dispatch than had previously been the case. Under this post-contingency congestion management protocol, a facility may be operated to a 30-minute, short-term emergency rating if there is sufficient quick start capability or switching to respond to the loss of a facility.

  On August 19, 2004, the FERC accepted PJM's post-contingency congestion management plan.[35] The program was implemented on September 1, 2004, and PJM continues to evaluate candidate facilities for inclusion under this protocol.

Persistent congestion in areas within PJM and the overall level of congestion costs suggest the importance of PJM's continuing efforts to improve the sophistication of its congestion analysis. Congestion analysis is central to implementing the FERC order to develop an approach identifying areas where investments in transmission would relieve congestion where that congestion might enhance generator market power and where such investments are needed to support competition.[36]

In an order dated December 19, 2002, granting PJM full RTO status, the FERC directed PJM to revise its regional transmission expansion planning protocol (RTEPP) to "more fully explain [...] how PJM's planning process will identify expansions that are needed to support competition" and to "provide authority for PJM to require upgrades both to ensure system reliability and to support competition."[37] The FERC approved implementing changes to the PJM Tariff and to its Operating Agreement, expanding PJM's regional transmission planning protocol to include economic planning. The program commenced retroactively with the regional planning cycle that had already begun on August 1, 2003. PJM will, when appropriate, initiate upgrades or expansions of the transmission system to enhance the economic and operational efficiency of wholesale electricity markets in PJM. PJM's economic planning process identifies transmission upgrades needed to address unhedgeable congestion. PJM defines unhedgeable congestion as the cost of congestion attributable to the portion of load affected by a transmission constraint that cannot be supplied by economic generation or hedged with available FTRs.[38] First, market forces are relied upon through the opening of a one-year market window during which merchant solutions are solicited through

35 108 FERC ¶ 61,196 (2004).
36 96 FERC ¶ 61,061 (2001).
37 101 FERC ¶ 61,345 (2002).
38 104 FERC ¶ 61,124 (2003).

the introduction of incentives and the posting of relevant market data. If market forces do not resolve unhedgeable congestion within an appropriate time period, PJM will determine, subject to cost-benefit analysis, transmission solutions that will be implemented through the RTEPP. To date, 54 facilities have experienced sufficient levels of unhedgeable congestion to trigger the opening of a market window to solicit merchant solutions to relieve congestion.

Financial Transmission and Auction Revenue Rights

In PJM, FTRs have been available to firm point-to-point and network service transmission customers[39] as a hedge against congestion costs since the inception of locational energy pricing on April 1, 1998. These firm transmission customers have access to FTRs because they pay the costs of the transmission system that enables firm energy delivery. Firm customers receive requested FTRs to the extent that they are consistent both with the physical capability of the transmission system and with other eligible customers' FTR requests.

Effective June 1, 2003,[40] PJM replaced the allocation of FTRs with an allocation of Auction Revenue Rights (ARRs) and an associated Annual FTR Auction. The process for allocating ARRs is identical to the previous process for allocating FTRs, but the revenues received for the allocated ARRs are based on the results of the Annual FTR Auction. Firm transmission customers have the option either to take ARRs or to take the underlying FTRs through a process called self-scheduling.

PJM also runs monthly auctions designed to permit bilateral FTR sales and to allow eligible participants to buy any residual system FTRs. For the 2003 to 2004 planning period, PJM introduced 24-hour FTRs into the monthly auctions. At the same time, PJM also added annual and monthly FTR options. Unlike standard FTRs, the options can never be a financial liability.

ARRs and FTRs are both financial instruments that entitle the holder to receive revenues or to pay charges based on nodal price differences. ARRs provide holders with revenues or charges based on the locational price difference between ARR sources (origins) and sinks (destinations) determined in the Annual FTR Auction.[41] In other words, ARR revenues are a function of FTR auction participants' expectations of locational price differences in the Day-Ahead Energy Market. FTRs provide holders with revenues or charges based on the locational price differences actually experienced in the Day-Ahead Energy Market.

ARR and FTR holders do not need to deliver energy to receive ARR or FTR credits, and neither instrument represents a right to the physical delivery of power. Both can, however, help protect load-serving entities (LSEs) and other market participants from congestion costs in the PJM Day-Ahead Energy Market. Market participants can also hedge against real-time congestion by matching real-time energy schedules with day-ahead energy schedules.

39 PJM network and firm, long-term point-to-point transmission service transmission customers are referred to as eligible customers.
40 87 FERC ¶ 61,054 (1999).
41 These nodal prices are a function of the market participants' annual FTR bids and binding transmission constraints. An optimization algorithm selects the set of feasible FTR bids that produces the most net revenue.

Overview

ARRs were available throughout the PJM Mid-Atlantic Region for the 2004 to 2005 planning period, while both ARRs and direct allocation FTRs were available to eligible market participants in the AP and ComEd Control Zones. Eligible customers in the AEP and DAY Control Zones received phase-in FTRs to carry them to the start of the next planning period. [42]

Market Structure

- **ARR Supply and Demand.** Total demand in the annual ARR allocation was 55,128 MW for the 2004 to 2005 planning period, up from 39,888 MW during the 2003 to 2004 planning period. ARR demand is limited by total amount of network and long-term, firm point-to-point transmission service ARR supply is limited by the capability of the transmission system to simultaneously accommodate the set of requested ARRs, and numerous combinations of ARRs are feasible. The Bedington-Black Oak interface and the Eastern Interface were the principal constraints limiting supply.

  In response to an order by the FERC,[43] PJM proposed changes to its FTR and ARR allocation processes that would allow certain long-term, firm point-to-point transmission service customers to participate in Stage 1 of the annual ARR allocation, thereby putting them on equal footing with network transmission service customers if transmission constraints occur in the ARR and FTR simultaneous feasibility test (SFT).

  PJM market rules automatically reassign ARRs and their associated revenue when load switches among LSEs. Nearly 34,000 MW of ARRs associated with $264,300 per MW-day of revenue were automatically reassigned during the period from June 2003 through December 2004. Individual MW of load may be reassigned multiple times over a period.

- **FTR Supply and Demand.** Total Annual FTR Auction demand was 861,323 MW during the 2004 to 2005 planning period. Under the Annual FTR Auction, there is no limit on demand. FTR supply is limited by the capability of the transmission system to accommodate simultaneously the set of requested FTRs, and numerous combinations of feasible FTRs. The derated Branchburg 500/230 transformer, the Bedington-Black Oak interface, the Wylie Ridge 500/345 transformer and the Kanawha River-Matt Funk 345 line were the principal constraints limiting supply. Total demand for annual FTR allocations was 62,830 MW during the 2004 to 2005 planning period.

Market Performance

- **FTR Price.** For the 2004 to 2005 planning period, just over 80 percent of Mid-Atlantic Region annual FTRs were purchased for less than $1 per MWh and 90 percent for less than $2 per MWh, while 99.9 percent of ComEd Control Zone annual FTRs were purchased for less than $1 per MWh. The overall average prices paid for annual FTR obligations were $1.27 per MWh for 24-hour, $0.16 per MWh for on-peak and $0.13 per MWh for off-peak FTRs. Comparable prices for the 2003 to 2004 planning period were $1.09 per MWh for 24-hour, $0.34 per MWh

42 The PJM planning period begins on June 1 and ends 12 months later on May 31. Annual FTR accounting changed from calendar years to planning periods beginning with the 2003 to 2004 planning period. The transition to this new accounting period required the 2003 calendar year accounting to be extended by five months to encompass January 1, 2003, through May 31, 2004. The 2004 to 2005 planning period began on June 1, 2004, and will end on May 31, 2005.
43 106 FERC ¶ 61,049 (2004).

for on-peak and $0.15 per MWh for off-peak FTRs. The overall average prices paid for 2004 to 2005 planning period annual FTR obligations and options were $0.31 per MWh and $0.19 per MWh, respectively, compared to $0.37 per MWh and $0.23 per MWh, respectively, in the 2003 to 2004 planning period. Average prices in Monthly FTR Auctions have dropped from $0.51 per MWh in 2002, to $0.27 MWh in 2003, to $0.10 MWh in 2004.

- **ARR Revenue.** Annual and Monthly FTR auction revenue is allocated to ARR holders based on ARR target allocations. PJM collected $358 million in FTR auction revenue during the 2003 to 2004 planning period and $379 million during the 2004 to 2005 planning period through the end of calendar year 2004.

- **FTR Revenue.** Congestion revenues are allocated to FTR holders based on FTR target allocations. PJM collected $680 million of congestion revenues during the 2003 to 2004 planning period and $627 million during the 2004 to 2005 planning period through the end of calendar year 2004.[44]

- **ARR Revenue Adequacy.** ARRs were 100 percent revenue adequate during the 2003 to 2004 and the 2004 to 2005 planning periods. ARR holders received credits valued at $311 million during the 2003 to 2004 planning period, with an average hourly ARR credit of $1.23 per MWh. ARR holders will receive credits valued at $345 million during the 2004 to 2005 planning period, with an average hourly ARR credit of $1.17 per MWh.

- **FTR Revenue Adequacy.** FTRs were 98 percent revenue adequate during the 2003 to 2004 planning period, receiving credits valued at $680 million. FTRs through December 31, 2004, of the planning period ending May 31, 2005, have been paid at 97 percent of the target allocation level.[45]

- **ARR Volume.** Of 55,128 MW in ARR requests for the 2004 to 2005 planning period, 33,589 MW were allocated. Eligible market participants subsequently self-scheduled 13,061 MW of these allocated ARRs as annual FTRs, effectively leaving 20,528 MW of ARRs outstanding. Of 39,888 MW in ARR requests for the 2003 to 2004 planning period, 28,933 MW were allocated. Eligible market participants subsequently self-scheduled 13,986 MW of these allocated ARRs as annual FTRs, effectively leaving 14,947 MW of ARRs outstanding.

- **FTR Volume.** Of 924,154 MW in annual FTR requests for the 2004 to 2005 planning period, 177,434 MW were allocated.

The Annual ARR Allocation and Annual FTR Auction together provide long-term, firm transmission customers with a mechanism to hedge congestion and provide all eligible market participants increased access to long-term FTRs. The Annual FTR Auction allows a market valuation of FTRs that consistent with the most efficient use of such financial instruments. The 2004 FTR auction process results were competitive and succeeded in providing all qualified market participants with equal access to FTRs. By explicitly providing that beneficial ARRs follow load as load shifts among, the rules remove a potential barrier to competition.

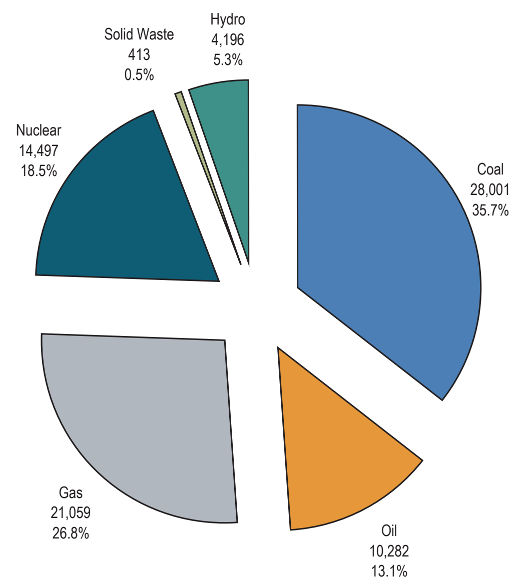
44 See Section 6, "Congestion," at Table 6-2.
45 See Section 6, "Congestion," for a more complete discussion of FTR revenue adequacy.

Generating Capacity and Output by Fuel Type

Capacity by Fuel Type

On January 1, 2004, PJM installed capacity[46] was approximately 78,400 MW, with a fuel mix that was 35.7 percent coal, 26.8 percent natural gas, 18.5 percent nuclear, 13.1 percent oil, 5.3 percent hydro and 0.5 percent solid waste.[47] (See Figure 1-2.)

Figure 1-2 - PJM capacity by fuel source: At January 1, 2004

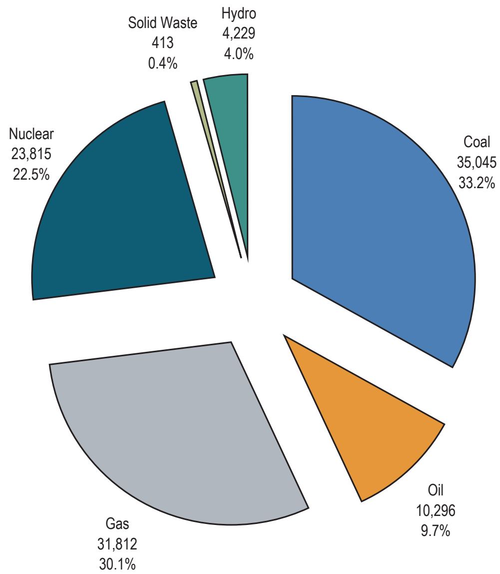


During Phase 1, unit retirements, ratings changes and changes in capacity imports and exports resulted in an installed capacity decrease of approximately 600 MW. On May 31, 2005, installed capacity was 77,800 MW.

With the integration of ComEd, and the implementation of the ComEd Capacity Market on June 1, 2004,[48] installed capacity increased by approximately 27,800 MW to nearly 105,600 MW, a 35.7 percent increase in total PJM capacity over the May 31 level. The ComEd Control Area had proportionally more nuclear and natural gas generating capability and less coal and oil generating capability, than PJM had prior to the Phase 2 integration. As a result, the nuclear share of total PJM installed capacity rose by 3.8 percent to 22.5 percent and the natural gas share increased by 3.2 percent to 30.1 percent while the coal share of capacity fell by 2.5 percent to 33.2 percent and the oil share declined by 2.9 percent to 9.7 percent.[49] (See Figure 1-3.)

46 Installed capacity includes net capacity imports and exports and can vary on a daily basis.
47 Values in percent may not add to 100 because of rounding.
48 Although the integration of the ComEd Control Area into PJM occurred on May 1, 2004, Commonwealth Edison chose to satisfy all capacity obligations in the ComEd Control Area for all entities until the new ComEd Capacity Market commenced on June 1, 2004.
49 Values in percent may not add to 100 because of rounding.

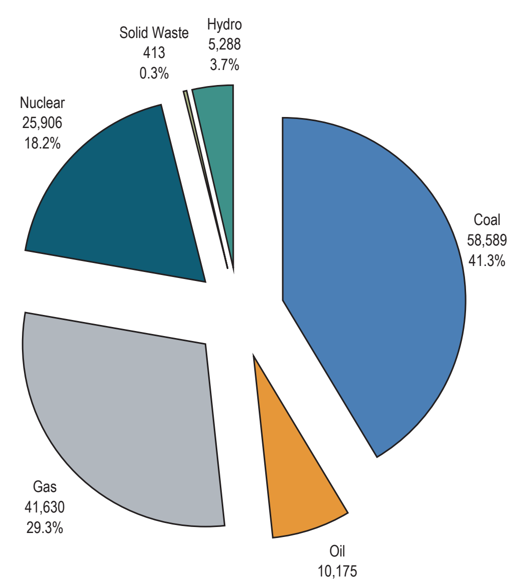
Figure 1-3 - PJM capacity by fuel source: At June 1, 2004



During Phase 2, unit retirements, capacity additions, ratings changes and changes in capacity imports and exports resulted in an installed capacity decrease of approximately 1,000 MW. On September 30, 2004, installed capacity was approximately 104,600 MW.

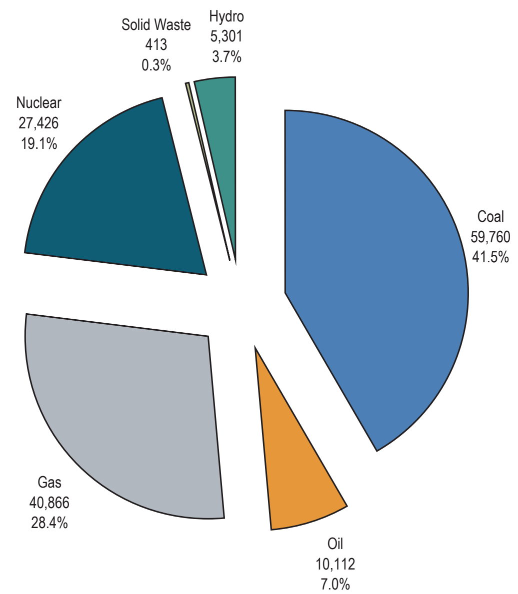
With the integration of the AEP and DAY Control Zones on October 1, 2004, installed capacity increased from the September 30 level by approximately 37,400 MW to 142,000 MW, a 35.8 percent increase. The AEP and DAY Control Zones had proportionally more coal generating capability than PJM had prior to the Phase 3 integration. As a result, the coal share of installed capacity increased by 8.0 percent to 41.3 percent while the shares of oil, natural gas, hydroelectric and nuclear generating capability decreased. (See Figure 1-4.)

Figure 1-4 - PJM capacity by fuel source: At October 1, 2004



On December 31, 2004, PJM installed capacity was about 144,000 MW. Of the total installed capacity, 59,800 MW, or 41.5 percent, was coal; 40,900 MW, or 28.4 percent, was natural gas; 27,400 MW, or 19.1 percent, was nuclear; 10,100 MW, or 7.0 percent, was oil; 5,300 MW, or 3.7 percent, was hydroelectric; and 400 MW, or 0.3 percent, was solid waste. (See Figure 1-5.)

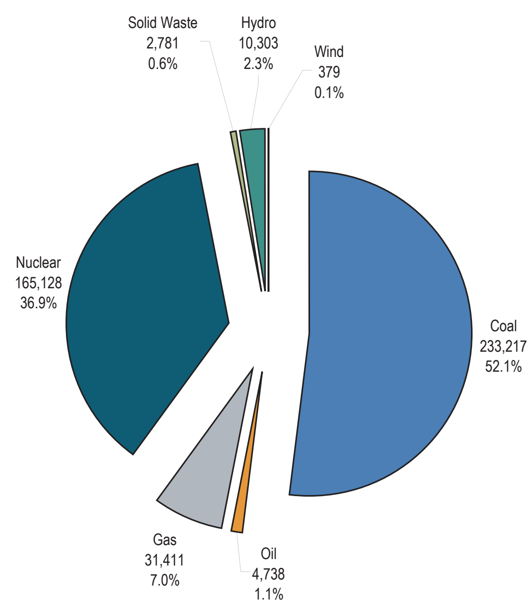
Figure 1-5 - PJM capacity by fuel source: At December 31, 2004



Generation by Fuel Type

In calendar year 2004, coal and nuclear units generated 88.9 percent of the total electricity. Coal was 52.1 percent, nuclear 36.9 percent, natural gas 7.0 percent, oil 1.1 percent, hydroelectric generation 2.3 percent, solid waste 0.6 percent and wind generation 0.1 percent of total generation. (See Figure 1-6.)

Figure 1-6 - PJM generation by fuel source (GWh): Calendar year 2004



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 Energy 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. For PJM, 2004 was a time of significant growth with three control zones being integrated into PJM Markets. The PJM Market Monitoring Unit's (MMU) analysis of the Energy Market treats these new zones as parts of existing markets as of the date of integration.

The MMU analyzed measures of energy market structure, participant behavior and market performance for 2004, including supply and demand conditions, market concentration, residual supplier index, price-cost markup, net revenue and prices. The performance of demand-side response programs was also evaluated. The MMU concludes that, despite concerns about market structure, the PJM Day-Ahead and Real-Time Energy Market results were competitive in 2004.

PJM Markets are designed to promote competitive outcomes derived from the interaction of supply and demand in each of the PJM Markets. Market design itself is the primary means of achieving and promoting competitive outcomes in the PJM Markets. One of the MMU's primary goals is to identify actual or potential market design flaws.[1] PJM's market power mitigation goals have focused on market designs that promote competition (a structural basis for competitive outcomes) and on limiting market power mitigation to instances where market structure is not competitive and thus where market design alone cannot mitigate market power. In the PJM Energy Market, this occurs only in the case of local market power. When a transmission constraint creates the potential for local market power, PJM applies a structural test to determine if the local market is competitive, applies a behavioral test to determine if generator offers exceed competitive levels and applies a market performance test to determine if such generator offers would affect the market price.

In the *2004 State of the Market Report*, the calendar year is divided into three phases, corresponding to market integration dates.

- **Phase 1.** The four-month period from January 1 through April 30, 2004, when PJM was comprised of 12 zones.[2] Eleven of these [i.e., the Atlantic Electric Company Control Zone (AECO), the Baltimore Gas & Electric Control Zone (BGE), the Delmarva Power & Light Control Zone (DPL), the Jersey Central Power & Light Company Control Zone (JCPL), the Metropolitan Edison Company Control Zone (Met-Ed), the PECO Energy Company Control Zone (PECO), the Pennsylvania Electric Company Control Zone (PENELEC), the Pepco Control Zone (PEPCO), the PPL Electric Utilities Corporation Control Zone (PPL), the Public Service Electric and Gas Company Control Zone (PSEG) and the Rockland Electric Company Control Zone (RECO)] comprised the Mid-Atlantic Region. The remaining zone, the Allegheny Power Company Control Zone (AP), comprised the PJM Western Region.

1 PJM Market Monitoring Plan, OATT, Attachment M.
2 Zones, control zones and control areas are geographic areas that customarily bear the name of a large utility service provider operating within their boundaries. The names apply to the geographic area, not to any single company. The geographic areas did not change with the formalization of the control zone and control area concepts during the Phase 3 integrations. For simplicity, zones are referred to as Control Zones for all three phases. The only exception is ComEd which is called the ComEd Control Area for Phase 2 only.

- **Phase 2.** The five-month period from May 1 through September 30, 2004, during which PJM was comprised of the Mid-Atlantic Region, including its 11 zones, the AP Control Zone and the Commonwealth Edison Company Control Area (ComEd).[3]

- **Phase 3.** The three-month period from October 1 through December 31, 2004, during which PJM was comprised of the Mid-Atlantic Region, including its 11 zones, the AP Control Zone and the ComEd Control Zone plus the American Electric Power Control Zone (AEP) and The Dayton Power & Light Company Control Zone (DAY). The ComEd Control Area became the ComEd Control Zone on October 1.

Overview

Market Structure

- **Supply.** During the June to September 2004 summer period, PJM Energy Markets received a maximum of 109,600 MW in supply offers, net of real-time imports or exports. The 2004 net supply offers represented an approximately 29,800 MW increase compared to the comparable 2003 summer period. The increase in 2004 was comprised of 29,342 MW from the Phase 2 ComEd Control Area integration and of 500 MW from a net increase in capacity from the Mid-Atlantic Region and the AP Control Zone.

- **Demand.** The PJM system peak load in 2004 was 77,887 MW, a coincident summer peak load reflecting the Mid-Atlantic Region, the AP Control Zone and the ComEd Control Area.[4] The PJM peak load in 2003 of 61,499 MW occurred prior to the integration of the ComEd Control Area. If the 2003 peak load were adjusted to include the ComEd Control Area for comparison purposes, the 2003 peak load of the combined area would have been 81,992 MW.[5] As Phase 3 integrations occurred too late to be relevant to the 2004 summer peak, they were excluded from this analysis.

- **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 mean larger numbers of sellers splitting market sales more equally. High concentration ratios indicate an increased potential for participants to exercise market power, although low concentration ratios do not mean that a market is competitive or that participants cannot exercise market power. Analysis of the PJM Energy Market indicates moderate market concentration overall. Further, analyses of supply curve segments indicate moderate concentration in the baseload segment, but high concentration in the intermediate and peaking segments. Analysis also indicates that the ComEd Control Area was highly concentrated overall and in each segment of the supply curve. Several other geographic areas of PJM exhibited moderate to high levels of concentration when transmission constraints defined local markets. No evidence exists, however, that market power was exercised in these areas during 2004, both because of generator obligations to serve load and because of PJM's rules limiting the exercise of local market power.

3 During the five-month period May 1, 2004, through September 30, 2004, the ComEd Control Zone (ComEd) was called the Northern Illinois Control Area (NICA).
4 For the purpose of the 2004 State of the Market Report, all hours are presented and all hourly data are analyzed using Eastern Prevailing Time (EPT). See Appendix H, "Glossary," for a definition of EPT and its relationship to Eastern Standard Time (EST) and Eastern Daylight Time (EDT).
5 This calculated 2003 peak load of the combined area was a total system coincident peak load and occurred on a different day and hour than the 2003 peak load for PJM.

- **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, that owner has market power. The residual supply index (RSI) is a measure of the extent to which generation owners are pivotal suppliers. Like concentration ratios, the RSI is an indicator of market structure. When the RSI is less than 1.00, a generation owner is pivotal. As with concentration ratios, the RSI is not a bright line test. While an RSI less than 1.0 clearly indicates market power, an RSI greater than 1.0 does not guarantee that there is no market power. As an example, suppliers can be jointly pivotal. The RSI results are consistent with the conclusion that the PJM Energy Market results were competitive in both 2003 and 2004, with an average RSI of 1.66 and 1.64, respectively. In 2004, a generation owner in the PJM Energy Market was pivotal for only eight hours, less than 0.1 percent of all hours during the year. This represents a slight increase in pivotal hours from 2003, when a generation owner was pivotal in the Energy Market for six hours, also less than 0.1 percent of all hours during the year.

- **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 response resources available in PJM during the nine-month period ended September 30, 2004, were 1,806 MW from active load management, 1,385 MW from the Emergency Load-Response Program and 724 MW from the Economic Load-Response Program. There were 317 MW enrolled in both the Load-Response Program and in active load management. The 11,562 MW in total DSR resources, including additional programs reported by PJM customers in response to a survey, were approximately 15 percent of PJM's peak demand.

Market Performance

- **Price-Cost Markup.** Price-cost markups are a measure of market power. The price-cost markup reflects both participant conduct and the resultant market performance. The price-cost markup index is defined here as the difference between price and marginal cost, divided by price for the marginal units in the PJM Energy Market. The MMU has expanded and refined the analysis of markup measures. Overall, data on the price-cost markup are consistent with the conclusion that PJM Energy Market results were reasonably competitive in 2004.

- **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 all PJM Markets. The net revenue calculation has been refined from the *2003 State of the Market Report*. Improvements include reflection of environmental costs, unit class-specific, forced-outage factors, annual planned outages, the hourly effects of ambient and cooling water temperature on plant performance and unforced capacity, FERC-approved reactive revenue requirements for each plant class and the addition of analysis for a new entrant pulverized coal plant. Alternate dispatch scenarios were also analyzed. In 2004, the perfect economic dispatch net revenues would not have covered the first year fixed costs of a new entrant CT with variable costs between $75 and $80 per MWh, a combined-cycle plant (CC) with variable costs between $50 and $55 per MWh or a pulverized coal plant (CP) with variable costs between $25 and $30 per MWh operating for all profitable hours.[6]

- **Energy Market Prices**. PJM's locational marginal prices (LMPs) are a direct measure of market performance. 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 2003 to 2004. The simple, hourly average system LMP was 10.8 percent higher in 2004 than in 2003, $42.40 per MWh versus $38.27 per MWh. When hourly load levels are reflected, the load-weighted LMP of $44.34 per MWh in 2004 was 7.5 percent higher than in 2003. When increased fuel costs are accounted for, the fuel-cost-adjusted, load-weighted, average LMP was 4.2 percent lower in 2004 than in 2003, $39.49 per MWh compared to $41.23 per MWh.

  PJM average real-time energy market prices increased in 2004 over 2003 for several reasons, including, but not limited to, significantly increased fuel costs for the marginal units. PJM did not experience extreme demand conditions during 2004. While average prices increased in 2004, the PJM system price was above $150 per MWh for only five hours, with the maximum LMP of $180.12 per MWh occurring on December 20, 2004, during the hour ending 0900 Eastern Prevailing Time (EPT).

Energy Market results for 2004 reflect supply-demand fundamentals. While the existing structure of the Energy Market does not guarantee competitive outcomes, actual market performance results were reasonably competitive in 2004 because the market was relatively long and demand was moderate. Given the structure of the Energy Market, tighter markets or a change in participant behavior are potential sources of concern in the Energy Market.

Mitigation

- **Offer Capping Statistics.** PJM rules provide that PJM offer caps units whenever they would otherwise have the ability to exercise local market power. Offer capping levels increased slightly in 2004 because of congestion and a larger service territory, but remained low overall. Offer capping does not have a significant, negative impact on unit net revenues.

Market Structure

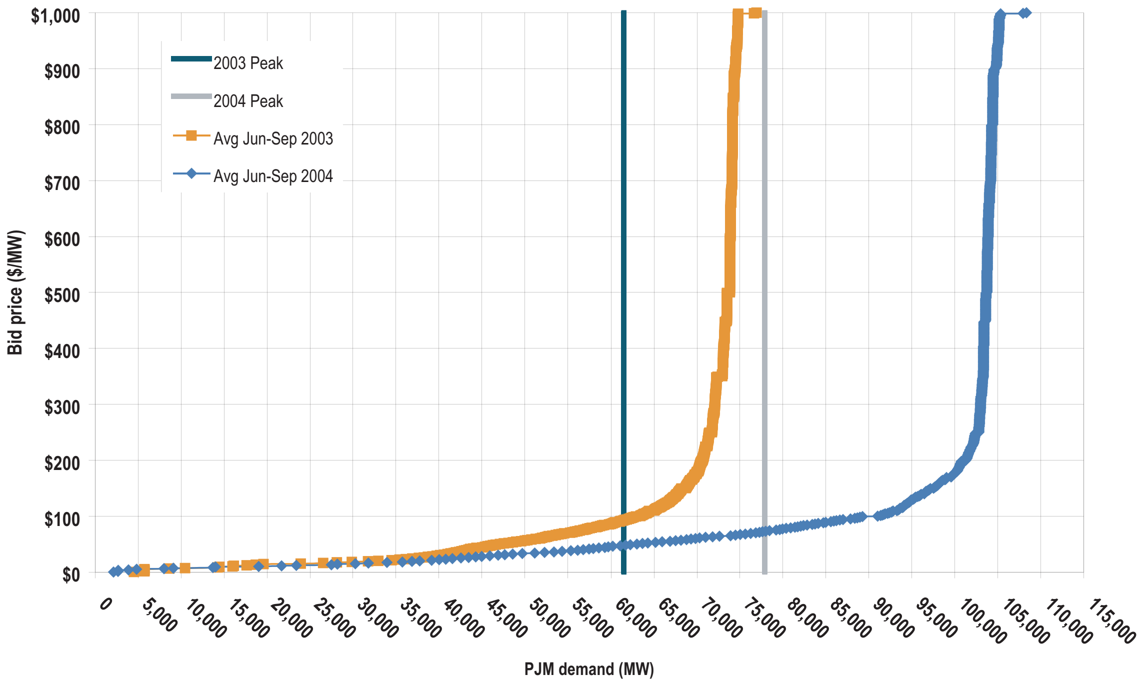
Supply

During the June to September 2004 summer period, PJM Energy Markets received a maximum of 109,600 MW in supply offers, net of real-time imports or exports. The 2004 net supply offers represented an approximately 29,800 MW increase compared to the comparable 2003 summer period. The increase in 2004 was comprised of 29,342 MW from the Phase 2 ComEd Control Area integration and

6 The costs reflect the new entry variable costs for each plant type, including the 2004 average natural gas costs for the CT and CC plants and the 2004 average coal costs for the CP plant.

of 500 MW from a net increase in capacity from the Mid-Atlantic Region and the AP Control Zone. During the summer of 2004, the demand curve intersected the supply curve at a lower price level than would have occurred with less or with a different mix of additional generation. (See Figure 2-1.)

Figure 2-1 - Average PJM aggregate supply curves: Summers 2003 and 2004



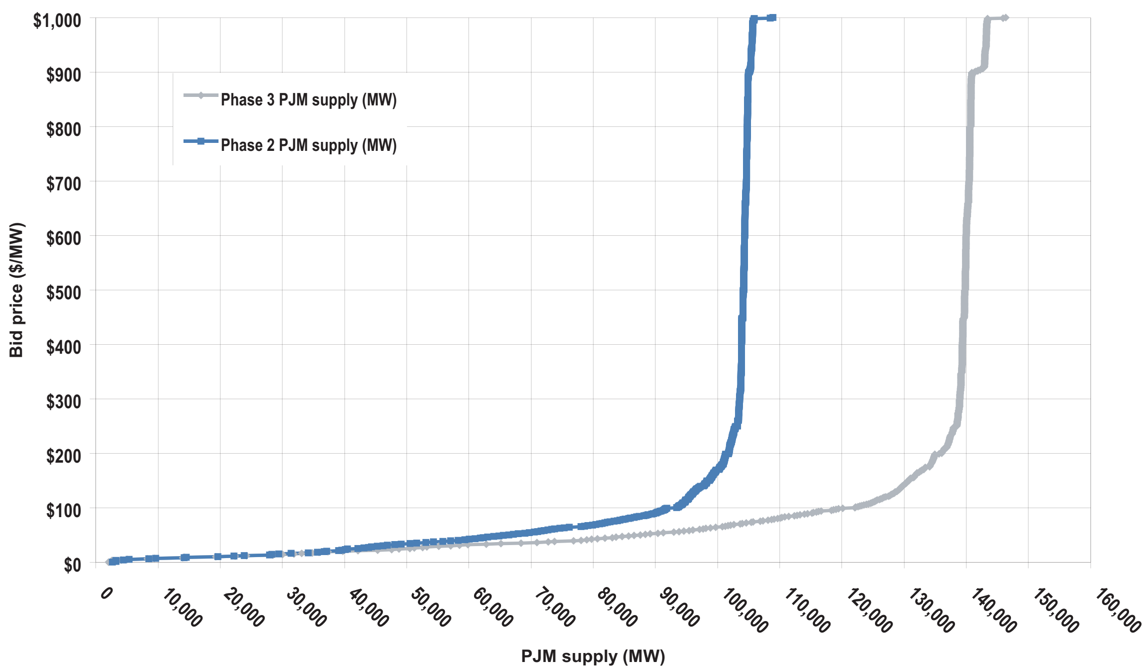
During the 12 months ended September 30, 2004,[7] approximately 2,300 MW of generation entered service in the Mid-Atlantic Region and AP Control Zone. The additions consisted of 450 MW in upgrades to existing generation and 1,850 MW in new generation. After accounting for offsetting decreases from the derating of 100 MW of generation, the removal of 400 MW from market to behind-the-meter operation and the retirement of 1,300 MW, the net increase in capacity was 500 MW. Most retired generation was in the PJM Mid-Atlantic Region. Virtually all of the 100 MW of derated generation was gas-fired while the retired generation consisted of 1,050 MW of fossil-fired steam units and 250 MW of combustion turbines (CTs). Except for 25 MW in diesel generation, the new units were gas-fired, combined-cycle systems. Upgrades to existing facilities included approximately 70 MW of hydroelectric, 100 MW of gas-fired, combined-cycle systems, 40 MW of fossil-fired steam units and 240 MW of nuclear generation. The net result was a slight flattening of the middle portion of the PJM aggregate supply curve as new combined-cycle plants replaced less efficient, higher fuel-cost steam generation.

The shape of the aggregate supply curve was changed only slightly by the new generation. The midportion of the aggregate supply curve was extended due to the addition of baseload generation in the Phase 2 integration. Gas-fired, combined-cycle systems represented about 80 percent of the new generation, with the other 20 percent including net upgrades to existing nuclear, hydroelectric and combustion turbine facilities.

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

The PJM supply curve was extended further with the additions of AEP and DAY in Phase 3. Figure 2-2 compares the average supply curves for Phases 2 and 3. The Phase 2 curve represents the average volume of offer MW for the month of September 2004, the month before the Phase 3 integrations. The Phase 3 curve represents the average volume of offer MW for the month of October 2004, the first month after the Phase 3 integrations. The average offered supply increased from about 110,000 MW for Phase 2 to about 145,000 MW for Phase 3. Since the Phase 3 integrations occurred after the summer peak period, they did not affect the summer peak demand within PJM.

Figure 2-2 - Average PJM aggregate supply curve comparison: Phases 2 and 3



Demand

In order to compare the 2004 summer peak load to the summer peak load in prior years, the change in the size of the PJM footprint had to be accounted for. PJM's geographic area was larger in the summer of 2004 than in prior years as the result of the Phase 2 integration of the ComEd Control Area. The comparison is presented in two ways. The peak load for the summer of 2004 is compared to what the summer peak load would have been in prior years if the larger footprint had been in place for those prior years. In addition the peak load for the summer of 2004 is calculated without the ComEd Control Zone and compared to the PJM peak load for prior years for the same footprint.

Table 2-1 shows the actual coincident peak load for 2004 (including ComEd) and the calculated coincident peak loads for 2003 and 2002 for the same footprint based on an analysis of hourly loads in PJM and ComEd. Table 2-1 shows that the 2004 actual peak load of 77,887 MW was 6,908 MW less than the calculated 2002 peak load of 84,795 MW, for the 2004 footprint.

Table 2-2 shows the calculated coincident peak load for PJM without ComEd and the actual coincident peak loads for PJM in 2003 and 2002. The 2004 calculated coincident peak load of 59,627 MW without ComEd was 4,135 MW less than the actual 2002 PJM coincident peak load of 63,762 MW.

When comparable footprints are used, the peak demand in 2004 was lower than the peak demand in 2003 or 2002.

Table 2-1 - Actual 2004 Phase 2 coincidental peak demand and calculated Phase 2 coincidental peak demand for 2002 and 2003

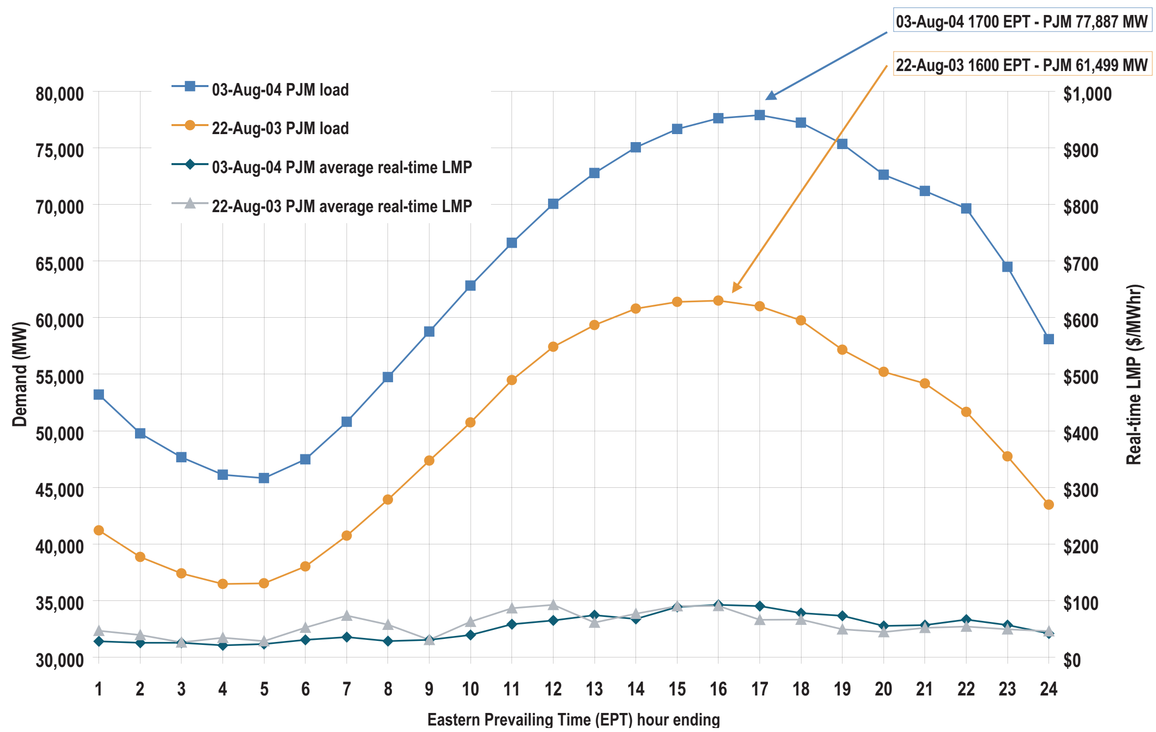
	Date	EPT Hour Ending	PJM Load (MW)	Difference (MW)
2002	1-Aug-02	1700	84,795	N/A
2003	21-Aug-03	1700	81,992	-2,803
2004	3-Aug-04	1700	77,887	-4,105

Table 2-2 - Calculated 2004 Phase 1 coincidental peak demand and actual Phase1 2003 coincidental peak demand for 2002 and 2003

	Date	EPT Hour Ending	PJM Load (MW)	Difference (MW)
2002	14-Aug-02	1600	63,762	N/A
2003	22-Aug-03	1600	61,499	-2,263
2004	17-Sep-04	1700	59,627	-1,872

The actual, unadjusted PJM coincident peak demand based on the actual footprint in each year increased from 61,499 MW in 2003 to 77,887 MW in 2004. The hourly load and average PJM LMP are shown for these two peak days in Figure 2-3.

Figure 2-3 - PJM peak-load comparison: Tuesday, August 3, 2004, and Friday, August 22, 2003



The unadjusted, actual peak demands for PJM based on the actual footprint in each year and the actual ComEd Control Area peak demands are shown in Table 2-3 for the years 2002, 2003 and 2004.

Table 2-3 - Actual Phase 1 and ComEd Control Area annual peak demand

	Pre-ComEd Control Area Integration			ComEd Control Area		
	Peak Demand (MW)	Date	EPT Hour Ending	Peak Demand (MW)	Date	EPT Hour Ending
2002	63,762	14-Aug-02	1600	21,804	1-Aug-02	1600
2003	61,499	22-Aug-03	1600	22,054	21-Aug-03	1600
2004	59,627	17-Sep-04	1700	19,794	3-Aug-04	1700

Market Concentration

The integration of the ComEd Control Area created a unique situation in which PJM and the ComEd Control Area were connected, for PJM redispatch of an integrated energy market, only by the Pathway.[8] When the Pathway was at its limit, the result was two separate energy markets. For this reason, the market concentration analysis treats the ComEd Energy Market separately from the PJM Energy Market throughout Phase 2. During Phases 1 and 2, the PJM Energy Market is considered the Mid-Atlantic Region and the AP Control Zone. During Phase 3, the PJM

8 For a detailed description of the Pathway, see Section 6, "Congestion."

Energy Market was a single market, comprised of the Phases 1 and 2 elements plus the AEP and DAY Control Zones. Accordingly, this analysis treats the PJM Energy Market as a single market during Phase 3.

During all phases of 2004, concentration in the PJM Energy Market was moderate overall. Analyses of supply curve segments[9] indicate moderate concentration in the baseload segment, but high concentration in the intermediate and peaking segments. During Phase 2, the ComEd Control Area was highly concentrated overall and in each segment 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 generation owner is pivotal if the output of the owner's generation facilities is needed to meet load.[10] Further, specific geographic areas of PJM exhibit moderate to high concentration that may be problematic when transmission constraints exist. No evidence suggests that market power was exercised in these areas during 2004, primarily because of generation owners' obligations to serve load and PJM rules limiting the exercise of local market power. If those obligations were to change, however, the market-power-related incentives would change as a result.

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 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 shares of all firms in a market. This analysis reflects the evolving nature of the PJM Markets during 2004. PJM Markets incorporate the Mid-Atlantic Region and the AP Control Zone in Phases 1 and 2 and in Phase 3, it encompasses those elements plus the ComEd, AEP and DAY Control Zones. The ComEd Control Area analyzed separately for Phase 2 only. Hourly PJM and ComEd Energy Market HHIs were calculated based on the real-time energy output of generators located in each geographic footprint, adjusted for hourly net imports. (See Table 2-4 and Table 2-8.) PJM and ComEd installed capacity HHIs were calculated based on the installed capacity of the generating resources, adjusted for aggregate import capability. (See Table 2-5 and Table 2-9.)

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. The maximum installed HHI was calculated by assigning all import capability to the market participant with

9 For the market concentration analysis, supply curve segments are based on a classification of units that generally participate in the PJM Energy Market at varying load levels. Unit class is a primary factor for each classification; however, each unit may have different characteristics that influence the exact segment for which it was classified.
10 See the RSI calculations in Section 2, "Energy Market," for a direct measure of whether generation owners were pivotal.

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) 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. [11]

PJM HHI Results

Calculations for installed and hourly HHI indicate that by the FERC standards, the PJM Energy Market during 2004 was moderately concentrated. (See Table 2-4.) Overall market concentration varied from 811 to 1634 based on the hourly Energy Market measure and from 909 to 1058 based on the installed capacity measure.

Table 2-4 - PJM hourly Energy Market HHI: Calendar year 2004

	Minimum	Average	Maximum
Phases 1 and 2	811	1075	1306
Phase 3	1101	1355	1634
Calendar Year	811	1163	1634

Table 2-5 - PJM installed capacity HHI: Calendar year 2004

	Minimum	Average	Maximum
Phases 1 and 2	944	1014	1084
Phase 3	805	893	981
Calendar Year	909	984	1058

11 77 FERC ¶ 61,263, "Inquiry Concerning the Commission's Merger Policy under the Federal Power Act: Policy Statement," Order No. 592, pp. 64-70.

Table 2-6 and Table 2-7 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 baseload segment is moderately concentrated. 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 included.

Table 2-6 - PJM hourly Energy Market HHI by segment: Calendar year 2004

	Statistic	Base	Intermediate	Peak
Phases 1 and 2	Maximum	1360	6292	10000
	Average	1209	2065	4604
	Minimum	1087	866	1143
Phase 3	Maximum	1897	6352	10000
	Average	1651	3761	5294
	Minimum	1408	1590	931
Calendar Year	Maximum	1897	6352	10000
	Average	1330	2565	4839
	Minimum	1087	866	931

Table 2-7 - PJM installed capacity HHI by segment: Calendar year 2004

	Base	Intermediate	Peak
Phases 1 and 2	1189	1161	1542
Phase 3	1560	909	797
Calendar Year	1291	1085	1291

ComEd HHI Results

Calculations for installed and hourly HHI indicate that the ComEd Control Area's Energy Market, during Phase 2 of 2004, was highly concentrated. (See Table 2-8.) Overall market concentration varied from 4005 to 7746 based on the hourly energy market measure and from 2670 to 4065 based on the installed capacity measure. (See Table 2-9.)

Table 2-8 - ComEd hourly Energy Market HHI: Phase 2, 2004

	Minimum	Average	Maximum
Phase 2	4005	5935	7746

Table 2-9 - ComEd installed capacity HHI: Phase 2, 2004

	Minimum	Average	Maximum
Phase 2	2670	3368	4065

Table 2-10 and Table 2-11 include HHI values for capacity and energy measures by supply curve segment, including base, intermediate and peaking plants in the ComEd Control Area during Phase 2 of 2004. The hourly measure and the installed measure indicate that, on average, all segments of the supply curve were highly concentrated.

Table 2-10 - ComEd hourly Energy Market HHI by segment: Phase 2, 2004

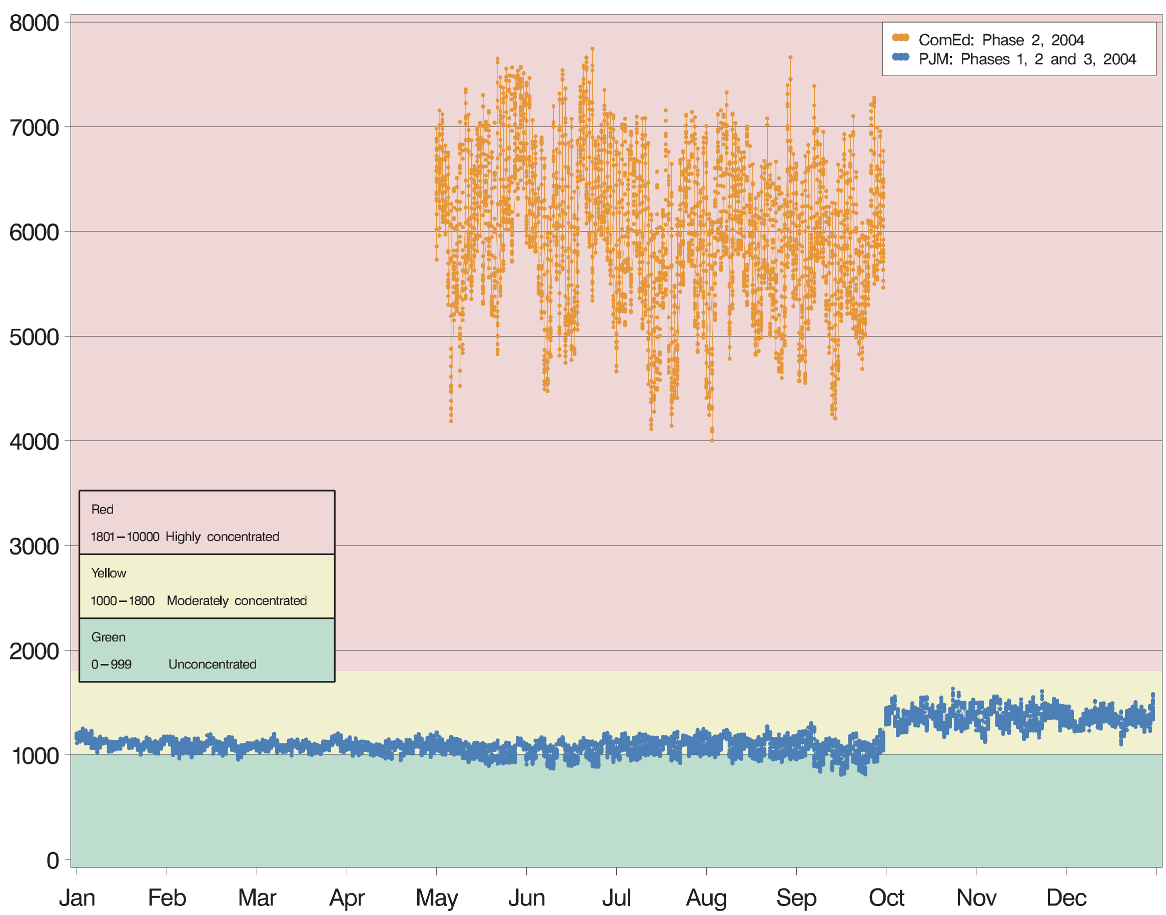
	Statistic	Base	Intermediate	Peak
Phase 2	Maximum	9358	7627	10000
	Average	9273	5708	7803
	Minimum	9146	3227	2162

Table 2-11 - ComEd installed capacity HHI by segment: Phase 2, 2004

	Base	Intermediate	Peak
Phase 2	9304	4109	2486

Figure 2-4 presents detailed hourly HHI results for the PJM and ComEd Energy Markets summarized in Table 2-4 and Table 2-8.

Figure 2-4 - PJM and ComEd hourly Energy Market HHI: Phases 1, 2 and 3, 2004



Local Market Concentration and Frequent Congestion

Although there was a decrease in total congestion-event hours in PJM from 2003 to 2004, with the exception of congestion from the Pathway, several geographic areas in the PJM Mid-Atlantic Region and the Western Region experienced frequent congestion and showed high local market concentration: namely the PSEG, DPL, AP, Met-Ed and AECO Control Zones.[12] Other areas, including the Erie and Towanda subareas of the PENELEC Control Zone, which were problematic in prior years, had congestion hours greatly reduced or eliminated during 2004.

- **PSEG North:** In calendar year 2004, congestion decreased from 1,059 hours in 2003 to 456 hours, with 65 percent of all congestion occurring during on-peak periods. The Roseland-Cedar Grove 230 kV line contributed 150 hours of congestion, representing a decrease of 79 percent from 2003 when it had been constrained for 719 hours. Seventeen other constraints, each occurring for less than 100 hours, accounted for the rest of the congestion. This level of congestion was a significant decrease from 2003, reflecting, in part, the derating of the Branchburg 500/230 kV transformer in northcentral PSEG in March 2004. The presence of the Branchburg constraint significantly limited the flow of power into the northern PSEG area, thus eliminating overloads that might otherwise have occurred. On average, during the hours when the Roseland-Cedar Grove line was constrained,[13] it affected 3,000 MW of load and increased LMP by 24 percent.[14] The average LMP for the affected load was $64, with $15 of congestion created by the Roseland-Cedar Grove constraint. This constraint caused high market concentration, with an average HHI of 5550. Minimum and maximum HHIs were 3800 and 7300.

- **PSEG Northcentral:** In 2004, congestion increased from 688 hours in 2003 to 1,121 hours, with 79 percent of all congestion occurring during on-peak periods. The Branchburg 500/230 kV transformer accounted for 90 percent of congestion in the area, a direct effect of the transformer having been derated in March 2004.[15] The transformer was constrained for 1,005 hours in 2004 compared to 41 hours in 2003. By limiting the flow through the transformer, this constraint also reduced the occurrence of other constraints such as the Edison-Meadow Road 138 kV line, which was constrained for 33 hours in 2004, down from 266 hours in 2003. The Branchburg – Readington 230 kV line was also constrained for 108 hours, but was down from 233 hours in 2003. Four additional constraints contributed to the remainder of congestion in this area. On average, during the hours in which the Branchburg transformer was constrained, it affected 8,250 MW of load and increased LMP by 38 percent, while the Branchburg-Readington line affected 5,000 MW of load and increased LMP by 29 percent during constrained hours. The average LMP for the load affected by the Branchburg 500/230 kV transformer was $92, with $35 created by congestion on the Branchburg 500/230 kV transformer. The Branchburg – Readington 230 kV line contributed $24 of congestion to the average LMP of $82 for its affected load. The 500 kV transformer and the 230 kV line caused moderate to high market concentration, with average HHIs of 1800 and 2800, respectively. HHIs ranged from a minimum of 1440 to a maximum of 3045.

12 For 2004, any area that experienced congestion for more than 100 hours was analyzed for market concentration and the effect of each constraint on LMP in the constrained area. HHIs were measured based on the installed capacity in the constrained area, adjusted for import capability, for the calendar year 2004.
13 Constraints occur during various periods of the year and different operating and market conditions can affect the contribution of a particular constraint to LMP. Constraints affecting similar areas may not make similar contributions to LMP if they do not occur during the same period. For example, the Keeney transformer constraint occurred primarily in the months before Phase 3, while the majority of the Eastern Interface constrained hours occurred during Phase 3.
14 The affected load was determined using a distribution factor analysis. Any substation with a distribution factor greater than, or equal to, 5 percent was deemed affected by the constraint. The contribution to LMP by each constraint was analyzed using the congestion component of LMP. The LMP and the congestion component for the affected load were weighted using the substations within the 5 percent distribution factor threshold and averaged over constrained hours only. For a broader discussion of the effect each constraint had on the defined PJM control zones during 2004, including unconstrained hours, see Section 6, “Congestion.”
15 For a discussion of the Branchburg transformer derating, see also Section 6, “Congestion.”

- **Eastern Interface.** During 2004, congestion on the Eastern Interface increased to 221 hours from 203 hours in 2003. Fifty-six percent of all congestion occurred during on-peak periods. The Eastern Interface affected, on average, 18,990 MW of load. This interface had the effect of increasing LMP for the affected load by 23 percent. The average LMP for this area was $64, $15 of which was attributable to this constraint. Market concentration in the affected area was moderate to high with an average HHI of 1568. Minimum and maximum HHIs were 1156 and 1980, respectively.

- **Delmarva Peninsula (DPLS)**. Congestion on the Delmarva Peninsula continued to improve with 320 hours of constrained operation in 2004, 73 percent occurring during on-peak periods, down from 522 hours in 2003. Still, the area experienced an increase in congestion on the Wye Mills 138/69 kV transformer from seven hours in 2003 to 128 hours in 2004. Congestion on frequently occurring constraints from previous years, such as the Indian River, Church and Cheswold transformers, along with the Hallwood-Oakhall 138 kV line, was either greatly reduced or eliminated in 2004. On average, during the hours when the Wye Mills transformer was constrained, it affected 240 MW of load and increased LMP by 29 percent for that load. The average LMP for the affected load was $100, with $29 of congestion created by this constraint. The Wye Mills 138/69 kV transformer caused high market concentration with an average HHI of 6810. The minimum and maximum HHIs were 3620 and 10000.

- **Delaware North (SEPJM/DPLN).** In 2004, the northern area of Delaware in the DPL Control Zone experienced a 47 percent decrease in congestion, to 102 hours from 194 hours in 2003. Seventy-nine percent of all congestion occurred during on-peak periods. The Keeney 500/230 kV transformer was the only constraint in this area and so it accounted for 100 percent of the congestion. During the hours in which the Keeney transformer was constrained, it affected 8,200 MW of load and increased LMP by 19 percent. The average LMP for the affected load was $59, with $11 of congestion created by the Keeney transformer. On average, the Keeney 500/230 kV transformer caused moderate market concentration with an HHI of 1585. Minimum and maximum HHIs were 1300 and 1870, respectively.

- **Southern New Jersey (AECO).** The southern New Jersey (SNJ) subarea of the AECO Control Zone experienced 919 hours of congestion, with two constraints, the Laurel-Woodstown 69 kV line and the Shieldalloy–Vineland 69 kV line, accounting for 92 percent of all congestion in the area. The Shieldalloy-Vineland line was constrained for 444 hours, with 75 percent of all these hours occurring during on-peak periods. The Laurel-Woodstown line was constrained for 401 hours, with 67 percent of all these hours occurring during on-peak periods. Seven other constraints, each occurring for less than 100 hours, contributed to the remainder of congestion in the area. During constrained hours, the Shieldalloy-Vineland and the Laurel-Woodstown constraints affected 945 MW and 520 MW of load, respectively. The Shieldalloy-Vineland constraint contributed $20 to a total LMP of $81, or a 25 percent increase for the affected load. The Laurel-Woodstown constraint contributed $27 to a total LMP of $96, or a 28 percent increase for the affected load. Both the Shieldalloy-Vineland and the Laurel-Woodstown constraints caused high market concentration ratios with average HHIs of 8400 and 8700, respectively. Minimum and Maximum HHIs were 7600 and 9400, respectively.

- **Cedar Subarea (AECO).** In 2004, the Cedar subarea in the AECO Control Zone continued to be frequently constrained. Two constraints accounted for most of the congestion in the area. The 742 constrained hours experienced during 2004 represented an increase from the 638 hours that had been experienced in 2003. Seventy-four percent of all congestion occurred during on-peak periods. In 2004, the Cedar interface was the primary cause of the congestion, with 605 hours or 82 percent of the total congestion, compared to 60 percent in 2003. By contrast, the Cedar-Motts 69 kV line saw a decline, from 245 hours in 2003, to 128 hours in 2004. On average, the Cedar-Motts line and the Cedar interface isolated approximately 120 MW of load. During the hours in which the Cedar interface was constrained, LMP in this area rose by 68 percent to an average LMP of $197, $133 of which can be attributed to the interface constraint. Additionally, the Cedar-Motts line created a 54 percent increase in the LMP in the area, to an average LMP of $160. The constrained line alone was responsible for $86 of this average LMP. The average HHI for these constraints was 6500. The minimum and maximum HHIs were 3000 and 10000.

- **Met-Ed West.** In 2004, the Met-Ed west subarea was constrained for 262 hours, a slight increase from 253 hours in 2003. Ninety-five percent of all congestion in the area occurred during on-peak periods. The Jackson 230/115 kV transformer was constrained for 231 hours in 2004, up from 45 hours in 2003. Five other constraints, each occurring for less than 100 hours, accounted for the remaining congestion in this area. During constrained hours, the Jackson 230/115 kV transformer affected, on average, 1,025 MW of load and contributed to a 48 percent increase in LMP for this affected load. The average LMP for this area was $115, with $56 attributable to the Jackson transformer. This constraint caused high market concentration, with an average HHI of 5063. Minimum and maximum HHIs were 2170 and 7955, respectively.

- **PENELEC Northcentral.** In 2004, the northcentral subarea of the PENELEC Control Zone was constrained for 244 hours, a 122 percent increase from 110 hours in 2003. Forty-six percent of all congestion in the area occurred during on-peak periods. The Tyrone – Westfall 115 kV line contributed to 41 percent of the congestion in the area, with 100 hours. Six additional constraints during the year, each occurring for less than 100 hours, accounted for the remainder of congestion hours. The Tyrone – Westfall 115 kV line affected, on average, 225 MW of load and had an increase of 38 percent on the average LMP. The LMP for the affected load was $48, of which $18 was from congestion on this line. This constraint caused high market concentration with an average HHI of 7400. Minimum and maximum HHIs were 5900 and 8900, respectively.

- **Bedington - Black Oak (AP).** In 2004, the Bedington – Black Oak 500 kV line was constrained for 1,131 hours, with 54 percent of congestion occurring during on-peak periods. Congestion was up slightly from 2003 when it had been constrained for 815 hours. The location and size of this line contributed to its substantial impact on the entire PJM system, with an average affected load of 39,170 MW. On average, this constraint caused a 20 percent increase in LMP during constrained hours. The affected load had an average LMP of $60, with $12 attributable to congestion from the Bedington – Black Oak line. The Bedington – Black Oak 500 kV line caused moderate concentration in the affected area overall with an average HHI of 970. Minimum and maximum HHIs were 850 and 1090, respectively.

- **Wylie Ridge (AP).** During 2004, congestion on the Wylie Ridge 345/500 kV transformers increased to 642 hours, compared to 537 hours in 2003. Nineteen percent of all congestion occurred during on-peak periods. The Wylie Ridge transformer affected approximately 33,500 MW and created a 13 percent increase in LMP during constrained hours. On average, the affected load experienced an LMP of $47, with the Wylie Ridge transformer contributing $6 to that amount. The area affected by this constraint was unconcentrated, with an average HHI of 818. Minimum and maximum HHIs were 745 and 890, respectively.

Pivotal Suppliers

In addition to the aggregate PJM, ComEd 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.[16] 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 price. As with concentration ratios, the RSI is not a bright line test. While an RSI less than 1.0 clearly indicates market power, an RSI greater than 1.0 does not guarantee that there is no market power. As an example, suppliers can be jointly pivotal.

RSI was calculated hourly for every generation owner. During Phase 2, the ComEd and PJM Control Areas were analyzed separately. The overall PJM and ComEd Energy Market RSI is the minimum RSI for each hour, equal to the RSI for the largest generation owner in each hour. (See Table 2-12 and Table 2-14.) The RSI was also calculated for the largest two generation owners together in order to determine the extent to which two suppliers were jointly pivotal. These results are reported in Table 2-13 and Table 2-15.

PJM RSI Results

The RSI results reported in Table 2-12 are consistent with the conclusion that PJM Energy Market results were competitive in both 2003 and 2004, with an average hourly RSI of 1.66 and 1.64, respectively.[17] In 2004, a generation owner in the PJM Energy Market was pivotal for only eight hours, less than 0.1 percent of all hours during the year. This represents a minimal increase in pivotal hours from 2003, when a generation owner was pivotal in the Energy Market for six hours, or slightly less than 1 percent of all hours. All hours when a single generation owner was pivotal in the Energy Market occurred in June 2004, when demand approached 60,000 MW. This indicates that, as the PJM Energy Market reaches peak demand periods, one or more large market suppliers are likely to be pivotal and to have the ability to influence prices. After the Phase 3 integrations, there were no hours when a generation owner was pivotal. The additional supply, coupled with

16 Total supply in the Energy Market is the sum of all offers to provide energy. In the event the net imports are negative (exports), they are treated as additional demand.
17 While there is no defined RSI threshold, the California Independent System Operator (CAISO) has used an energy market RSI value exceeding 1.20 to 1.50 as an indicator of a reasonably competitive market.

moderate demand averaging approximately 65,000 MW during Phase 3, was a contributing factor to zero pivotal hours. The RSI calculations for the top two suppliers together indicate the minimum RSI during Phases 1 and 2 would be 0.81, rising to 0.91 during Phase 3 while the average RSI calculated for two suppliers together was 1.36.

Table 2-12 - PJM RSI statistics: Calendar years 2003 to 2004

	Number of Hours RSI < 1.10	Number of Hours RSI < 1.00	Percent of Hours RSI < 1.00	Average RSI	Minimum RSI
Calendar Year 2003	91	6	0.07%	1.66	0.99
Phases 1 & 2 , 2004	45	8	0.12%	1.62	0.96
Phase 3, 2004	0	0	0.00%	1.68	1.15
Calendar Year 2004	45	8	0.09%	1.64	0.96

Table 2-13 shows RSI results for the top two generation owners together.

Table 2-13 - PJM top two supplier RSI statistics: Calendar years 2003 to 2004

	Number of Hours RSI < 1.10	Number of Hours RSI < 1.00	Percent of Hours RSI < 1.00	Average RSI	Minimum RSI
Calendar Year 2003	822	299	3.41%	1.40	0.83
Phases 1 & 2, 2004	791	165	2.51%	1.36	0.81
Phase 3, 2004	113	17	0.77%	1.36	0.91
Calendar Year 2004	904	182	2.07%	1.36	0.81

Phase 2 ComEd Control Area RSI Results

In the ComEd Control Area there were 2,287 hours, or 62 percent of the hours during Phase 2, when a generation owner was pivotal. These RSI results are reported in Table 2-14. The average RSI was 0.97 and the minimum was 0.64. The ComEd Control Area HHI market concentration results indicate that the market is highly concentrated, thus resulting in periods when one or more generation owners had the potential ability to influence the market price. The RSI was also calculated for the top two suppliers in the ComEd Control Area, again indicating the existence of pivotal suppliers. For the top two supplier analysis, all hours of Phase 2 had an RSI of less than 1.0. The existence of the Pathway and the joint dispatch with PJM significantly mitigated the ability of participants to exercise market power in the ComEd Control Area during Phase 2. The results of the Energy Market overall, including ComEd, were competitive for 2004.

Table 2-14 - ComEd RSI statistics: Phase 2, 2004

	Number of Hours RSI < 1.10	Number of Hours RSI < 1.00	Percent of Hours RSI < 1.00	Average RSI	Minimum RSI
Phase 2	3,132	2,287	62%	0.97	0.64

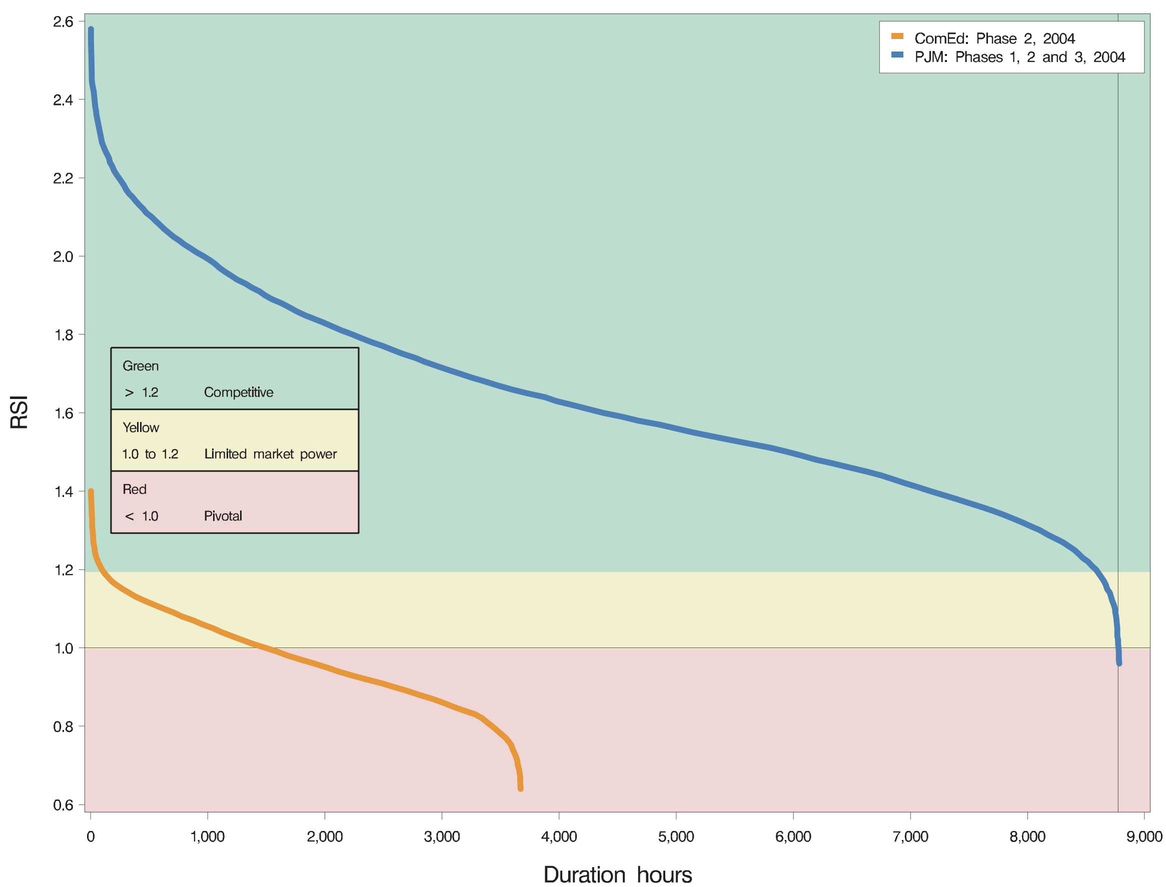
Table 2-15 shows RSI results for the top two generation owners together in ComEd.

Table 2-15 - ComEd top two supplier RSI statistics: Phase 2, 2004

	Number of Hours RSI < 1.10	Number of Hours RSI < 1.00	Percent of Hours RSI < 1.00	Average RSI	Minimum RSI
Phase 2	3,672	3,672	100%	0.33	0.20

Figure 2-5 shows the RSI duration curves for PJM and ComEd during 2004. The curve shows the significant number of hours below 1.0 for ComEd and the limited number of hours below 1.0 for PJM.

Figure 2-5 - PJM and ComEd RSI duration curve: Calendar year 2004



Ownership of Marginal Units

Table 2-16 presents the ownership distribution of marginal units. The table shows the percent of the five-minute intervals for which one or more companies owned the marginal unit, based on data for all units that were on the margin for one or more five-minute intervals during the specified year. For example, in 2000, three different companies each owned the marginal unit from 15 percent to 20 percent of the time. In 2004, only one company owned the marginal unit from 15 to 20 percent of the intervals while, for the first time, one company owned the marginal unit from 20 to 30 percent of the time. The higher proportion of the time that a small number of companies own the marginal unit, the greater the potential market power concern.

Table 2-16 - Ownership of marginal units (By number of companies in frequency category): Calendar years 2000 to 2004

	Number of Companies that Owned the Marginal Unit in Frequency Category:				
	5% or less	5% to 10%	10% to 20%	15% to 20%	20% to 30%
2000	9	2	2	3	0
2001	14	4	2	2	0
2002	19	4	2	2	0
2003	20	4	1	2	0
2004	27	6	0	1	1

Offer Capping

PJM has clear rules limiting the exercise of local market power.[18] The rules provide for offer capping when conditions on the transmission system create a structurally noncompetitive local market, when units in that local market have made noncompetitive offers and when such offers would set the price above the competitive level in the absence of mitigation. Offer-capped units receive the higher of the market price or their offer cap. Thus, if overall market conditions lead to a price greater than the offer cap, the unit receives the overall market price. 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.

Table 2-17 through Table 2-20 present data on the frequency of offer capping, by month, for the past four years.

Offer capping has generally declined since 2001, but did increase slightly in 2004. Conditions in specific subareas of PJM have affected the overall frequency of cost 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, the need to run local units out of merit order decreased significantly because of both the transmission improvements and the completion of maintenance outages. These factors had the combined effect of decreasing offer-capped hours per MW in 2002 and subsequent years. In 2001, 2.8 percent of total run hours were offer-capped. This number dropped to 1.6 percent in 2002 and

18 See "PJM Operating Agreement, Schedule 1," Section 6.4.2.

1.1 percent in 2003. In 2004, it rose slightly to 1.3 percent. This increase can be attributed to congestion activity in the AECO zone and the congestion related to the Branchburg transformer as well as other congestion in 2004.[19]

Table 2-17 - Average day-ahead, offer-capped units: Calendar years 2001 to 2004

	2001		2002		2003		2004	
	Average Units Capped	Percent	Average Units Capped	Percent	Average Units Capped	Percent	Average Units Capped	Percent
Jan	0.5	0.1%	0.6	0.1%	0.5	0.1%	0.4	0.1%
Feb	3.2	0.7%	0.4	0.1%	0.7	0.1%	0.2	0.0%
Mar	6.8	1.5%	0.1	0.0%	0.1	0.0%	0.2	0.0%
Apr	3.4	0.8%	0.7	0.1%	0.6	0.1%	0.3	0.1%
May	2.8	0.6%	0.2	0.0%	0.3	0.0%	0.6	0.1%
Jun	4.7	1.0%	1.4	0.3%	0.7	0.1%	1.1	0.2%
Jul	3.8	0.8%	1.9	0.4%	1.4	0.3%	2.6	0.4%
Aug	1.9	0.4%	4.5	0.8%	2.1	0.4%	3.0	0.4%
Sep	5.0	1.1%	1.9	0.4%	1.1	0.2%	3.1	0.4%
Oct	4.2	0.9%	0.4	0.1%	0.9	0.2%	0.6	0.1%
Nov	2.1	0.5%	0.6	0.1%	0.2	0.0%	0.5	0.1%
Dec	0.4	0.1%	0.8	0.1%	0.1	0.0%	0.5	0.1%

Table 2-18 - Average day-ahead, offer-capped MW: Calendar years 2001 to 2004

	2001		2002		2003		2004	
	Average MW Capped	Percent	Average MW Capped	Percent	Average MW Capped	Percent	Average MW Capped	Percent
Jan	32	0.1%	40	0.1%	37	0.1%	51	0.1%
Feb	16	0.0%	30	0.1%	27	0.1%	68	0.1%
Mar	101	0.3%	6	0.0%	4	0.0%	48	0.1%
Apr	286	1.0%	48	0.1%	38	0.1%	41	0.1%
May	286	1.0%	14	0.0%	52	0.1%	52	0.1%
Jun	591	1.7%	48	0.1%	69	0.2%	49	0.1%
Jul	203	0.6%	77	0.1%	132	0.3%	243	0.4%
Aug	91	0.2%	106	0.2%	148	0.3%	348	0.5%
Sep	332	1.0%	78	0.2%	139	0.3%	221	0.4%
Oct	193	0.6%	57	0.1%	100	0.2%	34	0.0%
Nov	192	0.6%	30	0.1%	21	0.1%	28	0.0%
Dec	18	0.1%	25	0.1%	25	0.1%	35	0.0%

19 See Section 6, "Congestion," for more detailed analysis of constrained facilities.

Table 2-19 - Average real-time, offer-capped units: Calendar years 2001 to 2004

	2001		2002		2003		2004	
	Average Units Capped	Percent	Average Units Capped	Percent	Average Units Capped	Percent	Average Units Capped	Percent
Jan	0.7	0.2%	1.6	0.3%	1.5	0.3%	2.7	0.4%
Feb	0.5	0.1%	0.8	0.2%	1.5	0.3%	0.7	0.1%
Mar	3.4	0.8%	0.4	0.1%	0.5	0.1%	0.8	0.1%
Apr	3.3	0.8%	1.0	0.2%	0.8	0.1%	1.9	0.3%
May	3.5	0.8%	1.2	0.2%	1.6	0.3%	5.9	0.8%
Jun	6.5	1.5%	3.1	0.6%	2.9	0.5%	3.9	0.5%
Jul	4.8	1.1%	8.6	1.6%	3.3	0.6%	4.7	0.7%
Aug	8.1	1.8%	9.7	1.8%	6.3	1.1%	6.3	0.9%
Sep	7.3	1.6%	4.1	0.8%	3.7	0.7%	4.2	0.6%
Oct	6.9	1.5%	1.4	0.3%	1.8	0.3%	1.1	0.1%
Nov	4.5	1.0%	1.2	0.2%	1.0	0.2%	1.1	0.1%
Dec	1.3	0.3%	1.5	0.3%	0.8	0.1%	3.3	0.4%

Table 2-20 - Average real-time, offer-capped MW: Calendar years 2001 to 2004

	2001		2002		2003		2004	
	Average MW Capped	Percent	Average MW Capped	Percent	Average MW Capped	Percent	Average MW Capped	Percent
Jan	46	0.1%	90	0.3%	87	0.2%	175	0.4%
Feb	7	0.0%	46	0.2%	74	0.2%	87	0.2%
Mar	84	0.3%	24	0.1%	44	0.1%	76	0.2%
Apr	248	0.9%	62	0.2%	29	0.1%	115	0.3%
May	291	1.1%	63	0.2%	101	0.3%	257	0.5%
Jun	455	1.4%	105	0.3%	110	0.3%	167	0.3%
Jul	247	0.8%	218	0.6%	252	0.6%	332	0.6%
Aug	372	1.0%	311	0.7%	294	0.7%	450	0.8%
Sep	553	1.9%	177	0.5%	241	0.7%	268	0.5%
Oct	571	2.1%	92	0.3%	96	0.3%	77	0.1%
Nov	410	1.5%	55	0.2%	53	0.2%	110	0.2%
Dec	90	0.3%	52	0.1%	44	0.1%	202	0.3%

The following tables show the number of generation units that met the specified criteria for total offer-capped run hours and percentage of offer-capped run hours 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 2-21 - Offer-capped unit statistics: Calendar year 2001

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 2-22 - Offer-capped unit statistics: Calendar year 2002

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 2-23 - Offer-capped unit statistics: Calendar year 2003

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

Table 2-24 - Offer-capped unit statistics: Calendar year 2004

Percentage of Offer-Capped Run Hours	2004 Minimum Offer-Capped Hours					
	500	400	300	200	100	1
90%	0	1	2	7	10	15
80%	3	4	5	15	24	38
75%	4	5	10	20	30	49
50%	5	8	13	24	36	80
25%	6	10	16	30	48	128
10%	8	12	20	37	71	189

As a general matter, offer capping does not result in financial harm to the affected units. Detailed analysis of actual net revenues for 2003 showed that 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. In fact, offer capping can, at times, result in higher revenues for offer-capped units than for 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 = $(P – MC)/P$]. The marginal unit is the unit that sets LMP in the five-minute interval. During congested intervals, identification of the highest relevant marginal cost unit is not feasible. Marginal cost is from the marginal unit during congested periods, and the markup of each marginal unit is load-weighted.[20] The markup index is normalized and can vary from -1.00, when the offer price is less than marginal cost, to 1.00, when the offer price is higher than marginal cost.[21] (See Figure 2-6.)

PJM receives daily price and cost offers for every unit in PJM for which construction began before July 9, 1996. For units constructed after that date, cost offers are estimated. The markup index is calculated for the marginal unit or units in every five-minute interval.

Measurements of markup have been refined and the analysis expanded for 2004. The markup measure makes better use of estimated cost data if unit cost data have not been submitted and reflects improvements in load weighting and refinements in identifying the highest marginal cost unit on the system. The reported markup index is the result of this detailed analysis. As the markup index for 2004 reflects the improved calculation method, the 2004 results must be cautiously compared with prior year results.

20 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.
21 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.

Figure 2-6 - Average monthly load-weighted markup indices: Calendar year 2004

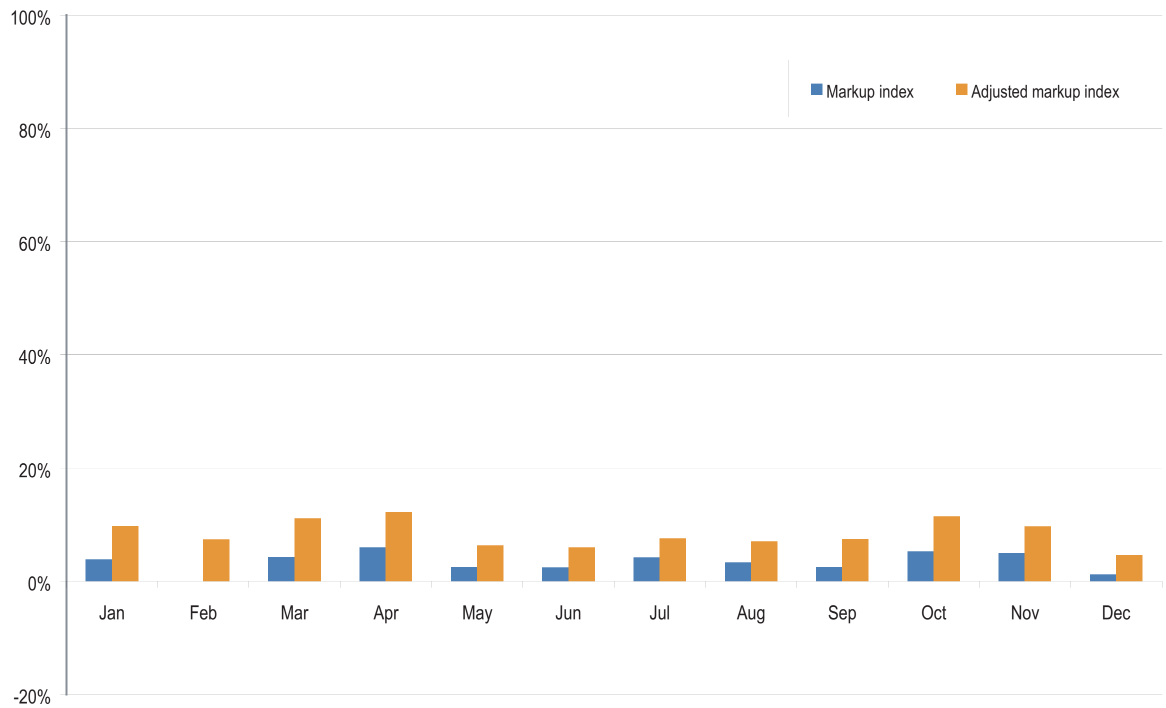


Figure 2-6 shows the average monthly markup index. The average markup index was 3.4 percent in 2004, with a maximum of 6.0 percent in April and a minimum markup index of 0.0 percent in February. Generators in PJM submit cost-based offers up to defined marginal cost plus 10 percent.[22] Since a significant number of generators have increased their cost-based offers by this 10 percent, the calculated markup index is low to the extent that the submitted offers are greater than actual marginal cost. The adjusted markup index in Figure 2-6 assumes that all unit owners have included a 10 percent markup over actual marginal cost. This is an extreme assumption, but provides an upper bound to the actual markup index. Given this assumption, the average 2004 adjusted index was 8.4 percent, with a maximum index of 12.3 percent in April and a minimum index of 4.7 percent in December. The correct markup index lies between the adjusted and unadjusted index values.

Actual markups for units exceed these average values at times and units with such markups set the market price during some intervals. Similarly, actual markups for units are less than the average values at times and units with negative markups also set the price during some intervals. The average markup is a reasonable measure of the extent to which energy offers at levels in excess of marginal cost set the price in PJM.

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

22 Manual M-14 provides the detailed definition of marginal cost that generation owners must follow when submitting cost-based offers. The 10 percent increment was designed to reflect the uncertainty associated with the calculation of marginal costs for the actual range of units in PJM.

any. Thus, if the marginal unit is a 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 and plant type. Figure 2-7 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 2004, units using petroleum and natural gas showed the highest unit markup indices, averaging 12.5 percent and 8.7 percent, respectively.

Figure 2-7 - Average markup index by type of fuel: Calendar years 2000 to 2004

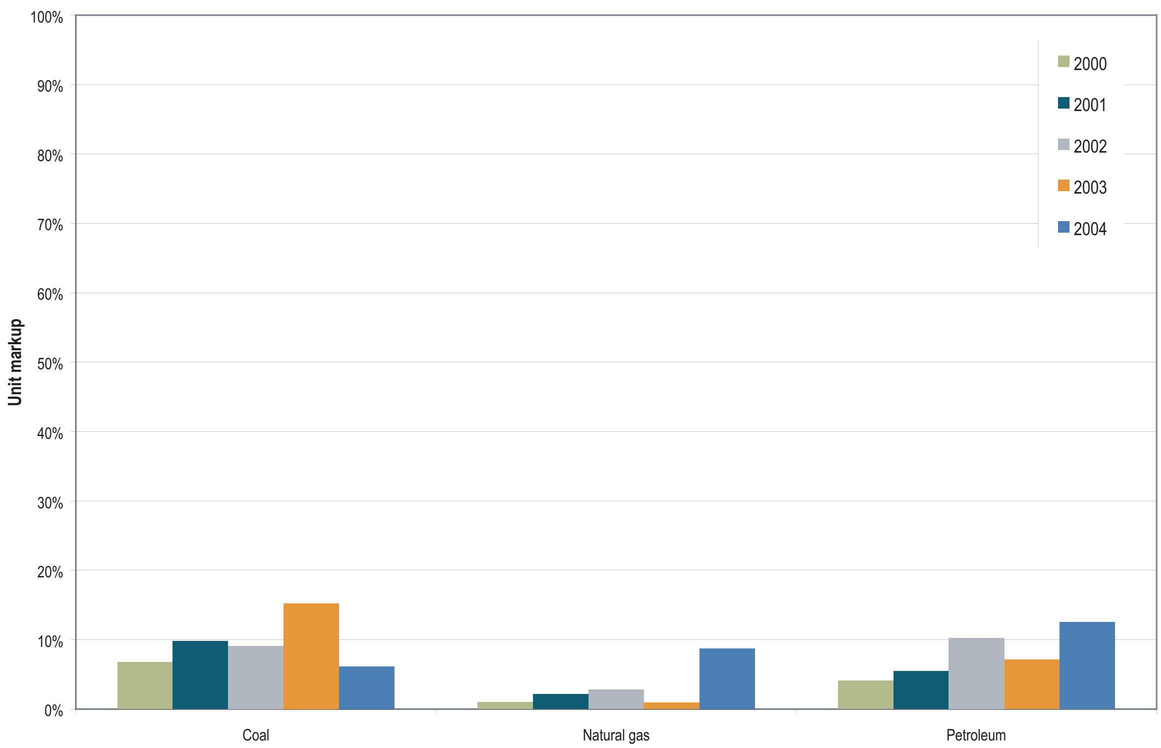


Table 2-25 shows the fuel type of marginal units. Between 2003 and 2004, the share of coal rose from 52 to 56 percent; the share of natural gas increased from 29 to 31 percent; the share of nuclear units held steady and the share of petroleum decreased from 18 to 12 percent.

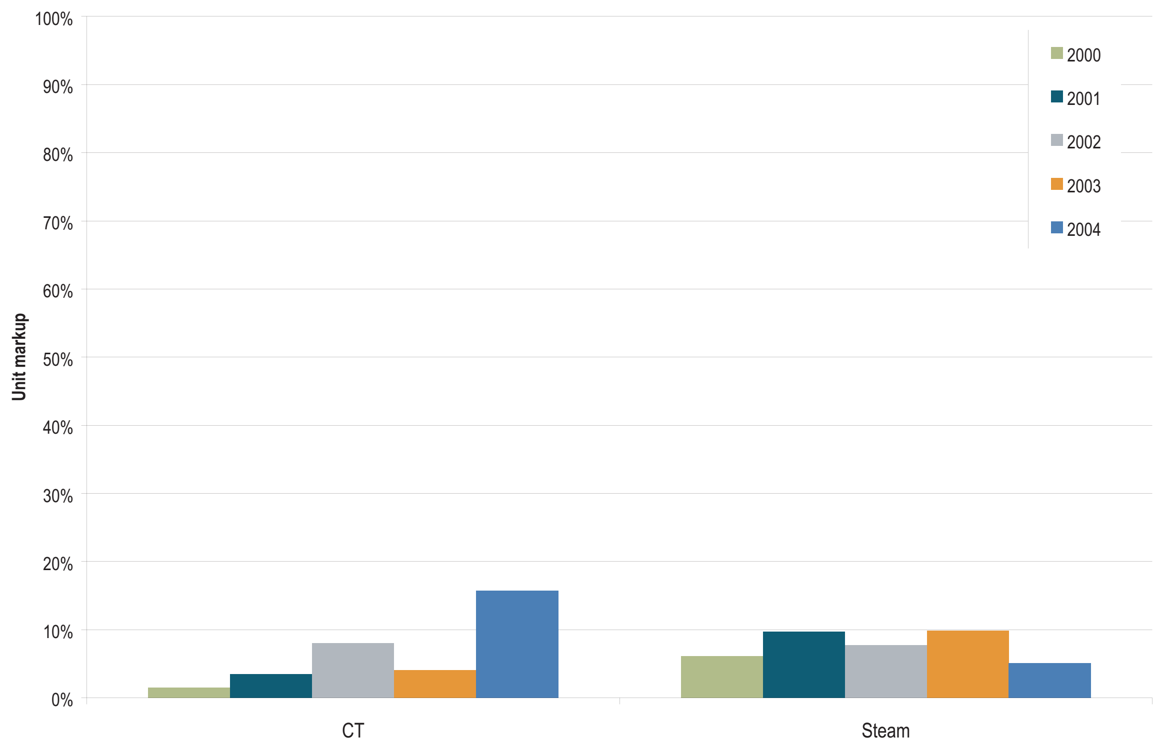
Table 2-25 - Type of fuel used by marginal units: Calendar years 2000 to 2004[23]

						Phase 2	
Fuel Type	**2000**	**2001**	**2002**	**2003**	**2004**	**ComEd**	**PJM**
Coal	48%	49%	55%	52%	56%	86%	41%
Misc	0%	0%	0%	0%	0%	0%	1%
Natural gas	18%	18%	23%	29%	31%	13%	36%
Nuclear	2%	1%	0%	1%	0%	0%	0%
Petroleum	31%	32%	21%	18%	12%	0%	22%

Table 2-25 presents results for the entire year. The two right-hand columns provide a breakdown of fuel type for marginal units during Phase 2, when the Pathway was present after the integration of the ComEd Control Area. Percentages shown reflect the types of units physically in the ComEd Control Area or the PJM Control Area, not the breakdown of units that were controlling price in those areas.

Figure 2-8 shows average markup index by unit type. The average annual markup index diverged somewhat for steam units and CTs. The average annual index increased for CTs to 16 percent in 2004 from 4 percent in 2003 and decreased for steam units to 5 percent from 10 percent in 2003.

Figure 2-8 - Average markup index by type of unit: Calendar years 2000 to 2004



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

Table 2-26 shows the type of units on the margin from 2000 to 2004. During 2004, the marginal unit was a CT 22 percent of the time and a steam unit 77 percent of the time.

Table 2-26 - Type of marginal unit: Calendar years 2000 to 2004

						Phase 2	
Unit Type	**2000**	**2001**	**2002**	**2003**	**2004**	**ComEd**	**PJM**
CT	37%	33%	26%	22%	22%	8%	92%
Steam	63%	67%	74%	77%	77%	38%	62%

Overall, the index results presented here are consistent with the conclusion that the Energy Market results were competitive in 2004.

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 the incentive to invest in new 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 economic dispatch in the PJM model.[24] Gross energy market revenue is the product of the energy market price and generation output. Gross revenues are also received from the Capacity Markets and the Ancillary Service Markets. Total gross revenue less variable cost equals net revenue. In other words, net revenue is the amount that remains, after variable costs have been subtracted from gross revenue, to cover fixed costs including a return on investment, depreciation, taxes and fixed operations and maintenance expenses.

The net revenues presented in this section are theoretical as they are based on explicitly stated assumptions about how a unit would operate, rather than based on the analysis of actual net revenues for actual units operating in PJM.

Table 2-27 illustrates the relationship between generator variable cost and net revenue from the PJM Energy Market alone for the years 1999 through 2004.[25]

24 Under the PJM model, operating reserve payments compensate generation owners when units operate at PJM's request when LMP is less than marginal cost over the day of operation. The PJM model also ensures that generators are compensated for startup and no-load costs when they are dispatched based on marginal costs or on their offer price.

25 Table 2-1 reflects final eGADS outage data for 2003 that were not available at the time of publication of the 2003 State of the Market Report (SOM). The final equivalent demand forced outage rate (EFORd) figure for 2003 was 7.0 percent, or 0.2 percent lower than the 7.2 percent EFORd available for and reported by the 2003 SOM. The 2004 value will be similarly adjusted in the 2005 SOM to reflect final eGADS outage data.

Table 2-27 - PJM energy market net revenue by unit marginal cost: Calendar years 1999 to 2004

Marginal Cost	1999	2000	2001	2002	2003	2004
$10	$152,087	$150,774	$186,887	$153,620	$231,927	$263,115
$20	$94,690	$89,418	$116,116	$85,661	$159,751	$185,956
$30	$72,489	$59,776	$78,368	$51,898	$110,126	$121,218
$40	$62,367	$39,519	$56,055	$31,650	$73,828	$74,920
$50	$57,080	$25,752	$42,006	$19,776	$47,277	$44,577
$60	$54,132	$16,888	$33,340	$13,101	$29,566	$25,328
$70	$52,259	$11,750	$27,926	$9,080	$18,001	$13,624
$80	$50,959	$8,586	$24,389	$6,623	$10,650	$6,929
$90	$49,840	$6,700	$22,080	$5,079	$6,273	$3,494
$100	$48,818	$5,640	$20,521	$4,109	$3,770	$1,784
$110	$47,863	$4,930	$19,375	$3,507	$2,250	$951
$120	$46,926	$4,385	$18,480	$3,063	$1,315	$518
$130	$46,007	$3,958	$17,716	$2,758	$723	$260
$140	$45,114	$3,609	$17,030	$2,501	$387	$124
$150	$44,228	$3,317	$16,421	$2,287	$218	$51
$160	$43,374	$3,102	$15,884	$2,115	$142	$24
$170	$42,523	$2,923	$15,395	$1,970	$94	$9
$180	$41,685	$2,768	$14,944	$1,828	$51	$0
$190	$40,856	$2,623	$14,542	$1,700	$23	$0
$200	$40,036	$2,488	$14,162	$1,607	$10	$0

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. In PJM, the market design includes other markets intended to contribute to the payment of fixed costs. In PJM, the Capacity, Energy and Ancillary Service Markets are all significant 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. In real markets, net revenue fluctuates annually based on actual conditions in all relevant markets.

The approach to the net revenue calculation has been refined in several ways in this report from the calculation presented in the *2003 State of the Market Report*.[26] This modified approach has been applied to each year from 1999 through 2004 so that the results are comparable. The modifications to the net revenue analysis include the addition of nitrogen oxide (NO_x) and sulfur dioxide (SO_2) emission market credit costs to the dispatch rate, adjustments to plant capacity and energy production based on hourly ambient air and river water temperatures, use of unit class-specific forced outage rates and calculation of ancillary service revenues based on actual PJM

26 See Section 2, "Energy Market, Net Revenue" 2003 State of the Market Report (March 10, 2004), pp. 57-69.

unit-class experience. In addition to a natural gas-fired combustion turbine (CT) and a two-on-one natural gas-fired combined-cycle plant (CC), a pulverized coal steam plant (CP) is included for the first time as a new entry technology in order to provide a more complete representation of entry conditions. In addition, two dispatch scenarios are analyzed for each new entry technology.

The net revenue calculations under perfect dispatch are an approximate measure, generally representing an upper bound of the markets' direct contribution to generator fixed costs. The energy market net revenue curve does not consider operating constraints that may affect actual net revenue of an individual plant. Such operating constraints are less likely to affect the net revenue calculations for combustion turbines, given their operational flexibility and the operating reserve revenue guarantee. For a combined-cycle steam plant, a two-hour hot status notification plus startup time, for a summer weekday, either 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 two unprofitable hours, or would result in reduced net revenues from the unprofitable hours.[27] The actual impact depends on the relationship between LMP and the operating costs of the unit. Likewise, a pulverized coal steam plant with an eight-hour cold status notification plus startup time could run overnight during hours of zero or negative profitability although the lower relative operating costs of a steam unit would generally reduce the significance of the issue.[28] Ramp limitations might prevent a combined-cycle or steam unit from starting and ramping up to full output in time to operate for all profitable hours.

Conversely, the net revenue measure does not include the potentially significant contribution to fixed cost from the explicit or implicit sale of the option value of physical units or from bilateral agreements to sell output at a price other than the real-time price, e.g. a forward price.

In order to provide an approximate lower bound to the perfect economic dispatch net revenues, additional dispatch scenarios were analyzed for each plant type.

Energy Market Net Revenue

The energy market revenues in Table 2-27 reflect net energy market revenues from all hours during 1999 to 2004 when the average PJM hourly locational market price exceeded the identified marginal cost of generation. The table includes 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 in dollars per MWh, adjusted for unit forced outages.[29] For example, during 2004, 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 2004, adjusted for forced outages, it would have received $121,218 per MW in net revenue from the Energy Market alone.

Figure 2-9 displays the information from Table 2-27. As Figure 2-9 illustrates, the energy market net revenue curve was higher in 2004 for units with marginal costs equal to or less than $40 and lower for those with marginal costs above $90 than for any year from 1999 through 2003. Thus, units

27 A two-hour hot start, including a notification period, is consistent with the CC technology.
28 An eight-hour cold status notification plus startup is consistent with the CP technology.
29 Energy market net revenue calculations reflect a forced outage rate equal to the actual PJM system forced outage rate for each year. Since this table includes a range of marginal costs from $10 to $200, an outage rate by class can not be utilized since there is no simple mapping of marginal cost to class of generation, e.g. the $60 range could include steam-oil, gas-CC and efficient gas-CTs. Class-specific forced outage rates are used for the class-specific net revenue calculations.

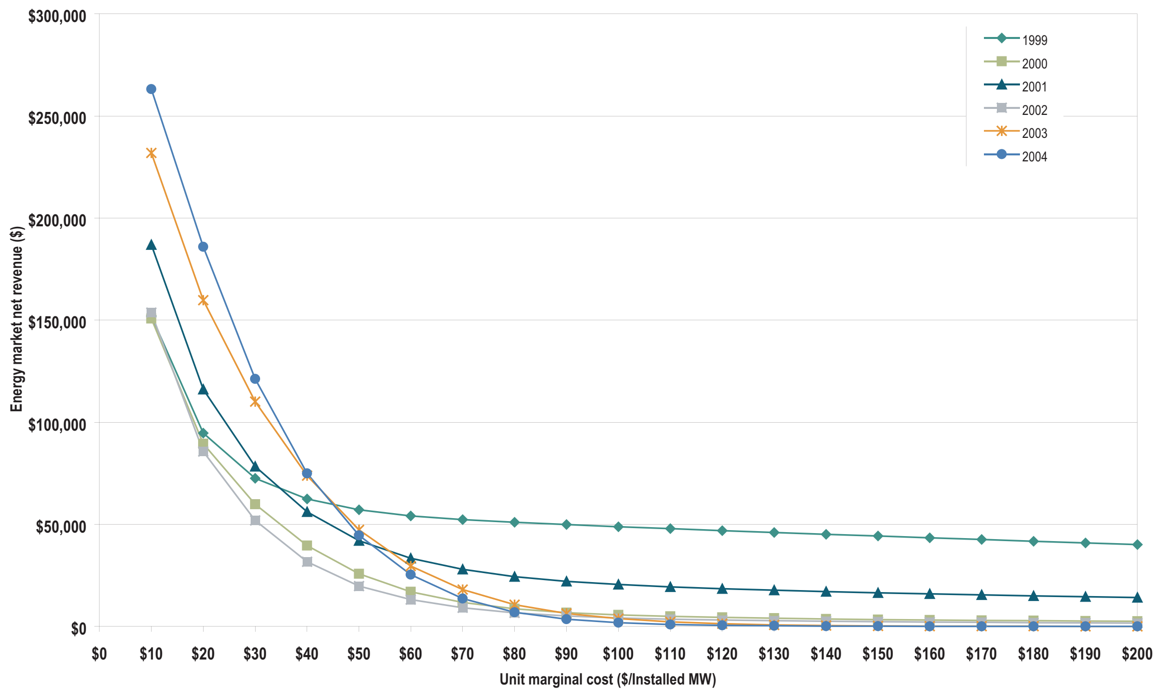
with relatively low marginal costs were more profitable in 2004 than in prior years and units with relatively high marginal costs were less profitable in 2004 than in prior years. If a unit with marginal costs of $30 per MWh had operated during all hours when the LMP exceeded $30 per MWh, it would have 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, about $110,000 in 2003 and about $121,000 in 2004.

The increase in 2004 net energy revenue for units with marginal costs less than or equal to $40 per MWh compared to earlier years is the result of changes in the frequency distribution of energy prices. Nominal prices have increased. In 2004, prices were less than or equal to $40 less frequently and thus were greater than $40 more frequently than in prior years. In 1999, LMP was less than or equal to $40 per MWh 91 percent of all hours. In 2000, this was 80 percent; in 2001, 79 percent; in 2002, 81 percent; in 2003, 61 percent, and in 2004, 54 percent.

The distribution of prices reflects a number of factors including load levels and fuel costs. An efficient CT could have produced energy at an average cost of $30 in 1999, but $75 in 2004. An efficient CC could have produced energy at an average cost of $20 in 1999, but $50 in 2004. An efficient CP could have produced energy at an average cost of $20 in 1999, but $30 in 2004.

The 2004 load-weighted LMP averaged $44.34 per MWh compared to $41.23 in 2003, $31.58 in 2002, $36.65 in 2001, $30.72 in 2000 and $34.07 in 1999. There were no price spikes in 2004. LMP did not exceed $200 in any hour in 2004, compared to one hour in 2003, nine hours in 2002, 40 hours in 2001, 13 hours in 2000 and 86 hours in 1999. As a result, units with high marginal costs were not as profitable in 2003 and 2004 as they had been 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, adjusted for forced outages, 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 2003 and about $2,000 in 2004.

Figure 2-9 - PJM energy market net revenue by unit marginal cost: Calendar years 1999 to 2004



Differences in the shape and position of net revenue curves for the six years result from different distributions of energy market prices. These differences illustrate, among other things, the significance of a relatively small number of high-priced hours to the profitability of high marginal cost units. Although average prices in 1999 were approximately equal to average prices in 2000, hourly average prices in 1999 were actually lower than hourly average prices in 2000 for all intervals except hours 1200 through 1800 EPT, when 1999 prices significantly exceeded those in 2000. These periods of high prices were responsible for the shape of the 1999 net revenue curve. The limited number of high-priced hours in 2000, 2002 and subsequent years resulted in lower net revenue for units operating at higher marginal costs.[30]

Capacity Market Net Revenue

Generators receive revenues from the sale of capacity in addition to revenue from the Energy and Ancillary Service Markets. In the PJM market design, the sale of capacity provides another important source of revenues to cover generator fixed costs. In 2004, PJM capacity resources received a weighted-average payment from the PJM Capacity Credit Markets of $17.74 per unforced MW-day, or $6,493 per MW-year of installed capacity. The 2003 Capacity Markets averaged $17.51 per unforced MW-day, or $5,945[31] per MW-year of installed capacity.

After its April 1, 2002, integration into PJM, the AP Control Zone and the PJM Mid-Atlantic Region had different Capacity Market designs. The AP Control Zone and the Mid-Atlantic Region were integrated into a single PJM Capacity Market on June 1, 2003. After the Phase 2 integration of the

30 See Section 2, Energy Market," at "Load and LMP," for detailed data on the annual distribution of prices.
31 The 2003 capacity value in dollars per installed MW-day has been increased $9 per installed MW-day from the 2003 State of the Market Report. This increase reflects the incorporation of final outage data for 2003 that were not available at the time of publication. The 2004 value will be similarly adjusted in the 2005 State of the Market Report to reflect final outage data.

ComEd Control Area in 2004, the PJM Capacity Market remained a discrete market, with market-clearing transactions based on unforced capacity while a separate capacity market was established for ComEd. During Phase 3 of 2004, the newly integrated AEP and DAY Control Zones were added to the PJM Capacity Market. When the PJM Capacity Market or the PJM Capacity Credit Market is referred to here, it is the single market reflecting the integrations as they occurred during the three phases of calendar year 2004, but excluding the ComEd Capacity Market. The ComEd Capacity Market will remain as a separate market until June 1, 2005, when all PJM control zones will be incorporated in a single, RTO-wide Capacity Market. The ComEd Capacity Market averaged $27.98 per installed MW.[32]

The PJM capacity market price used for net revenue calculations is the Mid-Atlantic Region market price through May 31, 2003, and the integrated Mid-Atlantic Region and AP Control Zone market price through September 30, 2004. Thereafter, the Phase 3 PJM capacity market price is used for the net revenue analysis.[33] The corresponding annual capacity market prices are presented in Table 2-28.

Table 2-28 - PJM's average annual capacity market price: Calendar years 1999 to 2004

	($ per Installed MW-Year)
1999	$18,124
2000	$20,804
2001	$32,983
2002	$11,601
2003	$5,945
2004	$6,493

Ancillary Service and Operating Reserve Net Revenue

Generators also receive revenue from the sale of ancillary services, including those from the Spinning Reserve and Regulation Markets as well as black start and reactive services. Aggregate ancillary service revenues were $3,667 per installed MW-year in 2004 versus $3,986 per installed MW-year in 2003. While actual, generator-specific ancillary service revenues vary with generator technology, ancillary service revenues are expressed here in terms of a system average per installed MW.

Table 2-29 - System average ancillary service revenues: Calendar years 1999 to 2004

	$ per Installed MW-Year
1999	$3,444
2000	$4,509
2001	$3,831
2002	$3,500
2003	$3,986
2004	$3,667

32 See Section 4, "Capacity Markets," for further details.
33 See Section 4, "Capacity Markets," for further details.

Although not included in the net revenue analyses, generators also receive operating reserve revenues from both the Day-Ahead and Real-Time Energy Markets. Operating reserve payments were about $3,600[34] per installed MW-year in 2003 and were also about $3,600 per installed MW-year in 2004. These payments, in part, ensure that generators are guaranteed accepted bid revenues from units scheduled by PJM, including the payment of startup and no-load costs.

New Entrant Net Revenue Analysis

The analysis of net revenues available for a new entrant has been expanded to include three power plant configurations: a natural gas-fired combustion turbine (CT), a two-on-one natural gas-fired combined-cycle plant (CC) and a conventional pulverized coal-fired, single reheat steam generation plant (CP). The CT plant consists of two GE Frame 7FA CTs, equipped with full inlet air mechanical refrigeration and selective catalytic reduction (SCR) for NO_x reduction. The CC plant consists of two GE Frame 7FA CTs equipped with evaporative cooling, a single heat recovery steam generator (HRSG) for each CT with steam reheat and SCR for NO_x reduction with a single steam turbine generator. The coal plant is a western Pennsylvania seam pulverized coal-fired plant, equipped with lime injection for SO_2 reduction and low NO_x burners in conjunction with over fire air for NO_x control.

Enhancements to the net revenue calculations include the use of actual hourly ambient air temperature[35] and river water cooling temperature[36] and the effect of each, as applicable, on plant heat rates[37] and generator output for each of the three plant configurations.[38] Plant heat rates were calculated for each hour to account for the efficiency changes and corresponding cost changes resulting from ambient air and river condition variations.[39] The effect of ambient air conditions and river water temperature on plant generation capability was calculated hourly to account for changes in energy production. For purposes of determining the amount of capacity that could be sold in the Capacity Market, the available capacity of each plant type was calculated based on the actual ambient conditions at the hour of each annual peak load, consistent with PJM rules for determining available capacity. Available capacity was then adjusted downward by the actual class average forced outage factor for each generator type in order to obtain the level of unforced capacity available for sale in PJM capacity auctions, by plant type.[40]

A further enhancement to the net revenue calculations was the addition of NO_x and SO_2 credit costs to the hourly plant dispatch cost, where applicable. These costs are included in the PJM definition of marginal cost. NO_x and SO_2 emission credit costs were obtained from actual historical daily spot cash prices for the prompt year.[41] NO_x credit costs were included only during the annual NO_x attainment period from May 1 through September 30. SO_2 credit costs were calculated for every hour of the year.

34 The 2003 average operating reserve payments in dollars per installed MW-day have been reduced about $100 per installed MW-day from the 2003 State of the Market Report. This decrease reflects final adjusted operating reserve data for 2003 that were not available at the time of publication. The 2004 value will be similarly adjusted in the 2005 State of the Market Report to reflect finalized adjusted operating reserve data.
35 Hourly ambient conditions supplied by Meteorlogix from the Philadelphia International Airport, Philadelphia, PA location.
36 Hourly river water conditions represent the Reedy Island Jetty Gauge station located on the Delaware River. Data obtained from U.S. Department of the Interior – U.S. Geological Survey < http://nwis.waterdata.usgs.gov/pa/nwis/qwdata?site_no-01482800>.
37 These heat rate changes were calculated by Strategic Energy Resources, Inc., a consultant to PJM, utilizing GE Energy's GateCycle Power Plant and Simulation Software. Neither GE Energy nor GE has reviewed this Report or the calculations and results of the work done by Strategic Energy Services, Inc. for PJM.
38 Strategic Energy Services, Inc.
39 All heat rate calculations are expressed in Btu per net KWh. No-load costs are included in the heat rate and subsequently the dispatch price since each unit type is dispatched at full load for every economic hour and off for every uneconomic hour; therefore there is a single offer point and no offer curve.
40 Outage figures obtained from the PJM eGADS database.
41 NO_x and SO_2 emission daily prompt prices obtained from Evolution Markets L.L.C.

A forced outage factor for each class of plant was calculated from PJM data.[42] This class-specific outage factor was then incorporated into all revenue calculations. Additionally, each plant was given a 15-continuous-day, planned annual outage in the fall season.

Variable operations and maintenance (VOM) expenses were estimated to be $5.00 per MWh for the CT plant, $1.50 per MWh for the CC plant and $2.00 per MWh for the pulverized coal plant. These estimates were provided by a consultant to PJM[43] and are based on quoted third party contract prices. The VOM expenses for the CT and CC plants include accrual of anticipated routine major overhaul expenses.[44] The burner tip fuel cost for natural gas came from published[45] commodity daily cash prices, with a basis adjustment for transportation costs. Coal burner tip cost was developed from the published prompt month price,[46] adjusted for rail transportation cost. The average burner tip fuel prices are shown in Table 2-30.

Ancillary service revenues for the provision of spinning reserve service for all three plant types are set to zero. GE Frame 7FA CTs are typically not configured to provide Tier 2 spinning reserve in PJM. The same is true for the CC configuration. Steam units, like the coal plant, do provide Tier 1 spinning reserve, but the 2004 Tier 1 revenues were minimal. Ancillary service revenues for the provision of regulation service for both the CT and CC plant are also set to zero as these plant types typically do not provide regulation service in PJM. Additionally, no black start service capability is assumed for the reference CT plant configuration in either costs or revenues. Ancillary service revenues for the provision of regulation were calculated for the pulverized coal plant. The regulation offer price was the sum of the calculated hourly cost to supply regulation service and an adder of $7.50, per PJM market rules. This offer price was compared to the hourly clearing price in the PJM Regulation Market. The clearing price includes both the offer price and the opportunity cost of the marginal unit in each hour. If the reference CP could provide regulation at a total cost including the CP opportunity cost that is less than the regulation clearing price, the regulation service net revenue would equal the market price of regulation minus the cost of CP regulation.

Generators receive revenues for the provision of reactive services based on cost of service filings with the FERC. The actual reactive service payments filed with and approved by the FERC for each generator class were used to determine the reactive revenues. Reactive service revenues are based on the weighted-average reactive service rate per MW-year calculated from the data in the FERC filings. For CTs, the calculated rate is $2,390 per installed MW-year; for CCs, the calculated rate is $3,816 per installed MW-year. Since there is not a representative sample of FERC-approved filings for reactive revenue requirements for new entry coal plants, a weighted-average reactive service rate for all filings was used for CP reactive service revenues.[47] The calculated reactive service rate for the CP is $2,988 per installed MW-year.

42 Outage figures obtained from the PJM eGADS database.
43 Strategic Energy Services, Inc.
44 Routine Combustor Inspection, Hot Gas Path and major inspection costs collected through the VOM adder. This figure was established by Strategic Energy Services, Inc. and compares favorably with actual Operations and Maintenance costs from similar PJM generating units.
45 Gas daily cash prices obtained from Platt's.
46 Coal prompt prices obtained from Energy Argus.
47 The CT plant reactive revenues are based on 14 recent FERC filings for CT reactive costs. The CC plant revenues are based on nine recent FERC filings for CC reactive costs, and the CP plant revenues are based on 24 recent FERC filings representing all classes of generation.

Table 2-30 - Burner tip average fuel price in PJM (Dollars per MBtu): Calendar years 1999 to 2004

	Natural Gas	Low Sulfur Coal
1999	$2.62	$1.62
2000	$5.18	$1.39
2001	$4.52	$2.14
2002	$3.81	$1.54
2003	$6.45	$1.76
2004	$6.65	$2.74

The total net revenues for 1999 to 2004 are shown in Table 2-31, Table 2-32 and Table 2-33 for the new entrant CT, CC and CP facilities.

Table 2-31 - New entrant gas-fired combustion turbine plant (Dollars per installed MW-year): Theoretical net revenue for calendar years 1999 to 2004

Year	Energy	Capacity	Spin	Regulation	Reactive	Total
1999	$62,065	$16,677	$0	$0	$2,390	$81,131
2000	$16,476	$20,200	$0	$0	$2,390	$39,066
2001	$39,269	$30,960	$0	$0	$2,390	$72,619
2002	$23,232	$11,516	$0	$0	$2,390	$37,139
2003	$12,154	$5,554	$0	$0	$2,390	$20,099
2004	$8,063	$5,376	$0	$0	$2,390	$15,829

Table 2-32 - New entrant gas-fired combined-cycle plant (Dollars per installed MW-year): Theoretical net revenue for calendar years 1999 to 2004

Year	Energy	Capacity	Spin	Regulation	Reactive	Total
1999	$89,600	$16,999	$0	$0	$3,816	$110,416
2000	$42,647	$19,643	$0	$0	$3,816	$66,106
2001	$68,949	$29,309	$0	$0	$3,816	$102,074
2002	$51,639	$10,492	$0	$0	$3,816	$65,948
2003	$50,346	$5,281	$0	$0	$3,816	$59,443
2004	$49,600	$5,241	$0	$0	$3,816	$58,657

Table 2-33 - New Entrant pulverized coal-fired steam plant (Dollars per installed MW-year): Theoretical net revenue for calendar years 1999 to 2004

Year	Energy	Capacity	Spin	Regulation	Reactive	Total
1999	$101,011	$17,798	$0	$5,596	$2,988	$127,393
2000	$112,202	$20,755	$0	$3,492	$2,988	$139,437
2001	$106,866	$30,862	$0	$1,356	$2,988	$142,072
2002	$101,345	$11,493	$0	$2,118	$2,988	$117,943
2003	$166,540	$5,688	$0	$2,218	$2,988	$177,433
2004	$136,280	$5,537	$0	$1,399	$2,988	$146,203

In order to demonstrate the sensitivity of the CT energy market net revenue results to the assumption of perfect dispatch with no operating constraints, energy market net revenues were calculated for a CT plant dispatched by PJM Operations. For this dispatch scenario, it was assumed that the CT plant could be dispatched by PJM Operations in four distinct blocks of four hours of continuous output for each block from the peak-hour period beginning with the hour ending 0800 EPT through to the hour ending 2300 EPT for any day when the average PJM real-time LMP was greater than, or equal to, the cost to generate including the cost for a complete start and shutdown cycle[48] for at least two hours during each four-hour block.[49] The blocks are dispatched independently and if there were not at least two economic hours in any given block then the CT was not dispatched. The calculations account for operating reserves based on PJM rules, when applicable, since the assumed operation is under the direction of PJM Operations. This dispatch scenario uses the same variable operations and maintenance costs, outage, fuel cost, emissions and plant performance assumptions reflected in the Table 2-31 results.

A comparison of the results is shown in Table 2-34 where the first column in Table 2-34 is the perfect economic dispatch energy market net revenue results from Table 2-31. For the six-year period, the average energy market net revenue under the perfect economic dispatch scenario was about $26,900 per installed MW-year while the six-year average for the peak-hour dispatch scenario is about $18,800 per installed MW-year or about a 30 percent reduction in energy market net revenues. Additional, more complex dispatch scenarios were analyzed for the CT plant however, the resultant effect on energy market net revenue was about the same as the results of the peak-hour dispatch scenario versus the perfect economic dispatch scenario.

Table 2-34 - Energy market net revenues for a combustion turbine plant under two dispatch scenarios(Dollars per installed MW-year)

	Perfect Economic Dispatch	Peak Hour Economic	Difference
1999	$62,065	$55,612	$6,452
2000	$16,476	$8,498	$7,978
2001	$39,269	$30,254	$9,015
2002	$23,232	$14,496	$8,736
2003	$12,154	$2,763	$9,390
2004	$8,063	$919	$7,144
Average	$26,876	$18,757	$8,119

In order to demonstrate the sensitivity of the CC energy market net revenue results to the assumption of perfect dispatch with no operating constraints, energy market net revenues were calculated for a CC plant dispatched by PJM Operations for continuous output from the peak-hour period beginning with the hour ending 0800 EPT and continuing to the hour ending 2300 EPT for any day when the average PJM real-time LMP was greater than, or equal to, the cost to generate including the cost for a complete start and shutdown cycle[50] for at least eight hours

48 Startup and shutdown fuel burn obtained from actual PJM installed capacity. Gas daily cash prices obtained from Platt's fuel prices. Per PJM Manual M-15, "Cost Development Guidelines," startup and shutdown station power consumption costs were obtained from the station service rates published quarterly by PJM settlements. No-load costs are included in the heat rate.
49 The first block represents the four-hour period starting at hour ending 0800 EPT until hour ending 1100 EPT. The second block represents the four-hour period starting at hour ending 1200 EPT until hour ending 1500 EPT. The third block represents the four-hour period starting at hour ending 1600 until hour ending 1900 EPT, and the fourth block represents the four-hour period starting at 2000 EPT until hour ending 2300 EPT.
50 Startup and shutdown fuel burn obtained from actual PJM installed capacity. Gas daily cash prices obtained from Platt's Fuel prices. Per PJM Manual M-15, "Cost Development Guidelines," startup and shutdown station power consumption costs were obtained from the Station Service rates published quarterly by PJM Settlements. No-load costs are included in the heat rate and subsequently the dispatch price since each unit type is dispatched at full load for every economic hour and off for every uneconomic hour; therefore there is a single offer point and no offer curve.

during that time period. If there were not eight economic hours in any given day, then the CC was not dispatched. The calculations account for operating reserves based on PJM rules, when applicable, since the assumed operation is under the direction of PJM Operations. This dispatch scenario uses the same variable operations and maintenance costs, outage, fuel cost, emissions and plant performance assumptions reflected in the Table 2-32 results.

A comparison of the results is shown in Table 2-35 where the first column in Table 2-35 is the perfect economic dispatch energy market net revenue results from Table 2-32. For the six-year period, the average energy market net revenue under the perfect economic dispatch scenario was about $58,800 per installed MW-year while the six-year average for the peak-hour dispatch scenario is about $42,100 per installed MW-year or about a 28 percent reduction in energy market net revenues. Additional, more complex dispatch scenarios were analyzed for the CC plant however, the resultant effect on energy market net revenue was about the same as the results of the peak-hour dispatch scenario versus the perfect economic dispatch scenario.

Table 2-35 - Energy market net revenues for a combined cycle plant under two dispatch scenarios (Dollars per installed MW-year)

	Perfect Economic Dispatch	Peak Hour Economic	Difference
1999	$89,600	$80,546	$9,055
2000	$42,647	$24,794	$17,854
2001	$68,949	$54,206	$14,743
2002	$51,639	$38,625	$13,015
2003	$50,346	$27,155	$23,191
2004	$49,600	$27,389	$22,211
Average	$58,797	$42,119	$16,678

In order to demonstrate the sensitivity of the CP energy market net revenue results to the assumption of perfect dispatch with no operating constraints, energy market net revenues were calculated assuming that the plant had a 24-hour minimum run time and was dispatched by PJM Operations for all available plant hours, both reasonable assumptions for a large CP. The calculations account for full operating reserves, when applicable, since the assumed operation is under the direction of PJM Operations. The additional dispatch scenario uses the same variable operations and maintenance costs, outage, fuel cost, emissions and plant performance assumptions reflected in the Table 2-33 results.[51]

A comparison of the results is shown in Table 2-36 where the first column in Table 2-36 is the perfect economic dispatch energy market net revenue results from Table 2-33. For the six-year period, the average, energy market net revenue under the perfect economic dispatch scenario was about $120,700 per installed MW-year while the six-year average for the available dispatch scenario is about $113,000 per installed MW-year or about a 6 percent reduction in energy market net revenues. The two scenarios are provided to present a reasonable bound of energy net revenues for a new entrant CP.

51 No-load costs are included in the heat rate and subsequently the dispatch price since each unit type is dispatched at full load for every economic hour and off for every uneconomic hour; therefore there is a single offer point and no offer curve.

Table 2-36 - Energy market net revenues for a pulverized coal plant under two dispatch scenarios(Dollars per installed MW-year)

	Perfect Economic Dispatch	All Available Hour Economic	Difference
1999	$101,011	$92,935	$8,076
2000	$112,202	$108,624	$3,578
2001	$106,866	$95,361	$11,506
2002	$101,345	$96,828	$4,517
2003	$166,540	$159,912	$6,628
2004	$136,280	$124,497	$11,783
Average	$120,707	$113,026	$7,681

Net Revenue Adequacy

To put the net revenue results in perspective, the first operating year annual fixed costs for the assumed new entrant CT plant configuration would be about $61,800 per installed[52] MW-year or about $72,200 per installed MW-year if levelized over the 20-year life of the project.[53] The first operating year annual fixed cost for the assumed CC and CP plant configurations would be about $80,000 per installed MW-year and $178,000[54] per installed MW-year, respectively. The levelized 20-year operating annual costs for the CC and CP plants would be about $93,500 per installed MW-year and $208,200 per installed MW-year, respectively. A tabulation of the first operating year and 20-year operating life levelized costs is shown in Table 2-37.[55]

Table 2-37 - New entrant first year and 20-year levelized fixed costs by plant type (Dollars per installed MW-year)

	First Year Fixed Cost	20-Year Levelized Fixed Cost
CP	$178,019	$208,247
CC	$79,969	$93,549
CT	$61,726	$72,207

In 2004, under the perfect economic dispatch scenario, net revenue from the Energy Market, the Capacity Market and ancillary services for a new entrant CT were approximately $16,000 per installed MW-year. The associated operating costs were between $75 and $80 per MWh, based on a design heat rate of 10,500 Btu per kWh, average daily delivered natural gas prices of $6.65 per MBtu and a VOM rate of $5 per MWh.[56] The resulting net revenue stream would not have covered the fixed costs of a new CT if it ran during all profitable hours.

52 Installed capacity at 92 degrees F.
53 This is the same analysis performed for PJM by Strategic Energy Services, Inc. in the development of the cost of new entry for the Reliability Pricing Model. The annual costs are based on a 20-year project life, 50/50 debt-to-equity financing with a target equity internal rate of return (IRR) of 12 percent and a debt rate of 7 percent. For depreciation, the analysis assumed a 20-year modified accelerated cost-recovery schedule (MACRS). A general annual rate of cost inflation of 2.5 percent was utilized in all calculations.
54 Installed capacity at average Philadelphia ambient air temperature of 54 degrees F. during study period of 1999 to 2004.
55 The figures in Table 11 represent the annual cost for the first year of operation. For example the $61,726 per installed MW-year figure represents the annual cost of the CT for the first operational year of the plant. Assuming a two year construction period, the cost for the first year of construction would be $58,752 per Installed MW-year.
56 The analysis used the daily gas costs and associated production cost for CTs and CCs.

In 2004, under the perfect economic dispatch scenario, net revenue from the Energy Market, the Capacity Market and ancillary services for a new entrant CC were approximately $59,000 per installed MW-year. The associated operating costs were between $50 and $55 per MWh, based on a design heat rate of 7,500 Btu per kWh, average daily delivered natural gas prices of $6.65 per MBtu and a VOM rate of $1.50 per MWh. The resulting net revenue stream would not have covered the fixed costs of the CC plant if it ran during all profitable hours.

In 2004, under the perfect economic dispatch scenario, net revenue from the Energy Market, the Capacity Market and ancillary services for a new entrant CP would have been approximately $146,000 per installed MW-year. The associated operating costs would have ranged between $25 and $30 per MWh,[57] based on a design heat rate of 9,500 Btu per kWh, average delivered coal prices of $2.74 per MBtu and a VOM rate of $2 per MWh. This revenue stream would not have covered the fixed costs of a CP plant if it ran during all profitable hours.

In 1999 and 2001 under the perfect economic dispatch scenario, the net revenue shown for the CT and CC plants was sufficient to cover the first year fixed costs of $61,700 per installed MW-year and $80,000 per installed MW-year, respectively. In 2000, 2002 and 2004, there was, however, a revenue shortfall for both plant types. For the CP, 2003 was the only year with sufficient net revenues to cover the first year fixed cost of $178,000 per installed MW-year.

Under the perfect economic dispatch scenario, the six-year net revenue averaged $44,300 per installed MW-year for new entrant CT plant, $77,100 per installed MW-year for new entrant CC plant and $141,700 per installed MW-year for a new entrant pulverized coal plant. Thus, under perfect economic dispatch over the six-year period, net revenue was not adequate to cover either CT or CP fixed costs, but was adequate to cover the first year fixed costs of new entrant CC plants.

Although it can be expected that in the long run, in a competitive market, net revenue from all sources will cover the fixed costs of investing in new generating resources, including a competitive return on investment, actual results are expected to vary from year to year. Wholesale energy markets, like other markets, are cyclical. When the markets are long, prices will be lower and when the markets are short, prices will be higher. Analysis of 2004 net revenue suggests that the fixed costs of peaking, mid-merit and baseload new entrants 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 2004, about 12,200 MW of capacity were in generation request queues for construction through 2008 (Figure 2-10), compared to an average installed capacity of 87,500 MW in 2004 and a year end installed capacity of 141,698 MW. Although it is clear that not all generation will be built, PJM is steadily adding capacity.

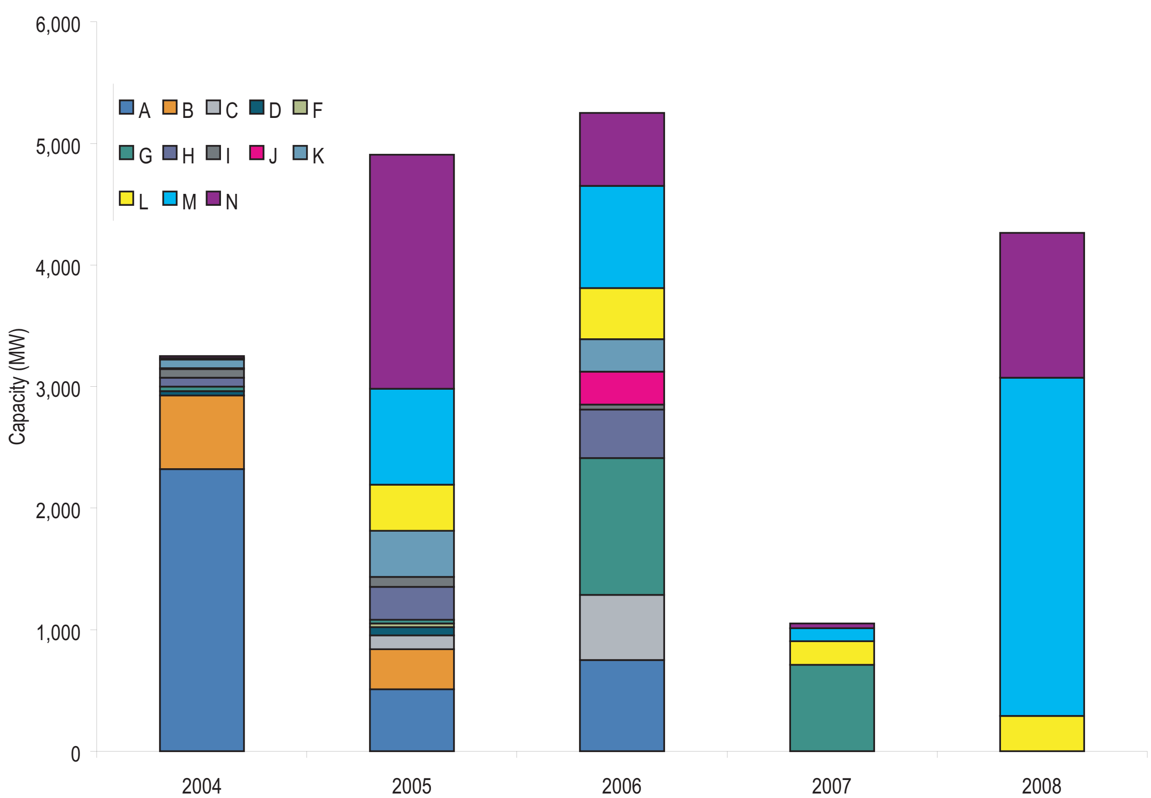
57 The analysis used the prompt coal costs and associated production cost for a CP.

Generation request queues are groups of proposed projects. Queue A was open from April 1997 to March 1999, Queue B was open from April 1999 through September 1999 and Queue C opened October 1999. After Queue C, a new queue is opened every six months. Queue O is currently active.

Capacity in the generation request queues for the five-year period beginning in 2004 and ending in 2008 increased from 14,000 MW in 2003 to 18,700 MW in 2004.[58] This 4,700 MW increase can be disaggregated into annual changes starting in 2004. Queued capacity slated for service in 2004 decreased by 2,000 MW from 2003, a 38 percent decrease. Queued capacity for service in 2005 decreased from 5,200 MW in 2003 to 4,900 MW, a 6 percent decrease. However, capacity in the queues for the years 2006, 2007 and 2008 has increased in 2004 over 2003. The capacity in the queues in 2004 for the years 2006, 2007 and 2008 was 5,200 MW, 1,000 MW and 4,300 MW. These values represent increases of 4,100 MW, 400 MW and 2,500 MW over the level of capacity in the queues in 2003 for the years 2006, 2007 and 2008.

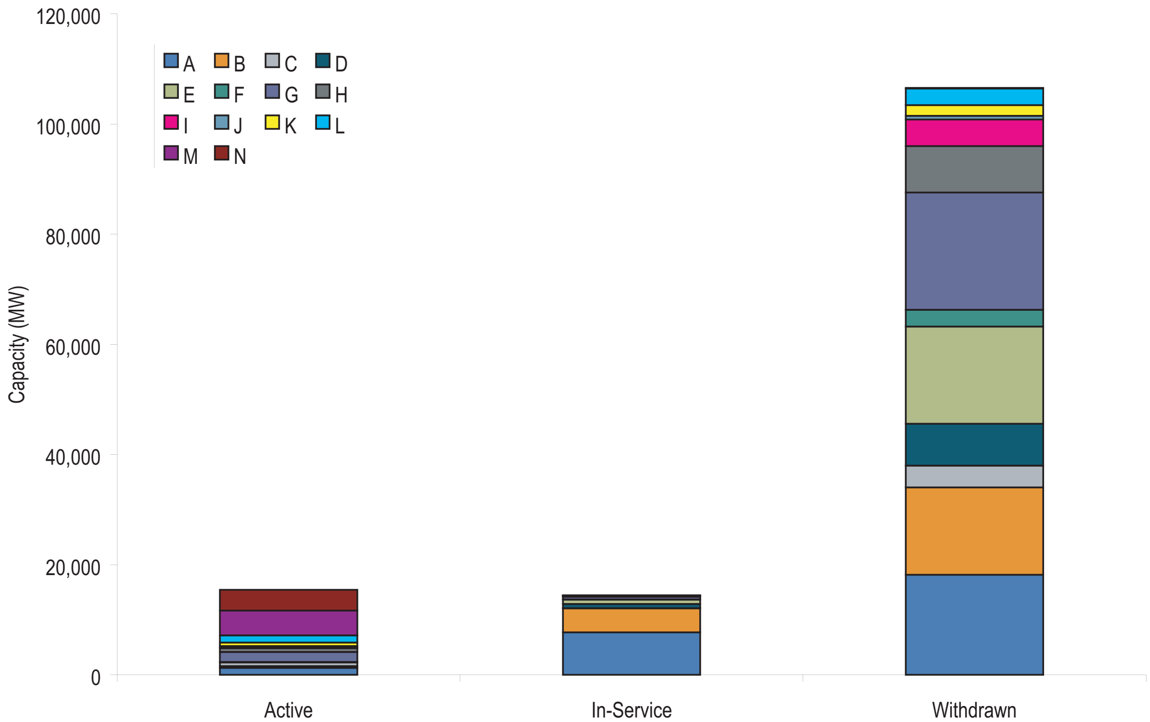
Figure 2-11 shows the amount of capacity added to the queues and the amount of capacity withdrawn from the queues since the beginning of the RTEP process as well as the total amount of capacity that entered the queues under RTEP and is now in service.

Figure 2-10 - Queued capacity by in-service date: At December 31, 2004



58 See the 2003 State of the Market Report (March 10, 2004), pp. 68-69, for the queues in 2003.

Figure 2-11 - New capacity in PJM queues: At December 31, 2004



Conclusion

While net revenue in PJM has been sufficient to cover the costs of new peaking units in some years, net revenue has been below the level required to cover the full costs of new generation investment for several years and below that level on average for new peaking units for the entire market period. The fact that investors' expectations have not been realized in every year could be taken as a reflection of cyclical supply-demand fundamentals in PJM Markets. However, it is also the case that there are some units in PJM, needed for reliability, that have revenues that are not adequate to cover annual going forward costs and that their owners, therefore, wish to retire. This suggests that market price signals and reliability needs are not fully synchronized.

The issue is how to understand this phenomenon and how to address it within the context of competitive markets. The level of net revenues in PJM Markets is not the result of the $1,000 per MWh offer cap, of local market power mitigation, or of a basic incompatibility between wholesale electricity markets and competition. Competitive markets can, and do, signal scarcity and surplus conditions through market-clearing prices. However, in PJM as in other wholesale electric power markets, the application of reliability standards means that scarcity conditions in the Energy Market occur with reduced frequency. Traditional levels of reliability require units that are only directly used and priced under relatively unusual load conditions. Thus, the Energy Market alone frequently does not directly value the resources needed to provide for reliability.

To address this issue, PJM is developing a reliability pricing model (RPM), which is a capacity market design intended to send supplemental signals to the market based on the locational and forward-looking need for generation resources to maintain system reliability in the context of a long-run competitive equilibrium in the Energy Markets.

Demand-Side Response (DSR)

Markets require both a supply side and a demand side to function effectively. The demand side of wholesale electricity markets is severely underdeveloped. This underdevelopment is among the basic reasons for maintaining an offer cap in PJM and in other wholesale power markets. It is widely recognized that wholesale electricity 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 to a fully functional demand side for its Energy Market.

A functional demand side of the electricity market does not mean that all customers curtail usage at specified levels of price. A fully functional demand side of the electricity 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 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 use. If these conditions are met, customers can decide for themselves the relationship between the price of power and the value of 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 can 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, however, 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 electricity market would also tend to induce more competitive behavior among suppliers and to limit their ability to exercise market power. If customers had the essential tools to respond to prices, then suppliers would have the incentive to deliver power on a cost-effective basis, consistent with their customers' evaluations.

On March 15, 2002, PJM submitted filing amendments to the PJM Open Access Transmission Tariff (PJM Tariff) and to the Amended and Restated Operating Agreement (PJM Operating Agreement) to establish a multiyear Economic Load-Response Program (the Economic Program).[59] On May 31, 2002, the FERC accepted the Economic Program, effective June 1, 2002, but with a December 1, 2004, sunset provision.[60] On October 29, 2004, the FERC extended the Economic Program until December 31, 2007. [61]

The PJM Economic Load-Response Program provides a PJM-managed accounting mechanism that requires payment of the real savings to the load-reducing customer that result from load reductions. Such a mechanism is required because of the complex interaction between the

59 *PJM Interconnection, L.L.C.,* Tariff Amendments, Docket No. ER02-1326-000 (March 15, 2002) .
60 99 FERC ¶ 61,227 (2002).
61 *PJM Interconnection, L.L.C.,* Letter Order, Docket No. ER04-1193-000 (October 29, 2004).

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 a transition to a structure whereby customers do not require mandated payments but where customers see and react to market signals or where customers enter into contracts with intermediaries who see and react to market signals on their behalf. Even as currently structured, however, the Economic Program represents a minimal and relatively efficient intervention into the market.

The pattern of prices within days and across months illustrates the fact that prices are directly related to demand and thus the potential of price elasticity of demand to affect prices. The ability of load to respond to changes in price is a critical component of a competitive market which remains as yet undeveloped in the wholesale electricity market.

On February 14, 2002, the PJM Members Committee approved a permanent Emergency Load-Response Program.[62] On March 1, 2002, PJM filed amendments to the PJM Tariff and to the PJM Operating Agreement to establish a permanent Emergency Load-Response Program (the Emergency Program).[63] By order dated April 30, 2002, the FERC approved the Emergency Program effective June 1, 2002. Like the Economic Program, a sunset date for it was set for December 1, 2004.[64] On October 29, 2004, the FERC extended the program until December 31, 2007, thereby making it coterminous with the Economic Program.[65]

Emergency Program

During the summer of 2004, the PJM Control Area experienced mild weather and associated load levels and, as a result, there was no activity in the Emergency Program in calendar year 2004.[66] The numbers of currently active sites with associated MW in the Emergency Program are shown in Table 2-38.[67] As of September 30, 2004, there were 1,385 MW of resources active in the Emergency Program.[68] This is a 243 percent increase from the 404 MW active at the end of 2003, which was, in turn, an increase of 60 percent from the 253 MW active in October 2002.[69]

Table 2-38 - Currently active participants in the Emergency Program

	Currently Active by Year Enrolled		Cumulative Total	
	Sites	MW	Sites	MW
2001	N/A	N/A	N/A	N/A
2002	53	253	53	253
2003	103	151	156	404
2004	4,144	981	4,300	1,385

62 *PJM Interconnection, L.L.C.,* Tariff Amendments, Docket No. ER02-1205-000 (March 1, 2002) .
63 *PJM Interconnection, L.L.C.,* Tariff Amendments, Docket No. ER02-1205-000 (March 1, 2002) .
64 99 FERC ¶ 61,139 (2002).
65 *PJM Interconnection, L.L.C.,* Letter Order, Docket No. ER04-1193-000 (October 29, 2004).
66 See discussion on load and LMP in Section 2, "Energy Market."
67 The number of currently active MW and sites may be smaller than the number of registered MW and sites reported by PJM because the number of registered sites includes registered participants that switched between the Emergency and the Economic Programs, downsized or went out of business.
68 For both Emergency and Economic programs the results reported for 2004 are based on the nine months, January through September, because those data were all that were available at the end of the calendar year. Under the terms of the Operating Agreement, participants have 60 days to submit data to PJM, after which LSEs and EDCs have an additional 10 days to verify these data. The results for 2003 reported herein are based on 12 months of data, but the 2003 State of the Market Report was based on the nine months of 2003 data available at the time of preparation. The 2002 program began on June 1, 2002. The 2002 data are based on the five-month period, June through October which are all the data available. The 2001 numbers are based on two months, July and August, which are again all the data available. During 2001, PJM had only a Customer Load-Reduction Pilot Program, which was an early stage of the present DSR program. It was effective from June 1, 2001, through May 31, 2002.
69 The numbers of registered sites and currently active sites with associated MW for Emergency and Economic programs of 2001 are not available.

Economic Program

The Economic Program has grown significantly in the three years since its 2001 inception, as measured by both total MW enrolled in the program and actual MWh response under the program. Data on the number of currently active sites in the Economic Program are presented in Table 2-39 along with the associated MW. As of September 30, 2004, there were 724 MW currently active in the Economic Program. This is a 23 percent increase from the 589 MW total active MW at the end of 2003, which was, in turn, an increase of 92 percent from the 306 MW active in October 2002.

Table 2-39 - Currently active participants in the Economic Program

	Currently Active by Year Enrolled		Cumulative Total	
	Sites	MW	Sites	MW
2001	N/A	N/A	N/A	N/A
2002	102	306	102	306
2003	138	283	240	589
2004	106	135	346	724

The total MWh of load reductions and the associated payments under the Economic Program are shown in Table 2-40. Load reduction levels in the Economic Program increased from 50 MWh in 2001 to 6,462 MWh in 2002 to 19,290 MWh in 2003 to 48,622 MWh in 2004.[70] Consistent with lower LMPs, payments per MWh have decreased steadily, falling first by 58 percent between 2001 and 2002, then by 64 percent between 2002 and 2003, and, more recently, by 28 percent from 2003 to 2004. The Economic Program's actual MWh of load reduction per currently active MW increased significantly, rising first during June through October of 2002, then jumping by 57 percent in calendar year 2003 and finally growing by 103 percent in the nine-month period, ending September 30 2004.

Table 2-40 - Performance of PJM Economic Program participants

	Total MWh	Total Payments	$/MWh	Total MWh per Cumulative Total MW
2001	50	$13,994	$283	N/A
2002	6,462	$761,977	$118	21
2003	19,290	$827,179	$43	33
2004	48,622	$1,487,848	$31	67

Overall, approximately 96 percent of the MWh reductions, 87 percent of payments and 93 percent of curtailed hours resulted from customers with the real-time rate option under the Economic Program. Only 0.4 percent of the MWh reductions, 1 percent of payments and 1 percent of curtailed hours resulted from customers with the day-ahead option. Finally, approximately 4 percent of the MWh reductions, 12 percent of the payments and 6 percent of the curtailed hours resulted from the pilot program. All nonhourly, metered program reductions occurred within the real-time market. (See Table 2-41.)

70 Load reductions are measured by multiplying hourly MW reductions by their duration (expressed in number of hours). 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 equal 4 MWh.

As an example of a participant in the Economic Program, a manufacturing company participant in the Program would consult with its Curtailment Service Provider in order to determine when and how to implement a load reduction. The manufacturing company would take account of expected LMP, its own shut-down costs and its minimum shut down time. In order to implement a load reduction in real time, the manufacturing company would move production to another shift with lower expected LMP or to another facility with a lower LMP, if available.

LMP-based customers did not experience any activity during the nine months ended September 30, 2004. A total of 22 retail customers registered as LMP-based customers, of which eight were active load management (ALM) customers. In total, 60 customers selected the ALM option. Because of the mild weather during the summer period of 2004, there was no ALM activity.

During the Phase 2 integration of the ComEd Control Area, participants in ComEd load management initiatives were provided with an opportunity to take part in PJM's DSR programs. By September 30, 2004, 4,121 ComEd retail customers had enrolled in the program. Of these, 4,119 had selected the Emergency Program and two selected the Economic Program. Of the ComEd participants, 221 entered the program as ALM/mandatory interruptible load (MIL) customers.[71] None registered as LMP-based customers.

Using actual demand reductions and real-time supply curves, during the nine months ended September 30, 2004, the price impact of the Economic Program was approximately $1 per MWh.[72]

The maximum hourly load reduction attributable to the Economic Program was 168 MW in the nine-month period ended September 30, 2004. Based on real-time supply curves for a representative day during the summer of 2004 and the summer peak load, a reduction of 1,000 MW would have created a $5 per MW LMP decrease. LMPs were lower during the summer of 2004 based on supply and demand fundamentals. The potential price impacts of load reductions were also attenuated by supply and demand fundamentals.[73]

During the nine months ended September 30, 2004, the Economic Program showed significant differences in activity among the PJM Control Zones. For example, 85 percent of MWh reductions, 75 percent of payments and 46 percent of curtailed hours under the real-time rate option occurred within a single zone. Overall, 82 percent of MWh reductions, 67 percent of payments and 44 percent of curtailed hours under the Economic Program, regardless of the type of rate the customer chose, were accounted for by a single zone. (See Table 2-41.) By contrast, two zones saw no activity in any DSR program. The same table shows that the total number of curtailed hours for the Economic Program was 6,241; the total payment amount was $1,487,848.

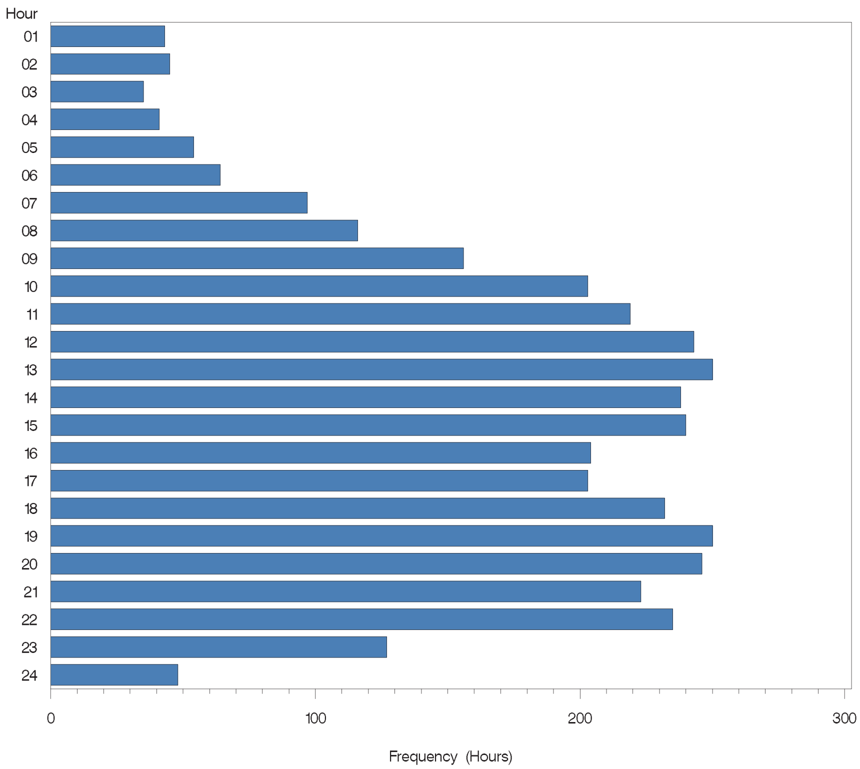
71 MIL is a month-by-month, year-round program for ComEd. For additional information, see Appendix H, "Glossary."
72 See Section 2, "Energy Market," at Figure 2-1, Average PJM aggregate supply curves: Summers 2003 and 2004.
73 See Section 2, "Energy Market," at Figure 2-1, "Average PJM aggregate supply curves: Summers 2003 and 2004."

Table 2-41 - PJM Economic Program by zonal reduction: Nine months ended September 30, 2004

	Real Time			Day Ahead			Pilot			Totals		
	MWh	Credits	Hours	MWh	Credits	Hours	MWh	Credits	Hours	MWh	Credits	Hours
AECO	1,828	$80,851	843	0	$0	0	0	$0	0	1,828	$80,851	843
AP	39,641	$978,547	2,678	0	$0	0	119	$11,175	56	39,760	$989,722	2,734
BGE	384	$26,091	124	0	$0	0	0	$0	0	384	$26,091	124
ComEd	1	$13	5	0	$0	0	0	$0	0	1	$13	5
DPL	13	$817	19	179	$7,961	50	0	$0	0	192	$8,779	69
JCPL	16	$1,966	14	0	$0	0	232	$27,706	123	248	$29,673	137
Met-Ed	57	$480	96	0	$0	0	517	$51,154	106	574	$51,634	202
PECO	15	$1,389	16	0	$0	0	0	$0	0	15	$1,389	16
PENELEC	0	$0	0	0	$0	0	999	$92,380	49	999	$92,380	49
PEPCO	0	$0	0	0	$0	0	0	$0	0	0	$0	0
PPL	3,424	$84,997	375	0	$0	0	15	$1,343	50	3,439	$86,340	425
PSEG	1,183	$120,977	1,637	0	$0	0	0	$0	0	1,183	$120,977	1,637
RECO	0	$0	0	0	$0	0	0	$0	0	0	$0	0
Total	46,561	$1,296,128	5,807	179	$7,961	50	1,881	$183,758	384	48,622	$1,487,848	6,241
Max	39,641	$978,547	2,678	179	$7,961	50	999	$92,380	123	39,760	$989,722	2,734
Avg	3,582	$99,702	447	14	$612	4	145	$14,135	30	3,740	$114,450	480

The DSR business rules provide for larger payments when LMP is greater than or equal to $75 per MWh than when LMP is below $75 per MWh. A significant level of Economic Program activity occurred when LMP was less than $75 per MWh, including 84 percent of all MWh reductions, 48 percent of all payments and 61 percent of all curtailed hours. Figure 2-12 shows that reductions under the Economic Program when LMP was less than $75 per MWh were dispersed over all hours of the day, with maximum activity spread fairly evenly over hours ended 1000 to 2200 EPT.

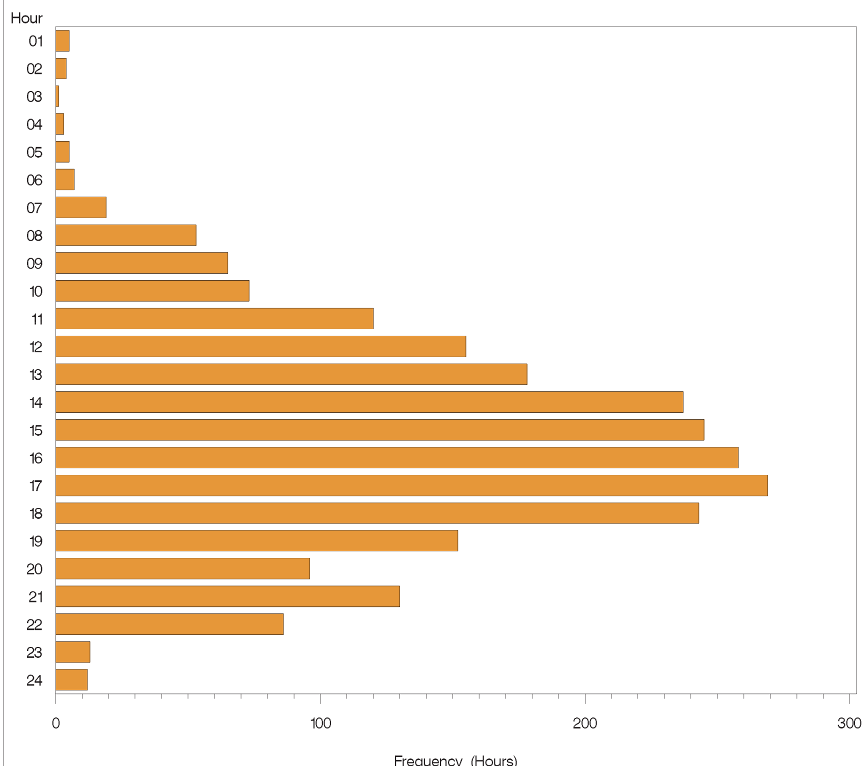
Figure 2-12 - Frequency distribution of Economic Program hours when LMP less than $75 per MWh (by hours): Nine months ended September 30, 2004



Hour	FREQ.	CUM. FREQ.	PCT.	CUM. PCT.
01	43	43	1.13	1.13
02	45	88	1.18	2.31
03	35	123	0.92	3.23
04	41	164	1.08	4.30
05	54	218	1.42	5.72
06	64	282	1.68	7.40
07	97	379	2.54	9.94
08	116	495	3.04	12.99
09	156	651	4.09	17.08
10	203	854	5.33	22.40
11	219	1073	5.75	28.15
12	243	1316	6.37	34.52
13	250	1566	6.56	41.08
14	238	1804	6.24	47.32
15	240	2044	6.30	53.62
16	204	2248	5.35	58.97
17	203	2451	5.33	64.30
18	232	2683	6.09	70.38
19	250	2933	6.56	76.94
20	246	3179	6.45	83.39
21	223	3402	5.85	89.24
22	235	3637	6.16	95.41
23	127	3764	3.33	98.74
24	48	3812	1.26	100.00

Figure 2-13 shows that reductions under the Economic Program when LMP was equal to or greater than $75 per MWh were generally concentrated more narrowly in hours ended 0700 to 2200 EPT, with maximum activity concentrated in hours ended 1400 to 1800 EPT.

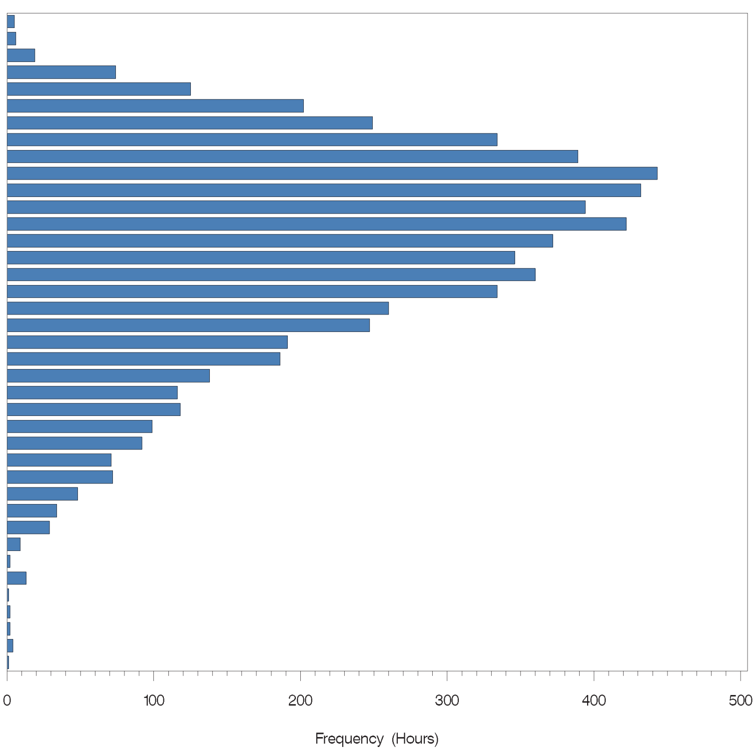
Figure 2-13 - Frequency distribution of Economic Program hours when LMP greater than or equal to $75 per MWh (by hours): Nine months ended September 30, 2004



Hour	FREQ.	CUM. FREQ.	PCT.	CUM. PCT.
01	5	5	0.21	0.21
02	4	9	0.16	0.37
03	1	10	0.04	0.41
04	3	13	0.12	0.54
05	5	18	0.21	0.74
06	7	25	0.29	1.03
07	19	44	0.78	1.81
08	53	97	2.18	3.99
09	65	162	2.68	6.67
10	73	235	3.01	9.67
11	120	355	4.94	14.62
12	155	510	6.38	21.00
13	178	688	7.33	28.32
14	237	925	9.76	38.08
15	245	1170	10.09	48.17
16	258	1428	10.62	58.79
17	269	1697	11.07	69.86
18	243	1940	10.00	79.87
19	152	2092	6.26	86.13
20	96	2188	3.95	90.08
21	130	2318	5.35	95.43
22	86	2404	3.54	98.97
23	13	2417	0.54	99.51
24	12	2429	0.49	100.00

Figure 2-14 shows the frequency distribution of Economic Program hourly reductions with respect to real-time zonal LMP in price ranges of $5 per MWh.[74] Participants with different zonal prices can reduce simultaneously within a specific hour. If their prices vary, this hour will appear in more than one of the $5 price increments of Figure 2-14. The Figure shows that activity was concentrated when LMP was between $35 and $85 per MWh. A majority, 61 percent, of all reductions took place when LMP was less than $75 per MWh.[75]

Figure 2-14 - Frequency distribution of Economic Program LMP (by hours): Nine months ended September 30, 2004



LMP ($/MWh)	FREQ.	CUM. FREQ.	PCT.	CUM. PCT.
$ 0 to $5	5	5	0.08	0.08
$ 5 to $10	6	11	0.10	0.18
$10 to $15	19	30	0.30	0.48
$15 to $20	74	104	1.19	1.67
$20 to $25	125	229	2.00	3.67
$25 to $30	202	431	3.24	6.91
$30 to $35	249	680	3.99	10.90
$35 to $40	334	1014	5.35	16.25
$40 to $45	389	1403	6.23	22.48
$45 to $50	443	1846	7.10	29.58
$50 to $55	432	2278	6.92	36.50
$55 to $60	394	2672	6.31	42.81
$60 to $65	422	3094	6.76	49.58
$65 to $70	372	3466	5.96	55.54
$70 to $75	346	3812	5.54	61.08
$75 to $80	360	4172	5.77	66.85
$80 to $85	334	4506	5.35	72.20
$85 to $90	260	4766	4.17	76.37
$90 to $95	247	5013	3.96	80.32
$95 to $100	191	5204	3.06	83.38
$100 to $105	186	5390	2.98	86.36
$105 to $110	138	5528	2.21	88.58
$110 to $115	116	5644	1.86	90.43
$115 to $120	118	5762	1.89	92.32
$120 to $125	99	5861	1.59	93.91
$125 to $130	92	5953	1.47	95.39
$130 to $135	71	6024	1.14	96.52
$135 to $140	72	6096	1.15	97.68
$140 to $145	48	6144	0.77	98.45
$145 to $150	34	6178	0.54	98.99
$150 to $155	29	6207	0.46	99.46
$155 to $160	9	6216	0.14	99.60
$160 to $165	2	6218	0.03	99.63
$165 to $170	13	6231	0.21	99.84
$170 to $175	1	6232	0.02	99.86
$175 to $180	2	6234	0.03	99.89
$180 to $185	2	6236	0.03	99.92
$185 to $190	4	6240	0.06	99.98
$190 to $195	1	6241	0.02	100.00

Nonhourly, Metered Program (Pilot Program)

PJM created the nonhourly, metered program to extend participation in the demand side of the market to smaller customers that lack hourly meters. PJM's nonhourly, metered program is a pilot program allowing such customers or their representatives to propose alternate methods for achieving measurable load reductions. PJM approves such methodologies on a case-by-case basis, and participants are otherwise subject to the rules and procedures governing the load-response program in which they have enrolled.

74 Posted preliminary Real-Time LMPs are used rather than final LMPs from PJM's settlements system as the posted preliminary LMPs represent the real-time prices to which program participants are reacting.
75 See Appendix C, "Energy Market" at Figure C-20, "Frequency Distribution of average zonal LMP over DSR events." It shows that most DSR events, 52 percent, took place when LMP was greater than $75 per MWh.

During the nine-month period ended September 30, 2004, activity under the nonhourly, metered program included 166 separate hourly reductions, totaling about 1,881 MWh and averaging about 11 MW per hour. The maximum hourly reduction was 49 MWh. Total payments under the program were $183,758.

Customer Demand-Side Response Programs

DSR Program Summary Data

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, PJM conducted surveys of LSEs in June 2004 and June 2003 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 June 2004 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 7,030 MW of load that is exposed to real-time prices either directly or through an intermediary competitive supplier.[76] 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 7,030 MW of load, a total of 2,592 MW or 37 percent, currently purchase electricity directly at an hourly LMP rate plus an adder. This load has chosen to pay LMP rates directly rather than to enter into a contract with a competitive supplier. The remaining 4,438 MW or 63 percent of load purchase electricity from an intermediary competitive supplier.

The survey also identified a total of 934 MW enrolled in independent DSR programs. Of the total, 203 MW or 22 percent were included in price responsive load programs or pilot programs, 453 MW or 48 percent participated in interruptible load programs and 278 MW or 30 percent of load is currently participating in emergency load-response programs of electricity distribution companies.

The June 2004 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, either directly or via competitive supplier intermediaries. 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.

76 The Load-Response Survey data were provided by PJM's Demand-Side Response department.

Summary data for demand-side response programs in PJM are presented in Table 2-42. The programs include the PJM Emergency Load-Response Program, the PJM Economic Load-Response Program, the PJM Active Load Management Program (net of ALM resources participating directly in other PJM demand-side programs) and additional programs reported by PJM customers in response to a survey.

Table 2-42 - Demand-side response programs: Nine months ended September 30, 2004

PJM Programs	MW Registered
PJM Economic Load-Response Program	724
PJM Emergency Load-Response Program	1,385
PJM Active Load-Management Resources	1,806
PJM ALM Resources Included in Load-Response Program	(317)
Total PJM Programs	3,598
Additional Programs Reported By Customers in PJM Survey	
Direct Customer Purchases Based on LMP Signals	2,592
Competitive Contracts	4,438
Independent	
Price-Responsive Load or Pilot Programs	203
Interruptible Load Programs	453
Emergency Load-Response Programs of EDCs	278
Total Independent	934
Total Additional Programs	7,964
Partial Summer Load Participation	0
Net Load, Including Survey Responses	11,562

Operating Reserves

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 Energy 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 startup and no-load offers, operating reserve payments ensure that all offer components are covered.[77]

Table 2-43 shows total operating reserve payments from 1999 through 2004. 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

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

for nine months based on generators' market-based offers. The Day-Ahead Energy 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 Real-Time Energy Market. Beginning on June 1, 2000, operating reserve payments include both day-ahead and balancing operating reserve payments. As Table 2-43 shows, between 2001 and 2002, operating reserve payments declined by about $62 million, or approximately 25 percent. Between 2002 and 2003, operating reserve payments rose by approximately $85 million or 45 percent. Between 2003 and 2004, operating reserve payments rose by approximately $105 million or 38 percent. However, this increase is primarily associated with the integration of ComEd, AEP and DAY Control Zones into the RTO. The monthly average operating reserve payments during Phase 1 were about $22.5 million, rising to about $33.2 million during Phase 2 and then to about $41.0 million during Phase 3.

Table 2-43 also shows the ratio of total operating reserve payments to the total value of PJM market billings. The ratio of operating reserves payments to total PJM billings increased from 4.0 percent in 2003 to 4.4 percent in 2004. Over the last six years, operating reserve payments ranged from a low of 3.0 percent in 1999 to a high of 7.5 percent in 2001.

Table 2-43 - Total day-ahead and balancing operating reserve charges: Calendar years 1999 to 2004

	Day-Ahead Payment	Real-Time Payment	Total Annual Payment	Annual Payment Change	Operating Reserves as a Percent of Total PJM Billing	Day-Ahead $/MWh	Day-Ahead Change	Real-Time $/MWh	Real-Time Change
1999	N/A	$53,588,547	$53,588,547	----	3.0%	N/A	N/A	N/A	N/A
2000	$60,028,266	$86,737,177	$146,765,443	174%	6.5%	$0.34	N/A	$0.53	N/A
2001	$80,165,425	$170,960,879	$251,126,304	71%	7.5%	$0.27	-20%	$1.07	100%
2002	$60,148,379	$128,932,236	$189,080,615	-25%	4.0%	$0.16	-40%	$0.79	-26%
2003	$87,309,127	$186,594,404	$273,903,531	45%	4.0%	$0.23	38%	$1.20	52%
2004	$129,230,218	$249,463,523	$378,693,741	38%	4.4%	$0.23	2%	$1.24	3%

Finally, Table 2-43 shows day-ahead and real-time operating reserve total payments and payments per MWh for each full year after the introduction of the Day-Ahead Energy Market. The day-ahead operating payments are charged to the sum of the day-ahead demand plus accepted decrement bids plus exports. (This is the denominator of the Day-Ahead Energy Market per MWh rates.) The real-time operating payments are charged to the sum of the load, generation and transaction deviations from the Day-Ahead Energy Market. (This is the denominator of the Real-Time Energy Market per MWh rates.) In this context, transaction deviations include deviations that result from cleared virtual bids or offers from the Day-Ahead Energy Market that were not subsequently delivered in the Real-Time Market. The day-ahead operating reserve rate remained unchanged at $0.23 per MWh in 2004 and the real-time operating reserve rate increased $0.04 per MWh, or 3.3 percent, from $1.20 per MWh in 2003 to $1.24 per MWh in 2004.

For each year from 2001 to 2004, total day-ahead and balancing operating reserve payments for the top 10 generating units were compared to the system total. As Table 2-44 shows, in 2001 the top 10 units represented 46.7 percent of total operating reserve payments. For 2002, the percentage dropped to 32.0 percent. For 2003, payments to the top 10 units represented 39.3 percent of total operating reserve payments and for 2004, payments increased to 46.3 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 2004. While in 2003 the top 10 units were owned by four companies, in 2004 the top 10 were owned by three companies. While in 2003 the top generator represented 26.5 percent of the total operating reserves paid, in 2004 the top generator represented 20.4 percent of the total operating reserves.

Table 2-44 - Top 10 operating reserve revenue units (by percent of total system): Calendar years 2001 to 2004

	Percent
2001	46.7%
2002	32.0%
2003	39.3%
2004	46.3%

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 Real-Time Energy 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 reserve 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. The markup is calculated using the formula [(Price – Cost)/Price] at the relevant operating point on the supply curve for each unit. As Table 2-45 shows, the markup for the top 10 units averaged 0.03 in 2001, 0.11 in 2002, 0.17 in 2003 and 0.03 in 2004. The markup for the top 10 units is a weighted average, where the weights are generator output when operating reserves are paid. The markup rose from 2001 through 2003, but declined in 2004. The decreased markup in 2004 resulted from a larger proportion of lower unit-specific markups combined with increased hours during which PJM dispatched the lower markup units out of merit order.

The top firm in 2003 received 68 percent of operating reserve payments made to the top 10 units and had a weighted-average markup of 0.24. The second highest firm in 2003 received 23 percent of operating reserve payments made to the top 10 units and had a weighted-average markup of

0.00 and the third highest firm received 5 percent of operating reserve payments made to the top 10 units and had a weighted-average markup of 0.06. By comparison, in 2004, the top firm received 61 percent of operating reserve payments made to the top 10 units and had a weighted-average markup of 0.12, while the corresponding numbers for the second highest firm were 31 percent of the total top 10 payments with a weighted-average markup of 0.01 and for the third highest firm were 5 percent of the total top 10 payments with a weighted-average markup of 0.00. In 2004, 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, 0.03 in 2003 and 0.03 in 2004. For each year 2001 to 2004, the top 10 units receiving operating reserve payments were either conventional steam or combined-cycle technology generation. As shown in Table 2-45, for 2001, 60 percent of the top 10 units were conventional steam and 40 percent were combined-cycle units. In 2002, 54 percent of the top 10 units were conventional steam and 46 percent were combined cycle, while in 2003 the shares were 50 percent conventional steam and 50 percent combined cycle. In 2004, the shares were 12 percent conventional steam and 88 percent combined cycle. The unit with the highest markup of the top 10 operating reserve units had a markup of 43 percent for 2001, 42 percent for 2002, 47 percent for 2003 and 43 percent for 2004.

Table 2-45 - Top 10 operating reserve revenue units' markup: Calendar years 2001 to 2004

	Top Units' Markup	Steam Percent of Top 10	Steam Markup	Combined Cycle Percent of Top 10	Combined Cycle Markup
2001	0.03	60%	0.02	40%	0.07
2002	0.11	54%	0.08	46%	0.20
2003	0.17	50%	0.19	50%	0.11
2004	0.03	12%	0.00	88%	0.05

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, has a 24-hour minimum run time and a minimum shutdown time or a long start time, then it receives higher operating reserve payments than if those operating parameters were not in place. Restrictive operating parameters can also 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, startup and no-load offers. 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.

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.[78]

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, prices are directly related to the marginal cost of the most expensive 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 significant price spikes in PJM have been directly related to scarcity conditions. In PJM, prices tend to increase as the market approaches scarcity conditions as a result of generator offers and the associated shape of the aggregate supply curve. The pattern of prices within days and across months and years illustrates how prices are directly related to demand conditions and thus also illustrates the potential significance of price elasticity of demand in affecting price.

The PJM system load and LMP reflect the configuration of the entire RTO. Thus, during Phases 2 and 3 of calendar year 2004, load and LMP reflect the integration of new PJM control zones.

Real-Time Energy Market Prices

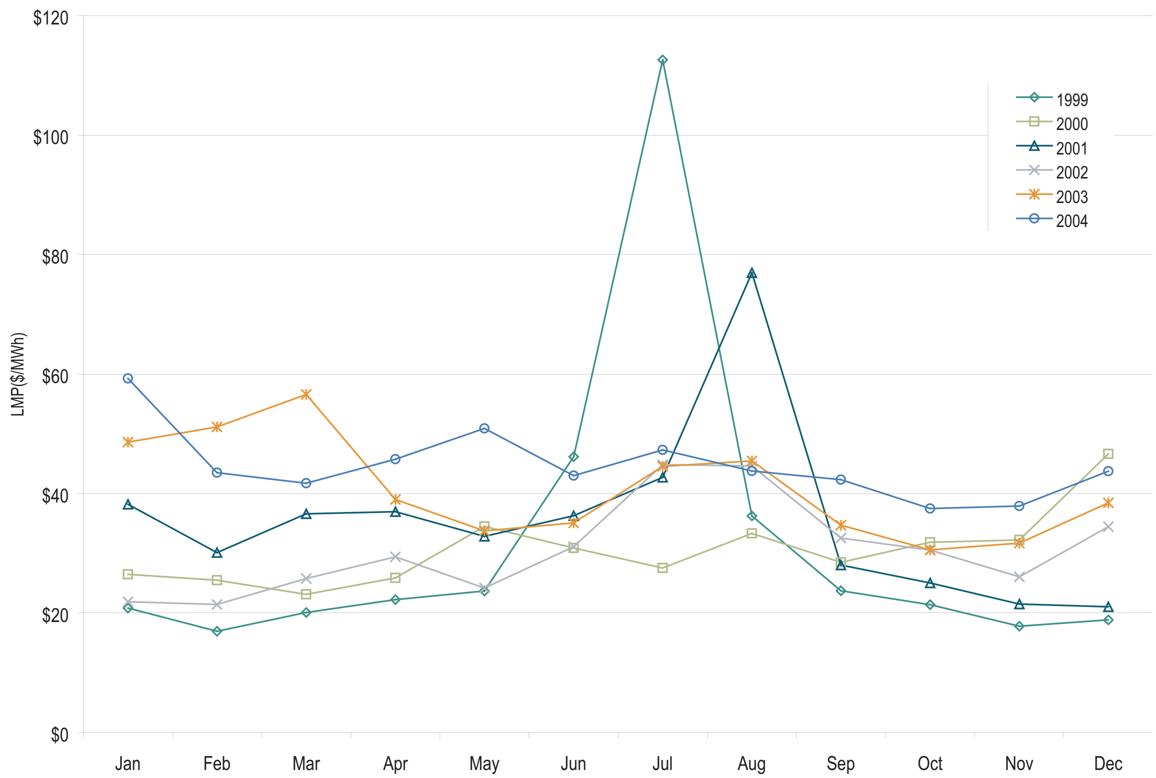
PJM real-time energy market prices increased in 2004. The simple hourly average system LMP[79] was 10.8 percent higher in calendar year 2004 than in 2003, $42.40 per MWh versus $38.27 per MWh. The simple average LMP in 2004 was higher than in all previous years since the introduction of markets in PJM. When hourly load levels are reflected, the hourly load-weighted 2004 average system LMP was 7.5 percent higher than it had been in 2003, $44.34 per MWh versus $41.23 per MWh. In 2004, the highest load levels occurred in the last quarter when LMP was relatively low while in 2003 the highest load levels occurred in the summer when LMP was relatively high. The last quarter of 2004 had approximately 79 percent more load than in 2003 as a result of the integrations of ComEd, AEP and DAY.

When increased fuel costs are accounted for, the fuel-cost-adjusted, load-weighted, average LMP in 2004 was 4.2 percent lower than in 2003, $39.49 per MWh compared to $41.23 per MWh. If fuel prices for the year 2004 had been the same as in 2003, the 2004 load-weighted LMP would have been $39.49 per MWh instead of $44.34 per MWh. This means that, if it had not been for fuel cost increases, LMP would have been lower in 2004 than in 2003.

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

During each month but February, March and August the 2004 real-time PJM system LMP was greater than it had been during 2003. Several factors affect LMP, including fuel prices and load. Natural gas and oil prices were lower during February and March than they had been during 2003, while all other months experienced higher natural gas and oil costs. Despite these higher fuel costs, PJM system LMP was lower in August because milder weather as measured by the temperature humidity index (THI) meant smaller loads.

Figure 2-15 - Monthly load-weighted, average LMP: Calendar years 1999 to 2004



Two principal factors contributed to higher overall LMP for 2004 and for these nine months in particular:

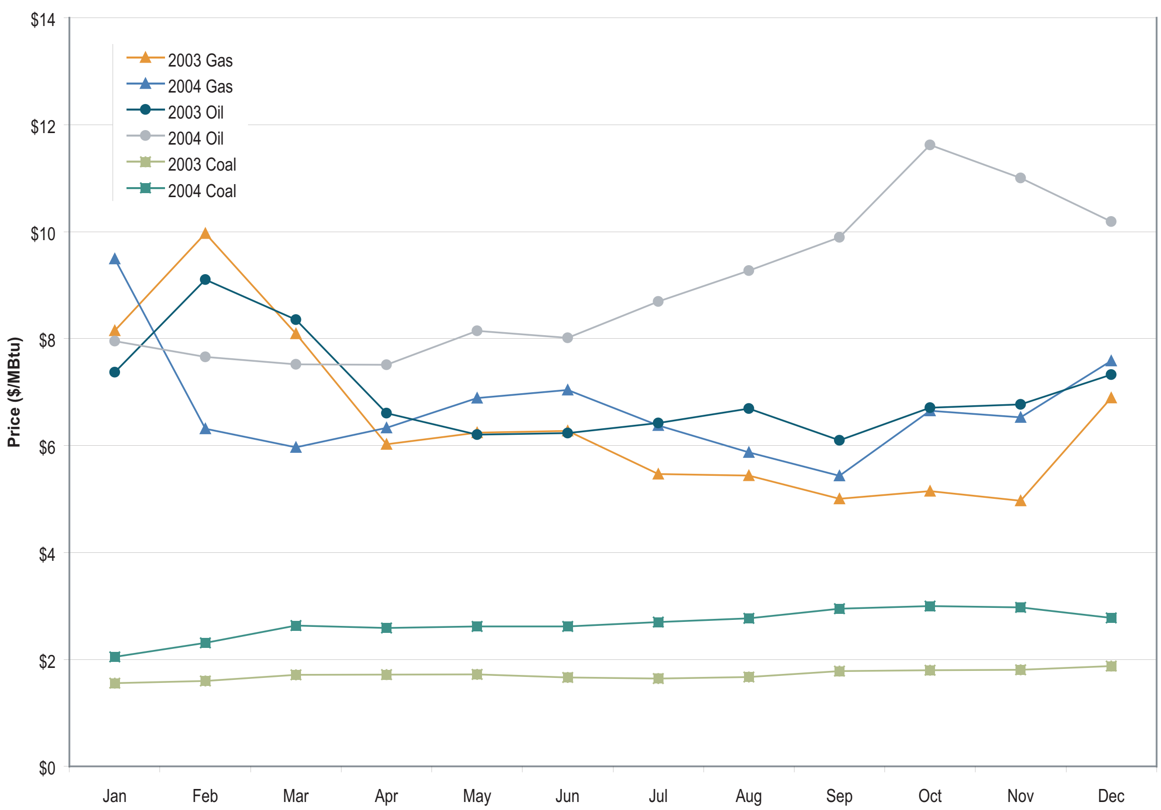
- **Fuel Prices.** Higher natural gas, oil and coal prices were a significant source of upward pressure on LMP in 2004. Figure 2-15 shows the PJM system monthly load-weighted LMP from 1999 through 2004. Figure 2-16 shows average, daily delivered natural gas, oil and coal prices for units within PJM.[80] Higher fuel costs affect LMP when units burning those fuels are on the margin and thus setting price.

- **Demand.** On average, PJM load increased in 2004 by 33.6 percent over the 2003 load. Figure 2-17 shows the extent to which the system load increase was the result of the integration of ComEd, AEP and DAY Control Zones. Figure 2-17 compares the system load with and without

80 Natural gas prices are the average of the daily cash price for Transco, Z6, non-New York and Texas Eastern, M-3 and adjusted for transportation to the burner tip. Oil prices are the daily price for No. 2 from the New York Harbor Spot Barge and adjusted for transportation. Coal prices are the average price for 1.5 and 2.0 pound sulfur content per MBtu Central Appalachian coal for prompt rail delivery from Energy Argus and adjusted for transportation.

the integrations. Figure 2-17 shows that the 2004 PJM load, even without the integrations, was slightly greater than it had been in 2003 by about 2.0 percent annually although the difference varies by month. The pattern of monthly load differences is largely a function of weather conditions. As Table 2-45 shows, while the maximum THI for May was higher in 2004 than in 2003, the reverse was true for June, July and August.[81]

Figure 2-16 - Spot fuel price comparison: Calendar years 2003 to 2004



81 Philadelphia temperature and relative humidity data were used to calculate THI and were obtained from Meteorlogix. See Appendix H, "Glossary," for THI definition.

Figure 2-17 - PJM average load: Calendar years 2003 to 2004

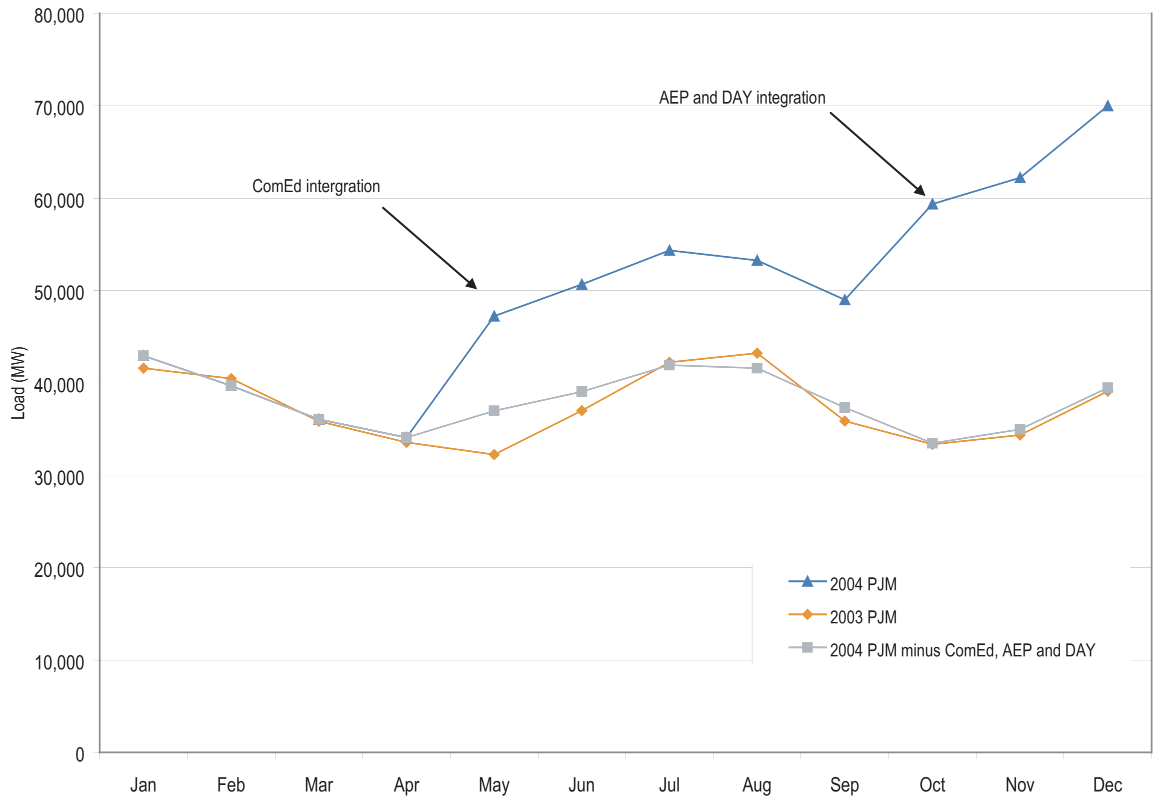


Table 2-46 - Average maximum temperature-humidity index (THI) comparison: May to September, 2003 and 2004

	2003	2004	Average Difference
May	65.24	72.62	7.38
Jun	73.67	73.42	-0.25
Jul	78.77	76.39	-2.38
Aug	79.07	75.86	-3.21
Sep	73.04	72.97	-0.07

Average Hourly, Unweighted System LMP

At $42.40 per MWh, the average hourly, unweighted system LMP for 2004 was 10.8 percent higher than for 2003. (See Table 2-47.)[82]

Table 2-47 - PJM average hourly LMP (Dollars per MWh): Calendar years 1998 to 2004[83]

	Locational Marginal Prices (LMPs)			Year-to-Year Changes		
	Average	Median	Standard Deviation	Average LMP	Median LMP	Standard Deviation
1998	$21.72	$16.60	$31.45	N/A	N/A	N/A
1999	$28.32	$17.88	$72.42	30.4%	7.7%	130.3%
2000	$28.14	$19.11	$25.69	-0.6%	6.9%	-64.5%
2001	$32.38	$22.98	$45.03	15.1%	20.3%	75.3%
2002	$28.30	$21.08	$22.40	-12.6%	-8.3%	-50.3%
2003	$38.27	$30.79	$24.71	35.2%	46.0%	10.3%
2004	$42.40	$38.30	$21.12	10.8%	24.4%	-14.5%

Price Duration

For 2004, PJM system prices exceeded $150 per MWh for only five hours, with the maximum LMP of $180.12 per MWh occurring on December 20 during the hour ending 0900 EPT.[84]

Prices reflect the interaction of demand, in the form of energy bids and supply, in the form of energy offers. In 2004, the additional capacity provided by the integrations of the ComEd, AEP and DAY Control Zones plus the addition of net new capacity in the rest of PJM shifted the aggregate supply curve to the right. The shape and location of the aggregate supply curve combined with the moderate levels of demand meant that there were no hours when scarcity conditions existed in 2004.

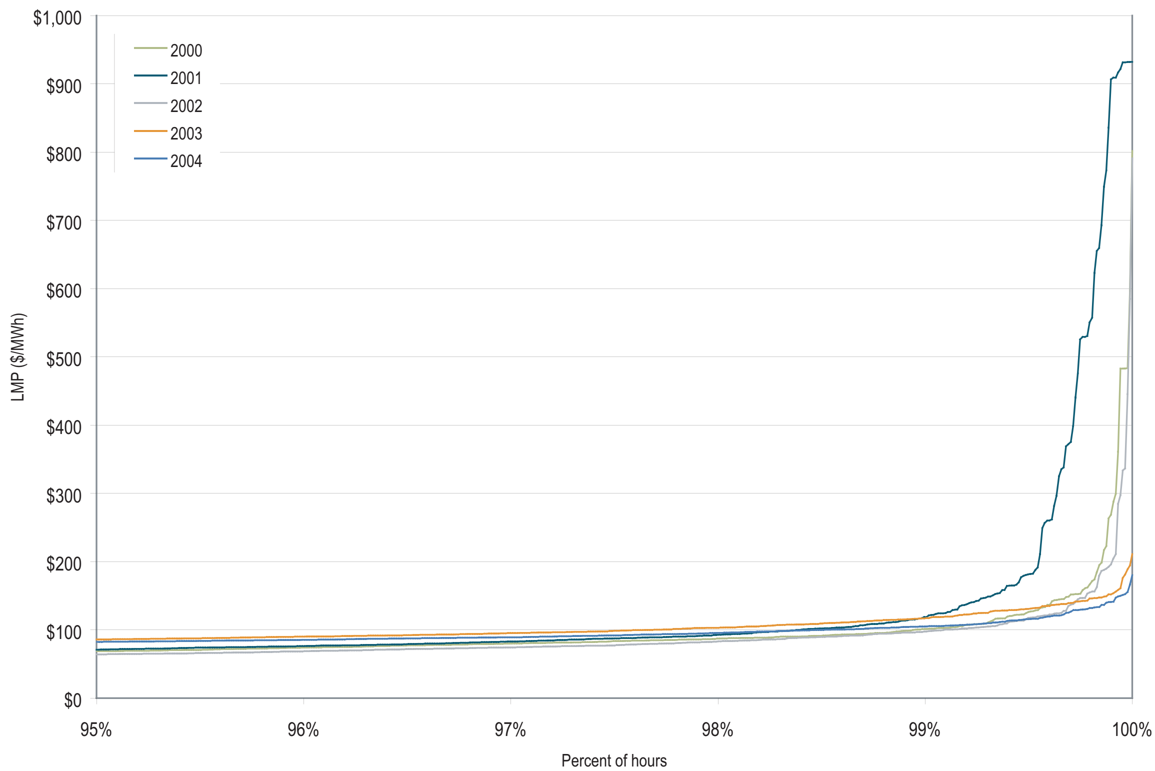
A price duration curve shows the percent of hours when LMP is at, or below, a given price for the year. Figure 2-18 presents price duration curves for hours above the 95th percentile from 2000 to 2004. Prices in this range occurred for 5 percent or less of the total hours in each year. Figure 2-18 shows that since 2000, prices have generally exceeded $100 per MWh for less than 2 percent of the hours. In the year 2000, prices exceeded $100 per MWh for 1.1 percent of the hours, in 2001 for 1.6 percent of the hours, in 2002 for 0.9 percent of the hours, in 2003 for 2.3 percent of the hours and in 2004 for 1.5 percent of the hours.

Figure 2-18 shows that LMP exceeded $900 per MWh in 2001. In 2001, prices rose to more than $900 per MWh for 10 hours during the week of August 6. Prices in 2002 exceeded $700 per MWh for only one hour, but exceeded $150 per MWh for 20 hours. Prices in 2003 exceeded $200 per MWh for only one hour, but exceeded $150 per MWh for a total of 11 hours. Prices in 2004 exceeded $150 per MWh for only five hours and exceeded $120 per MWh for a total of 35 hours.

82 Hourly statistics were calculated from hourly integrated, PJM system LMPs and market-clearing prices (MCPs) for January to March 1998. MCP is the single market-clearing price calculated by PJM prior to implementation of LMP.
83 In the 2003 State of The Market Report the 1999 standard deviation was reported as $75.41, but was $75.42, and the 2001 standard deviation was reported as $45.30, but was $45.03.
84 See Appendix C, "Energy Market," and Figure C-7.

Above the 95th percentile, the price duration curve was lower in 2004 than in 2003. Although average LMP for PJM was greater in 2004 than in 2003, the top 5 percent of prices in 2003 exceeded the top 5 percent of prices in 2004.

Figure 2-18 - Price duration curves for the PJM Real-Time Energy Market during hours above the 95th Percentile: Calendar years 2000 to 2004



Load

Table 2-48 presents summary load statistics for the seven-year period 1998 to 2004. The average load of 49,963 MW in 2004 was 33.6 percent higher than in 2003, reflecting the integrations of the ComEd, AEP and DAY Control Zones.

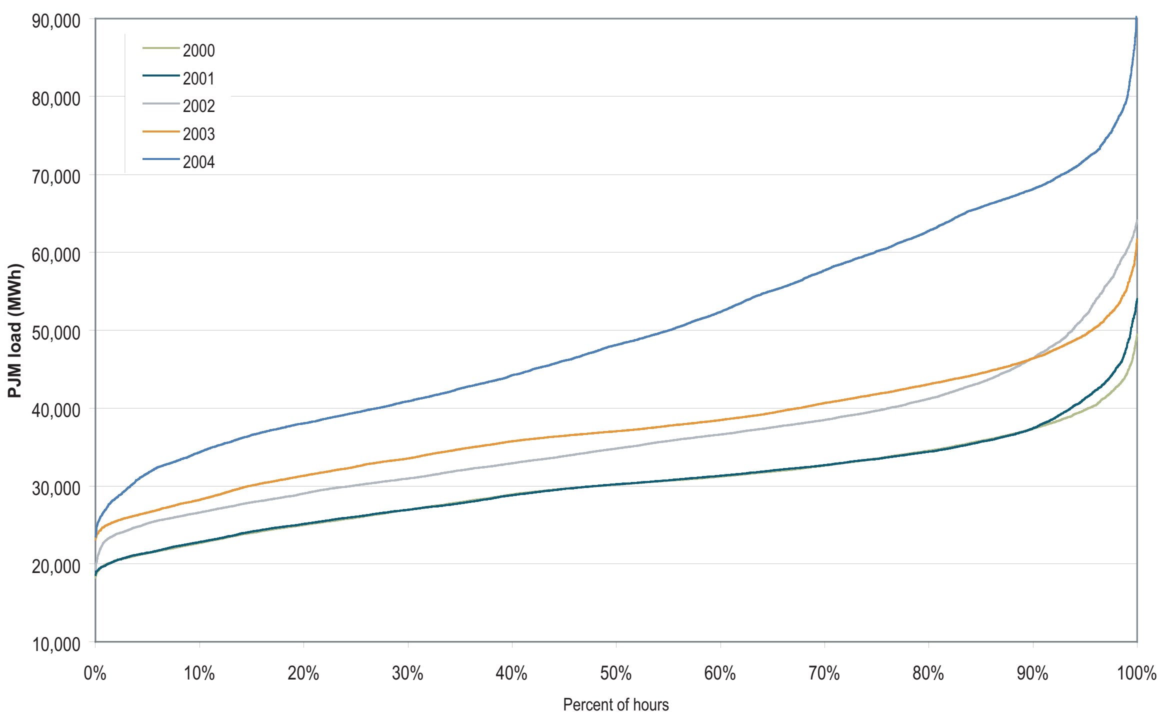
Table 2-48 - PJM average load: Calendar years 1998 to 2004[85]

	PJM Load (MWh)			Year-to-Year Changes		
	Average	Median	Standard Deviation	Average Load	Median Load	Standard Deviation
1998	28,577	28,653	5,512	N/A	N/A	N/A
1999	29,640	29,341	5,956	3.7%	2.4%	8.1%
2000	30,113	30,170	5,529	1.6%	2.8%	-7.2%
2001	30,297	30,219	5,873	0.6%	0.2%	6.2%
2002	35,797	34,804	7,964	18.2%	15.2%	35.6%
2003	37,395	37,029	6,834	4.5%	6.4%	-14.2%
2004	49,963	48,103	13,004	33.6%	29.9%	90.3%

Load Duration

Figure 2-19 shows load duration curves from 2000 through 2004. A load duration curve shows the percent of hours that load was at, or below, a given level for the year. The 2004 load duration curve reflects the integrations of the ComEd, AEP and DAY Control Zones.

Figure 2-19 - PJM hourly load duration curves: Calendar years 2000 to 2004



85 In the 2003 State of The Market Report, the mean, median and standard deviation values for 2002 were reported as 35,551, 34,596 and 7,942, respectively, but were 35,797, 34,804 and 7,964.

Load-Weighted LMP

Market participants typically purchase more energy during high-priced periods because higher demand generally results in higher prices, all else constant. As a result, load-weighted average prices are generally higher than simple average prices. However, in 2004 the highest loads occurred in the last quarter of the year, when LMP was relatively low, due to the combined effect of the integrations while in 2003 the highest load levels occurred in the summer when prices were relatively high. As a result, when hourly prices are weighted by hourly load levels, the increase from 2003 to 2004 in the hourly load-weighted, average LMP was only 7.5 percent while the simple average LMP increased by 10.8 percent.

Load-weighted LMP reflects the average LMP paid for actual MWh generated and consumed during a year. Load-weighted LMP is the average of PJM hourly LMPs, each weighted by the PJM total hourly load.

As Table 2-49 shows, 2004 load-weighted LMP rose to $44.34 per MWh, 7.5 percent higher than it had been in 2003, 40.4 percent higher than in 2002 and 21.0 percent higher than in 2001.[86]

Table 2-49 - PJM load-weighted, average LMP (Dollars per MWh): Calendar years 1998 to 2004

	Load-Weighted Average LMP			Year-to-Year Changes		
	Average	Median	Standard Deviation	Average LMP	Median LMP	Standard Deviation
1998	$24.16	$17.60	$39.29	N/A	N/A	N/A
1999	$34.07	$19.02	$91.49	41.0%	8.1%	132.8%
2000	$30.72	$20.51	$28.38	-9.8%	7.9%	-69.0%
2001	$36.66	$25.08	$57.26	19.3%	22.3%	101.8%
2002	$31.58	$23.40	$26.73	-13.9%	-6.7%	-53.3%
2003	$41.23	$34.95	$25.40	30.6%	49.4%	-5.0%
2004	$44.34	$40.16	$21.25	7.5%	14.9%	-16.3%

Fuel Cost and Price

Changes in LMP can result from changes in unit costs. The impact of fuel costs on LMP depends on the fuel burned by marginal units, the units setting LMP. Fuel costs make up between 80 and 90 percent of marginal costs depending on generating technology. To account for differences in fuel cost between the years 2003 and 2004, the 2004 load-weighted LMP was adjusted to reflect the change in price of fuels used by the marginal units and the change in marginal MWh generated by each fuel type.[87]

Spot prices were used for the gas and oil fuel prices. Estimated adders for NO_x emissions credit costs based on the spot price of NO_x emission credits were included in the unit-specific offers of gas and oil-fired units during the May through September ozone season. Coal prices were calculated based on unit-specific cost-based offers. The coal prices also include adders for NO_x emissions credit costs during ozone season. The calculated 2004 coal costs increased 22 percent over 2003.

86 See Appendix C, "Energy Market," for on-peak and off-peak, load-weighted LMP details.
87 See Appendix C, "Energy Market," for fuel-cost adjustment method.

Table 2-50 compares the 2004 fuel-cost-adjusted, load-weighted, average LMP to the 2003 load-weighted, average LMP. After adjustment for fuel price changes, load-weighted, average LMP in 2004 was 4.2 percent lower than in 2003. If fuel prices for the year 2004 had been the same as in 2003, the 2004 load-weighted LMP would have been $39.49 per MWh instead of $44.34 per MWh.[88] If it had not been for fuel price increases, LMP would have been lower in 2004 than in 2003. The fact that higher fuel prices were reflected in higher energy market prices is consistent with the functioning of a competitive market.

Table 2-50 - PJM fuel-cost-adjusted, load-weighted LMP (Dollars per MWh): Calendar years 2003 to 2004

	2003	2004	Change
Average LMP	$41.23	$39.49	-4.2%
Median LMP	$34.95	$34.47	-1.4%
Standard Deviation	$25.40	$20.81	-18.1%

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 Table 2-51, Figure 2-21 and Figure 2-22 show, day-ahead and real-time prices have converged. PJM average day-ahead prices were lower than real-time prices by $0.97 per MWh during 2004. This is the first time since the introduction of the PJM Day-Ahead Energy Market that day-ahead prices have been lower than real-time prices on average for a full year. The relationship between day-ahead and real-time prices changes from hour to hour in every year. On average, day-ahead prices were higher than real-time prices by $0.45 per MWh in 2003, by $0.12 per MWh in 2002, by $0.37 per MWh in 2001 and by $1.61 per MWh in 2000.

In 2004 during Phase 1, day-ahead prices in PJM were $0.72 per MWh lower than real-time prices. During Phase 2, day-ahead prices in PJM were $1.61 per MWh lower than real-time prices. By contrast, in the ComEd Control Area during Phase 2, day-ahead prices were greater than real-time prices by $0.83 per MWh. During Phase 3, day-ahead prices were lower than real-time prices by $0.24 per MWh. In the AEP Control Zone during Phase 3, day-ahead prices were greater than real-time prices by $1.23 per MWh.

88 If the calculation of the 2004 fuel-cost-adjusted, load-weighted average LMP used spot coal prices rather than coal prices based on unit-specific cost-based offers, then the 2004 fuel-cost-adjusted, load-weighted average LMP would be $36.35 per MWh rather than $39.49 per MWh and, after adjustment for these modified fuel price changes, load-weighted, average LMP in 2004 would 11.8 percent lower than in 2003.

Figure 2-20 shows 2004 day-ahead and real-time price duration curves. Day-ahead prices were slightly but consistently lower on average than real-time prices.

Figure 2-20 - PJM price duration curves for the Real-Time and Day-Ahead Energy Markets: Calendar year 2004

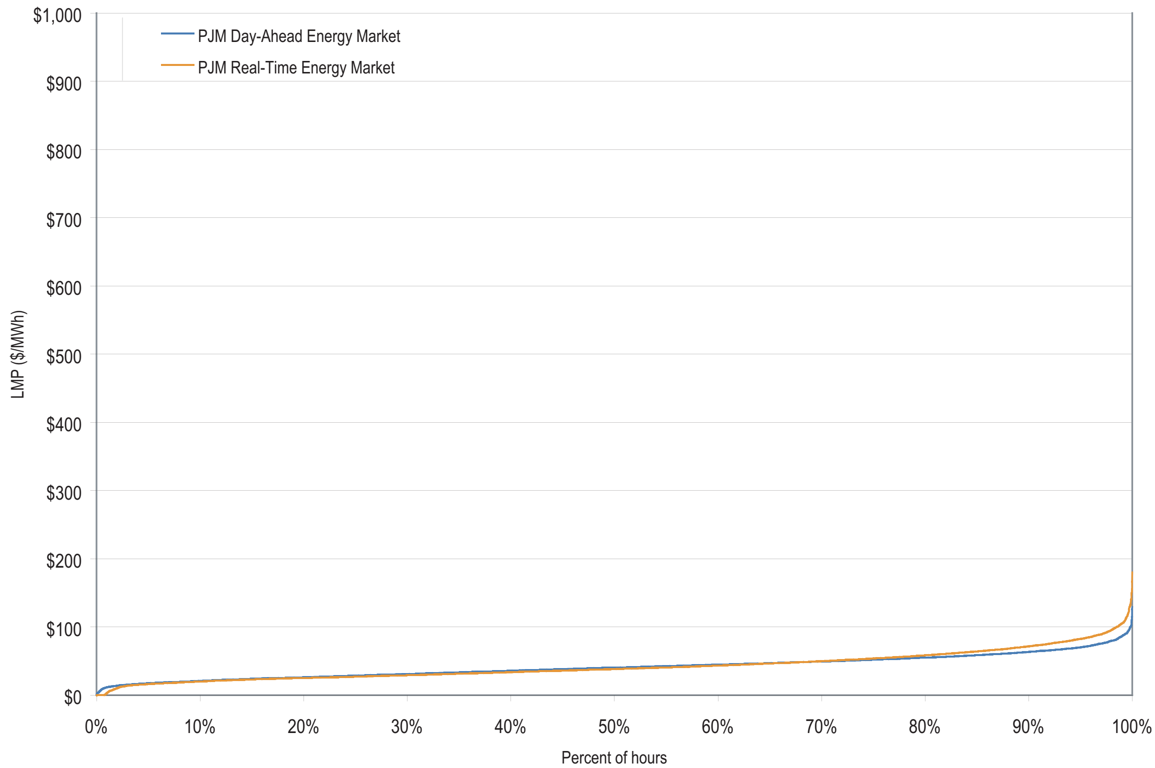


Figure 2-21 shows the hourly differences between day-ahead and real-time LMP in 2004. Although the average difference between the Day-Ahead and Real-Time Energy Markets was $0.97 per MWh for the entire year, Figure 2-21 shows considerable variation, both positive and negative, between day-ahead and real-time prices. Figure 2-22 shows that average day-ahead and real-time LMPs were very close on an hourly basis, but that average real-time LMP was greater than average day-ahead LMP for 20 out of 24 hours.[89]

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

Figure 2-21 - Hourly real-time minus day-ahead average LMP: Calendar year 2004

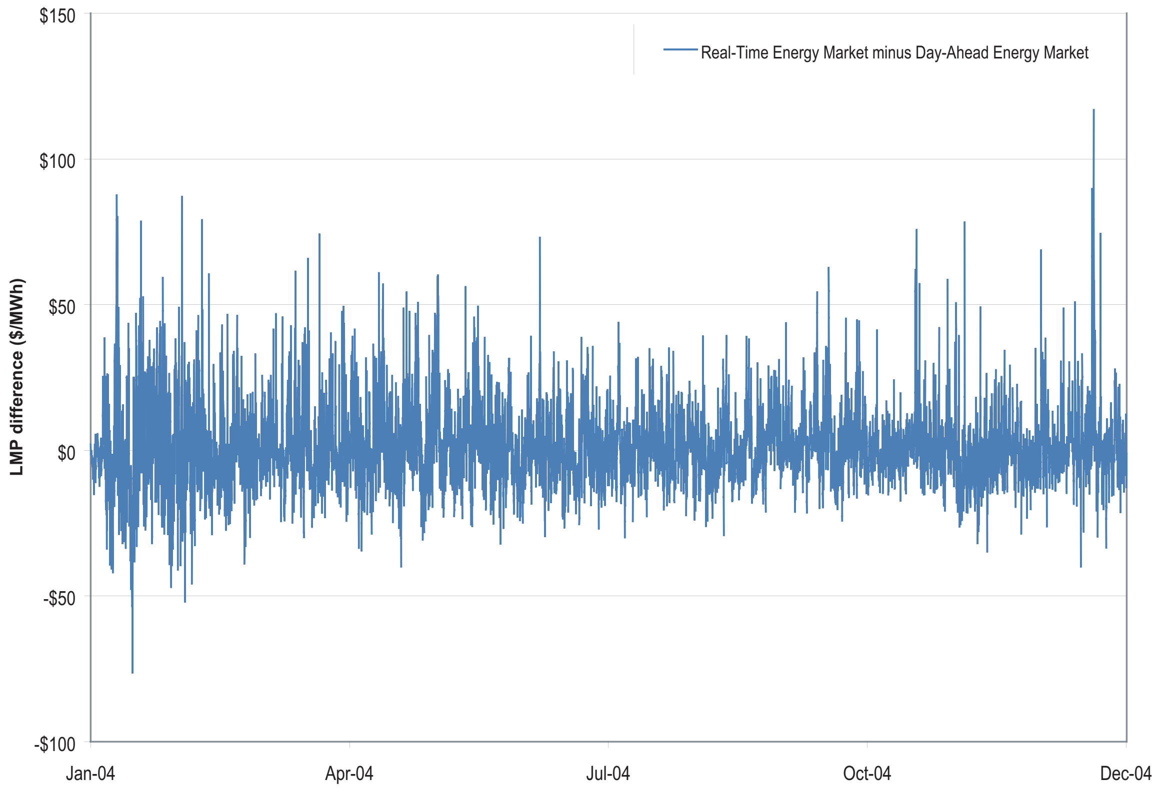


Figure 2-22 - PJM hourly system average LMP: Calendar year 2004

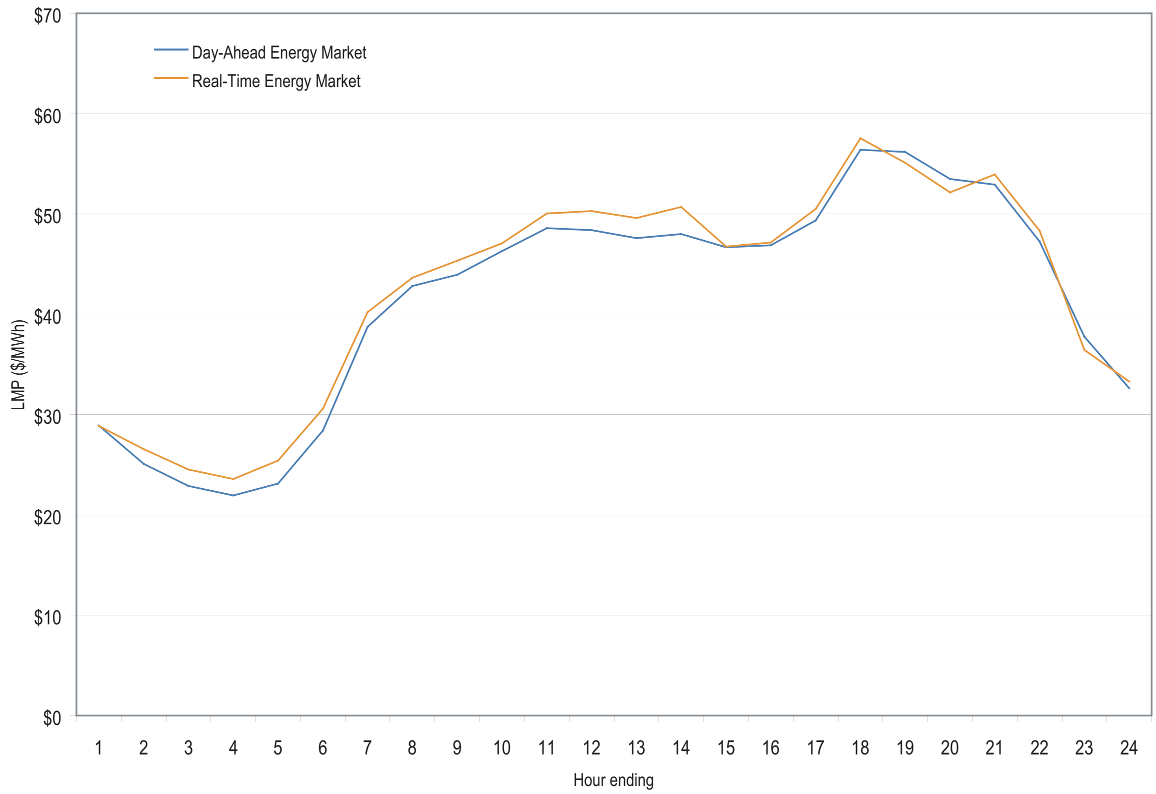


Table 2-51 presents summary statistics for the two markets. During 2004, average LMP in the Real-Time Energy Market was $0.97 per MWh or 2.3 percent higher than average LMP in the Day-Ahead Energy Market. The real-time median LMP was 5.4 percent lower than day-ahead LMP, reflecting an average difference of $2.06 per MWh. Consistent with the price duration curve, price dispersion in the Real-Time Energy Market was 21.4 percent greater than in the Day-Ahead Energy Market, with an average difference in standard deviation between the two markets of $4.53 per MWh.

Table 2-51 - Real-Time and Day-Ahead Energy Market LMP (Dollars per MWh): Calendar year 2004

	Day Ahead	Real Time	Difference	Difference as Percent Real Time
Average LMP	$41.43	$42.40	$0.97	2.3%
Median LMP	$40.36	$38.30	-$2.06	-5.4%
Standard Deviation	$16.60	$21.12	$4.53	21.4%

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,[90] three types of financially binding generation offers are made and cleared:

- **Self-Scheduled.** Offer to supply a fixed block of MW that must run from a specific unit, or as a minimum amount of MW that must run on a specific unit that also has a dispatchable component above the minimum.[91]

- **Generator Offer.** Offer to supply a schedule of MW from a specific unit and the corresponding offer prices.

- **Increment Offer.** Financial offer to supply specified MW at, or above, a given price. An increment offer is a financial offer that can be submitted by any market participant.

90 All references to day-ahead generation and increment offers are presented in cleared MW in the "Day-Ahead and Real-Time Generation" portion of Section 2, "Energy Market."
91 The definition of self-scheduled is based on documentation contained within the "PJM eMKT Users' Guide," pp. 89-93.

Figure 2-23 shows average hourly values of day-ahead generation, day-ahead generation plus increment offers and real-time generation for 2004. Day-ahead generation is all the self-scheduled and generator offers cleared in the Day-Ahead Energy Market. During 2004, 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 always exceeded real-time generation.

Figure 2-23 - Real-time and day-ahead generation (Average hourly values): Calendar year 2004

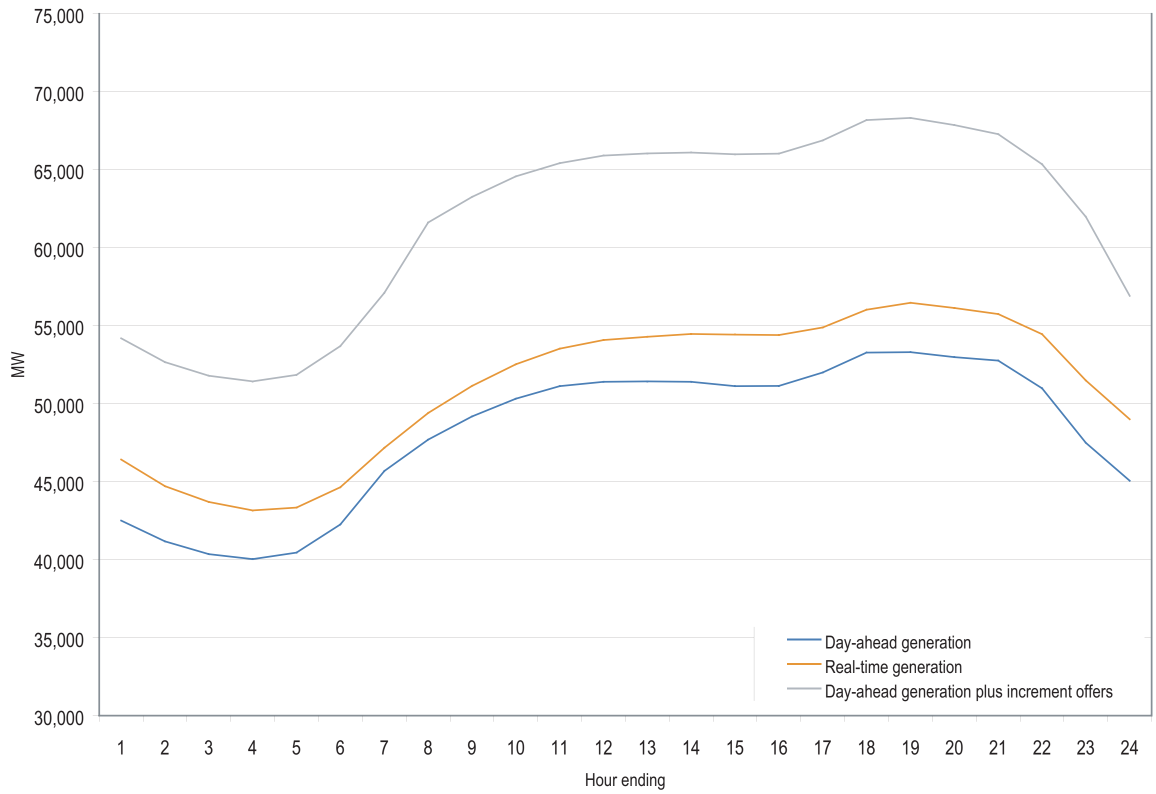


Table 2-52 presents summary statistics for 2004 day-ahead and real-time generation and the average differences between them. Day-ahead generation averaged 2,937 MWh less than real-time generation. Day-ahead generation offers plus cleared increment (INC) offers were 10,619 MWh higher than real-time generation, on average.

Table 2-52 - Real-time and day-ahead generation (MWh): Calendar year 2004

	Day Ahead			Real Time	Average Difference	
	Generation	Cleared INC Offers	Generation plus Cleared INC Offers	Generation	Generation	Generation plus Cleared INC Offers
Average MWh	48,131	13,555	61,687	51,068	-2,937	10,619
Median MWh	46,519	12,858	59,306	50,096	-3,577	9,210
Standard Deviation	13,249	3,934	16,791	13,790	-542	3,000

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

Figure 2-24 shows the average 2004 hourly values of total day-ahead load, total fixed-demand bids, total price-sensitive bids, total decrement bids and total real-time load (total day-ahead load is the sum of the three types of demand bids).

Figure 2-24 - Real-time and day-ahead loads (Average hourly values): Calendar year 2004

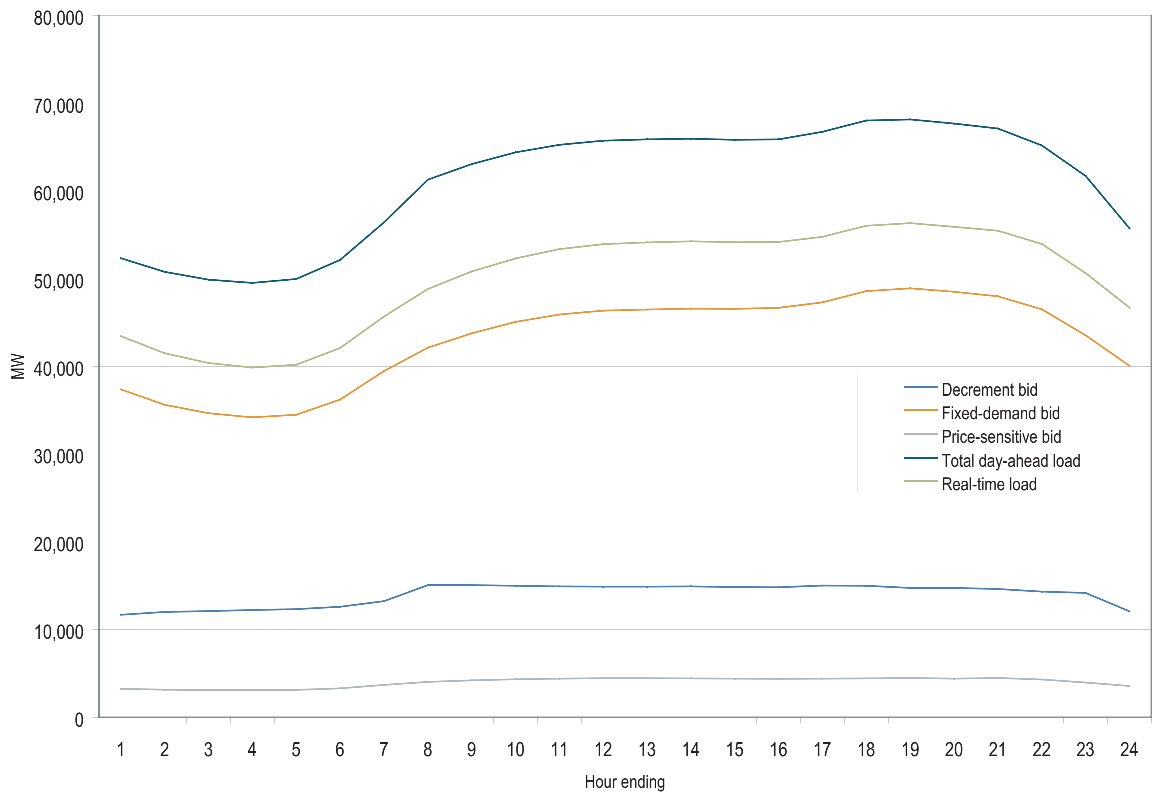


Table 2-53 presents 2004 summary statistics for day-ahead load components, total day-ahead load, real-time load and the difference between total day-ahead load and total real-time load.

As Figure 2-24 and Table 2-53 show, during 2004 total day-ahead load was higher than real-time load by an average of 11,071 MWh. The table also shows that, at 70.5 percent, fixed demand was the largest component of day-ahead load. At 6.6 percent, price-sensitive load was the smallest component, with cleared decrement bids accounting for the remaining 22.9 percent of day-ahead load.

Table 2-53 - Real-time and day-ahead load (MWh): Calendar year 2004

	Day Ahead				Real Time	
	Fixed Demand	Price Sensitive	Cleared DEC Bid	Total Load	Total Load	Difference
Average MWh	43,046	4,004	13,983	61,034	49,963	11,071
Median MWh	41,397	3,875	13,593	58,544	48,103	10,442
Standard Deviation	11,985	985	4,096	16,320	13,004	3,316

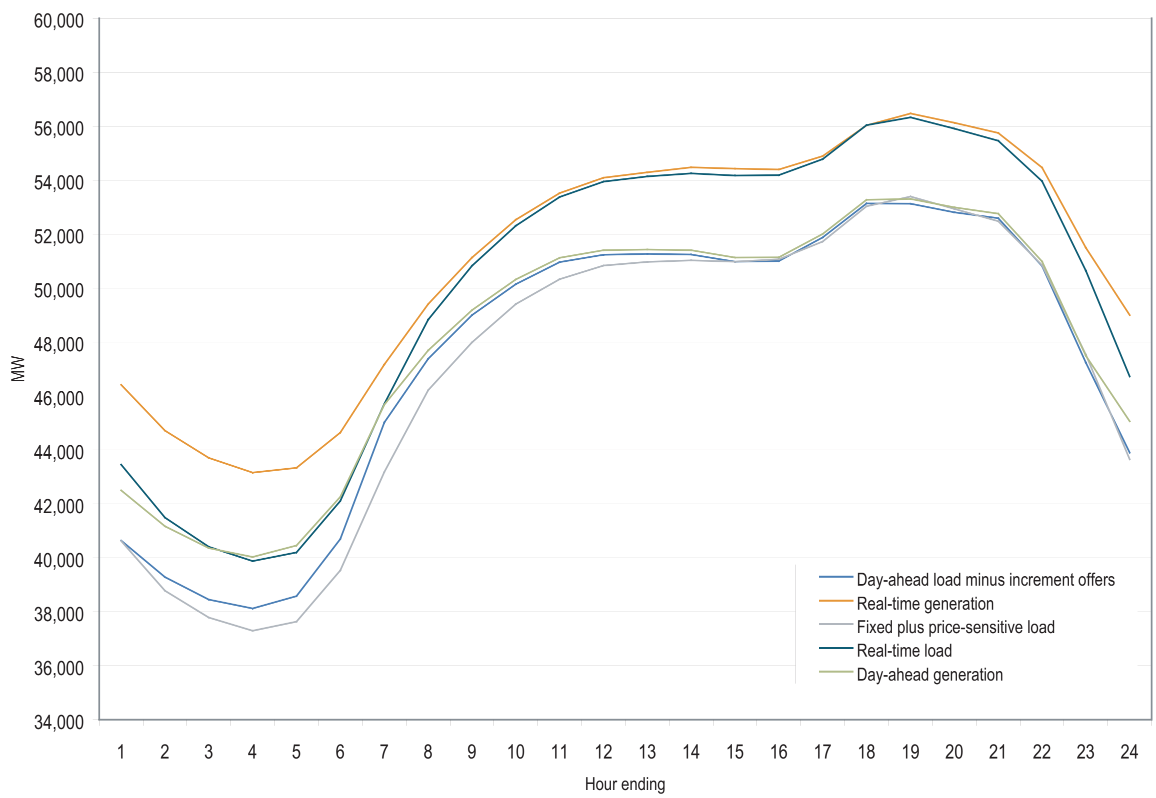
As Figure 2-24 shows, day-ahead load components increased during on-peak hours (i.e., hours ending 0800 to 2300 EPT) as did real-time load. Table 2-54 shows the average load MWh values in the Day-Ahead and Real-Time Energy Markets for 2004 during off-peak and on-peak hours. During 2004, real-time load was always higher than fixed-demand load plus price-sensitive load in the Day-Ahead Energy Market. If, however, decrement bids are included, then the day-ahead load always exceeded real-time load, and total day-ahead load was higher than real-time load during both off-peak and on-peak hours. The average difference during off-peak hours was 10,205 MWh, while the average difference during on-peak hours was 12,055 MWh. The percentage of day-ahead load represented by each of the components was different during off-peak as compared to during on-peak periods. Fixed demand accounted for the largest percentage of day-ahead load at approximately 70 percent and 71 percent during the off-peak and on-peak periods, respectively. Price-sensitive load accounted for the smallest percentage of day-ahead load at approximately 6 percent and 7 percent during the off-peak and on-peak periods, respectively. Cleared decrement bids accounted for 23 percent and 22 percent for the off-peak and on-peak periods, respectively.

Table 2-54 - Day-ahead loads during on-peak and off-peak hours (MWh): Calendar year 2004

	Day Ahead								Real Time	
	Off Peak				On Peak				Off Peak	On Peak
	Fixed Demand	Price Sensitive	DEC Bid	Total Load	Fixed Demand	Price Sensitive	DEC Bid	Total Load	Total Load	Total Load
Average MW	38,470	3,497	12,869	54,836	48,246	4,581	15,248	68,075	44,631	56,020
Median MW	36,829	3,408	12,712	52,644	48,814	4,465	15,967	69,792	43,028	56,578
Standard deviation	10,064	769	3,513	13,540	11,872	881	4,337	16,355	10,845	12,595

Figure 2-25 shows day-ahead and real-time load and generation for 2004. For this analysis, increment offers were subtracted from total day-ahead load. The total day-ahead load is the sum of the fixed-demand bids, price-sensitive bids and the decrement bids. The subtraction of increment offers from day-ahead load equals the day-ahead generation that would have had to be turned on to meet the load.

Figure 2-25 - Real-time and day-ahead load and generation (Average hourly values): Calendar year 2004



Conclusion

PJM average day-ahead prices were lower than real-time prices by $0.97 per MWh during 2004. This is the first time since the introduction of the PJM Day-Ahead Energy Market that day-ahead prices were lower than real-time prices on average for a full year. A small variance between day-ahead and real-time prices is consistent with the functioning of a competitive market.

The simple average hourly system LMP was 10.8 percent higher in 2004 than in 2003. The hourly load-weighted average system LMP was 7.5 percent higher in 2004 than it had been in 2003. The fuel-cost-adjusted, load-weighted, average system LMP was 4.2 percent lower in 2004 than in 2003. If it had not been for fuel cost increases, LMP would have been lower in 2004 than in 2003. The fact that higher fuel prices were reflected in higher energy market prices is consistent with the functioning of a competitive market.