2004 State of the Market

Market Monitoring Unit

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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."

TABLE OF CONTENTS

Table of Contents

FIGURES

INTRODUCTION 19

SECTION 2 - ENERGY MARKET 45

SECTION 5 - ANCILLARY SERVICE MARKETS 177

SECTION 6 - CONGESTION 201

TABLES

SECTION 2 - ENERGY MARKET 45

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.

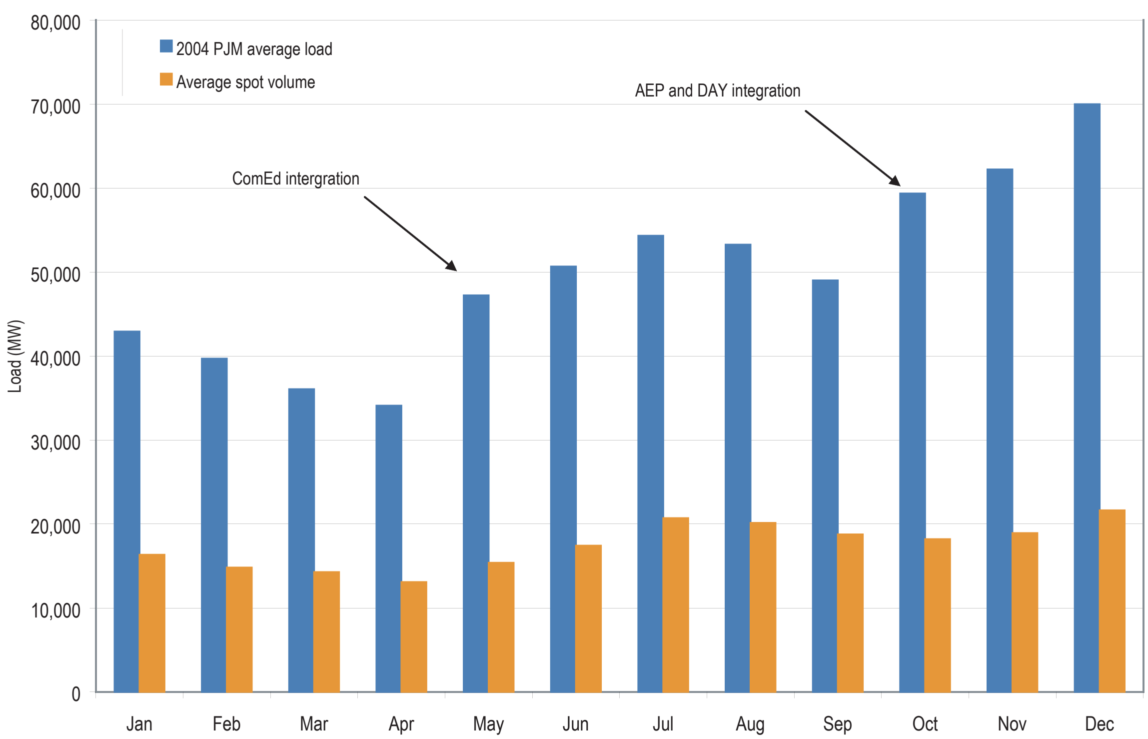
The PJM Energy Market comprises all types of energy transactions, including the sale or purchase of energy in PJM's Day-Ahead and Real-Time Energy Markets, bilateral and forward markets and self-supply. Energy transactions analyzed in this report include those in the PJM Day-Ahead and Real-Time Energy 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.

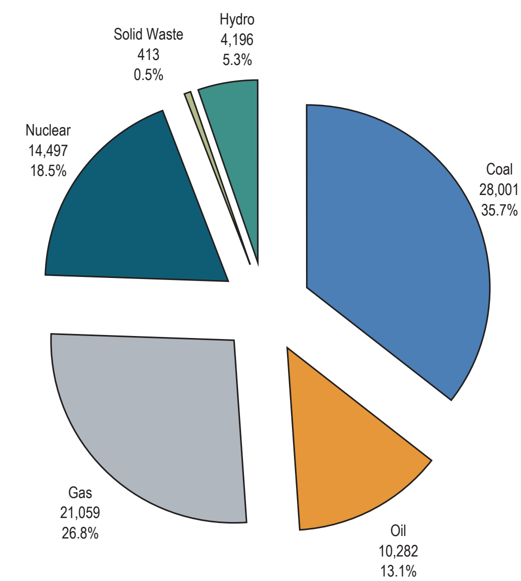
44 See Section 6, "Congestion," at Table 6-2.
45 See Section 6, "Congestion," for a more complete discussion of FTR revenue adequacy.

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

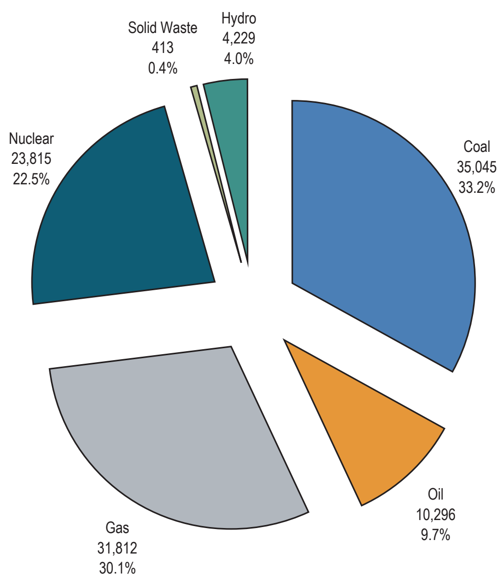


During Phase 1, unit retirements, ratings changes and changes in capacity imports and exports resulted in an installed capacity decrease of approximately 600 MW. On May 31, 2005, installed capacity was 77,800 MW.

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.

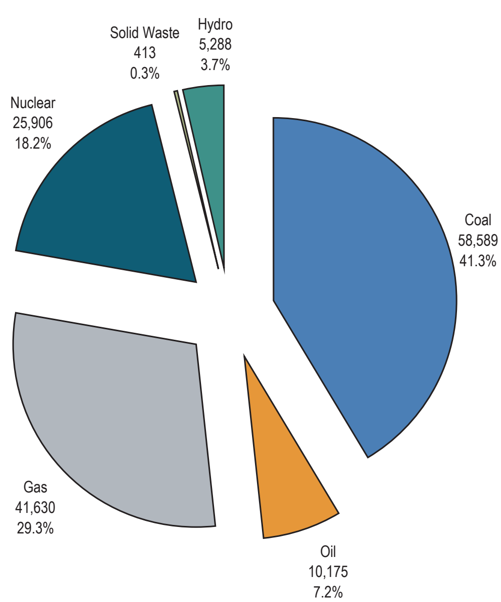
Figure 1-3 - PJM capacity by fuel source: At June 1, 2004



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.

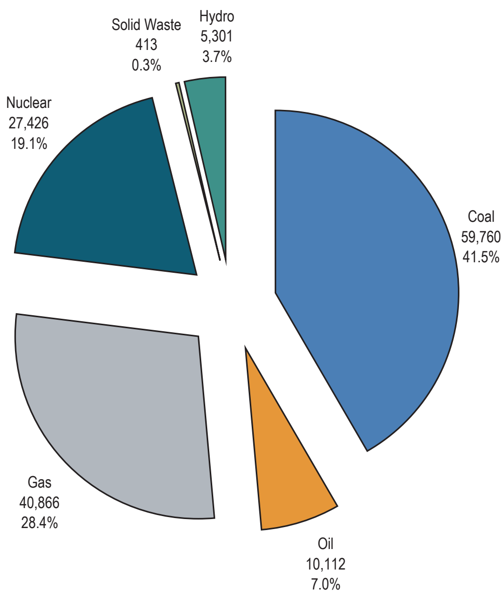
With the integration of the AEP and DAY Control Zones on October 1, 2004, installed capacity increased from the September 30 level by approximately 37,400 MW to 142,000 MW, a 35.8 percent increase. The AEP and DAY Control Zones had proportionally more coal generating capability than PJM had prior to 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.)

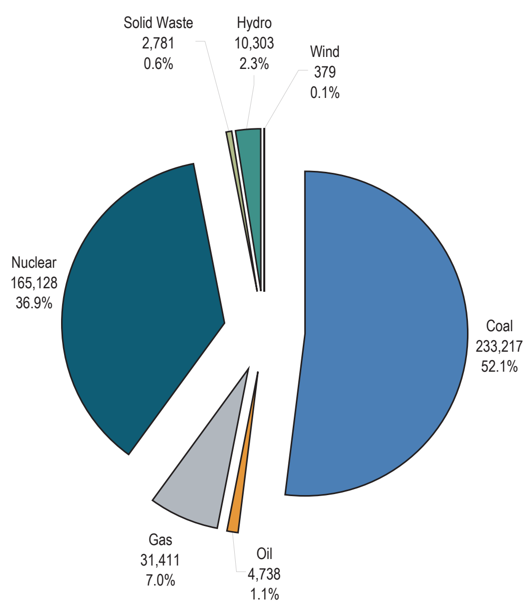
Figure 1-5 - PJM capacity by fuel source: At December 31, 2004



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

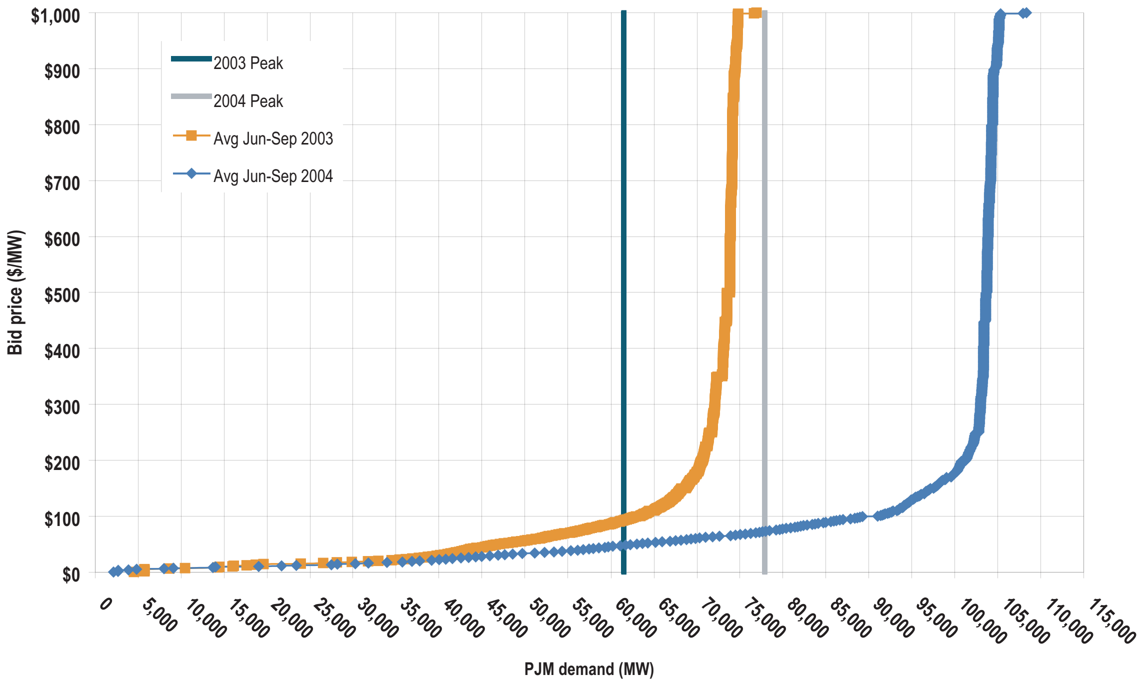
Supply

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



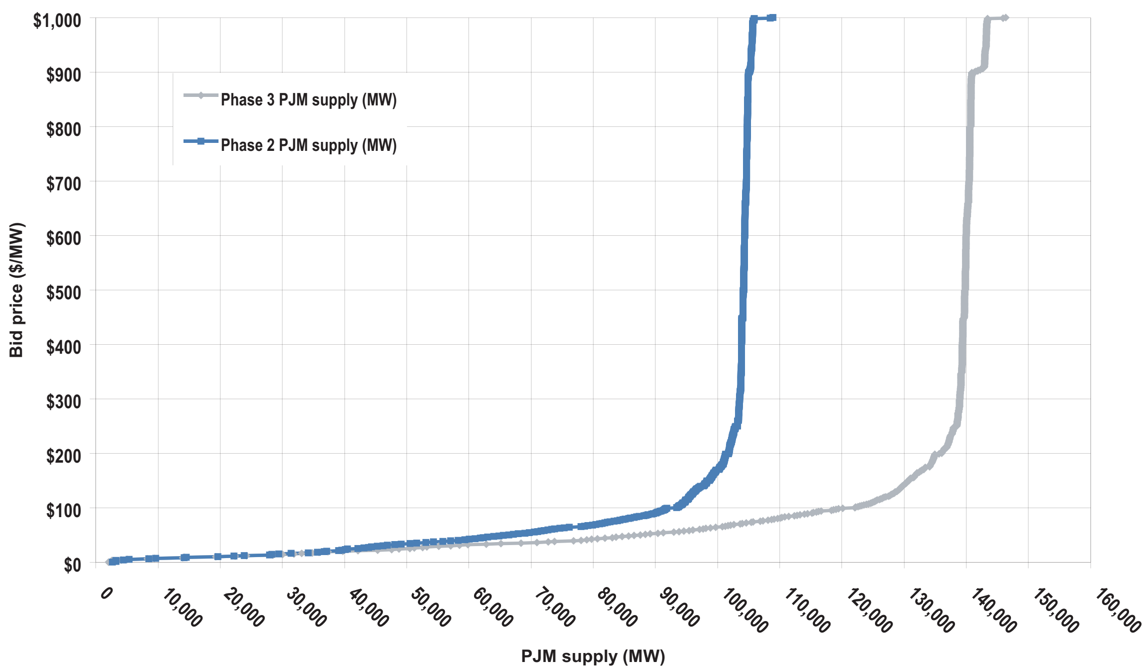
During the 12 months ended September 30, 2004,[7] approximately 2,300 MW of generation entered service in the Mid-Atlantic Region and AP Control Zone. The additions consisted of 450 MW in upgrades to existing generation and 1,850 MW in new generation. After accounting for offsetting decreases from the 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

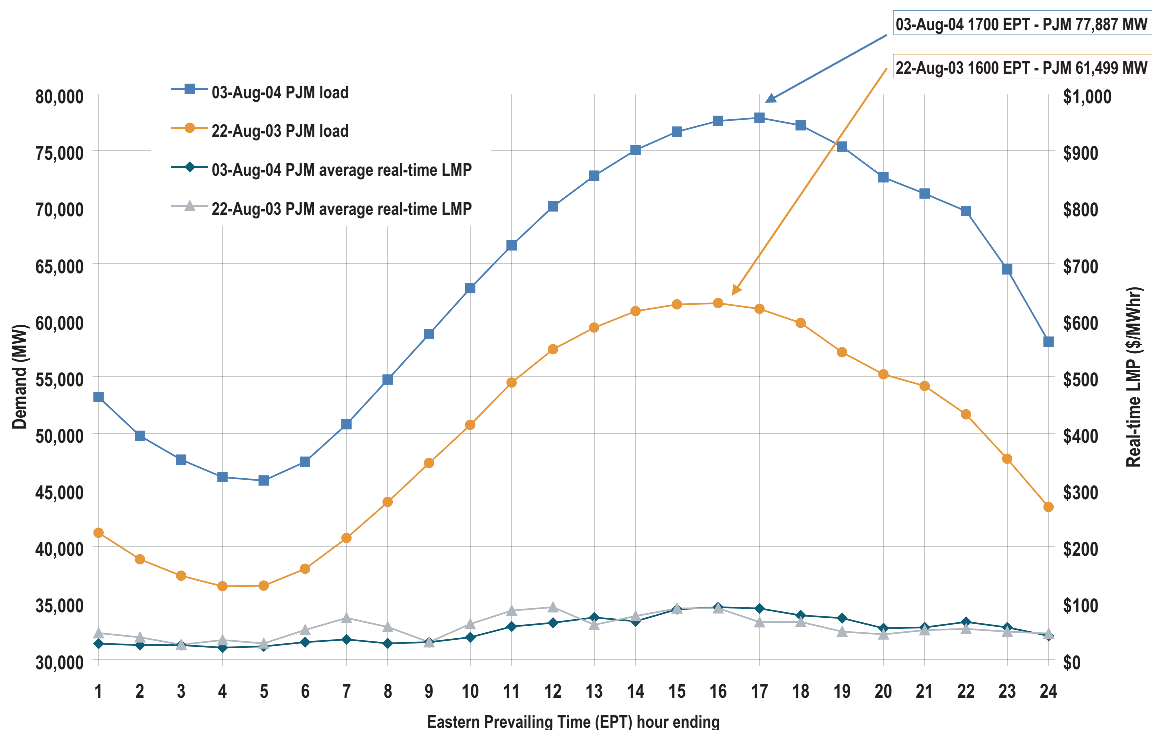
	Date	EPT Hour Ending	PJM Load (MW)	Difference (MW)
2002	1-Aug-02	1700	84,795	N/A
2003	21-Aug-03	1700	81,992	-2,803
2004	3-Aug-04	1700	77,887	-4,105

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

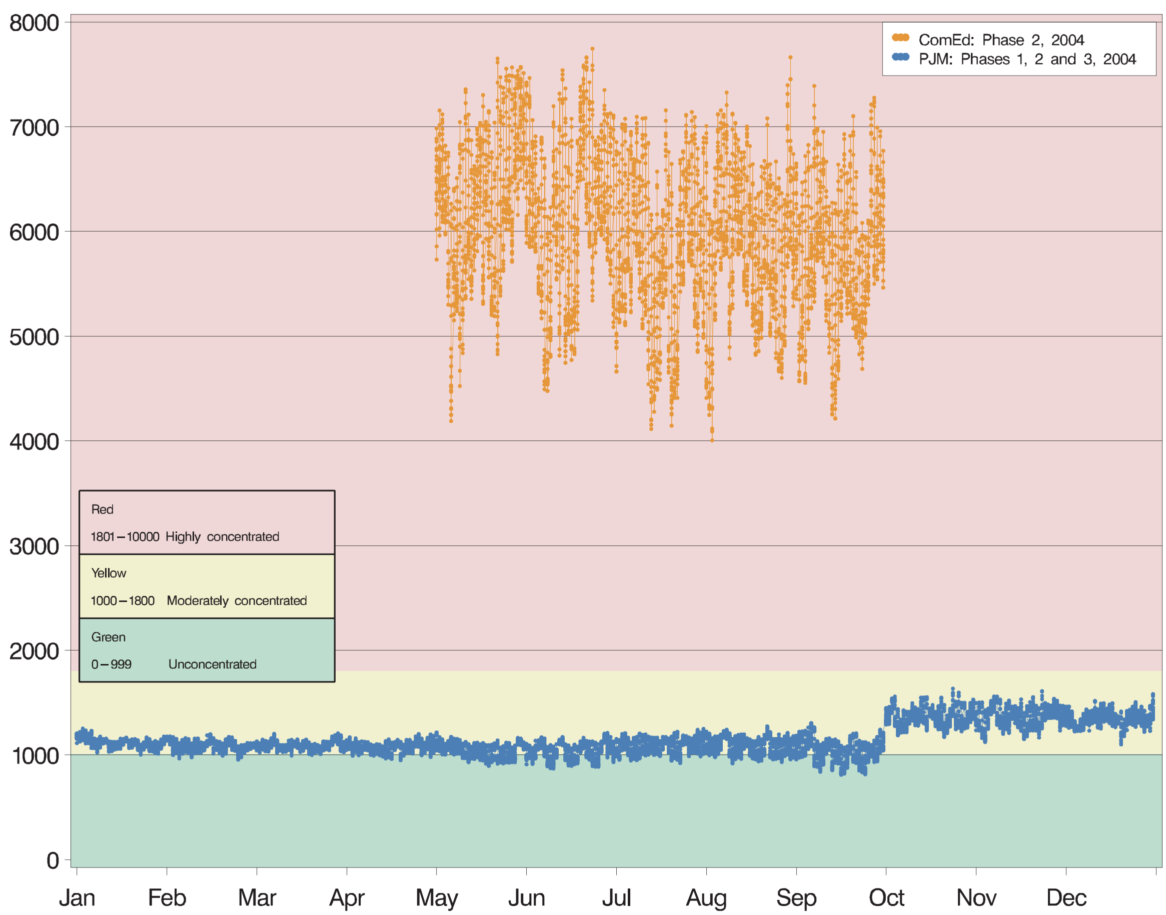
	Statistic	Base	Intermediate	Peak
Phase 2	Maximum	9358	7627	10000
	Average	9273	5708	7803
	Minimum	9146	3227	2162

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

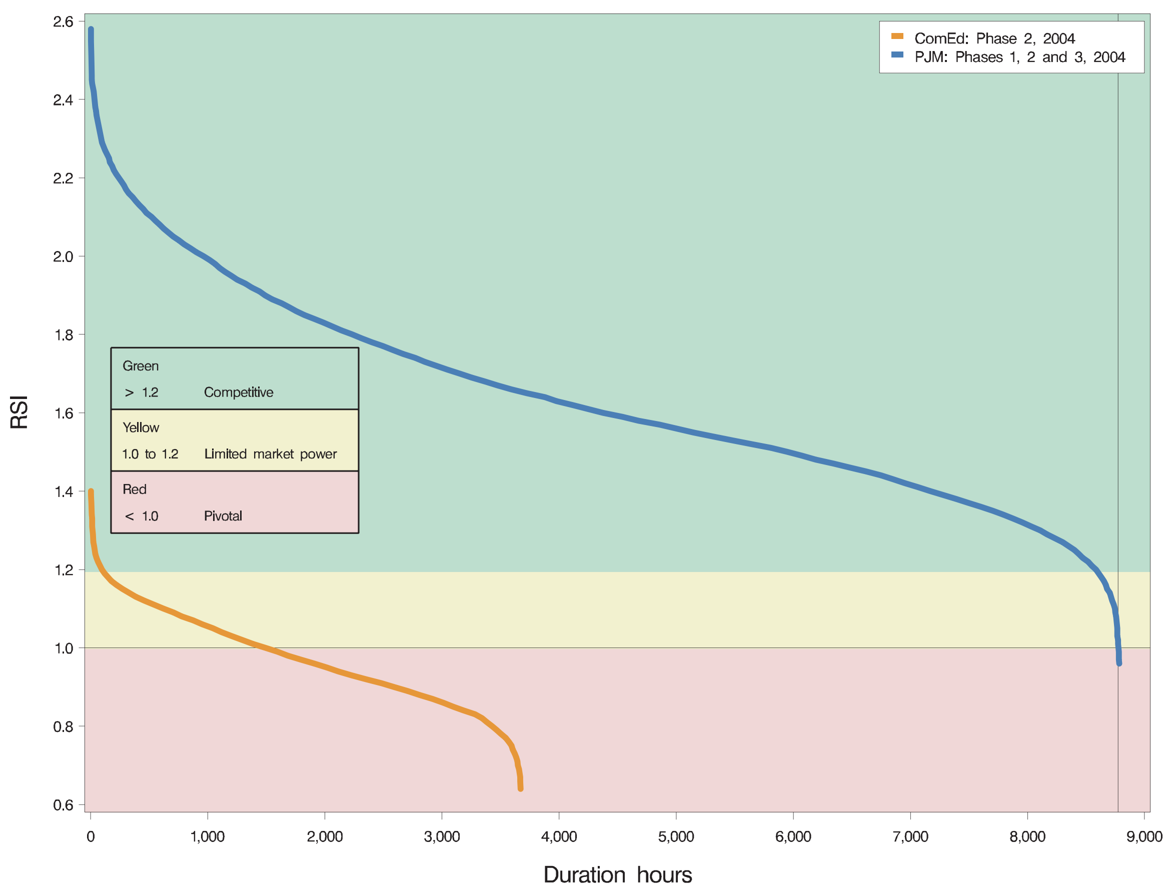
Table 2-15 shows RSI results for the top two generation owners together in ComEd.

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

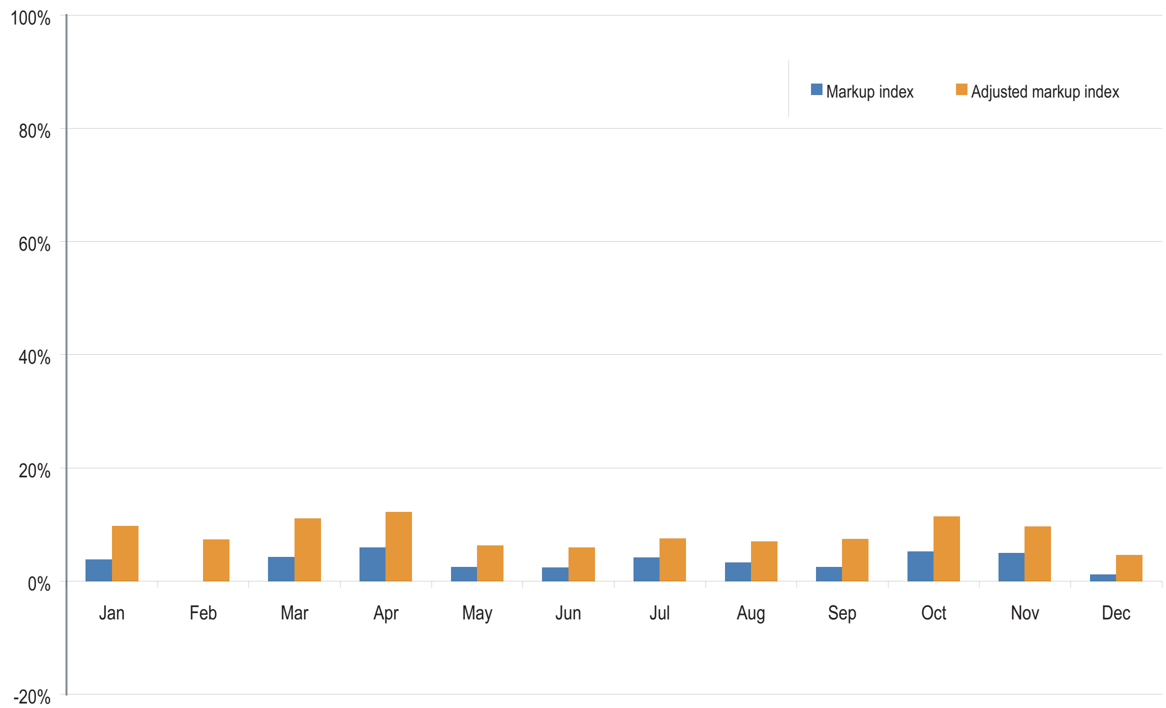


Figure 2-6 shows the average monthly markup index. The average markup index was 3.4 percent in 2004, with a maximum of 6.0 percent in April and a minimum markup index of 0.0 percent in February. Generators in PJM submit cost-based offers up to defined marginal cost plus 10 percent.[22] Since a significant 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

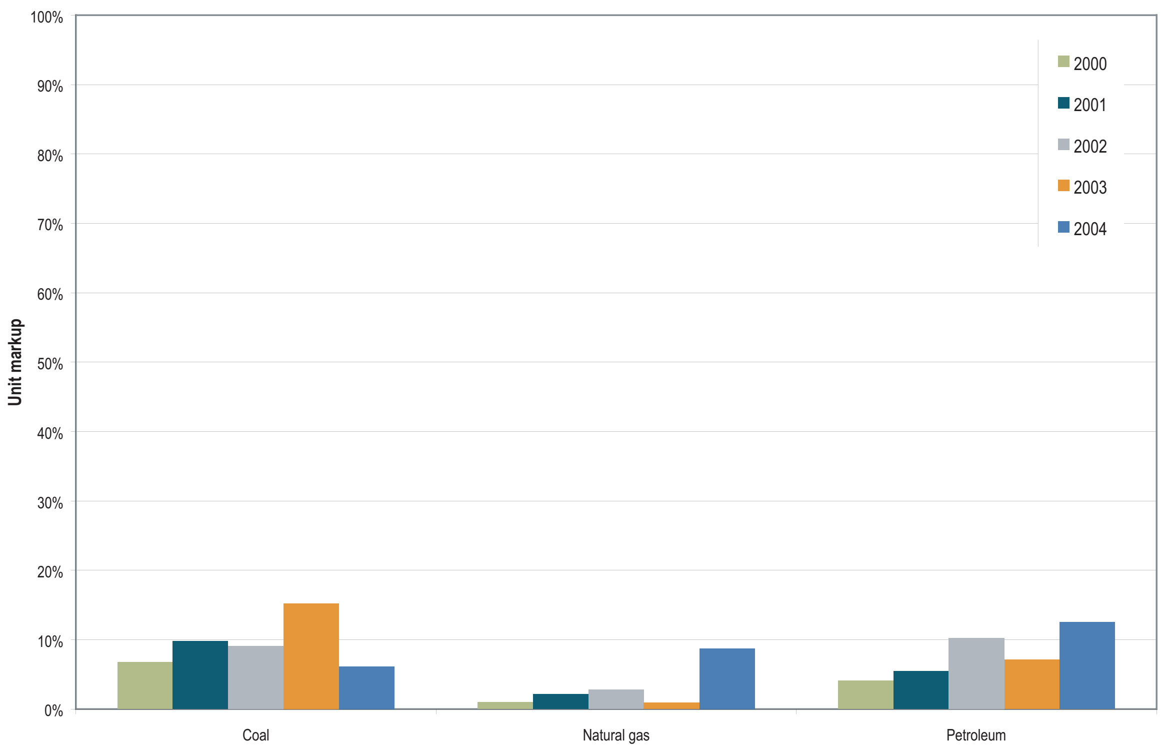


Table 2-25 shows the fuel type of marginal units. Between 2003 and 2004, the share of coal rose from 52 to 56 percent; the share of natural gas increased from 29 to 31 percent; the share of nuclear units held steady and the share of petroleum decreased from 18 to 12 percent.

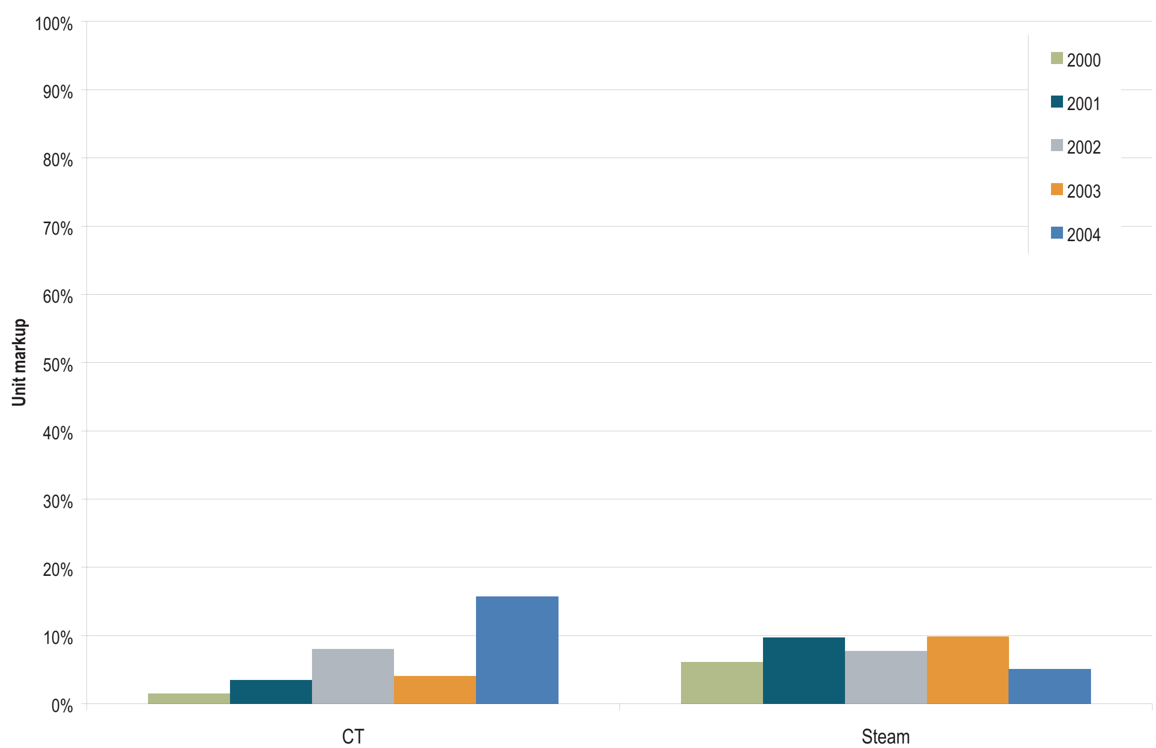
Table 2-25 - Type of fuel used by marginal units: Calendar years 2000 to 2004[23]

						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.

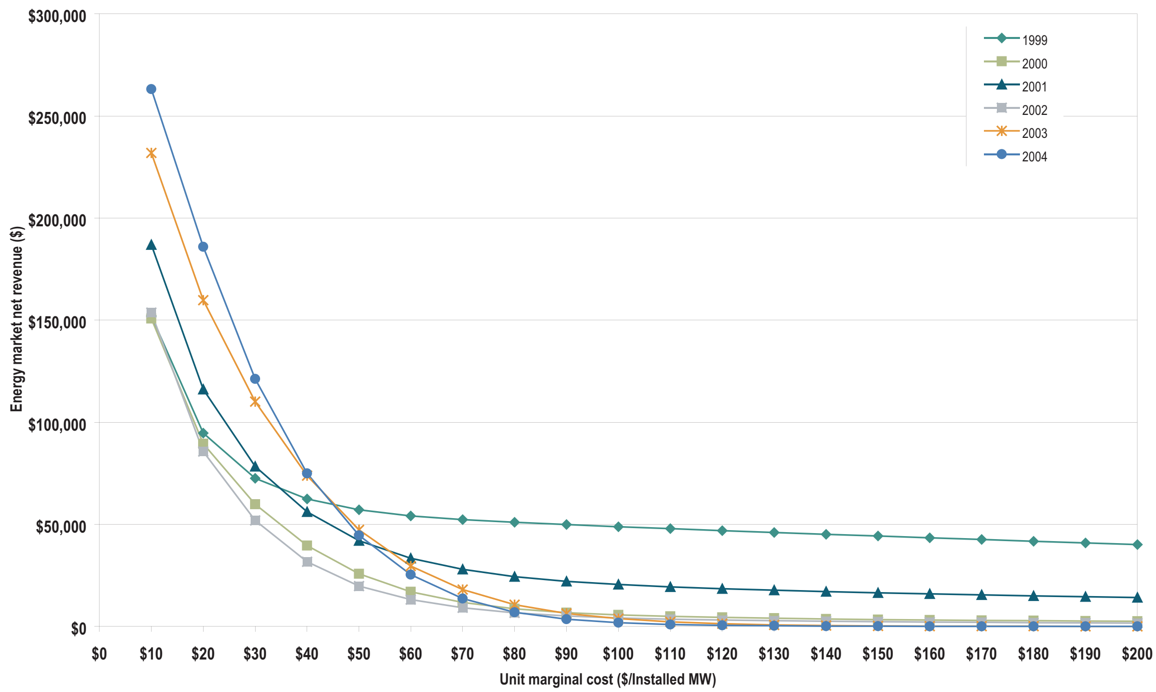
with relatively low marginal costs were more profitable in 2004 than in prior years and units with relatively high marginal costs were less profitable in 2004 than in prior years. If a unit with marginal costs of $30 per MWh had operated during all hours when the LMP exceeded $30 per MWh, it would have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

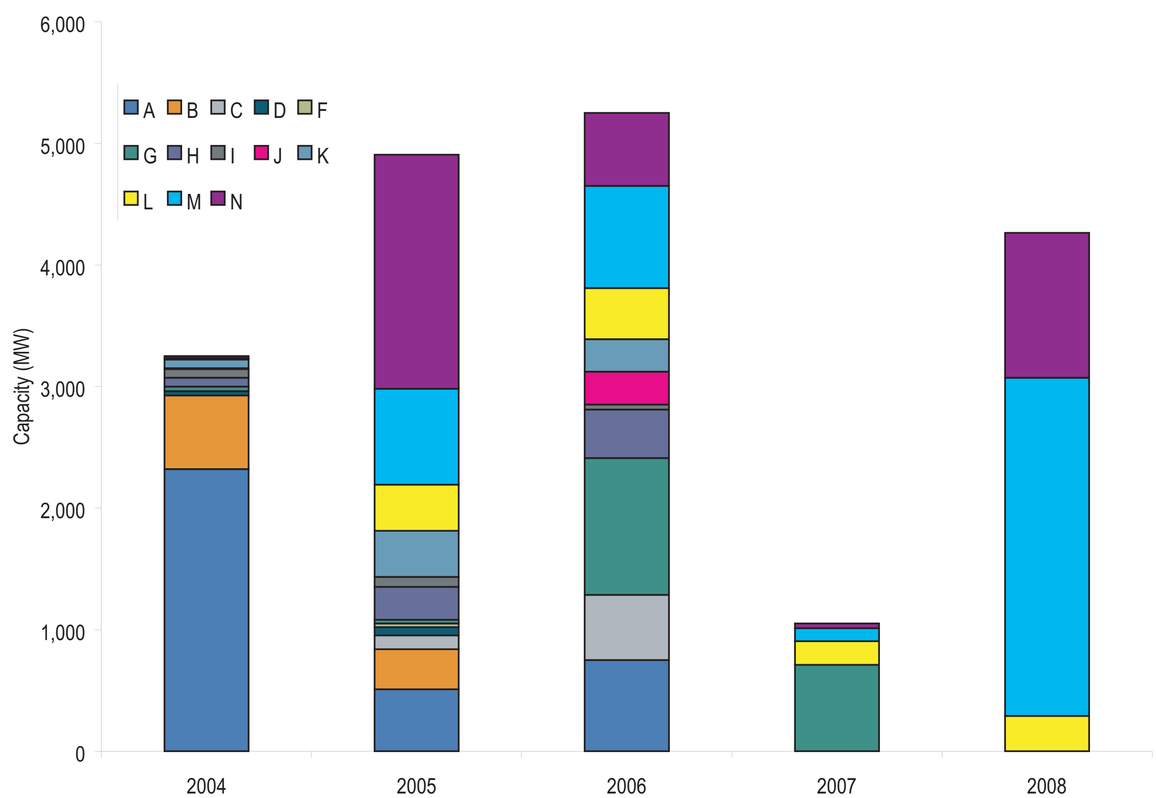
57 The analysis used the prompt coal costs and associated production cost for a CP.

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.

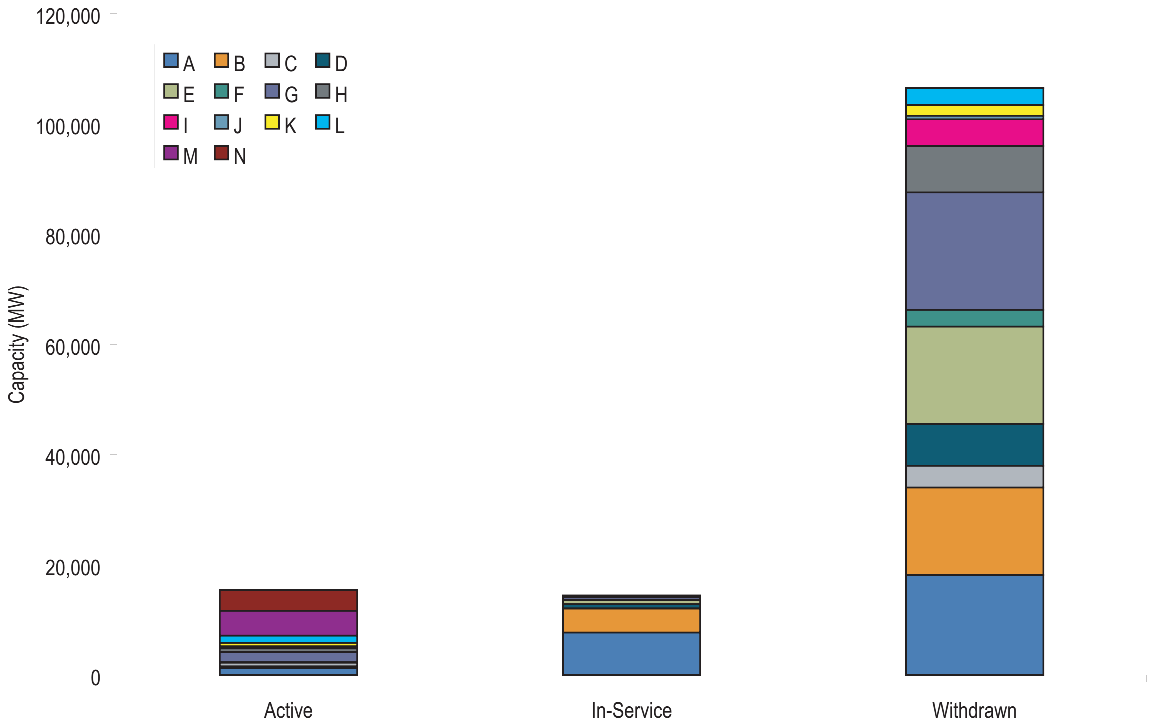
Figure 2-11 shows the amount of capacity added to the queues and the amount of capacity withdrawn from the queues since the beginning of the RTEP process as well as the total amount of capacity that entered the queues under RTEP and is now in service.

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.

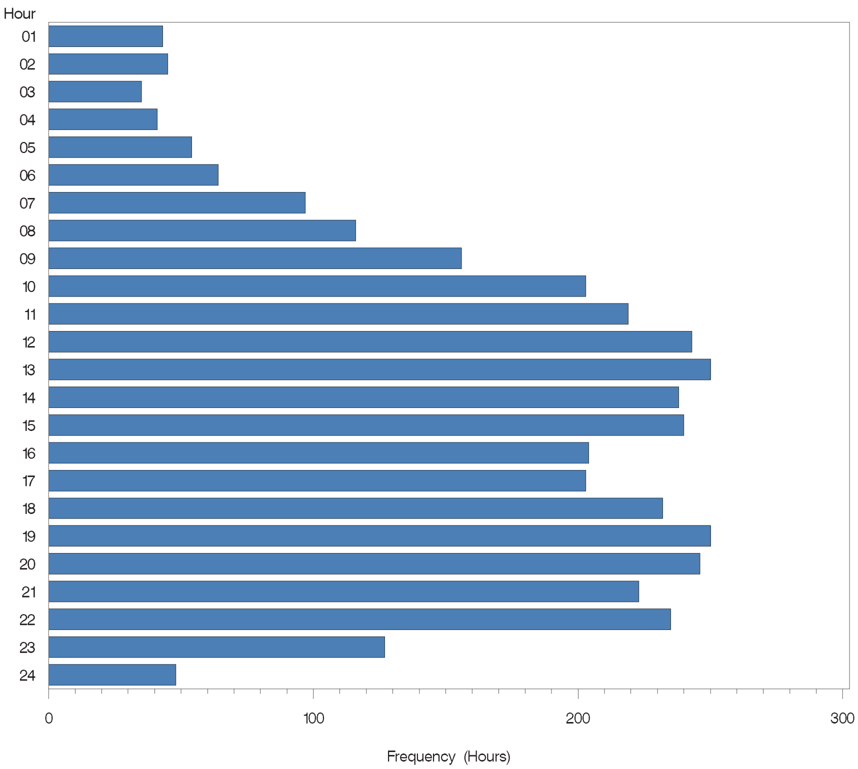
71 MIL is a month-by-month, year-round program for ComEd. For additional information, see Appendix H, "Glossary."
72 See Section 2, "Energy Market," at Figure 2-1, Average PJM aggregate supply curves: Summers 2003 and 2004.
73 See Section 2, "Energy Market," at Figure 2-1, "Average PJM aggregate supply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

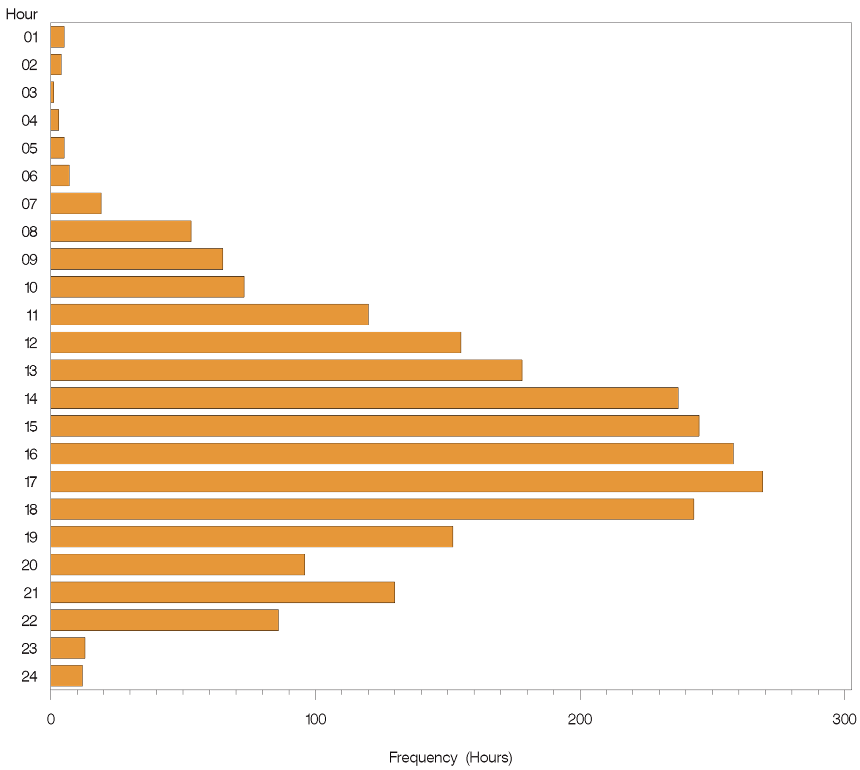
Figure 2-12 - Frequency distribution of Economic Program hours when LMP less than $75 per MWh (by hours): Nine months ended September 30, 2004



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.

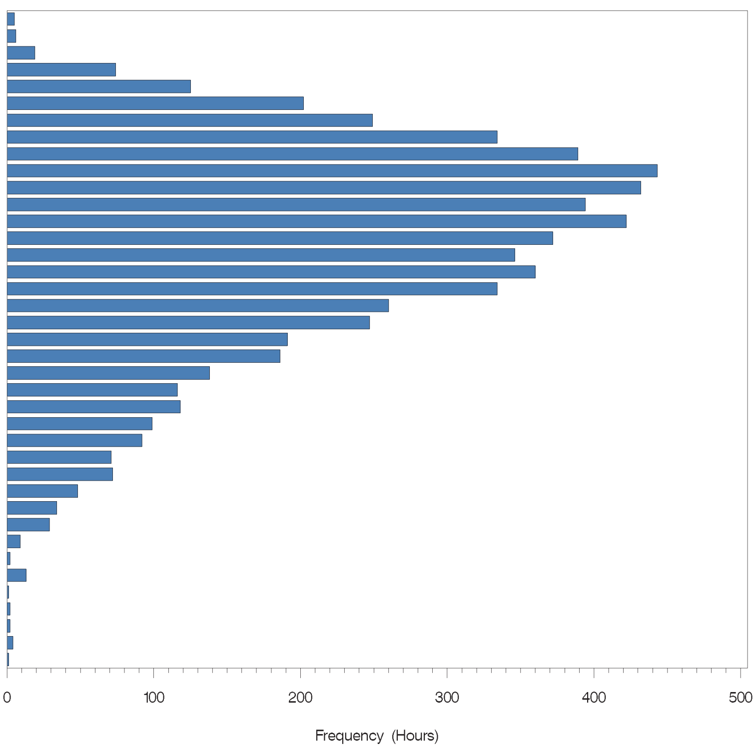
Figure 2-13 - Frequency distribution of Economic Program hours when LMP greater than or equal to $75 per MWh (by hours): Nine months ended September 30, 2004



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

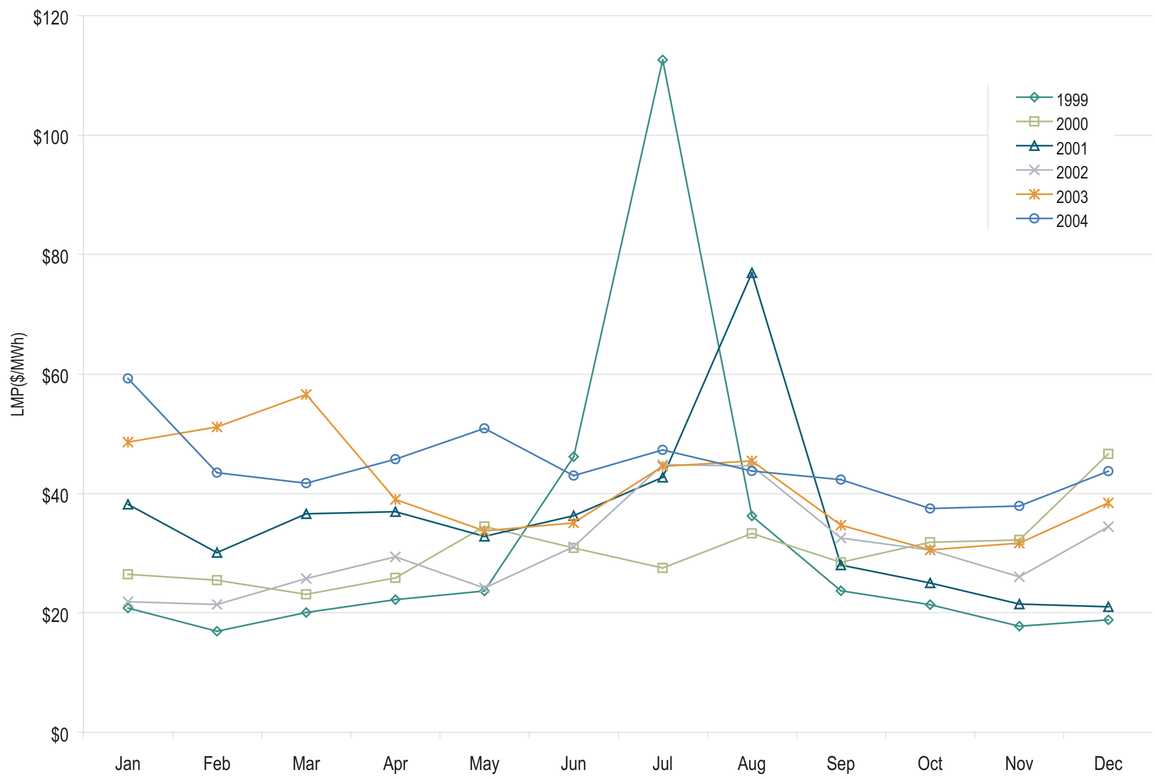
PJM real-time energy market prices increased in 2004. The simple hourly average system LMP[79] was 10.8 percent higher in calendar year 2004 than in 2003, $42.40 per MWh versus $38.27 per MWh. The simple average LMP in 2004 was higher than in all previous years since the introduction of markets in PJM. 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:

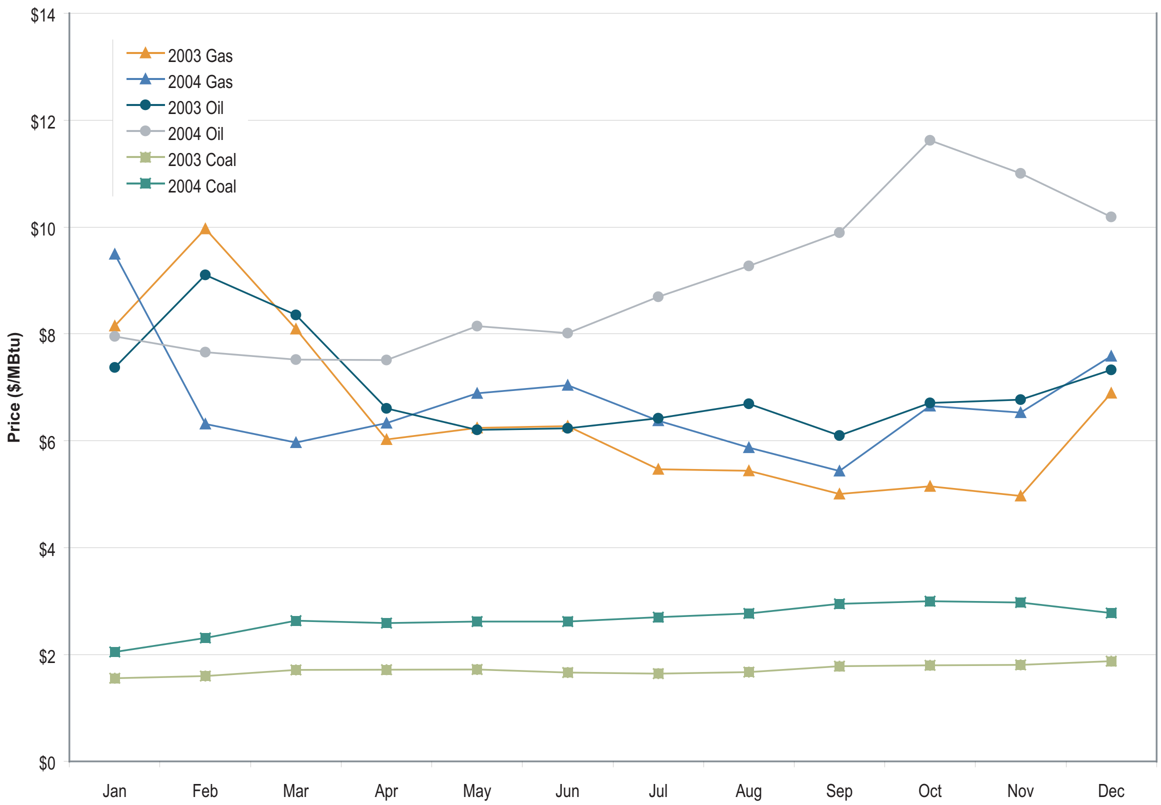
- **Fuel Prices.** Higher natural gas, oil and coal prices were a significant source of upward pressure on LMP in 2004. Figure 2-15 shows the PJM system monthly load-weighted LMP from 1999 through 2004. Figure 2-16 shows average, daily delivered natural gas, oil and coal prices for units within PJM.[80] 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

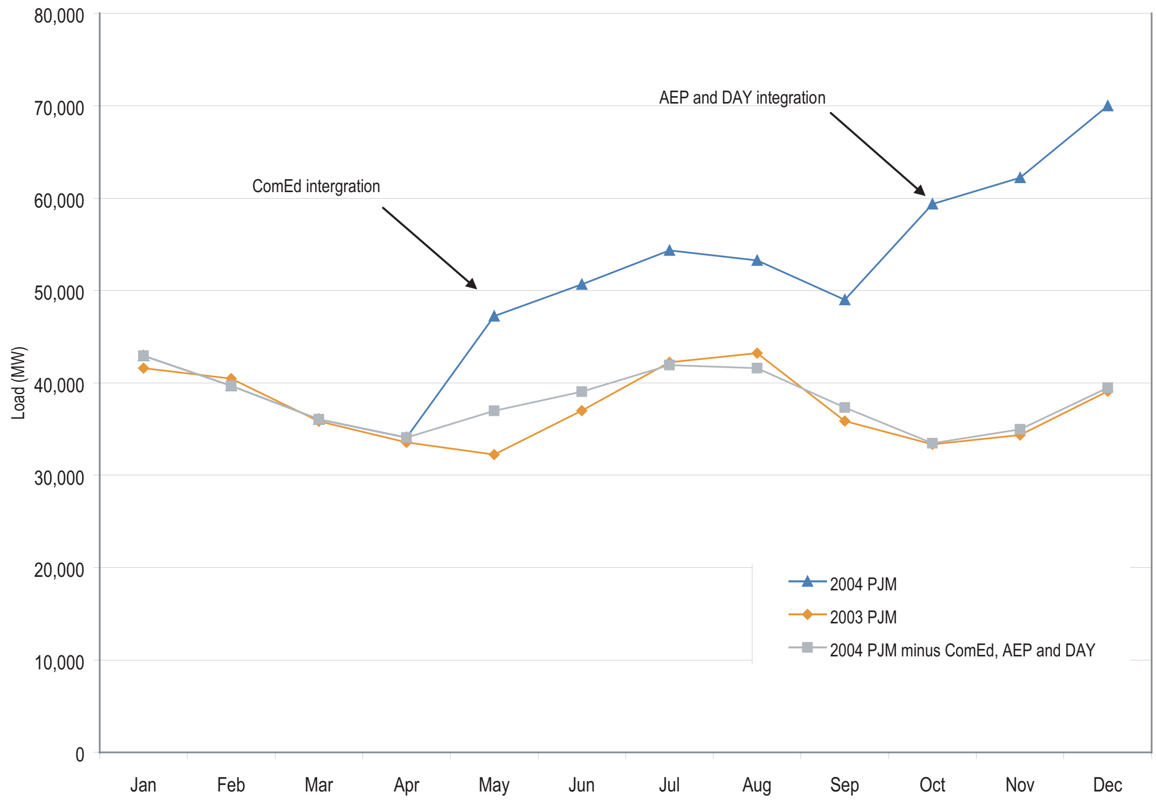


Table 2-46 - Average maximum temperature-humidity index (THI) comparison: May to September, 2003 and 2004

	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.

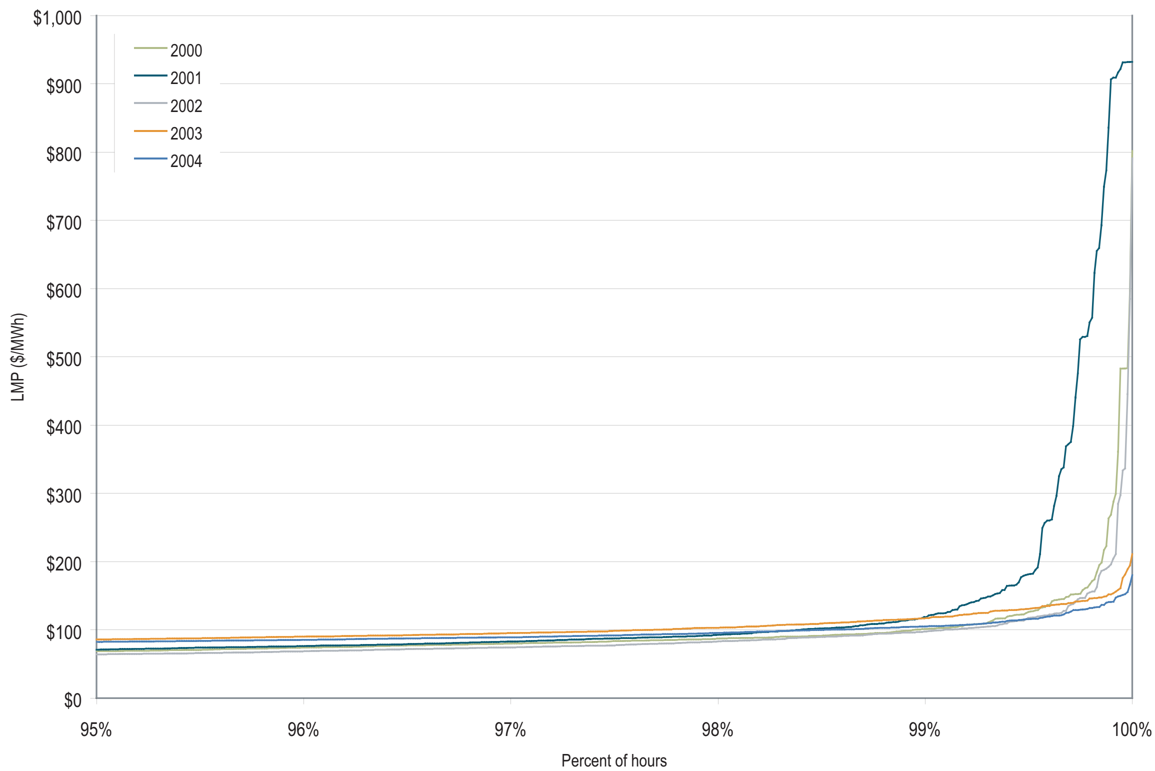
A price duration curve shows the percent of hours when LMP is at, or below, a given price for the year. Figure 2-18 presents price duration curves for hours above the 95th percentile from 2000 to 2004. Prices in this range occurred for 5 percent or less of the total hours in each year. Figure 2-18 shows 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.

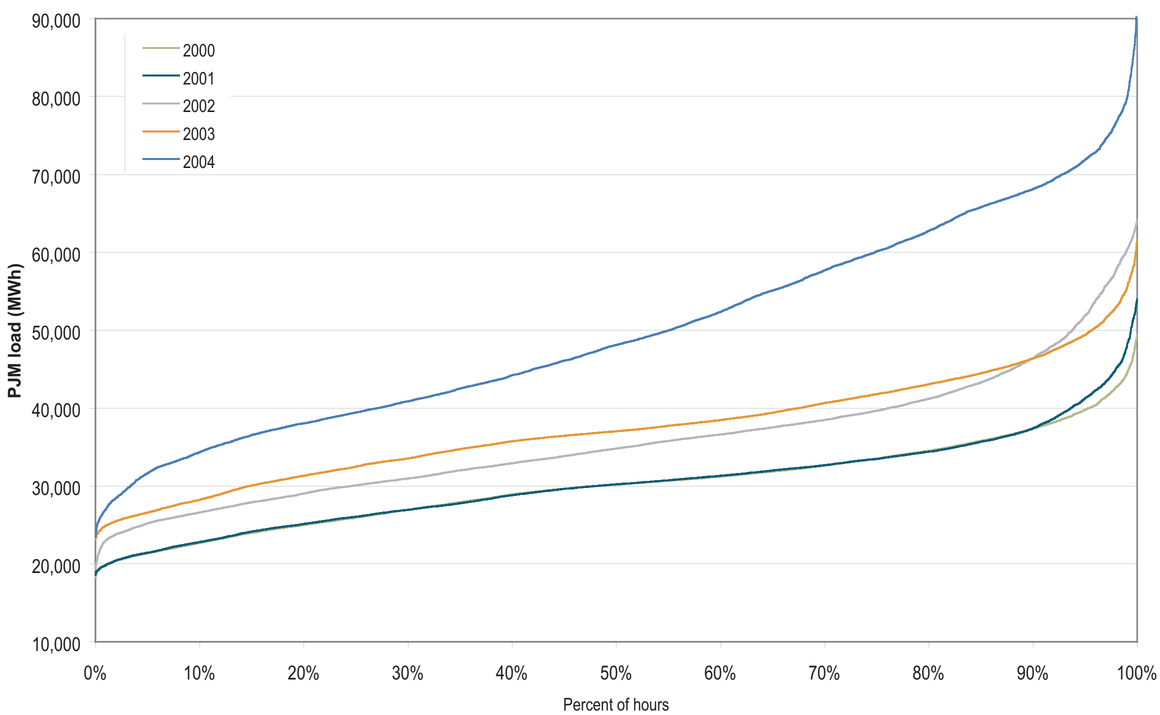
Table 2-48 - PJM average load: Calendar years 1998 to 2004[85]

	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

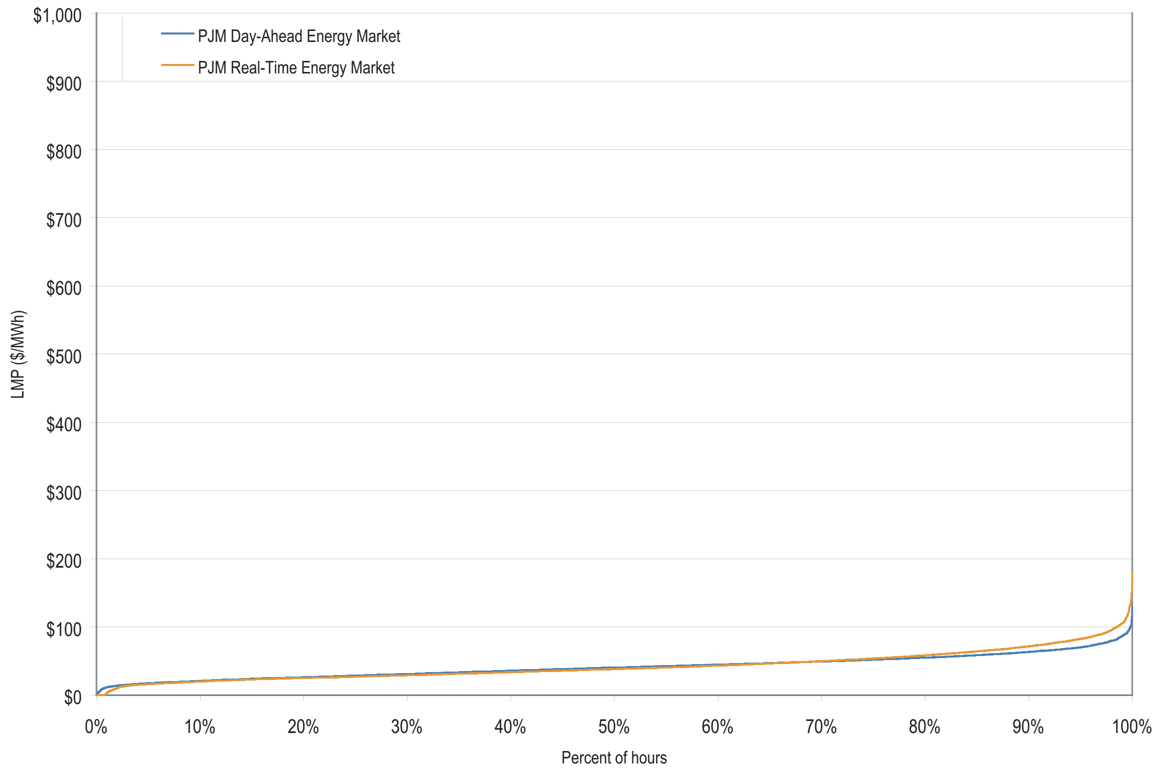


Figure 2-21 shows the hourly differences between day-ahead and real-time LMP in 2004. Although the average difference between the Day-Ahead and Real-Time Energy Markets was $0.97 per MWh for the entire year, Figure 2-21 shows considerable variation, both positive and negative, between day-ahead and real-time 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

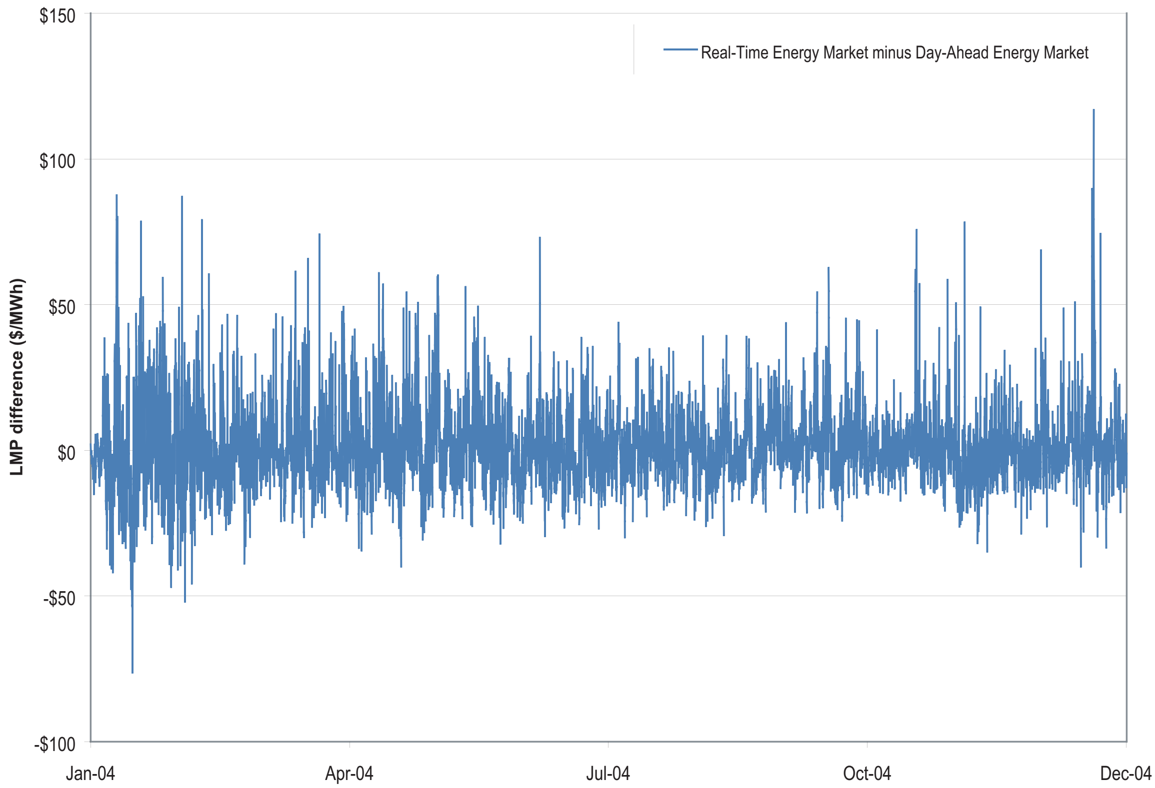


Figure 2-22 - PJM hourly system average LMP: Calendar year 2004

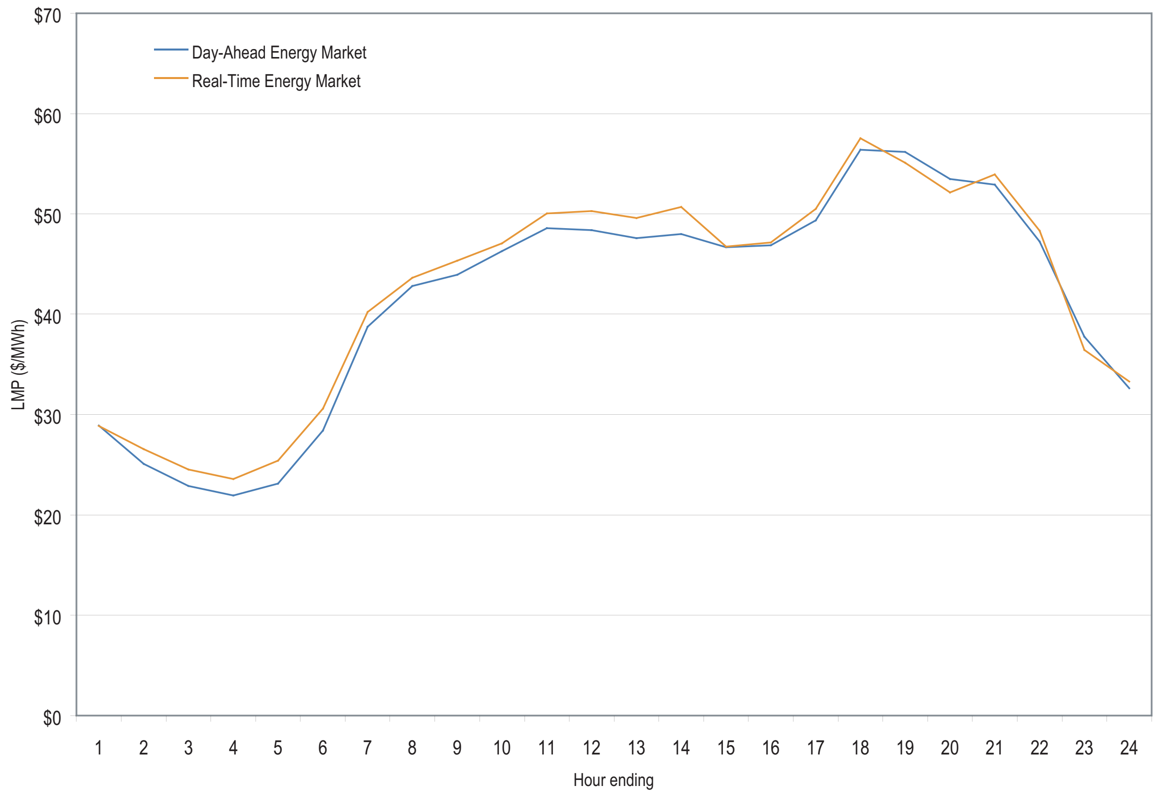


Table 2-51 presents summary statistics for the two markets. During 2004, average LMP in the Real-Time Energy Market was $0.97 per MWh or 2.3 percent higher than average LMP in the Day-Ahead Energy Market. The real-time median LMP was 5.4 percent lower than day-ahead LMP, reflecting an average difference 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

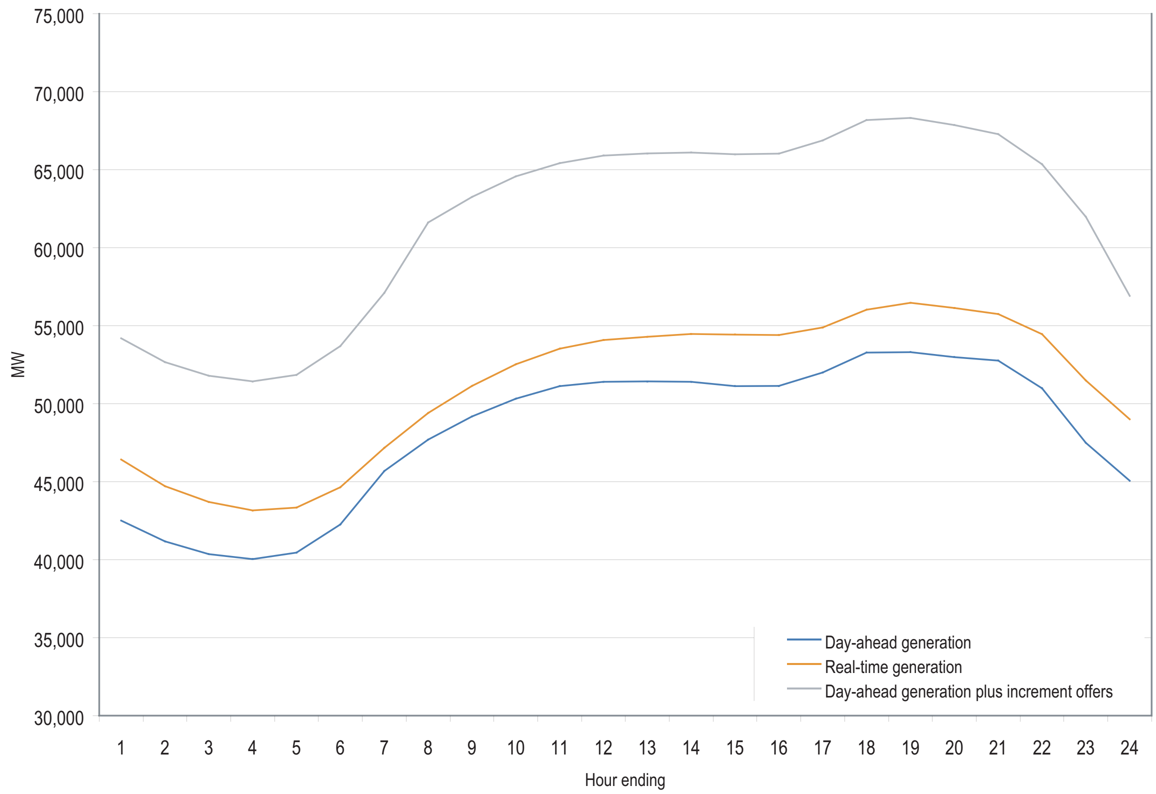


Table 2-52 presents summary statistics for 2004 day-ahead and real-time generation and the average differences between them. Day-ahead generation averaged 2,937 MWh less than real-time generation. Day-ahead generation offers plus cleared increment (INC) offers were 10,619 MWh higher than real-time generation,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

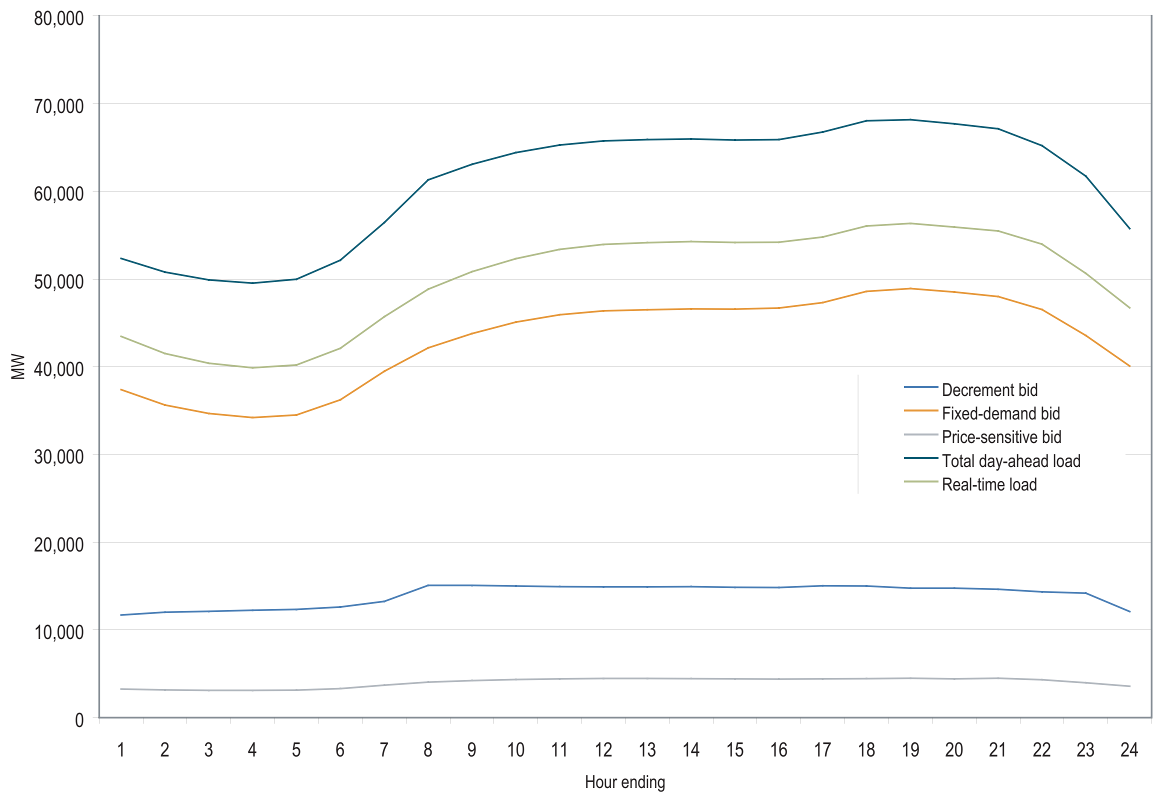


Table 2-53 presents 2004 summary statistics for day-ahead load components, total day-ahead load, real-time load and the difference between total day-ahead load and total real-time load.

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

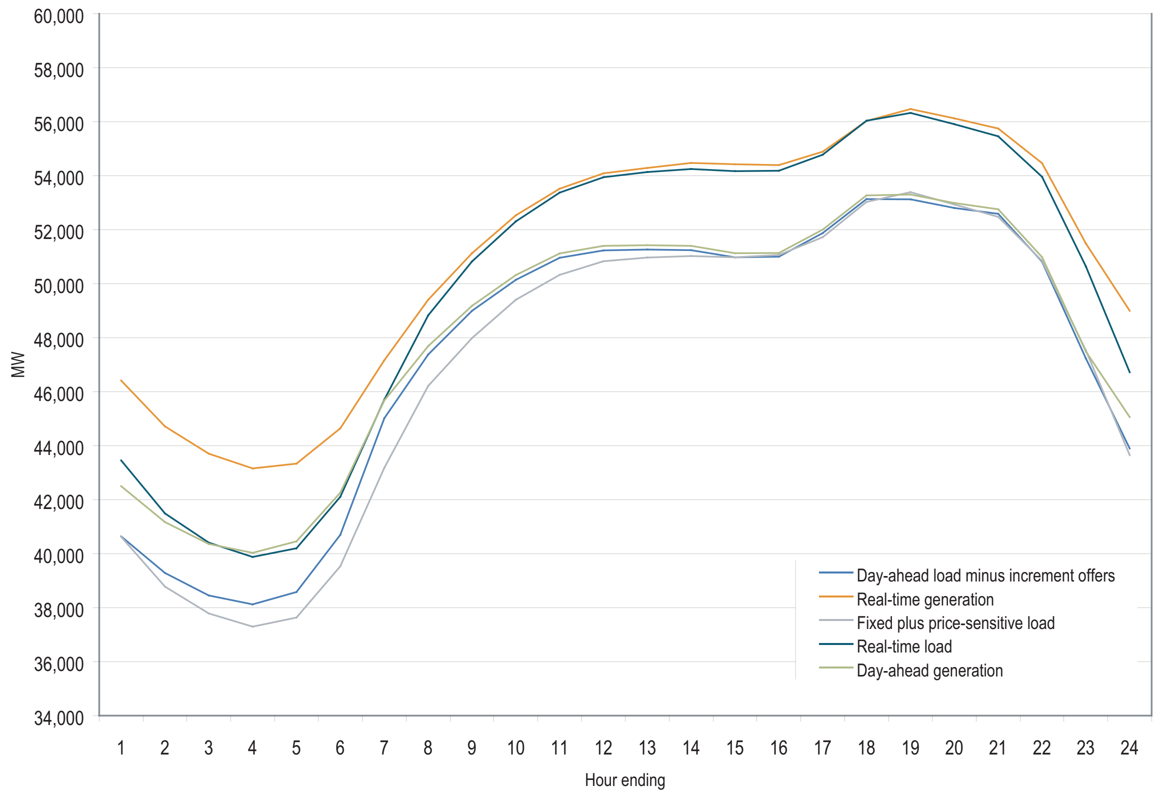
As Figure 2-24 shows, day-ahead load components increased during on-peak hours (i.e., hours ending 0800 to 2300 EPT) as did real-time load. Table 2-54 shows the average load MWh values in the Day-Ahead and Real-Time Energy Markets for 2004 during off-peak and on-peak hours. During 2004, real-time load 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.

SECTION 3 - 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.

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.[1,2] 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.

- **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

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[4] (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

1 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.
2 Control areas external to PJM are referred to as control areas not control zones. For example, the FirstEnergy control area is not referred to as the FirstEnergy control zone.
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 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**[5]

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

5 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.[6]

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 ISO.** The "Joint Operating Agreement between the Midwest Independent Transmission System Operator, Inc. and PJM Interconnection, L.L.C." (JOA)[7] 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.[8]

- **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

6 See Appendix D, "Interchange Transactions" for a more detailed discussion of interface pricing issues.
7 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).
8 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.

Interchange Transaction Activity

Aggregate Imports and Exports (by Phase)

New control zones were integrated into PJM in 2004 and these integrations affected the PJM balance of imports and exports. Historically, PJM had been a net importer of power and that continued to be the case during the first phase of 2004. With the integration of the ComEd Control Area and the AEP and DAY Control Zones, PJM became a net exporter of power. (See Figure 3-1.)

Phase 1

During the four-month period ended April 30, 2004, PJM was a net importer of energy for each month. Net interchange of 7.4 million MWh during 2004 exceeded net interchange of 3.7 million MWh for the comparable 2003 period. This increase was the result of both an increase in gross imports (11.8 from 10.4 million MWh for the 2004 and 2003 periods, respectively) and a decrease in gross exports (4.5 from 6.8 million MWh for the 2004 and 2003 periods, respectively). For the periods under comparison, the peak months for net interchange were January in 2004 (2.3 million MWh) and March in 2003 (1.5 million MWh).

Phase 2

During the five-month period ended September 30, 2004, PJM became, for the first time, a net exporter of energy in each month as net exports from ComEd outweighed net imports of the preintegration PJM. Monthly exports averaged 3.9 million MWh and monthly imports averaged 2.8 million MWh for an average monthly net interchange of -1.1 million MWh.

Phase 3

During the three-month period ended December 31, 2004, PJM continued to be a net exporter of power. Monthly exports averaged 5.6 million MWh and monthly imports averaged 4.3 million MWh for an average monthly net interchange of -1.3 MWh.

2004 Trends

While PJM market participants have generally imported and exported energy primarily in the Real-Time Energy Market, that pattern appears to be changing. (See Figure 3-1.) Day-ahead volume continues to be relatively small by comparison. (See Figure 3-2.) In 2004, transactions in the Day-Ahead Energy Market were 27 percent of the gross import volume (18 percent in 2003) in the Real-Time Market while transactions in the Day-Ahead Market were 39 percent of the gross export volume (16 percent in 2003) in the Real-Time Market. The increased level of transactions in the

Day-Ahead Market compared to the level of transactions in the Real-Time Market was even more evident in Phase 3. Transactions in the Day-Ahead Market were 35 percent of the gross import volume in the Real-Time Market while transactions in the Day-Ahead Market were 53 percent of the gross export volume in the Real-Time Market in Phase 3.

Figure 3-1 - PJM real-time imports and exports: Calendar year 2004

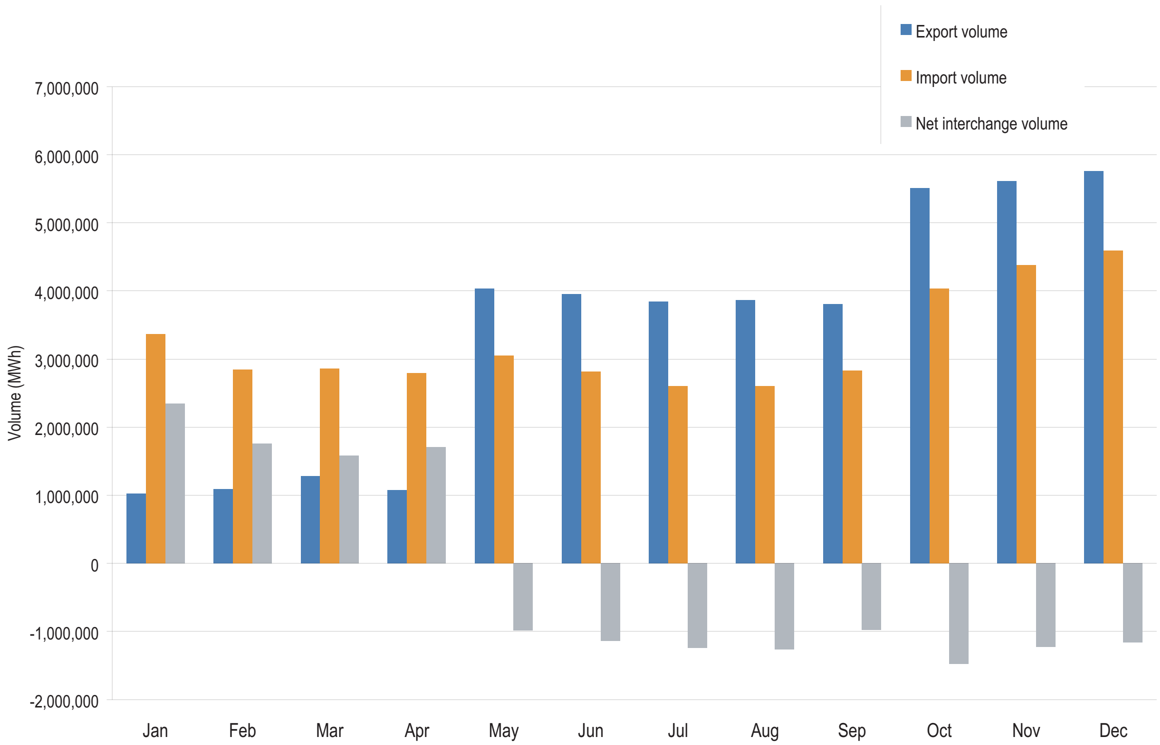


Figure 3-2 - Total day-ahead import and export volume: Calendar year 2004

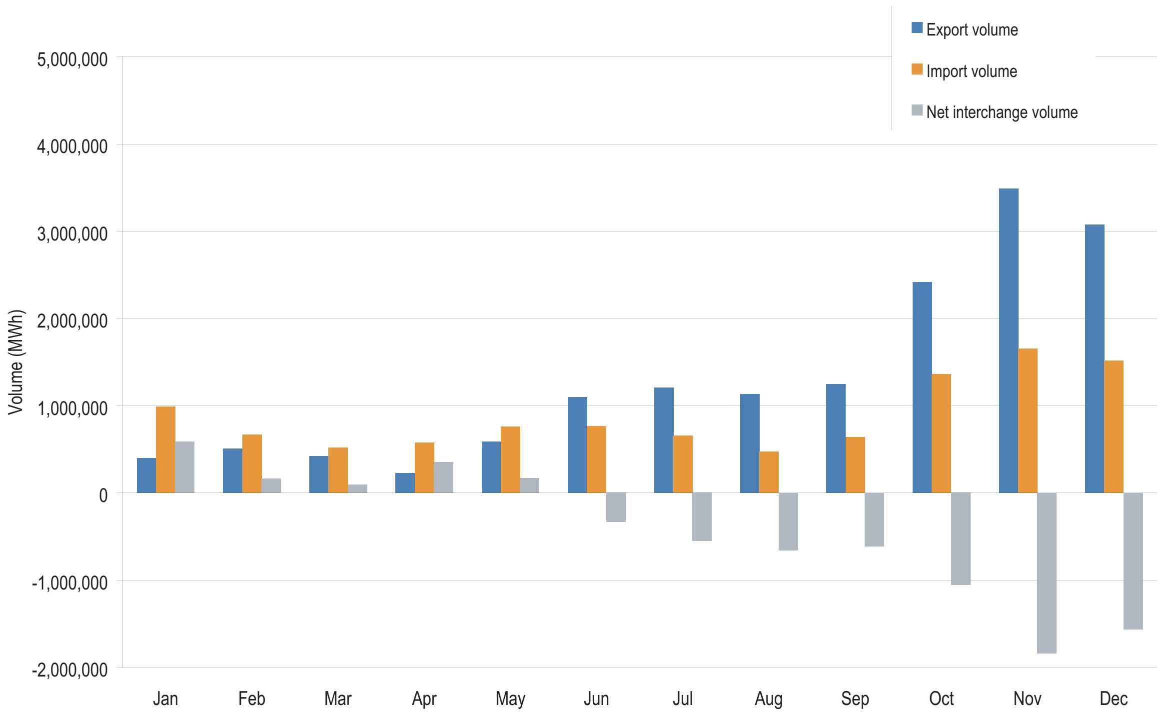
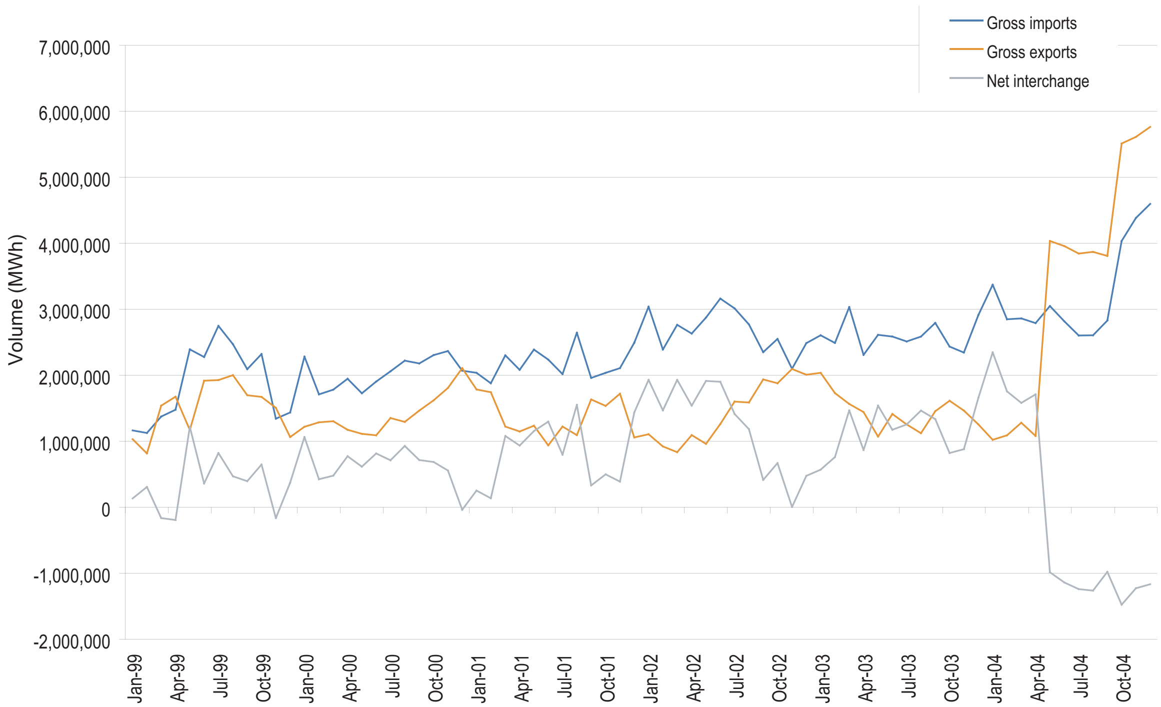


Figure 3-3 shows import and export volume for PJM from 1999 through 2004. Gross exports exhibited a particularly sharp increase in Phase 2 that was not matched by imports while the increase in gross exports and imports in Phase 3 was more balanced.

Figure 3-3 - PJM import and export transaction volume history: Calendar years 1999 to 2004



Interface Imports and Exports (by Phase)

Total imports and exports are comprised of flows at each PJM interface. Net interchange is shown by interface for each phase of 2004 in Table 3-1 while gross imports and exports are shown by interface for each phase of 2004 in Table 3-2 and Table 3-3.

Phase 1

During Phase 1, when PJM encompassed the Mid-Atlantic Region and the AP Control Zone, net interchange was relatively stable with a standard deviation of 0.3 million MWh on a monthly net interchange average of 1.8 million MWh. PJM/FE and PJM/AEP together accounted for 94 percent of the net imports (50 and 44 percent, respectively). As had previously been the case, PJM/NYIS was the lone net exporting interface.

The highest levels of gross imports occurred on the PJM/FE interface (47 percent) and on the PJM/AEP interface (39 percent). The PJM/ Duquesne Light Company (PJM/DLCO), PJM/Dominion Virginia Power (PJM/VAP) and PJM/NYIS interfaces had the lowest gross import volumes, with 4 percent, 4 percent and 5 percent, respectively. Approximately 82 percent of the gross exports occurred at the PJM/NYIS interface while PJM/AEP, PJM/VAP, PJM/FE and PJM/DLCO carried 2 percent, 3 percent, 9 percent and 4 percent, respectively.

Phase 2

With the addition of the ComEd Control Area to PJM, the number of external interfaces increased from five to 14. Ten of these interfaces were net exporters of PJM power. The largest of them was PJM/AEPNI with 44 percent of net export volume, followed by PJM/MidAmerican Energy Company (PJM/MEC) with 18 percent and PJM/NYIS with 11 percent. PJM/Alliant Energy Corporation east (PJM/ALTE), the PJM/Alliant Energy Corporation west (PJM/ALTW), PJM/Ameren Corporation (PJM/AMRN), PJM/Central Illinois Light Company (PJM/CILC), PJM/ Northern Indiana Public Service Company (PJM/NIPS), PJM/VAP and PJM/Wisconsin Energy Corporation (PJM/WEC) made up the remaining net exporting interfaces. Four of PJM's Phase 2 interfaces were net importers of power. The largest was PJM/FE with 49 percent of total net imports, followed by PJM/AEPPJM with 38 percent. PJM/IP and PJM/DLCO were the other two importers.

The highest levels of gross imports during this period occurred on the PJM/FE interface (38 percent) and the PJM/AEPPJM interface (28 percent). The PJM/IP and PJM/NYIS each had sizable gross import volume at 10 percent and 14 percent, respectively. The remaining 10 interfaces accounted for 10 percent of gross import volume. Approximately 35 percent of gross exports occurred at the PJM/AEPNI interface. PJM/NYIS had the second highest Phase 2 gross export volume with 19 percent. The PJM/MEC interface was the next highest at 14 percent. The other 11 interfaces carried the remaining 32 percent of gross export volume.

Phase 3

With the addition of the AEP and DAY Control Zones, external interfaces increased in number from 14 to 22. Twelve of these interfaces were net exporters of PJM power. The two largest net exporting interfaces totaled 43 percent of the total net exporting volume. They were PJM/NYIS at 22 percent and PJM/MECS with 21 percent. PJM/DLCO, PJM/VAP, PJM/ALTE, PJM/ALTW, PJM/MEC, PJM/WEC, PJM/ Carolina Power & Light Company east (CPLE), PJM/ Carolina Power & Light Company west (CPLW), PJM/ Duke Energy Corp. (DUK) and PJM/Tennessee Valley Authority (TVA) made up the remaining net exporting interfaces.

Ten of PJM's Phase 3 interfaces were net importers of power. Ninety-two percent of the net import volume was carried on three of these interfaces. PJM/IP carried 33 percent, PJM/OVEC carried 30 percent and PJM/FE carried 29 percent of the volume. The other seven interfaces made up the remaining 8 percent of net import volume.

Approximately two-thirds of the gross import volume occurred on three interfaces. PJM/FE had the highest share at 26 percent. PJM/IP and PJM/OVEC carried 21 and 19 percent, respectively. The other 19 interfaces made up the remaining third of gross import volume. The distribution of gross export volume over the interfaces is more diverse than that of gross imports. The highest two gross exporting interfaces made up slightly more than a third (35 percent) of the total gross exporting volume. PJM/NYIS was the highest at 20 percent followed by PJM/MECS at 15 percent. The other 20 interfaces made up the remaining 65 percent of gross export volume.

Table 3-1 - Net interchange volume by interface (MWh x 1,000): Calendar year 2004

Interface	Phase 1				Phase 2					Phase 3		
	Jan-04	Feb-04	Mar-04	Apr-04	May-04	Jun-04	Jul-04	Aug-04	Sep-04	Oct-04	Nov-04	Dec-04
AEP	1,586.1	1,083.7	966.1	935.5								
DLCO	77.2	71.6	83.0	71.9	-86.0	4.6	68.4	103.0	77.6	-5.0	-19.6	-75.4
FE	1,208.6	1,222.3	1,400.6	1,358.0	1,360.4	994.7	730.9	708.2	831.6	598.4	852.7	862.3
NYIS	-681.0	-731.4	-947.1	-700.2	-193.8	-462.1	-244.8	-300.1	-525.5	-1,144.2	-919.2	-566.0
VAP	148.8	102.6	72.4	40.6	-73.4	-98.9	-98.0	-54.5	-27.9	-446.3	-555.4	-476.0
AEPNI					-1,291.3	-1,231.2	-1,308.8	-1,302.5	-1,415.0			
AEPPJM					528.7	673.1	701.8	726.7	912.9			
ALTE					-115.0	-100.9	-93.4	-100.2	-98.4	-102.1	-100.7	-108.7
ALTW					-257.4	-137.4	-162.5	-143.8	-150.4	-167.3	-164.7	-196.8
AMRN					-29.9	-108.6	-84.7	-119.5	9.2	-62.3	155.6	-45.6
CILC					4.6	-11.7	6.6	-4.0	3.8	3.5	6.9	7.4
IP					193.8	169.9	129.8	237.5	309.2	813.9	924.3	886.7
MEC					-525.7	-524.1	-596.2	-590.1	-420.6	-555.6	-393.3	-576.5
NIPS					-89.4	-2.6	-29.4	-262.5	-152.3	47.0	52.0	34.0
WEC					-417.9	-310.1	-268.4	-168.5	-337.3	-256.8	-279.7	-354.5
MECS										-796.1	-823.5	-904.7
CPLE										-258.2	-261.9	-215.9
CPLW										-73.1	-69.3	-72.1
CIN										474.9	-289.6	24.3
DUK										-315.8	-130.7	-236.6
EKPC										30.3	8.6	-4.9
IPL										20.0	19.4	13.4
LGEE										78.2	60.4	52.4
OVEC										829.0	743.2	854.4
TVA										-187.4	-44.9	-66.5

Table 3-2 - Gross import volume by interface (MWh x 1,000): Calendar year 2004

Interface	Phase 1				Phase 2					Phase 3		
	Jan-04	Feb-04	Mar-04	Apr-04	May-04	Jun-04	Jul-04	Aug-04	Sep-04	Oct-04	Nov-04	Dec-04
AEP	1,599.3	1,105.7	982.8	957.5								
DLCO	127.4	139.9	126.1	106.4	89.5	109.2	135.6	158.5	112.6	118.5	120.6	132.1
FE	1,285.9	1,325.4	1,513.6	1,458.5	1,504.6	1,131.5	858.0	826.0	934.8	921.7	1,195.1	1,235.5
NYIS	184.5	143.9	138.8	154.6	368.3	382.7	451.7	414.6	275.6	139.0	215.2	255.1
VAP	164.9	124.5	94.3	107.8	32.5	19.6	9.3	14.3	20.5	7.1	12.0	12.7
AEPNI					36.0	50.1	33.8	52.6	49.8			
AEPPJM					614.7	771.1	752.7	754.5	931.4			
ALTE					0.3	0.0	0.0	0.1	0.2	0.4	0.0	0.2
ALTW					5.3	9.2	6.0	6.3	3.7	1.1	1.0	1.7
AMRN					54.8	14.1	23.6	24.9	67.5	201.5	321.4	212.4
CILC					5.9	3.1	7.9	0.6	7.3	3.6	7.1	8.0
IP					253.9	233.4	212.7	290.3	352.6	844.3	957.8	928.5
MEC					2.7	3.5	6.0	5.9	24.8	29.6	40.4	33.3
NIPS					70.5	80.6	94.9	41.2	40.0	67.5	64.5	47.6
WEC					2.3	2.4	2.1	9.2	1.6	2.8	1.1	3.7
MECS										32.2	21.7	18.1
CPLE										63.2	41.5	99.6
CPLW										0.0	0.0	0.0
CIN										617.1	398.9	439.0
DUK										4.5	46.3	76.0
EKPC										34.9	21.8	14.2
IPL										25.7	19.9	15.1
LGEE										80.1	63.2	57.0
OVEC										830.4	746.7	864.8
TVA										9.7	86.5	136.7

Table 3-3 - Gross export volume by interface (MWh x 1,000): Calendar year 2004

Interface	Phase 1				Phase 2					Phase 3		
	Jan-04	Feb-04	Mar-04	Apr-04	May-04	Jun-04	Jul-04	Aug-04	Sep-04	Oct-04	Nov-04	Dec-04
AEP	13.1	22.0	16.7	22.0								
DLCO	50.2	68.3	43.1	34.5	175.6	104.6	67.2	55.5	35.0	123.6	140.2	207.5
FE	77.3	103.0	113.0	100.5	144.3	136.8	127.1	117.9	103.3	323.3	342.4	373.2
NYIS	865.5	875.3	1,086.0	854.8	562.1	844.8	696.5	714.7	801.1	1,283.2	1,134.3	821.1
VAP	16.0	21.9	21.9	67.2	105.9	118.6	107.3	68.8	48.3	453.4	567.5	488.7
AEPNI					1,327.3	1,281.3	1,342.6	1,355.0	1,464.8			
AEPPJM					86.0	97.9	50.8	27.8	18.6			
ALTE					115.3	100.9	93.4	100.3	98.6	102.5	100.7	108.9
ALTW					262.7	146.6	168.5	150.1	154.1	168.4	165.7	198.5
AMRN					84.7	122.6	108.3	144.3	58.3	263.7	165.7	258.0
CILC					1.3	14.8	1.2	4.5	3.5	0.1	0.2	0.6
IP					60.1	63.5	82.9	52.8	43.4	30.4	33.5	41.8
MEC					528.5	527.5	602.3	596.0	445.4	585.3	433.7	609.8
NIPS					159.9	83.2	124.4	303.7	192.3	20.5	12.5	13.6
WEC					420.2	312.5	270.5	177.8	338.9	259.6	280.8	358.2
MECS										828.3	845.1	922.8
CPLE										321.4	303.4	315.5
CPLW										73.1	69.3	72.1
CIN										142.2	688.4	414.7
DUK										320.4	177.0	312.7
EKPC										4.6	13.2	19.1
IPL										5.8	0.5	1.8
LGEE										1.9	2.8	4.6
OVEC										1.4	3.5	10.4
TVA										197.2	131.4	203.3

2004 Trends

With the integration of the ComEd Control Area, PJM's long-standing status as a net importer of power changed and PJM became a net exporter. In Phase 2, ComEd's net export volume exceeded the net import volume in the rest of the PJM system. PJM continued to be a net exporter after the integration of the AEP and DAY Control Zones. While most of ComEd's exports were at the PJM/AEPNI interface, PJM internalized the PJM/AEPNI and PJM/AEPPJM interfaces in Phase 3, yet continued to be a net exporter of power. Phase 3 exports were spread more evenly over multiple interfaces.

Changing Interfaces

New Interfaces

During 2004, PJM experienced two integrations, each of which changed the number of external interfaces. On May 1, 2004, when the ComEd Control Area became part of PJM, the RTO's boundaries were altered. The external interfaces changed from the five previous interfaces [NYIS, FE, DLCO, VAP and AEP] to a total of 14 external interfaces.

On October 1, when the AEP and DAY Control Zones became part of PJM, the boundaries shifted again. The number of external interfaces grew from 14 to 22.

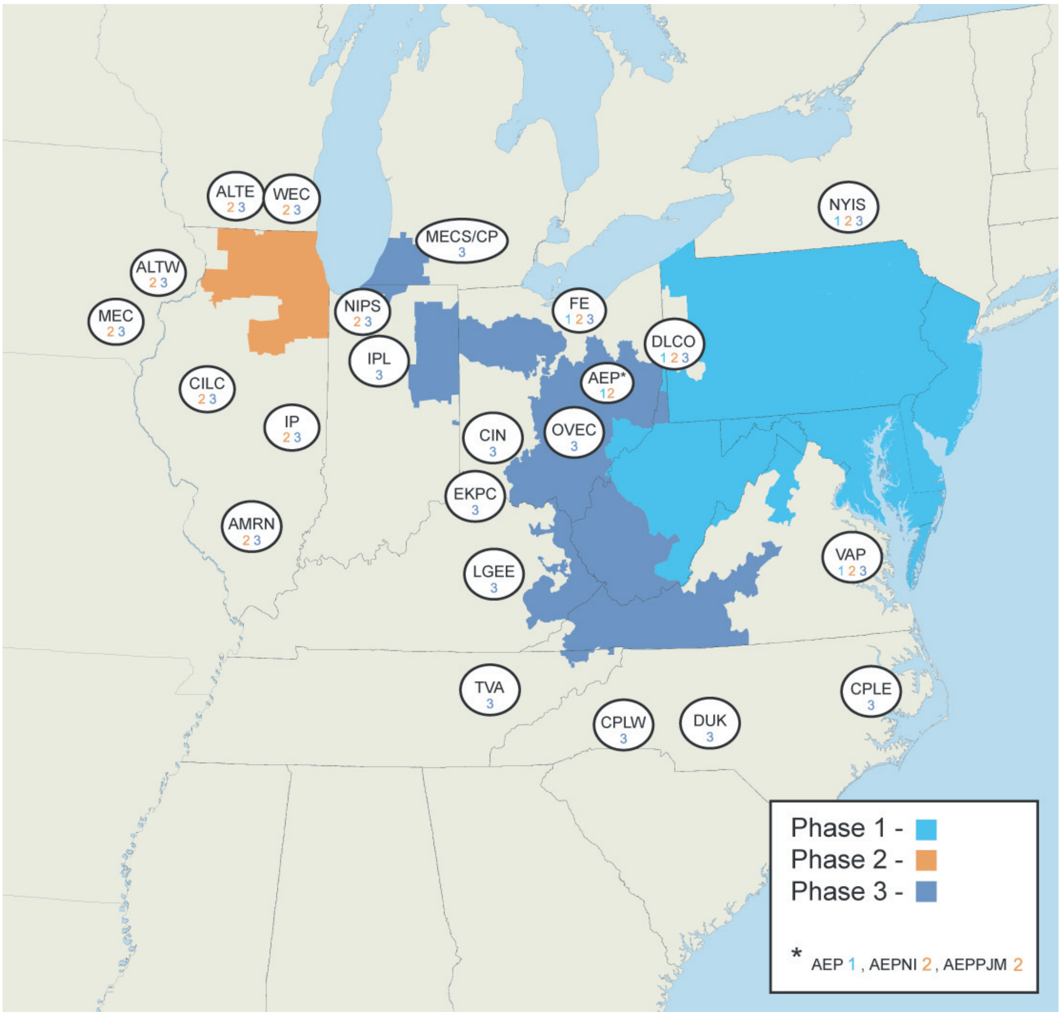
Table 3-4 shows the changes in interfaces during 2004.

Table 3-4 - Active interfaces: Calendar year 2004

Interface	Phase 1				Phase 2					Phase 3		
	Jan-04	Feb-04	Mar-04	Apr-04	May-04	Jun-04	Jul-04	Aug-04	Sep-04	Oct-04	Nov-04	Dec-04
AEP	Active	Active	Active	Active								
DLCO	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active
FE	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active
NYIS	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active
VAP	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active
AEPNI					Active	Active	Active	Active	Active			
AEPPJM					Active	Active	Active	Active	Active			
ALTE					Active	Active	Active	Active	Active	Active	Active	Active
ALTW					Active	Active	Active	Active	Active	Active	Active	Active
AMRN					Active	Active	Active	Active	Active	Active	Active	Active
CILC					Active	Active	Active	Active	Active	Active	Active	Active
IP					Active	Active	Active	Active	Active	Active	Active	Active
MEC					Active	Active	Active	Active	Active	Active	Active	Active
NIPS					Active	Active	Active	Active	Active	Active	Active	Active
WEC					Active	Active	Active	Active	Active	Active	Active	Active
MECS										Active	Active	Active
CPLE										Active	Active	Active
CPLW										Active	Active	Active
CIN										Active	Active	Active
DUK										Active	Active	Active
EKPC										Active	Active	Active
IPL										Active	Active	Active
LGEE										Active	Active	Active
OVEC										Active	Active	Active
TVA										Active	Active	Active

The approximate geographic location of these interfaces can be seen in Figure 3-4. The AEP interface had three variants in 2004, all of which are shown in Figure 3-4.

Figure 3-4 - PJM's evolving footprint and its interfaces



New Interface Pricing Points

Before ComEd's integration, the PJM interface pricing points had been: NYISO, AEPVPIMP, AEPVPEXP, FE, DLCO and the Ontario Independent Electricity System Operator (Ontario IESO). Interface pricing points differ from interfaces in that transactions can be scheduled to an interface based on a contract transmission path while pricing points are developed and applied based on the electrical impact of the external power source on PJM tie lines, regardless of the contract transmission path.[9] Interface pricing points were added and changed as PJM expanded in 2004. Table 3-5 illustrates which interface pricing points were used during each of the three phases of PJM's evolution during the year.

9 See Appendix D, "Interchange Transactions," for a more detailed discussion of interface pricing.

PJM establishes prices for transactions with external control areas by assigning interface pricing points to external control areas. The interface pricing points are designed to reflect the way a transaction from or to an external area actually impacts PJM electrically. External control areas are either adjacent to PJM or not adjacent to PJM. Transactions between PJM and external control areas need to be priced at the PJM border. A set of external pricing points is used to create such interface prices. The challenge is to create an interface price, composed of external pricing points, that accurately represents flows between PJM and an external control area and therefore to create price signals that embody the underlying economic fundamentals. Transactions between adjacent control areas and PJM flow on one or more physical tie lines that together constitute the interface between the two control areas.[10]

Table 3-5 - Active pricing points by interface: Calendar year 2004

Pricing Point	Phase 1				Phase 2					Phase 3		
	Jan-04	Feb-04	Mar-04	Apr-04	May-04	Jun-04	Jul-04	Aug-04	Sep-04	Oct-04	Nov-04	Dec-04
AEPVPEXP	Active	Active	Active	Active	Active	Active	Active	Active	Active			
AEPVPIMP	Active	Active	Active	Active	Active	Active	Active	Active	Active			
DLCO	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active
FE	Active	Active	Active	Active	Active	Active	Active	Active	Active			
Ontario IESO	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active
NYIS	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active
AEPNI					Active	Active	Active	Active	Active			
ALTENI					Active	Active	Active	Active	Active			
ALTWNI					Active	Active	Active	Active	Active			
AMRNNI					Active	Active	Active	Active	Active			
CILCNI					Active	Active	Active	Active	Active			
IPNI					Active	Active	Active	Active	Active			
IPPJMEXP					Active	Active	Active	Active	Active			
IPPJMIMP					Active	Active	Active	Active	Active			
MECNI					Active	Active	Active	Active	Active			
MECPJMEXP					Active	Active	Active	Active	Active			
MECPJMIMP					Active	Active	Active	Active	Active			
NIPSNI					Active	Active	Active	Active	Active			
NYISNIEXP					Active	Active	Active	Active	Active			
NYISNIIMP					Active	Active	Active	Active	Active			
WECNI					Active	Active	Active	Active	Active			
WECPJMEXP					Active	Active	Active	Active	Active			
WECPJMIMP					Active	Active	Active	Active	Active			
MICHFE										Active	Active	Active
NIPSCO										Active	Active	Active
NORTHWEST										Active	Active	Active
OVEC										Active	Active	Active
SOUTHEAST										Active	Active	Active
SOUTHWEST										Active	Active	Active

10 See Appendix D, "Interchange Transactions," for a more complete discussion of the development of pricing points.

Interchange Transaction Issues

TLRs

Data for Phase 3 indicate that PJM called fewer TLRs after the integration of the AEP and DAY Control Zones, that the reduced TLRs were primarily in the newly integrated control zones, that TLRs for the PJM Mid-Atlantic Region remained low and that the increase in TLRs in November and December over October was at a border facility affected by flows from a non-LMP market. Monthly average PJM TLRs declined by 60 percent, from 52 during Phase 2 to 21 in Phase 3. (See Figure 3-5.) A large proportion (45 percent) of these reductions came on flowgates located in AEP with an average of 18 TLRs per month in Phase 2 and four per month in Phase 3. PJM has been the control area reliability coordinator for AEP since February 2003 and in that capacity was responsible, among other functions, for calling TLRs to relieve transmission constraints. The flowgates on the border between PJM in Phase 2 and external control areas were the other primary source of reductions in TLRs in Phase 3. TLRs on flowgates in the PJM Control Area remained relatively unchanged, averaging between two and three per month. The number of unique flowgates for which PJM declared TLRs also declined, from an average of 13 different flowgates per month during Phase 2 to an average of six different flowgates per month in Phase 3. (See Figure 3-6.) Of the 63 TLRs called by PJM in Phase 3, 60 percent were on just one flowgate, Wylie Ridge, a facility particularly impacted by flow from the FE control area. Since FE is not part of PJM, TLRs are a primary method of constraint relief for Wylie Ridge. As with other chronically constrained facilities, TLRs for this constraint could be reduced through LMP-based redispatch if the generating units in the FE control area were available for such redispatch. While PJM does have an agreement with FE with regard to the redispatch of the Sammis Generating Station for congestion management, this was not adequate to entirely address the constraint issues at Wylie Ridge.[11]

Before the Phase 3 integration, PJM routinely called TLRs to relieve transmission constraints in the AEP control area on facilities like the Kanawah-Matt Funk 345 kV line and the Kammer Transformer. These AEP transmission constraints were integrated into PJM in Phase 3. As a result, TLRs for AEP have been reduced. Historically, these facilities had been responsible for the majority of PJM's declared TLRs. For example, flowgate 2403 (Kanawah-Matt Funk 345) had a monthly average of three TLRs from January 2003 through September 2004. In Phase 3, this number was reduced to an average of less than one TLR per month.

11 See "Amended and Restated Operating Agreement of PJM Interconnection, L.L.C." (December 30, 2004), p. Original Sheet No. 141D < http://www.pjm.com/documents/ downloads/agreements/oa.pdf > (613 KB).

Figure 3-5 - PJM and Midwest ISO transmission loading relief (TLR) procedures: 2003 and 2004

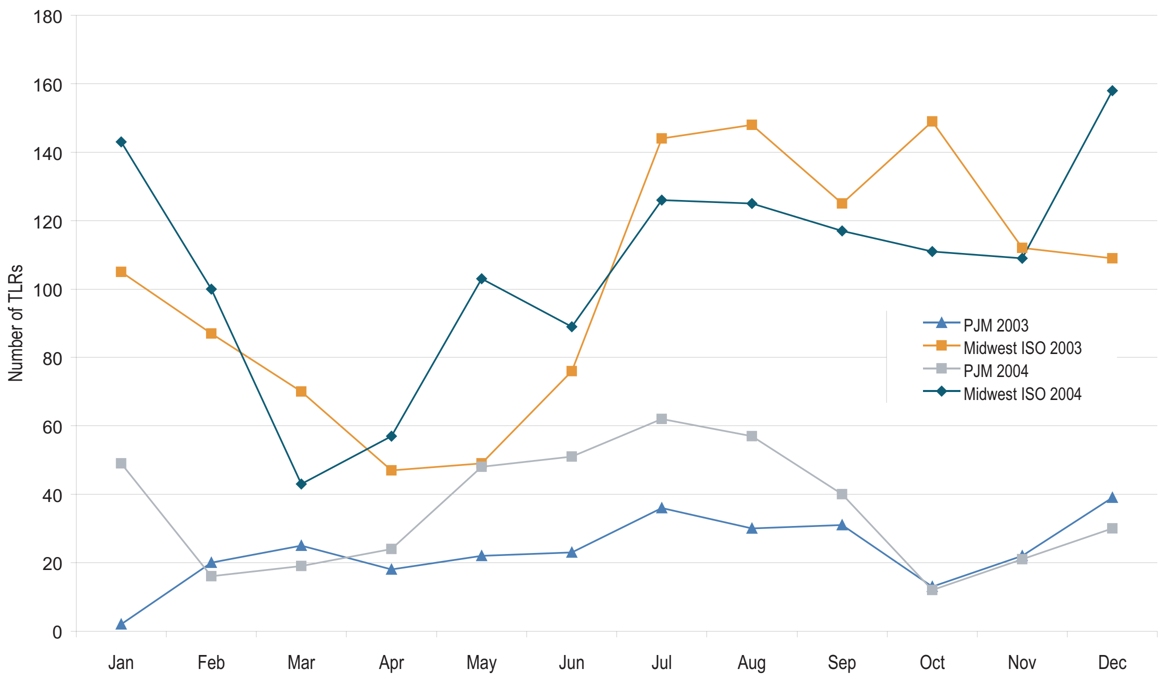
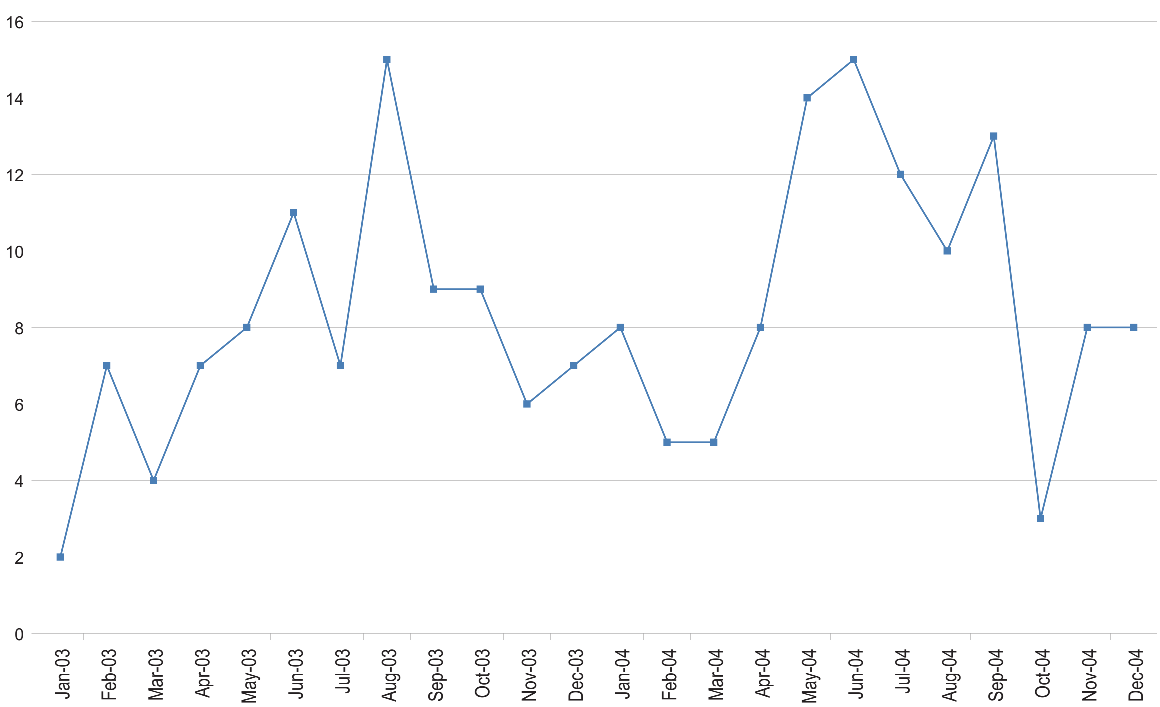


Figure 3-6 - Number of unique PJM flowgates: Calendar years 2003 to 2004



Following the completion of the Phase 3 integrations, the general relationship between the number of TLRs declared by the Midwest ISO and the number declared by PJM has continued. (See Figure 3-5.) Reliance on economic redispatch in response to pricing signals reduces the need to call TLRs to resolve constraints within an RTO although not necessarily at the border between an LMP market and a contract path market. The Midwest ISO system currently relies on TLRs to provide relief, but is expected to rely on redispatch when its power markets begin to operate.

The PJM/ Midwest ISO Joint Operating Agreement (JOA)

PJM and the Midwest ISO entered into a JOA that became effective on March 1, 2004, in anticipation of the integration of ComEd, AEP and DAY and their power flow effects. The JOA specifically indicated that "[…] certain other electric utilities will be integrated into the systems and markets PJM administers and controls, and it is recognized that such integration may result in changed flows on the system of PJM and the Midwest ISO as they exist prior to such integration."[12] A major part of the JOA dealt with congestion management at the "seams" of the control areas. As a market-based system, PJM controls congestion through LMP while the Midwest ISO will continue to use TLRs for congestion control until it introduces markets.[13] The JOA addresses issues so as to consistently ensure that parallel path flows and impacts are recognized and managed consistent with ensuring system reliability.[14]

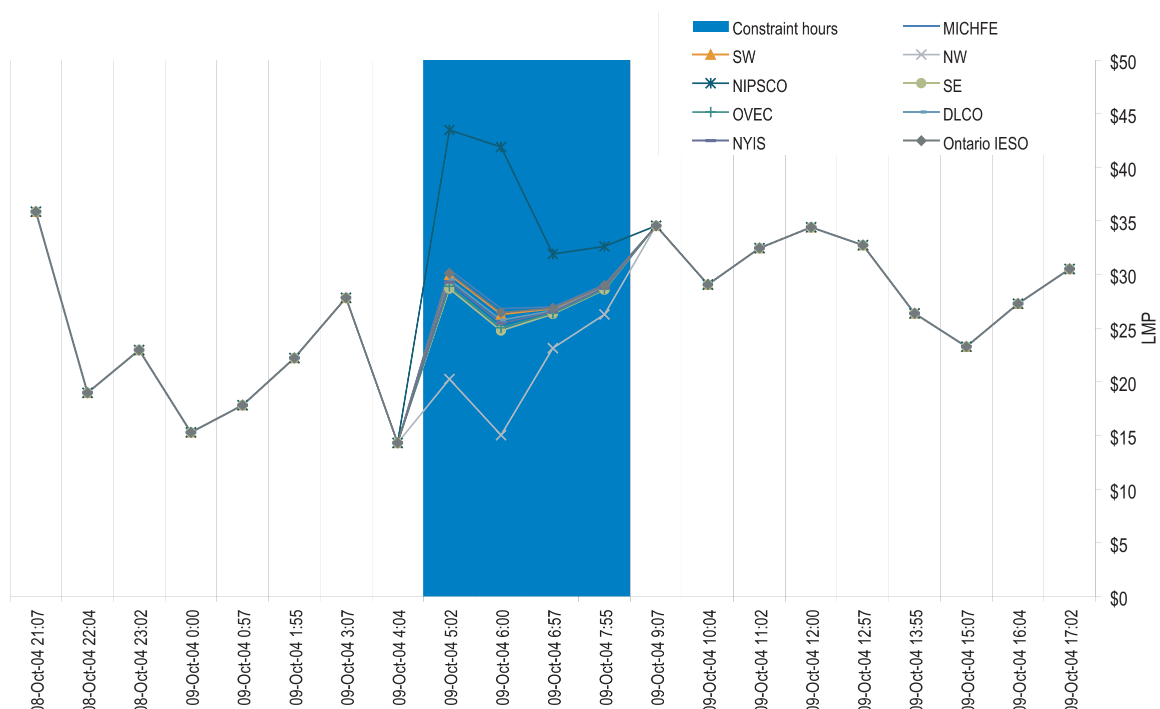
The JOA includes a list of flowgates[15] where PJM and the Midwest ISO plan a coordinated response to congestion events and for which PJM will redispatch generation to aid in reducing congestion.[16] Generally, the JOA describes a process whereby the flows of power within PJM (the market-based entity) which impact a coordinated flowgate are categorized as "firm" and "non-firm" flows.[17] Firm power flows are those from designated network resources used to serve designated network loads and firm point-to-point network and native load (NNL) customers. All other flows are categorized as economic dispatch "non-firm" flows. Further, each unit within PJM that is contributing to these flows is identified. This categorization of power flows and identification of units contributing to those flows allows the power flows in PJM's market system to be compatible with the transmission service categories used in a TLR-based congestion management system. When a congestion event on a coordinated flowgate occurs, units can be redispatched and/or TLRs can be called to provide the most effective relief in a consistent manner.

During October 2004, a number of coordinated flowgates in the Midwest ISO experienced congestion and PJM redispatched generation to provide relief. When PJM redispatches for flowgate control, LMP increases on the congested side, but falls on the uncongested side. These price movements are economic signals that represent the relative value of generation and load in areas surrounding the constraint. Figure 3-7 depicts such actions at a time when a coordinated flowgate was actually constrained.

12 See the JOA between the Midwest ISO and PJM (December 31, 2003), Original Sheet No. 3 <http://www.pjm.com/ documents/downloads/agreements/joa-complete.pdf> (906 KB).
13 In the future the Midwest ISO will transition to a market-based system. At that time, the Phase 2, market-to-market of this JOA will be implemented.
14 See generally the JOA between the Midwest ISO and PJM (December 31, 2003) <http://www.pjm.com/documents/downloads/agreements/joa-complete.pdf> (906 KB).
15 "Flowgate refers to a representative modeling of facilities or groups of facilities that may act as potential constraint points on the regional system." See the JOA between the Midwest ISO and PJM (December 31, 2003), Substitute Original Sheet No. 8 (Issued April 2, 2004) <http://www.pjm.com/documents/downloads/agreements/joa-complete.pdf> (906 KB).
16 "Coordinated flowgate or (CF) shall mean a Flowgate impacted by an Operating Entity as determined by one of the four studies detailed in Section 3 of the Congestion Management Process. For a Market-Based Operating Entity, these Flowgates will be subject to the requirements of the congestion management portion of the Congestion Management Process (Sections 4 and 5). A coordinated flowgate may be under the operational control of a third party." JOA, Substitute Original Sheet No. 34 (Issued April 2, 2004). PJM and the Midwest ISO are operating entities.
17 See the JOA between the Midwest ISO and PJM (December 31, 2003), Attachment 2, "Congestion Management Process" (Issued April 2, 2004), p. 101 <http://www.pjm.com/ documents/downloads/agreements/joa-complete.pdf> (906 KB).

The Crete – St. Johns Tap 345 kV line, located near the southern tip of Lake Michigan, is one of several facilities that have experienced constrained conditions. Congestion there results from power flows around the tip of Lake Michigan from northwest Indiana into Michigan. When these flow patterns develop and cause congestion, PJM's redispatch of generating units results in a pricing arrangement that lowers LMP on the western, uncongested side of the constraint, but raises it on the eastern, congested side. One way to observe this relationship is to examine pricing point LMPs during an actual event. (See Figure 3-7.) In this example, on the morning of October 9th, when the Crete – St. Johns Tap flowgate was constrained, the NIPSCO pricing point (constrained side) LMP rose to over $43 while the Northwest pricing point LMP fell to $15. This $28 difference in LMP represents the result of PJM's redispatch actions to reduce congestion on the flowgate. After the constraint had cleared, LMP separation ceased and PJM's pricing point LMPs were again equal.

Figure 3-7 - Midwest ISO constraints and pricing point LMPs: October 8 to 9, 2004



If one starts with an uncongested system (represented by equal pricing point LMPs), LMP at one or more pricing points will increase while LMP at others will decrease during a congestion event. In the example, one sees that all PJM pricing points have the same LMP (all lines are drawn on top of each other) in the hours before the constrained period (blue-shaded area). During the time of constraint, price separation at the pricing points (and elsewhere) occurs when units are redispatched and the congestion is resolved. Generally, because the redispatching process adds generation that is more expensive than that running before the event, LMP rises. The economic dispatch process brings the output of the lower-priced generation to the point that any further output from it aggravates the constraint. Then higher-priced units, located on the side of the constraint that needs additional power, begin to produce it. One sees in the blue-shaded area that pricing point LMPs change relative to each other during the congestion event. The NIPSCO pricing point LMP moves in a higher direction while the Northwest pricing point LMP moves lower. The other pricing point LMPs also change, but not as significantly as those associated with NIPSCO and Northwest. Their pricing points carry the greatest burden of congestion at the Crete – St. Johns Tap facility. A constraint on another facility would cause a different pattern of separation. One should note, however, that the other pricing point LMPs do change with congestion at Crete – St. Johns Tap. The magnitude of a constraint's impact on any pricing point is clear from the amount of change in its LMP. After the redispatching process has relieved the constrained facility, the system comes to equilibrium and pricing point LMPs are all equal again. When one looks at PJM during the October 2004 congestion events of the coordinated flowgates, the average high price was $43.30 and the average low was $19.32. The greatest separation was $104.08.

Price separation at pricing points also occurs when facilities other than coordinated flowgates are congested. If one were to compare the variability of pricing point LMPs during periods of constrained and unconstrained operation of coordinated flowgates, one would see that price separation at the pricing points is higher when the coordinated flowgates are constrained. This is true, even if congestion is present elsewhere when the coordinated flowgates are unconstrained.

In October 2004, the standard deviation of pricing point LMPs was $2.32 in the hours when none of the coordinated flowgates were congested. This value provides a reference point. During the hours when coordinated flowgates were congested, the average standard deviation of the LMPs was $6.72, or almost triple the price variance experienced when the coordinated flowgates were uncongested. Congestion on coordinated flowgates causes a much greater variance in interface pricing point LMP than occurs when other parts of the system are congested.

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 although actual, associated energy deliveries flow on the path of least resistance. Loop flow can also occur 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 result when transactions are scheduled into or out of PJM on one interface, but actually flow on another interface. PJM can only manage loop flow based on contract paths between external systems using TLR procedures. Loop flow based on gaming PJM price differentials can be managed, in part, by improving the pricing of transactions at the PJM interfaces.

Although total PJM net scheduled and actual flows were approximately equal in 2004, such was not the case for each individual interface. (See Table 3-6.) As a general matter, PJM operates so as to balance overall actual and scheduled interchange, but does not attempt to maintain a balance between actual and scheduled interchange at individual interfaces.

During Phase 1, for PJM as a whole, net scheduled and actual interface flows were comparatively balanced. Actual system imports were 7.0 million MWh, below the scheduled total of 7.4 million MWh by less than 0.4 million MWh or approximately 5 percent. Flow balance varied, however, at each individual interface. The PJM/NYIS interface was the most imbalanced, with net actual exports exceeding scheduled by 1.4 million MWh or 47 percent, for an average of 491 MW during each hour of the period. At the PJM/AEP interface, net actual imports exceeded scheduled by 0.5 million MWh or 11 percent. At the PJM/FE interface, net scheduled imports exceeded actual by less than 0.3 million MWh or 5 percent. At the PJM/DLCO interface, net actual imports exceeded scheduled by 0.6 million MWh or 184 percent. At the PJM/VAP interface, net actual imports exceeded scheduled by 0.2 million MWh or 66 percent.

During Phase 2, for PJM as a whole, net scheduled and actual interface flows were comparatively balanced. Actual system exports were 5.6 million MWh, equaling the scheduled total of 5.6 million MWh. Flow balance varied, however, at each individual interface. The PJM/AEPPJM interface was the most imbalanced, with net actual imports exceeding scheduled by 3.0 million MWh or 86 percent, for an average of 825 MW during each hour. At the PJM/NYIS interface, net actual exports exceeded scheduled by 2.8 million MWh or 164 percent.

During Phase 3 of 2004, for PJM as a whole, net scheduled and actual interface flows were comparatively balanced. Actual system exports were 3.6 million MWh, exceeding the scheduled total of 3.7 million MWh by 0.1 million MWh or 2 percent. Flow balance varied, however, at each individual interface. The PJM/MECS interface was the most imbalanced, with net actual exports exceeding scheduled by 1.6 million MWh or 71 percent, for an average of 722 MW during each hour of the period. At the PJM/TVA interface, net actual imports exceeded net scheduled exports by 1.5 million MWh or 413 percent. At the PJM/IP interface, net scheduled exports exceeded actual by 1.4 million MWh or 62 percent. At the PJM/OVEC interface, net actual imports exceeded scheduled by 1.2 million MWh or 55 percent.

Table 3-6 - Net scheduled and actual PJM interface flows (MWh x 1,000): Calendar year 2004

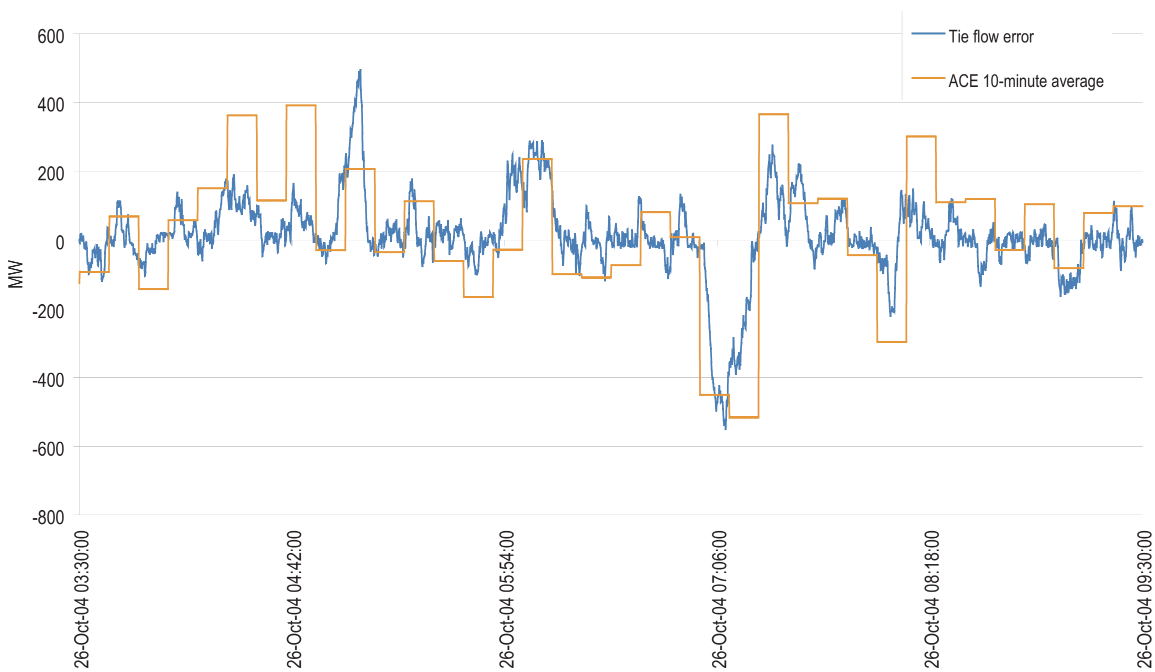
Interface	Actual	Net scheduled	Difference	Difference (Percent)
AEP	5,080	4,571	509	11%
DLCO	863	304	560	184%
FE	4,937	5,190	-252	-5%
NYIS	-4,487	-3,060	-1,427	47%
VAP	605	364	240	66%
Phase 1 System	6,999	7,369	-370	-5%
AEPPJM	6,574	3,543	3,031	86%
AEPNI	-4,323	-6,549	2,226	-34%
WEC	202	-1,502	1,704	-113%
AMRN	-751	-333	-417	125%
ALTE	-2,603	-508	-2,095	412%
IP	43	1,040	-997	-96%
CILC	367	-1	368	-65917%
NIPS	-2,150	-536	-1,613	301%
ALTW	-1,183	-851	-332	39%
MEC	-1,914	-2,657	743	-28%
DLCO	746	168	579	345%
FE	5,016	4,626	390	8%
NYIS	-4,551	-1,726	-2,825	164%
VAP	-1,109	-353	-756	214%
Phase 2 System	-5,635	-5,640	5	-0%
CPLE	102	-654	756	-116%
CPLW	-650	-193	-458	237%
DUK	-772	-525	-247	47%
EKPC	57	37	21	56%
OVEC	3,345	2,161	1,184	55%
TVA	1,132	-362	1,494	-413%
CIN	1,004	89	914	1024%
IPL	1,194	45	1,148	2534%
LGEE	191	173	18	10%
MECS	-3,841	-2,246	-1,594	71%
WEC	236	-769	1,005	-131%
AMRN	300	35	265	761%
ALTE	-1,602	-277	-1,325	479%
IP	903	2,351	-1,448	-62%
CILC	502	13	489	3831%
NIPS	-967	126	-1,093	-865%
ALTW	-640	-464	-176	38%
MEC	-746	-1,391	644	-46%
DLCO	333	-102	435	-425%
FE	1,116	1,992	-876	-44%
NYIS	-3,746	-2,427	-1,319	54%
VAP	-1,079	-1,312	233	-18%
Phase 3 System	-3,630	-3,700	70	-2%

Transactions and PJM Area Control Error (ACE)

A critical operations function for PJM is balancing load and generation on a real-time basis. The ACE metric defines this balance.[18] The net contribution of external transactions is an important component of the generation element of ACE. Import and export transactions are netted and the result is added to the generation component of ACE. When the sum of scheduled and the sum of actual power flows to or from external areas differ, a deviation between generation and load is created. This is equivalent to a generator that is dispatched, but then over- or under-generates compared to the expected output level. When PJM experiences ACE deviation, the difference between actual and scheduled transaction power flows can be part of the reason. This is termed tie flow error.

Figure 3-8 provides an example of the contribution of tie flow error to ACE deviation. The ACE measurement (actually a 10-minute average of the ACE) is plotted against the tie flow error. There is a positive correlation between the level of tie flow errors and ACE deviation. The mismatch between scheduled and actual flow contributes to the ACE deviation and thus requires corrective action by PJM.

Figure 3-8 - Contribution of tie flow error to area control error (ACE)



PJM and NYISO Transaction Issues

If the interface prices were defined in a comparable manner by PJM and the NYISO, if there were identical rules governing external transactions in PJM and the NYISO, if there were not time lags built into the rules governing such transactions and if there were no risks associated with such transactions, prices at the interfaces would be expected to be very close and the level of transactions

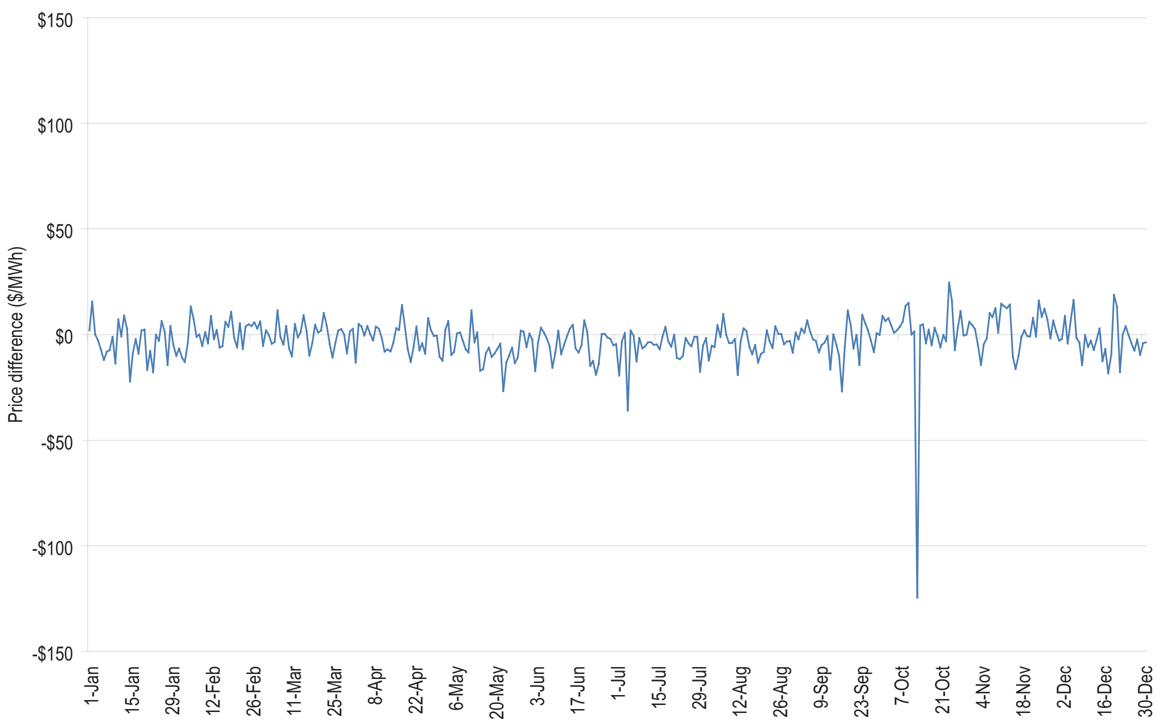
18 See Appendix F, "Ancillary Service Markets."

would be expected to be related to any price differentials. The fact that none of these conditions exists is important in explaining the observed relationship between interface prices and inter-ISO power flows, and those price differentials.[19]

PJM's price for transactions with the NYISO, termed the NYIS pricing point by PJM, represents the value of power at the PJM-NYISO border, as determined by the PJM Market. Similarly, the NYISO's price for transactions with PJM, termed the PJM proxy bus by the NYISO, represents the value of power at the NYISO-PJM border, as determined by the NYISO market.

The 2004 hourly average prices for PJM/NYIS and the NYISO PJM proxy bus price were $46.72 and $44.33, respectively. The simple average difference between the PJM/NYIS interface price and the NYISO PJM proxy bus price increased and changed sign from 2003 to 2004 yet remained relatively small and the variability in the difference decreased. The simple average PJM NYISO interface price difference was $0.34 per MWh in 2003 and $-2.39 per MWh in 2004. (See Figure 3-9.) The PJM/NYIS price was higher on average than the NYISO PJM proxy bus price in 2004. This reverses the prior pattern where the NYISO PJM proxy bus price was higher than the PJM/NYIS price. The fact that PJM's net export flow volume for 2004, at 7.4 million MWh, is 28 percent lower than the three-year, 2001-to-2003 average is at least partially consistent with the change in the simple average price difference. While relatively small, the simple average interface price difference does not reflect the continuing, substantial underlying hourly variability in prices during 2003 and 2004.

Figure 3-9 - Daily hourly average price difference (NY proxy - PJM/NYIS): Calendar year 2004



19 See also the discussion of these issues in the *2003 State of the Market Report*, Section 3, "Interchange Transactions."

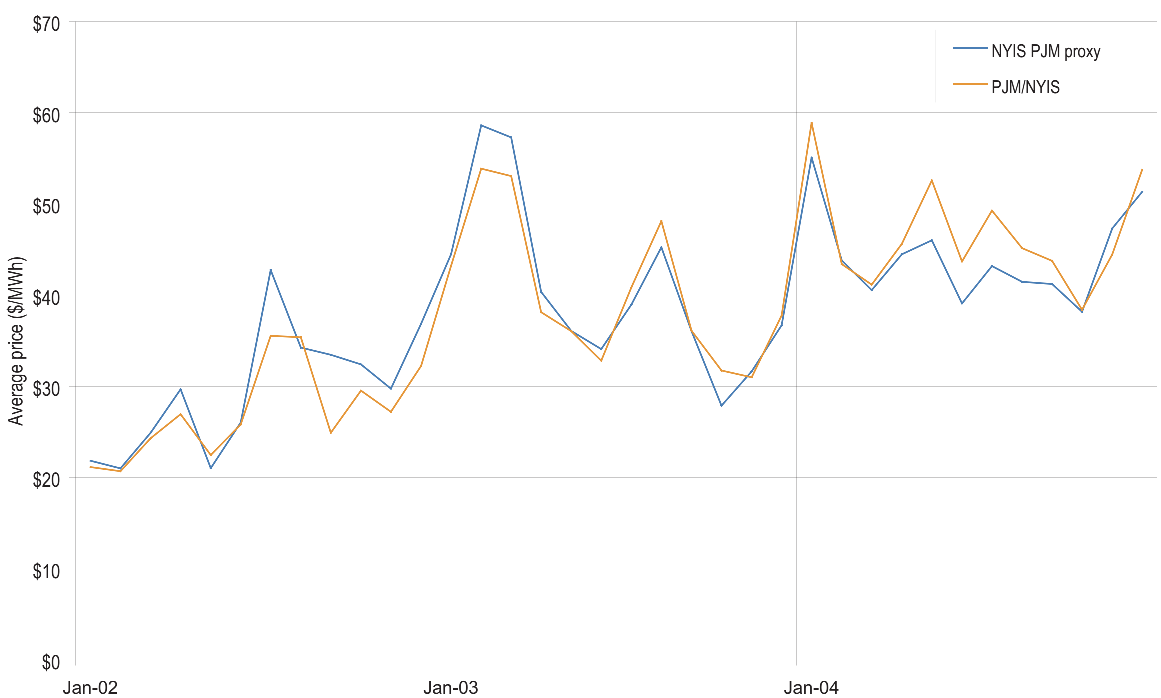
The difference between the PJM/NYIS interface price and the NYISO PJM proxy bus price fluctuated between positive and negative about eight times per day during 2003 and 2004. The number of times that the price difference fluctuated remained relatively constant over the period.

Standard deviation is a direct measure of variability. The standard deviation of hourly price was \$25.00 in 2003 and \$23.64 in 2004 for the PJM/NYIS price, but \$37.72 in 2003 and \$30.00 in 2004 for the NYISO PJM proxy bus price. The standard deviation of the difference in interface prices was \$36.21 in 2003 and \$29.55 in 2004. The absolute value of the price differences is another measure of price variability. The average of the absolute value of the hourly price difference was \$16.13 in 2003 and \$14.01 in 2004. Absolute values reflect the price differences without regard to whether they are positive or negative.

A number of factors are responsible for the observed relationship between interface prices. The fact that the simple average of interface prices is relatively small suggests that competitive forces prevent price deviations from persisting. That is further supported by the frequency with which the price differential switches between positive and negative. However, continuing significant variability in interface prices is consistent with the fact that interface prices are defined and established differently, making it difficult for prices to equalize, regardless of other factors.

In addition to small, average interface price differences and to large hourly price differences, there is a significant correlation between monthly average hourly PJM and NYISO interface prices during the entire period 2002 to 2004. Figure 3-10 shows this correlation between hourly PJM and NYISO interface prices.

Figure 3-10 - Monthly hourly average NYISO PJM proxy bus price and the PJM/NYIS price: Calendar years 2002 to 2004



SECTION 4 - 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.[1]

The PJM Capacity Credit Market[2] and the ComEd Capacity Credit Market[3] 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,[4] 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.

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.[5] 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.

- **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).[6]

- **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.

1 See Appendix H, "Glossary," for definitions of PJM Capacity Credit Market terms.
2 All PJM Capacity Market values (capacities) are in terms of unforced MW.
3 All ComEd Capacity Market values (capacities) are in terms of installed MW.
4 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.
5 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.
6 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).

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. [7]

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. [8]

Overview

The PJM Market Monitoring Unit (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.

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.

7 "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.
8 For purposes of this "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.

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,[9] average installed capacity increased by 7,781 MW or 11.1 percent to 77,673 MW, 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.

9 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.

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.[10]

  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.

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

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[11] percent in 2003. In 2004, the average PJM EFORd continued its upward trend, reaching 8.0 percent. 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).[12]

11 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.
12 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.

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.

Market Structure for the PJM Capacity Market

Ownership Concentration

Phases 1 and 2

Concentration ratios[13] are a summary measure of market share, a key element of market structure. High concentration ratios mean that a comparatively small number of sellers dominate a market, while low concentration ratios mean that a larger number of sellers shares market sales more equally. Concentration measures must be applied carefully in assessing the competitiveness of markets. Low aggregate market concentration ratios do not establish that a market is competitive, that market participants cannot exercise market power or that concentration is not high in particular geographic market areas. High aggregate market concentration ratios do, however, indicate an increased potential for market participants to exercise market power.

The MMU structural analysis indicates that the PJM Capacity Credit Markets in the first and second intervals of 2004 exhibited moderate levels of concentration in the Daily Capacity Credit Market and high levels of concentration in the Monthly and Multimonthly Capacity Credit Markets. As shown in Table 4-1, HHIs for the Daily Capacity Credit Market averaged 1373 during the first and second intervals of 2004, with a maximum of 3096 and a minimum of 1050 (four firms with equal market shares would result in an HHI of 2500). HHIs for the longer term Monthly and Multimonthly Capacity Credit Markets averaged 3319, with a maximum of 8900 and a minimum of 1114 (three firms with equal market shares would result in an HHI of 3333). On average, 1,087 MW were traded in the Daily Capacity Credit Market and 4,031 MW were traded in the Monthly and Multimonthly Capacity Credit Markets. The total of 5,118 MW represented, on average, 7.2 percent of total load obligation for the period of which 1.5 percent was attributable to the Daily Capacity Credit Market and 5.7 percent was attributable to the Monthly and Multimonthly Capacity Credit Markets.

13 See Section 2, "Energy Market," for a more detailed discussion of concentration ratios and the HHI.

Table 4-1 - PJM Capacity Market HHI: Calendar year 2004

Term	Statistic	Daily Market HHI	Monthly and Multimonthly Market HHI
Phases 1 and 2	Average	1373	3319
	Minimum	1050	1114
	Maximum	3096	8900
Phase 3	Average	1631	2608
	Minimum	1292	1316
	Maximum	2561	4151
Calendar Year	Average	1516	3031
	Minimum	1050	1114
	Maximum	3096	8900

Table 4-2 - PJM Capacity Market residual supply index (RSI): Calendar year 2004

Term	Statistic	Daily Market RSI	Monthly and Multimonthly Market RSI
Phases 1 and 2	Average	1.72	0.61
	Minimum	0.44	0.01
	Maximum	2.51	2.36
Phase 3	Average	6.22	2.95
	Minimum	2.11	0.26
	Maximum	9.97	14.92
Calendar Year	Average	4.21	1.74
	Minimum	0.44	0.01
	Maximum	9.97	14.92

Table 4-2 shows residual supply index (RSI) values for the Daily Capacity Credit Market Auctions and the Monthly and Multimonthly Capacity Credit Market Auctions for the PJM Capacity Market. The RSI is a measure of the extent to which generation owners are pivotal suppliers in the PJM Capacity Market. A generation owner is pivotal if the capacity of the owner's generation facilities is needed to meet the demand for capacity. When a generation owner is pivotal, it has the ability to affect market 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. 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 unilaterally 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 significant ability to influence prices.

The RSI results for the Daily Capacity Credit Market indicate that the RSI fell below 1.0 in 73 (27 percent) of the daily auctions, while the average level was 1.72. The RSI results for the Monthly and Multimonthly Markets indicate that the average RSI was 0.61 with 44 of the monthly auctions (81 percent) having RSI values less than 1.0. These results are consistent with the conclusion that there were significant structural issues in the Capacity Markets in PJM in Phases 1 and 2.

Phase 3

The MMU structural analysis indicates that the PJM Capacity Credit Markets in the third interval of 2004, after the integration of the AEP and DAY Control Zones, exhibited moderate levels of concentration in the Daily Capacity Credit Market and high levels of concentration in the Monthly and Multimonthly Capacity Credit Markets. As shown in Table 4-1, HHIs for the Daily Capacity Credit Market averaged 1631 during the last interval of 2004; with a maximum of 2561 and a minimum of 1292 (three firms with equal market shares would result in an HHI of 3333). HHIs for the longer term Monthly and Multimonthly Capacity Credit Markets averaged 2608, with a maximum of 4151 and a minimum of 1316. On average 986 MW were traded in the Daily Capacity Credit Market and 3,775 MW were traded in the Monthly and Multimonthly Capacity Credit Markets. The total of 4,761 MW represented, on average, 4.8 percent of total load obligation for the period, of which 1.0 percent was attributable to the Daily Capacity Credit Market and 3.8 percent was attributable to the Monthly and Multimonthly Capacity Credit Markets.

RSI results for Phase 3 indicate that RSI levels were higher for both the Daily Capacity Credit Markets and the Monthly and Multimonthly Capacity Credit Markets than in Phases 1 and 2. However, the RSI levels still fell below 1.0 five times (28 percent) in the long-term Capacity Markets.

Demand

Phases 1 and 2

During the first and second intervals of 2004, PJM EDCs[14] and their affiliates maintained a large market share of load obligations in the PJM Capacity Market, averaging 76 percent (Figure 4-1), a reduction of 14 percentage points from 2003. The market share of PJM EDCs alone averaged 58 percent of the PJM load while the market share of their affiliates averaged 18 percent. The market shares for 2003 were 68 percent and 22 percent, respectively. The market share of LSEs not affiliated with any EDC was 6 percent and the market share of non-PJM EDCs and their affiliates averaged 18 percent. The corresponding values from 2003 were 4 percent and 6 percent, respectively.

During the first and second intervals of 2004, reliance on the PJM Capacity Credit Markets varied by sector. [15] As Table 4-3 shows, PJM EDCs relied on the Capacity Credit Markets for an average of -0.8 percent of their 2004 first and second interval unforced capacity obligations, while their affiliates relied on Capacity Credit Markets for an average of 1.5 percent of theirs. Affiliates of non-PJM EDCs obtained an average of -4.4 percent of their unforced capacity obligations from the

14 PJM electricity distribution companies (EDCs) refer to entities with a franchise service territory within the PJM boundaries. Non-PJM EDCs are electricity distribution companies whose franchise service territories lie outside of PJM boundaries.
15 The measure of a sector's reliance on the Capacity Credit Market is the sector's daily net Capacity Credit Market position divided by its capacity obligation. (This excludes self-supply and bilateral transactions.) Thus, a negative share means that a sector sold more capacity credits than it purchased for the relevant time period. A positive number means that a sector purchased more capacity credits than it sold for the relevant time period.

Capacity Credit Markets, while unaffiliated LSEs obtained an average of 15.2 percent of their capacity obligations from the Capacity Credit Markets. The large increase in reliance on the Capacity Credit Markets by unaffiliated LSEs in June 2004 was the result of the expiration of unit-specific bilateral contracts held by unaffiliated LSEs. In June these contracts were replaced by reliance on the Daily Capacity Credit Market. The reliance of unaffiliated LSEs on the Capacity Credit Markets subsequently decreased as these LSEs entered into bilateral capacity credit contracts during the rest of the second interval.

Figure 4-1 - PJM Capacity Market load obligation served (Percent): Calendar year 2004

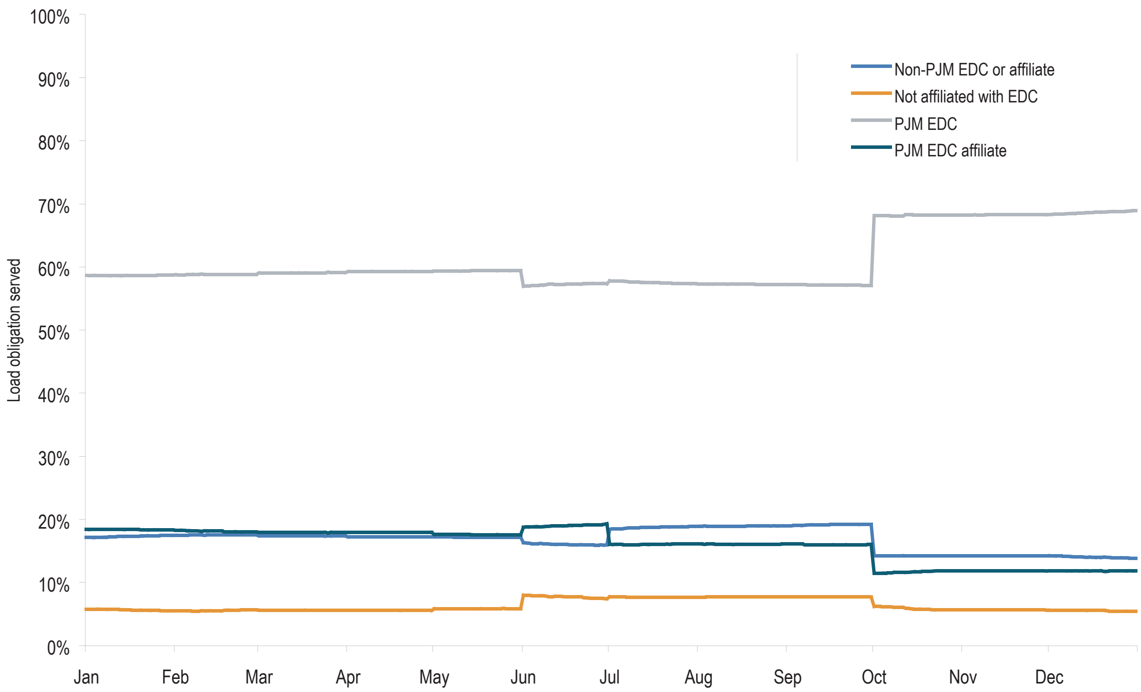


Table 4-3 - Load obligation served by PJM Capacity Market sectors: Calendar year 2004

	PJM EDC			PJM EDC Affiliate			Non-PJM EDC or Affiliate			Not Affiliated with EDC		
	Average Obligation (MW)	Average CCM Credits (MW)	CCM Credits to Obligation	Average Obligation (MW)	Average CCM Credits (MW)	CCM Credits to Obligation	Average Obligation (MW)	Average CCM Credits (MW)	CCM Credits to Obligation	Average Obligation (MW)	Average CCM Credits (MW)	CCM Credits to Obligation
Jan	41,256	-786	-1.9%	12,928	-16	-0.1%	12,177	-75	-0.6%	3,982	876	22.0%
Feb	41,454	-769	-1.9%	12,772	199	1.6%	12,343	-208	-1.7%	3,916	777	19.9%
Mar	41,651	-826	-2.0%	12,656	610	4.8%	12,257	-268	-2.2%	3,962	484	12.2%
Apr	41,853	-351	-0.8%	12,656	529	4.2%	12,154	-607	-5.0%	3,943	429	10.9%
May	41,940	-337	-0.8%	12,427	309	2.5%	12,138	-186	-1.5%	4,133	214	5.2%
Jun	40,569	-381	-0.9%	13,467	-388	-2.9%	11,372	-541	-4.8%	5,481	1,310	23.9%
Jul	40,915	-178	-0.4%	11,412	158	1.4%	13,311	-1,063	-8.0%	5,481	1,083	19.8%
Aug	40,781	266	0.7%	11,444	188	1.6%	13,493	-1,115	-8.3%	5,503	661	12.0%
Sep	40,756	205	0.5%	11,416	85	0.7%	13,656	-857	-6.3%	5,511	567	10.3%
Oct	67,401	-190	-0.3%	11,556	-25	-0.2%	14,082	-669	-4.8%	5,807	884	15.2%
Nov	67,497	-36	-0.1%	11,720	-229	-2.0%	14,096	-455	-3.2%	5,589	720	12.9%
Dec	67,898	56	0.1%	11,717	-97	-0.8%	13,875	-669	-4.8%	5,482	711	13.0%
AVERAGE												
Calendar Year	47,867	-276	-0.6%	12,176	111	0.9%	12,917	-561	-4.3%	4,902	726	14.8%
Jan-May	41,632	-613	-1.5%	12,687	327	2.6%	12,213	-267	-2.2%	3,988	554	13.9%
Jan-Sep	41,242	-350	-0.8%	12,348	187	1.5%	12,548	-548	-4.4%	4,659	710	15.2%
Jun-Sep	40,757	-21	-0.1%	11,926	14	0.1%	12,965	-897	-6.9%	5,494	905	16.5%
Oct-Dec	67,599	-57	-0.1%	11,663	-116	-1.0%	14,017	-599	-4.3%	5,626	772	13.7%

Phase 3

During the third interval of 2004, PJM EDCs and their affiliates gained market share of PJM load obligations, averaging 80 percent. (See Figure 4-1.) The market share of PJM EDCs averaged 68 percent of the PJM load. The market share of the affiliates of PJM EDCs averaged 12 percent. The market share of entities not affiliated with an EDC was about 6 percent and the market share of non-PJM EDCs and their affiliates averaged about 14 percent.

During the third interval of 2004, reliance on the PJM Capacity Credit Markets varied by sector. As Table 4-3 shows, PJM EDCs relied on Capacity Credit Markets for an average of -0.1 percent of their 2004 third interval unforced capacity obligation while their affiliates relied on Capacity Credit Markets for an average of -1.0 percent of theirs. Affiliates of non-PJM EDCs obtained an average of -4.3 percent of their unforced capacity obligations from the Capacity Credit Markets, while unaffiliated LSEs obtained an average of 13.7 percent of their capacity obligations from the Capacity Credit Markets.

Supply and Demand

Phases 1 and 2

- **First Interval of 2004.** During the first interval of 2004, capacity resources exceeded capacity obligations in PJM on every day. The pool was long by an average of 2,359 MW. In other words, capacity resources exceeded obligation, on average, by 2,359 MW daily. This is considered an excess capacity position. The amount of capacity resources in PJM on any day reflects the addition of new resources, the retirement of old resources and the importing or exporting of capacity resources. These daily changes are functions of market forces. The total pool capacity obligation is set annually via an administrative process.

  System net excess capacity can be determined using unforced capacity, obligation, the sum of members' excesses and the sum of members' deficiencies. Table 4-4 presents these data for the first interval of 2004.[16] Net excess is the net pool position, calculated by subtracting total capacity obligation from total capacity resources. Since total capacity obligation includes expected total load plus a reserve margin, a pool net excess position of zero is consistent with established reliability objectives.

  As shown in Figure 4-2, Figure 4-3 and Figure 4-4, capacity owners' external purchases (imports) of capacity resources were relatively flat through most of the first interval. This is consistent with the fact that the external daily forward energy price spread against PJM prices did not provide a consistent price signal over the interval.[17] These external transactions include approximately 1,200 MW of capacity resources that were exported to the NYISO throughout calendar year 2004.

- **Second Interval of 2004.** During the second interval of 2004, capacity resources exceeded capacity obligations in PJM on every day. The pool was long by an average of 695 MW. Table 4-5 presents these data for the second interval of 2004.[18] The primary reason for the reduction in system excess was that, as shown in Figure 4-2, Figure 4-3 and Figure 4-4, capacity owners decreased external purchases of capacity resources at the beginning of the second interval (June).

16 These data are posted on a monthly basis at www.pjm.com under the PJM Market Monitoring Unit link.
17 The PJM price in Figure 4-3 is the firm, daily forward on-peak PJM Western Hub energy price, while the external price is the firm, daily forward on-peak price for Cinergy (converted to dollars per MW-day).
18 These data are posted on a monthly basis at www.pjm.com under the PJM Market Monitoring Unit link.

Table 4-4 - PJM capacity summary (MW): January through May 2004

	Mean	Standard Deviation	Minimum	Maximum
Installed Capacity	78,025	451	77,260	78,751
Unforced Capacity	72,878	393	72,210	73,525
Obligation	70,519	110	70,274	70,686
Sum of Excess	2,365	486	1,588	3,127
Sum of Deficiency	6	16	0	49
Net Excess	2,359	479	1,588	3,122
Imports	3,770	183	3,523	4,092
Exports	1,318	57	1,078	1,473
Net Exchange	2,453	203	2,050	2,814
Unit-Specific Transactions	59,607	24	59,521	59,629
Capacity Credit Transactions	69,495	524	68,657	70,412
Internal Bilateral Transactions	129,101	513	128,267	130,022
Daily Capacity Credits	994	245	640	1,549
Monthly Capacity Credits	1,199	135	1,018	1,363
Multimonthly Capacity Credits	2,619	391	2,065	3,028
All Capacity Credits	4,812	283	4,395	5,258
ALM Credits	1,207	0	1,207	1,207

Table 4-5 - PJM capacity summary (MW): June through September 2004

	Mean	Standard Deviation	Minimum	Maximum
Installed Capacity	77,234	403	76,485	77,640
Unforced Capacity	71,838	379	71,177	72,231
Obligation	71,142	167	70,852	71,409
Sum of Excess	695	298	292	1,117
Sum of Deficiency	0	0	0	3
Net Excess	695	298	292	1,117
Imports	2,335	257	1,922	2,611
Exports	1,432	71	1,326	1,566
Net Exchange	903	269	482	1,171
Unit-Specific Transactions	11,813	57	11,747	11,879
Capacity Credit Transactions	60,452	1,442	57,249	61,760
Internal Bilateral Transactions	72,265	1,490	68,996	73,639
Daily Capacity Credits	1,203	240	731	1,971
Monthly Capacity Credits	971	118	828	1,152
Multimonthly Capacity Credits	3,325	72	3,213	3,388
All Capacity Credits	5,499	259	5,044	6,336
ALM Credits	927	82	880	1,072

Figure 4-2 - Capacity obligations to the PJM Capacity Market: Calendar year 2004

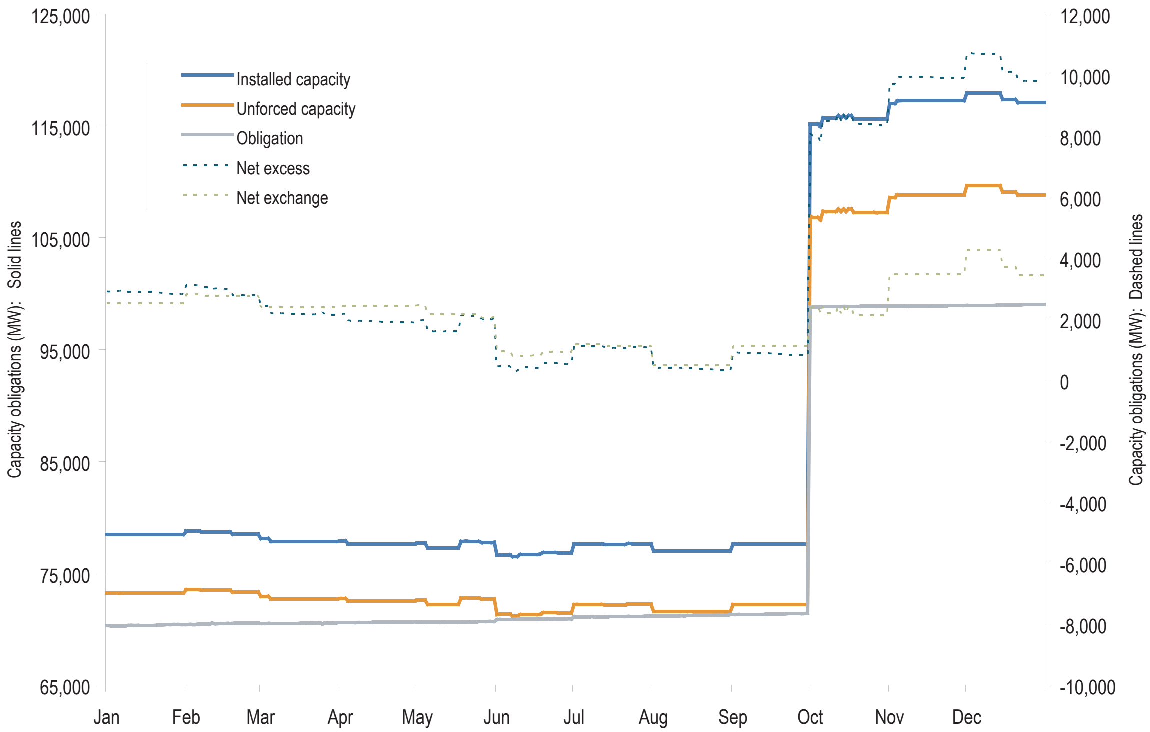
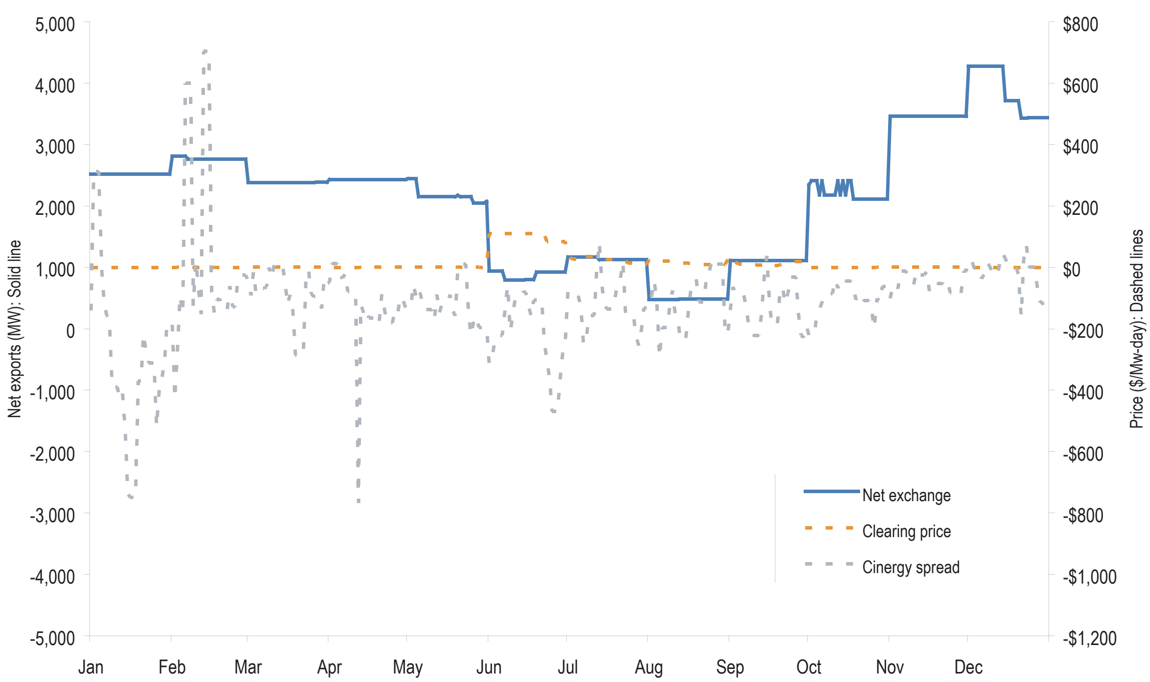


Figure 4-3 - PJM daily capacity credit market-clearing price and Cinergy spread vs. net exchange: Calendar year 2004



Phase 3

In the third interval of 2004, capacity resources exceeded capacity obligations in PJM every day. The pool was long by an average of 9,515 MW. Table 4-6 presents these data for the third interval of 2004.[19] The large increase in the average for all values in the tables was caused by the integration of the AEP and DAY Control Zones. Average net excess increased by 8,820 MW, or 1,269 percent, over the second interval. Average obligation increased by 27,764 MW, or 39.0 percent, over the second interval.

Table 4-6 - PJM capacity summary (MW): October through December 2004

	Mean	Standard Deviation	Minimum	Maximum
Installed Capacity	116,770	894	114,916	117,926
Unforced Capacity	108,422	908	106,592	109,645
Obligation	98,906	56	98,809	99,003
Sum of Excess	9,515	865	7,783	10,707
Sum of Deficiency	0	0	0	0
Net Excess	9,515	865	7,783	10,707
Imports	6,392	876	5,219	7,355
Exports	3,211	304	2,872	3,923
Net Exchange	3,181	748	2,118	4,278
Unit-Specific Transactions	12,597	23	12,581	12,668
Capacity Credit Transactions	64,571	421	64,114	65,330
Internal Bilateral Transactions	77,168	435	76,695	77,957
Daily Capacity Credits	986	241	671	1,512
Monthly Capacity Credits	773	94	664	893
Multimonthly Capacity Credits	3,002	121	2,833	3,088
All Capacity Credits	4,761	195	4,517	5,238
ALM Credits	1,662	8	1,653	1,669

External Capacity Transactions

Phases 1 and 2

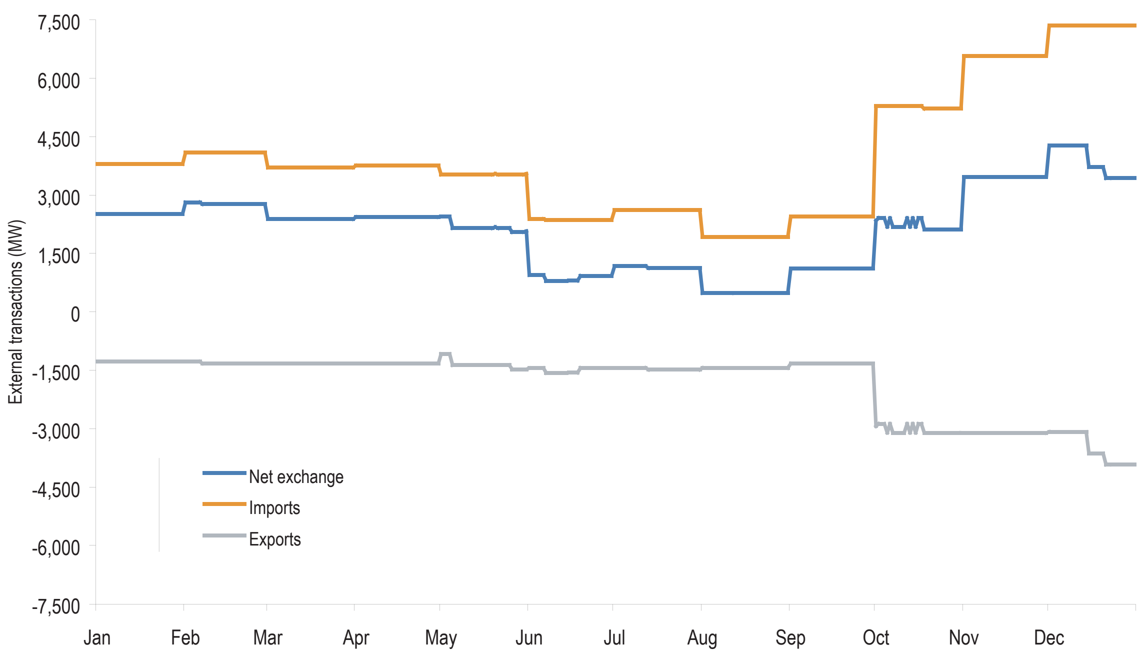
PJM capacity resources may be traded bilaterally within and outside of PJM. Figure 4-4 presents PJM external bilateral capacity transaction data for 2004. (Table 4-4, Table, 4-5 and Table 4-6 also include data on imports and exports.)

During the first interval, an average of 3,770 MW of capacity resources was imported into the PJM Capacity Market, while an average of 1,318 MW was exported. The result was an average net exchange of 2,453 MW of capacity resources. The maximum exports were 1,473 MW, while the maximum imports were 4,092 MW.

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

During the second interval, an average of 2,335 MW of capacity resources was imported into PJM while an average of 1,432 MW was exported, resulting in an average net exchange of 903 MW of capacity resources. The maximum exports were 1,566 MW, while the maximum imports were 2,611 MW. Imports decreased by about 1,200 MW on June 1, 2004 (Figure 4-4); this was the main reason for the reduction in net excess on the same date.

Figure 4-4 - External PJM Capacity Market transactions: Calendar year 2004



Phase 3

During the third interval, an average of 6,392 MW of capacity resources was imported into the PJM Capacity Market while an average of 3,211 MW was exported, resulting in an average net exchange of 3,181 MW of capacity resources. The maximum level of exports was 3,923 MW, while the maximum level of imports was 7,355 MW. Imports increased by about 2,800 MW as Phase 3 began (Figure 4-4) and exports increased by 1,400 MW upon the integration of the AEP and DAY Control Zones. These external transactions include approximately 1,300 MW of capacity resources that were exported to the NYISO throughout calendar year 2004.

Internal Bilateral Transactions

Phases 1 and 2

During the first interval of 2004, internal, unit-specific transactions for the PJM Capacity Market averaged 59,607 MW. (See Figure 4-5.) Internal capacity credit transactions in the first interval of 2004 averaged 69,495 MW. Internal, unit-specific and capacity credit bilateral transactions may be traded between parties multiple times with the result that transaction volume can exceed obligation.

During the second interval of 2004, internal, unit-specific transactions for the PJM Capacity Market averaged 11,813 MW, a decline of 80.2 percent from the first interval. (See Figure 4-5.) As of June 1, 2004, unit-specific capacity transactions were no longer required in order to qualify for an FTR.[20] Internal capacity credit transactions in the second interval of 2004 averaged 60,452 MW, which represents a 13.0 percent decrease from the first interval.

Phase 3

Internal, unit-specific transactions for the PJM Capacity Market during the third interval of 2004 averaged 12,597 MW, a 6.6 percent increase over the second interval of 2004. (See Figure 4-5 and Table 4-6.) Internal capacity credit transactions, in the third interval of 2004 averaged 64,571 MW, an increase of 4,119 MW or 6.8 percent when compared to the second interval of 2004.

Active Load Management (ALM) Credits

Phases 1 and 2

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

During the first interval of 2004, ALM credits in the PJM Capacity Market averaged 1,207 MW, down approximately 7 percent from 1,292 MW in 2003. (See Table 4-4.) ALM participation declined for a number of reasons, including the shifting of participants to other demand-side response (DSR) programs.

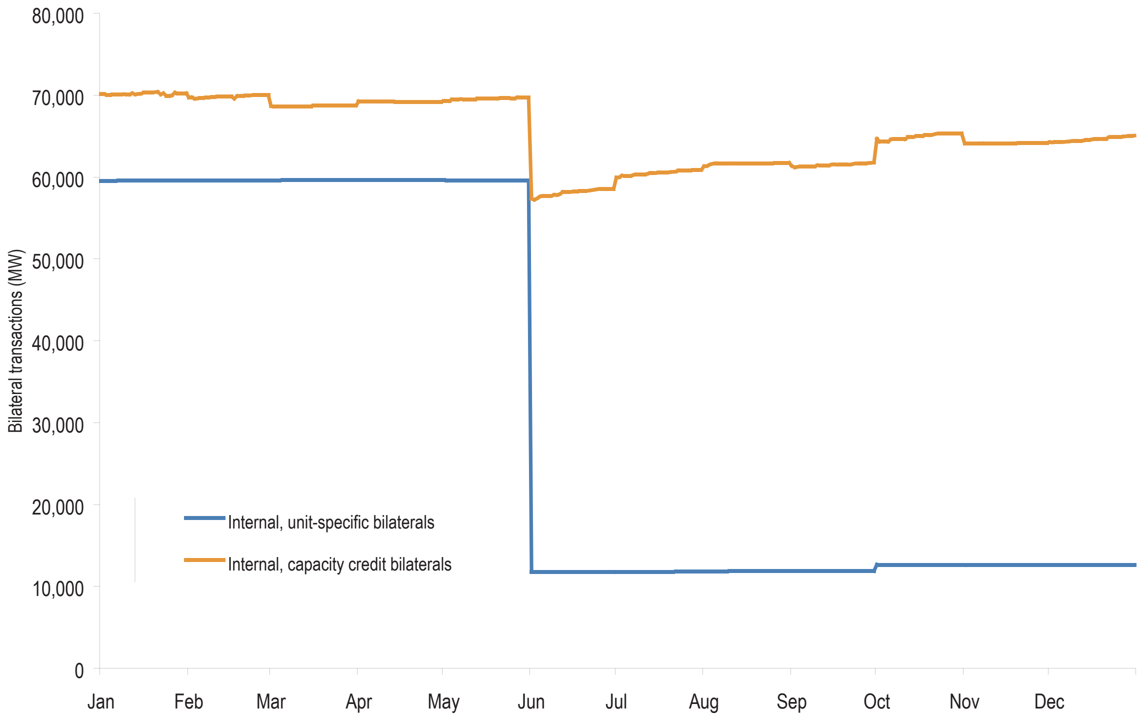
During the second interval of 2004, ALM credits in the PJM Capacity Market averaged 927 MW, down approximately 23 percent from 1,207 MW during the second interval of 2003. (See Table 4-5.)

Phase 3

ALM credits in PJM averaged 1,662 MW in the third interval of 2004, an increase of approximately 79.3 percent from 927 MW in the second interval of 2004. (See Table 4-6.)

20 See Section 7, "Financial Transmission and Auction Revenue Rights," for a more complete explanation of this rule change.

Figure 4-5 - Internal bilateral PJM Capacity Market transactions: Calendar year 2004



Market Performance in the PJM Capacity Markets

Capacity Credit Market Volumes

Phases 1 and 2

During the first interval of 2004, PJM operated Daily, Monthly and Multimonthly Capacity Credit Markets. Table 4-4 shows the Daily Capacity Credit Market averaged 994 MW of transactions, or about 1.4 percent of the average capacity obligations for the period. Trading in the PJM Daily Capacity Credit Market increased by 65.1 percent compared to activity in the market in the first interval of 2003. The average volume for all capacity credits during the first interval of 2004 was 4,812 MW and the volume for the corresponding interval in 2003 was 3,779 MW.

Table 4-5 shows that during the second interval, the PJM Daily Capacity Credit Market averaged 1,203 MW of transactions, or about 1.7 percent of the average capacity obligation for the period. Trading in the PJM Daily Capacity Credit Market increased, by an average of 1,720 MW, or 62.9 percent, compared to what had been experienced during the same period of 2003.

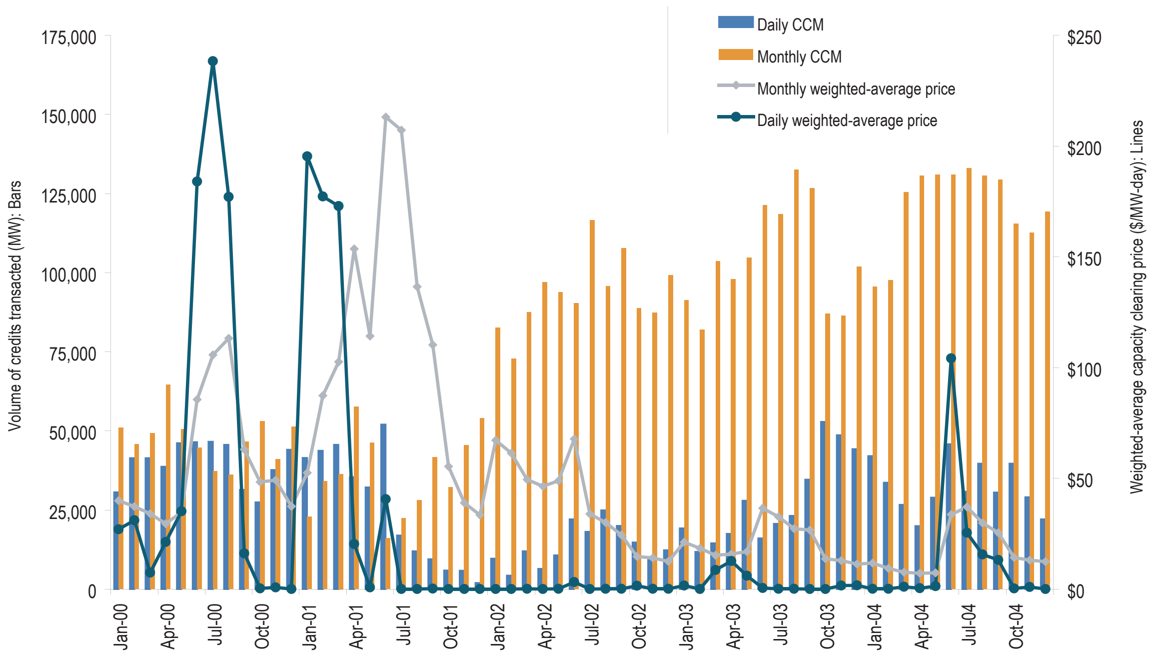
Phase 3

Table 4-6 shows that during the third interval, the PJM Daily Capacity Credit Market averaged 986 MW of transactions, or about 1.0 percent of the average capacity obligation for the period. Trading in the PJM Daily Capacity Credit Market decreased in the last interval of 2004, with average daily volume declining by 217 MW or 18.0 percent.

Capacity Credit Market Volumes: Calendar Years 1999 to 2004

Figure 4-6 shows prices and volumes in PJM's Daily and longer term Capacity Credit Markets from 2000 through 2004. Since the interval system was introduced in June 2001, overall volume in the Monthly and Multimonthly Capacity Credit Markets has increased and prices in both the daily and longer term markets have declined and remained relatively stable with the exception of the second interval of 2004. Although daily volume has risen to pre-June 2001 levels, capacity obligations have increased by more than 25 percent. The share of load obligation traded in the PJM Daily Capacity Market has declined since the introduction of Interval Markets, while the share of load obligation traded in Monthly and Multimonthly Capacity Markets has increased. Daily capacity market volume declined from 2.5 percent of average obligation in 2000 to 1.6 percent in the last two intervals of 2003. In comparison, average daily capacity credit market volume in 2004 increased to 1,062 MW from 907 MW in 2003, but as a percent of obligation, 2004 volume remained approximately the same at 1.4 percent of obligation. Monthly and multimonthly capacity market volume increased from 3.0 percent of obligation in 2000 to 5.2 percent of average obligation in the last two intervals of 2003. In comparison, average monthly and multimonthly capacity credit market volume in 2004 increased to 3,966 MW from 3,435 MW in 2003, but 2004 volume as a percent of obligation declined slightly to 5.1 percent from 5.2 percent in 2003. With the integration of the AEP and DAY Control Zones, by virtue of their participation, total volume traded has increased. Nonetheless, because of the new participants' reliance on their own resources, volume as a percent of obligation has declined once again, with values approaching 1 percent for the Daily Capacity Credit Market and 4 percent for the Monthly and Multimonthly Capacity Credit Markets since October 2004.

Figure 4-6 - PJM Daily and Monthly Capacity Credit Market (CCM) performance: Calendar years 2000 to 2004



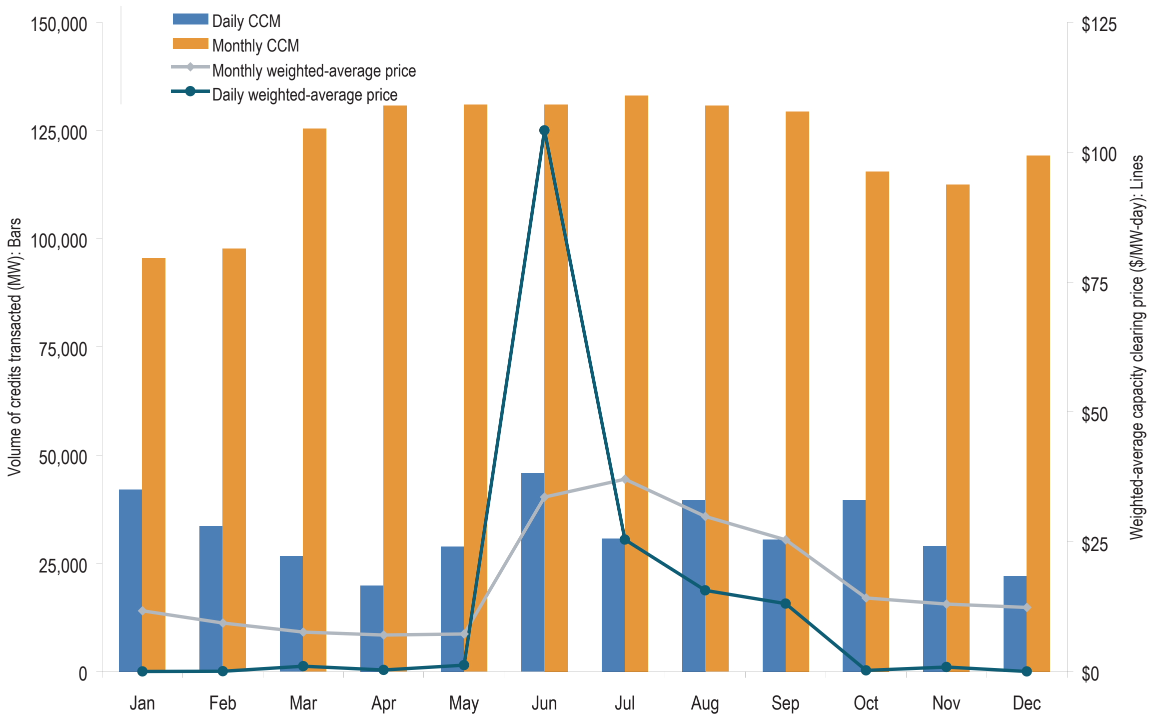
Capacity Credit Market Prices

Phases 1 and 2

Table 4-7 and Figure 4-7 show prices and volumes in the first interval for PJM's Daily and longer term Capacity Credit Markets. The volume-weighted average price for the first interval of 2004 was $0.51 per MW-day in the Daily Capacity Credit Market and $8.38 per MW-day in the Monthly and Multimonthly Capacity Credit Markets. The volume-weighted average price for all Capacity Credit Markets was $6.75 per MW-day.[21] Prices in the Daily Capacity Credit Market were relatively constant during the first interval of the year and declined slightly in the Monthly and Multimonthly Capacity Credit Markets. (See Figure 4-7.) Prices in the Monthly and Multimonthly Markets during the first interval of 2004 were 51.7 percent lower than during the same period of 2003. Prices in the Daily Capacity Credit Market were 91.5 percent lower for the period.

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

Figure 4-7 - PJM Daily and Monthly Capacity Credit Market (CCM) performance: Calendar year 2004



The volume-weighted average price for the second interval of 2004 was $31.53 per MW-day in the PJM Monthly and Multimonthly Capacity Credit Markets and $44.79 per MW-day in the Daily Capacity Credit Market. The volume-weighted average price for all Capacity Credit Markets was $34.43 per MW-day.[22] Table 4-7 and Figure 4-7 show price and volume in both PJM's Daily and longer term Capacity Credit Markets. Prices increased in this interval because the market was tighter. Net excess in the second interval declined 71 percent from an average 2,359 MW in the first interval to 695 MW. (See Table 4-4 and Table 4-5.)

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

Table 4-7 - PJM Capacity Credit Markets: Calendar year 2004

	Average Daily Volume (MW)	Monthly and Multimonthly Volume (MW)	Combined Volume (MW)	Daily Weighted-Average Price ($ per MW-day)	Monthly and Multimonthly Weighted-Average Price ($ per MW-day)	Combined Weighted-Average Price ($ per MW-day)
Jan	1,357	3,083	4,440	$0.05	$11.72	$8.16
Feb	1,159	3,368	4,527	$0.10	$9.35	$6.98
Mar	860	4,045	4,905	$1.06	$7.61	$6.46
Apr	664	4,357	5,021	$0.33	$7.07	$6.18
May	932	4,223	5,155	$1.25	$7.26	$6.17
Jun	1,527	4,366	5,893	$104.15	$33.60	$51.89
Jul	993	4,293	5,287	$25.41	$37.06	$34.87
Aug	1,279	4,216	5,495	$15.64	$29.88	$26.57
Sep	1,017	4,313	5,330	$13.08	$25.39	$23.04
Oct	1,279	3,726	5,005	$0.24	$14.19	$10.63
Nov	967	3,752	4,720	$0.91	$13.00	$10.52
Dec	712	3,846	4,558	$0.03	$12.36	$10.43
			Average			
Calendar Year	1,062	3,966	5,028	$17.21	$17.88	$17.74
Jan-May	994	3,817	4,812	$0.51	$8.38	$6.75
Jun-Sep	1,203	4,296	5,499	$44.79	$31.53	$34.43
Jan-Sep	1,087	4,031	5,118	$22.32	$19.36	$19.99
Oct-Dec	986	3,775	4,761	$0.40	$13.17	$10.53

Phase 3

The volume-weighted average price for the third interval of 2004, as shown in Table 4-7, was $13.17 per MW-day in the Monthly and Multimonthly Capacity Credit Markets and $0.40 per MW-day in the Daily Capacity Credit Market. The volume-weighted average price for all Capacity Credit Markets was $10.53 per MW-day.[23] Prices in the PJM Capacity Credit Market approached pre-June 2004 levels in the last interval of the calendar year. (See Figure 4-7.) Prices in the PJM Capacity Credit Markets in the third interval of 2004 were somewhat less than those in the third interval of 2003. In the third interval of 2003 prices averaged $12.53 per MW-day in the Monthly and Multimonthly Capacity Credit Markets, $1.03 per MW-day in the Daily Capacity Credit Market and $16.03 per MW-day for the volume-weighted average price for all Capacity Credit Markets.

Capacity Credit Market Prices: Calendar Years 1999 to 2004

The volume-weighted average price for all Capacity Credit Markets was $52.86 per MW-day in 1999, $60.55 in 2000, $95.34 in 2001, $33.40 in 2002, $17.51 in 2003 and $17.74 in 2004. The volume-weighted average price for the Monthly and Multimonthly Capacity Credit Markets was $70.66 per MW-day in 1999, $53.16 in 2000, $100.43 in 2001, $38.21 in 2002, $21.57 in 2003 and $17.88 in 2004, while the price in the Daily Capacity Credit Market averaged $3.63 per MW-day in 1999, $69.39 in 2000, $87.98 in 2001, $0.59 in 2002, $2.14 in 2003 and $17.21 in 2004.

Daily Capacity Credit Market – Summer 2004

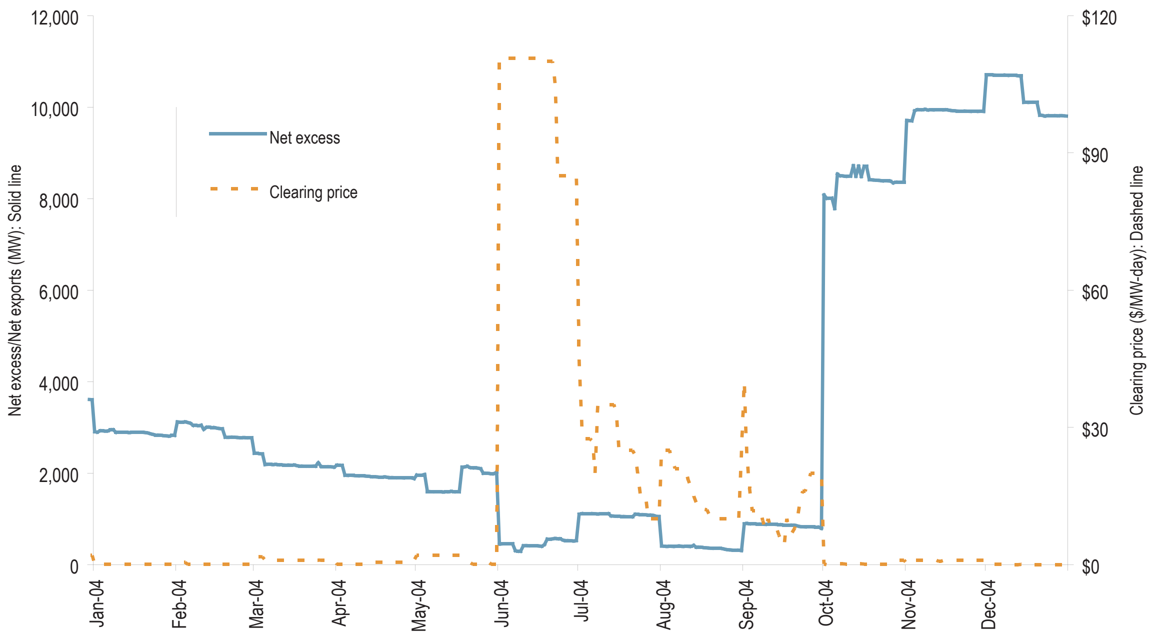
Prices in the PJM Daily Capacity Credit Market increased sharply on June 1, 2004, rising to $110.61 per MW-day from $0.05 per MW-day on May 31. The price increase persisted for about a month. (See Figure 4-8.) The price increase was the result of competitive market fundamentals, including an increase in demand in the Daily Markets and a decrease in supply available to the Daily Markets. The overall average price for the summer interval was $44.79, an increase of $44.66 over the $0.13 summer interval price in 2003. The overall average price in the Daily Markets for 2004 was $17.21, an increase of $15.07 over the 2003 average daily market price of $2.14.

Table 4-8 - The PJM Capacity Market's summer parameters: July to September 2004

Capacity Market Parameters Summer Interval 2004	June 2004			July 2004			August 2004			September 2004		
	Average	Maximum	Minimum	Average	Maximum	Minimum	Average	Maximum	Minimum	Average	Maximum	Minimum
Average Daily CCM Demand (MW)	1,532	2,124	1,368	993	1,178	894	1,289	1,413	1,246	1,029	1,087	974
Offered Supply (MW)	1,864	2,228	1,717	1,802	2,021	1,708	1,524	1,586	1,257	1,577	1,838	731
Net Excess (MW)	462	571	292	1,086	1,117	1,046	370	420	305	861	900	791
Capacity Not Offered (MW)	125	427	67	277	401	238	125	407	68	301	890	114

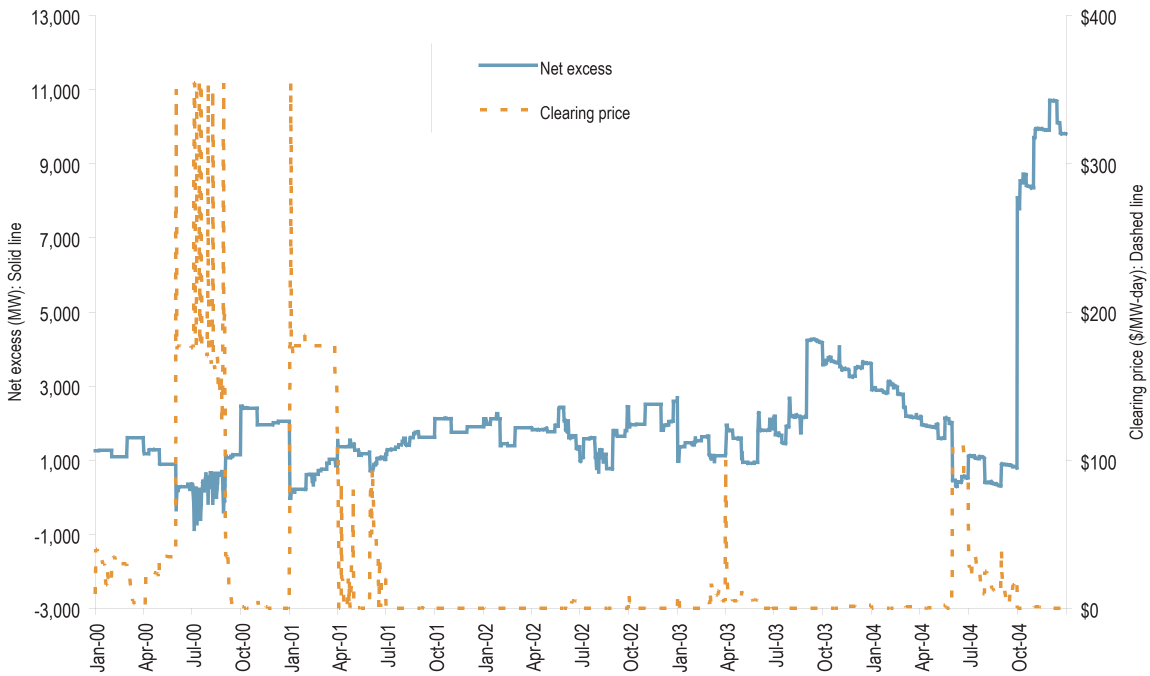
23 Graph and average price data are all in terms of unforced capacity. Capacity credits are, by definition, in terms of unforced capacity.

Figure 4-8 - The PJM Capacity Market's net excess vs. capacity credit market-clearing prices: Calendar year 2004



Daily capacity market prices generally increase when the market gets tighter, as measured by the difference between available supply and demand, termed net excess. More precisely, daily capacity market prices generally increase when the net excess is below 1,000 MW. Figure 4-9 shows the relationship between net excess and the daily capacity credit market-clearing prices from January 2000 through December 2004.

Figure 4-9 - The PJM Capacity Market's net excess vs. capacity credit market-clearing prices: January 2000 to December 2004



On June 1, 2004, the net excess decreased to 449 MW from 2,017 MW on May 31, as shown in Figure 4-9. The decrease in net excess was caused by a decrease of more than 1,100 MW in imports; an increase of approximately 200 MW in obligation, an approximate 325 MW reduction in unforced capacity caused by a change in the 12-month rolling EFORd and other changes such as capacity retirements, adjustments and additions.

The reliance of entities unaffiliated with EDCs on the Capacity Credit Markets increased from 5.2 percent in May to 23.9 percent in June. (See Table 4-3.) More significantly, market participants' overall reliance on the Daily Capacity Credit Markets increased from 1.5 percent on May 31, 2004, to 2.8 percent on June 1, 2004. The reliance of entities unaffiliated with EDCs on the Capacity Credit Markets increased from 5.5 percent on May 31, 2004, to 28.9 percent on June 1, 2004. In addition to these increases, this sector also gained market share at the beginning of the planning period. Figure 4-1 shows that their market share of obligation increased from 5.9 percent on May 31, 2004, to 8.0 percent on June 1, 2004.

Table 4-9 - The PJM Capacity Market's parameters: Comparison of 2004 winter vs. summer interval

	2004 Winter Interval			2004 Summer Interval			Winter Summer Difference	
	Average	Maximum	Minimum	Average	Maximum	Minimum	Average Change	Percent Change
Average Daily CCM Demand (MW)	994	1,549	640	1,210	2,124	894	215	21.7%
Offered Supply (MW)	2,599	2,291	731	1,691	2,228	731	-908	-34.9%
Net Excess (MW)	2,359	2,017	292	695	1,117	292	-1,664	-70.5%
Capacity Not Offered (MW)	754	890	67	207	890	67	-547	-72.5%

A comparison of the second (summer) interval to the first (winter) interval also illustrates the changed fundamentals. Demand in the Daily Capacity Credit Market increased to 1,210 MW in the second interval, a 21.7 percent increase from the first interval average of 994 MW. (See Table 4-9.) Net excess in the second interval decreased by 1,664 MW, or 70.5 percent, from an average 2,359 MW in the first interval to an average of 695 MW in the second interval. Average offered supply decreased by 34.9 percent in the second interval to 1,691 MW from 2,599 MW in the first interval.

A decrease in net excess may lead to higher prices because of factors related to both the demand side and the supply side of the Daily Capacity Market. While the aggregate demand for capacity is fixed, market participants have the flexibility to choose whether to self-supply, to purchase bilaterally, to purchase in the variety of monthly and multimonthly auctions or to purchase in the Daily Capacity Market. The actual demand for capacity can be quite elastic, but varies by capacity auction. Demand in the Daily Capacity Market tends to be the least elastic of all the market options because a consequence of failing to cover one's obligation in the Daily Market is incurring a capacity deficiency charge. Participants also have until the end of the day of any daily auction to procure capacity bilaterally before becoming short for the operating day and being obligated to pay a capacity deficiency charge. Thus, as more market participants shift to reliance on the Daily Capacity Market, the more inelastic overall demand for capacity becomes and the more likely is price volatility in the Daily Capacity Market.

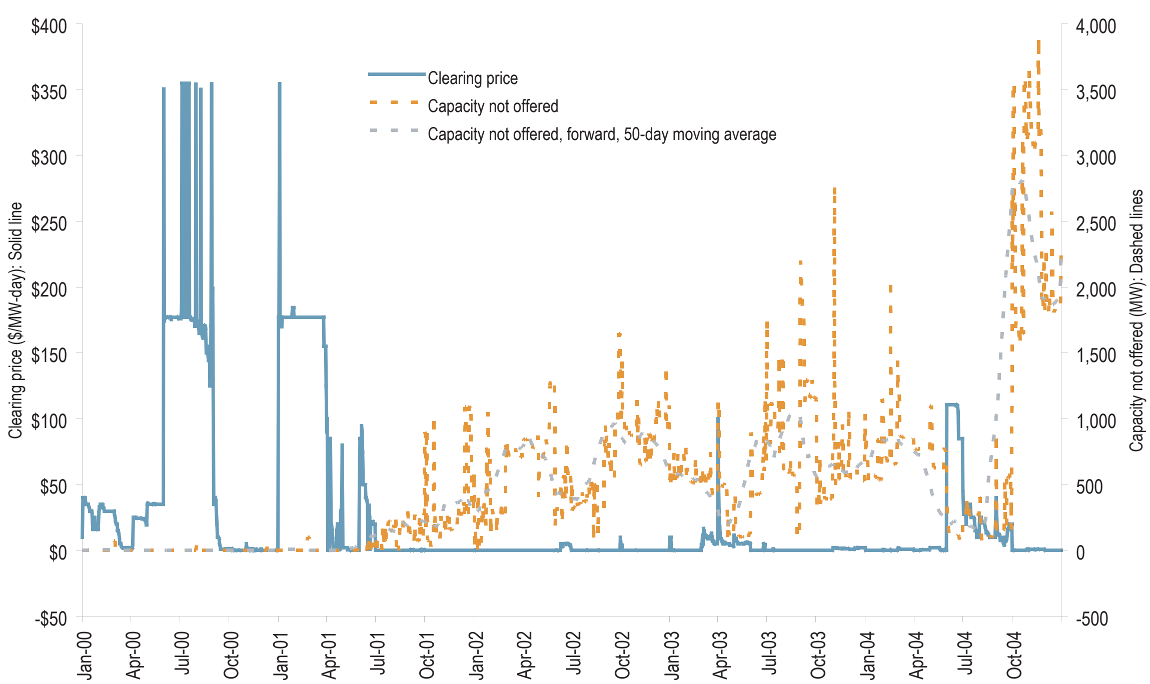
Another reason that a decrease in net excess leads to higher prices is the shape of the supply curve. The supply curve for capacity is upwardly sloped. As the level of relatively inelastic demand increases, it intersects the supply curve at higher prices. The incremental cost of capacity and thus the competitive price of capacity is the net avoidable cost of capacity. The net avoidable cost of capacity is equal to the annual cost to maintain a unit as a capacity resource, less net revenues received from other markets. In other words, it would be rational to retire a unit if it does not recover its net avoidable costs from a combination of the Energy, Ancillary Service and Capacity Markets. The overall supply curve for capacity has baseload units as the lowest cost sources of supply as energy market revenues typically offset all of the avoidable costs and has intermediate units as the next most expensive sources of capacity as energy and ancillary service markets revenues offset a significant portion of avoidable costs, depending on unit characteristics. Older combustion turbines tend to be at the top of the overall capacity market supply curve as some of these units have poor heat rates and high annual maintenance costs. These units operate only infrequently, especially in years with relatively mild temperatures like 2004, and, therefore, earn very little from the Energy and Ancillary Service Markets. As a result these units have, in some cases, very high net avoidable costs.

Reflecting both demand-side and supply-side factors, market participants increased both bid and offer prices commencing with the June 1, 2004, Daily Capacity Credit Market. The average bid price increased from $239.36 per MW-day on May 31, 2004, to $354.01 per MW-day on June 1, 2004. The average offer price increased from $2.30 per MW-day on May 31, 2004, to $67.37 per MW-day on June 1, 2004.

These fundamental supply and demand factors contributed significantly to the increase in the daily capacity credit market-clearing price. The daily capacity market prices reflected a reasonably competitive outcome given the underlying fundamentals. Offer prices, even the relatively high clearing offer prices, were in general based on avoidable costs of the relevant units. While there was the clear potential for the exercise of market power in these markets based on both the market structure and supply-demand conditions, the evidence is that the outcomes generally reflected competitive offers. In this case, outcomes reflected competitive offers not because the market structure constrained participants to behave in a competitive manner, but because key market participants chose to behave in a competitive manner.

Nonetheless, one cause for concern is that not all available capacity was offered into the market. Mandatory participation requirements in the Daily Capacity Credit Market were eliminated effective July 1, 2001.

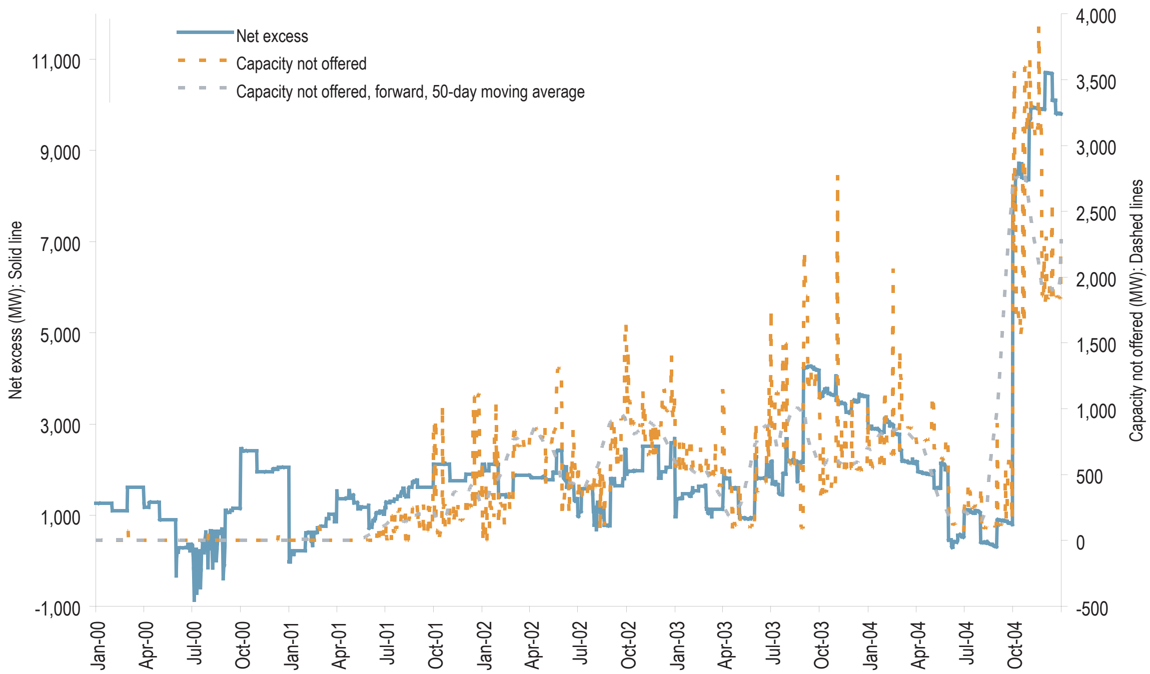
Figure 4-10 - The PJM Capacity Market's clearing price vs. capacity not offered: January 2000 to October 2004



As Figure 4-10 shows, since July 1, 2001, not all capacity has been offered into the Capacity Credit Markets on a daily basis. However, the level of capacity not offered is inversely related to prices and directly related to net excess (see Figure 4-11) as capacity owners offer more of their available capacity to the market when prices are high and net excess is low and offer less when prices are low and net excess is high. Consistent with this general pattern, capacity not offered decreased by 72.5 percent to 207 MW in the second interval from 754 MW in the first interval. As a general matter, the withholding of capacity has not had an impact on prices. The withholding of capacity did not have a significant impact on prices during June.

On July 1, 2004, additional unforced capacity became available to the market as new capacity resources entered. Net excess increased from 527 MW to 1,101 MW. In addition, market participants who had purchased capacity in the Daily Market in June began to enter into capacity credit bilateral transactions as shown in Figure 4-5. The capacity-clearing price trended downward for the remainder of the summer.

Figure 4-11 - The PJM Capacity Market's net excess vs. capacity not offered: Calendar years 2000 to 2004

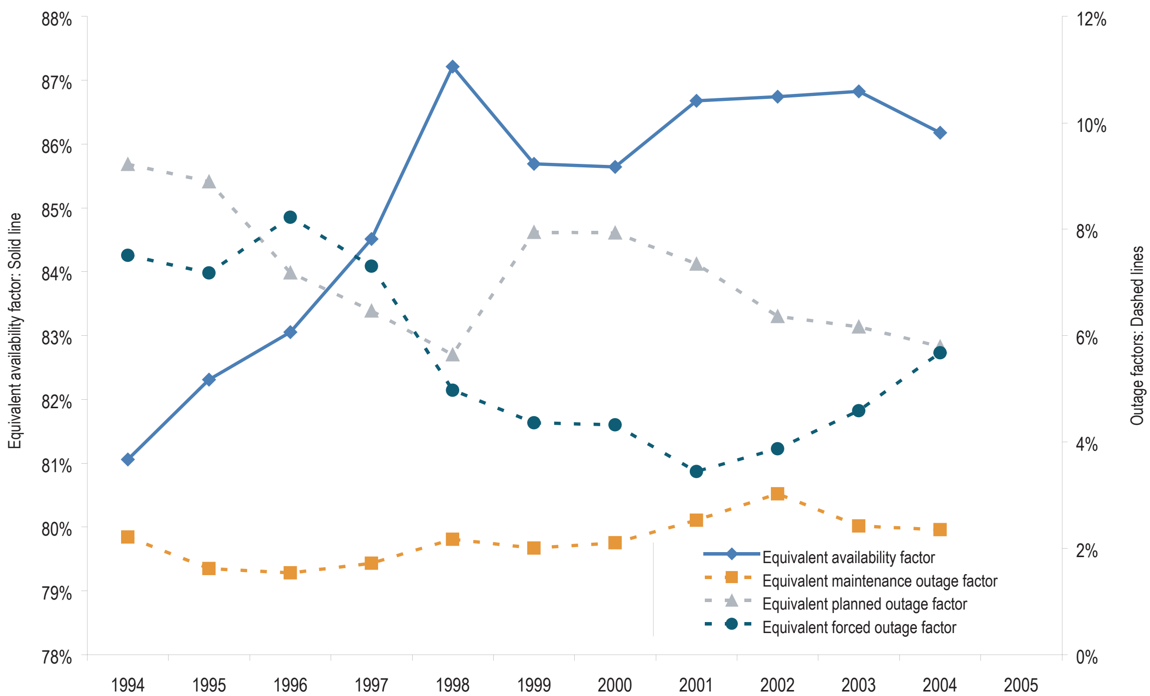


The conclusion is that the increase in capacity credit market-clearing prices during June 2004 and their subsequent reduction were the result of market fundamentals, including an increased reliance on Daily Capacity Markets and a decrease in available capacity. Although the market structure made the exercise of market power possible, market participants chose to behave in a competitive manner and the market outcomes reflected that behavior.

Generator Performance

Certain outage statistics are calculated by reference to total hours in the year rather than statistical probability. Figure 4-12 shows these performance measures for all PJM units, excluding those in the ComEd Control Zone and the more recently integrated AEP and DAY Control Zones. The equivalent availability factor equals the proportion of hours in a year that a unit is available to generate at full capacity. The sum of the equivalent availability factor, the equivalent maintenance outage factor, the equivalent planned outage factor and equivalent forced outage factor equals 100 percent. The increase in the equivalent forced outage factor from 2003 to 2004 corresponded with a decrease in the equivalent availability factor. Equivalent planned and maintenance outage factors did not change significantly in 2004 from 2003. The PJM aggregate equivalent availability factor was 86.8 percent in 2003 and 86.2 percent in 2004.

Figure 4-12 - PJM equivalent outage and availability factors: Calendar years 1994 to 2004



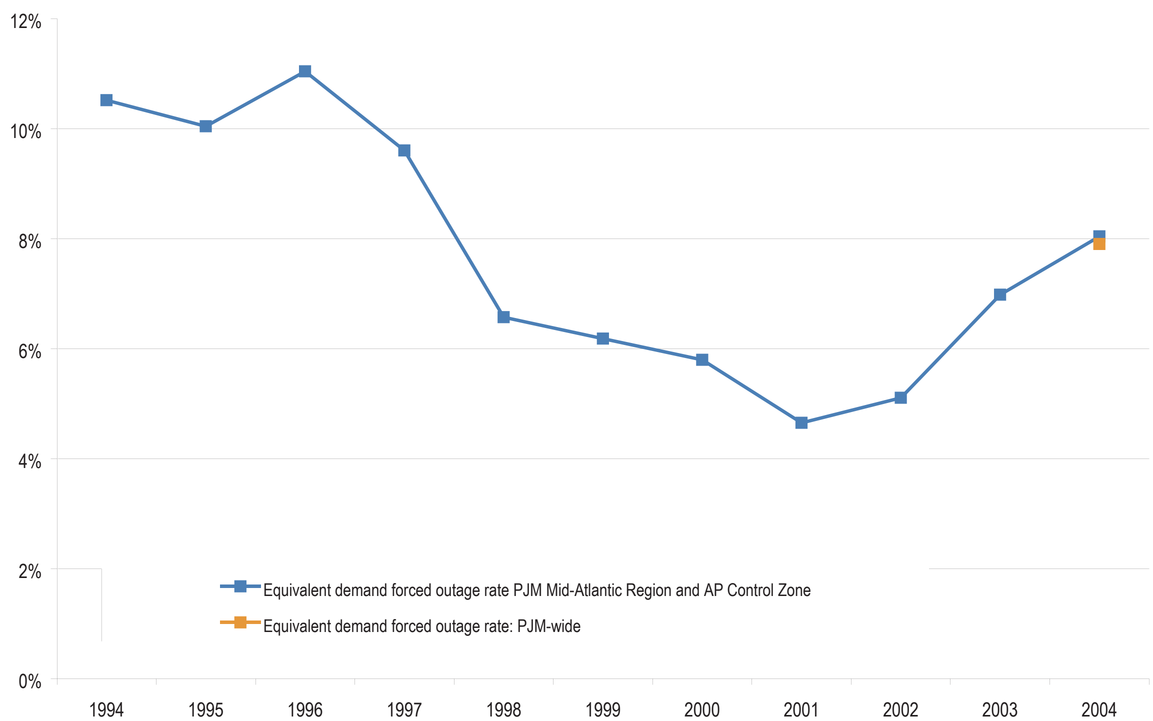
EFORd is a statistical measure of the probability that a unit will fail, either partially or totally, to perform when it is needed. Unforced capacity for any individual generating unit is equal to one minus the EFORd multiplied by the generating unit's net dependable summer capability. The PJM Capacity Market creates an incentive to minimize the forced outage rate because the amount of capacity resources available from a unit is inversely related to the forced outage rate. EFORd calculations use historical data, including equivalent[24] forced outage hours, service hours, average

24 Equivalent forced outage hours are the sum of all forced outage hours in which a generating unit is fully inoperable and all partial forced outage hours in which a generating unit is partially inoperable prorated to represent full hours.
25 See PJM Manual M22, "Generator Resource Performance Indices, Revision 13" (May 1, 2004), p. 7.
26 The 2004 PJM availability factors and forced outage rates are calculated for the AP Control Zone of the PJM Western Region and the PJM Mid-Atlantic Region combined. The equivalent outage and availability factors figure, Figure 0-12 and the EFORd figure, Figure 0-13, are comparable to corresponding figures in the 2003 State of the Market Report (March 10, 2004), pp. 132 and 133.

forced outage duration, average run time, average time between unit starts, available hours and period hours.[25] Between 1996 and 2001, the average PJM[26] EFORd trended downward, reaching 4.8 percent in 2001 and then increasing to 5.2 percent in 2002, 7.0 percent in 2003 and 8.0 percent in 2004. The increase in EFORd of 1.0 percent from 2003 to 2004 was the result of increased forced outage rates across most unit types. Fossil steam units' EFORd contributed 0.5 percentage points, combustion turbine units' EFORd contributed 0.1 percentage points, hydroelectric units' EFORd contributed 0.1 percentage points, combined-cycle units' contributed 0.1 percentage points and nuclear units contributed 0.2 percentage points to the overall increase of 1.0 percentage point. Of the 672 generating units in the EFORd analysis, 336 units (about 50 percent) had increased EFORds, 250 units had decreased EFORds and the remaining 86 units had unchanged EFORds. In the absence of offsetting improvements in EFORd by 250 units, the EFORd would have increased by 3.6 percentage points to 10.6 percent. The 250 units with lower forced outage rates reduced the EFORd by 2.6 percentage points, to the observed 8.0 percent EFORd.

Figure 4-13 shows the average EFORd since 1994 for all units in the PJM Mid-Atlantic Region and AP Control Zone. Figure 4-13 also includes data for 2004 for the entire PJM Control Area, including all integrated control zones. The PJM overall EFORd for 2004 was 7.9 percent. The EFORd is reported only for 2004 for the entire PJM Control Area as data are either not available or incomplete for the years 1994 through 2003 for the AEP, DAY and ComEd Control Zones.

Figure 4-13 - Trends in PJM equivalent demand forced outage rate (EFORd): Calendar years 1994 to 2004



Market Structure for the ComEd Capacity Market

Ownership Concentration

Phases 2 and 3 (June through December 2004)

As the discussion of market structure for PJM Capacity Markets explains, concentration ratios[27] are a summary measure of market share, a key element of market structure.

MMU structural analysis indicates that ComEd's Capacity Credit Markets from June 1 of Phase 2, through Phase 3 of 2004, exhibited high levels of concentration in the Monthly and Multimonthly Capacity Credit Markets.[28] As shown in Table 4-10, HHIs for Monthly and Multimonthly Capacity Credit Markets averaged 6419, with a maximum of 10000 and a minimum of 2804. One entity owned or controlled nearly two-thirds of total capacity in the ComEd Control Zone.

Table 4-10 - ComEd Capacity Market HHI: Seven months ended December 31, 2004

Statistic	Daily Market HHI	Monthly and Multimonthly Market HHI
Average	N/A	6419
Minimum	N/A	2804
Maximum	N/A	10000

Table 4-11 - ComEd Capacity Market residual supply index (RSI): Seven months ended December 31, 2004

Statistic	Daily Market RSI	Monthly and Multimonthly Market RSI
Average	N/A	2.58
Minimum	N/A	0.00
Maximum	N/A	25.60

Table 4-11 shows RSI values for the Monthly and Multimonthly Capacity Credit Market Auctions for the ComEd Capacity Market. A minimum RSI value of 0 means that only one capacity supplier participated in at least one auction. The high average RSI value of 2.58 and the high maximum RSI value were, in part, the result of the relatively small volumes that were bid in the Capacity Credit Market Auctions, as shown in Table 4-12. Of the 48 capacity auctions held for ComEd in 2004, 26 had RSI values of less than 1.0, meaning that at least one supplier was pivotal in these auctions.

In response to identified structural market power issues in the ComEd Capacity Market, in December 2003, PJM filed a market power mitigation proposal with the FERC to limit capacity offers to the higher of $30 per MW-day or the demonstrated incremental costs of specific capacity

27 See Section 2, "Energy Market," for a discussion of concentration ratios and the HHI.
28 PJM Capacity Market results are reported by the time period during which the auction was run and not by the time period to which the auction applies.

resources. The $30 limit was based on the estimated going-forward costs of a combustion turbine. The FERC denied PJM's market power mitigation proposal in August 2004 based on a finding that there was an overall $160 per MW-day offer cap in place and that the potential for market power in the ComEd Capacity Market did not warrant the proposed mitigation measures.[29]

Demand

Phases 2 and 3 (June through December 2004)

During the seven-month period ended December 31, 2004, PJM EDCs together had an approximately 86 percent market share of load obligation in the ComEd Capacity Market (calculated from Table 4-12). Though all customers in the ComEd Control Zone were eligible for retail access, switching was generally limited to larger commercial and industrial (C&I) customers.[30] Switching was affected by a number of factors. The local utility's bundled rates have been fixed at, or below, 1997 levels since the passage of the Illinois Electric Service Customer Choice and Rate Relief Law of 1997.[31] In addition, any customer switching from bundled service to a retail choice option must pay a transition charge on the energy bought from alternative sources.

Table 4-12 - Load obligation served by ComEd Capacity Market sectors: Seven months ended December 31, 2004

	ComEd Control Zone EDCs			ComEd Control Zone EDC Affiliates			Non-ComEd Control Zone EDC or Affiliates			Not Affiliated with EDCs		
	Average Obligation (MW)	Average CCM Credits (MW)	CCM Credits to Obligation	Average Obligation (MW)	Average CCM Credits (MW)	CCM Credits to Obligation	Average Obligation (MW)	Average CCM Credits (MW)	CCM Credits to Obligation	Average Obligation (MW)	Average CCM Credits (MW)	CCM Credits to Obligation
Jan	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Feb	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Mar	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Apr	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
May	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Jun	21,506	142	0.7%	1,290	212	16.4%	2,366	-354	-15.0%	0	0	0.0%
Jul	21,611	142	0.7%	1,196	212	17.7%	2,354	-244	-10.4%	0	-110	0.0%
Aug	21,838	146	0.7%	1,193	212	17.8%	2,130	-248	-11.7%	0	-110	0.0%
Sep	21,573	146	0.7%	1,254	212	16.9%	2,336	-298	-12.8%	0	-60	0.0%
Oct	14,271	51	0.4%	834	-88	-10.6%	1,560	55	3.5%	0	-18	0.0%
Nov	14,260	51	0.4%	838	-88	-10.5%	1,567	68	4.3%	0	-31	0.0%
Dec	14,266	56	0.4%	834	-88	-10.6%	1,565	68	4.3%	0	-36	0.0%
Average	18,466	105	0.6%	1,062	83	7.8%	1,981	-136	-6.8%	0	-52	0.0%

Table 4-12 also shows how various market sectors rely on the Capacity Credit Market. The measure of reliance on the Capacity Credit Market is the sector's monthly net Capacity Credit Market position divided by the sector's capacity obligation. A negative CCM credit value means that a sector has

29 108 FERC ¶61,187 (2004).
30 See Illinois Commerce Commission, "Competition in Illinois Retail Electric Markets in 2003" (April 2004) <.http://www.icc.state.il.us/ec/docs/040414garpt16120.pdf > (156 KB). In a phone interview on January 7, 2005, ICC staff confirmed that switching remains limited to the larger customers.
31 Illinois General Assembly, "Electric Service Customer Choice and Rate Relief Law of 1997," (220 ILCS 5/16-111 (b)).

sold more capacity credits than it has purchased for a month. A positive CCM credit value means that a sector has purchased more capacity credits than it has sold for a month. ComEd Control Zone EDCs and affiliates were net purchasers in the Capacity Credit Market while non-ComEd Control Zone EDC affiliates and entities not affiliated with EDCs were net sellers.

Commonwealth Edison Company (an EDC in the ComEd Control Zone) is the major electric distribution company in this market. Having spun off its generating assets to an affiliate, ExGen (included among ComEd Control Zone EDC affiliates), the company met an average of 99.4 percent of its capacity obligation through bilateral transactions with this affiliate. Even though it satisfied less than 1 percent of its capacity obligation through the ComEd Capacity Credit Market, Commonwealth Edison Company was a major player in this market since its net purchases were over 50 percent of the total volume in the market for the seven-month period.

Supply and Demand

Phases 2 and 3 (June through December 2004)

The ComEd Control Area was integrated into PJM on May 1, 2004, but the ComEd Capacity Market was not implemented until June 1, 2004. During May 2004, capacity obligations in the ComEd Control Area were satisfied wholly by Commonwealth Edison Company according to the procedures PJM established. The ComEd Capacity Market operates under rules based on installed capacity with obligation fixed on a monthly basis. There is no daily capacity credit market. The interim ComEd Capacity Market structure includes three intervals: June to September 2004; October to December 2004; and January to May 2005. The capacity obligation for each interval is based on the forecasted interval peak and the installed reserve margin, both of which are recalculated for each interval.[32] These rules will remain in effect through May 31, 2005, after which all ComEd Control Zone capacity obligations will be satisfied under the capacity market rules that are in effect on that date for the entire RTO.[33]

The level of resources available to satisfy the capacity obligation in the ComEd Capacity Market during any month reflects the addition of new resources, the retirement of old resources and the importing or exporting of capacity resources.

Net excess equals total capacity resources less capacity obligation. Since obligation includes expected load plus a reserve margin, a net excess of zero or greater is consistent with established reliability objectives. For the seven-month period ended December 31, 2004, the ComEd Capacity Credit Market had an average net excess of 5,672 MW. (See Table 4-13.)[34]

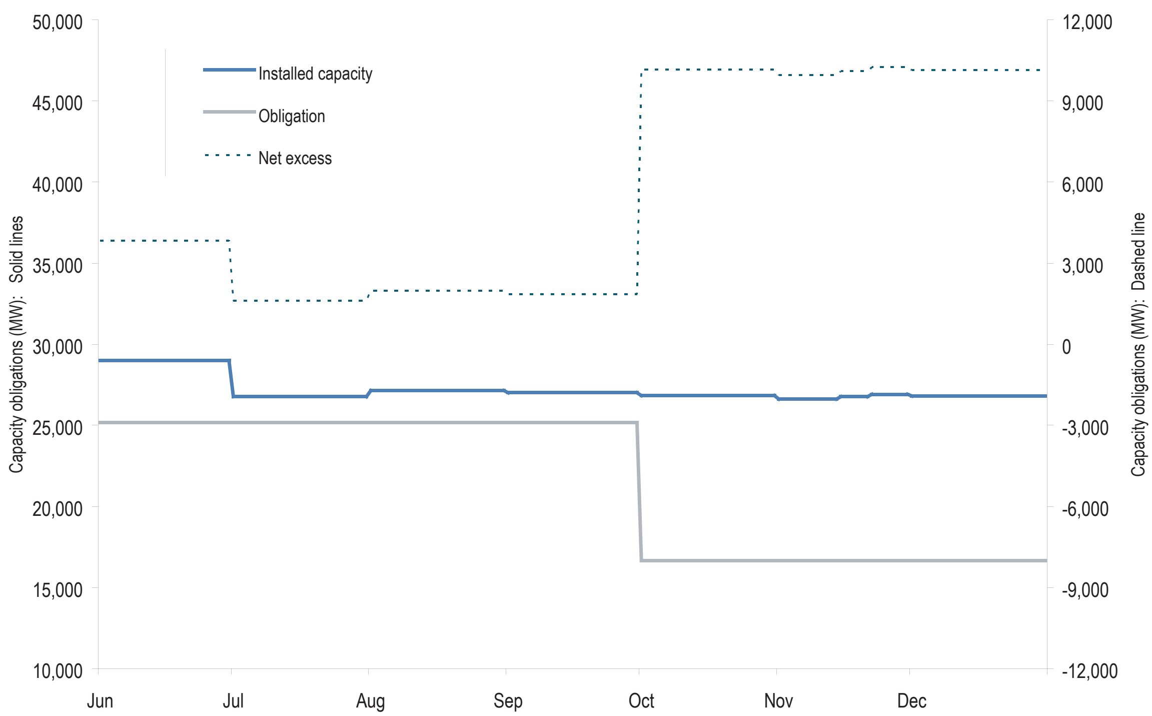
As shown in Figure 4-14, during the last seven months of calendar year 2004, capacity resources exceeded capacity obligations in the ComEd Capacity Market every month. The 8,498 MW decrease in obligation from 25,163 MW to 16,665 MW and the corresponding 8,317 MW increase in net excess from 1,852 MW to 10,169 MW as Phase 3 began were caused by the downward change to the capacity obligation to reflect the lower interval peak and higher installed reserve margin of the October to December period.

32 "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. 48A – 48D.
33 See Appendix E, "Capacity Markets."
34 These data are posted on a monthly basis at www.pjm.com under the PJM Market Monitoring Unit link.

Table 4-13 - ComEd capacity summary (MW): Seven months ended December 31, 2004

	Mean	Standard Deviation	Minimum	Maximum
Installed Capacity	27,181	750	26,615	28,999
Unforced Capacity	27,181	750	26,615	28,999
Obligation	21,509	4,216	16,665	25,163
Sum of Excess	5,672	3,935	1,609	10,249
Sum of Deficiency	0	0	0	0
Net Excess	5,672	3,935	1,609	10,249
Imports	388	14	360	404
Exports	1,223	281	747	1,597
Net Exchange	-835	291	-1,237	-343
Unit-Specific Transactions	6,306	542	5,683	6,775
Capacity Credit Transactions	26,703	2,363	23,659	29,025
Internal Bilateral Transactions	33,009	2,898	29,342	35,801
Daily Capacity Credits	0	0	0	0
Monthly Capacity Credits	91	63	10	171
Multimonthly Capacity Credits	1,208	243	912	1,457
All Capacity Credits	1,299	304	949	1,629
MIL Credits	263	96	153	346

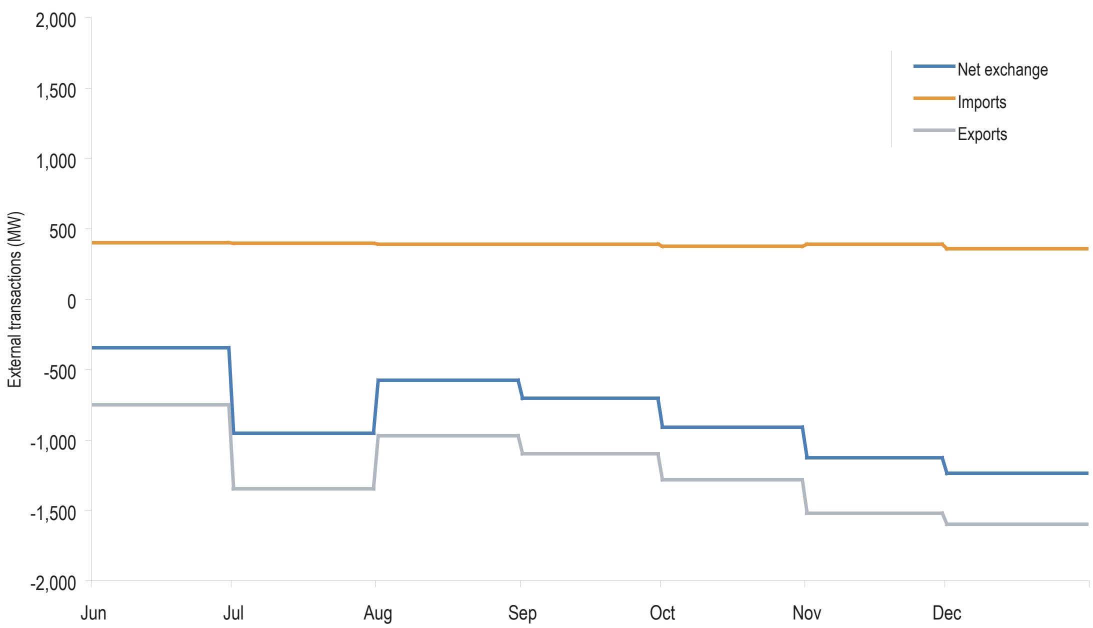
Figure 4-14 -Capacity obligations to the ComEd Capacity Market: Seven months ended December 31, 2004



External Bilateral Transactions

ComEd capacity resources may be traded bilaterally within and outside of ComEd. External bilateral transactions are imports and exports of capacity resources and may include areas inside and outside the PJM footprint. Figure 4-15 presents ComEd's external bilateral capacity transaction data for the seven-month period ended December 31, 2004. (Table 4-13 also includes data on imports and exports.) During this period, ComEd was a net exporter of capacity resources. Capacity imports averaged 388 MW and capacity exports averaged 1,223 MW, resulting in an average net exchange of -835 MW of capacity resources. Net exchange is equal to imports less exports.

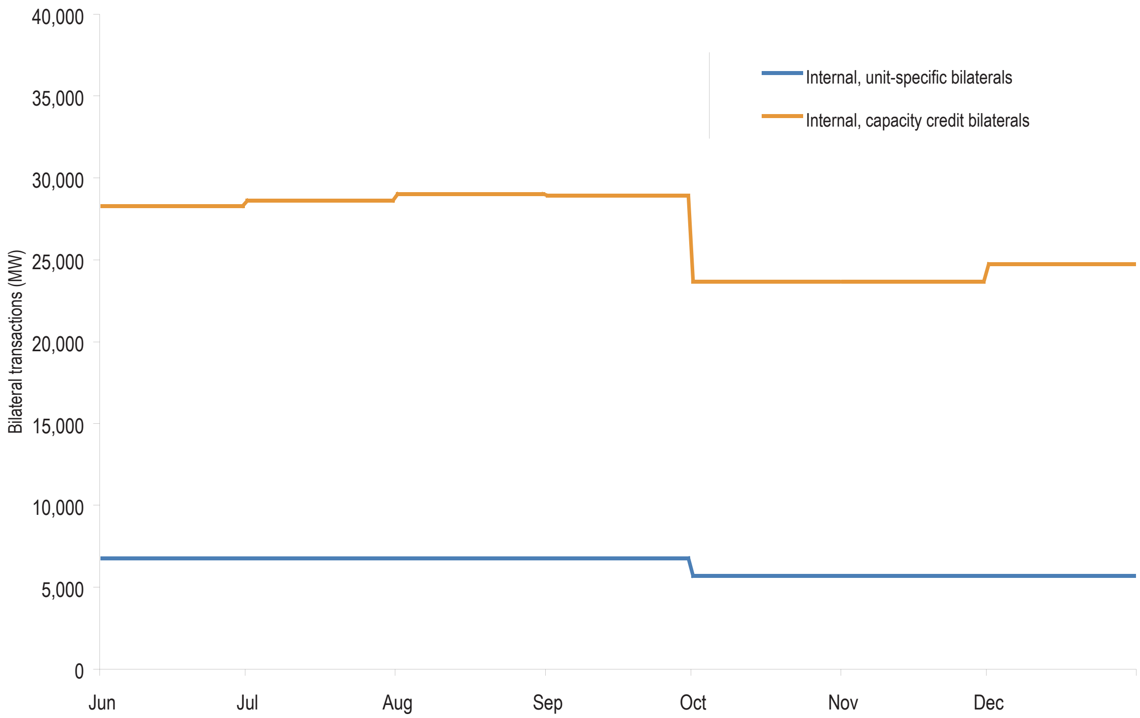
Figure 4-15 - External ComEd Capacity Market transactions: Seven months ended December 31, 2004



Internal Bilateral Transactions

Figure 4-16 presents data on ComEd's internal bilateral capacity transactions for the seven months ended December 31, 2004. (Table 4-13 also includes data on internal bilateral transactions.) Both unit-specific bilaterals and capacity credit bilaterals decreased on October 1, 2004, when lower obligations for the October to December interval became effective. Unit-specific bilaterals decreased 1,092 MW from 6,775 MW to 5,683 MW while capacity credit bilaterals decreased 5,268 MW from 28,927 MW to 23,659 MW. Bilateral capacity transactions can total more than the obligation because capacity credits can be traded multiple times among entities.

Figure 4-16 - Internal bilateral ComEd Capacity Market transactions: Seven months ended December 31, 2004



Market Performance for the ComEd Capacity Market

Capacity Credit Market Volumes

Between April and December 2004, the PJM RTO operated 48 Monthly and Multimonthly Capacity Credit Market Auctions to help LSEs satisfy their ComEd Control Zone capacity obligations for the June 2004 to May 2005 capacity planning period.[35] Table 4-13 shows that Monthly and Multimonthly Capacity Credits averaged 1,299 MW, or about 6 percent of the average capacity obligation for the seven months ending December 31, 2004. Table 4-14 shows monthly ComEd capacity credit market average daily volumes. Average daily volumes decreased by 680 MW from 1,629 MW to 949 MW when Phase 3 began and the obligation decreased for the October to December interval.

35 See PJM, "NICA Installed Capacity Credit Results" < ftp://ftp.pjm.com/pub/ capacity_credit_market/results/nica/ccmmonthly-nica.csv > (4.8 KB).

Capacity Credit Market Prices

Table 4-14 also shows the ComEd monthly and multimonthly capacity credit market prices for June through December 31, 2004. The volume-weighted average prices ranged from a low of $24.17 per MW-day in December to a high of $32.26 per MW-day in July. These prices were, with the exception of July, less than the $30 per MW-day offer cap that had been proposed by PJM to mitigate market power in the ComEd Capacity Market.

Table 4-14 - ComEd Capacity Credit Markets: Seven months ended December 31, 2004

	Monthly and Multimonthly Volume (MW)	Monthly and Multimonthly Weighted-Average Price ($ per MW-day)
Jan	N/A	N/A
Feb	N/A	N/A
Mar	N/A	N/A
Apr	N/A	N/A
May	N/A	N/A
Jun	1,507	$29.06
Jul	1,525	$32.26
Aug	1,584	$28.77
Sep	1,629	$28.64
Oct	949	$24.43
Nov	952	$24.29
Dec	957	$24.17
Average Jun-Dec	1,299	$27.98

Although the market structure in the ComEd Capacity Market was highly concentrated and auctions were frequently characterized by a single pivotal supplier, market performance results were consistent with the competitive benchmark established prior to the market by the MMU of $30 per MW-day. Market sellers chose to offer their capacity to the market at prices which were generally near, or below, the $30 per MW-day level. While there is no information to support the statement that individual suppliers offered their capacity at a competitive price based on unit costs, the markets did clear with only a few exceptions at a price less than $30 per MW-day. The conclusion is thus that the ComEd Capacity Market results were reasonably competitive in 2004.

SECTION 5 - 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.[1] 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.[2] 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.[3] 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.

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.[4] 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 75 FERC ¶ 61,080 (1996).
2 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.
3 See "PJM Manual for Scheduling Operations, M-11," Revision 22 (October 19, 2004), p. 71.
4 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).[5]

- **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.

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 PJM Market Monitoring Unit (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.[6] 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.

5 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).
6 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).

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)[7] 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.

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."[8,9] 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.

7 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.
8 See Section 2, "Energy Market" for a more complete discussion of concentration ratios and the Herfindahl-Hirschman Index (HHI).
9 The HHIs reported in this summary are based on regulation capacity that is both offered to the market and is eligible to provide regulation.

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.

  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.[10] 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. [11]

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.

10 See "Regulation Capacity, Daily Availability, Hourly Supply and Price," in Appendix F, "Ancillary Service Markets," for a definition of capacity, availability and supply.
11 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.

Regulation Market

Regulation Market Structure

Demand

Demand for regulation is price inelastic as it does not change with price for regulation. The demand for regulation is set administratively based on reliability objectives. In some PJM Regulation Markets demand varies with overall load, and in other PJM Regulation Markets demand is fixed regardless of market conditions.

The PJM Mid-Atlantic Region has different regulation requirements for on-peak hours and off-peak hours. The regulation requirement for the peak period is 1.1 percent of the peak-load forecast; for the off-peak period, it is 1.1 percent of the valley-load forecast.[12] On October 22, 2004, the PJM Mid-Atlantic Region's regulation requirement was temporarily increased by 175 MW for both on-peak and off-peak periods. On December 16, 2004, the PJM Mid-Atlantic Region's regulation requirement was reduced from this level by 50 MW. During Phases 1 and 2, PJM Mid-Atlantic Region regulation requirements ranged from 215 MW of regulation capability for off-peak periods to 583 MW for on-peak periods. During Phase 3, requirements ranged from 227 MW of regulation capability for off-peak periods to 659 MW for on-peak periods.[13]

In the AP Control Zone, the regulation requirement was 1.0 percent of the peak forecast load and did not vary between on-peak and off-peak periods. During Phases 1 and 2, the requirement ranged from 53 MW to 82 MW.

In the ComEd Control Area during Phase 2, the regulation requirement was 300 MW during weekday hours ending 0000, 0100, 0700, 0800, 0900 and 2300 EPT although it was not possible to actually assign 300 MW of regulation until mid-August 2004 because it was not available. For all other hours, the requirement was 150 MW.

During Phase 3, the PJM Western Region had a regulation requirement of 1 percent of the forecast peak load. On October 22, 2004, the Western Region regulation zone's regulation requirement was increased to 1 percent of the forecast peak load plus 175 MW. In the third week of December, the Western Region regulation zone's regulation requirement was reduced to 1 percent of forecast peak load plus 125 MW. The Western Region regulation zone requirement during Phase 3 ranged from 303 MW to 635 MW.

Regulation obligation is determined hourly for each load-serving entity (LSE) by applying the real-time load ratio share (adjusted for scheduled load responsibility) to the actual amount of regulation assigned for that hour adjusted for any bilaterals and self-supply. The hourly regulation charge for each LSE is equal to the hourly regulation market-clearing price (RMCP) multiplied by the MW of regulation purchased from the market, plus the LSE's percentage share of any opportunity cost incurred by generation owners over and above the RMCP, plus the LSE's percentage share of any unrecovered costs incurred by those units the regional transmission organization (RTO) called on for the sole purpose of providing regulation.

12 See "PJM Manual for Scheduling Operations, M-11," Revision 22 (October 19, 2004), pp. 50 - 51.
13 For additional detail, please refer to Appendix F, "Ancillary Service Markets."

Supply

The supply of regulation can be measured as regulation capability, regulation offered, regulation offered and eligible, or regulation assigned. For purposes of evaluating the Regulation Market, the relevant regulation supply is defined as the level of supply that is both offered to the market on an hourly basis and is eligible to participate in the market on an hourly basis. The level of supply that clears in the market on an hourly basis is assigned regulation.

Regulation capability represents the total volume of regulation capability reported by resource owners based on unit characteristics.

Regulation offered represents the level of regulation capability actually offered to the PJM Regulation Market. Resource owners may offer those units with approved regulation capability into the PJM Regulation Market. PJM does not require a resource capable of providing regulation service to offer its capability to the market. Regulation offers may be submitted on a daily basis and these daily offers may be modified on an hourly basis.

Regulation offered and eligible represents the level of regulation capability actually offered to the PJM Regulation Market and actually eligible to provide regulation in an hour. Some regulation offered to the market is not eligible to participate in the Regulation Market as a result of identifiable offer parameters specified by the supplier. As an example, the regulation capability of a unit will be included in regulation offered based on the daily offer and availability status, but that regulation capability will not be eligible in one or more hours because the supplier sets the availability status to unavailable for one or more hours of that same day. (The availability status of a unit may be set in both a daily offer and an hourly update table in the PJM market software.) As another example, the regulation capability of a unit will be included in regulation offered if the owner of a unit offers regulation, but that regulation capability will not be eligible if the owner sets the unit's economic maximum generation level equal to its economic minimum generation level. In that case, the unit cannot provide regulation and is not eligible to provide regulation. As another example, the regulation capability of a unit will be included in regulation offered but that regulation capability will not be eligible if the unit is not operating, unless the unit is a combustion turbine that meets specific operating parameter requirements.

Only those offers which are eligible to provide regulation in an hour are part of supply for that hour, and only those offers are considered for purposes of clearing the market. Regulation assigned represents those regulation resources selected through the regulation market-clearing mechanism to provide regulation service for a given hour.

Market Concentration

PJM Mid-Atlantic Regulation Market – Calendar Year 2004

In the 2004 Regulation Market in the Mid-Atlantic Region, the submitted capability[14] was 2,140 MW with an average daily offer[15] volume of 1,543 MW, or approximately 72 percent of the submitted capability. In the 2004 Regulation Market in the Mid-Atlantic Region, the level of regulation resources

14 Submitted capability is defined as the maximum daily offer volume during the period without regard to the actual availability of the resource.
15 Average daily offer volume is defined for the period, includes units offered for the day and excludes resources which are unavailable on a daily basis.

offered on an hourly level and the level of regulation resources both offered and eligible to participate on an hourly level in the market were lower than the total level of regulation resources offered. In 2004 the average hourly offer level was 1,170 MW for the Mid-Atlantic Region's Regulation Market while the average hourly eligible offer level was 948 MW.

The ratio of the hourly regulation supply offered to the hourly regulation requirement, averaged 2.90 for the PJM Mid-Atlantic Region in 2004. When this ratio equals 1.0, it indicates that offered supply exactly equals demand for the referenced time period. Based upon regulation offered and eligible, this ratio averaged 2.33. The average regulation requirement for the PJM Mid-Atlantic Region during 2004 was 418 MW.

Hourly HHI values were calculated based upon the regulation offered, regulation offered and eligible, and regulation assigned. Based upon regulation offered, HHI ranged from a maximum of 2151 to a minimum of 1097 with an average value of 1546. Based upon regulation offered and eligible, HHI values ranged from a maximum of 2770 to a minimum HHI of 1088, with an average value of 1608. Based upon regulation assigned, HHI values ranged from a maximum of 7256 to a minimum HHI of 1226. The average HHI value for regulation assigned was 2511.

Table 5-1 - PJM hourly Regulation Market HHI: Calendar year 2004

	Minimum	Average	Maximum
Offered	1097	1546	2151
Eligible	1088	1608	2770
Assigned	1226	2511	7256

During 2004, there was one supplier with a market share in excess of 20 percent for regulation offered. That market share was 24.5 percent. There was one supplier with a market share of 20 percent based on regulation offered and eligible. There were two suppliers with a market share in excess of 20 percent based on assigned regulation, with the largest market share 27.1 percent.

During 2004, less than 1 percent of the hours had an RSI value less than 1.0 for offered supply. In terms of offered and eligible supply, 3 percent of the hours had an RSI value less than 1.0. An RSI value less than 1.0 indicates that the market had a single pivotal supplier. The offer of a single pivotal supplier is required in order to clear the market and that pivotal supplier therefore has market power. While the RSI is not a bright line test, these results are consistent with multiple pivotal suppliers and a competitive outcome.

Table 5-2 - PJM hourly Regulation Market RSI statistics: Calendar year 2004

	Percent of Hours RSI < 1.10	Percent of Hours RSI < 1.00	Average RSI	Minimum RSI
Offered	0%	0%	2.18	0.89
Eligible	6%	3%	1.79	0.52

Based on these market structure data, the MMU concludes that the market structure of the PJM Mid-Atlantic Region's Regulation Market is consistent with a competitive outcome. The market in the PJM Mid-Atlantic Region is currently operated by PJM as a competitive market.

ComEd Regulation Market – Phase 2

During the Phase 2 Regulation Market in the Com Ed Control Area, the submitted capability was 487 MW with an average daily offer volume of 296 MW[16] or approximately 60 percent of the submitted capability. The level of resources offered on an hourly level and the level of regulation resources both offered and eligible to participate on an hourly level in the Regulation Market were lower than the total level of regulation resources offered. During Phase 2, the average hourly offer level was 276 MW while the average hourly eligible offer level was 260 MW.

The ratio of the hourly regulation supply offered to the hourly regulation requirement, averaged 1.68 for the Phase 2 ComEd Regulation Market. Based upon regulation offered and eligible, this ratio averaged 1.57. The average regulation requirement for the ComEd Control Area during Phase 2 was 176 MW.[17]

Hourly HHI values were calculated based upon the regulation offered, regulation offered and eligible and regulation assigned. Based upon regulation offered, HHI ranged from a maximum of 10000 to a minimum of 5000 with an average value of 5713. Based upon regulation offered and eligible, HHI values ranged from a maximum of 10000 to a minimum HHI of 5000, with an average value of 5817. Based upon regulation assigned, HHI values ranged from a maximum of 10000 to a minimum HHI of 5000. The average HHI value for regulation assigned was 7195.

Table 5-3 - ComEd Control Area hourly Regulation Market HHI: Phase 2, 2004

	Minimum	Average	Maximum
Offered	5000	5713	10000
Eligible	5000	5817	10000
Assigned	5000	7195	10000

During Phase 2, there were two suppliers with a market share in excess of 20 percent for regulation offered. The largest such market share was 68.4 percent. There were two suppliers with market shares in excess of 20 percent based on offered and eligible regulation. The largest such market share was 69 percent. There were two suppliers with a market share in excess of 20 percent based on regulation assigned. The largest such market share was 77.2 percent.

During Phase 2, 99.9 percent of the period was characterized by a residual supplier index (RSI) of less than 1.0 for regulation offered and for regulation offered and eligible. An RSI value less than 1.0 indicates that the market was characterized by a single pivotal supplier. The offer of a single pivotal supplier is required in order to clear the market, and that pivotal supplier, therefore, has market power.

16 This level of participation is slightly higher than the 55 percent level reported by the Market Monitor in his October 1, 2004, Declaration (paragraph 46). The Declaration can be found at <http://www.pjm.com/markets/market-monitor/downloads/mmu-reports/20041004-public-market-based-rates.pdf> (6.8 MB). The calculation in the Declaration was based upon the offer volume as a percentage of the pre-integration stated regulating capability of resources, as provided by the owners, rather than the actual maximum market offer levels used here.
17 See Appendix F, "Ancillary Service Markets," for additional detail on the regulation requirements.

A lack of supply diversity and low offer volume contributed to the concentration levels indicated by the observed HHI and RSI values.

Table 5-4 - ComEd Control Area hourly Regulation Market RSI statistics: Phase 2, 2004

	Percent of Hours RSI < 1.10	Percent of Hours RSI < 1.00	Average RSI	Minimum RSI
Offered	100%	100%	0.53	0
Eligible	100%	100%	0.49	0

Based on this market structure data, the MMU concludes that the market structure of the ComEd Control Area was not consistent with a competitive outcome. The Regulation Market in the ComEd Control Area was operated by PJM as a cost-based market with market-clearing prices.

PJM Western Region Regulation Market – Phase 3

The PJM Western Region's Regulation Zone during Phase 3 was comprised of the ComEd, AEP, DAY and AP Control Zones. In the Phase 3 Regulation Market in the PJM Western Region, the submitted capability was 1,815 MW with an average daily offer volume of 1,399 MW, or approximately 77 percent of the submitted capability. In the Phase 3 Regulation Market in the PJM Western Region, the level of resources offered on an hourly level and both offered and eligible to participate on an hourly basis in the Regulation Market was lower than the level of regulation resources offered. During Phase 3, the average hourly offer level was 958 MW while the average hourly eligible offer level was 881 MW.

The ratio of the hourly regulation supply offered to the hourly regulation requirement, averaged 2.12. Based upon regulation offered and eligible, this ratio averaged 1.93. The average regulation requirement for the PJM Western Region during Phase 3 was 476 MW.

Hourly HHI values were calculated based upon the regulation offered, regulation offered and eligible and regulation assigned. Based upon regulation offered, HHI ranged from a maximum of 4318 to a minimum of 2335 with an average value of 3262. Based upon regulation offered and eligible, HHI values ranged from a maximum of 5648 to a minimum HHI of 2283, with an average value of 3426. Based upon regulation assigned, HHI values ranged from a maximum of 10000 to a minimum of 2209. The average HHI value for regulation assigned was 4012.

Table 5-5 - Western Region hourly Regulation Market HHI: Phase 3, 2004

	Minimum	Average	Maximum
Offered	2335	3262	4318
Eligible	2283	3426	5648
Assigned	2209	4012	10000

During Phase 3, there were two suppliers with a market share in excess of 20 percent for offered supply. The largest market share for offered regulation was 47.9 percent. There were two suppliers with market shares in excess of 20 percent for regulation offered and eligible. The largest market share for regulation offered and eligible was 51 percent. There were two suppliers with a market share in excess of 20 percent for regulation assigned. The largest market share for regulation assigned was 47.9 percent.

During Phase 3 in the Western Region, 56 percent of the hours had a residual supplier index (RSI) less than 1.0 for regulation offered. For regulation offered and eligible, 78 percent of the Phase 3 hours had an RSI value less than 1.0.

Table 5-6 - Western Region hourly Regulation Market RSI statistics: Phase 3, 2004

	Percent of Hours RSI < 1.10	Percent of Hours RSI < 1.00	Average RSI	Minimum RSI
Offered	64%	56%	1.11	0.66
Eligible	86%	78%	0.95	0.59

Based on these market structure data, the MMU concludes that the market structure of the PJM Western Region was not consistent with a competitive outcome. The Regulation Market in the PJM Western Region is currently operated by PJM as a cost-based market with market-clearing prices.

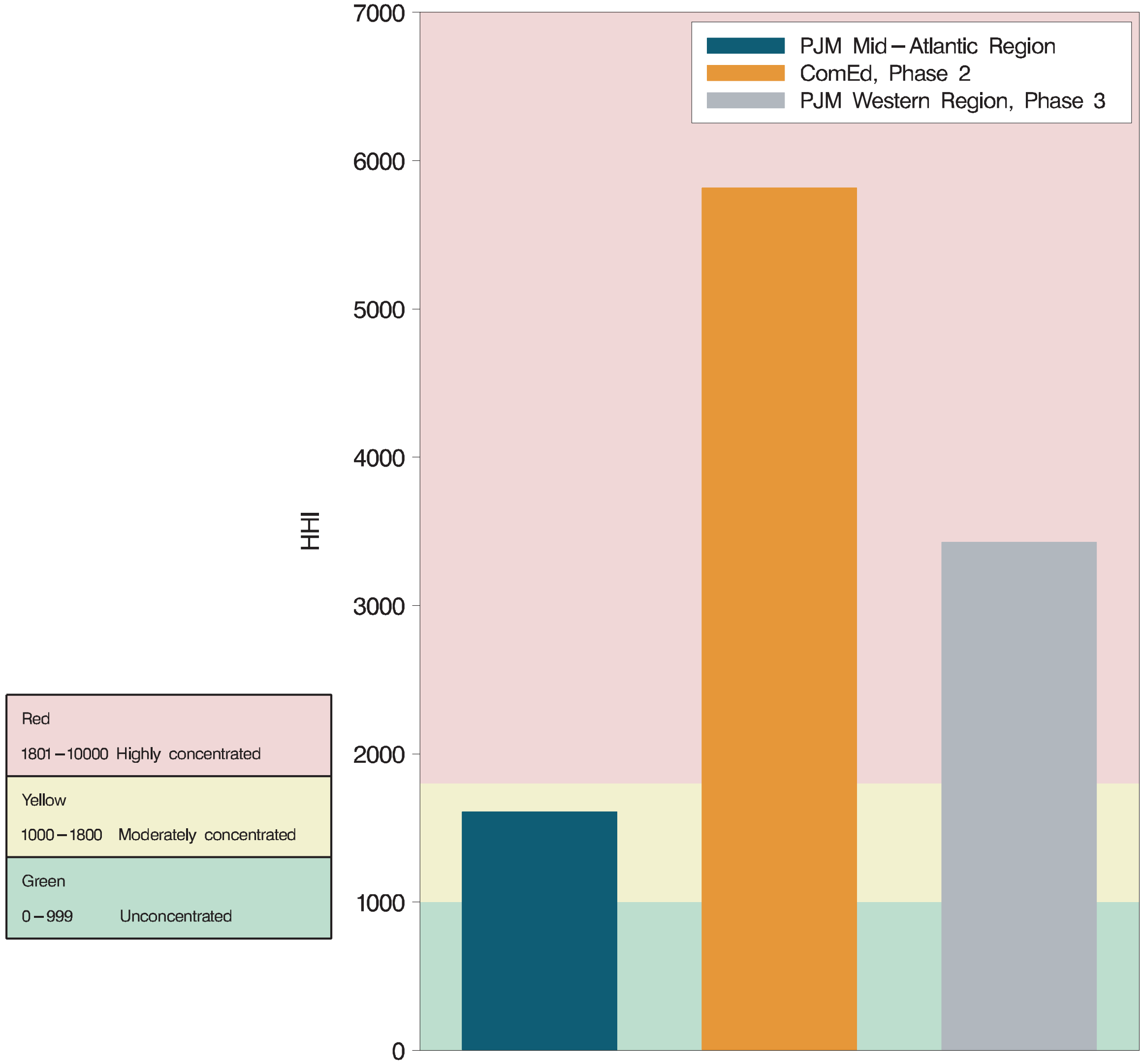
On October 1, 2004, the PJM Market Monitor filed with the FERC a Declaration regarding the expected competitiveness of the Regulation Market in the PJM Western Region. For that analysis, the MMU gathered data on regulation capability from the generators in the Western Region and cross-checked the data against other available sources. The data available at that time reflected the regulation capability reported by generation owners that had not yet been validated in actual market operation within PJM or been subjected to PJM tests of regulation capability. The MMU analyzed the Regulation Market configuration consistent with the Commission's April 14, 2004, order.[18] The data reported in the Declaration indicated a regulation capability in the PJM Western Region of 1,977 MW. It was assumed for purposes of analysis in the Declaration that all regulation capability would be offered to the market.

Actual market regulation capability, regulation offered and regulation offered and eligible during Phase 3 were below the regulation capability reported in the Declaration. The level of market participation in the Western Region during Phase 3 averaged approximately 77 percent of the regulation capability. This is similar to the results during 2004 in the PJM Mid-Atlantic Region's Regulation Market where approximately 72 percent of the total regulation capability was offered into the market. Though the level of participation is similar, different patterns of ownership in the Western Region resulted in higher market concentration levels and lower RSI levels in the Western Region than in the PJM Mid-Atlantic Region.

18 107 FERC¶ 61,018 (2004); see also 107 FERC ¶ 61,026 (2004).

Summary of Market Concentration

Figure 5-1 - PJM system Regulation Market HHI: Calendar year 2004



HHI levels during calendar year 2004 in the PJM Mid-Atlantic Region's Regulation Market were 1608 on average, based on regulation offered and eligible which is at the upper end of the moderately concentrated designation under the FERC "Merger Policy Statement."[19] HHI levels during Phase 2 in the ComEd Control Area's Regulation Market were 5817 on average, based on regulation offered and eligible, or highly concentrated. HHI levels during Phase 3 in the PJM Western Region's Regulation Market were 3426 on average, based on regulation offered and eligible, or highly concentrated. (See Figure 5-1.)

19 See Section 2, "Energy Markets," at "Market Concentration" for a discussion of HHI.

Regulation Market Performance

Regulation Offers

Generators wishing to participate in any of the PJM Regulation Markets submitted regulation offers for specific units by hour 1800 EPT of the day before the operating day. The regulation offer price is subject to a $100 per MWh offer cap in the PJM Mid-Atlantic Region and a cost plus $7.50 per MWh offer cap elsewhere, with the exception of the AP Control Zone during Phases 1 and 2. In the AP Control Zone during Phases 1 and 2, regulation offers were capped at the cost of providing regulation service because there was only one regulation supplier. The AP zone's regulating units were compensated at their individual regulation offer plus LOC rather than at a single market-clearing price.

The offer price is the only component of the regulation offer applicable for the entire operating day. The following information must be included in each offer, but can be entered or changed up to 60 minutes prior to the operating hour: regulating status; regulation capability; and high and low regulation limits. The Regulation Market is cleared on a real-time basis, and regulation prices are posted hourly throughout the operating day. The amount of self-scheduled regulation is confirmed 60 minutes before each operating hour, and regulation assignments are made 30 minutes before each operating hour.

The Regulation Market in the PJM Mid-Atlantic Region (calendar year 2004), in the AP Control Zone (Phases 1 and 2), in the ComEd Control Area (Phase 2) and in the PJM Western Region (Phase 3) was cleared hourly, based upon both offers submitted by the units and the hourly opportunity cost of each unit.[20] The effective offer price is the sum of the unit-specific offer and the opportunity cost. In order to clear the market, PJM ranks the units by effective offer price and selects in order until the amount of regulation required for the hour is satisfied at least cost. The price that results in the required amount of regulation is the regulation market-clearing price (RMCP), and the unit that sets this price is the marginal unit.

Regulation Prices

Figure 5-2 shows both the daily average regulation market-clearing price and the opportunity cost for the marginal units in the PJM Mid-Atlantic Region during calendar year 2004. Figure 5-3 shows the same data for the ComEd Control Area's Regulation Market during Phase 2 and for the PJM Western Region's regulation zone during Phase 3. All units chosen to provide regulation in the PJM Mid-Atlantic Region and in the ComEd regulation zone during Phase 2 received as payment the higher of the clearing price multiplied by the unit's assigned regulating capability, or the unit's regulation bid multiplied by its assigned regulating capability plus the individual unit's real-time opportunity cost.[21] Units in the AP Control Zone during Phases 1 and 2 were compensated at the unit's own cost plus the actual lost opportunity cost of the unit while providing that regulation. The AP Control Zone did not have a market-clearing price.

20 PJM estimates the opportunity cost for units providing regulation based on a forecast of locational marginal price (LMP) for the upcoming hour. Opportunity cost is included in the market-clearing price.
21 See "PJM Operating Agreement, Accounting, m28," Revision 27, Section 4, "Regulation Credits" (October 1, 2004), pp. 26-27. PJM uses estimated opportunity cost to clear the market and real-time opportunity cost to compensate generators that provide regulation and spinning. Real-time opportunity cost is calculated using real-time LMP.

Figure 5-2 - PJM Mid-Atlantic Region daily average regulation clearing price and estimated opportunity costs: Calendar year 2004

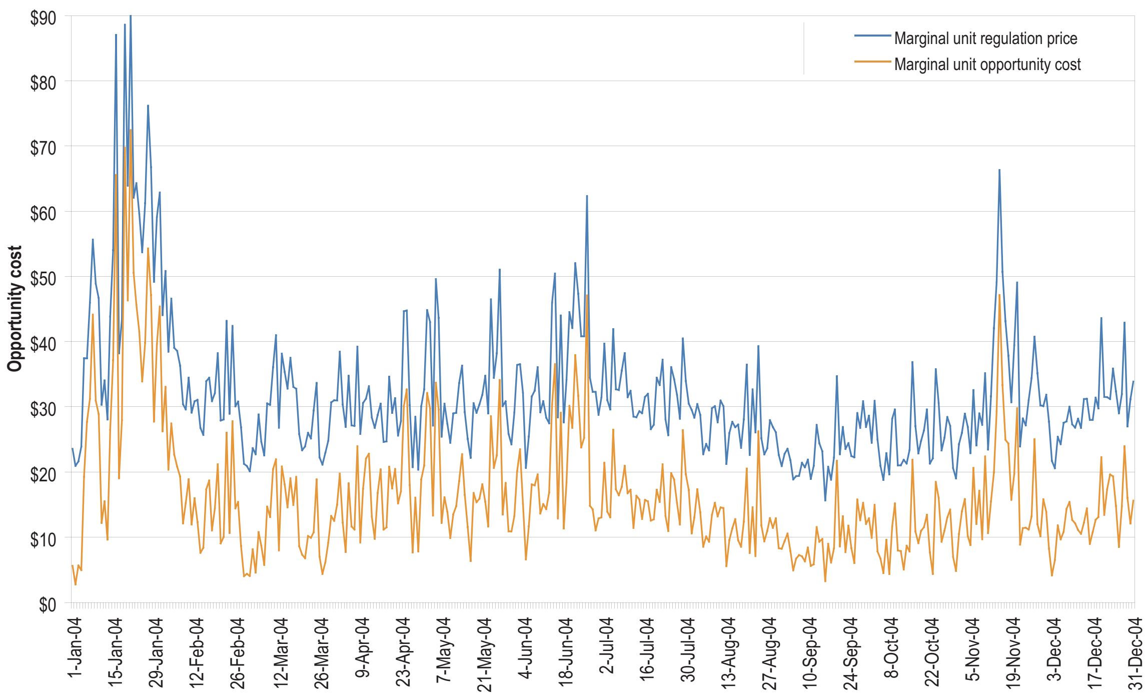
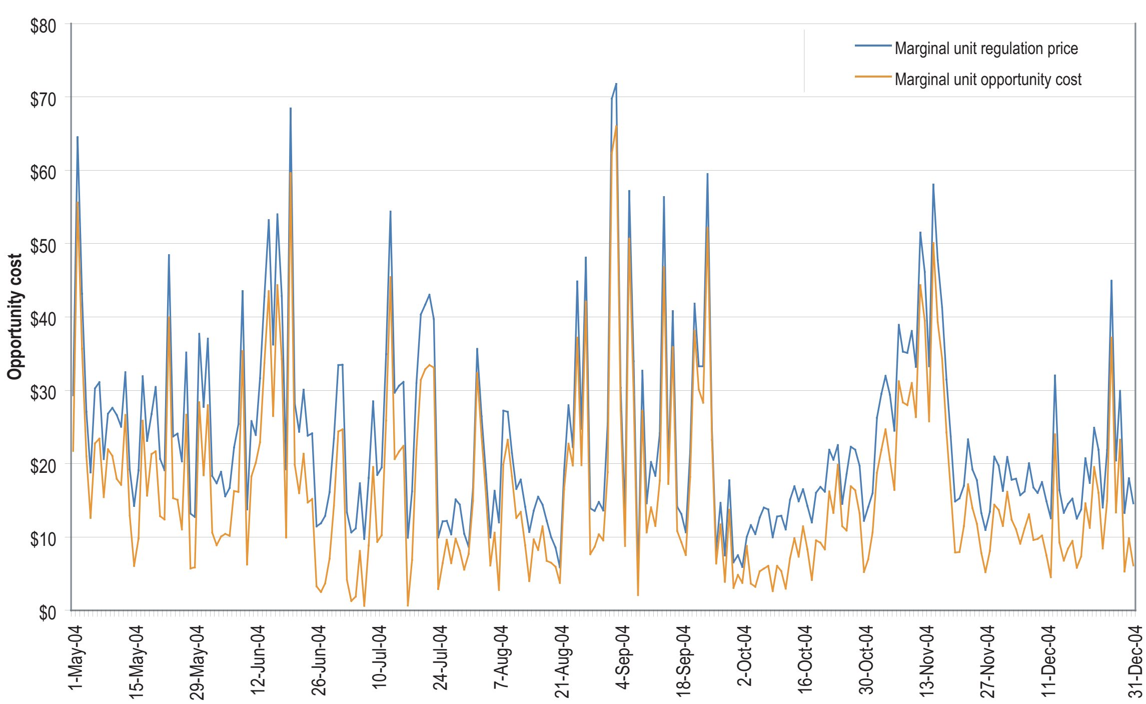


Figure 5-3 - ComEd (Phase 2) / Western Region (Phase 3) daily average regulation clearing price and opportunity costs: Phases 2 and 3, 2004



As Figure 5-4 shows, during calendar years 2003 and 2004, hourly regulation prices in the PJM Mid-Atlantic Region were relatively stable despite several significant, short-term spikes in the price of regulation during February 2004 that resulted from price spikes in the Energy Market affecting the regulation price via the OC.

Figure 5-4 - PJM Mid-Atlantic Region daily regulation MW purchased vs. price per MW: March 1, 2003, to December 31, 2004

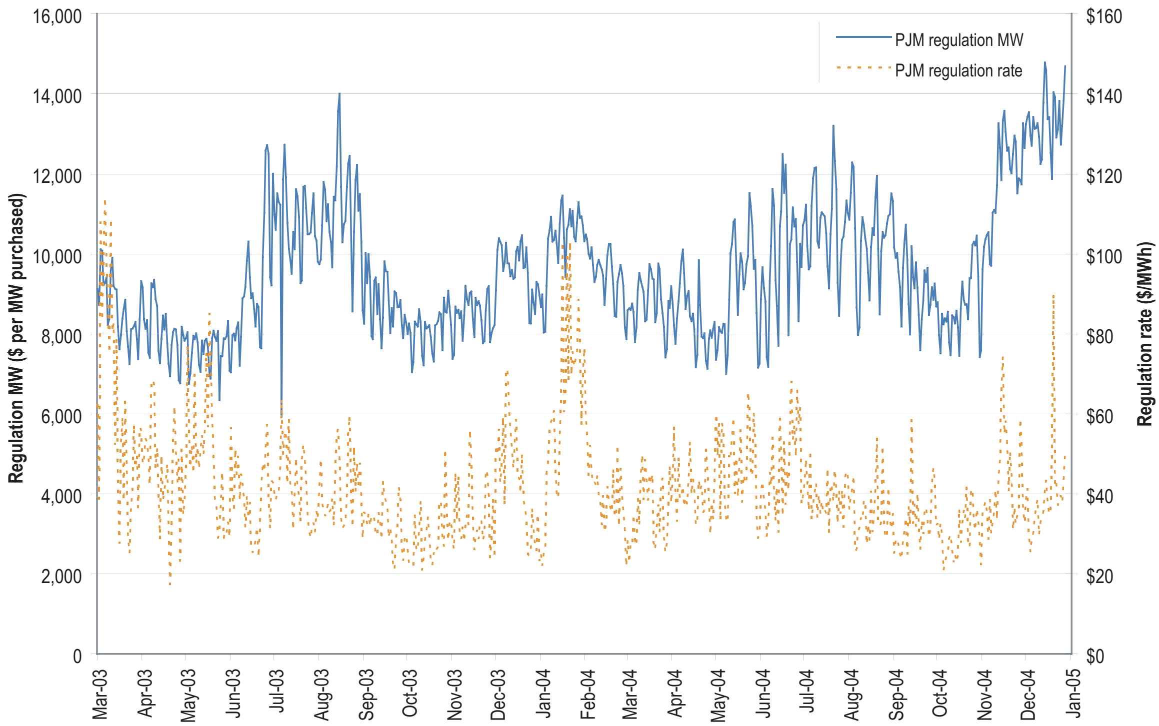
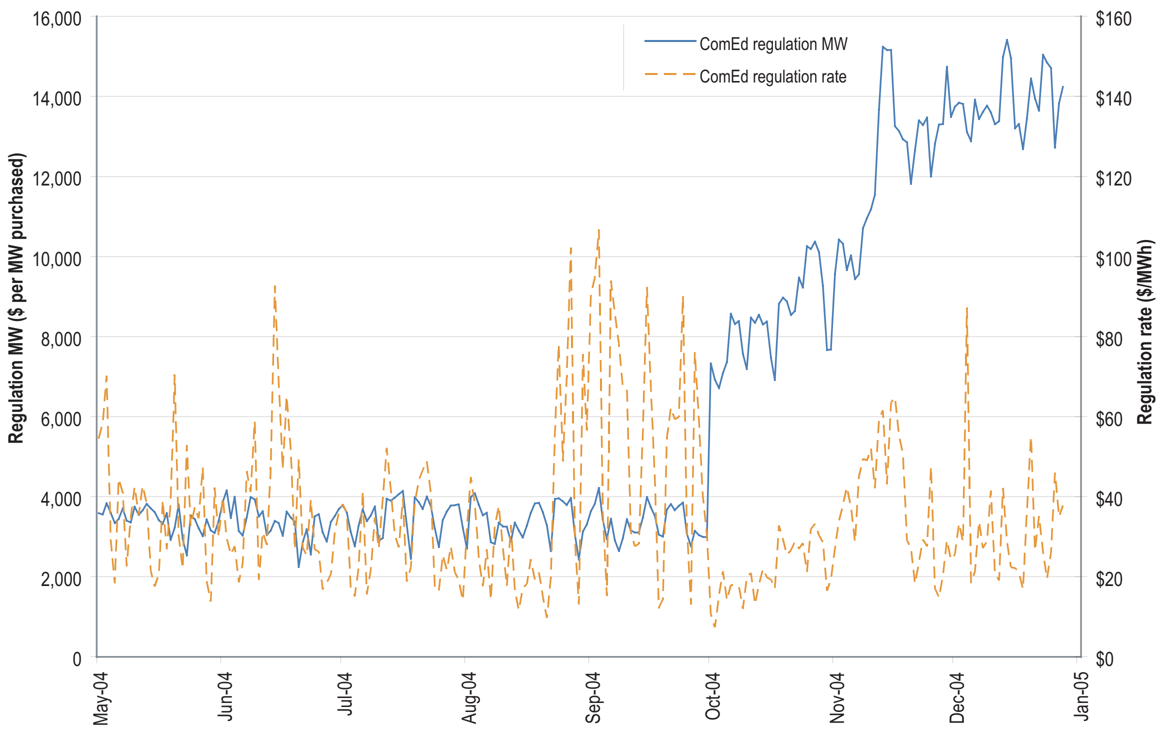


Figure 5-4 compares the regulation price per MWh for the PJM Mid-Atlantic Region to the demand for regulation for the calendar years 2003 and 2004. In the PJM Mid-Atlantic Region, the price of regulation has tended to follow system locational marginal energy price (LMP). Demand for regulation is a linear function of forecasted energy demand. When loads increase, the result is an increase in demand for regulation. System LMP increases with load because higher priced units must be dispatched to meet demand. Increases in system LMP cause the opportunity cost to rise by increasing the spread between LMP and the energy offers of the regulating units. As a result, load, energy prices and regulation prices are highly correlated.

Figure 5-5 compares the regulation price for the ComEd Control Area to the demand for regulation during Phase 2. The graph displays the same data for the newly configured PJM Western Region's Regulation Market during Phase 3. During Phase 2, PJM fixed demand for regulation in the ComEd regulation zone at 300 MW during weekday hours ending 0000, 0100, 0700, 0800, 0900 and 2300 EPT. For all other hours, the requirement was 150 MW. For this reason, in the ComEd regulation zone the relationship between the price of regulation and the price of energy was not the same as in the PJM Mid-Atlantic Region. More important in ComEd were the regulation supply and the cost of supplying regulation. For the first three to four months after becoming part of PJM, the ComEd regulation zone did not have enough regulation available hourly to meet demand. This limitation forced PJM to dispatch additional generation capable of regulation so as to meet demand for regulation. Furthermore, at times of minimum generation, some regulating units had to be taken offline to prevent an overgeneration imbalance. In late August 2004, additional regulation capability was added in the ComEd regulation zone. Overall, the inflexibility of demand and the shortage of available regulating units caused relatively wide price swings in the ComEd Control Area during Phase 2.

Figure 5-5 - ComEd (Phase 2) / Western Region (Phase 3) daily regulation MW purchased vs. cost per MWh: Phases 2 and 3, 2004



The price of regulation for the PJM Mid-Atlantic Region was approximately the same in Phases 1 and 2, 2004 (i.e., $42.75 per MWh) as it had been in 2003 (i.e., $42.30 per MWh). During Phase 3, the price of regulation for the PJM Mid-Atlantic Region was $38.26 per MWh. The average price of regulation in the PJM Mid-Atlantic Region for calendar year 2004 was $41.48 per MWh. In the AP Control Zone during Phases 1 and 2, the price of regulation was 30 percent higher than it had been in 2003 ($33.71 per MWh compared to $25.15 per MWh). The higher regulation prices in AP for 2004 were the result primarily of higher fuel prices. For the ComEd Control Area during Phase 2, the price of regulation was $39.22 per MWh. For the PJM Western Region's Regulation Market during Phase 3, the average price of regulation was $31.14 per MWh.

Regulation Availability

During the market-clearing process, the PJM Market Operations Group assigns all regulation in economic order until the amount of required regulation is satisfied. If there is a lack of capacity because of unit maintenance or unit unavailability, market operations staff can call on units that have not been scheduled for generation in order to satisfy regulation requirements. If regulating MW needed to meet the requirement remain unavailable, market operations reports this condition to PJM dispatching operations and a regulation deficit occurs.

The PJM Mid-Atlantic Region almost never experienced a deficit of regulation during calendar year 2004. In fact, the Mid-Atlantic Region experienced a regulation deficit during only 0.2 percent of all hours during Phases 1 and 2 and during only 3.8 percent of all hours during Phase 3. The AP Control Zone during Phases 1 and 2 had regulation deficits during 6.5 percent of all hours. The ComEd Control Area during Phase 2 had regulation deficits during 19 percent of all hours. These deficits occurred for several reasons, including a shortage of regulation-certified units during the first two months of Phase 2 and unavailable regulation units. Seventy-four percent of these regulation deficits occurred during on-peak hours when regulation demand was higher while 26 percent of these regulation deficits occurred during off-peak hours. In ComEd a relatively large percentage of lower priced generating units were not capable of regulation and, during times of minimum generation, units capable of regulation were not available. By mid-August 2004, additional regulation capability entered the market, alleviating the shortage and increasing regulation prices. The PJM Western Region during Phase 3 had regulation deficits during only 0.2 percent of all hours.

Spinning Reserve Market

Spinning Reserve Market Structure

Supply

Spinning reserve is an ancillary service defined as generation that is synchronized to the system and capable of producing output within 10 minutes. Spinning reserve can, at present, be provided by a number of sources, including steam units with available ramp, condensing hydroelectric units, condensing CTs and CTs running at minimum generation.

All of the units that participate in the Spinning Reserve Market are categorized as either Tier 1 or Tier 2 spinning. Tier 1 resources are those units that are online following economic dispatch and able to respond to a spinning event by ramping up from their present output. All units operating on the PJM system are considered potential Tier 1 resources, except for those explicitly assigned to Tier 2 spinning. Tier 2 resources include units that are backed down to provide spinning capability and condensing units synchronized to the system and available to increase output.

PJM introduced a market for spinning reserve on December 1, 2002. Before the Spinning Reserve Market, Tier 1 spinning reserve had not been compensated directly and Tier 2 spinning reserve had been compensated on a unit-specific, cost-based formula.

Under the Spinning Reserve Market rules, Tier 1 resources are paid when they respond to an identified spinning event as an incentive to respond when needed. Tier 1 spinning payments or credits are equal to the integrated increase in MW output above economic dispatch from each generator over the length of a spinning event, multiplied by the spinning energy premium less the hourly integrated LMP. The spinning energy premium is defined as the average of the five-minute LMPs calculated during the spinning event plus $50 per MWh.[22] All units called on to supply Tier 1 or Tier 2 spinning have their actual MW monitored. Tier 1 units are not penalized if their output fails to match their expected response as they are only compensated for their actual response. Tier 2 units assigned spinning by market operations are compensated whether or not they are actually called on to supply spinning so they are penalized if their MW output fails to meet their assignment.

There were significant changes to the geographic structure of PJM's Spinning Reserve Markets in 2004. In Phase 1, PJM had two Spinning Reserve Markets: the PJM Mid-Atlantic Region and the AP Control Zone. In Phase 2, the ComEd spinning zone was created, resulting in three separate Spinning Reserve Markets. In Phase 3, AEP and DAY were integrated and PJM was divided into three separate Spinning Reserve Markets: the Mid-Atlantic Region's, ComEd's and the AP-AEP-DAY Western Region's Spinning Reserve Markets.

Under the Spinning Reserve Market rules, Tier 2 spinning resources are paid in order to be available as spinning reserve, regardless of whether the units are called upon to generate in response to a spinning event. The price for Tier 2 spinning resources is determined in a market for Tier 2 spinning resources. Several steps are necessary before the hourly Tier 2 Spinning Reserve Market is cleared. Ninety minutes prior to the start of the hour, PJM estimates the amount of Tier 1 reserve available from every unit; 60 minutes prior to the start of the hour, self-scheduled Tier 2 units are identified. If spinning requirements are not met by Tier 1 and self-scheduled Tier 2 resources, then a Tier 2 clearing price is determined 30 minutes prior to the start of the hour. This Tier 2 price is equivalent to the merit order price of the highest price, Tier 2 resource needed to fulfill spinning requirements, the marginal unit. A unit's merit order price is a combination of the unit's spinning offer price, the cost of energy use per MWh of capability and the unit's opportunity cost.[23]

The spinning offer price submitted for a unit can be no greater than the maximum value of the unit's operating and maintenance cost plus a $7.50 per MWh margin.[24,25] The market-clearing price is comprised of the marginal unit's offer price, cost of energy use and opportunity cost. All units cleared in the Spinning Reserve Market are paid the higher of either the market-clearing price or the unit's spinning offer plus the unit-specific LOC and cost of energy use incurred. The Mid-Atlantic Region's Tier 2 Spinning Reserve Market is cleared on cost-based offers because the structural conditions for competition do not exist. The structural issue can be more severe when the Spinning Reserve Market becomes local because of transmission constraints.

22 See "PJM Manual 11: Scheduling Operations," Revision 23 (December 7, 2004), pp. 66-67.
23 Although it is unusual, a PJM dispatcher can deselect units which have been committed after the clearing price is established. This only happens if real-time system conditions require dispatch of a spinning unit for constraint control, or problems with a generator or monitoring equipment are reported.
24 See "PJM Manual 11: Scheduling Operations," Revision 23 (December 7, 2004), p. 58.
25 See PJM Manual 15: Cost Development Guidelines, Rev. 4, (September 1, 2004), p. 31.

The AP-AEP-DAY Western Region spinning reserve zone and the ComEd spinning reserve zone operate under business rules that are similar to those in the Mid-Atlantic Region. The Spinning Reserve Markets in the AP-AEP-DAY Western Region spinning reserve zone and the ComEd spinning reserve zone are cleared on cost-based offers because there are not enough suppliers to support a competitive market for these services.

Demand

Tier 2 spinning requirements are determined by subtracting the amount of Tier 1 spinning available from the total control area spinning reserve requirement for the period. Total spinning reserve requirement is different for each of the three spinning reserve ancillary service markets. For the Mid-Atlantic Region's spinning reserve zone, the requirement is 75 percent of the largest contingency on the PJM system, provided that 25 percent of the largest contingency is available as nonsynchronized, 10-minute reserve. For the ComEd spinning reserve zone, the requirement is 50 percent of ComEd's load ratio share of the largest contingency in the MAIN NERC region. From October 1 to December 3, 2004, this was computed to be 269 MW. After December 3, the ComEd spinning requirement was recomputed to be 216 MW. For the AP-AEP-DAY Western Region spinning reserve zone, the requirement is 1.5 percent of the daily peak-load forecast.

Figure 5-6 - PJM Control Area average hourly required spinning vs. Tier 2 spinning purchased: Calendar years 2003 to 2004

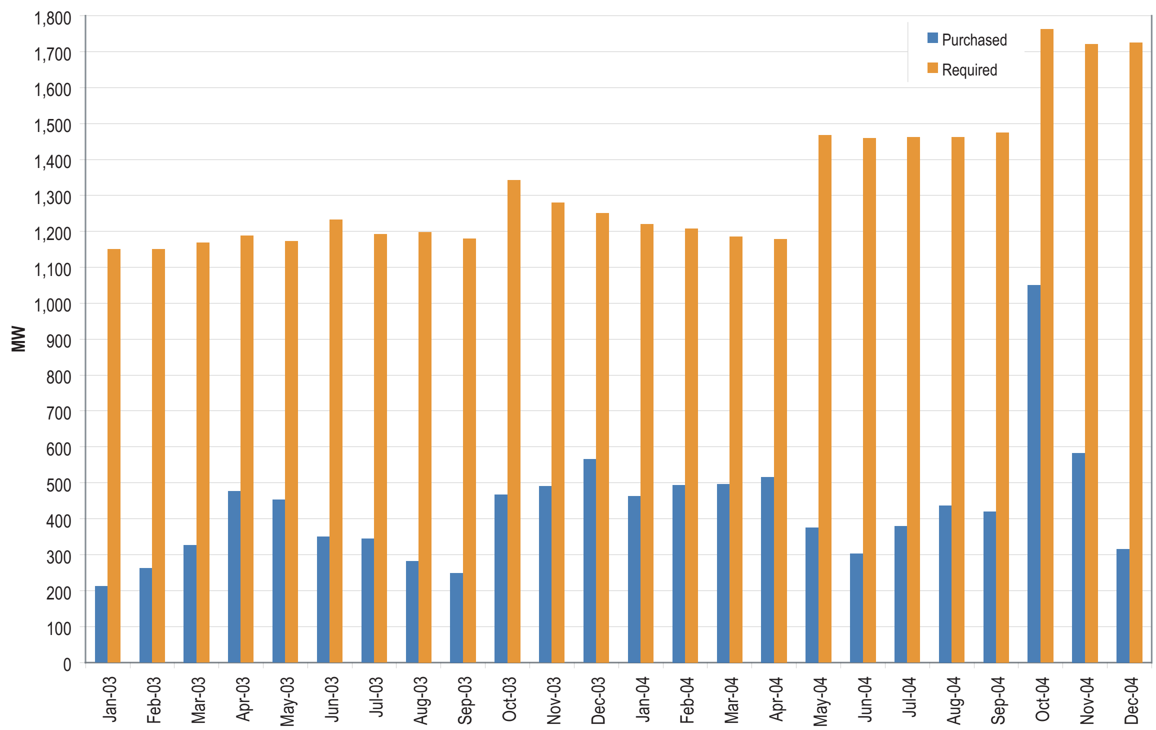
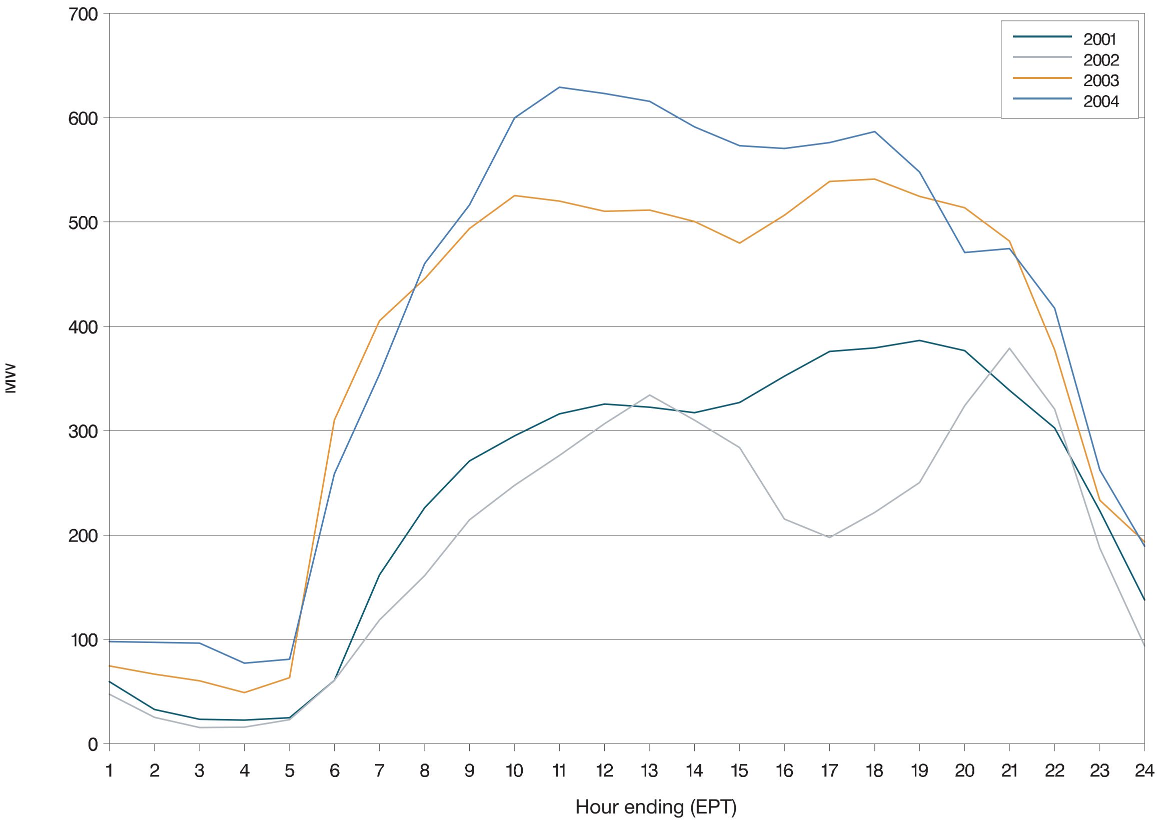


Figure 5-6 shows the annual average hourly Tier 2 spinning MW that PJM purchased during 2003 and 2004 across all spinning zones. Tier 2 spinning MW requirements and purchases were higher in the last quarter of 2003 than they had been during prior years because a disturbance control standard (DCS) violation in July 2003 increased spinning requirements. Tier 2 spinning MW requirements increased in 2004 as the result of the Phase 2 and 3 integrations.

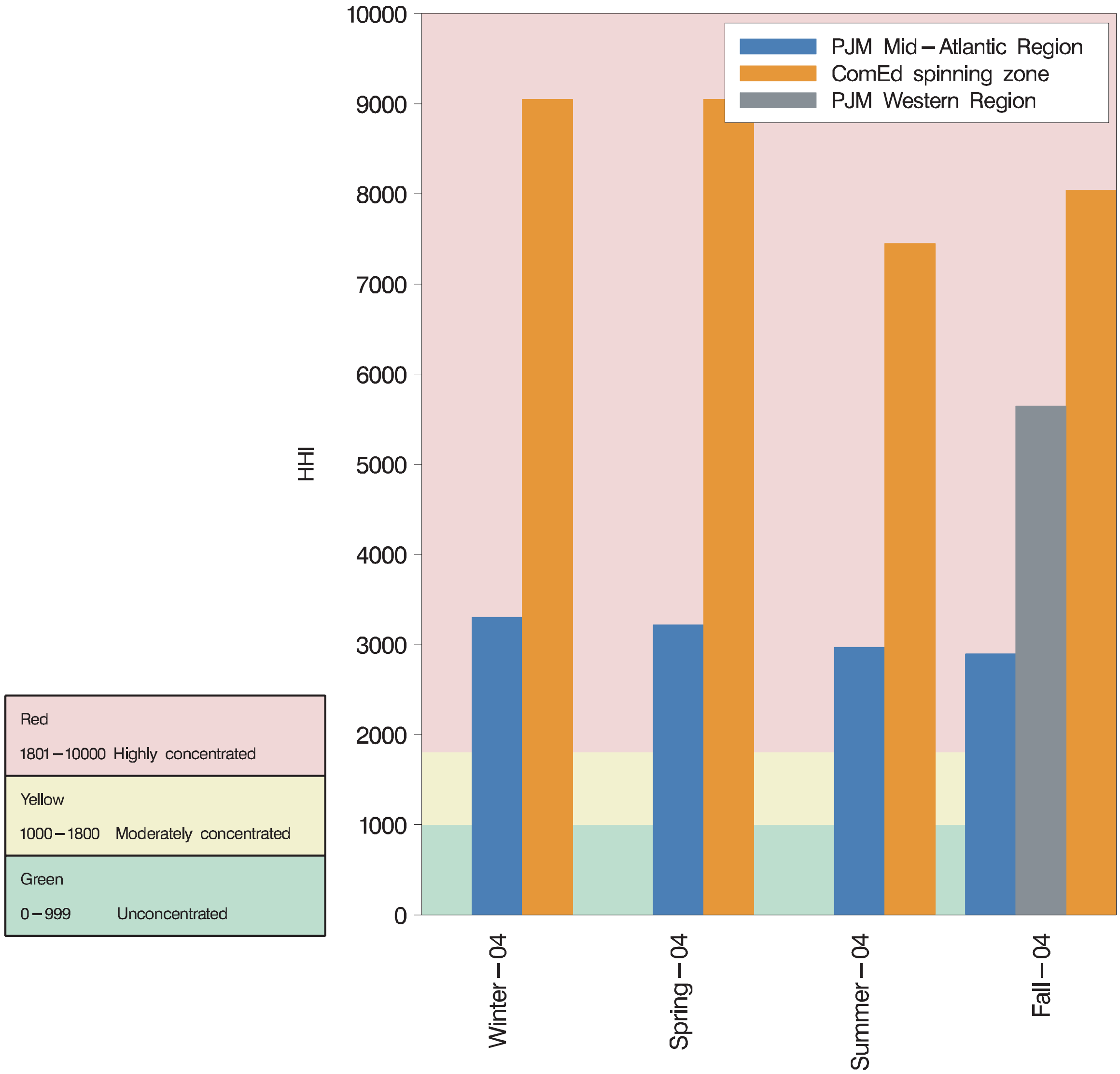
Figure 5-7 - PJM Control Area average hourly Tier 2 spinning MW: Calendar years 2001 to 2004



Market Concentration

Concentration is high in the Tier 2 Spinning Reserve Market in all three geographic markets. (See Figure 5-8.) During calendar year 2004, average HHI for Tier 2 spinning in the Mid-Atlantic Region was 3095 which is highly concentrated. In ComEd, during Phases 2 and 3, the average HHI was 8398. In PJM's AP-AEP-DAY Western Region Spinning Reserve Market during Phase 3 the average HHI was 5648.

Figure 5-8 - PJM system Spinning Reserve Market HHI: Calendar year 2004



Spinning Reserve Market Performance

Spinning Reserve Offers

Figure 5-6 compares average hourly required spinning reserve by month to the average hourly amount of Tier 2 spinning reserve purchased. The average difference was 948 MW.

The PJM spinning requirement is different for each of the three spinning reserve ancillary service territories in the RTO. During calendar year 2004, the monthly average required spinning reserve for the PJM Mid-Atlantic Region varied between 2,300 MW and 863 MW, but averaged approximately 1,100 MW. For the AP Control Zone during Phases 1 and 2, the spinning reserve requirement was between 60 and 124 MW and averaged 99.3 MW. For ComEd during Phase 2, the requirement was always 269 MW. For ComEd in Phase 3, the requirement was 269 MW until December 3, when it was lowered to 216 MW, giving a Phase 3 average of 253 MW. For PJM's AP-AEP-DAY Western Region's Spinning Reserve Market during Phase 3, the hourly spinning reserve requirement was between 242 MW and 494 MW and averaged approximately 370 MW.

Spinning Reserve Prices

Figure 5-9 shows the average price per MW associated with meeting PJM demand for spinning reserve. The average price per MW remained the same in 2004 as it had been in 2003, approximately $15.50 per MWh. There are no price data presented for the Western Region's Spinning Reserve Market because there was almost always adequate Tier 1 spinning reserve to meet the requirements for spinning reserve without clearing the Tier 2 market.

Figure 5-9 - Tier 2 spinning credits per MW: Calendar years 2003 to 2004

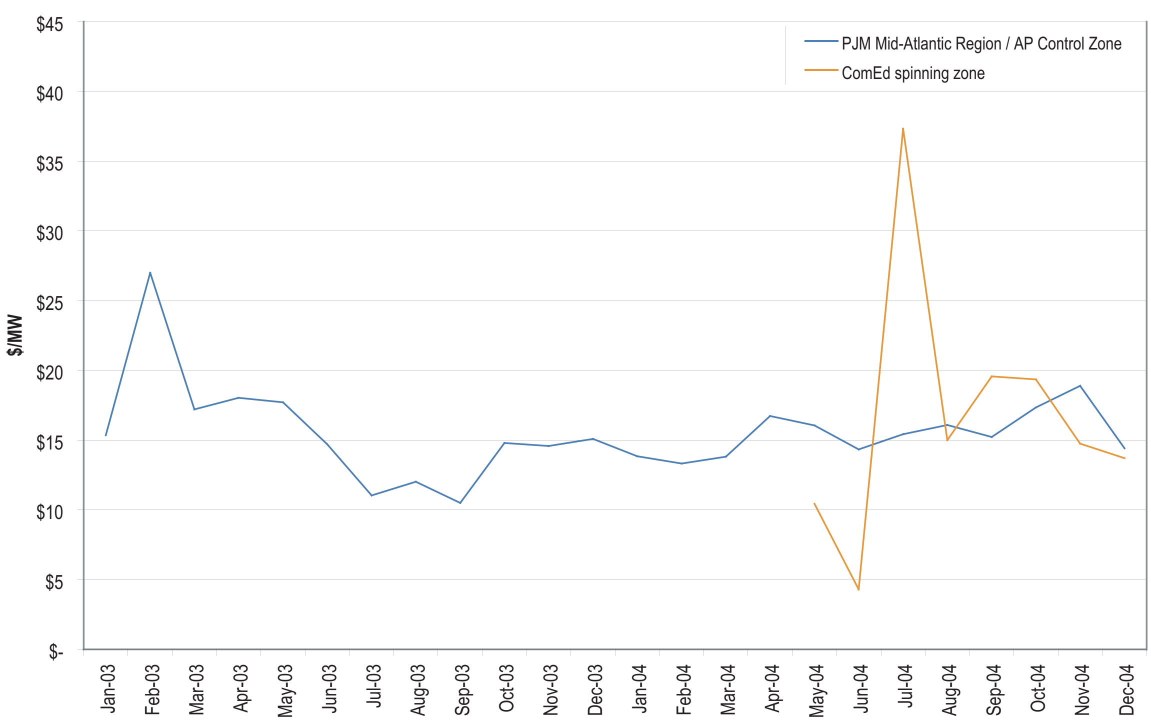


Figure 5-10 displays Tier 2 spinning reserve market-clearing prices (SRMCP) for 2004. Tier 2 spinning reserve prices in the PJM Mid-Atlantic Region were moderate in 2004, averaging $11.01. In ComEd, during Phases 2 and 3, Tier 2 spinning reserve market-clearing prices averaged $15.26. Tier 2 spinning reserve prices spiked in ComEd during July, primarily because of high opportunity costs. As was true in the Regulation Market, these spikes reflected the fact that the marginal units' opportunity costs were relatively high during certain hours because of high energy prices. Offer cost was not a factor in high ComEd SRMCPs. Tier 2 spinning reserve offer prices were capped at $7.50 per MW plus costs and were always less than $10 per MW. The marginal units were needed to meet the spinning requirements for the ComEd spinning zone. The PJM AP-AEP-DAY Western Region's Spinning Reserve Market during Phase 3 almost never had a clearing price because available Tier 1 spinning was always sufficient to cover the spinning requirement. Twice the Tier 2 Spinning Reserve Market was cleared averaging $9.53.

Figure 5-10 - PJM daily average spinning reserve market-clearing prices: Calendar year 2004

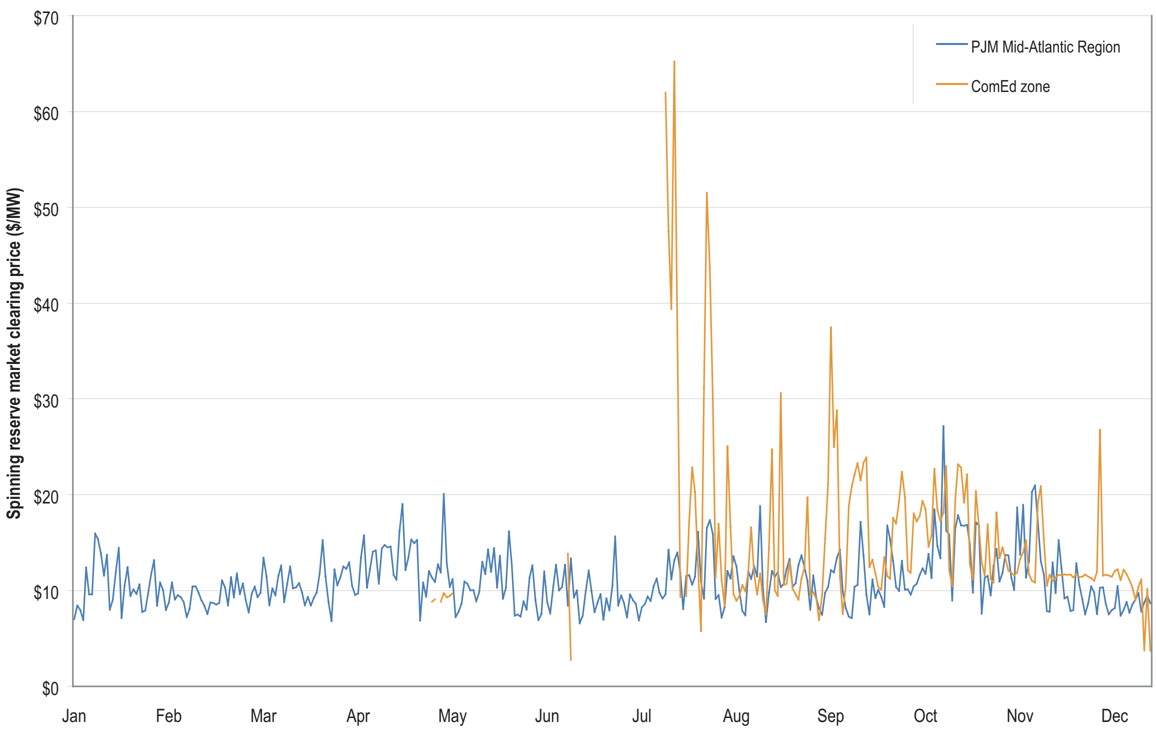


Table 5-7 - Spinning volumes and credits, Tier I and Tier 2: Calendar years 2003 and 2004

	Region	Tier 1 MW	Tier 1 Credits	Tier 2 MW	Tier 2 Credits
2003	PJM Control Area	7,603	$474,490	3,257,908	$50,910,740
2004	ComEd	603	$33,307	390,513	$6,666,075
2004	PJM Mid-Atlantic	5,853	$356,306	3,166,078	$48,487,250
2004	AP-AEP-DAY	626	$34,387	212	$5,125

Table 5-7 shows the level of Tier 1 and Tier 2 spinning reserve purchased from suppliers during calendar years 2003 and 2004. Tier 1 resources are paid only if they respond during spinning events while Tier 2 resources are paid for providing hourly reserve. As a general result, more Tier 2 resources are purchased than Tier 1 resources, and Tier 2 payments are higher than Tier 1 payments. An important exception to this general rule occurred in the PJM AP-AEP-DAY Western Region's Spinning Reserve Market where there is a large baseload of available operating reserves. During October and early November, Tier 1 spinning reserve services were almost always sufficient to cover the spinning requirement so Tier 2 spinning reserve was rarely purchased. During the second week of November, however, when temperatures fell and baseload units were operating higher up their output curves, then an AP-AEP-DAY Western Region Spinning Reserve Market emerged for Tier 2 resources.

Spinning Reserve Availability

A spinning reserve deficit occurs when PJM is not able to assign enough Tier 2 spinning to meet the spinning reserve requirement. Except for two brief periods during the first and third weeks of October when a transmission outage doubled the size of the PJM Mid-Atlantic Region's largest contingency, neither PJM's Mid-Atlantic Region, nor its AP Control Zone, nor its AP-AEP-DAY Western Region, nor its ComEd Spinning Reserve Markets had significant spinning reserve deficits during 2004.

SECTION 6 - 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.[1] The result is that the price of energy in the constrained area is higher than elsewhere because of the transmission limitations. Locational marginal prices (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.

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.

- **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.

1 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.
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.
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).

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.[4] This means that Financial Transmission Rights (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 transmission loading relief procedures (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

4 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 United States Federal Energy Regulatory Commission (FERC) accepted PJM's post-contingency congestion management plan.[5] 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.[6]

In an order dated December 19, 2002, granting PJM full regional transmission organization (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."[7] 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.[8] First, market forces are relied upon through the opening of a one-year market window during which

5 108 FERC ¶ 61,196 (2004).
6 96 FERC ¶ 61,061 (2001).
7 101 FERC ¶ 61,345 (2002).
8 104 FERC ¶ 61,124 (2003).

merchant solutions are solicited through 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.

Congestion Accounting

Transmission congestion can exist in PJM's Day-Ahead and Real-Time Energy Markets. Separate accounting settlements are performed for each market. The day-ahead market settlement is based on scheduled hourly quantities and on day-ahead hourly prices. The real-time settlement is based on actual hourly (integrated) quantity deviations from day-ahead scheduled quantities and on real-time prices integrated over the hour.

Transmission congestion charges in the Day-Ahead Energy Market can be directly hedged by using FTRs which are accounted for on a planning period basis. Real-time congestion charges can be hedged by FTRs to the extent that a participant's energy flows in real time are consistent with those in the Day-Ahead Energy Market.

Total congestion charges are the sum of the implicit and explicit day-ahead and balancing congestion charges, plus the day-ahead and balancing congestion charges implicitly paid in the Spot Market, minus any negatively valued FTR target allocations.

- **Implicit Congestion Charges.** These charges are incurred by network service customers in delivering their generation to their load and equal the difference between a participant's load charges and generation credits, less the participant's spot market bill. In the Day-Ahead Energy Market, load charges are calculated as the sum of the demand at every bus times the bus LMP. Demand includes load, decrement bids and sale transactions. Generation credits are similarly calculated as the sum of the supply at every bus times the bus LMP, where supply includes generation, increment bids and purchase transactions. In the Real-Time Energy Market, load charges and generation credits are calculated the same way, using the differences between day-ahead and real-time demand and supply and valuing congestion using real-time LMP.

- **Explicit Congestion Charges.** These charges are incurred by point-to-point service transactions and are equal to the product of the transacted MW and LMP differences between sources (origins) and sinks (destinations) in the Day-Ahead Energy Market. Real-Time Energy Market explicit congestion charges are equal to the product of the differences between the real-time and day-ahead transacted MW and the differences between the real-time LMP at the transactions' sources and sinks.

- **Spot Market Congestion Charges.** These charges are equal to the difference between total spot market purchase payments and total spot market sales revenues.

Total Calendar Year Congestion

Congestion costs have ranged from 6 to 9 percent of annual total PJM 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. Table 6-1 shows total congestion by year from 2000 through 2004. Total congestion costs were $808 million in calendar year 2004, a 62 percent increase from $499 million in calendar year 2003. The increased size of the total PJM Energy Market contributed to the increase in total congestion charges. The total PJM billing for 2004 was approximately $8.7 billion, a 26 percent increase over the approximately $6.9 billion billed in 2003.

The integration of ComEd and then of AEP and DAY contributed to the measured increase in total congestion during 2004. Congestion during the combined Phases 2 and 3 of the year was twice that of the comparable eight-month period in 2003, with 38 percent of this occurring during the five-month, Phase 2 period.

Even though 2004 saw a moderating of congestion frequency on the PJM Western Interface, on the Doubs and Kammer transformers, and on the Cedar Grove-Roseland 230 kV line (Table 6-5), increases in congestion frequency on the Branchburg Transformer, Wylie Ridge transformer and Bedington-Black Oak line (an interface between AP and the PJM Mid-Atlantic Region) offset the effects of these decreases.

Table 6-1 - Total annual PJM congestion [Dollars (millions)]: Calendar years 1999 to 2004

	Congestion Charges	Percent Increase	Total PJM Billing	Percent of PJM Billing
1999	$53	N/A	N/A	N/A
2000	$132	149%	$2,300	6%
2001	$271	105%	$3,400	8%
2002	$430	59%	$4,700	9%
2003	$499	16%	$6,900	7%
2004	$808	62%	$8,700	9%
Total	$2,193	N/A	N/A	N/A

Hedged Congestion

Table 6-2 lists congestion charges, FTR target allocations and credits, payout ratios, and congestion credit deficiencies and excess congestion charges by month. At the end of the 12-month planning period, excess congestion charges are used to offset any monthly congestion credit deficiencies. In 2003, however, when the congestion accounting period was changed from a calendar year to a planning period, the accounting period was extended on a one-time basis through May 31, 2004. The transitional period was, therefore, a 17-month period that began on January 1, 2003, and ended on May 31, 2004. PJM is currently in a 12-month planning period that began on June 1, 2004, and will end on May 31, 2005.

Table 6-2 - Monthly PJM congestion accounting summary [Dollars (millions)]: By planning period

		Congestion Charges	FTR Target Allocations	Congestion Credits	FTR Payout Ratio	Credits Deficiency	Credits Excess
Planning Period 2003 to 2004	Jan-03	$66	$94	$66	70%	$29	$0
	Feb-03	$14	$18	$14	77%	$4	$0
	Mar-03	$52	$42	$42	100%	$0	$10
	Apr-03	$27	$23	$23	100%	$0	$4
	May-03	$27	$41	$27	67%	$14	$0
	Jun-03	$52	$57	$52	90%	$6	$0
	Jul-03	$96	$85	$85	100%	$0	$10
	Aug-03	$59	$53	$53	100%	$0	$6
	Sep-03	$42	$44	$42	95%	$2	$0
	Oct-03	$32	$33	$32	97%	$1	$0
	Nov-03	$18	$17	$17	100%	$0	$1
	Dec-03	$15	$13	$13	100%	$0	$2
	Jan-04	$57	$54	$54	100%	$0	$3
	Feb-04	$22	$16	$16	100%	$0	$6
	Mar-04	$21	$18	$18	100%	$0	$3
	Apr-04	$23	$25	$23	92%	$2	$0
	May-04	$59	$62	$59	95%	$3	$0
	Total	$680	$696	$635	91%	$60	$45
	Values After Excess Congestion Charges Distributed						
		$680	$696	$680	98%	$16	$0
Planning Year 2004 to 2005 (through December 31, 2004)	Jun-04	$64	$67	$64	95%	$3	$0
	Jul-04	$116	$114	$114	100%	$0	$1
	Aug-04	$121	$128	$121	94%	$7	$0
	Sep-04	$47	$47	$47	99%	$0	$0
	Oct-04	$46	$39	$39	100%	$0	$7
	Nov-04	$74	$81	$74	91%	$7	$0
	Dec-04	$160	$150	$150	100%	$0	$9
	Total	$627	$627	$609	97%	$18	$18

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 period that ended May 31, 2004. FTRs were paid at 98 percent of the target allocation level during that period. For the first seven months of the planning period ending May 31, 2005 (June 1 through December 31, 2004), FTRs have paid at 97 percent of the target allocation level. This payout ratio may change for the full planning period depending on whether there are net excess revenues at the end of the planning period.

Although aggregate FTRs provided a hedge against 98 percent of the target allocation level during the 17-month period that ended May 31, 2004, all those paying congestion charges were not necessarily hedged at that level. Aggregate numbers do not reveal the underlying distribution of FTR holders, their revenues or those paying congestion.

Monthly Congestion

Table 6-3 shows monthly congestion charge variations by planning period. During the 17-month period that ended May 31, 2004, monthly congestion charges ranged from a maximum of $96 million in July 2003 to a minimum of $14 million in February 2003. For the balance of 2004, monthly congestion charges ranged from a high of $160 million in December 2004 to a low of $46 million in October 2004.

Table 6-3 - Monthly PJM congestion revenue statistics [Dollars (millions)]: By planning period

	Maximum	Mean	Median	Minimum	Range
2003 to 2004	$96	$40	$32	$14	$82
2004 to 2005*	$160	$90	$74	$46	$114

*The 2004 to 2005 period is presented on a planning period-to-date basis through December 31, 2004.

Approximately 32 percent of all congestion occurring in the 17-month period that ended May 31, 2004, occurred during the summer and winter peak-demand months of July and January.[9] The $686 million in congestion charges during Phases 2 and 3, 2004 were over twice the $340 million during the comparable 2003 period. The increased size of the total PJM Energy Market from the three integrations during Phases 2 and 3 contributed significantly to this increase.

Zonal Congestion

Constraints were examined by zone and categorized by their effect on regions as well as subareas. Zones correspond to regulated utility franchise areas. Regions generally comprise two or more zones, and subareas consist of portions of one or more zones. At the end of 2004, PJM was comprised of two regions. The PJM Mid-Atlantic Region with 11 control zones and the PJM Western Region with four control zones: the AP, ComEd, AEP and DAY Control Zones.

LMP differentials were calculated for each PJM control zone to provide an approximate indication of the geographic dispersion of congestion costs. LMP differentials for control zones are presented in Figure 6-1 for calendar years 2001 through 2004, and were calculated as the difference between zonal LMP and the Western Hub LMP. The Western Hub was chosen as the unconstrained reference price because it reasonably represents the unconstrained price of energy in the PJM Mid-Atlantic Region.

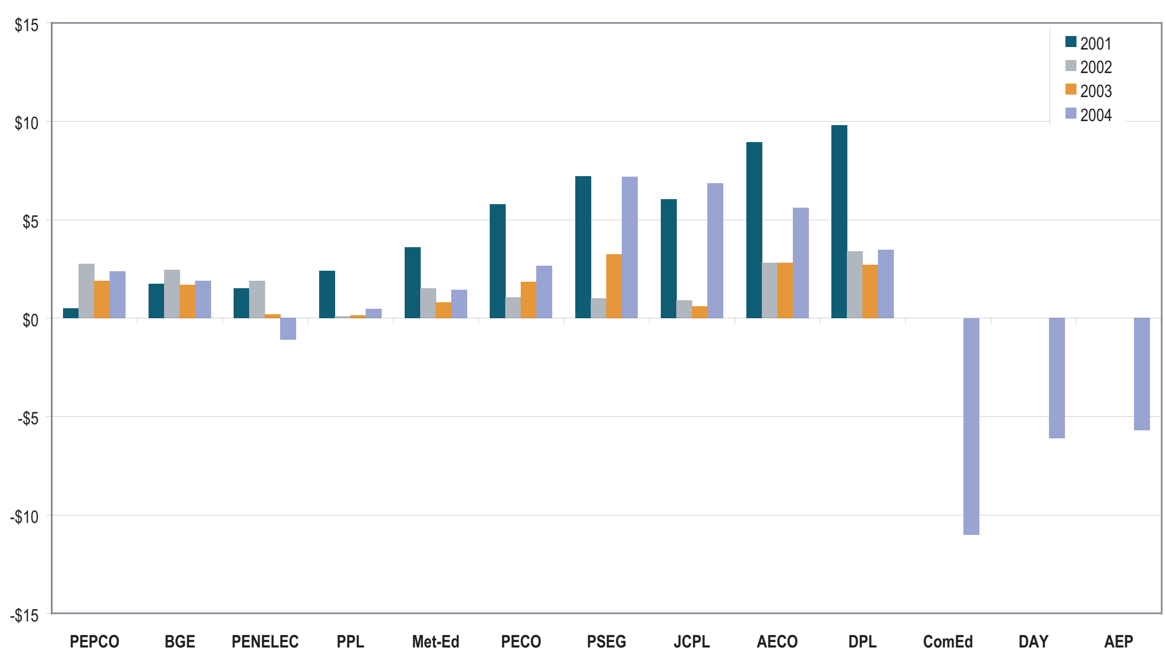
Figure 6-1 shows some new overall congestion patterns in 2004. The historically positive price differential for the PENELEC zone, which was nearly zero in 2003, became slightly negative during

9 The 17-month planning period ended May 31, 2004, included one July summer-peak month and two January winter-peak months.

2004. PENELEC is generally not affected by constraints on major interfaces and its congestion has been predominately local, particularly on the Erie West and the Erie South transformers. The installation of additional transformers at Erie West and Erie South alleviated the area's chronic congestion. Congestion on the Branchburg transformer in the PSEG zone had a downward effect on prices in the PENELEC zone and is responsible for the negative price differential observed relative to the Western Hub in 2004. The Branchburg transformer had a more significant effect on the prices in the PSEG, JCPL and AECO zones. Unlike zones located west of the constraint, the PSEG, JCPL and AECO zones experienced upward pressure on prices resulting from congestion on Branchburg. Further increasing prices in the AECO zone was congestion on AECO zone facilities such as the Cedar interface, Laurel-Woodstown and the Sheildalloy-Vineland line.

The three new zones integrated into PJM during Phases 2 and 3 of 2004 exhibited a negative price differential relative to the Western Hub. Overall, the ComEd Control Zone, during the eight months from its May 1, 2004, integration until the end of the calendar year, exhibited an average differential of approximately $11 per MWh. During Phase 2, Pathway congestion occurred most frequently in a direction from ComEd into the PJM Mid-Atlantic Region, indicating that the price of the marginal resource in PJM was higher than the price in the ComEd Control Area. The resultant price separation tended to make the ComEd Control Area price lower than the price in the PJM Mid-Atlantic Region and consequently at the Western Hub. The AEP and DAY Control Zones, which were integrated during Phase 3, also exhibited lower prices than the PJM Western Hub during the three months of Phase 3. The AEP and DAY Control Zones each exhibited an average differential of approximately $6 per MWh relative to the PJM Western Hub during the final three months of 2004, driven in large part by congestion on the Wylie Ridge transformer.

Figure 6-1 - Annual zonal LMP differences (Reference to Western Hub): Calendar years 2001 to 2004



Congested Facilities

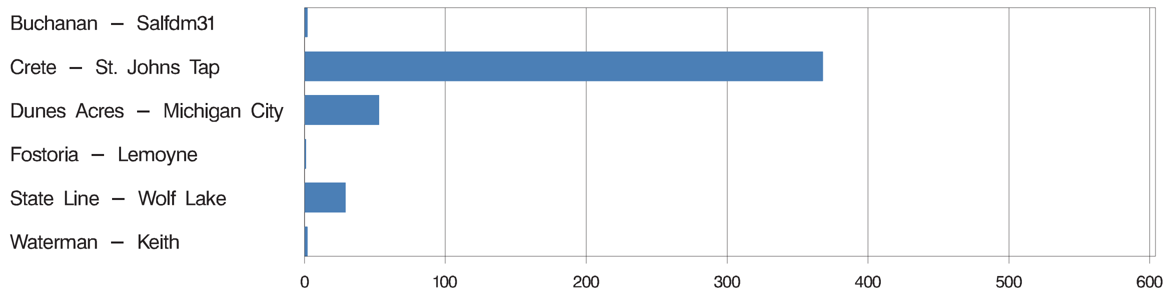
A congestion event exists when a unit or units must be dispatched out of merit order to control the impact of a contingency on a monitored facility or to control an actual overload. Congestion-event hours refer to the total number of congestion hours for a particular facility. This differs from a constraint hour which refers to any hour during which one or more facilities are congested. Constraints are often simultaneous and, therefore, total congestion-event hours can exceed the number of hours in a year. During calendar year 2004, 185 monitored facilities were constrained, 11 more than had been constrained during 2003. In 2004, there were 11,205 congestion-event hours, a 15 percent increase from 9,711 in 2003. Included in the total for 2004 were 2,512 congestion-event hours associated with the Phase 2 transmission Pathway between PJM and the ComEd Control Area before the integration of the AEP and DAY Control Zones in Phase 3.

The existence of the Pathway during Phase 2 served to reduce congestion on certain PJM facilities. While the throughput capability of the AEP system did not change as a result of the introduction of the Pathway, the congestion management procedures relating to service associated with the Pathway did. Historically, TLR procedures were used to curtail transactions and to address reliability issues. With the incorporation of the Pathway into PJM redispatch procedures, LMP became the mechanism for addressing congestion. Consequently when the Pathway was constrained, PJM would redispatch the system to relieve the limit violation. When the Pathway was constrained from ComEd to PJM, redispatch resulted in the raising of generation in the PJM Control Area relative to that in the ComEd Control Area. Of the Pathway's 2,512 congestion-event hours during 2004, 2,183 hours, or 87 percent, were in the direction from ComEd to PJM. This had the effect of reducing west-to-east flow into the PJM Control Area and raising the prices in the PJM Control Area relative to ComEd. Therefore, as a result of controlling Pathway flow through redispatch, other constraints benefited from the corresponding reduction in flow from the west. Reductions in congestion-event hours associated with the PJM Western and Central Interfaces are examples of constraints which benefited from reduced west-to-east flows during Phase 2. This dynamic also contributed to prices in the PJM Western Region control zones having a lower average value as compared to the PJM Western Hub price. In addition, average temperatures during the summer across the expanded RTO footprint were relatively mild, further reducing loads.

Before Phase 2 integration began, PJM and the Midwest Independent Transmission System Operator, Inc. (Midwest ISO) had developed a "Joint Operating Agreement"[10] (JOA) which defines a coordinated methodology for congestion management. This protocol establishes reciprocal, coordinated flowgates in the combined footprint whose operating limits are respected by both operators. A flowgate is a single or group of transmission elements intended to model MW flow impact relating to transmission limitations and transmission service usage.[11] PJM models these coordinated flowgates and controls for them in their security-constrained economic dispatch. To date, the most significant of these has been the Crete–St. Johns Tap line located near the southern tip of Lake Michigan. The Crete–St. Johns Tap line accounted for 368 of the 455 congestion-event hours caused by Midwest ISO flowgates during 2004. Midwest ISO flowgates accounted for 4 percent of the total PJM congestion-event hours during 2004. Figure 6-2 shows the number of hours during which PJM took dispatch action to control various Midwest ISO flowgates during calendar year 2004.

10 See "Joint Operating Agreement between the Midwest Independent Transmission System Operator, Inc. and PJM" (March 1, 2004). The agreement is referred to here as the JOA.
11 See NERC Operating Manual, "Flowgate Administration Reference Document," Version 1 (March 21, 2002).

Figure 6-2 - Midwest ISO flowgates impacting PJM dispatch: Calendar year 2004

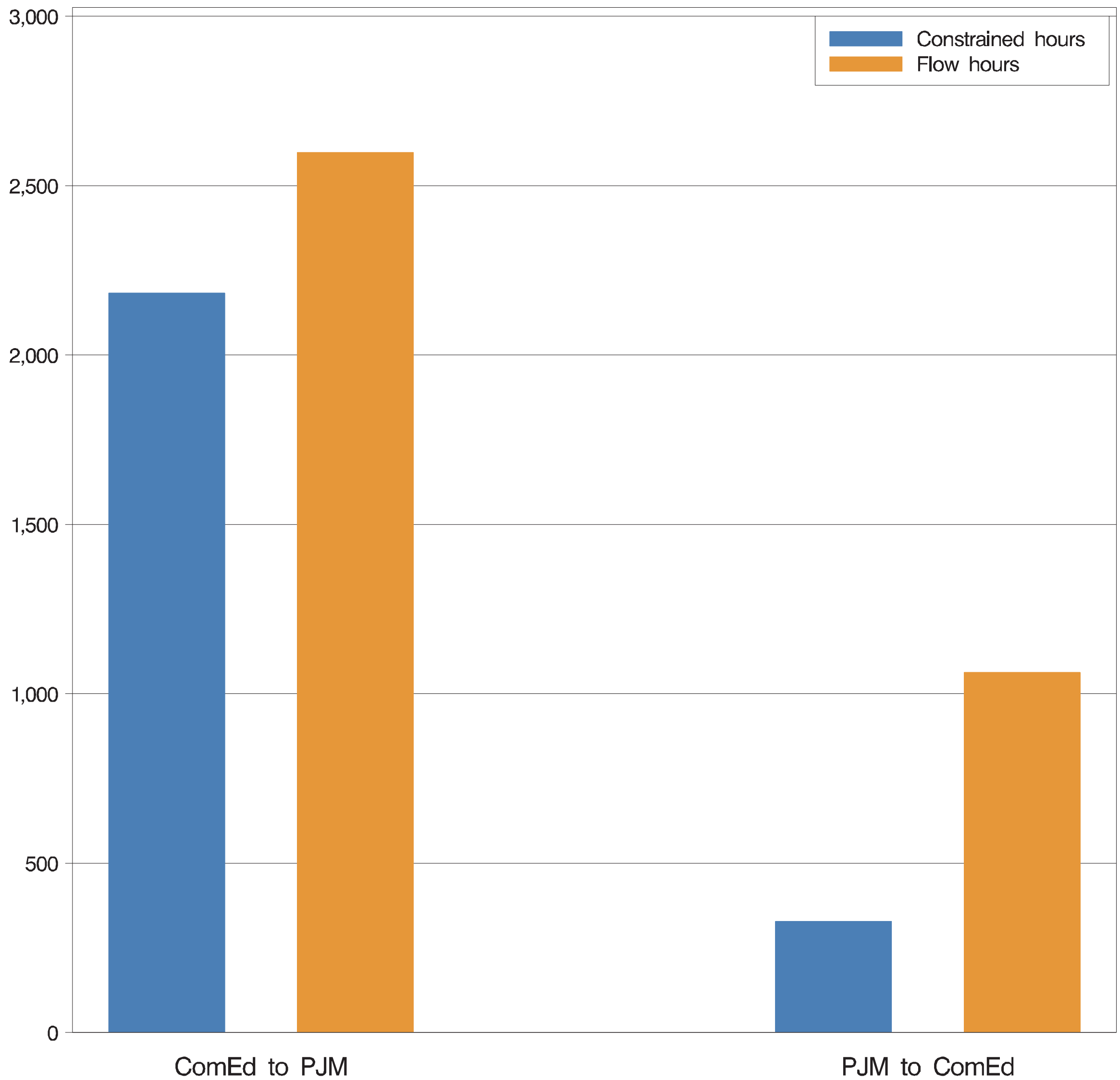


Pathway Congestion during Phase 2

With the integration of the ComEd Control Area on May 1, 2004, PJM instituted a Pathway connecting the PJM Control Area (i.e., the Mid-Atlantic Region and the AP Control Zone) with the ComEd Control Area.[12] This Pathway was an approximately 500-MW, bidirectional, transmission Pathway comprised of transmission service through the AEP Control Zone before its integration into PJM at the beginning of Phase 3.[13] The Pathway's purpose was to facilitate coordinated economic dispatch across its two control areas: the Mid-Atlantic Region plus the AP Control Zone and the new ComEd Control Area. With regard to security-constrained economic dispatch, the Pathway was treated as a closed interface and subject to redispatch procedures to maintain flows within prescribed limits. When Pathway flow was within its limits, the two control areas were dispatched as a single energy market. When Pathway flow was at a directional limit, price separation could occur between the control areas, reflecting a constraint across the Pathway. The Pathway experienced 2,512 hours of congestion during Phase 2, comprising 22 percent of the total PJM congestion-event hours during calendar year 2004. Figure 6-3 shows the directional flow and congestion-event hours for the Pathway.

12 106 FERC ¶ 61,253 (2004).
13 See PJM Internal Audit Department, "Special Investigation ComEd Integration Pathway Issue, Final Report" (June 8, 2004) < http://www.pjm.com/documents/ downloads/ferc/ 2004docs/june/20040625-ferc-pathway-internal-audit-report-redacted.pdf > (121 KB).

Figure 6-3 - Pathway directional flows and hours of congestion: Phase 2, 2004



Pathway flow was predominately into the PJM Control Area reflecting the fact that marginal prices were typically higher in the PJM Control Area than in the ComEd Control Area. When North American Electric Reliability Council (NERC) TLRs were initiated for which Pathway flow had significant impact, the directional limit was adjusted to reduce flow on the constrained facility. Table 6-4 summarizes the number of hours when the Pathway limit was reduced into the ComEd and into the PJM Control Areas.

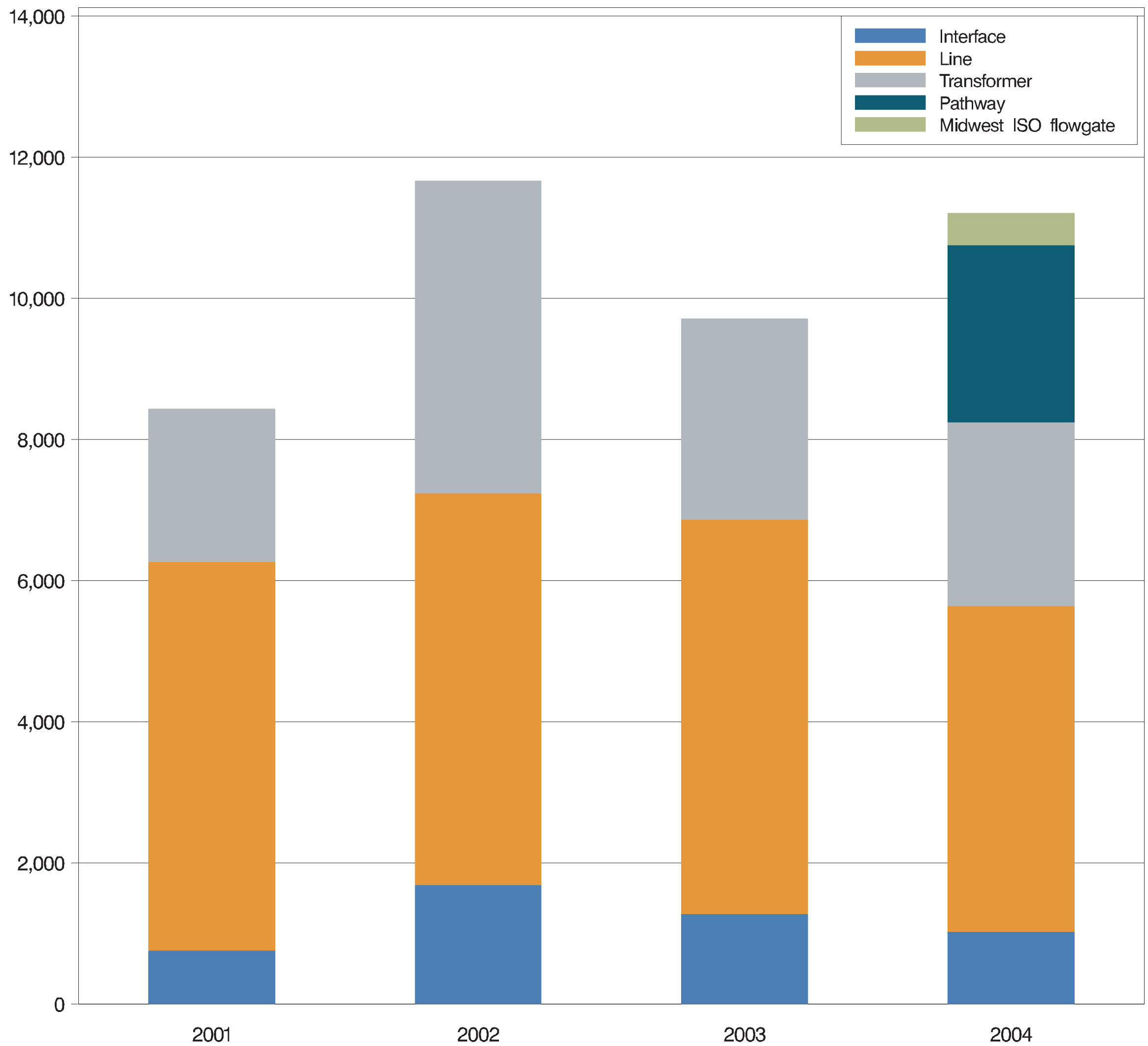
Table 6-4 - Pathway capability limits: Phase 2, 2004

Pathway Capability Limit	ComEd to PJM	PJM to ComEd
0 to 99 MW	203	25
100 to 199 MW	415	119
200 to 299 MW	141	15
300 to 399 MW	138	20
400 to 500 MW	2,775	3,493

Congestion by Facility Type

Figure 6-4 provides congestion-event hour subtotals comparing calendar year results by facility type: line, transformer and interface. Newly included in 2004 is a category for Midwest ISO flowgates for which PJM instituted out of merit order dispatch of generation to control congestion. Midwest ISO flowgates accounted for 455 hours, or 4 percent of total PJM congestion-event hours in 2004. Also included in 2004 is a depiction of congestion associated with the Phase 2 transmission Pathway between the PJM and the ComEd Control Areas. The total number of PJM congestion-event hours increased by about 15 percent to 11,205 hours in 2004 from 9,711 hours in 2003. The 2004 increase in congestion-event hours was attributable to the Pathway and to the Midwest ISO flowgates, which together constituted 26 percent of total PJM congestion-event hours during 2004. Of the Midwest ISO flowgates, the Crete-St. Johns Tap was the most frequently constrained, with 368 hours during 2004. Congestion frequency on transformers, lines and interfaces all showed declines as compared to 2003 levels.

Figure 6-4 - Congestion-event hours by facility type: Calendar years 2001 to 2004



Transformer constraints occurred during 249 fewer hours in calendar year 2004 than in 2003. The largest decreases in congestion occurred on the North Meshoppen, Kammer and Doubs transformers. These three facilities together experienced 882 fewer hours of congestion during 2004 than 2003. Of these, the North Meshoppen transformer had the largest reduction in constrained operation. In sharp contrast to its 442 congestion-event hours during 2003, the North Meshoppen transformer was never constrained during 2004. This improvement was the result of a second transformer and series reactors having been installed at North Meshoppen during 2003. Reduced congestion on the Doubs transformer was the result of a new 500/230 kV transformer installed by Dominion Virginia Power at the Pleasant View station. Conversely, the Branchburg 500 kV transformer located in northern PSEG was constrained for 1,005 hours during 2004 and was the second most frequently constrained facility in PJM during 2004.[14] By comparison, the

14 Bedington – Black Oak was the most frequently constrained facility in PJM during 2004 with 1,131 congestion-event hours.

Branchburg transformers were constrained for 41 hours during 2003. On March 17, 2004, PSEG significantly reduced the emergency and normal ratings of the Branchburg number 1 and number 2 transformers as the result of a deteriorating condition identified during an inspection. On May 25, 2004, a special protection scheme (SPS) was installed at Branchburg to reduce congestion impacts of derated facilities. A third transformer is scheduled to be installed at Branchburg by June 30, 2005, to relieve this constraint. The number 1 and number 2 transformers at Branchburg are scheduled to be replaced by June 2007.

Interface constraints occurred during 256 fewer hours in 2004 than in 2003. Interfaces are typically defined by a cross section of transmission paths and are used to represent the flow into or through a wider geographic area. The largest improvements were on the PJM west 500[15] and PJM Western Interfaces. Combined, these two interfaces accounted for a 305-hour decline in congestion-event hours during 2004. The PJM Eastern Interface experienced 221 congestion-event hours in 2004 as compared to 203 hours during 2003. During December 2004, the PJM Eastern Interface experienced 160 hours, or 72 percent of its annual total congestion-event hours because of generation outages at the Salem and Hope Creek stations. Of all the interfaces, the Cedar interface in the AECO Control Zone experienced the largest increase in congestion versus 2003. The 605 hours of congestion on this interface constituted a 53 percent increase over 2003, and triggered the opening of a market window under the PJM economic planning process for new or upgraded transmission facilities.[16] The Cedar interface accounted for 5 percent of total PJM congestion-event hours during 2004.

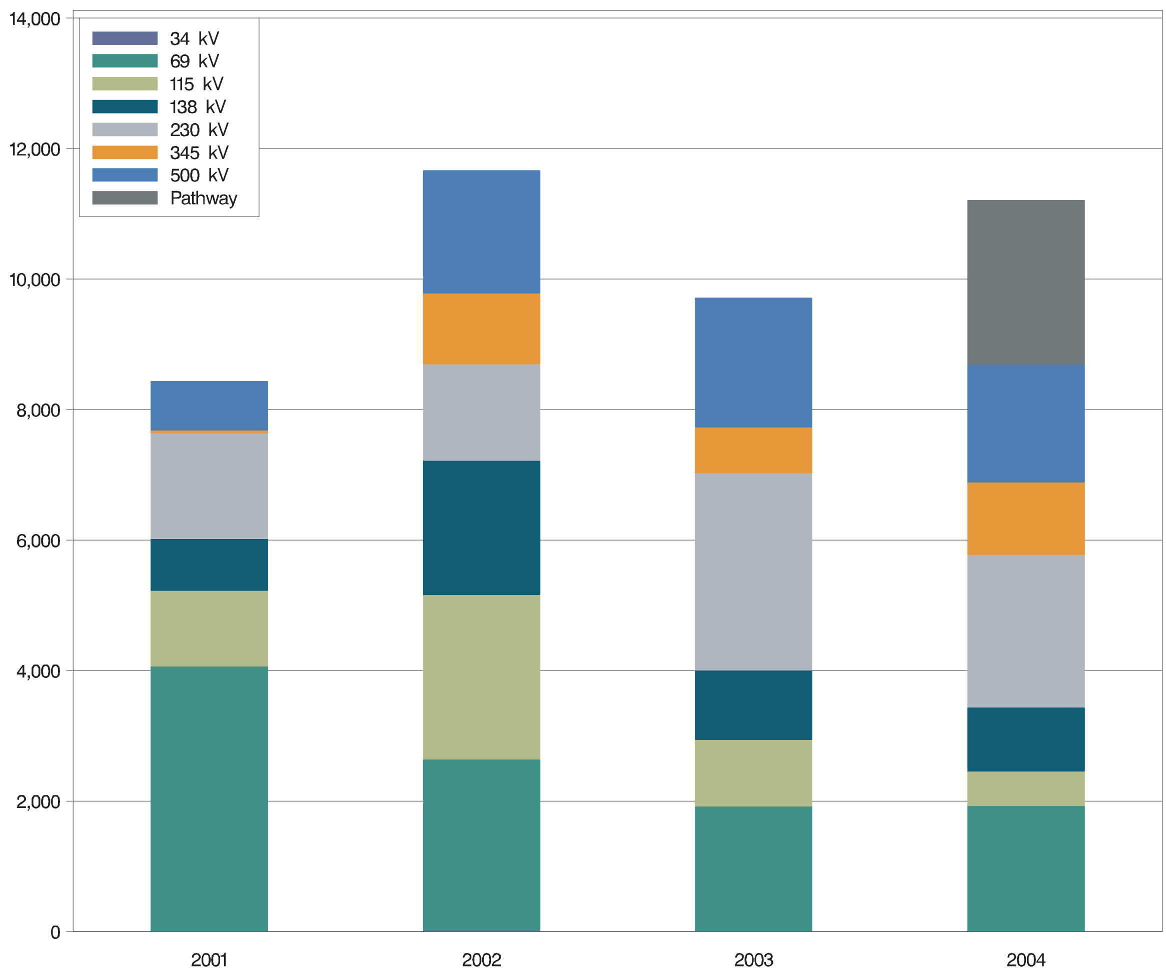
Thermal transmission line limits accounted for 41 percent of all congestion-event hours experienced in 2004. The 4,622 hours of transmission line congestion in 2004 constituted a 968-hour decrease from 2003 levels. Cedar Grove-Roseland had the largest reduction in congestion with 150 hours as compared to the 719 hours experienced during 2003. Also significantly reduced were the Hummelstown-Middletown Junction 230 kV, Branchburg-Readington 230 kV, Edison-Meadow Road 138 kV and Laurel-Woodstown 69 kV lines which together experienced 907 fewer congestion-event hours than they had in 2003. The Shieldalloy-Vineland 69 kV line located in southern New Jersey had the largest increase in congestion with 444 hours during 2004, nearly five times the 2003 level. The Bedington-Black Oak line with 1,131 congestion-event hours was the single most constrained facility in PJM during 2004. Both the Shieldalloy-Vineland and Bedington-Black Oak 500 kV lines were among 54 facilities which experienced enough unhedgeable congestion during 2004 to trigger the opening of a market window under the PJM economic planning process.

Figure 6-5 depicts congestion-event hour subtotals by facility voltage class. Congestion on the Phase 2 transmission Pathway between the PJM and the ComEd Control Areas is depicted as a separate item. Congestion-event hours on 230 kV class facilities were down 676 hours from 2003, with the largest reduction in this class coming from the Cedar Grove-Roseland 230 kV line in PSEG. Contributing to this 569-hour decrease in congestion was the presence of the Branchburg transformer constraint, which limited the flow of power into the northern PSEG area, effectively reducing the occurrence of the Cedar Grove-Roseland 230 kV constraint. There were 484 fewer congestion-event hours on 115 kV facilities in 2004 as compared to 2003. The largest reduction in congestion among 115 kV class facilities was the North Meshoppen transformer in PENELEC. During 2003, a second transformer was installed at North Meshoppen along with series reactors

15 The PJM west 500 interface constraint is used in response to simultaneous post-contingency voltage problems caused by high transfers across the western, central and/or eastern PJM Mid-Atlantic system, and the southern portion of the PJM Mid-Atlantic system.
16 See Appendix H, "Glossary," for definitions of the voltage threshold levels relevant to triggering economic planning activity.

resulting in a 442-hour reduction in congestion in 2004 as compared to 2003. Congestion on 500 kV class facilities occurred for 176 fewer hours as compared to 2003. The Kammer transformer, PJM west and PJM west 500 kV interfaces together contributed 525 hours toward this reduction. Congestion on 345 kV class facilities increased by 410 hours as compared to 2003. This increase was driven by congestion on the Wylie Ridge transformer which was constrained 642 hours during 2004 as compared to 537 hours during 2003.

Figure 6-5 - Congestion-event hours by facility voltage: Calendar years 2001 to 2004



Constraint Duration

Table 6-5 lists calendar year 2003 and 2004 constraints that affected more than 10 percent of PJM load or that were most frequently in effect and shows changes in congestion-event hours between the years.[17]

17 Constrained-hour data presented here use the convention that if congestion occurs for 20 minutes or more in an hour, the hour is congested.

Constraints 1 through 8 are the primary operating interfaces. For this group, the number of congestion-event hours decreased from 2,376 to 2,235 hours between 2003 and 2004, a 6 percent drop. The AP Control Zone facilities, items number 1, 2, 7 and 8, were constrained 1,870 hours in 2004, an 11 percent increase in frequency compared to 2003. This increase was driven by increased congestion frequency on the Bedington-Black Oak line and the Wylie Ridge transformer. The PJM Mid-Atlantic Region facilities, items number 3 to 6, were constrained 365 hours, a 47 percent decrease versus 2003.

Table 6-5 - Congestion-event summary: Calendar years 2003 to 2004

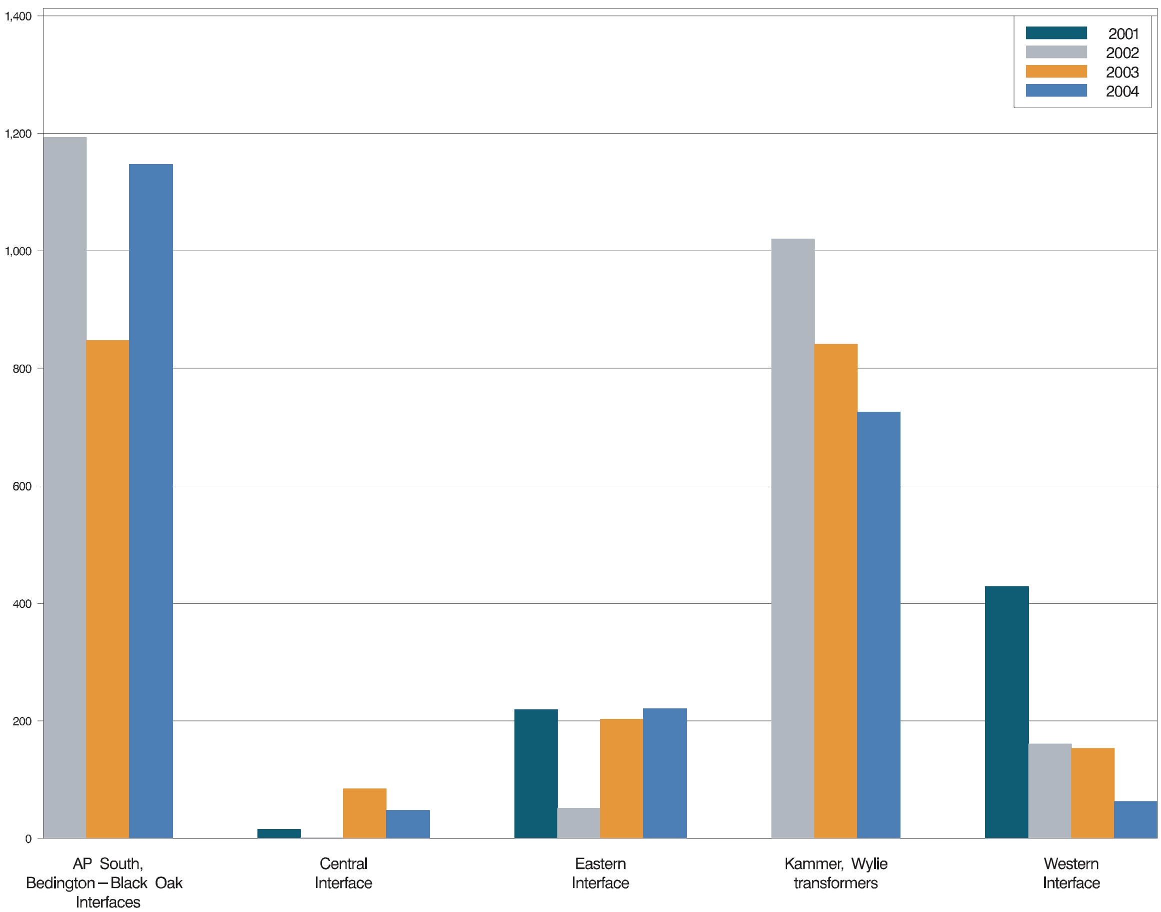
No.	Constraint	Congestion-Event Hours			Percent of Annual Hours		
		2003	2004	Change	2003	2004	Change
1	Kammer Transformer	304	84	-220	3%	1%	-3%
2	Wylie Ridge Transformer	537	642	105	6%	7%	1%
3	Western Interface	153	63	-90	2%	1%	-1%
4	PJM West 500	248	33	-215	3%	0%	-2%
5	Central Interface	84	48	-36	1%	1%	-0%
6	Eastern Interface	203	221	18	2%	3%	0%
7	AP South Interface	32	13	-19	0%	0%	-0%
8	Bedington - Black Oak	815	1,131	316	9%	13%	4%
9	Doubs Transformer	305	85	-220	3%	1%	-3%
10	Branchburg - Readington	242	108	-134	3%	1%	-2%
11	Cedar Grove - Roseland	719	150	-569	8%	2%	-7%
12	Branchburg Transformer	41	1,005	964	0%	11%	11%
13	Shieldalloy-Vineland	89	444	355	1%	5%	4%
14	Keeney AT5N Transformer	194	102	-92	2%	1%	-1%
15	Crete - St. Johns Tap	N/A	368	N/A	N/A	4%	N/A
16	Cedar Interface	396	605	209	5%	7%	2%
17	Lewis-Motts - Cedar	245	128	-117	3%	1%	-1%
18	Laurel - Woodstown	597	401	-196	7%	5%	-2%
19	Jackson Transformer	45	231	186	1%	3%	2%
20	Wye Mills AT2 Transformer	7	128	121	0%	1%	1%
21	North Meshoppen Transformer	442	0	-442	5%	0%	-5%
22	Kanawah-Matt Funk	N/A	51	N/A	N/A	1%	N/A
23	Cloverdale-Lexington	N/A	31	N/A	N/A	0%	N/A

During 2004, constraint frequency on the main operating interfaces affecting large amounts of PJM load was reduced considerably.

Congestion-Event Hours by Facility

Constraints that affected regions during calendar years 2001 through 2004 are presented in Figure 6-6. The Bedington-Black Oak line and the Wylie transformers were the most significant regional constraints, and together comprised 16 percent of total PJM congestion-event hours. Congestion on the Bedington-Black Oak line and on the Wylie transformers increased by 316 hours and 105 hours, respectively, versus 2003 levels. The Kammer transformer and the PJM Western Interface were constrained considerably less often than in 2003, down 72 percent and 59 percent, respectively. The ability to dispatch resources to the west of these constraints resulting from the integration of the ComEd, AEP and DAY Control Zones provided better control and reduced the occurrence of congestion.

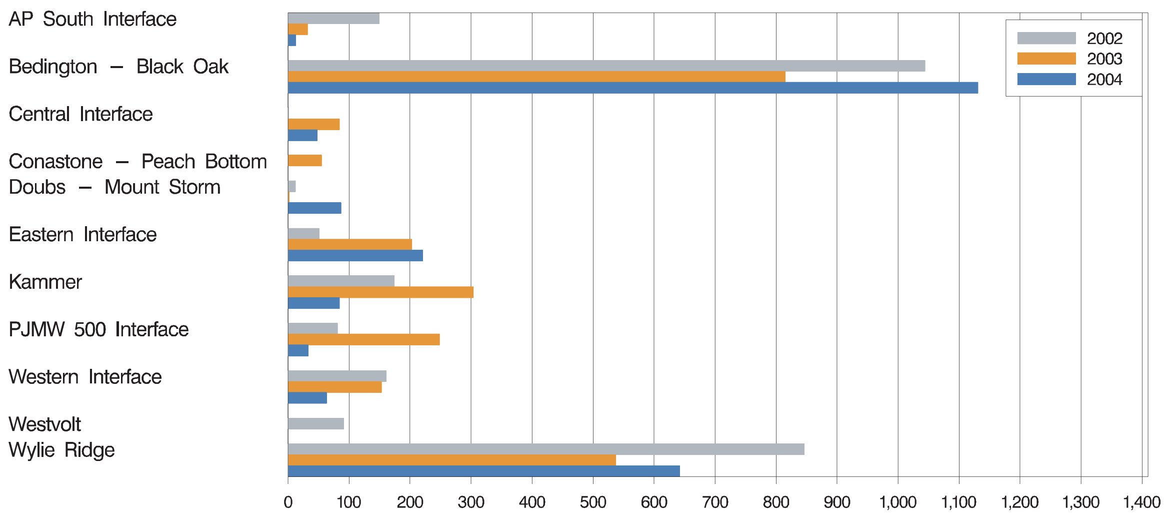
Figure 6-6 - Regional constraints and congestion-event hours by facility: Calendar years 2001 to 2004



Congestion-Event Hours for the 500 kV System

Constraints on the 500 kV system generally have a regional impact. Figure 6-7 shows the occurrences of 500 kV constraints. The Wylie Ridge 500/345, Kammer 765/500, Bedington-Black Oak and the AP south interfaces were constrained a combined total of 1,870 congestion-event hours in 2004 as compared to 1,688 hours in 2003, an increase of 182 hours or about 11 percent. In the PJM Mid-Atlantic Region, the Western, Central and Eastern Interfaces were constrained a total of 332 hours, a 52 percent reduction over the 688 hours experienced during 2003.

Figure 6-7 - 500 kV zone congestion-event hours by facility: Calendar years 2002 to 2004



Congestion-Event Hours for the Bedington-Black Oak and AP South Interfaces

The AP extra-high-voltage (EHV) system is the primary conduit for energy transfers from the AP and midwestern generating resources to southwestern PJM and eastern Virginia load, and, to a lesser extent, to central and eastern PJM. Two AP reactive interface constraints, Bedington-Black Oak and AP south, often restrict west-to-east energy transfers across the AP EHV system. During Phase 3, Bedington-Black Oak and AP south were constrained 341 hours and 12 hours, respectively. During this same period in 2003, Bedington-Black Oak and AP south were constrained 78 hours and 15 hours, respectively. By comparison during Phases 1 and 2 combined, Bedington-Black Oak and AP south were constrained 790 hours and one hour, respectively. With 1,131 congestion-event hours, Bedington-Black Oak was the most frequently constrained facility in PJM during calendar year 2004. Bedington-Black Oak experienced sufficient unhedgeable congestion during 2004 to trigger the opening of a market window under the PJM economic planning process. The PJM Market Monitoring Unit concluded that the AP Control Zone's south interface constraint was competitive enough to be exempted from offer-capping procedures and recommended this modification in an August 26, 2004, filing to the FERC.[18] Prior to the integration of the AP Control Zone into PJM on April 1, 2002, the primary controlling action for these constraints had been for AP to restrict energy transfers through its system, including transfers from western resources to PJM and Dominion Virginia Power (VAP). This action had the effect of raising the overall PJM dispatch rate higher than it would have been if the transactions had not been curtailed. The result was increased energy prices for the entire PJM Mid-Atlantic Region, regardless of location. There was no impact on measured congestion because the entire PJM system was affected.

After the AP Control Zone was integrated into the PJM market and the redispatch of PJM generation was used to control AP transmission facilities, a significant change in price impacts occurred. Rather than simply restricting relatively low-cost energy transfers, higher cost generating units

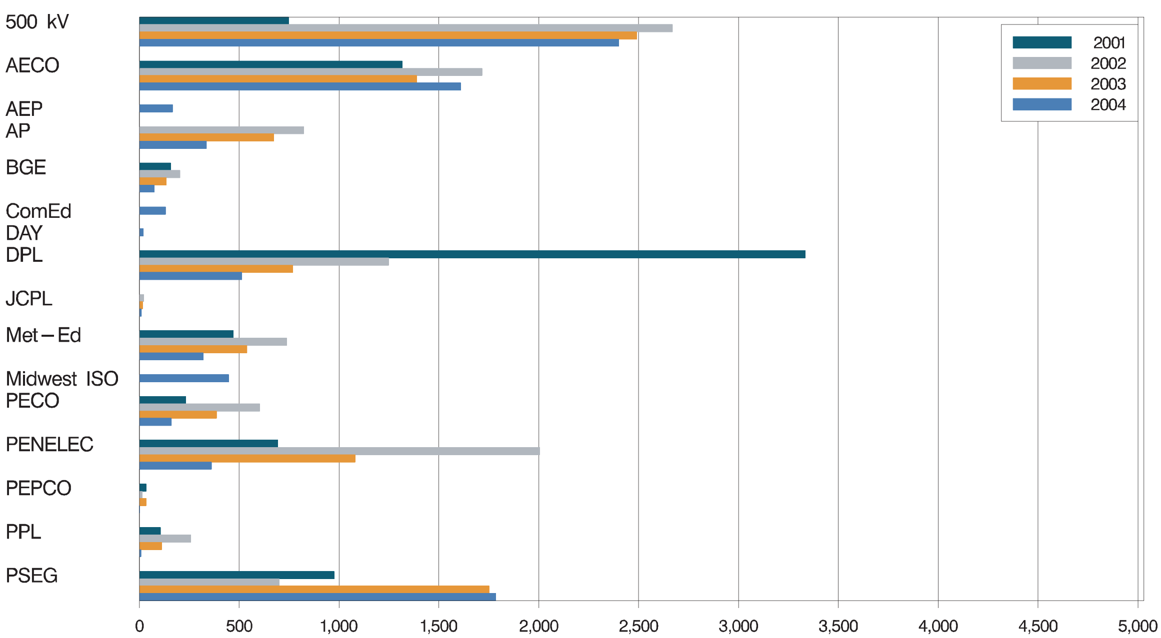
18 *PJM Interconnection, L.L.C.*, Compliance Filing, Docket Nos. ER04-539-001, 002 and ER04-121-000 (October26, 2004), Report of the PJM Market Monitor, paragraph 17.

were dispatched out of merit order (redispatched) in order to serve load in the transmission-constrained areas. As a result, the price of energy in the constrained areas was higher than elsewhere and congestion occurred. Higher LMPs resulted only at those locations directly limited by a constrained facility while lower LMPs occurred elsewhere. The PEPCO Control Zone was the most directly affected by these constrained facilities, followed by the BGE Control Zone.

Local Congestion

Constraints within specific zones from calendar years 2001 through 2004 are presented in Figure 6-8 which compares the frequency of constraints that occurred in each zone and on the 500 kV system. In 2004, the PSEG Control Zone had 1,784 congestion-event hours, a 2 percent increase versus 2003. Significant decreases in constrained operation on the PSEG system 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 Erie West and North Meshoppen transformers experienced 624 fewer hours of congestion during 2004 and drove the 67 percent reduction in congestion in the PENELEC Control Zone. Congestion-event hours in the AECO Control Zone increased by 221 hours, or 16 percent, in 2004 versus 2003. This was driven by increased congestion frequency on the Shieldalloy-Vineland line and the Cedar interface, which combined experienced 1,049 hours of congestion during 2004.

Figure 6-8 - Congestion-event hours by zone: Calendar years 2001 to 2004



Zonal and Subarea Congestion-Event Hours and Congestion Components

Figure 6-9 through Figure 6-36 present constraints by control zones and subareas, and demonstrate the influence of individual constraints on zonal prices during calendar year 2004. Constraints can have wide-ranging effects, influencing prices across multiple zones. To illustrate this, the figures depict the congestion component of each zone's annual average LMP. The effects of each constraint during calendar year 2004 are expressed as a percent of the control zone's annual average LMP. The top 10 constraints affecting zonal LMP are depicted in the congestion component graphs.

Figure 6-9 illustrates AECO Control Zone constraints. In particular, the very small Cedar subarea, consisting of just two 69 kV substations, Motts Farm and Cedar, continued to be frequently constrained and accumulated enough unhedgeable congestion to trigger the opening of a market window under the PJM economic planning process. Cedar subarea congestion comprised 7 percent of all PJM congestion-event hours during 2004. Also significant was the Laurel-Woodstown 69 kV line in southern New Jersey (SNJ), which comprised 25 percent of the total congestion-event hours in the AECO Control Zone during 2004. The Shieldalloy-Vineland 69 kV line, also located in SNJ, experienced 444 hours of congestion during 2004, or 28 percent of the total hours for the AECO zone. Both the Laurel-Woodstown and Shieldalloy-Vineland 69 kV lines triggered the opening of a market window through the PJM economic planning process during 2004.

Figure 6-9 - AECO Control Zone congestion-event hours by facility: Calendar years 2002 to 2004

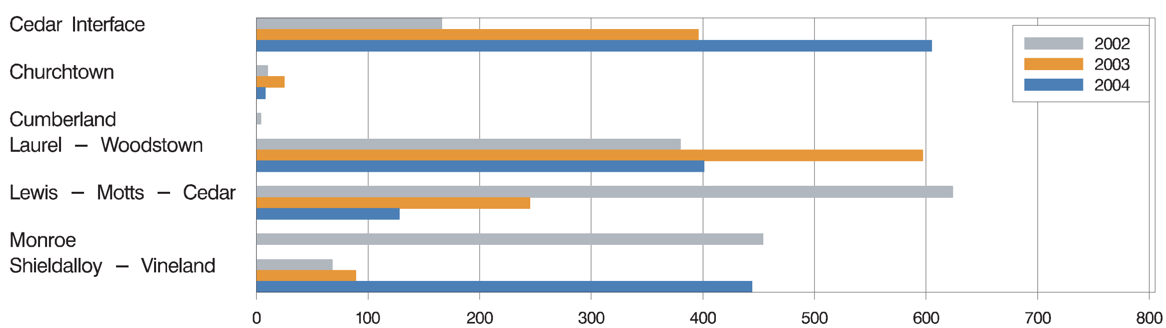


Figure 6-10 depicts the congestion components of AECO zone LMP. The Bedington-Black Oak and Shieldalloy-Vineland constraints caused the greatest increase in prices within the AECO zone. The Cedar Grove-Roseland constraint caused the greatest decrease in prices in the AECO zone.

Figure 6-10 - AECO Control Zone congestion components: Calendar year 2004

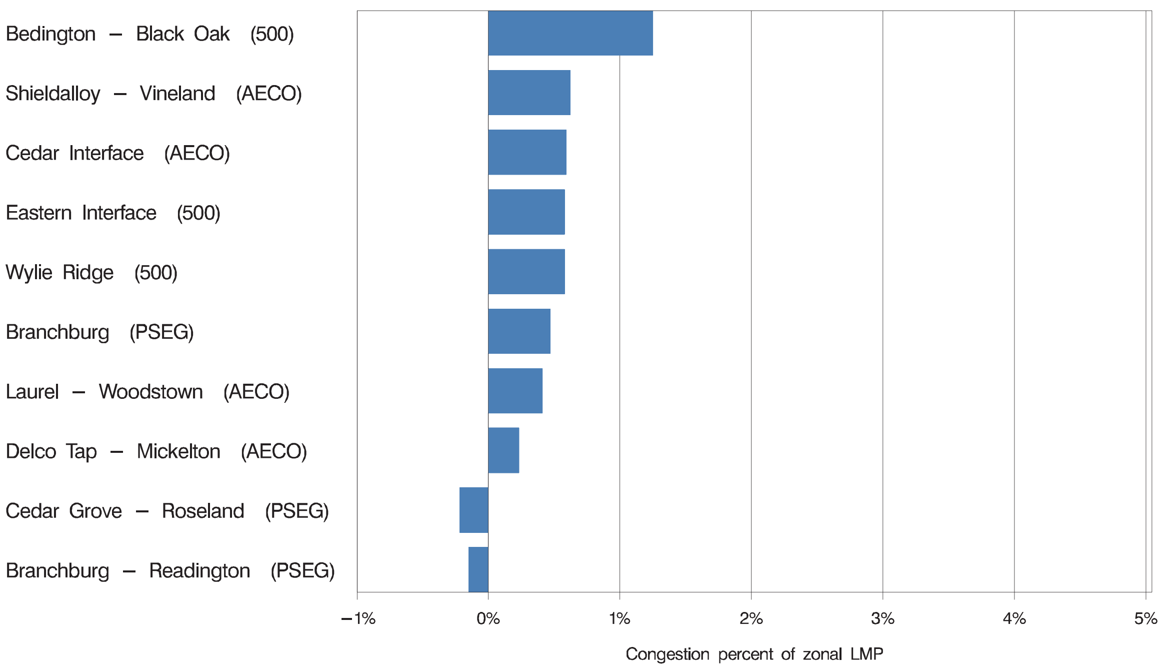


Figure 6-11 illustrates the AP Control Zone constraints. Congestion-event hours in the AP zone were reduced considerably from 2003 levels, down a total of 266 hours or 21 percent. Driving this improvement was a reduction in congestion on the Doubs 500/230 kV transformer which experienced 220 fewer congestion-event hours during 2004 than it had in 2003. This reduction is attributable in part to the installation by Virginia Power of a new 500/230 kV transformer at the Pleasant View station.

Figure 6-11 - AP Control Zone congestion-event hours by facility: Calendar years 2002 to 2004

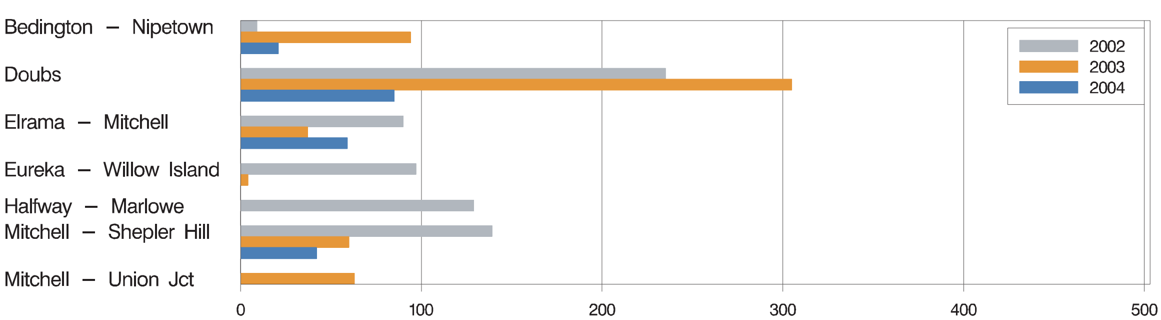


Figure 6-12 depicts the congestion components of the AP Control Zone LMP. The Bedington-Black Oak constraint caused the greatest increase in prices while the Branchburg transformer constraint in PSEG caused the greatest decrease in prices in the AP zone.

Figure 6-12 - AP Control Zone congestion components: Calendar year 2004

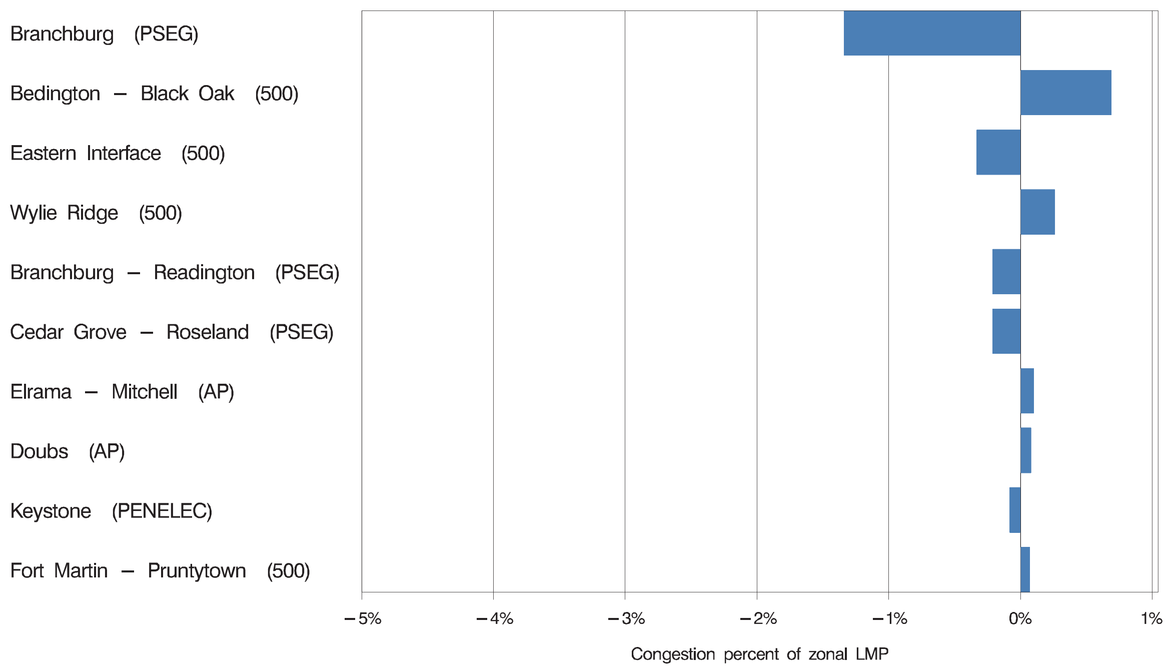


Figure 6-13 illustrates the BGE Control Zone constraints. With 74 congestion-event hours, the BGE Control Zone comprised less than 1 percent of the total PJM congestion-event hours in 2004. One facility, the Brandon Shores-Riverside 230 kV line, had been significantly constrained during 2003, but experienced only 25 hours of congestion during 2004.

Figure 6-13 - BGE Control Zone congestion-event hours by facility: Calendar years 2002 to 2004

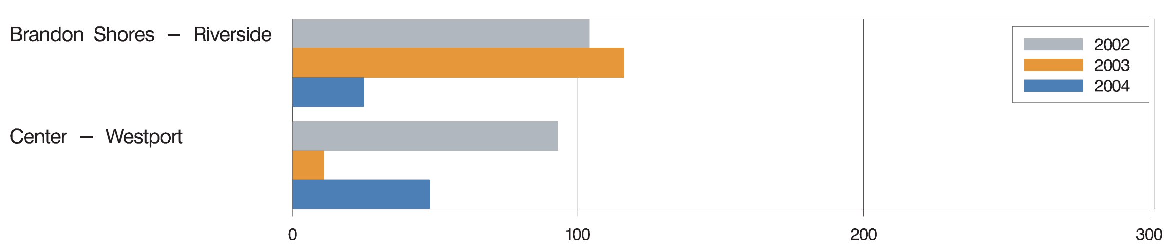


Figure 6-14 depicts the congestion components of the BGE Control Zone LMP. The Bedington-Black Oak constraint caused the greatest increase in prices while the Branchburg transformer constraint in PSEG caused the greatest decrease in prices in the BGE zone.

Figure 6-14 - BGE Control Zone congestion components: Calendar year 2004

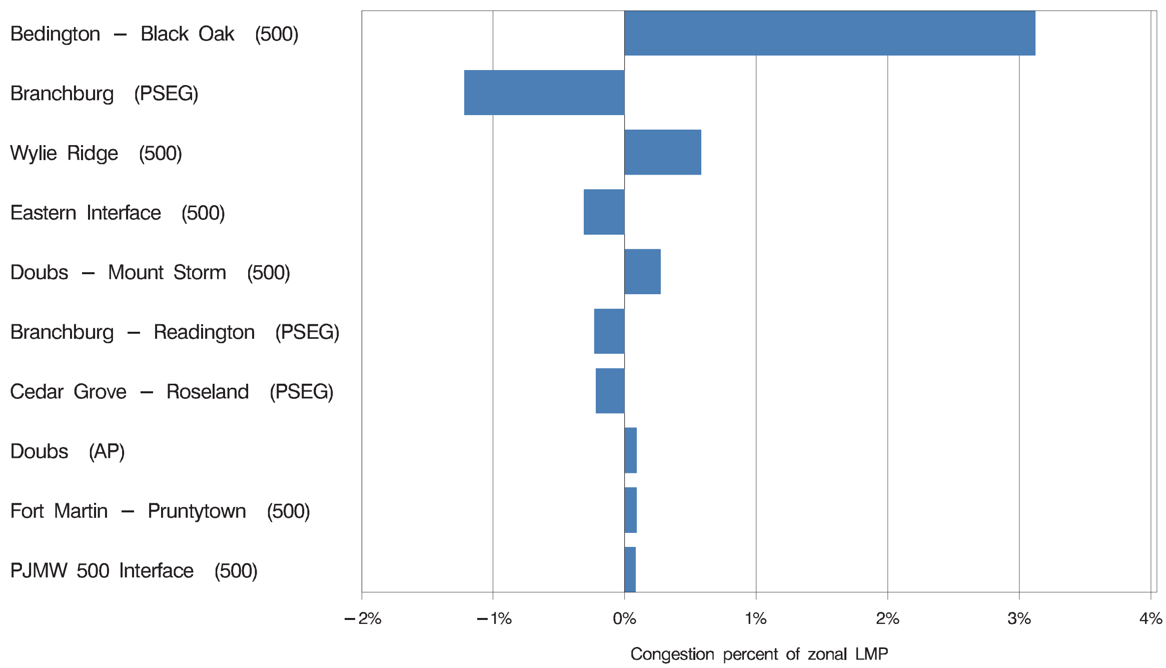


Figure 6-15 depicts DPL Control Zone constraint occurrences. It shows that the southern portion of the Delmarva Peninsula (DPLS) has experienced numerous constraints over the past three years, but their frequency has declined steadily. This continuing improvement in performance is attributable to investments in transmission improvements and reinforcements during the last four years. During 2004, congestion-event hours in the DPL zone fell 33 percent from 2003 levels. DPL zone congestion-event hours represented 5 percent of total congestion-event hours in PJM. While improvements were widespread, the largest contributions came from reductions at the Keeney AT5N transformer and the Cheswold 138/69 kV transformer. Improvements at Keeney are the result of disconnect upgrades at Keeney. These upgrades were performed on the AT-50 and AT-51 transformers and were completed in March and April 2004 respectively. Improvements at Cheswold are the result of the replacement of the Cheswold 138/69 kV transformer in May 2003. As a result, this facility experienced no congestion during 2004 versus the 77 hours experienced in 2003 and the 263 hours during 2002. Although constraints in DPLS have historically been much more frequent than those in the northern subarea of DPL (DPLN) and in the southeast PJM (SEPJM) subarea, the difference in congestion-event hours has decreased significantly.

Figure 6-15 - DPL Control Zone congestion-event hours by subarea: Calendar years 2001 to 2004

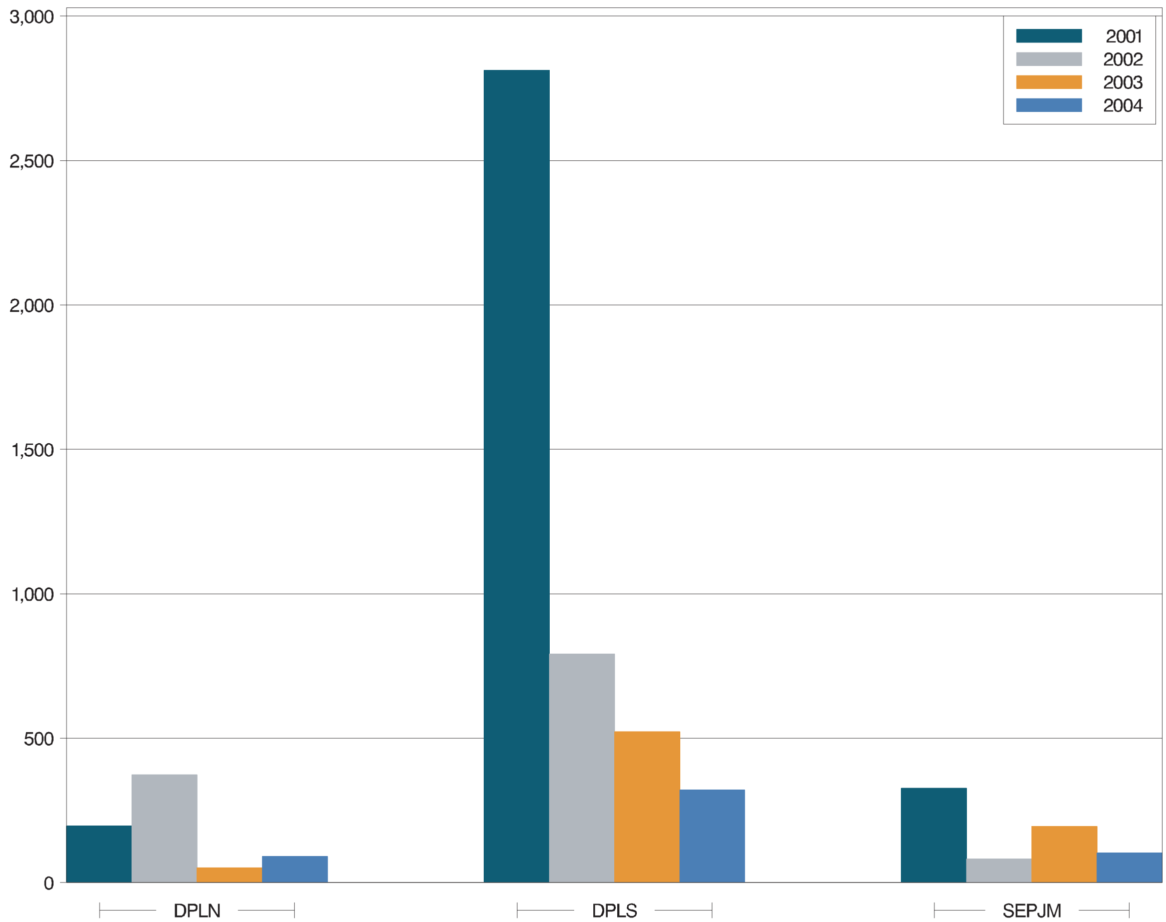


Figure 6-16 illustrates DPLS congestion-event hours by facility. The largest improvement was a 77-hour reduction on the Cheswold transformer in calendar year 2004 as compared to 2003. The reduction on Cheswold is largely attributable to the upgrade of the Cheswold 138/69 kV transformer in May 2003. Only one facility in DPLS was constrained more than 100 hours during 2004. The Wye Mills AT2 69 kV transformer was constrained 128 hours and was the most constrained facility in the DPL Control Zone.

Figure 6-16 - DPLS subarea of the DPL Control Zone (Congestion-event hours by facility): Calendar years 2002 to 2004

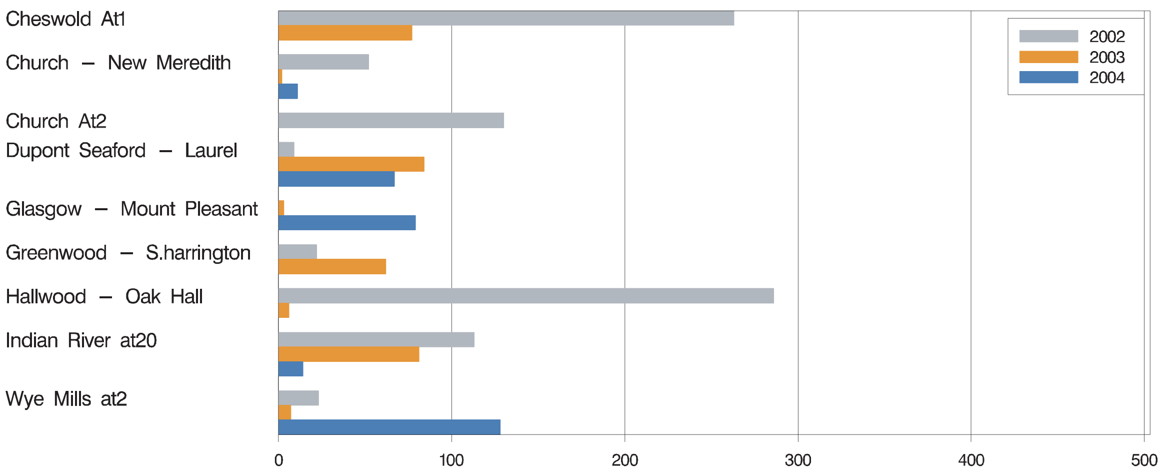
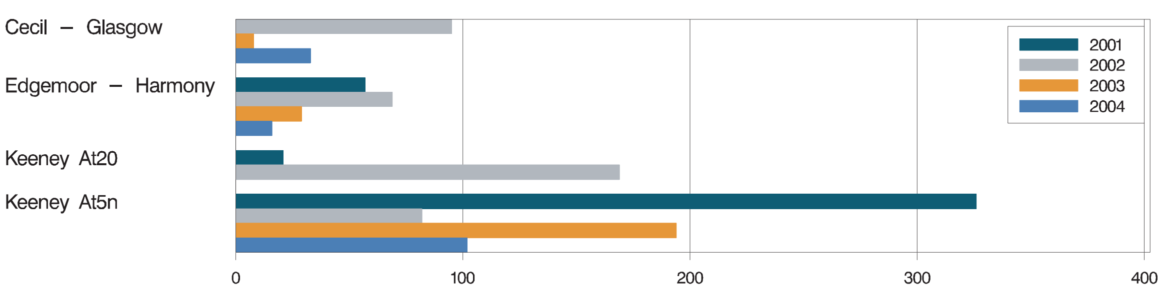


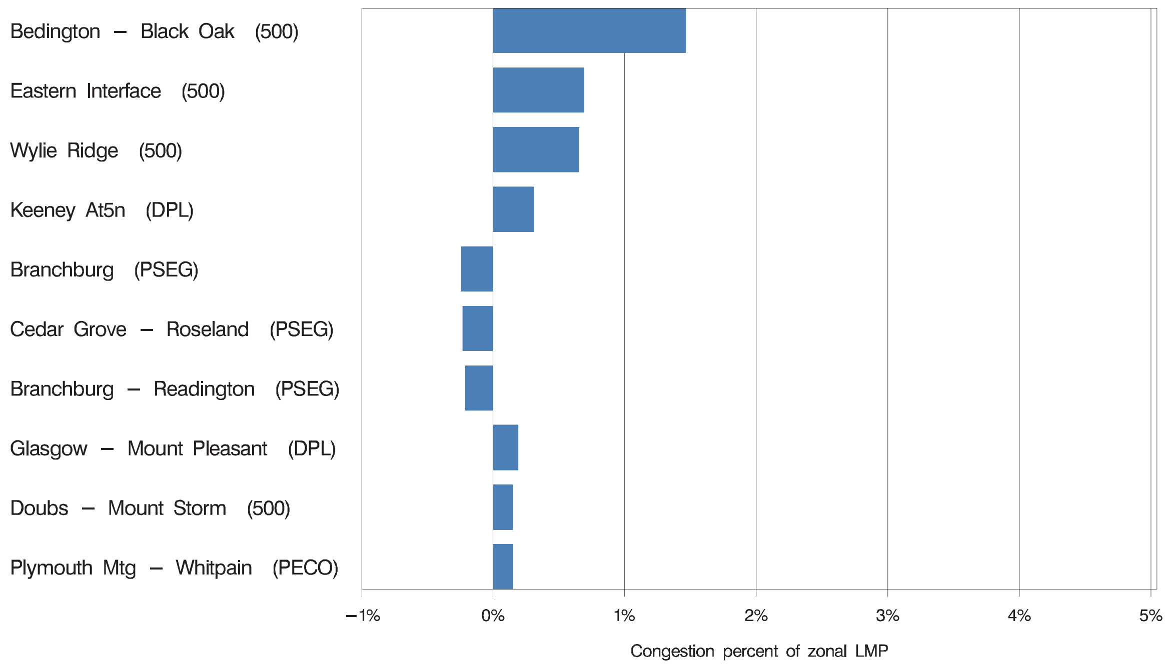
Figure 6-17 presents the same information for the DPLN and SEPJM subareas. The Keeney 500/230 kV transformer (Keeney AT5N), with 102 congestion-event hours, continued to be the most constrained facility in SEPJM although it showed the largest decrease in frequency versus 2003. No other facilities were constrained more than 50 hours in DPLN or SEPJM in 2004.

Figure 6-17 - DPLN and SEPJM subareas of the DPL Control Zone (Congestion-event hours by facility): Calendar years 2001 to 2004



As Figure 6-18 shows, the Bedington-Black Oak, PJM Eastern Interface and Wylie Ridge transformer constraints caused the greatest increase in prices while the Branchburg transformer, Branchburg-Readington and Cedar Grove-Roseland constraints caused the greatest decrease in prices in the DPL zone.

Figure 6-18 - DPL Control Zone congestion components: Calendar year 2004



The JCPL Control Zone, for which no congestion frequency graph is provided, has experienced little internal transmission congestion during the past two years. The JCPL Control Zone experienced 16 congestion-event hours in 2003 and only nine congestion-event hours in 2004.

As Figure 6-19 shows, the Branchburg transformer and Bedington-Black Oak constraints caused the greatest increase in prices while Cedar Grove-Roseland was the only constraint causing a decrease in prices in the JCPL zone.

Figure 6-19 - JCPL Control Zone congestion components: Calendar year 2004

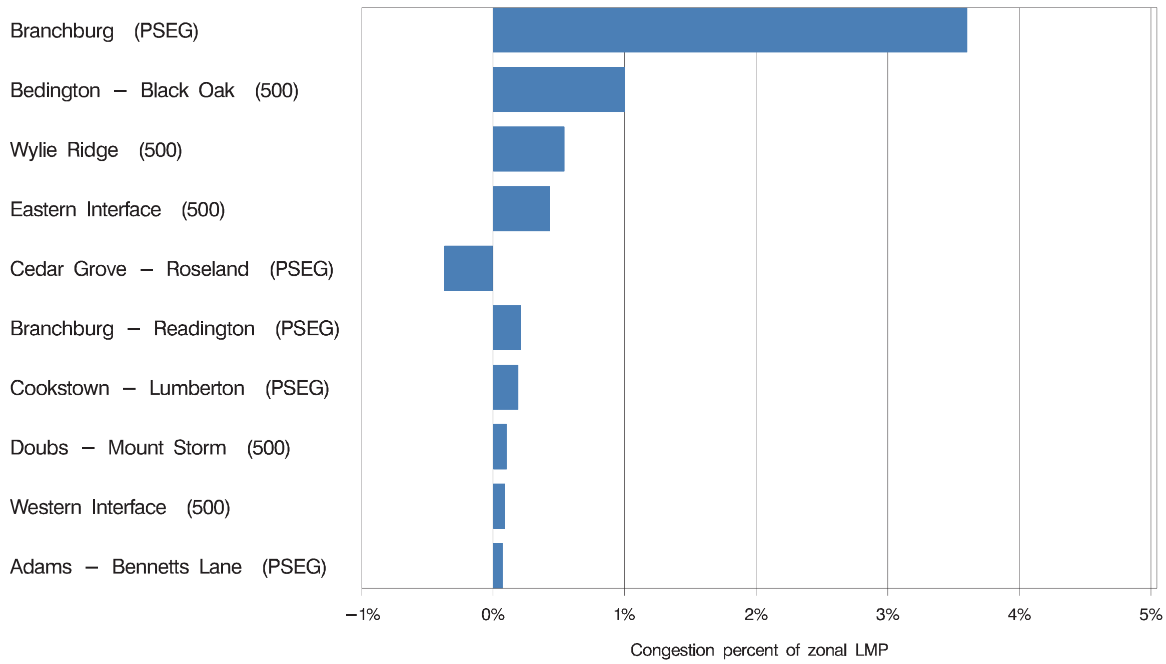
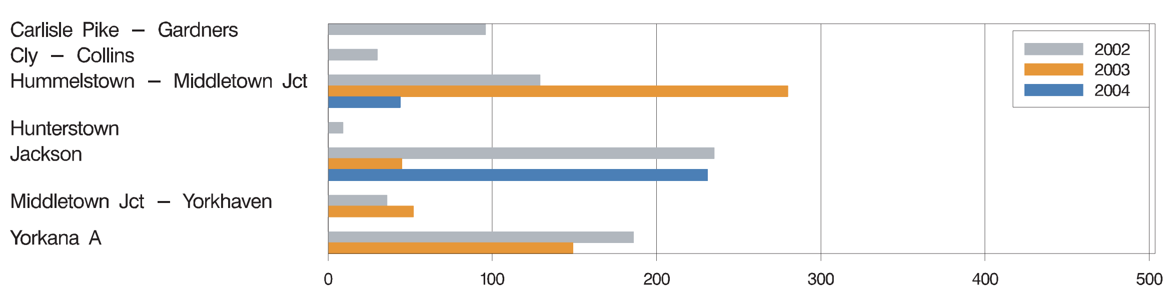


Figure 6-20 illustrates Met-Ed Control Zone constraints. Congestion in Met-Ed was down 219 hours from 2003 levels, a 41 percent reduction. Southcentral Pennsylvania (SCPA) subarea congestion decreased considerably compared to 2003, constituting 18 percent of total Met-Ed congestion-event hours in 2004 as compared to 52 percent during 2003. The largest improvement was on the Hummelstown-Middletown Junction 230 kV line. This had been the most frequently constrained facility in Met-Ed during 2003, but was constrained only 44 hours in 2004. A driver for the 2003 congestion-event hours on the Hummelstown-Middletown Junction 230 kV line was a forced outage on the Middletown Junction-South Lebanon 230 kV line from December 2002 through January 2003. No similar outage affecting the Hummelstown-Middletown Junction line occurred during 2004. Congestion-event hours in the Met-Ed west subarea (MEW) increased slightly as compared to 2003. This was driven largely by the Jackson 230/115 transformer which was constrained 231 hours as compared to 45 hours in 2003, and was the only Met-Ed zonal

Figure 6-20 - Met-Ed Control Zone congestion-event hours by facility: Calendar years 2002 to 2004



facility constrained more than 50 hours in 2004. The Yorkana A transformer which had experienced 149 hours of congestion during 2003 had no congestion during 2004. These year-to-year changes in congestion on Jackson and Yorkana were caused by the return to service in August 2003 of the Hunterstown 500/230 kV transformer, following an outage of approximately one year's duration. That outage had the effect of relieving loading on the Jackson 230/115 kV transformer while simultaneously increasing loading on the Yorkana transformer. The Yorkana A transformer experienced enough unhedgeable congestion during 2003 to trigger the opening of a market solution window. In fact, the PJM economic planning cycle for it began retroactively on August 1, 2003. The Jackson transformer incurred sufficient unhedgeable congestion during 2004 to open a market solution window for it as well.

Figure 6-21 depicts the congestion components of the Met-Ed Control Zone LMP. The Bedington-Black Oak, Jackson transformer and Wylie Ridge transformer constraints caused the greatest increase in prices while the Branchburg transformer constraint caused the greatest decrease in prices in the Met-Ed zone.

Figure 6-21 - Met-Ed Control Zone congestion components: Calendar year 2004

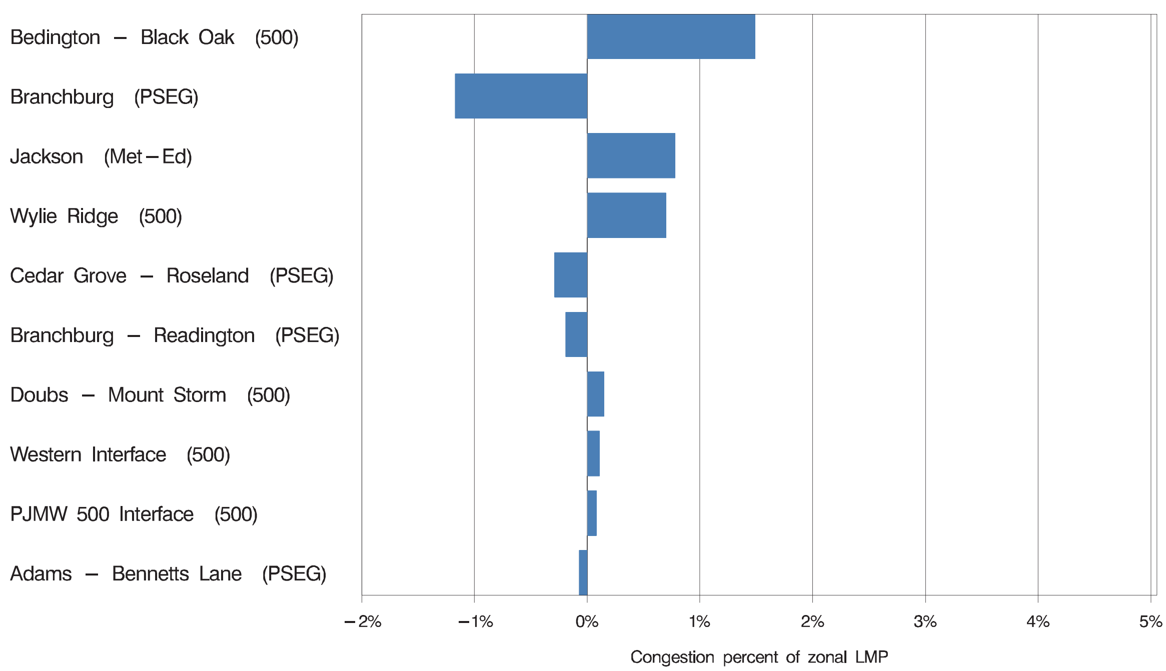


Figure 6-22 illustrates constraints in the PECO Control Zone where in 2004 no facilities were constrained more than 75 hours. Congestion frequency overall was down 58 percent as compared to 2003, with a significant reduction in congestion-event hours in the Plymouth and Whitpain areas of PECO's service territory. In 2004, there were 74 congestion-event hours associated with Plymouth and Whitpain area facilities as compared to 197 hours during 2003. During 2003, these constraints had been caused largely by planned transmission outages at the Plymouth and Whitpain substations in support of upgrades associated with new generator interconnections.

Figure 6-22 - PECO Control Zone congestion-event hours by facility: Calendar years 2002 to 2004

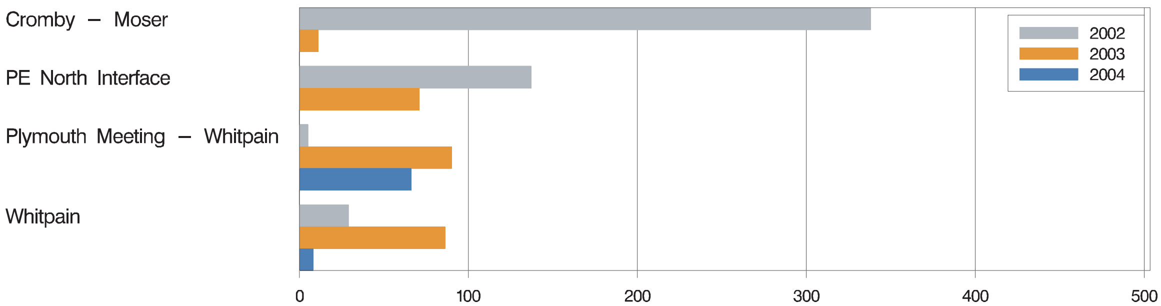


Figure 6-23 shows the congestion components of the PECO Control Zone LMP. The Bedington-Black Oak and Wylie Ridge transformer constraints caused the greatest increase in prices while the Cedar Grove-Roseland and Branchburg-Readington constraints in PSEG caused the greatest decrease in prices in the PECO zone.

Figure 6-23 - PECO Control Zone congestion components: Calendar year 2004

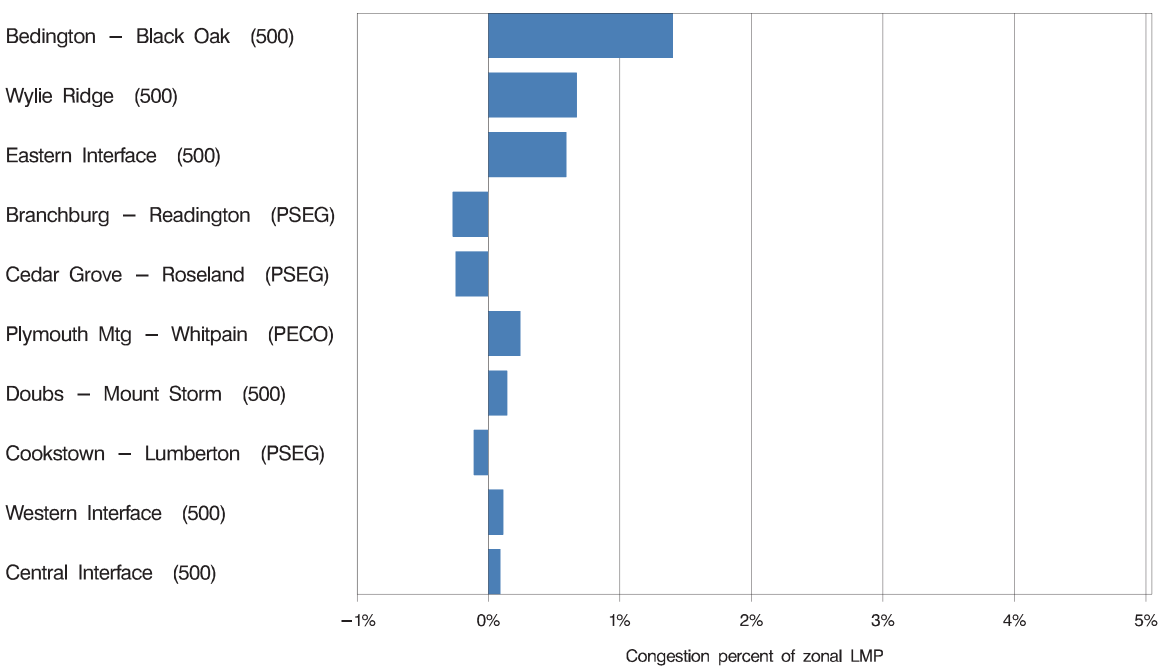


Figure 6-24 illustrates PENELEC Control Zone constraints. Congestion-event hours in the PENELEC Control Zone have steadily declined since reaching a peak of 2,005 hours during 2002. Congestion-event hours in the PENELEC zone were down 67 percent versus 2003, and were considerably lower in northwestern PENELEC. In 2004, the Erie West transformer experienced no congestion, a result of the installation of a second transformer at Erie West. During 2003, this had been the most frequently constrained facility in the northwestern PENELEC (PNNW) subarea. Similarly, the North Meshoppen transformer experienced no congestion in 2004 versus 442 congestion-event hours in 2003 in the northeastern (PNNE) subarea. During 2003, a second transformer was installed at North Meshoppen along with series reactors to address this problem. In total, the PENELEC Control Zone constituted 3 percent of total PJM congestion-event hours during 2004.

Figure 6-24 - PENELEC Control Zone congestion-event hours by facility: Calendar years 2002 to 2004

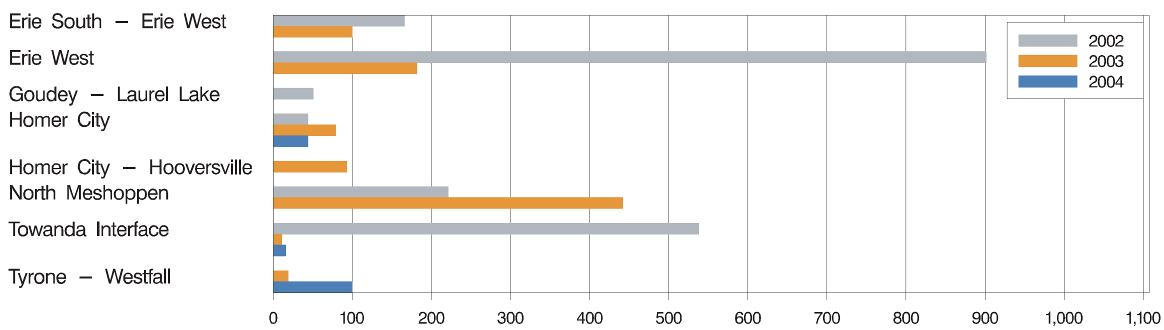
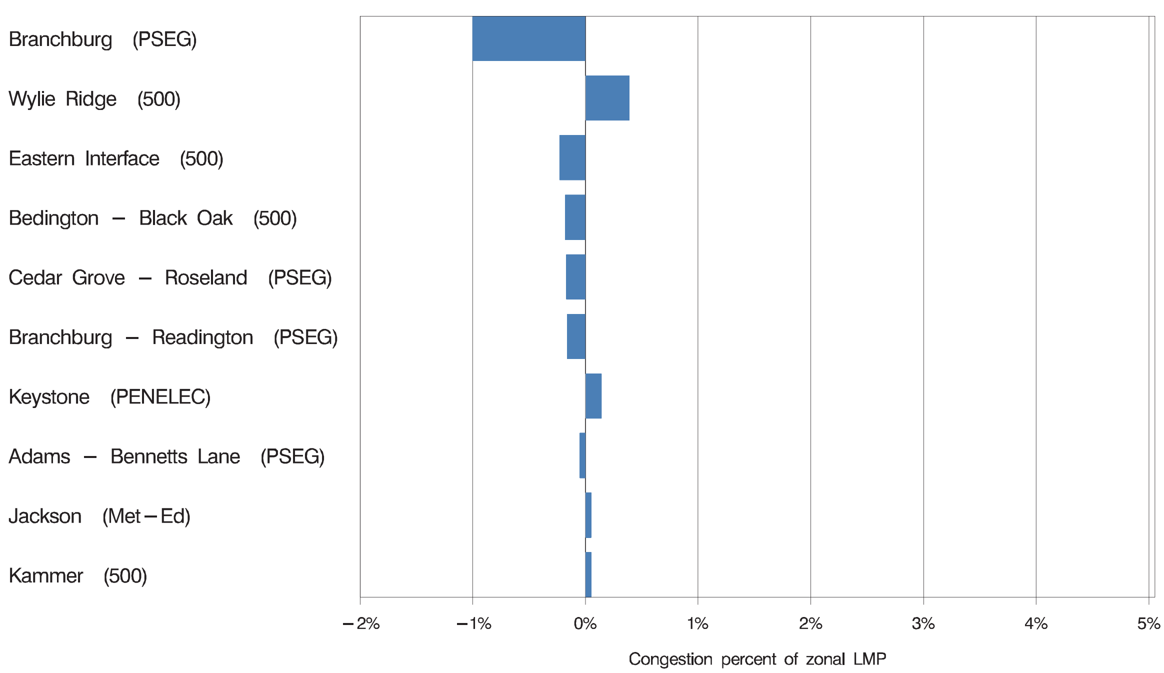


Figure 6-25 shows that the Wylie Ridge transformer constraint caused the greatest increase in prices while the Branchburg transformer constraint caused the greatest decrease in prices in the PENELEC zone.

Figure 6-25 - PENELEC Control Zone congestion components: Calendar year 2004



The PEPCO Control Zone, for which no congestion frequency figure is shown, has experienced very few internal transmission constraints, with 34 congestion-event hours in 2003 and one congestion-event hour in 2004. While the PEPCO zone itself has experienced few internal constraints, prices there can be affected by congestion elsewhere on the system. As Figure 6-26 shows, the Bedington-Black Oak and Wylie Ridge transformer constraints caused the greatest increase in prices while the Branchburg transformer constraint caused the greatest decrease in prices in the PEPCO zone.

Figure 6-26 - PEPCO Control Zone congestion components: Calendar year 2004

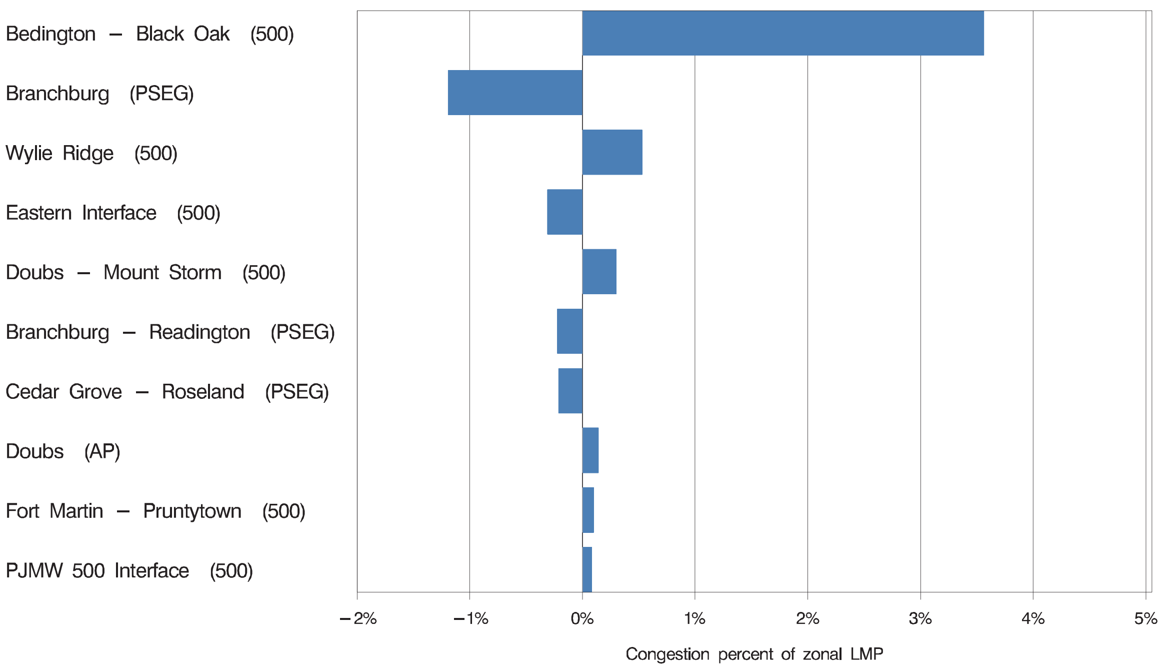


Figure 6-27 illustrates the frequency of PPL Control Zone constraints. During 2004, PPL experienced no significant congestion-event hours. There were eight congestion-event hours for the year, down from 112 congestion-event hours in 2003.

Figure 6-27 - PPL Control Zone congestion-event hours by facility: Calendar years 2002 to 2004

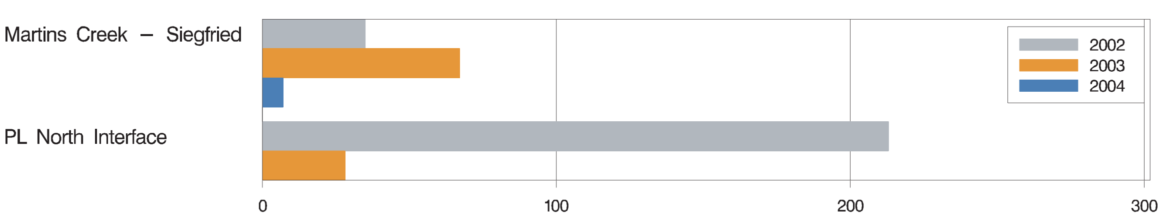


Figure 6-28 shows that the Bedington-Black Oak and Wylie Ridge transformer constraints caused the greatest increase in prices while the Branchburg transformer constraint caused the greatest decrease in prices in the PPL zone.

Figure 6-28 - PPL Control Zone congestion components: Calendar year 2004

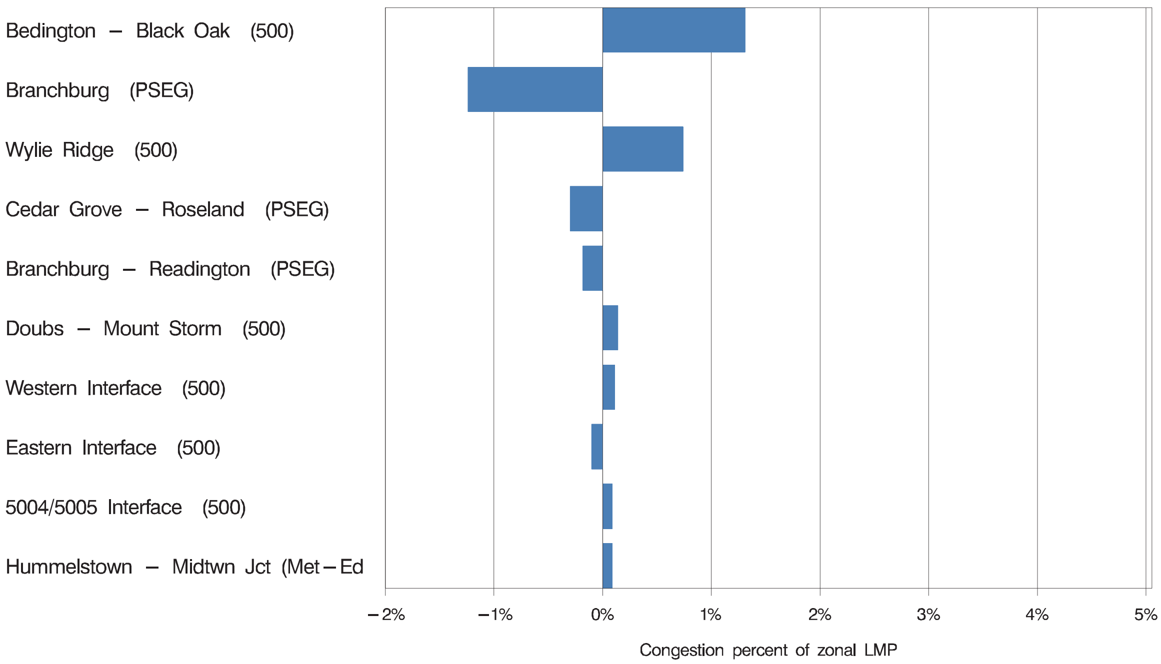


Figure 6-29 illustrates constraint occurrences in the PSEG Control Zone. Total congestion frequency in PSEG was 2 percent lower in 2004 versus 2003. The three facilities that were the most often constrained in PSEG during 2003 had the largest reductions in congestion-event hours in 2004. Cedar Grove-Roseland 230, which affects approximately one-half of PSEG zone load, and two northcentral PSEG (PSNC) facilities, Branchburg-Readington 230 and Edison-Meadow Road 138 kV, had a combined reduction in congestion of 1,044 hours. These reductions were caused, in large part, by the rating reduction on the Branchburg transformers which had the effect of limiting imports into the northern PSEG Control Zone and reducing the loading on these facilities. PSEG had the second most frequently constrained facility in PJM during 2004, the Branchburg 500/230 kV transformers. The Branchburg 500/230 kV transformers comprised 56 percent of all congestion-event hours in the PSEG zone and 9 percent of all PJM congestion. On March 17, 2004, PSEG significantly reduced the emergency and normal ratings of the Branchburg number 1 and number 2 transformers because of a deteriorating condition identified during an inspection. On May 25, 2004, a special protection scheme (SPS) was installed at Branchburg to reduce the impact on congestion from the derated facilities. A third transformer is scheduled to be installed at Branchburg by June 30, 2005, to relieve this constraint. The number 1 and number 2 transformers at Branchburg are scheduled to be replaced by June 2007.

Figure 6-29 - PSEG Control Zone congestion-event hours by facility: Calendar years 2002 to 2004

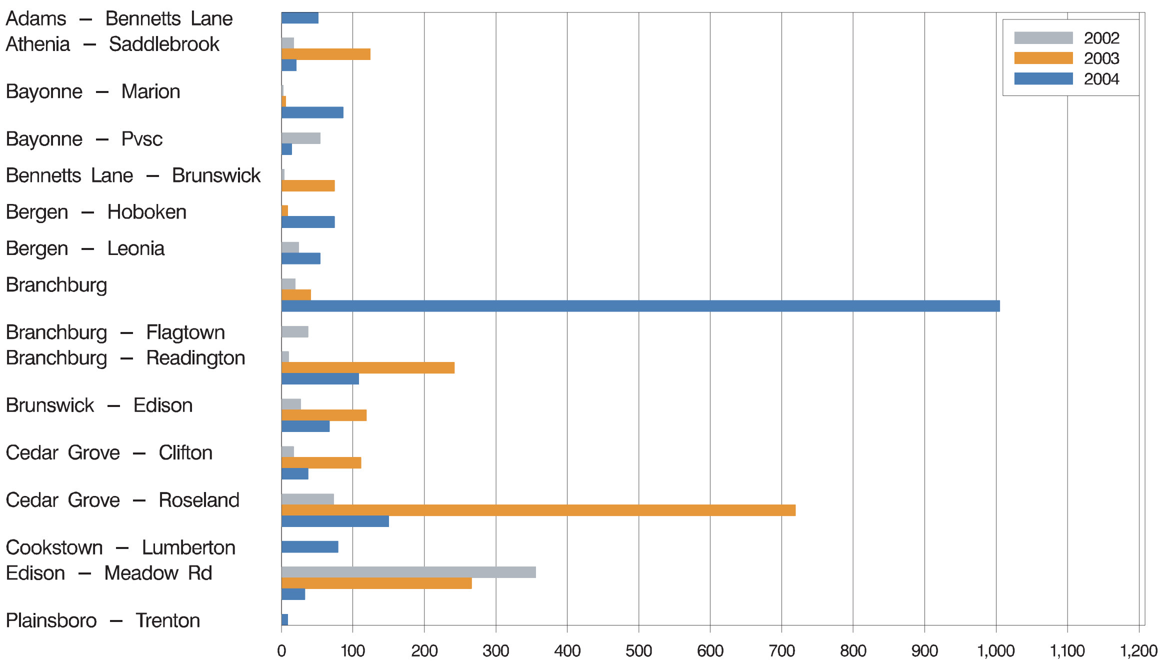


Figure 6-30 shows that the Branchburg transformer, a PSEG Control Zone facility, and the Bedington-Black Oak constraints increased prices in the PSEG Control Zone. There were no constraints that significantly reduced prices in PSEG zone during 2004.

Figure 6-30 - PSEG Control Zone congestion components: Calendar year 2004

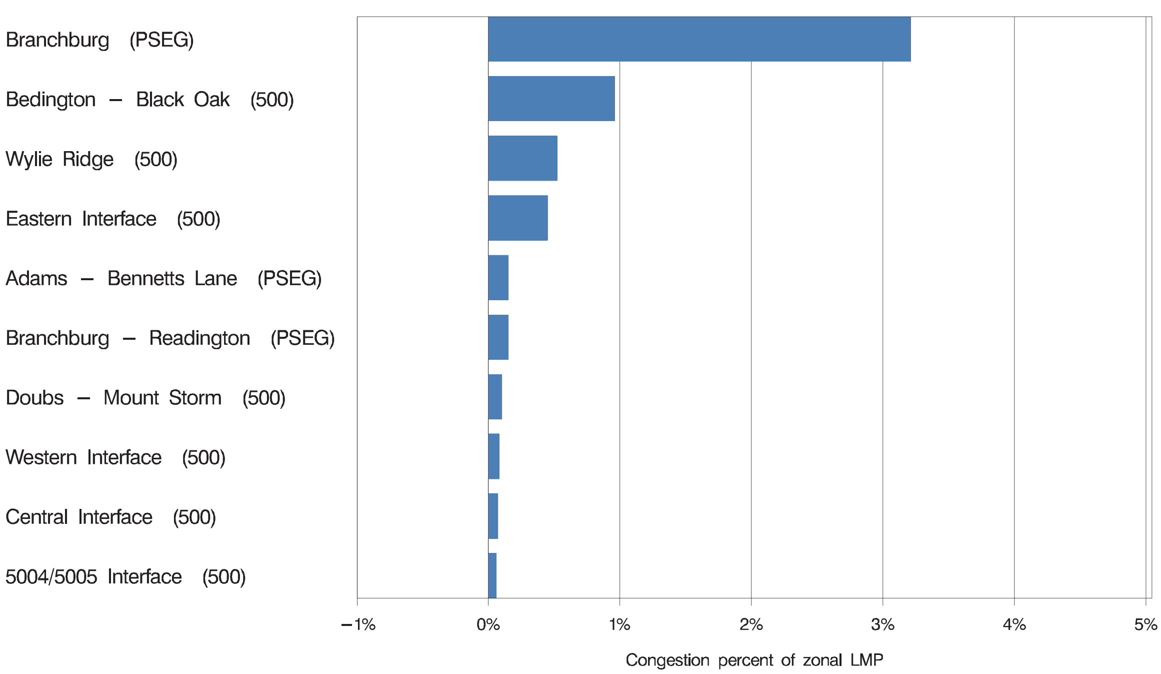


Figure 6-31 illustrates constraint occurrences in the ComEd Control Zone after its integration into PJM. Since May 1, congestion frequency levels in ComEd have been comparatively low, with only 130 congestion-event hours during the eight-month period comprising Phases 2 and 3 of calendar year 2004. The most significant constraint was the Waukegan-Round Lake 138 kV line with 97 congestion-event hours. Congestion experience in the ComEd zone was minimized by post-contingency switching procedures which are employed where PJM would traditionally have initiated out of merit dispatch. Also contributing to the low level of congestion is that a number of large generators, primarily located in the eastern portion of the ComEd system, often ran independent of PJM economic dispatch. This had the effect of reducing west-to-east flows on facilities that might otherwise have been subject to congestion.

Figure 6-31 - ComEd Control Zone congestion-event hours by facility: Phases 2 and 3, 2004

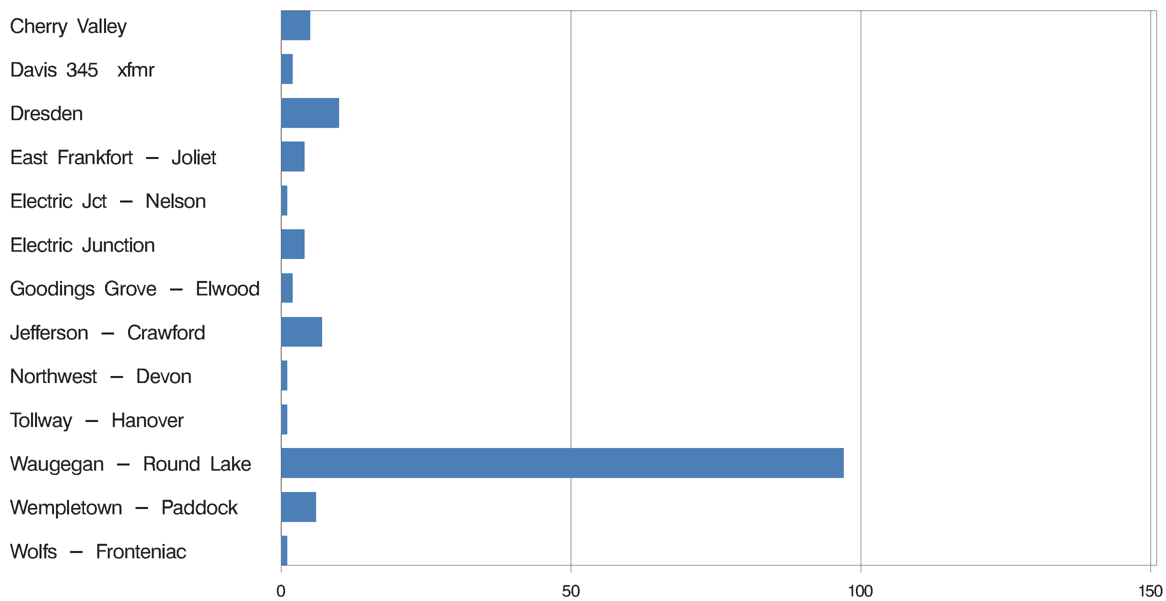


Figure 6-32 depicts congestion components of the ComEd Control Zone LMP during Phases 2 and 3. As one can see, the Phase 2 Pathway between the PJM and ComEd Control Areas was the most significant congestion component of ComEd price. The Pathway reduced prices in ComEd overall, consistent with the fact that Pathway flow was predominantly from the ComEd into the PJM Control Area. Such flows placed ComEd on the unconstrained side of the interface, thus tending to depress prices relative to the other PJM Control Area. Constraints on the Branchburg transformer, the Bedington-Black Oak line and the Crete – St. Johns Tap line, a Midwest ISO flowgate, also reduced prices in ComEd. There were no constraints that significantly increased prices in the ComEd zone during 2004.

Figure 6-32 - ComEd Control Zone congestion components: Phases 2 and 3, 2004

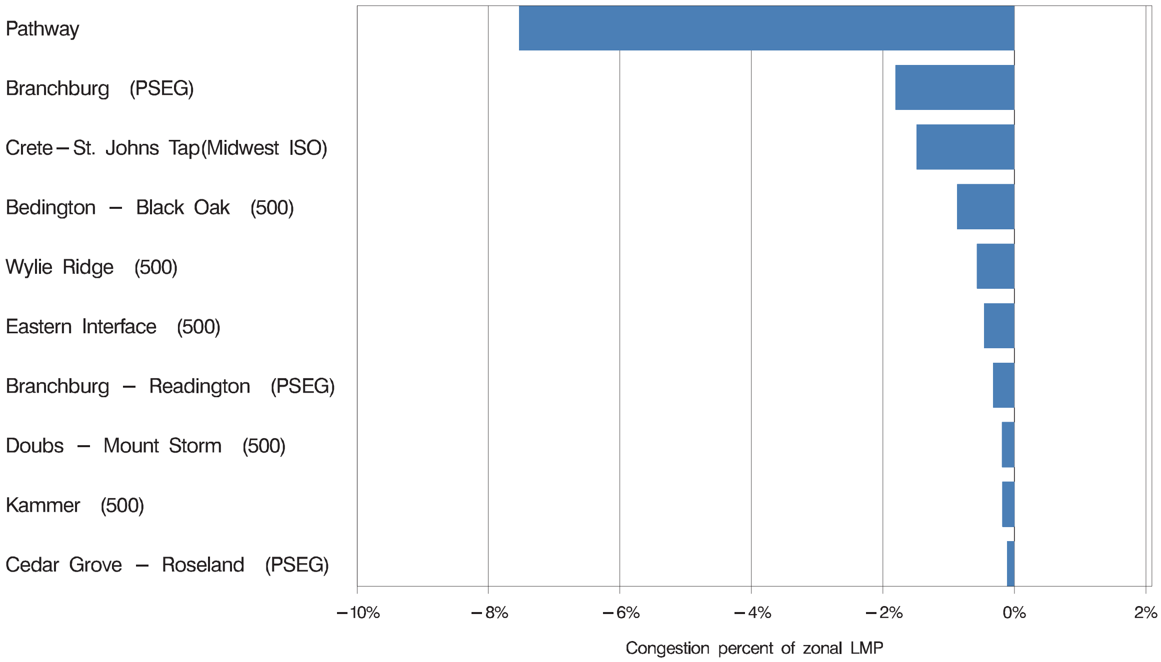
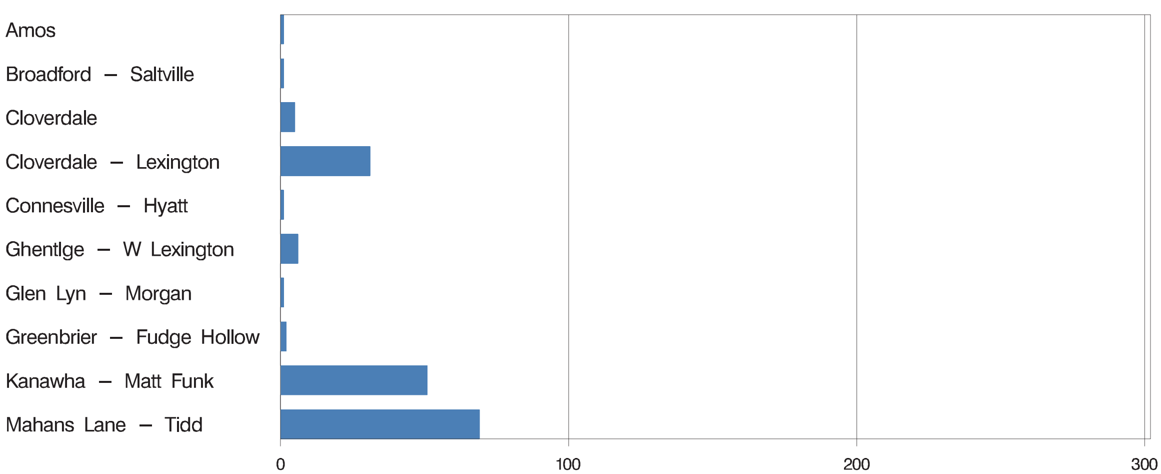


Figure 6-33 illustrates constraint occurrences in the AEP Control Zone since its Phase 3 integration into PJM. The Kanawah-Matt Funk 345 kV line experienced 51 hours of congestion between October 1, 2004, and December 31, 2004. AEP currently has a 765 kV line under construction from Wyoming to Jackson's Ferry that should reduce congestion on Kanawah-Matt Funk after its June 2006 in-service date.[19] Also congested was the Mahans Lane-Tidd 138 kV line with 69 congestion-event hours during Phase 3. Before the integration, congestion on these facilities had been managed through the use of NERC TLRs. Since then, however, given PJM's reliance on LMP, the impacts of these constraints have become more localized.

Figure 6-33 - AEP Control Zone congestion-event hours by facility: Phase 3, 2004



19 *PJM Interconnection, L.L.C.*, Compliance Filing, Docket Nos. ER04-539-001, 002 and ER04-121-000 (October 26, 2004), Report of the PJM Market Monitor, paragraph 17.

Figure 6-34 shows that the Wylie Ridge and PJM Eastern Interface constraints caused the greatest reduction in prices in the AEP zone. There were no constraints that significantly increased prices in the AEP zone during 2004.

Figure 6-34 - AEP Control Zone congestion components: Phase 3, 2004

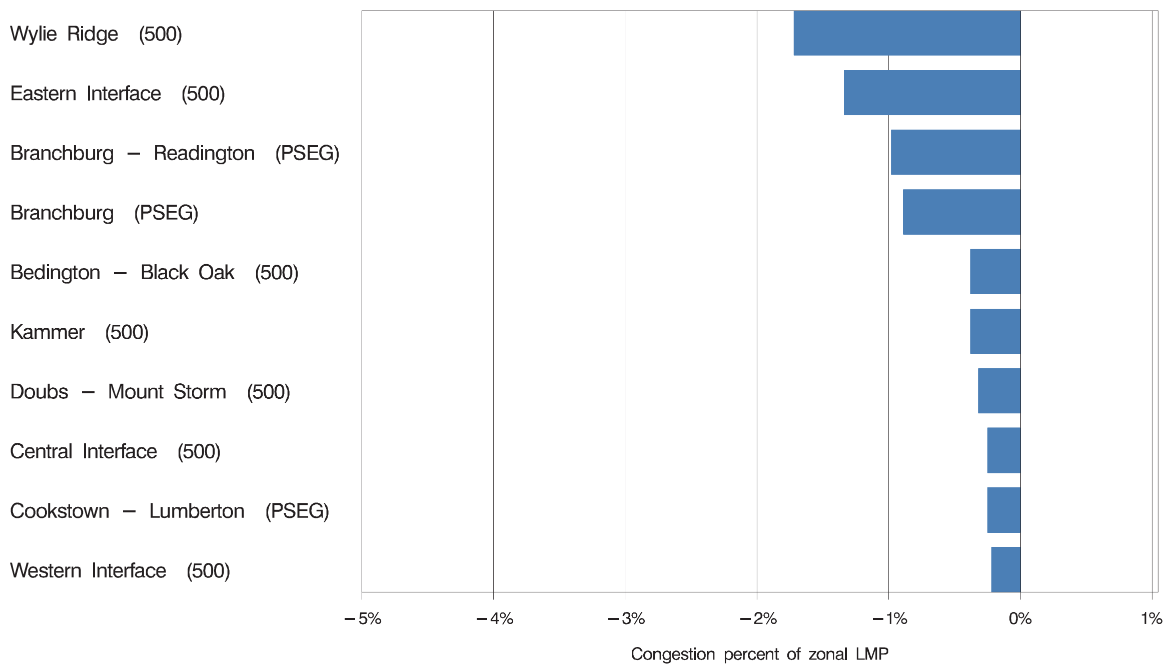


Figure 6-35 illustrates constraint occurrences in the DAY Control Zone which has experienced only 19 hours of congestion since its Phase 3 integration into PJM.

Figure 6-35 - DAY Control Zone congestion-event hours by facility: Phase 3, 2004

Figure 6-36 depicts the congestion components of the DAY Control Zone's LMP. The influence of constraints on prices in the DAY zone very closely mirrored that of the AEP zone. The Wylie Ridge and PJM Eastern Interface constraints caused the greatest reduction in prices in the DAY zone. There were no constraints that significantly increased prices in the DAY zone during 2004.

Figure 6-36 - DAY Control Zone congestion components: Phase 3, 2004

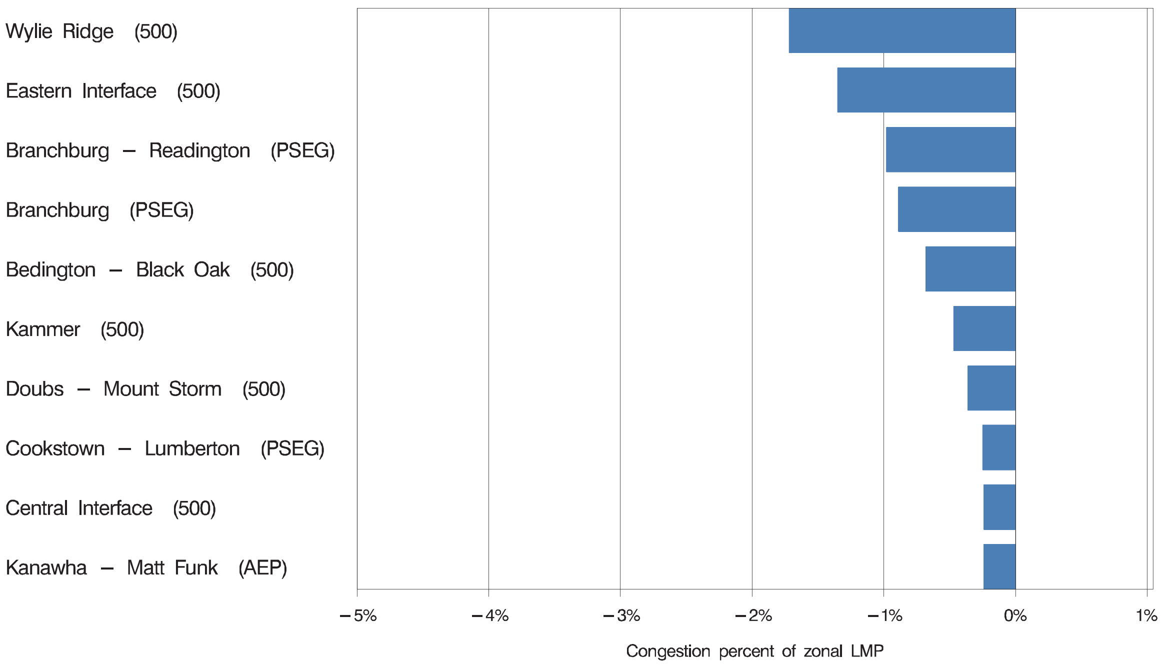


Table 6-6 lists congestion-event hours by facility type and voltage.

Table 6-6 - Congestion-event hour summary by facility type and voltage class: Calendar years 2001 to 2004

Type	Voltage (kV)	Congestion-Event Hours				% of Congestion-Event Hours			
		2001	2002	2003	2004	2001	2002	2003	2004
All	All	8,435	11,662	9,711	*11,205	100%	100%	100%	100%
	500	759	1,888	1,985	1,809	9%	16%	20%	16%
	345	38	1,084	705	1,115	0%	9%	7%	10%
	230	1,625	1,474	3,016	2,340	19%	13%	31%	21%
	138	744	2,056	1,071	977	9%	18%	11%	9%
	115	1,154	2,527	1,018	534	14%	22%	10%	5%
	69	4,115	2,619	1,916	1,918	49%	22%	20%	17%
	34	0	14	0	0	0%	0%	0%	0%
Midwest ISO Flowgate	All	-	-	-	455	-	-	-	4%
	500	-	-	-	0	-	-	-	0%
	345	-	-	-	369	-	-	-	3%
	230	-	-	-	4	-	-	-	0%
	138	-	-	-	82	-	-	-	1%
Interface	All	752	1,683	1,274	1,018	9%	14%	13%	9%
	500	747	586	764	397	9%	5%	8%	4%
	345	0	5	0	0	0%	0%	0%	0%
	230	0	388	103	0	0%	3%	1%	0%
	115	0	538	11	16	0%	5%	0%	0%
	69	5	166	396	605	0%	1%	4%	5%
Line	All	5,507	5,552	5,590	4,622	65%	48%	58%	41%
	500	12	1,128	917	1,328	0%	10%	9%	12%
	345	38	233	168	99	0%	2%	2%	1%
	230	1,164	658	2,104	996	14%	6%	22%	9%
	138	408	1,163	815	756	5%	10%	8%	7%
	115	214	413	187	280	3%	4%	2%	2%
	69	3,671	1,943	1,399	1,163	44%	17%	14%	10%
	34	0	14	0	0	0%	0%	0%	0%
Transformer	All	2,176	4,427	2,847	2,598	26%	38%	29%	23%
	500	0	174	304	84	0%	1%	3%	1%
	345	0	846	537	647	0%	7%	6%	6%
	230	461	428	809	1,340	5%	4%	8%	12%
	138	336	893	256	139	4%	8%	3%	1%
	115	940	1,576	820	238	11%	14%	8%	2%
	69	439	510	121	150	5%	4%	1%	1%

*Total includes an additional 2,512 congestion-event hours attributable to the Pathway between ComEd and PJM during Phase 2.

Post-Contingency Congestion Management Program

The PJM "Transmission Operations Manual" states in relevant part:

> The PJM RTO Bulk Power Electric Supply System is operated so that loading on all PJM Monitored Bulk Power Transmission Facilities are within normal continuous ratings, and so that immediately following any single facility malfunction or failure, the loading on all remaining facilities can be expected to be within emergency ratings.[20]

In part in response to stakeholders' concerns regarding congestion on the Delmarva Peninsula, PJM developed, tested and implemented a protocol that results in less frequent out of merit dispatch than had been the case under the then-current system.

On August 19, 2004, the FERC accepted PJM's plan.[21] The program was implemented on September 1, 2004. The FERC noted that the expansion of this program has the potential to:

- Reduce redispatch costs in chronically congested areas in the PJM region;
- More accurately reflect the local benefits of avoided redispatch and enhanced reliability;
- Reduce the potential for the exercise of local market power;
- Reduce emissions; and
- Allow for more efficient use of assets.

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. PJM continues to evaluate candidate facilities for inclusion under this protocol. The Jackson and Yorkana transformers in Met-Ed were added to the program during 2004.

PJM Economic Planning Process

Planning the enhancement and expansion of transmission capability on a regional basis is one of the primary functions of regional transmission organizations. PJM implements this function pursuant to the RTEPP set forth in Schedule 6 of the PJM Operating Agreement. A key part of this regional planning protocol is the evaluation of both generation interconnection and merchant transmission interconnection requests, the procedures for which are codified under Part IV of the PJM Open Access Transmission Tariff.

PJM's RTEPP includes an economic planning component that is still under development. The FERC approved the PJM economic transmission planning process in October 2003 and it began retroactively with the regional planning cycle that started on August 1, 2003.

The objective of the economic planning component of the regional transmission planning protocol

20 See PJM manual, "Transmission Operations (m03), Revision 12" (October 1, 2004).
21 108 FERC ¶ 61,196 (2004).

is to provide cost-effective transmission solutions to alleviate unhedgeable congestion that no market participant has proposed to resolve. Unhedgeable congestion is transmission system congestion with a cost that PJM finds cannot be mitigated by economic generation, FTRs or other financial instruments available pursuant to its Tariff or under the Operating Agreement.

PJM posts the hourly shadow price, along with the hourly and cumulative monthly total gross congestion cost of each constraint. When the cumulative monthly total gross congestion cost of a constraint exceeds the applicable initial threshold, PJM posts a notice to that effect and begins determining the extent to which the total affected load cannot be hedged.

PJM posts the hourly and cumulative monthly unhedgeable congestion associated with each constraint for which it undertakes such calculations, as well as the portions of unhedgeable congestion attributable to recurring and nonrecurring causes of transmission constraints. When the cumulative monthly unhedgeable congestion associated with a constraint exceeds the applicable market threshold, PJM posts a notice advising that it will begin an initial cost-benefit analysis of potential transmission enhancements that would relieve the applicable transmission constraint. PJM then opens a one-year “market window” to solicit merchant solutions.

Market-based proposals solicited during the market window may take many forms including generation, transmission or demand-side response solutions. A market-based solution differs from a traditional utility solution because it may be proposed by an entity other than the regulated transmission owner. If no market-based solution is proposed within one year from the date of publication of the results of the initial cost-benefit analysis, PJM will include in the “PJM Regional Transmission Expansion Plan”[22] the transmission enhancement that is the most cost-effective, feasible solution.

Table 6-7 identifies the facilities for which a market window has been opened. Depending upon their initiation dates, market windows for these facilities will close beginning in March 2005. Proposed solutions may only be designated as a “market solution,” and thus be eligible for expedited processing, following the close of the associated market window and by request of the developer. No proposals as yet carry this designation as the first market window will close on March 4, 2005.

22 See “PJM Regional Transmission Expansion Plan” (Revised August 1, 2004) <http://www.pjm.com/planning/rtep-baseline-reports/downloads/regionalplan_5_0.chm)> (6.8 KB).

Table 6-7 - Constraints with open market window

One Year Market Window is Open for the Following Congested Facilities	Market Window Open Date	Market Window Close Date	Location of Facility Based on Transmission Owner Zones
Adams - Brunswick 230 kV "X-2224"	4-Mar-04	4-Mar-05	PSEG
Bedington - Black Oak 500 kV (Voltage)	4-Mar-04	4-Mar-05	AP
Bedington - Black Oak 500 kV (Thermal)	4-Mar-04	4-Mar-05	AP
Greystone - Portland 230 kV	4-Mar-04	4-Mar-05	Met-Ed / JCPL
PJM West 500 kV	4-Mar-04	4-Mar-05	Multiple Zones
North Wales - Whitpain 230 kV	4-Mar-04	4-Mar-05	PECO
Eastern Interface	4-Mar-04	4-Mar-05	Multiple Zones
Jackson 230/115 kV	4-Mar-04	4-Mar-05	Met-Ed
Yorkana 230/115 kV	4-Mar-04	4-Mar-05	Met-Ed
Cedar Grove - Clifton 230 kV "K-2263"	4-Mar-04	4-Mar-05	PSEG
Adams - Bennetts Lane 230 kV "X-2224"	4-Mar-04	4-Mar-05	PSEG
Brunswick - Edison 138 kV	4-Mar-04	4-Mar-05	PSEG
Sheildalloy - Vineland 69 kV	4-Mar-04	4-Mar-05	AECO
Edison - Meadow Road 138 kV "R-1318"	4-Mar-04	4-Mar-05	PSEG
Elroy - Hosensack 500 kV	4-Mar-04	4-Mar-05	PECO / PPL
Edgewood - N. Salisbury 69 kV	4-Mar-04	4-Mar-05	DPL
Cedar Interface	4-Mar-04	4-Mar-05	AECO
Northern PECO Voltage Interface	4-Mar-04	4-Mar-05	PECO
Athenia - Saddlebrook 230 kV	4-Mar-04	4-Mar-05	PSEG
Central Interface	4-Mar-04	4-Mar-05	Multiple Zones
Laurel - Woodstown 69 kV	4-Mar-04	4-Mar-05	AECO
DuPont Seaford - Laurel 69 kV	4-Mar-04	4-Mar-05	DPL
Western Interface	4-Mar-04	4-Mar-05	Multiple Zones
Landis - Minotola 69 kV	4-Mar-04	4-Mar-05	AECO
Sammis - Wylie Ridge 345 kV	4-Mar-04	4-Mar-05	AP
Lewis - Motts Farm 69 kV	4-Mar-04	4-Mar-05	AECO
Plymouth Meeting - Whitpain 230 kV "220-14"	4-Mar-04	4-Mar-05	PECO
Keeney 500/230 kV "AT51"	4-Mar-04	4-Mar-05	DPL
Plymouth Meeting - Whitpain 230 kV "220-13"	4-Mar-04	4-Mar-05	PECO
Martins Creek - Morris Park 230 kV	4-Mar-04	4-Mar-05	PPL / JCPL
Bergen - Leonia 230 kV	1-Apr-04	1-Apr-05	PSEG
Bergen - Hoboken 230 kV	1-Apr-04	1-Apr-05	PSEG
Wylie Ridge 500/345 kV #5	1-Apr-04	1-Apr-05	AP
Harrison - Kammer Tap 500 kV	1-Apr-04	1-Apr-05	AP
Branchburg 500/230 kV #1	18-May-04	18-May-05	PSEG
Branchburg 500/230 kV #2	18-May-04	18-May-05	PSEG
Wylie Ridge 500/345 kV #7	20-Jul-04	20-Jul-05	AP
Keeney 500/230 kV "AT50"	20-Jul-04	20-Jul-05	DPL
Branchburg - Flagtown 230 kV	20-Jul-04	20-Jul-05	PSEG
Bayonne - Marion 138 kV	29-Nov-04	29-Nov-05	PSEG
Roseland - Whippany 230 kV	29-Nov-04	29-Nov-05	JCPL/PSEG
Jackson 230/115 kV "5"	29-Nov-04	29-Nov-05	Met-Ed
Glasgow - Mt Pleasant 138 kV	29-Nov-04	29-Nov-05	DPL
Richmond - Waneeta 230 kV	29-Nov-04	29-Nov-05	PECO
Red Lion 500/230 kV "AT50"	29-Nov-04	29-Nov-05	DPL
Doubs - Mt Storm 500 kV	29-Nov-04	29-Nov-05	APS/VAP
Beckett - Paulsboro 69 kV	29-Nov-04	29-Nov-05	AECO
Hudson 230/138 kV #2	29-Nov-04	29-Nov-05	PSEG
Brunner - Yorkana 230 kV	29-Nov-04	29-Nov-05	PPL/Met-Ed
Wye Mills 138/69 kV "AT-2"	29-Nov-04	29-Nov-05	DPL
Sickler 230/69 kV #1	29-Nov-04	29-Nov-05	AECO
Cedar - Sands Point 69 kV	29-Nov-04	29-Nov-05	AECO
Talbot-Trappe 69 kV	29-Nov-04	29-Nov-05	DPL
Fort Martin - Prutytown 500 kV	1-Dec-04	1-Dec-05	AP

SECTION 7 - FINANCIAL TRANSMISSION AND AUCTION REVENUE RIGHTS

In PJM, Financial Transmission Rights (FTRs) have been available to firm point-to-point and network service transmission customers[1] 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,[2] 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.[3] 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.

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.[4] 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),

1 PJM network and firm, long-term point-to-point transmission service transmission customers are referred to as eligible customers.
2 87 FERC ¶ 61,054 (1999).
3 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.
4 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.

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.

- **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).[5]

- **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.

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. [6]

Overview

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 United States Federal Energy Regulatory Commission (FERC),[7] 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.

5 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).
6 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.
7 106 FERC ¶ 61,049 (2004).

- **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 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.[8]

- **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.[9]

8 See Section 6, “Congestion,” at Table 6-2, “Monthly PJM congestion accounting summary [Dollars (in millions)]: By planning period.”
9 See Section 6, “Congestion,” for a more complete discussion of FTR revenue adequacy.

- **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 is 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 suppliers, the rules remove a potential barrier to competition.

Auction Revenue Rights

ARRs are financial instruments that entitle their holders to receive revenue based on prices in the Annual FTR Auction. The ARR target allocation (i.e., what the ARR holder should receive) is equal to the product of the ARR MW and the sink-minus-source price difference from the Annual FTR Auction. An ARR's value can be positive or negative depending on these sink-minus-source price differences, with negative differences resulting in a liability for the holder. Based on the annual and monthly FTR auction revenue, ARR holders are granted credits that can range from zero to the target allocations. ARR holders receiving credits equal to the target allocations are deemed fully funded.

ARRs have been available to eligible participants[10] since June 1, 2003, when the Annual ARR Allocation was first implemented for the 2003 to 2004 planning period. The initial allocation covered the PJM Mid-Atlantic Region and the AP Control Zone, while the 2004 to 2005 planning period's allocation covered the PJM Mid-Atlantic Region and the AP and ComEd Control Zones. Eligible participants in the AEP and DAY Control Zones received phase-in, direct allocation FTRs instead of ARRs upon their integration into PJM on October 1, 2004.

Market Structure

Supply and Demand

Since ARRs are financial instruments allocated annually to network and long-term, firm point-to-point transmission customers, the maximum ARR demand equals the subscribed amount of such services. On June 1, 2004, PJM provided 85,233 MW of network and 3,713 MW of firm point-to-point service. Therefore, maximum demand for ARRs would be 88,946 MW, the sum of network and long-term, firm point-to-point transmission service.

10 See generally "PJM Operating Agreement Accounting Manual" (May 01, 2004) <http://www.pjm.com/contributions/pjm-manuals/pdf/m28v27.pdf> (306 KB); and "PJM Financial Transmission Rights Manual" (December 07, 2004) <http://www.pjm.com/ contributions/pjm-manuals/pdf/m06v06.pdf> (207 KB).

ARR demand was 55,128 MW during the 2004 to 2005 planning period, up from 39,888 MW during the 2003 to 2004 planning period. ARR supply is limited by the capability of the transmission system to accommodate simultaneously the set of requested ARRs, and numerous combinations of ARRs are feasible. For the set of requested ARRs, available supply was 33,589 MW. This level of ARR availability was higher than the 28,933 MW available during the 2003 to 2004 planning period, but still left 21,539 MW of ARR demand unfulfilled. The Bedington-Black Oak interface and the Eastern Interface were the principal constraints limiting supply, followed by Byron-Cherry Valley 345 and Cedar Grove-Clifton 230.

ARR Allocation

Firm point-to-point and network service transmission customers[11] can request ARRs in quantities ranging from zero to a MW amount consistent with their transmission service.

PJM allocates annual ARRs to eligible customers in a two-stage process:

- **Stage 1.** Network transmission customers can obtain ARRs to their load from generation resources that historically have served load in the zone or load aggregate where the network transmission customer's load is located. ARRs were not available to firm point-to-point transmission customers in Stage 1.[12]

- **Stage 2.** Network transmission customers can obtain ARRs from any generator, hub, zone or interface to any part of their zonal load without an allocated ARR. Firm point-to-point customers can obtain ARRs consistent with their transmission service. There are four rounds, and 25 percent of remaining system capability is allocated in each round.

If the requested set of ARRs is not simultaneously feasible,[13] customers are allocated pro rata shares in direct proportion to their requested MW and in inverse proportion to their impact on binding constraints as follows:

Individual *pro rata* MW = (Constraint capability) * (Individual requested MW / Total requested MW) * (1 / per MW effect on line)[14]

External capacity resources must have a confirmed transmission service request in OASIS prior to the annual ARR allocation. If firm transmission service is used to deliver external capacity into PJM and the capacity resource is located in a control zone that joins PJM, the firm point-to-point transmission service may be converted to network service after control zone integration.

Market participants constructing transmission expansion projects may request an allocation of incremental ARRs consistent with the project's increased transmission capability. Such incremental ARRs are effective for the lesser of 30 years or the life of the facility or upgrade. Such participants can also permanently relinquish their incremental ARRs at any time during the life of the ARRs as long as overall system simultaneous feasibility can be maintained.

11 Network service transmission customers have reliability obligations to supply load at one or more points on the system and must obtain capacity plus reserves from qualified capacity resources. Firm point-to-point transmission customers have reserved transmission capability between two points that is usually used to deliver resources into or out of the RTO. Both types of customers are referred to as eligible customers in this section.
12 PJM has proposed that certain point-to-point customers should be allowed to participate in this stage, placing them on equal footing with network service transmission customers.
13 The simultaneous feasibility test (SFT) ensures that the approved set of ARRs can be supported by the transmission system and is meant to ensure ARR revenue adequacy.
14 See Appendix G, "Financial Transmission Rights and Auction Revenue Rights" for an illustration explaining this calculation in greater detail.

ARRs associated with shorter term, firm transmission service can be requested within the planning period through the PJM Open Access Same-Time Information System (OASIS).

ARR Reassignment for Retail Load Switching

Current PJM rules ensure that when load switches among LSEs during the planning period, a proportional share of associated ARRs within a given transmission or load aggregation zone is automatically reassigned to follow that load.[15] ARR reassignment occurs only if the LSE losing load has ARRs with net positive economic value. An LSE gaining load in the same zone is allocated a proportional share of positively valued ARRs within the zone based on the shifted load. This rule supports competition by ensuring that the hedge against congestion follows load, thereby removing a barrier to competition among LSEs and, by ensuring that only ARRs with a positive value are reassigned, preventing an LSE from assigning poor ARR choices to other LSEs.

Table 7-1 - ARRs automatically reassigned for network load changes by control zone (MW-day): June 1, 2003, to December 31, 2004

	AECO	BGE	DPL	JCPL	PECO	PENELEC	PEPCO	PPL	PSEG	RECO	Met-Ed	AEP	AP	ComEd	DAY	Total
Jun-03	3	25	7	0	25	34	26	11	0	0	40	0	0	0	0	171
Jul-03	2	30	3	15	43	0	2	2	9	0	0	0	127	0	0	233
Aug-03	1,592	5	0	2,801	35	0	281	0	3,411	324	1	0	0	0	0	8,450
Sep-03	17	2	24	70	25	0	162	6	242	0	0	0	0	0	0	548
Oct-03	16	2	125	63	16	0	4	6	144	0	0	0	0	0	0	376
Nov-03	24	19	13	99	11	0	2	12	180	0	7	0	0	0	0	367
Dec-03	15	4	10	33	475	4	2	14	123	0	1	0	0	0	0	681
Jan-04	10	1	53	31	230	0	257	13	120	0	20	0	0	0	0	733
Feb-04	2	7	1	17	18	4	136	121	52	0	0	0	28	0	0	385
Mar-04	31	12	1	9	14	0	139	1	41	0	14	0	0	0	0	261
Apr-04	3	10	2	43	14	1	5	8	20	0	51	0	0	0	0	158
May-04	7	206	44	82	330	1	3	46	148	0	6	0	0	5,175	0	6,047
Jun-04	54	275	104	517	172	20	580	58	295	0	65	0	6	1,033	0	3,177
Jul-04	52	2,644	2,255	45	14	0	3,063	1	77	0	3	0	0	308	0	8,460
Aug-04	2	64	10	31	13	0	138	1	105	0	0	0	0	269	0	633
Sep-04	2	225	17	14	14	0	122	10	78	3	0	0	0	68	0	551
Oct-04	0	233	15	0	9	0	407	1	38	0	0	16	13	66	3	800
Nov-04	3	60	6	0	14	0	24	7	29	0	0	3	0	34	0	180
Dec-04	4	317	10	0	376	0	882	3	76	5	0	16	1	89	0	1,778
Total	1,837	4,140	2,699	3,868	1,848	64	6,234	318	5,185	332	207	36	174	7,042	3	33,986

Table 7-1 and Table 7-2 summarize ARR MW and associated revenue automatically reassigned for network load in each control zone where changes occurred between June 2003 and December 2004. Nearly 34,000 MW of ARRs were automatically reassigned, generating more than $40 million of revenue for LSEs receiving ARRs during the 19-month period, or $264,300 per MW-day of revenue associated with. Most automatic reassignment of ARRs was associated

15 See PJM manual, "Financial Transmission Rights (m06), Revision 6" (December 07, 2004) <http://www.pjm.com/contributions/pjm-manuals/pdf/m06v06.pdf> (207 KB).

with state-mandated programs. As an example, in New Jersey, 8,127 MW of ARRs were automatically reassigned for its Basic Generation Service Program during August 2003.[16] Similarly, in Maryland, 7,962 MW of ARRs were automatically reassigned for its Standard Offer Service Program during July 2004.[17]

Table 7-2 - ARR revenue automatically reassigned for network load changes by control zone (Thousands of dollars per MW-day): June 1, 2003, to December 31, 2004

	AECO	BGE	DPL	JCPL	PECO	PENELEC	PEPCO	PPL	PSEG	RECO	Met-Ed	AEP	AP	ComEd	DAY	Total
Jun-03	$0.0	$0.4	$0.0	$0.0	$0.3	$1.2	$0.8	$0.0	$0.0	$0.0	$0.3	$0.0	$0.0	$0.0	$0.0	$3.0
Jul-03	$0.0	$0.2	$0.0	$0.0	$0.6	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.8
Aug-03	$12.5	$0.1	$0.0	$0.0	$0.5	$0.0	$5.0	$0.0	$45.2	$2.3	$0.0	$0.0	$0.0	$0.0	$0.0	$65.6
Sep-03	$0.2	$0.0	$0.5	$0.0	$0.4	$0.0	$2.7	$0.0	$3.3	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$7.0
Oct-03	$0.2	$0.0	$2.5	$0.0	$0.2	$0.0	$0.1	$0.0	$1.9	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$5.0
Nov-03	$0.3	$0.3	$0.3	$0.0	$0.2	$0.0	$0.0	$0.1	$2.4	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$3.6
Dec-03	$0.2	$0.1	$0.2	$0.0	$7.2	$0.1	$0.0	$0.1	$1.6	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$9.6
Jan-04	$0.1	$0.0	$0.9	$0.0	$2.7	$0.0	$4.7	$0.1	$1.6	$0.0	$0.3	$0.0	$0.0	$0.0	$0.0	$10.5
Feb-04	$0.0	$0.1	$0.0	$0.0	$0.3	$0.1	$2.5	$0.7	$0.7	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$4.4
Mar-04	$0.4	$0.2	$0.0	$0.0	$0.2	$0.0	$3.3	$0.0	$0.6	$0.0	$0.2	$0.0	$0.0	$0.0	$0.0	$4.9
Apr-04	$0.0	$0.2	$0.1	$0.1	$0.2	$0.0	$0.1	$0.1	$0.3	$0.0	$0.3	$0.0	$0.0	$0.0	$0.0	$1.3
May-04	$0.1	$3.8	$0.9	$0.0	$6.5	$0.0	$0.1	$0.5	$2.0	$0.0	$0.1	$0.0	$0.0	$0.0	$0.0	$13.9
Jun-04	$1.3	$2.3	$1.0	$7.3	$3.6	$0.5	$1.8	$0.2	$8.1	$0.0	$0.7	$0.0	$0.0	$0.0	$0.0	$26.8
Jul-04	$1.4	$25.7	$32.2	$0.8	$0.2	$0.0	$11.2	$0.0	$2.1	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$73.5
Aug-04	$0.0	$0.6	$0.1	$0.5	$0.2	$0.0	$0.5	$0.0	$2.7	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$4.6
Sep-04	$0.0	$2.2	$0.2	$0.2	$0.3	$0.0	$0.4	$0.1	$2.1	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$5.5
Oct-04	$0.0	$2.3	$0.2	$0.0	$0.1	$0.0	$1.3	$0.0	$1.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$4.9
Nov-04	$0.1	$0.6	$0.1	$0.0	$0.1	$0.0	$0.1	$0.1	$0.8	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$1.8
Dec-04	$0.1	$2.7	$0.1	$0.0	$8.3	$0.0	$4.0	$0.0	$2.2	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$17.4
Total	$16.9	$41.8	$39.3	$9.0	$32.2	$1.8	$38.6	$2.0	$78.5	$2.3	$2.0	$0.0	$0.0	$0.0	$0.0	$264.3

ARRs and Integrations

Phase-In FTRs

During any planning period when new control zones are being integrated, PJM directly allocates phase-in FTRs to eligible customers in those zones. These FTRs remain in effect until the start of the next planning period. These customers can elect to receive either annual ARRs or direct allocation FTRs at the start of the first two full planning periods of their PJM membership, but do not retain the direct allocation, FTR option after the two-year transition period. Table 7-3 summarizes the availability of ARRs and direct allocation FTRs.

16 N.J.S.A. 48:3-57 (2004).
17 Md. PUBLIC UTILITY COMPANIES Code Ann § 7-510 (2003)..

Table 7-3 - ARRs vs. directly allocated FTRs: Eligibility

Region/Zone	ARRs	Direct Allocation FTRs
Mid-Atlantic	Yes	No
AP	Yes	Through 2004/2005 planning period
ComEd	Yes	Through 2005/2006 planning period
AEP and DAY	Yes	Through 2006/2007 planning period

Eligible customers in the PJM Mid-Atlantic Region had the option to receive annual ARRs for the 2004 to 2005 planning year, while eligible customers in the AP and ComEd Control Zones had the option to choose either ARRs or direct allocation FTRs. On their October 1, 2004, integration date, eligible customers in the AEP and DAY Control Zones received phase-in, direct allocation FTRs effective through the end of the planning period.

Congestion Mitigation Credits

In a January 28, 2004, order, the FERC responded to protests concerning PJM Tariff provisions for allocating FTRs and ARRs to customers in newly integrated control zones. The FERC required that the PJM Tariff be amended to create a new allocation methodology so that customers in the new zones could raise and the FERC could resolve any concerns about the initial allocations before the integrations. The FERC order stated:

> We find that under the procedures set forth in PJM's tariff, there is some uncertainty as to the exact level of ARRs that a customer in an area joining PJM will receive. To provide customers in new areas with an opportunity to raise any specific concerns with their ARR allocation before it is implemented, we will require PJM to make a further compliance filing with the Commission. Specifically, we will require PJM to amend section 5.2.2(e) of its tariff to state that PJM, prior to the initial allocation of FTRs in new regions, will make a filing with the Commission under section 205 of the Federal Power Act with the proposed allocation of ARRs.[18]

In its subsequent May 28, 2004, order, the FERC added:

> Because the allocation process provides preference to network service customers, the Commission finds that PJM's annual allocation process for FTRs and ARRs under its existing Tariff and Operating Agreement appears to be unjust and unreasonable under section 206 of the Federal Power Act, and the Commission is instituting procedures to determine a just and reasonable allocation process for succeeding years.[19]

In responding, PJM acknowledged that the two-stage allocation process included a preference for native load customers served from resources that had historically served their load. PJM explained that the two-stage process resulted from a "compromise" in PJM's Market Implementation Committee designed to "give native load customers a priority in requesting ARRs from resources that historically served the load in the transmission zone," and to provide ample flexibility for market participants to pursue hedging strategies consistent with their changing needs in the second stage.[20]

18 106 FERC ¶ 61,049 (2004).
19 107 FERC ¶ 61,223 (2004) "Order Conditionally Accepting June Annual Allocation for Commonwealth Edison Zone," Docket No. ER04-742-000.
20 107 FERC ¶ 61,223 (2004) "Order Conditionally Accepting June Annual Allocation for Commonwealth Edison Zone," Docket No. ER04-742-000.

FERC ordered that if long-term, firm point-to-point transmission customers in the ComEd and AEP Control Zones were not allocated their full request for ARRs or FTRs that they be provided with congestion mitigation outside of the FTR and ARR markets. PJM implemented this order by offering mitigation credits equal to FTR payments to those eligible customers that had not received their requested allocation.

Total mitigation credit costs are assessed as uplift charges. All firm network and point-to-point transmission service customers with ARRs, FTRs or congestion mitigation credits within the ComEd and AEP Control Zones pay these zonal uplift charges.

For the portions of the 2004 to 2005 planning period remaining after their Phase 2 and Phase 3 integration, Table 7-4 summarizes FTRs requested by and awarded to customers in the relevant control zones, including mitigation FTRs.

Table 7-4 - ComEd and AEP Control Zones FTR mitigation credits: Planning period 2004 to 2005

Zone	Period	FTR Requests (MW)	FTR Awarded (MW)	Mitigation (MW)	Mitigation Percent
ComEd	May-04	888	440	448	50%
ComEd	Jun-Sep-04	1,431	864	567	40%
ComEd	Oct-04-May-05	476	308	168	35%
AEP	Oct-04-May-05	1,005	51	954	95%
Total		**3,800**	**1,662**	**2,138**	**56%**

ARR Performance

Volume

Of 55,128 MW in ARR requests for the 2004 to 2005 planning period, 33,589 MW (61 percent) were allocated. Eligible market participants subsequently converted 13,061 MW of these allocated ARRs into annual FTRs (39 percent), leaving 20,528 MW of ARRs outstanding. During the 2003 to 2004 planning period, supply had been 28,933 MW for the set of ARRs requested, leaving 10,955 MW of demand unfulfilled. Eligible market participants subsequently converted 13,986 MW of ARRs into annual FTRs, leaving 14,947 MW of ARRs outstanding.

Revenue

An ARR credit received equals the product of the ARR MW and the sink-minus-source price difference from the Annual FTR Auction. The degree to which ARR credits provide a complete congestion hedge is determined by the prices that result from the Annual FTR Auction. The prices that result from the Annual FTR Auction are the result of bids based on participants' expectations about the level of congestion in the Day-Ahead Energy Market. The resultant ARR credit could be greater than, less than or equal to the actual congestion that occurs on the selected path in the Day-Ahead Energy Market and thus could provide a hedge with varying levels of completeness.

Eligible customers can also opt to retain the underlying FTRs linked to their ARRs through a process termed self-scheduling. The underlying FTR[21] has a hedge value based on actual day-ahead congestion on the selected path instead of on what bidders are willing to pay in the Annual FTR Auction based on their expectations of day-ahead congestion on the selected path.

ARR holders will receive $345 million in credits from the Annual FTR Auction during the 2004 to 2005 planning period, with an average hourly ARR credit of $1.17 per MWh. During the comparable 2003 to 2004 planning period, ARR holders received $311 million in ARR credits, with an average hourly ARR credit of $1.23 per MWh.

Revenue Adequacy

An ARR target allocation defines revenue that an ARR holder should receive and is equal to the product of ARR MW and the ARR sink-to-source price differences established during the Annual FTR Auction. FTR auction revenue is the net revenue it generates and equals the sum of the products of FTR MW and FTR sink-to-source price differences. All ARRs receive ARR credits equal to their target allocations and would be fully funded if total annual FTR auction revenue were greater than or equal to the sum of all ARR target allocations. If total annual FTR auction revenue were less than that, however, the available revenue would be proportionally allocated among all ARR holders and revenue from the Monthly FTR Auctions would be used to make up any ARR target allocation deficiencies.

Table 7-5 lists ARR target allocations and revenue sources earmarked to ARRs. Net annual FTR auction revenue has been sufficient to cover ARR target allocations, providing ARR revenue adequacy during both the 2003 to 2004 and the 2004 to 2005 planning periods. The 2004 to 2005 planning period's Annual and Monthly FTR Auctions generated a surplus of $34 million in auction revenue through year-end, above the amount needed to pay ARRs 100 percent of their target allocations. These surplus funds are used to fund FTR target allocation deficiencies in the Day-Ahead Energy Market.

Table 7-5 - ARR revenue adequacy [Dollars (million)]: By planning period

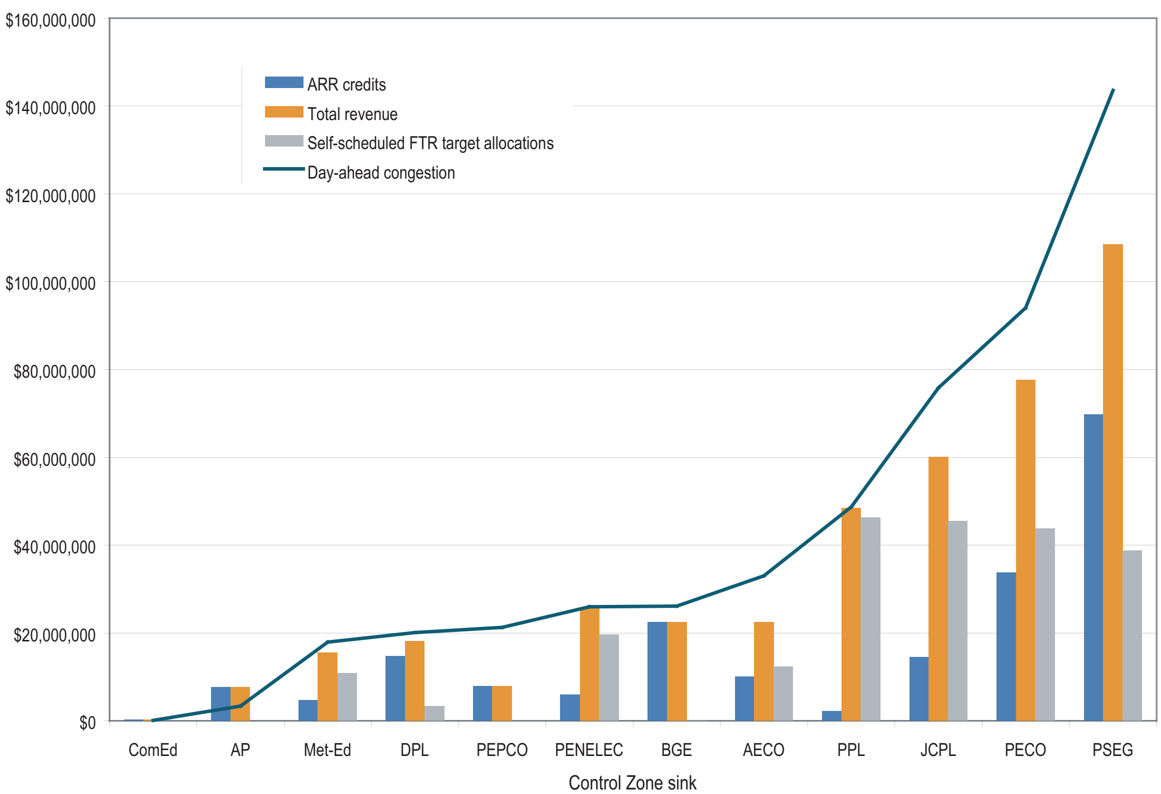
Item	2003/2004	2004/2005
Total FTR Auction Revenue	$358	$379
Annual FTR Auction Net Revenue	$333	$370
Monthly FTR Auction Net Revenue*	$26	$10
ARR Target Allocations	$311	$345
ARR Credits	$311	$345
Surplus Auction Revenue	$48	$34
ARR Payout Ratio	**100%**	**100%**
* Through December 31, 2004		

21 FTR value is determined each hour in the Day-Ahead Energy Market and equals the product of the FTR sink-minus-source Day-Ahead Energy Market price difference and the FTR MW.

ARR Revenue versus Congestion

One measure of the effectiveness of ARRs as a hedge against congestion is a comparison between the revenue received by holders of the allocated ARRs and the congestion across the corresponding paths. This comparison is presented in Figure 7-1. Revenue received includes ARR revenue (the blue bars), the revenue from ARRs self-scheduled as FTRs (the gray bars) and the sum of these revenues (the orange bars). The line shows the amount of congestion incurred in the Day-Ahead Energy Market across the corresponding ARR and self-scheduled FTR paths. Data shown are for the first seven months of the 2004 to 2005 planning period and summed by ARR control zone sink. For example, the figure shows that between June 1, 2004, and December 31, 2004, ARRs allocated to JCPL Control Zone load received a total of $61 million in revenue, $15 million in ARR and $46 million in self-scheduled FTR credits, against $76 million in day-ahead congestion.

Figure 7-1 - ARR and self-scheduled FTR congestion hedging by control zone: Planning period 2004 to 2005 through December 31, 2004

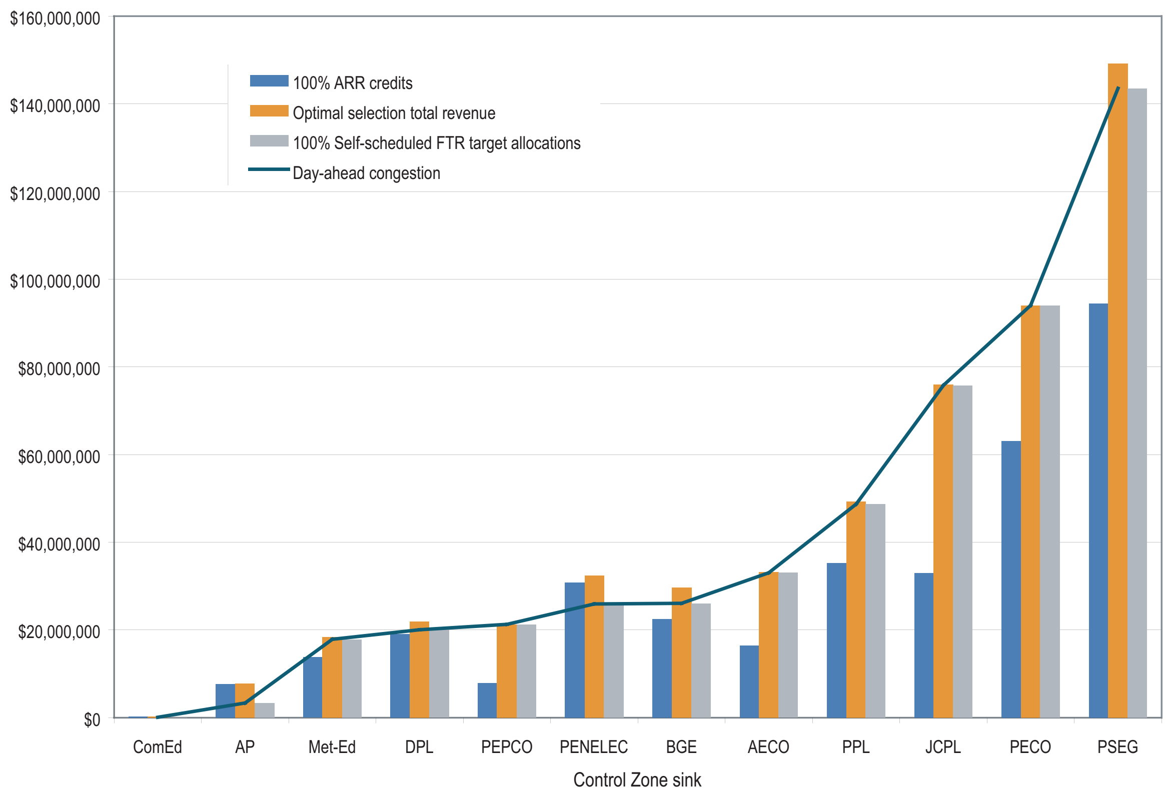


During the first seven months of the 2004 to 2005 planning period, congestion costs across the 33,589 MW of allocated ARRs were $510 million. These costs are calculated as the product of the ARR MW and the hourly day-ahead ARR sink and source LMP differences. As has been indicated, 13,061 MW of ARRs were converted into FTRs through the self-scheduling option, with 20,582 MW remaining as ARRs. ARRs that were not self-scheduled provided $194 million of ARR credits, representing a hedge of 38 percent of the $510 million in congestion costs incurred, while the self-scheduled FTRs provided $221 million of revenue, hedging an additional 43 percent of congestion costs. Total congestion hedged by both was $415 million, or 81 percent, down from 89 percent during the 2003 to 2004 planning period.

Figure 7-1 shows that load in four of 12 transmission zones, ComEd, AP, PENELEC and PPL, was fully hedged by the selected combination of ARRs and self-scheduled FTRs. The ComEd Control Zone actually experienced negative congestion and would have been fully hedged without ARRs or FTRs. ARRs into the PEPCO, PSEG, PECO, JCPL and AECO Control Zones accounted for $91 million of unhedged congestion, out of a total unhedged congestion of $95 million. Two of these, JCPL and PSEG, were the zones most affected by the Branchburg transformer derating. Nonetheless, ARRs into the PSEG Control Zone provided a hedge of 76 percent, up from 60 percent during the 2003 to 2004 planning period.

To evaluate the consequences of actual ARR and self-scheduled FTR choices, three possible hedging strategies were compared. Figure 7-2 illustrates the results for the first seven months of the 2004 to 2005 planning period.

Figure 7-2 - Optimal ARR and self-scheduled FTR portfolio congestion hedging by control zone: Planning period 2004 to 2005 through December 31, 2004



The first hedging strategy would take all allocated ARRs without any self-scheduling of FTRs. The second hedging strategy would convert all allocated ARRs into FTRs, an approach that would hedge all congestion less any FTR funding deficiencies. If ARR holders had held all their ARRs, shown in Figure 7-2 as the blue bars, they would have received $345 million of ARR credits against $510 million of congestion, a 68 percent hedge. If ARR holders had converted all their ARRs to FTRs, shown as the gray bars, they would have received $510 million of ARR credits against $510 million of congestion, a 100 percent hedge. Figure 7-2 shows that the selected ARRs would have been more valuable converted to FTRs for all but three control zones (ComEd, AP, PENELEC), while in these zones ARRs would have provided a better hedge.

The third hedging strategy (a hypothetical strategy) would retain those ARRs more valuable as ARRs and convert those more valuable as FTRs into FTRs, thereby achieving an optimal combination of ARRs and self-scheduled FTRs. The analysis represents the maximum achievable hedge based on an after-the-fact evaluation.

For the first seven months of the 2004 to 2005 planning period (i.e., June to December 2004), this hypothetical combination of ARRs and self-scheduled FTRs, shown as the orange bars, would have netted $534 million, covering 105 percent of the $510 million congestion across the ARRs and leaving a surplus of $23 million. For the 2003 to 2004 planning period, the optimally selected combination of ARRs and self-scheduled FTRs would have netted $234 million, covering 117 percent of the $199 million in congestion across the ARRs and leaving a surplus of $35 million.

The analysis demonstrates that while the hypothetical mix of ARRs and self-scheduled FTRs always returns the most revenue, customers in most control zones could have obtained nearly the maximum possible revenue by selecting the all self-scheduled FTR strategy, although for some control zones ARRs are more valuable than FTRs.

Financial Transmission Rights

Although FTRs have been available to eligible participants since the 1998 introduction of LMPs, the Annual FTR Auction was first implemented for the 2003 to 2004 planning period. For the 2004 to 2005 planning period, the auction covered the PJM Mid-Atlantic Region and the AP and ComEd Control Zones. Eligible participants in the AEP and DAY Control Zones received phase-in, direct allocation FTRs upon their integration into PJM on October 1, 2004.

FTRs are financial instruments that entitle their holders to receive revenue based on prices in the Day-Ahead Energy Market. The FTR target allocation (i.e., what the FTR holder should receive) is equal to the product of the FTR MW and the sink-minus-source price differences that occur in the hourly Day-Ahead Energy Market. The value of an FTR can be positive or negative depending on these sink-minus-source price differences, with negative differences resulting in a liability for the holder. Depending on the congestion charges collected, FTR holders receive congestion credits between zero and their target allocations. When FTR holders receive their target allocation the associated FTRs are termed fully funded.

There are two different FTR hedge types. An FTR obligation provides a credit, positive or negative, equal to the product of the FTR MW and the sink-to-source price difference that occurs in the hourly Day-Ahead Energy Market. An FTR option provides only positive credits. As FTR options require that feasibility exist in the SFT both with and without them, FTR options are priced higher than FTR obligations.

There are three standard FTR obligation and option products: 24-hour, on-peak and off-peak FTRs. The 24-hour FTRs are effective 24 hours a day, seven days a week, while on-peak FTRs are effective only during on-peak periods defined as the hours ending 0800 through 2300, Eastern Prevailing Time (EPT) Monday through Friday, excluding NERC holidays. Off-peak FTRs are in effect during all other periods.

Market Structure

Before the Annual FTR Auction, only network service and long-term, firm, point-to-point transmission service customers were able to obtain annual FTRs. Now all qualified market participants can participate in the Annual FTR Auction. In addition, auction market participants are free to request long-term FTRs between any pricing nodes on the system, not just from designated capacity resources to network load or solely along a long-term, firm, point-to-point transmission service path. As a result, total demand for FTRs has expanded.

Supply and Demand

The principal mechanism for obtaining FTRs is the Annual FTR Auction, including the option to obtain underlying FTRs in place of allocated ARRs. Total FTR supply is limited by the capability of the transmission system to simultaneously accommodate the set of requested FTRs, and numerous combinations of FTRs are feasible. FTRs can also be obtained in the Monthly FTR Auctions, as direct allocation FTRs (available to customers in recently integrated control zones) and via bilateral trades of existing FTRs.

Table 7-6 shows that 177,434 MW of annual FTR bids and allocation requests were cleared and allocated in the Annual FTR Auction and allocations for the 2004 to 2005 planning period: 93,344 MW in the Mid-Atlantic Region, 46,722 MW in the ComEd Control Zone, 28,495 MW in the AEP and DAY Control Zones combined and 8,874 MW in the AP Control Zone. A total of 974,934 MW were bid, offered, or requested to be allocated.

Table 7-8 shows just the Annual FTR Auction data. (Table 7-6 shows both Annual Auction data and annual allocation requests.) As shown, 119,629 MW of annual FTRs were purchased in Annual FTR Auctions for the 2004 to 2005 planning period: 93,344 MW in the Mid-Atlantic Region and 26,285 in the ComEd Control Zone. A total of 861,323 MW were bid and a total of 50,780 MW were offered. By comparison, for the 2003 to 2004 planning period, a total of 80,928 MW of annual FTRs were transacted in the Mid-Atlantic Region.

Table 7-6 - Annual FTR market volume: Planning period 2004 to 2005

Region/Zone	Bid and Requested Count	Bid and Requested Volume (MW)	Cleared Volume (MW)
Buy Activity			
AEP/DAY	1,283	29,582	28,495
AP	102	8,874	8,874
ComEd	6,154	257,842	46,722
Mid-Atlantic	58,200	627,856	93,344
Total	65,739	924,154	177,434
Sale Activity			
AEP/DAY	N/A	N/A	N/A
AP	N/A	N/A	N/A
ComEd	376	6,283	1,344
Mid-Atlantic	8,943	44,497	5,170
Total	9,319	50,780	6,514

During any planning period when new control zones are being integrated, PJM directly allocates phase-in FTRs to eligible customers in those control zones. These FTRs remain in effect until the start of the next planning period. These customers can elect to receive either annual ARRs or direct allocation FTRs at the start of the first two full planning periods of their PJM membership, but no longer have the direct allocation FTR option after the two-year transition period. Table 7-3 summarizes the availability of ARRs and direct allocation FTRs within the different regions and control zones.

Each March, PJM conducts an Annual FTR Auction during which all eligible market participants can bid on the next planning period's FTRs consistent with total transmission system capability. The auction takes place over four rounds as follows:

- **Round 1.** Market participants make offers for FTRs between any source and sink. These offers can be 24-hour, on-peak or off-peak FTR obligations or FTR options. Locational prices are determined by maximizing the offer-based value of FTRs cleared.[22] Auction participation is not restricted to any class of customers, and any market participant can make offers for available FTRs. ARR holders wishing to self-schedule their previously allocated ARRs as FTRs must initiate the self-scheduling process in this round. One-quarter of each self-scheduled FTR clears as a 24-hour FTR in this and each of the subsequent three rounds. Self-scheduled FTRs must have the same source and sink as the ARR. No bid price is associated with self-scheduled FTRs. Such self-scheduled FTRs clear as price-taking FTR obligations.

- **Rounds 2 to 4.** Market participants make offers for FTRs. Locational prices are determined by maximizing the offer-based value of FTRs cleared. FTRs purchased in earlier rounds can be offered for sale in later rounds.

22 Both Annual and Monthly FTR Auctions determine nodal prices as a function of market participants' FTR bids and binding transmission constraints. An optimization algorithm selects the set of feasible FTR bids that produces the maximum amount of net revenue, thus maximizing the value of transmission assets. A feasible set of FTR bids is a set that does not impose a flow on any transmission facility in excess of its rating.

By self-scheduling ARRs as price-taking buy-bids in the Annual FTR Auction, customers with ARRs receive FTRs along their ARR path. ARR holders are guaranteed that they will receive their requested FTRs and such self-scheduled bids will be ineligible to set auction price. ARRs may be self scheduled only as 24-hour FTRs. ARR holders that self-schedule ARRs as FTRs still hold the associated ARR. Self-scheduling transactions net out such that the ARR holder buys the FTR in the auction, receives the corresponding revenue based on holding the corresponding ARR and is left with ownership of the FTR as a hedge.

PJM also conducts Monthly FTR Auctions during which market participants can bid on monthly FTRs consistent with residual transmission system capability for the following month. These are single-round auctions in which market participants make offers for FTRs and FTR holders can offer monthly segments of their FTRs.

FTRs can also be obtained in two other ways. Eligible participants can trade them through the PJM-administered, bilateral market or market participants can trade them among themselves without PJM involvement.

As Table 7-6 shows, Annual FTR demand in PJM was 924,154 MW during the 2004 to 2005 planning period. At the more local regional or zonal levels, the 2004 to 2005 planning period demand was 627,856 MW in the Mid-Atlantic Region, 257,842 MW in the ComEd Control Zone, 29,582 MW in the combined AEP and DAY Control Zones and 8,874 MW in the AP Control Zone.

One result of operating an FTR Auction with unlimited participation is that participants may put in unlimited demands based on a variety of financial strategies. This is in contrast to the situation prior to the FTR Auction when demand for FTRs was limited to the loads of firm transmission customers. FTR supply is limited by the capability of the transmission system to accommodate simultaneously the set of requested FTRs, and numerous combinations of FTRs are feasible. For the requested FTRs for the 2004 to 2005 planning period, supply met demand at 177,434 MW, leaving 746,720 MW of demand unfulfilled. Supply was 93,344 MW in the Mid-Atlantic Region, leaving 534,513 MW of demand unfulfilled. Demand exceeded supply by 211,120 MW in the ComEd Control Zone and by 1,087 MW in the combined AEP and DAY Control Zones. Supply equaled demand in the AP Control Zone. Table 7-7 lists the principal constraints that precluded awarding all FTRs requested.

Table 7-7 - Annual FTR Auction and allocation principal binding transmission constraints: Planning period 2004 to 2005

Region/Zone	Principal Constraints
AEP/DAY	Kanawha River-Matt Funk 345 kV
AP	None
Mid-Atlantic	Branchburg transformer (derated), Bedington-Black Oak Interface, and Wylie Ridge transformer
ComEd	Stations 15518 138 kV and 11414 138 kV

Annual FTR holders offered an average of 2,960 MW of FTRs per month in the Monthly FTR Auctions, while demand averaged 18,246 MW per month.

In addition to the Annual and Monthly FTR Auctions, FTRs can be traded between market participants through bilateral transactions. Bilateral activity was consistent with previous years, with 1,433 MW of FTRs traded in calendar year 2004, as compared to 1,352 MW in calendar year 2003 and 7,173 MW in calendar year 2002.

Market Performance

Volume

For the entire PJM footprint, for the 2004 to 2005 planning period, 177,434 MW of annual FTRs were purchased and allocated out of 924,154 MW bid and requested. (See Table 7-6.) For the Mid-Atlantic Region, 93,344 MW were purchased and allocated out of 627,856 MW bid and requested. For the ComEd Control Zone, 46,722 MW were purchased and allocated out of 257,842 MW bid and requested. For the AEP and DAY Control Zones combined, 28,495 MW were purchased and allocated out of 29,582 MW bid and requested. Finally, for the AP Control Zone, 8,874 MW were purchased and allocated out of 8,874 MW bid and requested. (See Table 7-6.) Eligible market participants converted 13,061 MW of Mid-Atlantic Region ARRs into annual FTRs. In comparison, during the 2003 to 2004 planning period, 86,767 MW were purchased and allocated, with 80,928 MW purchased and allocated in the Mid-Atlantic Region and 5,839 MW purchased and allocated in the AP Control Zone. For the 2003 to 2004 planning period, eligible market participants converted 13,986 MW of Mid-Atlantic Region ARRs into annual FTRs.

In the ComEd Control Area and AP Control Zone where participants had a choice between ARRs and direct allocation FTRs, they opted for significantly more direct allocation FTRs than ARRs, with a total of 33,249 MW in direct allocation FTRs compared to 363 MW in ARRs.

Revenue

Table 7-8 shows Annual FTR Auction summary data. During the 2004 to 2005 planning period, the Annual FTR Auctions for the ComEd Control Zone and the Mid-Atlantic Region netted $369.6 million in revenue, with buyers paying $380.0 million and sellers receiving $10.4 million. By contrast, for the 2003 to 2004 planning period, the Mid-Atlantic Region Annual FTR Auction had netted $332.8 million in revenue, with buyers paying $345.8 million and sellers receiving $13.0 million. As Table 7-5 shows, ARR holders received $345 million in FTR auction revenue.

Table 7-8 - Annual FTR Auction market volume, price and revenue: Planning period 2004 to 2005

Region/Zone	Bids	Bid MW	Cleared MW	Average Bid Price ($/MWh)	Average Cleared Price ($/MWh)	Revenue ($)
Net Activity						
AEP/DAY	N/A	N/A	N/A	N/A	N/A	N/A
AP	N/A	N/A	N/A	N/A	N/A	N/A
ComEd	N/A	N/A	N/A	N/A	N/A	$7,964,048
Mid-Atlantic	N/A	N/A	N/A	N/A	N/A	$361,634,985
Total	N/A	N/A	N/A	N/A	N/A	$369,599,033
Buy Bids						
AEP/DAY	N/A	N/A	N/A	N/A	N/A	N/A
AP	N/A	N/A	N/A	N/A	N/A	N/A
ComEd	5,675	233,467	26,285	$0.02	$0.06	$10,888,800
Mid-Atlantic	58,200	627,856	93,344	$0.14	$0.60	$369,061,658
Total	59,903	861,323	119,629	$0.11	$0.48	$379,950,458
Sale Offers						
AEP/DAY	N/A	N/A	N/A	N/A	N/A	N/A
AP	N/A	N/A	N/A	N/A	N/A	N/A
ComEd	376	6,283	1,344	$1.78	$0.33	($2,924,752)
Mid-Atlantic	8,943	44,497	5,170	$0.05	$0.22	($7,426,673)
Total	9,319	50,780	6,514	$0.26	$0.24	($10,351,425)

23 As some FTRs are bid with negative prices, some winning FTR bidders are actually paid to take FTRs. These payments reduce the amount of net auction revenue. Therefore, the sum of the highest revenue producing FTRs can exceed net auction revenue.

Figure 7-3 summarizes the total revenue associated with all FTRs regardless of source to the 10 FTR sinks (destinations) that produced the most Annual FTR Auction revenue. FTRs to these sinks accounted for $390.4 million or about 103 percent of all revenue paid[23] and constituted 39 percent of all FTRs bought in Annual FTR Auctions for the 2004 to 2005 planning period. These sinks include the control zones and hubs of the Mid-Atlantic Region.

Figure 7-3 - Highest revenue producing FTR sinks purchased in the Annual FTR Auction: Planning period 2004 to 2005

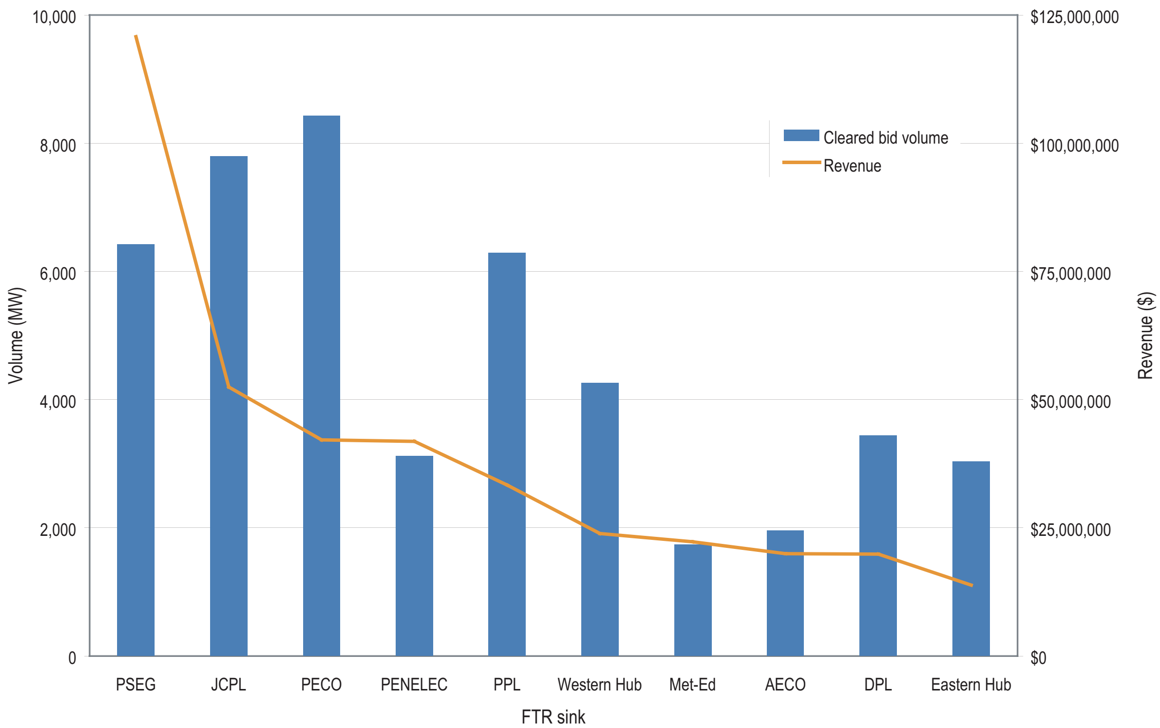


Figure 7-4 summarizes the total revenue associated with all FTRs regardless of sink from the 10 FTR sources (origins) that produced the most Annual FTR Auction revenue for the 2004 to 2005 planning period. FTRs from these sources accounted for $187 million or about 49 percent of all revenue paid and included 17 percent of all FTRs bought in Annual FTR Auctions. These sources are generally located at large generating facilities throughout the Mid-Atlantic Region.

Figure 7-4 - Highest revenue producing FTR sources purchased in the Annual FTR Auction: Planning period 2004 to 2005

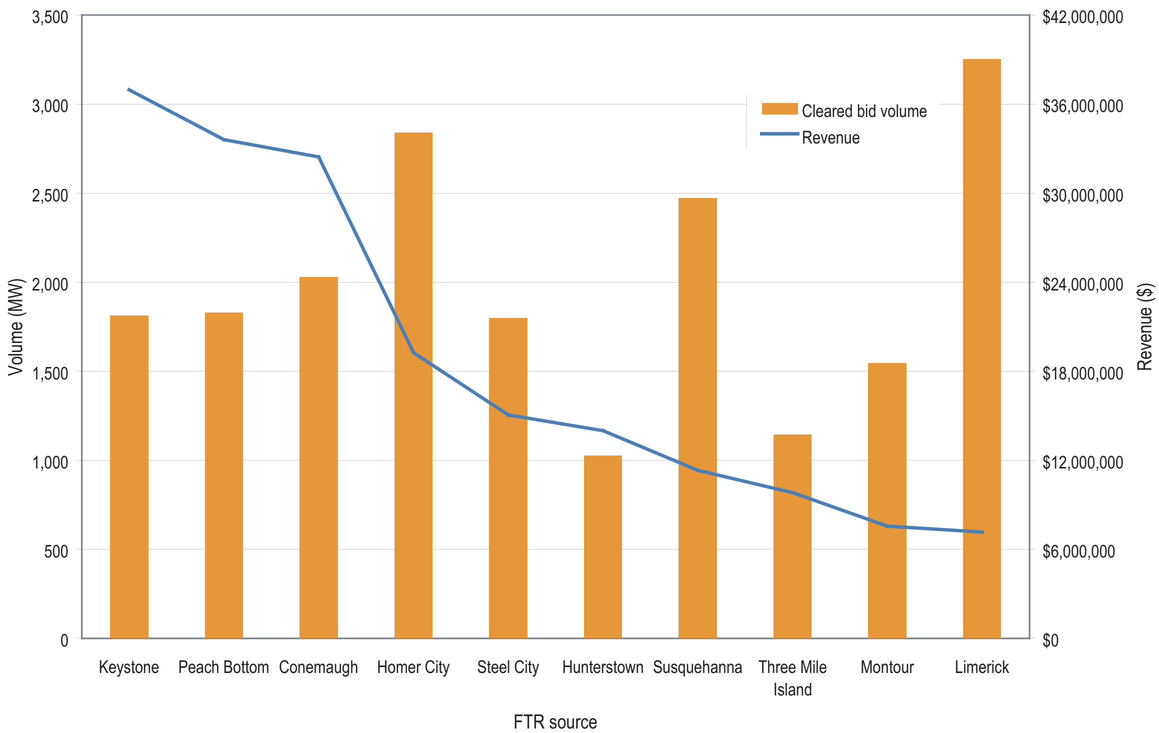


Figure 7-5 summarizes the total revenue associated with all FTRs regardless of source to the 10 FTR sinks that produced the most monthly FTR auction revenue during the period June 2003 through December 2004. FTRs to these sinks accounted for $49 million, or about 13 percent of all revenue paid and included 12 percent of all FTRs bought in Monthly FTR Auctions. The sinks tended to be located in the Mid-Atlantic Region or the AP Control Zone.

Figure 7-5 - Highest revenue producing FTR sinks purchased in the Monthly FTR Auctions: June 2003 to December 2004

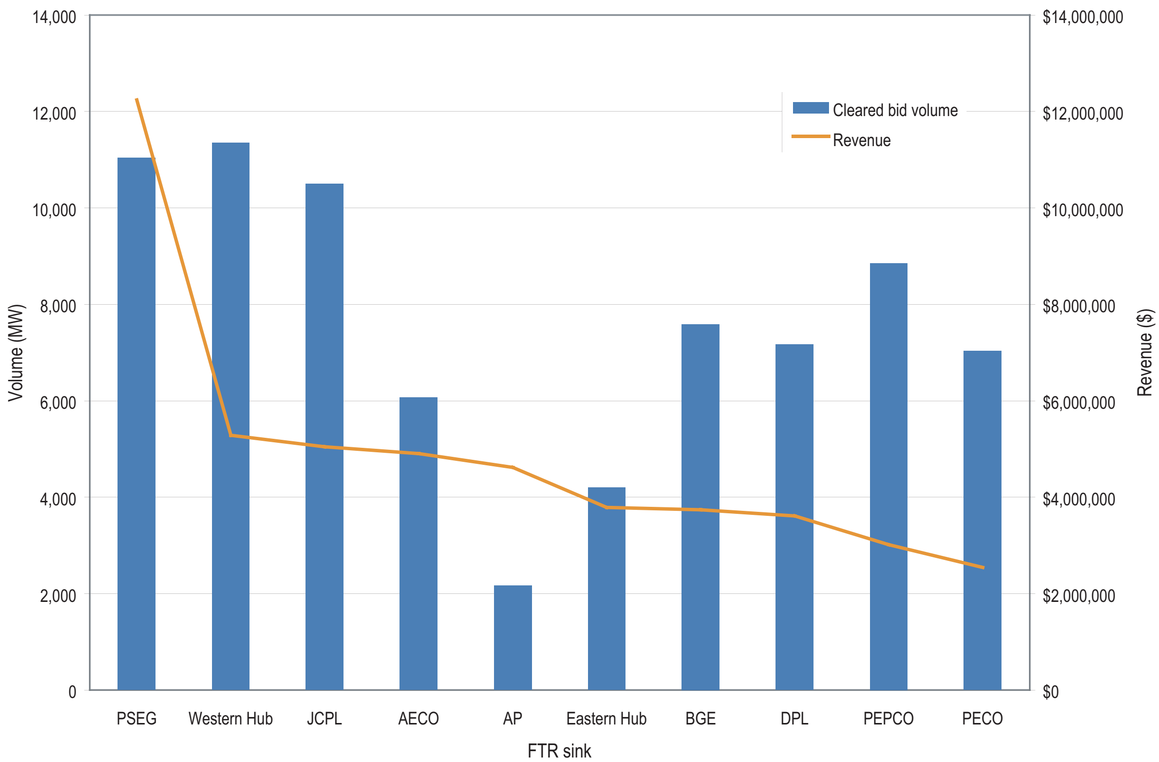


Figure 7-6 summarizes the total revenue associated with all FTRs regardless of sink from the 10 FTR sources that produced the most monthly FTR auction revenue during the period June 2003 through December 2004. FTRs from these sources accounted for $46 million, or about 12 percent of all revenue paid and included 12 percent of all FTRs bought in Monthly FTR Auctions.

Figure 7-6 - Highest revenue producing FTR sources purchased in Monthly FTR Auctions: June 2003 to December 2004

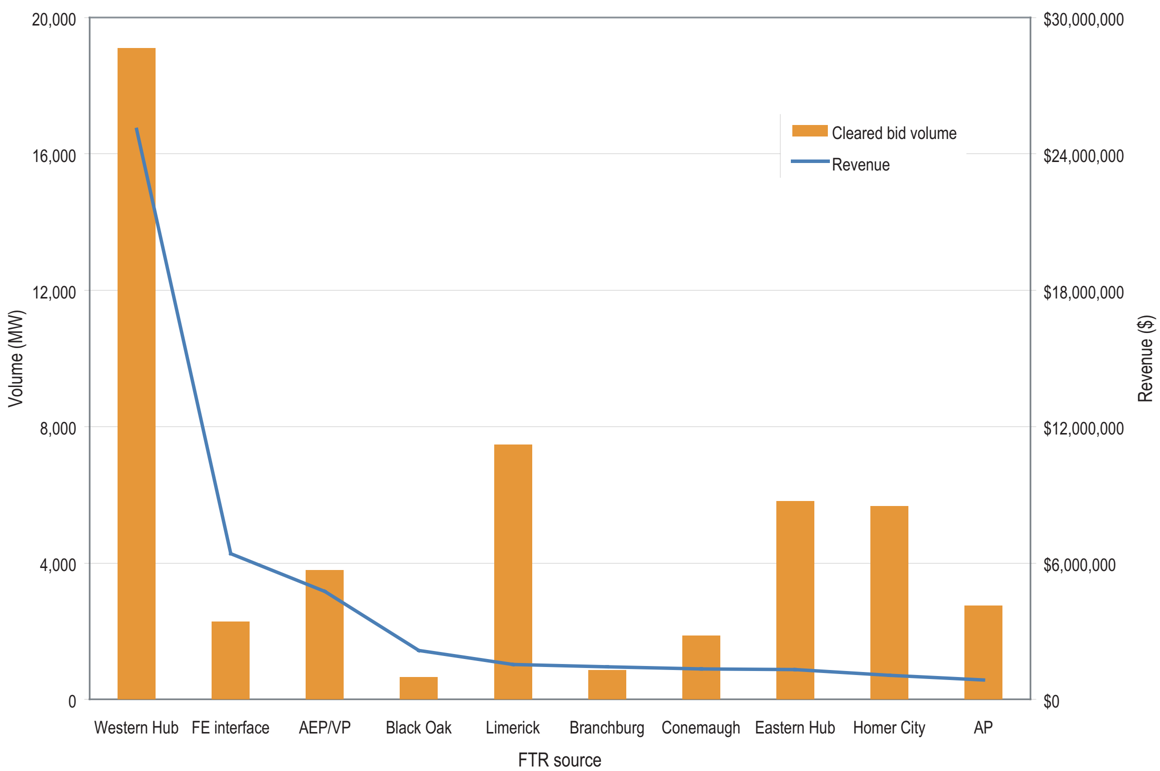
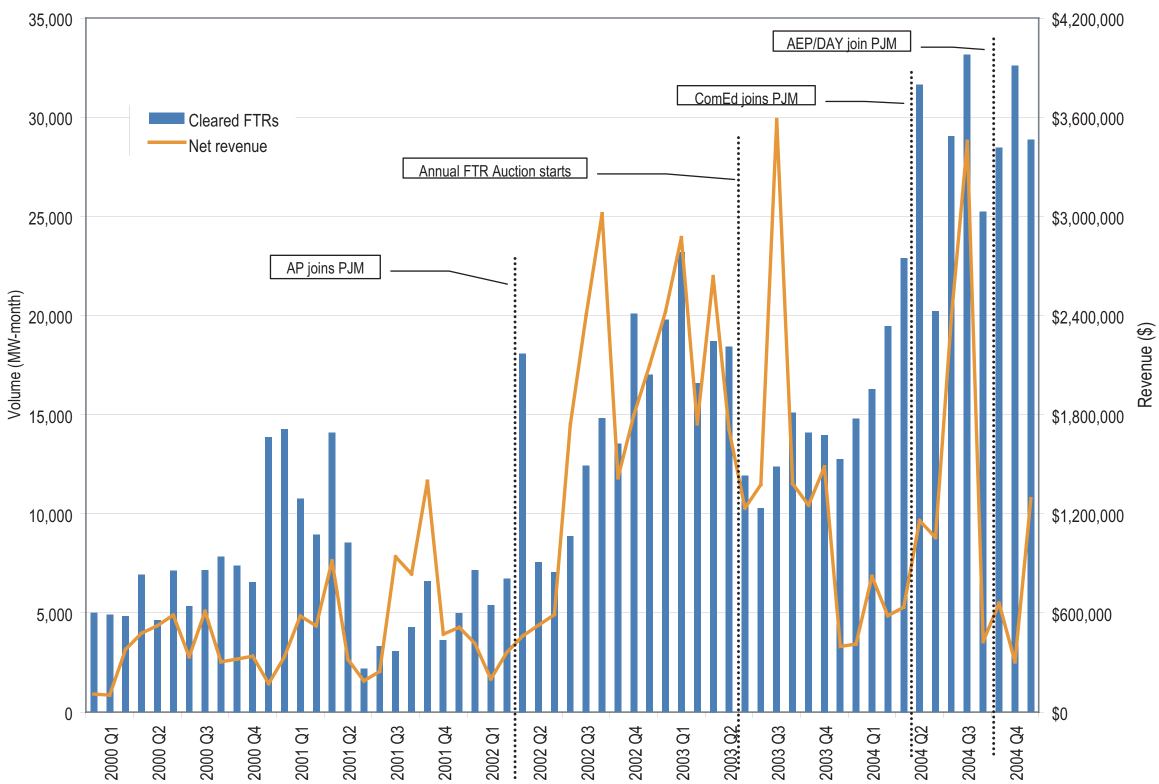


Figure 7-7 depicts the total cleared bid and offer volume together with the total auction revenue generated in Monthly FTR Auctions during calendar years 2000 through 2004. Average monthly auction revenue grew from $350,000 per month in 2000 to $600,000, $1.2 million and $1.8 million per month in 2001, 2002 and 2003, respectively, before declining to $1.1 million per month in 2004. Total volume increased from the historic average of 6,900 MW-months during calendar year 2000 and 2001 to 11,500 and 15,500 MW-months in 2002 and 2003, respectively. Total volume rose to 25,200 MW-months in 2004. As Figure 7-7 shows, monthly auction volume and revenue both declined on average immediately after PJM implemented the first Annual FTR Auction in June 2003. Volume grew steadily during the post-auction period.

Figure 7-7 - Monthly FTR Auction cleared volume and net revenue: Calendar years 2000 to 2004



Price

Table 7-8 shows the number of bids, volume, prices, and revenue for buy and sell bids, as well as totals for the sum of bids and volume and net revenue for Annual FTR Auction activity. Table 7-9 splits the buy activity into its bid and self-scheduled FTR components.

As Table 7-8 shows, during the 2004 to 2005 planning period, FTRs bought in the Mid-Atlantic Region were priced 10 times higher than those in the ComEd Control Zone, with the average cleared price for the former at $0.60 per MWh and for the latter $0.06. By contrast, FTRs sold in the ComEd Control Zone were priced 1.5 times higher than those in Mid-Atlantic Region, with an average cleared prices of approximately $0.33 per MWh for the former and $0.22 for the latter. The 2004 to 2005 planning period's Mid-Atlantic Region price increased $0.49 per MWh from the 2003 to 2004 planning period.

Table 7-9 shows buy activity in terms of its bid and self-scheduled components. Self-scheduled FTRs were priced $1.41 per MWh higher than bid FTRs, up $0.44 per MWh from a year ago, while Mid-Atlantic Region buy-bids were up $0.09 per MWh from the 2003 to 2004 planning period.

The average price paid in the Monthly FTR Auctions during the first seven months of the 2004 to 2005 planning period was $0.10 per MWh, down from $0.21 MWh over the 2003 to 2004 planning period.

Table 7-9 - Annual FTR Auction buy-bid volume, price and revenue: Planning period 2004 to 2005

Region/Zone Buy Activity	Bids	Bid MW	Cleared MW	Bid Price	Cleared Price	Revenue
Bid						
AEP/DAY	N/A	N/A	N/A	N/A	N/A	N/A
AP	N/A	N/A	N/A	N/A	N/A	N/A
ComEd	5,675	233,467	26,285	$0.02	$0.06	$10,888,800
Mid-Atlantic	54,228	614,795	80,283	$0.14	$0.41	$218,711,402
Total	59,903	848,263	106,568	$0.11	$0.33	$229,600,202
Self-scheduled FTRs						
AEP/DAY	N/A	N/A	N/A	N/A	N/A	N/A
AP	N/A	N/A	N/A	N/A	N/A	N/A
ComEd	N/A	N/A	N/A	N/A	N/A	N/A
Mid-Atlantic	3,972	13,061	13,061	N/A	$1.74	$150,350,257
Total	3,972	13,061	13,061	N/A	$1.74	$150,350,257

-

The 2004 to 2005 planning period's price duration curves depicted in Figure 7-8 show that 81 percent of Mid-Atlantic Region annual FTRs were purchased for less than $1 per MWh and 90 percent for less than $2 per MWh. Nearly all, 99.9 percent, of ComEd Control Zone annual FTRs were purchased for less than $1 per MWh. Negative prices shown on duration curves occur because some FTRs are bid with negative prices, and some winning FTR bidders are paid to take FTRs.

Overall, average prices paid for the 2004 to 2005 planning period's 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 for on-peak and $0.15 per MWh for off-peak FTRs. The overall average prices paid for the 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 dropped from $0.51 per MWh in 2002, to $0.27 MWh in 2003, to $0.10 MWh in 2004.

Figure 7-8 - Annual FTR Auction buy-bid price duration curve: Planning period 2004 to 2005

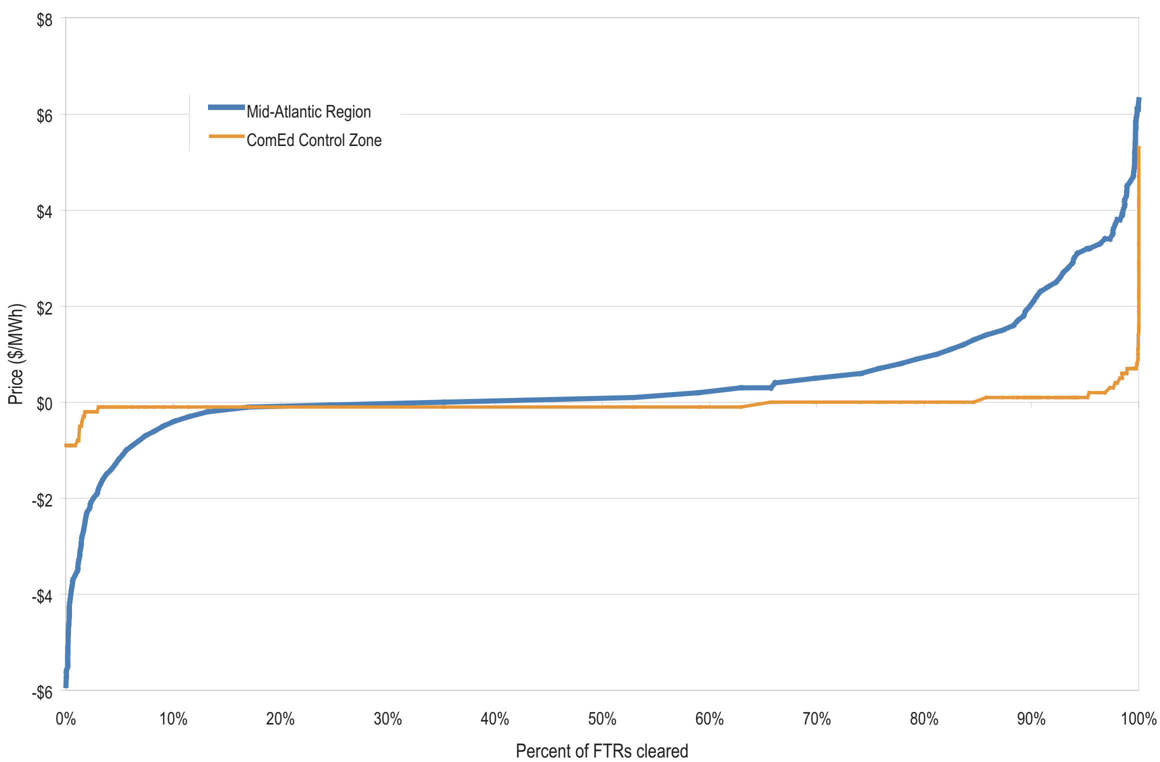
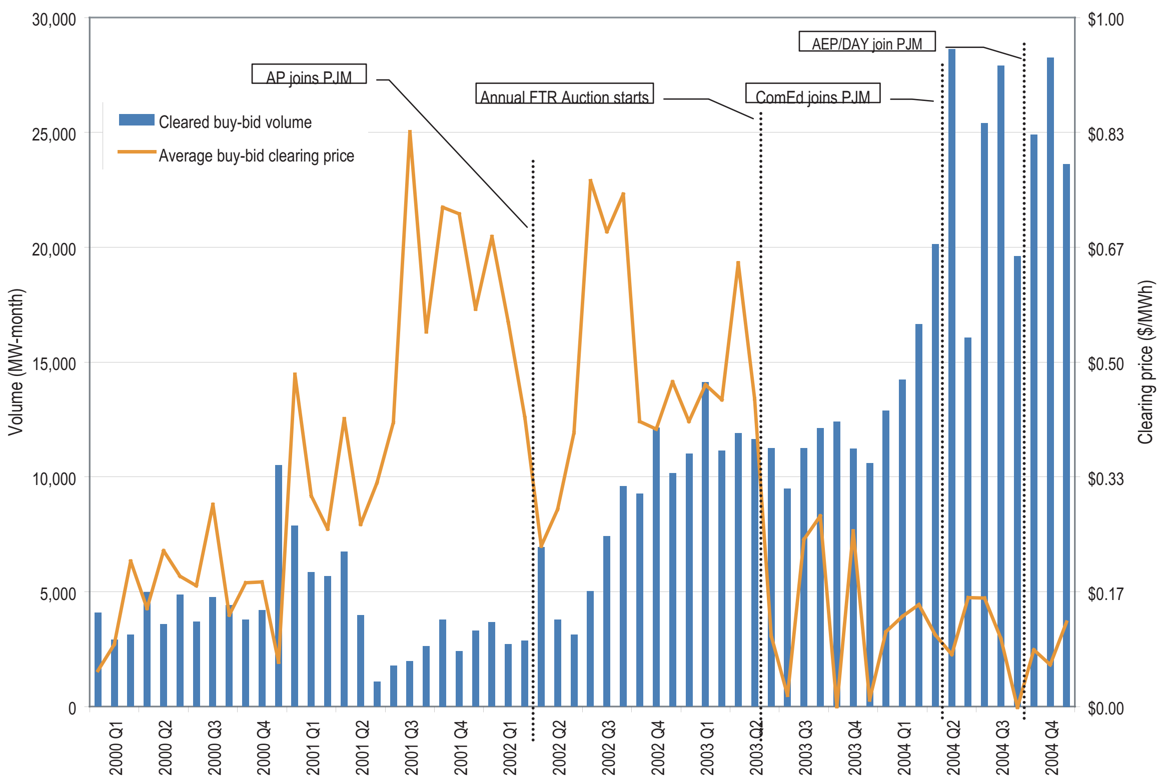


Figure 7-9 presents monthly FTR auction cleared-bid volume and average buy-bid clearing price. It shows that the average cleared-bid price dropped from an historic average of $0.49 per MWh during calendar years 2001 and 2002 to $0.27 per MWh in 2003 and to $0.10 per MWh in 2004, with the entire drop occurring after the start of the Annual FTR Auction. Volume steadily increased from 4,250 MW-months in 2000 and 2001 to 6,400, 11,500 and 21,500 MW-months in 2002, 2003 and 2004, respectively. A bid and offer volume comparison continues to show that bid volume exceeds offer volume by a ratio of nearly 10-to-1.

Figure 7-9 - Monthly FTR Auction cleared buy-bids and average buy-bid price: Calendar years 2000 to 2004



Revenue Adequacy

Congestion revenue is created in an LMP system when all loads pay and all generators receive their respective LMPs. The difference between the sums of these payments and receipts creates most system congestion revenue.[24] When load pays more than generators receive, positive congestion revenue exists and is available to cover the target allocations of FTR holders. Load exceeds generation in constrained areas because some of this load is served by imports. Generation imports are paid the uncongested price at their bus. Generation in a constrained area receives the congested price and all load in the constrained area pays the congested price. As a result, load congestion payments are usually greater than the increased generation receipts. Table 7-10 illustrates how total congestion revenue is generated and how FTR target allocations and congestion receipts are determined.

24 There are two other revenue sources available to be paid as FTR credits: 1) The negative revenue generated by FTRs that are in the direction opposite to congestion (such FTRs are a liability to the holders); and 2) Annual and monthly FTR auction revenue that remains after all ARRs are paid their full ARR target allocations. Table 7-5 shows $34 million in surplus FTR auction revenue for the 2004 to 2005 planning period to date.

As load and generation are equal on an overall system basis and the price of unconstrained energy is the same everywhere, any differences between load payments and generation credits is attributable to transmission congestion. FTR target allocations are equal to the product of the sink-minus-source LMP difference and the FTR MW. These are separated into positively and negatively valued FTRs, with the revenue from the negatively valued FTRs accruing to pay the positively valued FTRs. FTR revenue adequacy exists when the sum of congestion credits is as great as the sum of congestion across the positively valued FTRs, and these FTRs are paid 100 percent of their target allocations. The SFT ensures that the particular set of awarded FTRs can be supported by the transmission system, thus ensuring FTR revenue adequacy. In general, revenue adequacy exists when the SFT simulation adequately models system conditions and limitations that occur in Day-Ahead and Real-Time Energy Markets.

Table 7-10 - Congestion revenue, FTR target allocations and FTR congestion credits: Illustration

Congestion revenue

Pricing Node	Day-Ahead LMP	Load	Load Payments	Generation	Generation Credits	Transmission Congestion Charges
A	$10	0	$0	100	$1,000	
B	$15	50	$750	0	$0	
C	$20	50	$1,000	100	$2,000	
D	$25	50	$1,250	0	$0	
E	$30	50	$1,500	0	$0	
Total		200	$4,500	200	$3,000	$1,500

FTR target allocations

Path	Day-Ahead Path Price	FTR MW	FTR Target Allocations	Positive FTR Target Allocations	Negative FTR Target Allocations
A-C	$10	50	$500	$500	$0
A-D	$15	50	$750	$750	$0
D-B	-$10	25	-$250	$0	-$250
B-E	$15	50	$750	$750	$0
Total				$2,000	-$250

Congestion accounting

Transmission congestion charges		$1,500
+Negative FTR target allocations		$250
=Total congestion charges		$1,750
Positive FTR target allocations	$2,000	
-FTR congestion credits	$1,750	
=Congestion credit deficiency	$250	
FTR payout ratio	0.875	

Although overall revenue adequacy is maintained throughout the entire planning period, revenue inadequacy can sometimes result because transmission facility ratings change with the season and instantaneous operating conditions. On lines and transformers, thermal ratings that limit power flow are affected primarily by temperature. Overallocation of FTRs is precluded by using the most restrictive rating set in the SFT simulation. When ratings change with the season, the actual instantaneous rating is never less than the rating used in the SFT. Instantaneous and planning period revenue adequacy are relatively certain for constraints associated with these facilities. Nonetheless, interface limits are voltage limits that are affected more by instantaneous operating conditions. Their variance over time is best described by distributions with large variances, not discrete values like lines and transformers.

Revenue inadequacy can also result if the SFT simulation does not adequately model system conditions and limitations that occur in the Day-Ahead Energy Market, or if there are systematic differences between actual and scheduled interface transactions.[25]

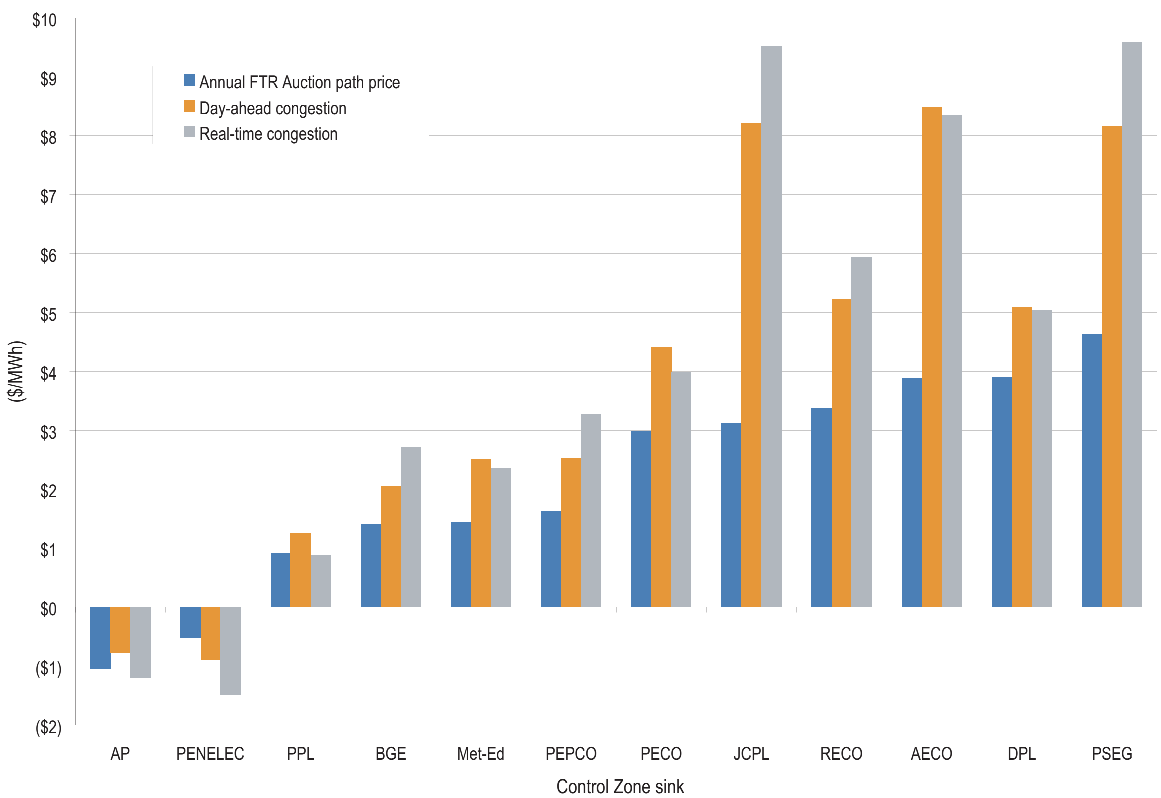
FTR target allocations are based on hourly, day-ahead FTR path prices and represent revenue required to hedge FTR holders fully against congestion. FTR credits represent revenue actually paid to FTR holders and, depending on market conditions, can be less than the target allocations needed to fully hedge congestion incurred during some periods. 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 period that ended May 31, 2004.[26] FTRs were paid at 98 percent of the target allocations during 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.[27]

25 See *2002 State of the Market Report* (March 05, 2003), pp. 56-59.
26 See Section 6, "Congestion," at Table 6-2, "Monthly PJM congestion accounting summary [Dollars (in millions)]: By planning period."
27 For full congestion accounting and FTR revenue adequacy data, see Section 6, "Congestion."

FTR Revenue versus Congestion

Figure 7-10 shows annual FTR auction prices and an approximate measure of day-ahead and real-time congestion for each Mid-Atlantic Region control zone with reference to Western Hub prices. The figure shows, for example, that an FTR from the Western Hub to the PECO Control Zone cost $3 per MWh in the Annual FTR Auction and that about $4.40 per MWh of day-ahead congestion and $4 per MWh of real-time congestion existed between the Western Hub and the zone. The data show that congestion costs, approximated in this way, exceeded the cost of FTRs for most zones.

Figure 7-10 - Annual FTR Auction prices vs. average day-ahead and real-time congestion for Mid-Atlantic Region Control Zones relative to the Western Hub: Planning period 2004 to 2005



A separate analysis examined FTR target allocations. Hourly FTR target allocations were segregated into those that were benefits and liabilities and summed by sink and by source for the calendar year 2004. Figure 7-11 shows the FTR sinks with the largest targeted benefit and liability. The top 10 sinks that produced a financial benefit accounted for 76 percent of total positive target allocations. These sinks were spread throughout PJM. FTRs with the AP Control Zone as their sink included 38 percent of all positive target allocations. The top 10 sinks that created liability accounted for 59 percent of total negative target allocations. These sinks were also spread throughout PJM. FTRs with the ComEd Control Zone as the sink encompassed 63 percent of all negative target allocations.

Figure 7-11 - Ten largest positive and negative FTR target allocations summed by sink: Calendar year 2004

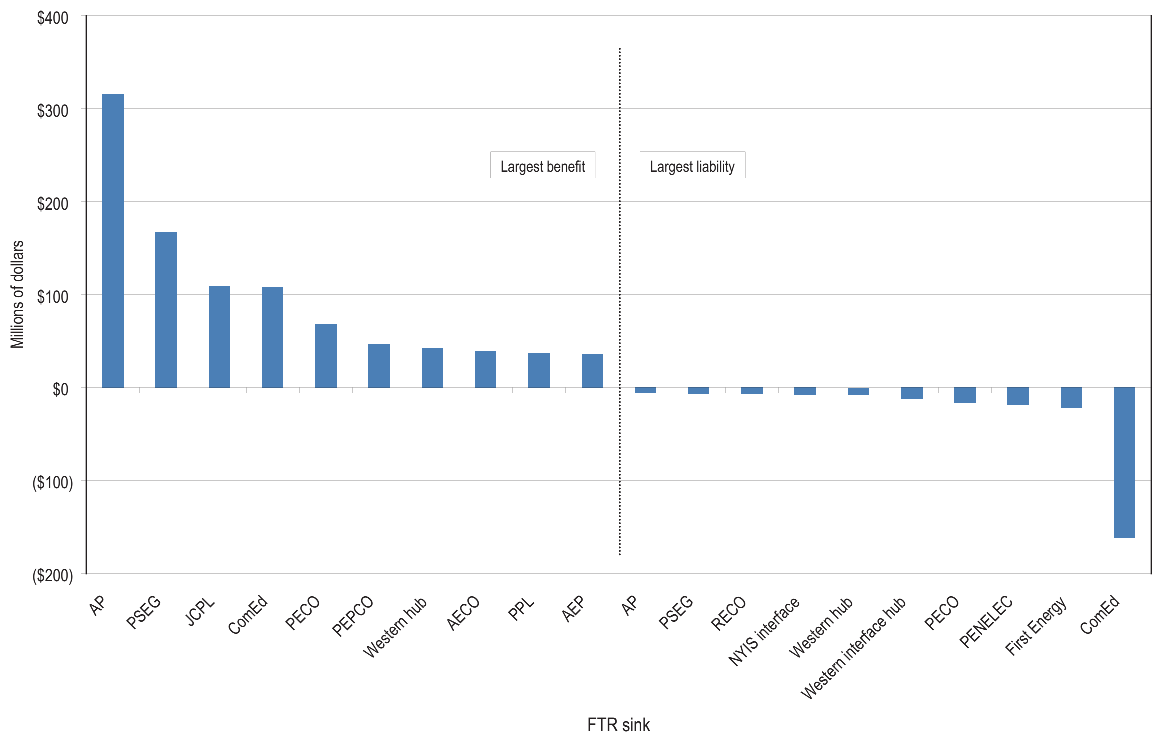
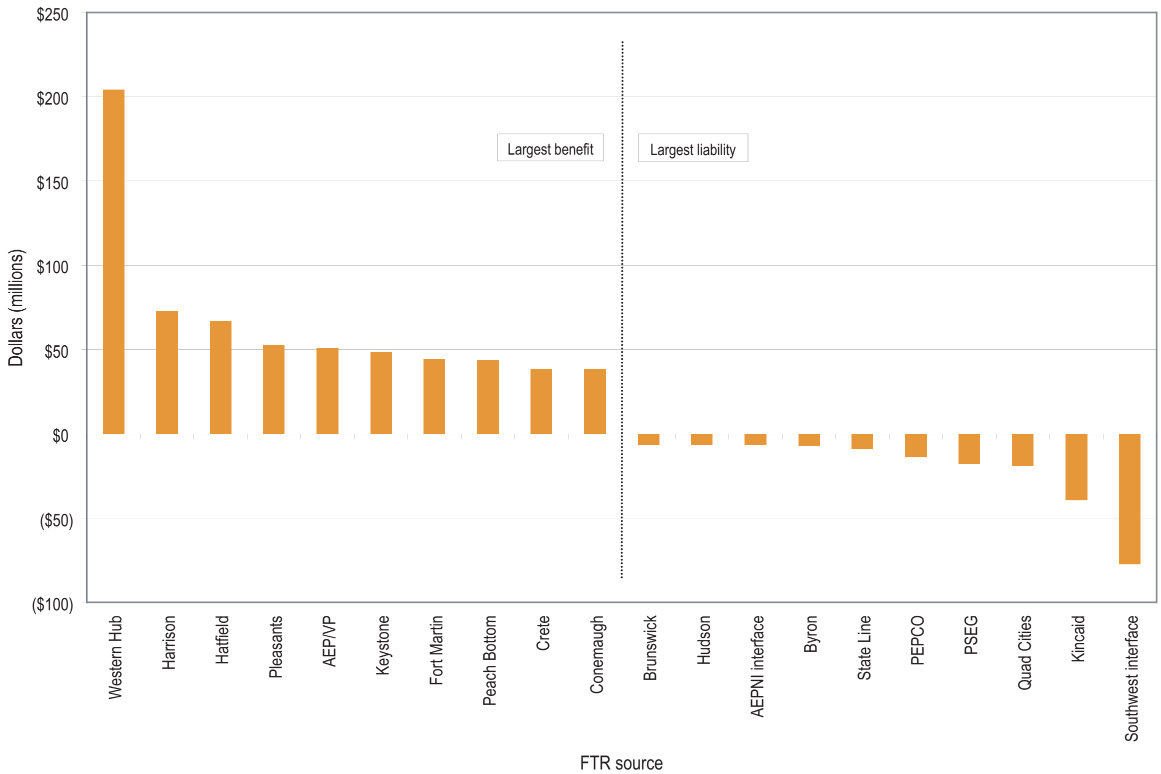
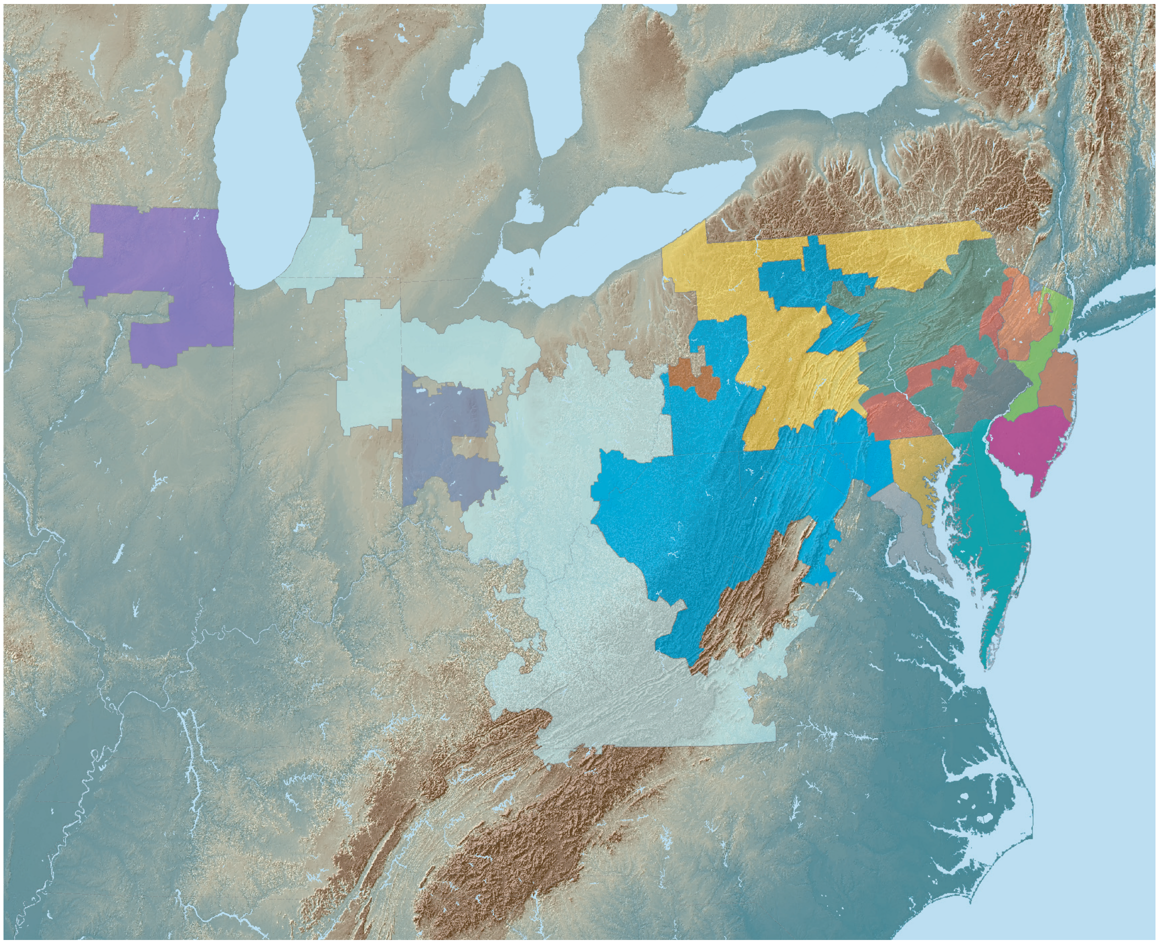


Figure 7-12 shows the same information for FTR sources. The top 10 sources that created financial benefit accounted for 52 percent of total positive target allocations. Eight of these 10 sources were located in or near the AP Control Zone. FTRs with the Western Hub as their source included 25 percent of all positive target allocations. The top 10 sources that were a liability accounted for 45 percent of total negative target allocations. These sources were generally located at the far western and eastern ends of PJM. FTRs with the southwest interface as the source encompassed more than 30 percent of all negative target allocations.

Figure 7-12 - Ten largest positive and negative FTR target allocations summed by source: Calendar year 2004



APPENDIX A - PJM SERVICE TERRITORY



Legend

ZONE

- Allegheny Power Systems
- American Electric Power Co., Inc.
- Atlantic Electric Company
- Baltimore Gas and Electric Company
- Commonwealth Edison
- Dayton Power and Light Co.
- Delmarva Power and Light Company
- Duquesne Light
- Jersey Central Power and Light Company
- Metropolitan Edison Company
- PPL Electric Utilities
- Peco Energy Company
- Pennsylvania Electric Company
- Potomac Electric Power Company
- Public Service Electric and Gas Company
- Rockland Electric Company

APPENDIX B - PJM MARKET MILESTONES

YEAR	MONTH	EVENT
1996	April	FERC Order 888
1997	April	Offer-based Energy Market
	November	FERC approval of PJM ISO status
1998	April	Cost-based Energy LMP Market
1999	January	Daily Capacity Market
	March	FERC approval of market-based rates for PJM
	March	Monthly and Multimonthly Capacity Market
	April	Competitive energy LMP Market
	April	FTR Market
2000	June	Regulation Market
	June	Day-Ahead Energy Market
	July	Customer Load-Reduction Pilot Program
2001	June	First PJM Emergency and Economic Load-Response Programs
2002	April	Integration of the AP Control Zone into PJM Western Region
	June	Second PJM Emergency and Economic Load-Response Programs
	December	Spinning Reserve Market
	December	FERC approval of full PJM RTO status
2003	May	Annual FTR Auction
2004	May	Integration of the ComEd Control Area into PJM
	October	Integration of AEP Control Zone into PJM Western Region
	October	Integration of DAY Control Zone into PJM Western Region

APPENDIX C - ENERGY MARKET

Frequency Distribution of LMP

Figure C-1, Figure C-2, Figure C-3, Figure C-4, Figure C-5, Figure C-6 and Figure C-7 provide frequency distributions of real-time locational marginal price (LMP), by hour, for 1998, 1999, 2000, 2001, 2002, 2003 and 2004.[1] The figures show the number of hours (frequency), the cumulative number of hours (cumulative frequency), the percent of hours (percent) and the cumulative percent of hours (cumulative percent) that LMP was within a given, $10-price interval, or for the cumulative columns, within the interval plus all the lower price intervals.[2]

The first six figures show that during the period 1998 to 2003, locational marginal price (LMP) was most frequently in the $10-per-MWh to $20-per-MWh interval. In 2004, however, LMP occurred in the $30-per-MWh to $40-per-MWh interval most frequently at 22.0 percent of the time and in the $20-per-MWh to $30-per-MWh interval nearly as frequently at 21.6 percent of the time. In 2004, LMP was less than $60 per MWh for 81 percent of the hours and less than $100 per MWh for 99 percent of the hours. LMP was $150 per MWh or greater for five hours (0.06 percent of the hours) in 2004.

Frequency Distribution of Load

Figure C-8, Figure C-9, Figure C-10, Figure C-11, Figure C-12, Figure C-13 and Figure C-14 provide the frequency distributions of PJM load by hour, for the calendar years 1998 through 2004. The figures show the number of hours (frequency), the cumulative number of hours (cumulative frequency), the percent of hours (percent) and the cumulative percent of hours (cumulative percent) that the load was within a given, 5,000 MW load interval, or for the cumulative columns, within the interval plus all the lower load intervals. The integration of the Allegheny Power Company (AP) Control Zone in 2002 and of the Commonwealth Edison Company (ComEd), the American Electric Power Company (AEP) and The Dayton Power & Light Company (DAY) Control Zones in 2004 means that annual comparisons of load frequency including those years are significantly affected by PJM's geographic growth.[3]

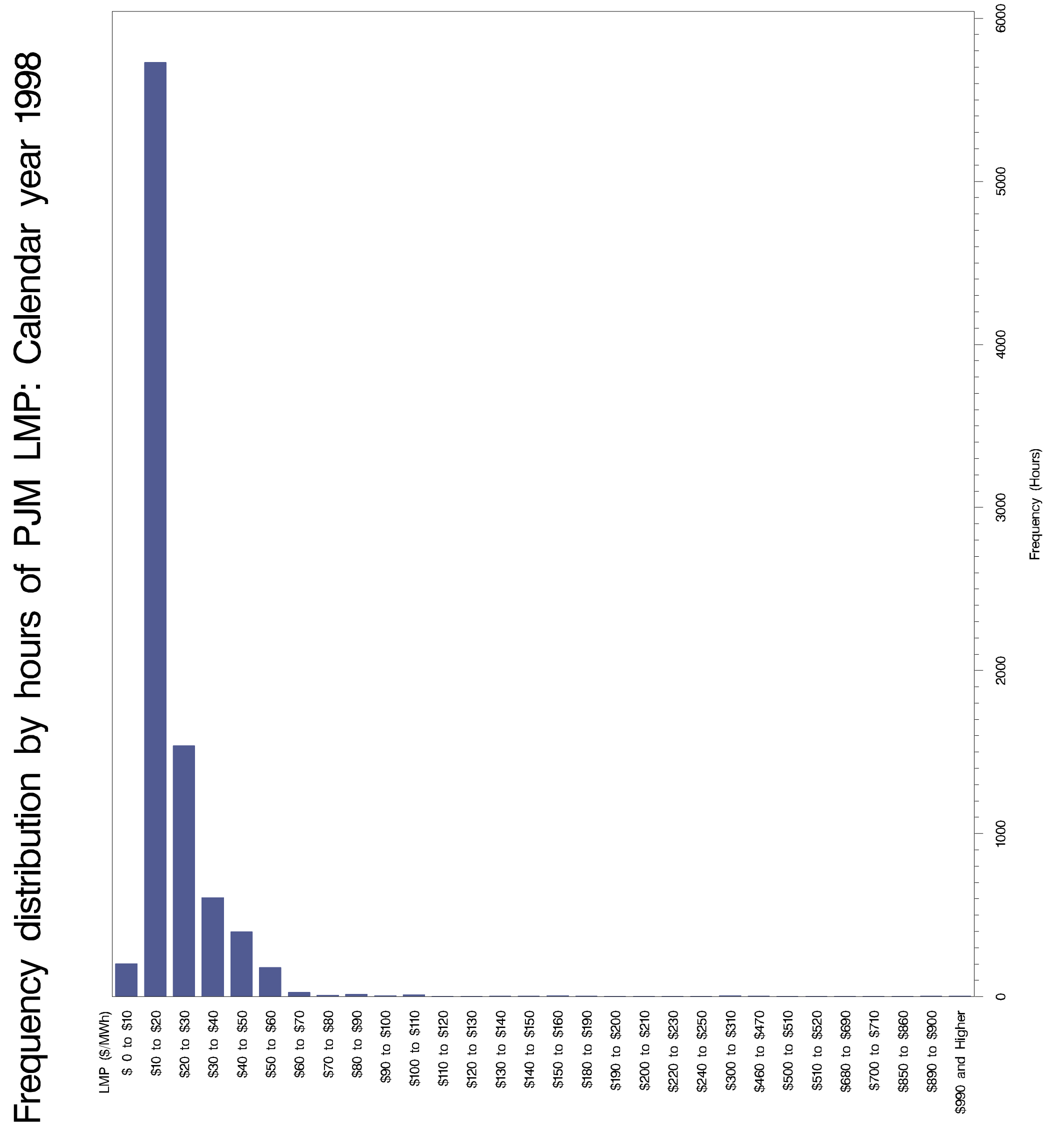
For the years 1998 and 1999, the most frequently occurring load interval was 25,000 MW to 30,000 MW at 35 and 34 percent of the hours, respectively. For the years 2000 and 2001, the most frequently occurring load interval was 30,000 MW to 35,000 MW at 34 and 35 percent of the hours, respectively. For the year 2002, the most frequently occurring load interval was 30,000 MW to 35,000 MW at 26 percent of the hours, with the load interval 35,000 MW to 40,000 MW nearly as frequent at 25 percent of the hours. In 2003, the most frequently occurring load interval was 35,000 to 40,000 MW at 31 percent of the hours, while load was less than 35,000 MW for 36 percent of the hours.

The frequency distribution of load in 2004 reflects the integration of the ComEd, AEP and DAY Control Zones. The most frequently occurring load interval was 35,000 MW to 40,000 MW at 16 percent of the hours. The next most frequently occurring interval was 40,000 MW to 45,000 MW at 15 percent of the hours. Load was less than 60,000 MW for 75 percent of the time, less than 70,000 MW for 93 percent of the time and less than 90,000 MW for all but nine hours.

1 LMP was instituted in PJM in April 1998. Before then, there had been a single system price, the market-clearing price (MCP).
2 Only positive LMP intervals are included in these figures.
3 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.

As the AEP and DAY Control Zone integrations did not occur until October 1, 2004, the summer peak reflected only the ComEd Control Area integration. That peak demand for the summer of 2004, including ComEd, was 77,887 MW and occurred on August 3, 2004.

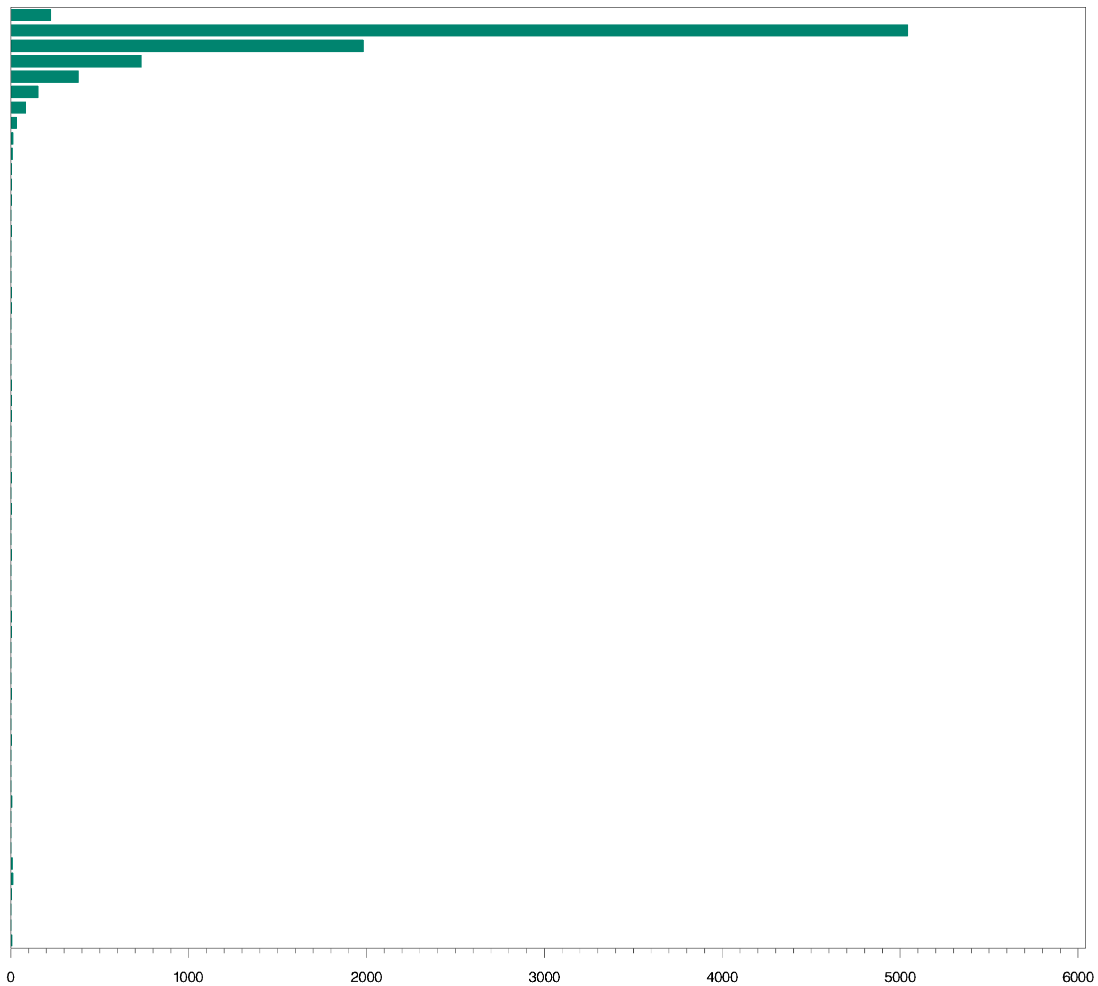
Figure C-1 - Frequency distribution by hours of PJM LMP: Calendar year 1998



LMP ($/MWh)	FREQ.	CUM. FREQ.	PCT.	CUM. PCT.
$ 0 to $10	203	203	2.32	2.32
$10 to $20	5729	5932	65.41	67.72
$20 to $30	1539	7471	17.57	85.30
$30 to $40	607	8078	6.93	92.23
$40 to $50	396	8474	4.52	96.75
$50 to $60	178	8652	2.03	98.78
$60 to $70	27	8679	0.31	99.09
$70 to $80	10	8689	0.11	99.20
$80 to $90	15	8704	0.17	99.37
$90 to $100	6	8710	0.07	99.44
$100 to $110	11	8721	0.13	99.57
$110 to $120	1	8722	0.01	99.58
$120 to $130	1	8723	0.01	99.59
$130 to $140	4	8727	0.05	99.63
$140 to $150	3	8730	0.03	99.67
$150 to $160	6	8736	0.07	99.74
$180 to $190	2	8738	0.02	99.76
$190 to $200	1	8739	0.01	99.77
$200 to $210	1	8740	0.01	99.78
$220 to $230	1	8741	0.01	99.79
$240 to $250	1	8742	0.01	99.81
$300 to $310	5	8747	0.06	99.86
$460 to $470	2	8749	0.02	99.89
$500 to $510	1	8750	0.01	99.90
$510 to $520	1	8751	0.01	99.91
$680 to $690	1	8752	0.01	99.92
$700 to $710	1	8753	0.01	99.93
$850 to $860	1	8754	0.01	99.94
$890 to $900	3	8757	0.03	99.98
$990 and Higher	2	8759	0.02	100.00

Figure C-2 - Frequency distribution by hours of PJM LMP: Calendar year 1999

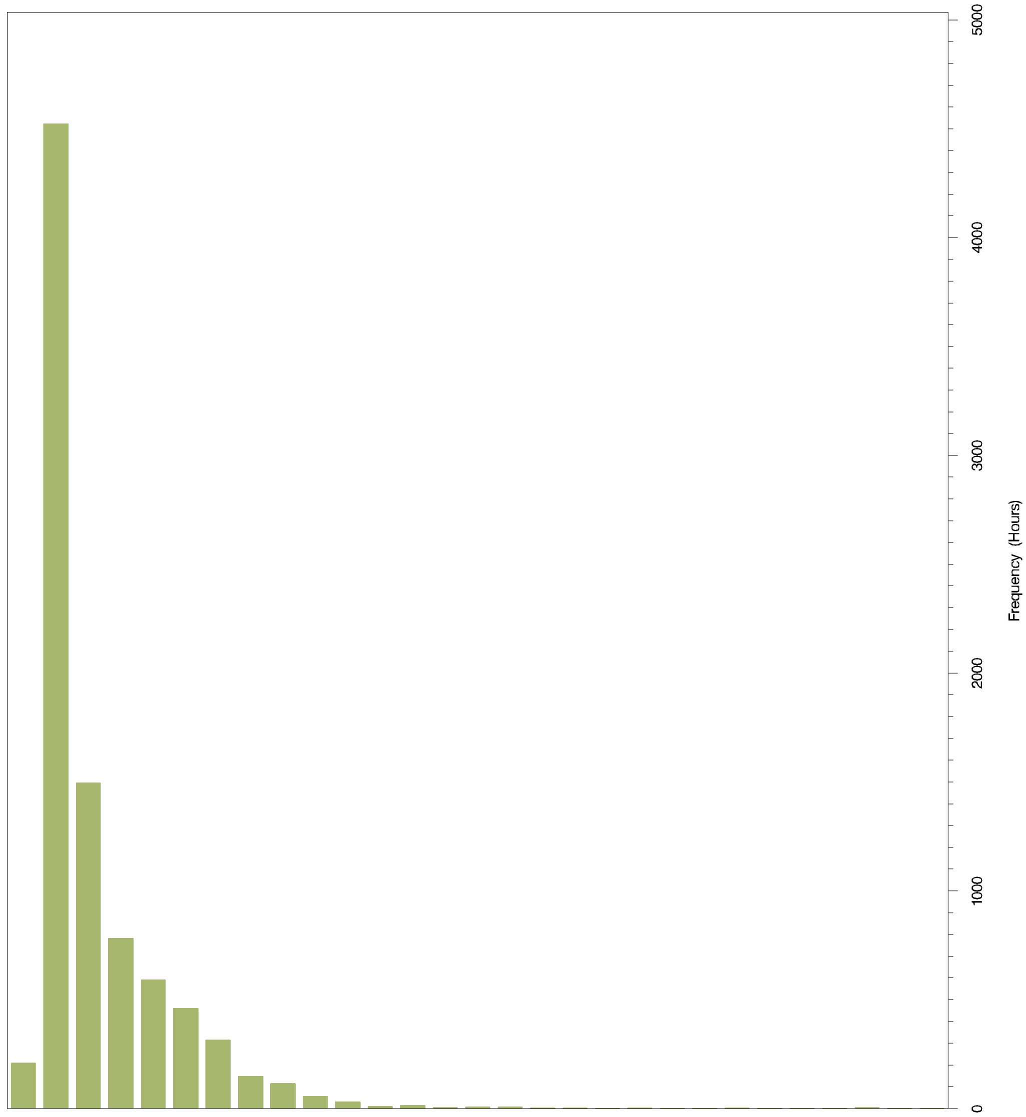
Frequency distribution by hours of PJM LMP: Calendar year 1999



LMP ($/MWh)	FREQ.	CUM. FREQ.	PCT.	CUM. PCT.
$ 0 to $10	226	226	2.58	2.58
$10 to $20	5042	5268	57.56	60.14
$20 to $30	1982	7250	22.63	82.77
$30 to $40	733	7983	8.37	91.14
$40 to $50	379	8362	4.33	95.47
$50 to $60	154	8516	1.76	97.23
$60 to $70	84	8600	0.96	98.18
$70 to $80	33	8633	0.38	98.56
$80 to $90	13	8646	0.15	98.71
$90 to $100	8	8654	0.09	98.80
$100 to $110	4	8658	0.05	98.85
$110 to $120	3	8661	0.03	98.88
$120 to $130	2	8663	0.02	98.90
$130 to $140	1	8664	0.01	98.92
$140 to $150	4	8668	0.05	98.96
$160 to $170	1	8669	0.01	98.97
$170 to $180	1	8670	0.01	98.98
$180 to $190	1	8671	0.01	99.00
$190 to $200	2	8673	0.02	99.02
$200 to $210	2	8675	0.02	99.04
$220 to $230	1	8676	0.01	99.05
$240 to $250	1	8677	0.01	99.06
$250 to $260	1	8678	0.01	99.08
$260 to $270	1	8679	0.01	99.09
$270 to $280	2	8681	0.02	99.11
$300 to $310	2	8683	0.02	99.13
$310 to $320	2	8685	0.02	99.16
$330 to $340	1	8686	0.01	99.17
$360 to $370	1	8687	0.01	99.18
$370 to $380	1	8688	0.01	99.19
$400 to $410	2	8690	0.02	99.21
$430 to $440	1	8691	0.01	99.22
$440 to $450	2	8693	0.02	99.25
$450 to $460	1	8694	0.01	99.26
$460 to $470	1	8695	0.01	99.27
$470 to $480	3	8698	0.03	99.30
$490 to $500	1	8699	0.01	99.31
$510 to $520	1	8700	0.01	99.33
$530 to $540	1	8701	0.01	99.34
$540 to $550	2	8703	0.02	99.36
$560 to $570	2	8705	0.02	99.38
$570 to $580	1	8706	0.01	99.39
$600 to $610	1	8707	0.01	99.41
$610 to $620	1	8708	0.01	99.42
$620 to $630	2	8710	0.02	99.44
$670 to $680	1	8711	0.01	99.45
$750 to $760	1	8712	0.01	99.46
$760 to $770	2	8714	0.02	99.49
$780 to $790	1	8715	0.01	99.50
$790 to $800	1	8716	0.01	99.51
$820 to $830	1	8717	0.01	99.52
$840 to $850	7	8724	0.08	99.60
$870 to $880	1	8725	0.01	99.61
$890 to $900	1	8726	0.01	99.62
$900 to $910	1	8727	0.01	99.63
$910 to $920	10	8737	0.11	99.75
$930 to $940	11	8748	0.13	99.87
$940 to $950	2	8750	0.02	99.90
$950 to $960	1	8751	0.01	99.91
$970 to $980	1	8752	0.01	99.92
$990 and Higher	7	8759	0.08	100.00

Figure C-3 - Frequency distribution by hours of PJM LMP: Calendar year 2000

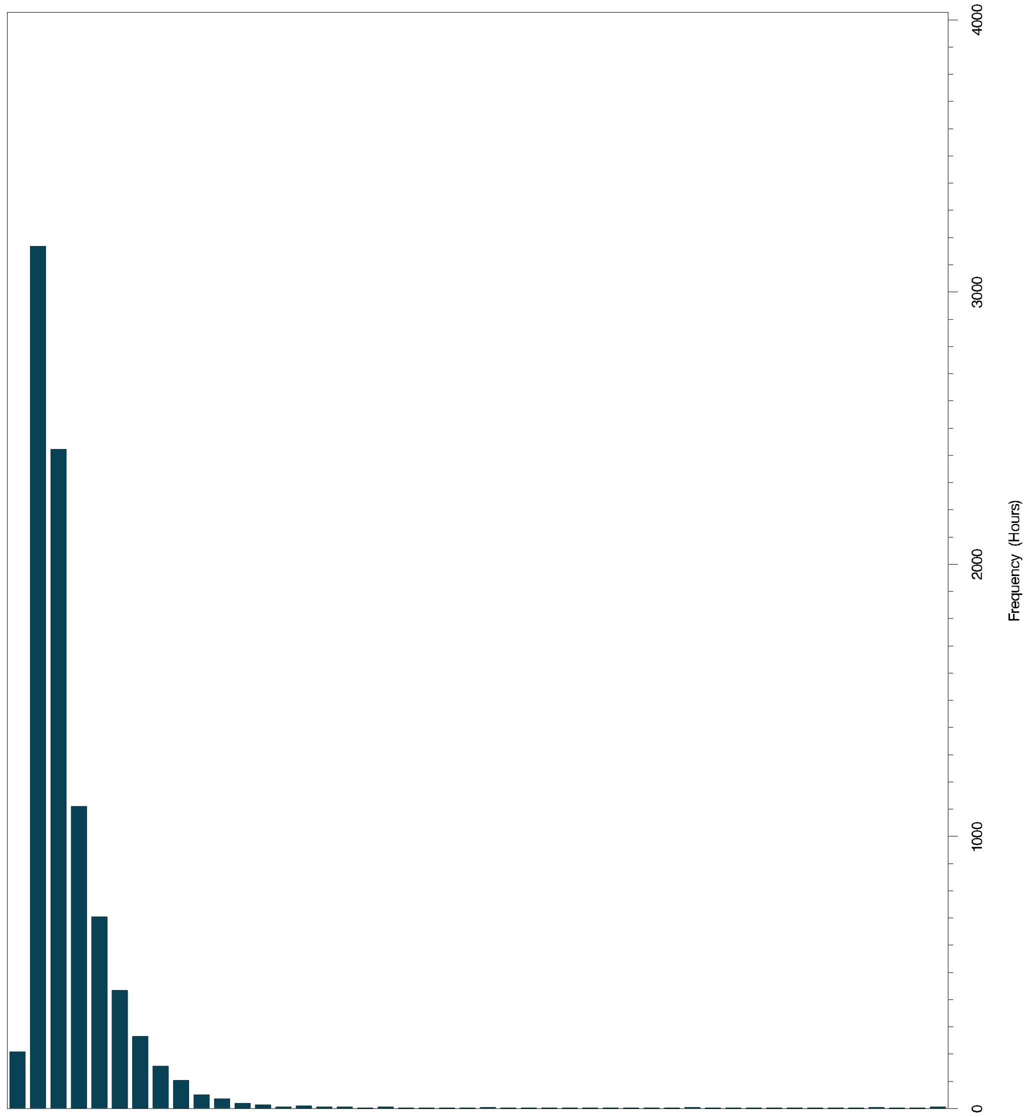
Frequency distribution by hours of PJM LMP: Calendar year 2000



LMP ($/MWh)	FREQ.	CUM. FREQ.	PCT.	CUM. PCT.
$ 0 to $10	209	209	2.38	2.38
$10 to $20	4522	4731	51.49	53.87
$20 to $30	1494	6225	17.01	70.88
$30 to $40	782	7007	8.90	79.78
$40 to $50	591	7598	6.73	86.51
$50 to $60	459	8057	5.23	91.73
$60 to $70	315	8372	3.59	95.32
$70 to $80	147	8519	1.67	96.99
$80 to $90	115	8634	1.31	98.30
$90 to $100	56	8690	0.64	98.94
$100 to $110	31	8721	0.35	99.29
$110 to $120	9	8730	0.10	99.40
$120 to $130	13	8743	0.15	99.54
$130 to $140	5	8748	0.06	99.60
$140 to $150	8	8756	0.09	99.69
$150 to $160	6	8762	0.07	99.76
$160 to $170	3	8765	0.03	99.80
$170 to $180	2	8767	0.02	99.82
$180 to $190	1	8768	0.01	99.83
$190 to $200	2	8770	0.02	99.85
$210 to $220	1	8771	0.01	99.86
$220 to $230	1	8772	0.01	99.87
$260 to $270	2	8774	0.02	99.90
$280 to $290	1	8775	0.01	99.91
$290 to $300	1	8776	0.01	99.92
$360 to $370	1	8777	0.01	99.93
$480 to $490	4	8781	0.05	99.98
$590 to $600	1	8782	0.01	99.99
$800 to $810	1	8783	0.01	100.00

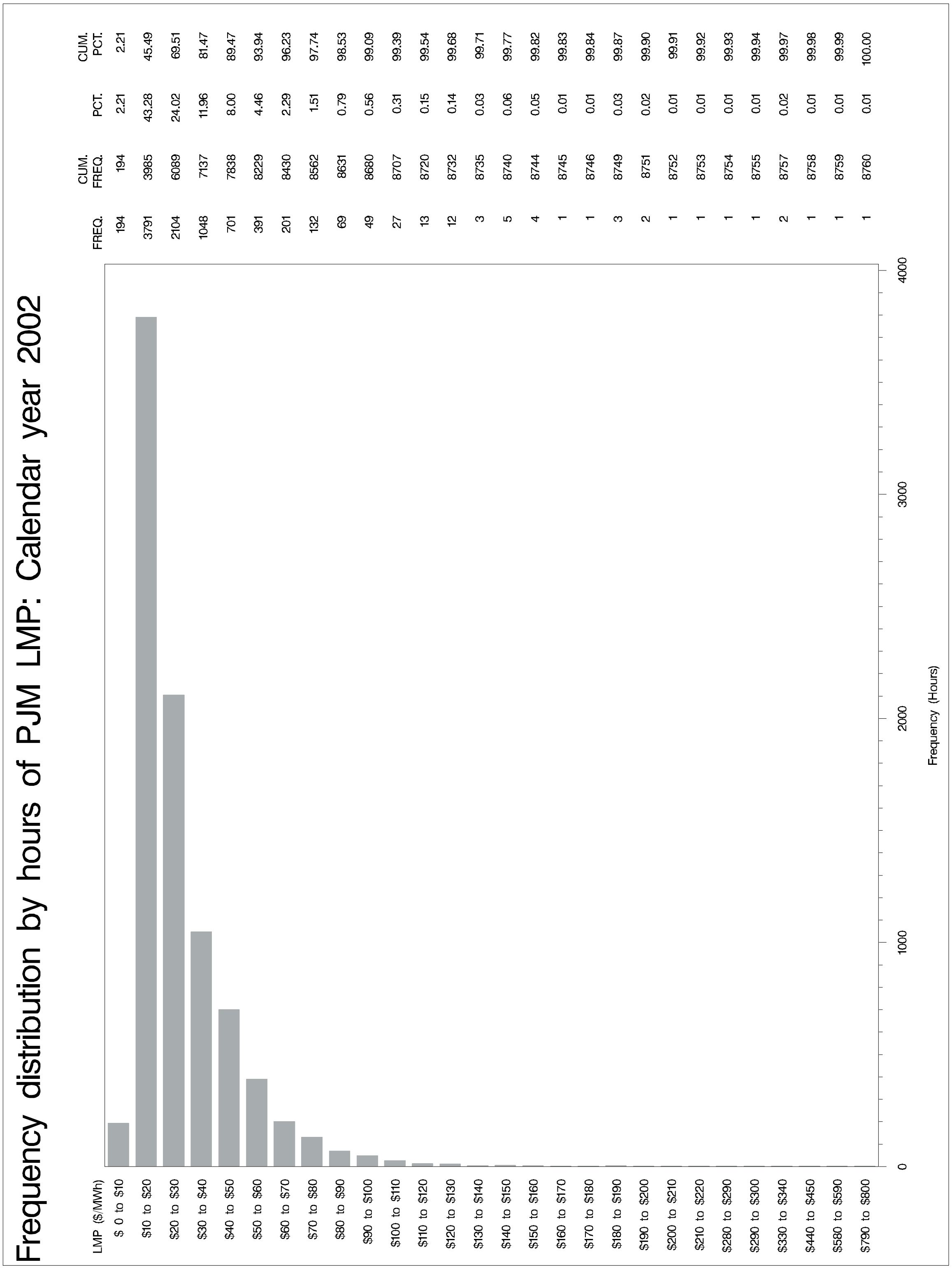
Figure C-4 - Frequency distribution by hours of PJM LMP: Calendar year 2001

Frequency distribution by hours of PJM LMP: Calendar year 2001



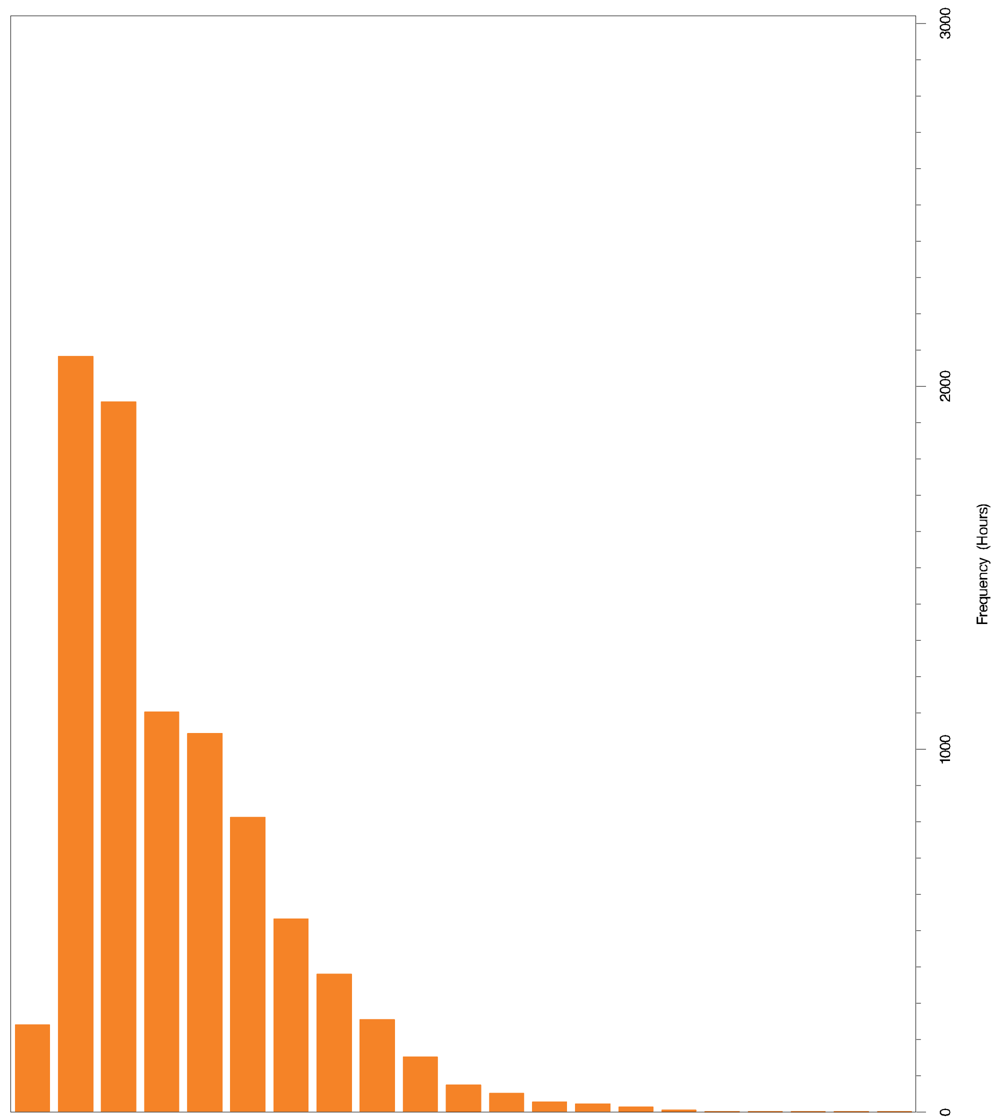
LMP ($/MWh)	FREQ.	CUM. FREQ.	PCT.	CUM. PCT.
$ 0 to $10	209	209	2.39	2.39
$10 to $20	3167	3376	36.16	38.54
$20 to $30	2423	5799	27.66	66.21
$30 to $40	1109	6908	12.66	78.87
$40 to $50	704	7612	8.04	86.90
$50 to $60	433	8045	4.94	91.85
$60 to $70	264	8309	3.01	94.86
$70 to $80	155	8464	1.77	96.63
$80 to $90	104	8568	1.19	97.82
$90 to $100	50	8618	0.57	98.39
$100 to $110	36	8654	0.41	98.80
$110 to $120	18	8672	0.21	99.01
$120 to $130	13	8685	0.15	99.16
$130 to $140	5	8690	0.06	99.21
$140 to $150	9	8699	0.10	99.31
$150 to $160	6	8705	0.07	99.38
$160 to $170	6	8711	0.07	99.45
$170 to $180	2	8713	0.02	99.47
$180 to $190	5	8718	0.06	99.53
$190 to $200	1	8719	0.01	99.54
$210 to $220	1	8720	0.01	99.55
$240 to $250	1	8721	0.01	99.57
$250 to $260	1	8722	0.01	99.58
$260 to $270	3	8725	0.03	99.61
$280 to $290	1	8726	0.01	99.62
$290 to $300	1	8727	0.01	99.63
$320 to $330	1	8728	0.01	99.65
$330 to $340	2	8730	0.02	99.67
$360 to $370	1	8731	0.01	99.68
$370 to $380	2	8733	0.02	99.70
$390 to $400	1	8734	0.01	99.71
$440 to $450	1	8735	0.01	99.73
$470 to $480	1	8736	0.01	99.74
$520 to $530	3	8739	0.03	99.77
$530 to $540	1	8740	0.01	99.78
$550 to $560	2	8742	0.02	99.81
$620 to $630	1	8743	0.01	99.82
$650 to $660	2	8745	0.02	99.84
$690 to $700	1	8746	0.01	99.85
$740 to $750	1	8747	0.01	99.86
$770 to $780	1	8748	0.01	99.87
$830 to $840	1	8749	0.01	99.89
$900 to $910	3	8752	0.03	99.92
$910 to $920	1	8753	0.01	99.93
$920 to $930	1	8754	0.01	99.94
$930 to $940	5	8759	0.06	100.00

Figure C-5 - Frequency distribution by hours of PJM LMP: Calendar year 2002



LMP ($/MWh)	FREQ.	CUM. FREQ.	PCT.	CUM. PCT.
$ 0 to $10	194	194	2.21	2.21
$10 to $20	3791	3985	43.28	45.49
$20 to $30	2104	6089	24.02	69.51
$30 to $40	1048	7137	11.96	81.47
$40 to $50	701	7838	8.00	89.47
$50 to $60	391	8229	4.46	93.94
$60 to $70	201	8430	2.29	96.23
$70 to $80	132	8562	1.51	97.74
$80 to $90	69	8631	0.79	98.53
$90 to $100	49	8680	0.56	99.09
$100 to $110	27	8707	0.31	99.39
$110 to $120	13	8720	0.15	99.54
$120 to $130	12	8732	0.14	99.68
$130 to $140	3	8735	0.03	99.71
$140 to $150	5	8740	0.06	99.77
$150 to $160	4	8744	0.05	99.82
$160 to $170	1	8745	0.01	99.83
$170 to $180	1	8746	0.01	99.84
$180 to $190	3	8749	0.03	99.87
$190 to $200	2	8751	0.02	99.90
$200 to $210	1	8752	0.01	99.91
$210 to $220	1	8753	0.01	99.92
$280 to $290	1	8754	0.01	99.93
$290 to $300	1	8755	0.01	99.94
$330 to $340	2	8757	0.02	99.97
$440 to $450	1	8758	0.01	99.98
$580 to $590	1	8759	0.01	99.99
$790 to $800	1	8760	0.01	100.00

Figure C-6 - Frequency distribution by hours of PJM LMP: Calendar year 2003



LMP ($/MWh)	FREQ.	CUM. FREQ.	PCT.	CUM. PCT.
$ 0 to $10	241	241	2.75	2.75
$10 to $20	2083	2324	23.78	26.53
$20 to $30	1957	4281	22.34	48.87
$30 to $40	1102	5383	12.58	61.45
$40 to $50	1043	6426	11.91	73.36
$50 to $60	812	7238	9.27	82.63
$60 to $70	532	7770	6.07	88.70
$70 to $80	380	8150	4.34	93.04
$80 to $90	255	8405	2.91	95.95
$90 to $100	152	8557	1.74	97.68
$100 to $110	75	8632	0.86	98.54
$110 to $120	52	8684	0.59	99.13
$120 to $130	28	8712	0.32	99.45
$130 to $140	23	8735	0.26	99.71
$140 to $150	14	8749	0.16	99.87
$150 to $160	5	8754	0.06	99.93
$160 to $170	1	8755	0.01	99.94
$170 to $180	1	8756	0.01	99.95
$180 to $190	2	8758	0.02	99.98
$190 to $200	1	8759	0.01	99.99
$210 to $220	1	8760	0.01	100.00

Figure C-7 - Frequency distribution by hours of PJM LMP: Calendar year 2004

Frequency distribution by hours of PJM LMP: Calendar year 2004

LMP ($/MWh)	FREQ.	CUM. FREQ.	PCT.	CUM. PCT.
$ 0 to $10	173	173	1.97	1.97
$10 to $20	712	885	8.11	10.08
$20 to $30	1900	2785	21.63	31.71
$30 to $40	1928	4713	21.95	53.65
$40 to $50	1445	6158	16.45	70.10
$50 to $60	994	7152	11.32	81.42
$60 to $70	668	7820	7.60	89.03
$70 to $80	445	8265	5.07	94.09
$80 to $90	270	8535	3.07	97.17
$90 to $100	117	8652	1.33	98.50
$100 to $110	72	8724	0.82	99.32
$110 to $120	25	8749	0.28	99.60
$120 to $130	14	8763	0.16	99.76
$130 to $140	10	8773	0.11	99.87
$140 to $150	6	8779	0.07	99.94
$150 to $160	3	8782	0.03	99.98
$160 to $170	1	8783	0.01	99.99
$180 to $190	1	8784	0.01	100.00

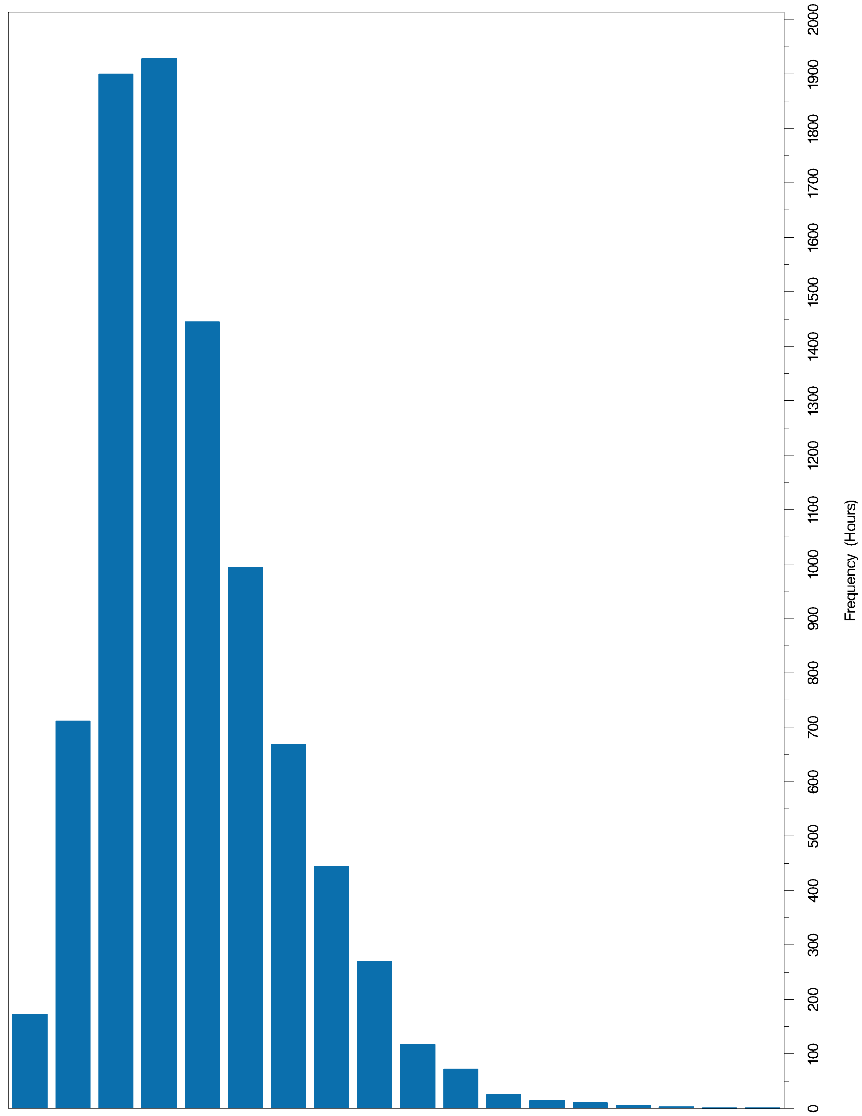


Figure C-8 - Frequency distribution of hourly PJM load: Calendar year 1998

Frequency distribution of hourly PJM load: Calendar year 1998

Load (MW)	FREQ.	CUM. FREQ.	PCT.	CUM. PCT.
20,000 and Less	356	356	4.06	4.06
20,000 to 25,000	2137	2493	24.39	28.46
25,000 to 30,000	3063	5556	34.97	63.42
30,000 to 35,000	2171	7727	24.78	88.21
35,000 to 40,000	704	8431	8.04	96.24
40,000 to 45,000	270	8701	3.08	99.33
45,000 to 50,000	59	8760	0.67	100.00

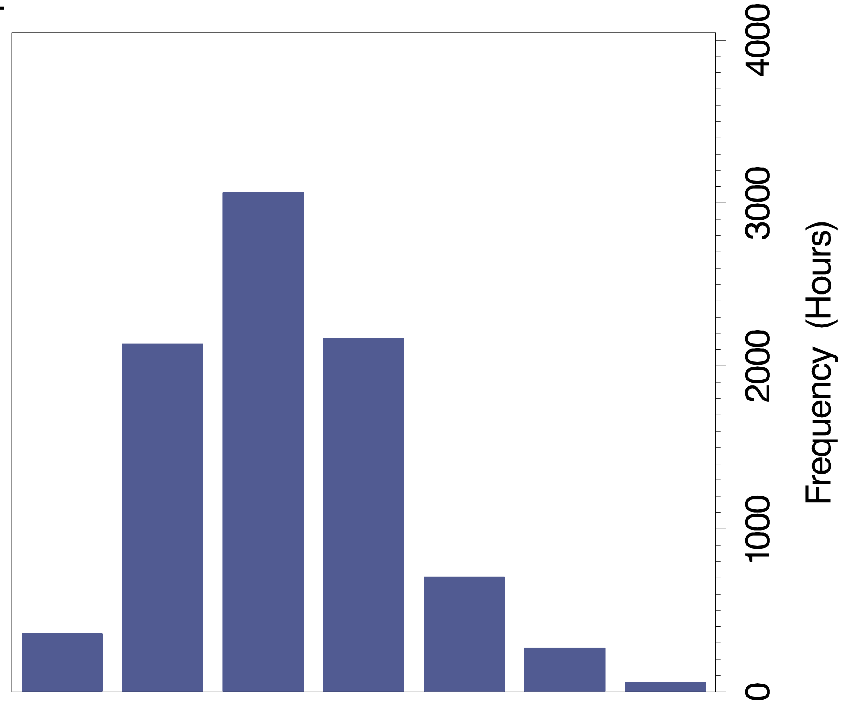
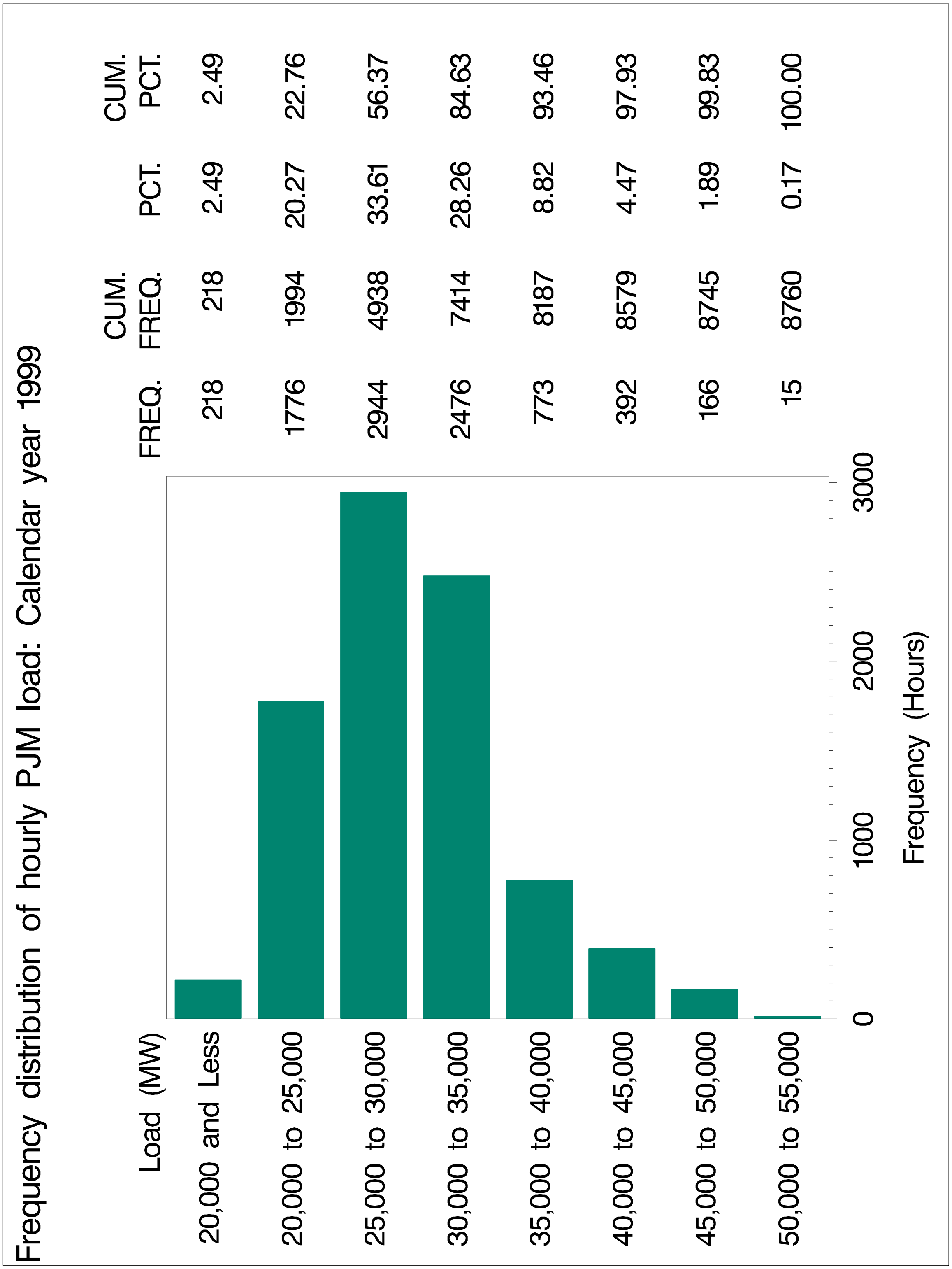


Figure C-9 - Frequency distribution of hourly PJM load: Calendar year 1999



Load (MW)	FREQ.	CUM. FREQ.	PCT.	CUM. PCT.
20,000 and Less	218	218	2.49	2.49
20,000 to 25,000	1776	1994	20.27	22.76
25,000 to 30,000	2944	4938	33.61	56.37
30,000 to 35,000	2476	7414	28.26	84.63
35,000 to 40,000	773	8187	8.82	93.46
40,000 to 45,000	392	8579	4.47	97.93
45,000 to 50,000	166	8745	1.89	99.83
50,000 to 55,000	15	8760	0.17	100.00

Figure C-10 - Frequency distribution of hourly PJM load: Calendar year 2000

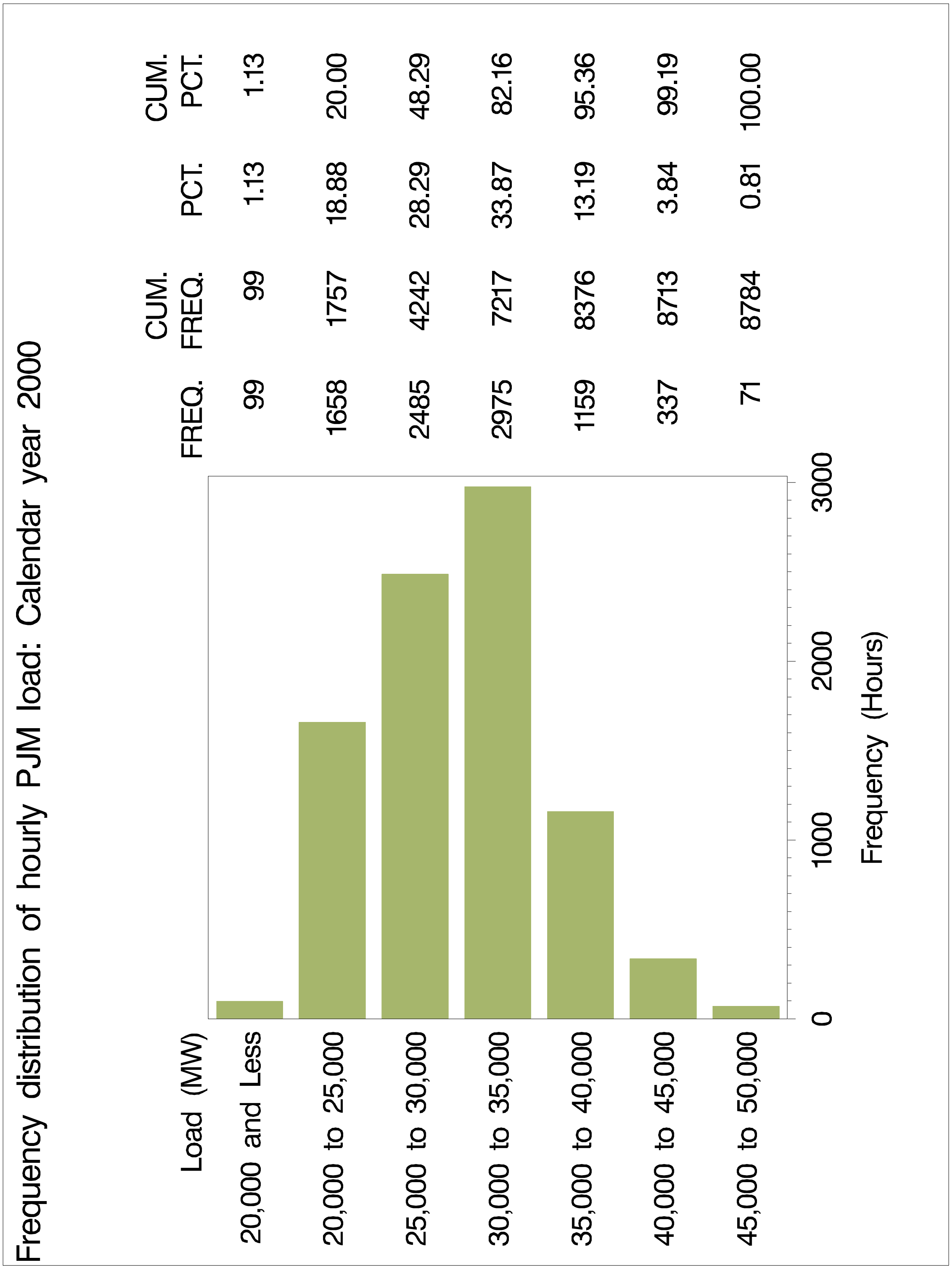


Figure C-11 - Frequency distribution of hourly PJM load: Calendar year 2001

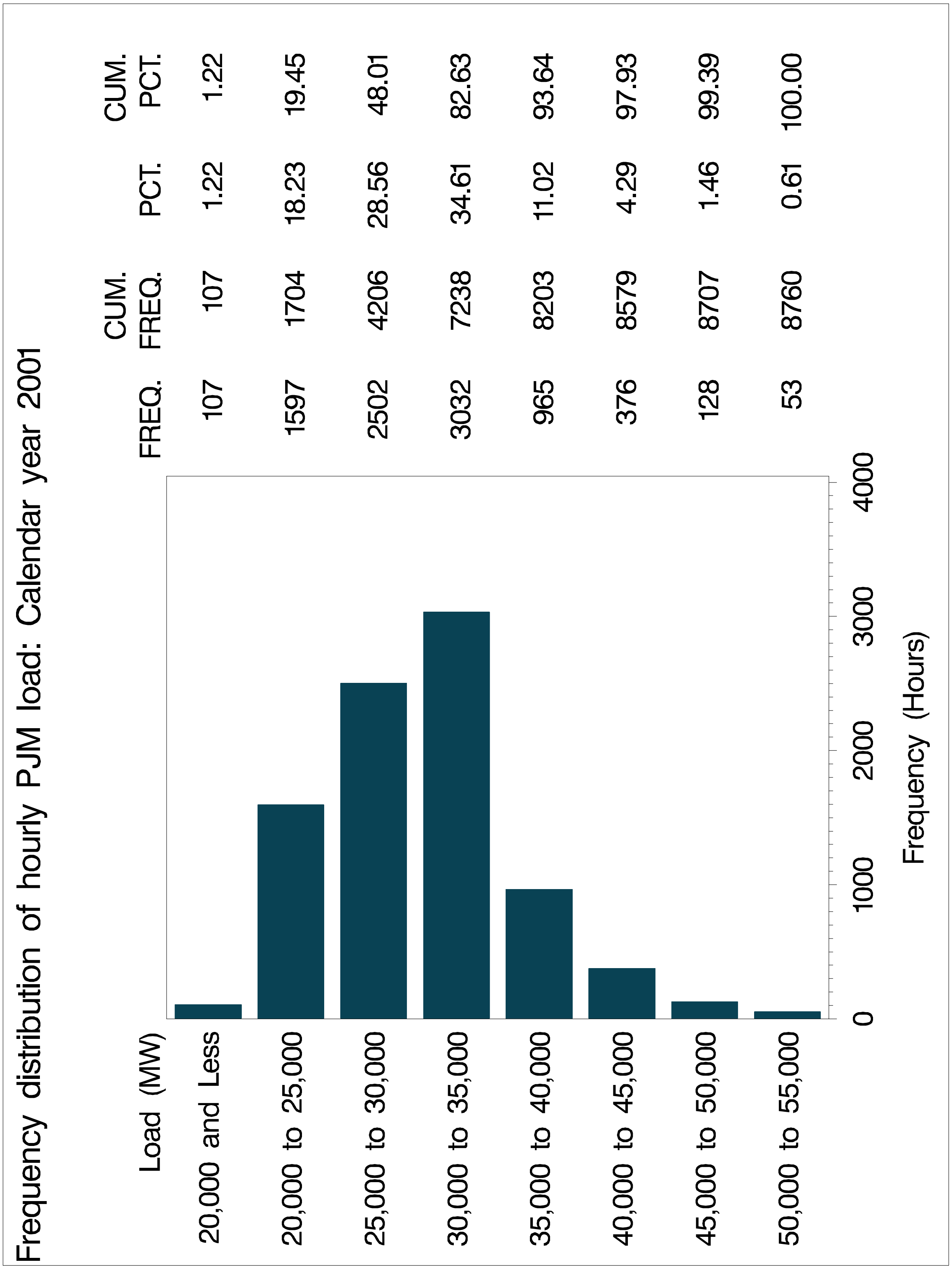


Figure C-12 - Frequency distribution of hourly PJM load: Calendar year 2002

Frequency distribution of hourly PJM load: Calendar year 2002

Load (MW)	FREQ.	CUM. FREQ.	PCT.	CUM. PCT.
20,000 and Less	4	4	0.05	0.05
20,000 to 25,000	398	402	4.54	4.59
25,000 to 30,000	1749	2151	19.97	24.55
30,000 to 35,000	2320	4471	26.48	51.04
35,000 to 40,000	2199	6670	25.10	76.14
40,000 to 45,000	1037	7707	11.84	87.98
45,000 to 50,000	508	8215	5.80	93.78
50,000 to 55,000	252	8467	2.88	96.66
55,000 to 60,000	198	8665	2.26	98.92
60,000 to 65,000	95	8760	1.08	100.00

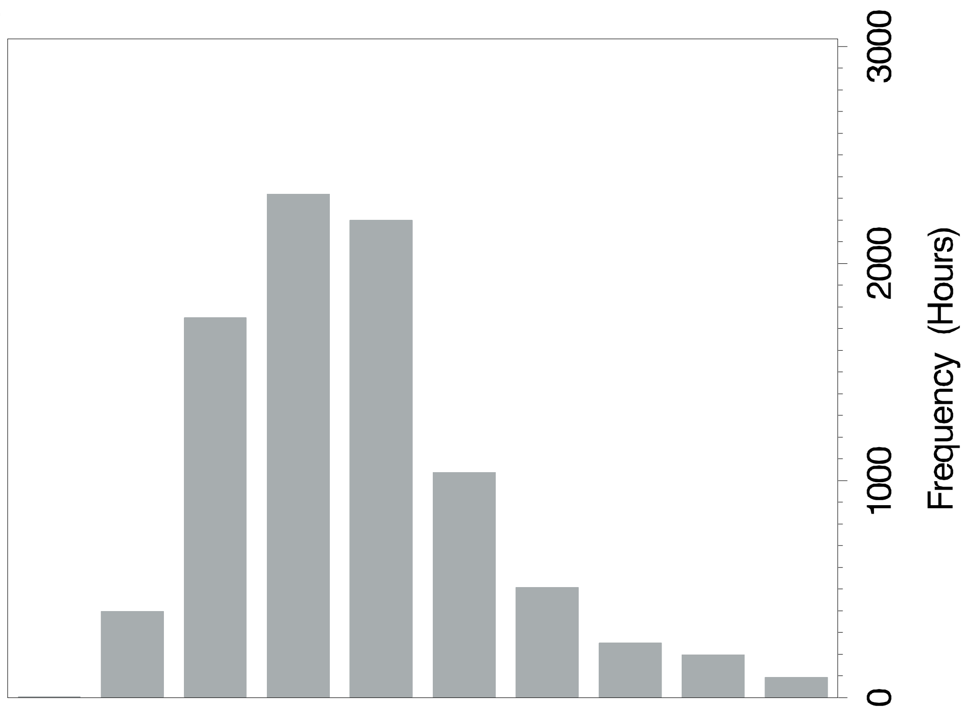
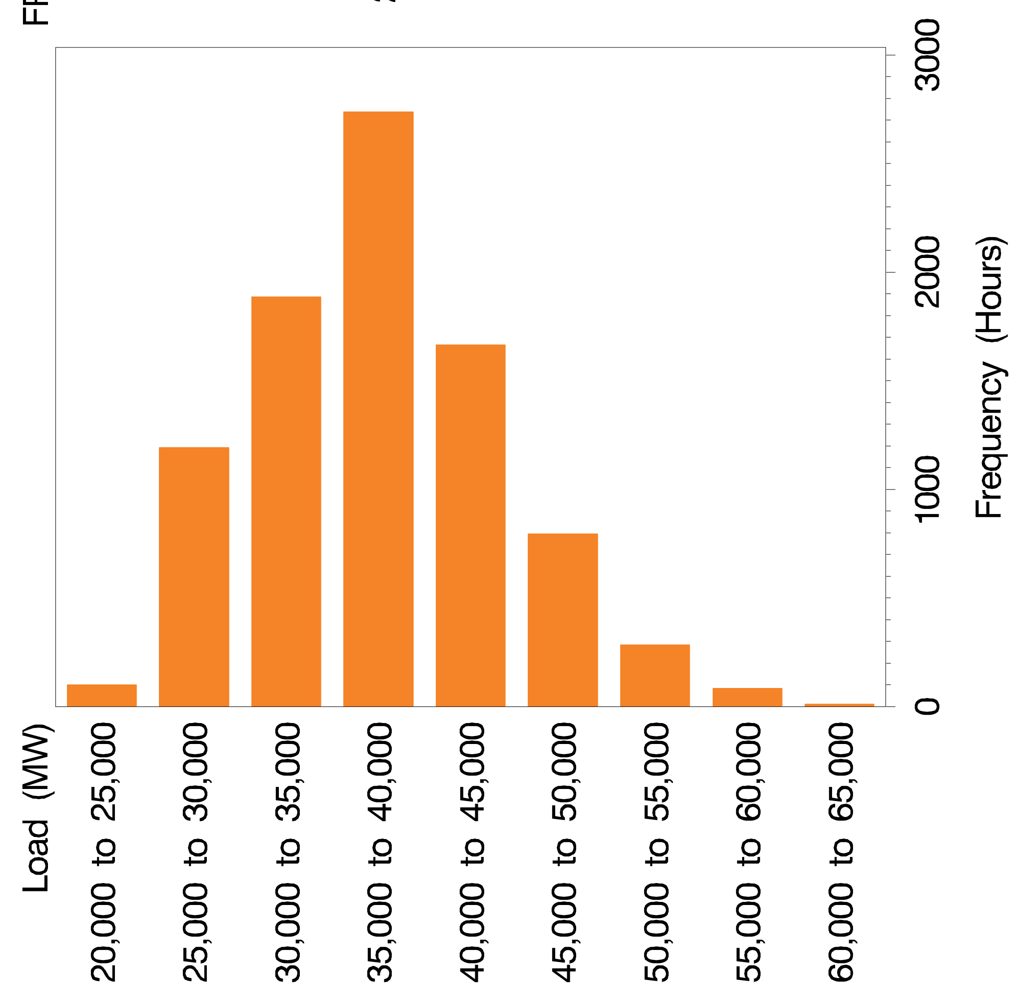


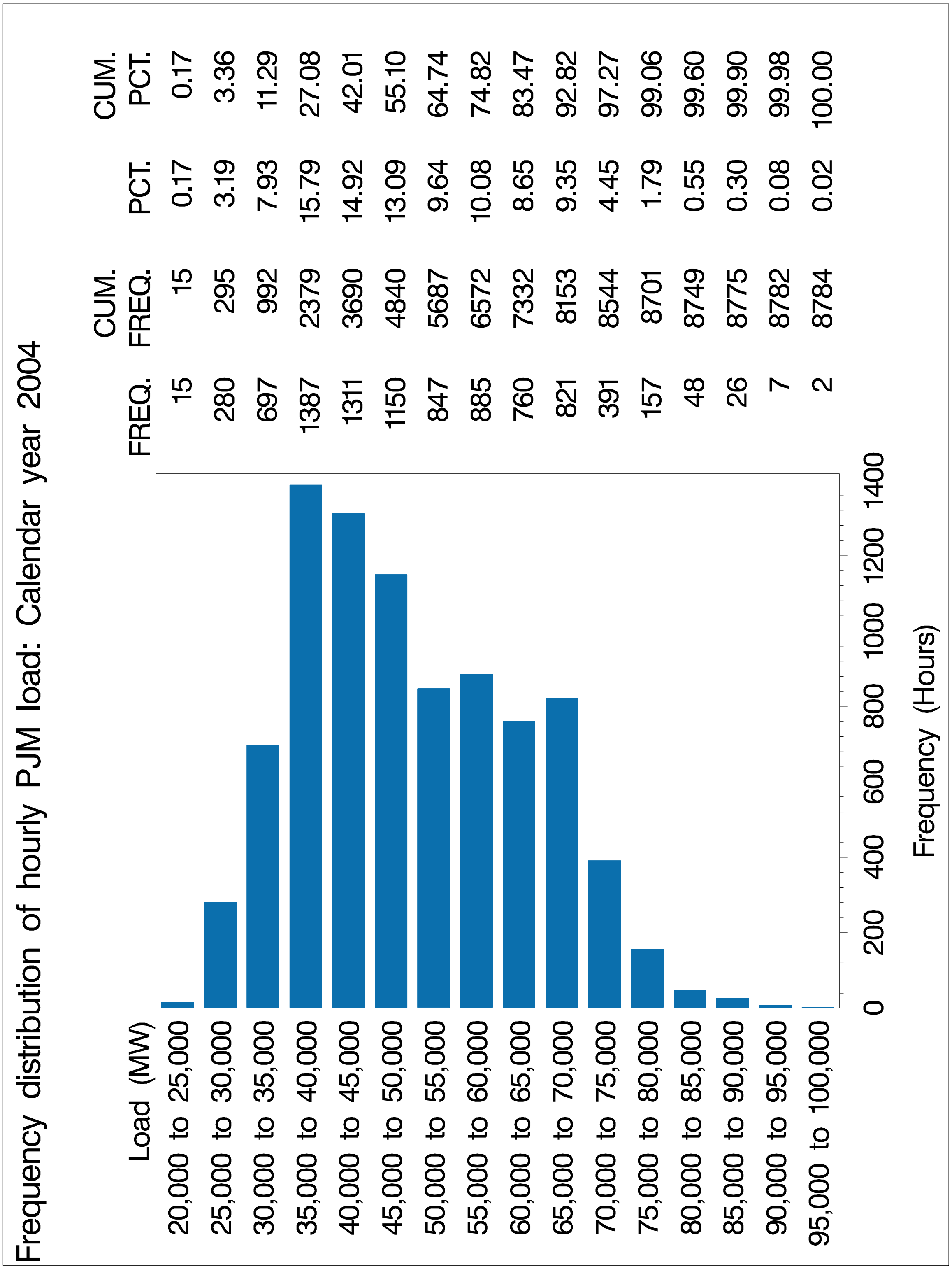
Figure C-13 - Frequency distribution of hourly PJM load: Calendar year 2003

Frequency distribution of hourly PJM load: Calendar year 2003



FREQ.	CUM. FREQ.	PCT.	CUM. PCT.
100	100	1.14	1.14
1193	1293	13.62	14.76
1887	3180	21.54	36.30
2738	5918	31.26	67.56
1666	7584	19.02	86.58
796	8380	9.09	95.66
284	8664	3.24	98.90
84	8748	0.96	99.86
12	8760	0.14	100.00

Figure C-14 - Frequency distribution of hourly PJM load: Calendar year 2004



Load (MW)	FREQ.	CUM. FREQ.	PCT.	CUM. PCT.
20,000 to 25,000	15	15	0.17	0.17
25,000 to 30,000	280	295	3.19	3.36
30,000 to 35,000	697	992	7.93	11.29
35,000 to 40,000	1387	2379	15.79	27.08
40,000 to 45,000	1311	3690	14.92	42.01
45,000 to 50,000	1150	4840	13.09	55.10
50,000 to 55,000	847	5687	9.64	64.74
55,000 to 60,000	885	6572	10.08	74.82
60,000 to 65,000	760	7332	8.65	83.47
65,000 to 70,000	821	8153	9.35	92.82
70,000 to 75,000	391	8544	4.45	97.27
75,000 to 80,000	157	8701	1.79	99.06
80,000 to 85,000	48	8749	0.55	99.60
85,000 to 90,000	26	8775	0.30	99.90
90,000 to 95,000	7	8782	0.08	99.98
95,000 to 100,000	2	8784	0.02	100.00

Off-Peak and On-Peak Load

Table C-1 presents summary load statistics for 1998 to 2004 for the off-peak and on-peak hours, while Table C-2 shows the percent change in load on a year-to-year basis. The on-peak period is defined for each weekday (Monday through Friday) as the hour ending 0800 to the hour ending 2300 Eastern Prevailing Time (EPT), excluding North American Electric Reliability Council (NERC) holidays. Table C-1 shows that in 2004 on-peak load was about 30 percent higher than off-peak load. This same spread is evident for all of the previous six years except for 2003 when it was 20 percent higher. The median peak load during the previous six years had ranged from 20 percent to 30 percent higher than the median off-peak load. With the addition of the ComEd, AEP and DAY Control Zones, average load during on-peak hours in 2004 was 34.2 percent higher than in 2003. Off-peak load in 2004 was 32.9 percent higher than in 2003. (See Table C-2.)

Table C-1 - Off-peak and on-peak load (MW): Calendar years 1998 to 2004

	Average Hourly Load			Median Hourly Load			Standard Deviation of Hourly Load		
	Off Peak	On Peak	On Peak/ Off Peak	Off Peak	On Peak	On Peak/ Off Peak	Off Peak	On Peak	On Peak/ Off Peak
1998	25,268	32,344	1.3	24,728	31,081	1.3	4,091	4,388	1.1
1999	26,453	33,269	1.3	25,780	31,950	1.2	4,947	4,824	1.0
2000	26,917	33,797	1.3	26,313	32,757	1.2	4,466	4,181	0.9
2001	26,804	34,303	1.3	26,433	33,076	1.3	4,225	4,851	1.1
2002	31,817	40,362	1.3	30,654	38,378	1.3	6,060	7,419	1.2
2003	33,595	41,755	1.2	32,971	40,802	1.2	5,546	5,424	1.0
2004	44,631	56,020	1.3	43,028	56,578	1.3	10,845	12,595	1.2

Table C-2 - Multiyear change in load: Calendar years 1998 to 2004

	Average Hourly Load		Median Hourly Load		Standard Deviation of Hourly Load	
	Off Peak	On Peak	Off Peak	On Peak	Off Peak	On Peak
1998	N/A	N/A	N/A	N/A	N/A	N/A
1999	4.7%	2.9%	4.3%	2.8%	20.9%	9.9%
2000	1.8%	1.6%	2.1%	2.5%	-9.7%	-13.3%
2001	-0.4%	1.5%	0.5%	1.0%	-5.4%	16.0%
2002	18.7%	17.7%	16.0%	16.0%	43.4%	52.9%
2003	5.6%	3.5%	7.6%	6.3%	-8.5%	-26.9%
2004	32.9%	34.2%	30.5%	38.7%	95.5%	132.2%

Off-Peak and On-Peak, Load-Weighted LMP: 2003 and 2004

Table C-3 shows load-weighted, average LMP for 2003 and 2004 during off-peak and on-peak periods. In 2003, the on-peak, load-weighted LMP was 60 percent greater than the off-peak LMP, while in 2004, it was 50 percent greater. On-peak, load-weighted, average LMP in 2004 was 5.1 percent higher than in 2003. Off-peak, load-weighted LMP in 2004 was 11.1 percent higher than in 2003. Similarly, both on-peak and off-peak median LMPs were higher in 2004 than in 2003, by 5.0 percent and 35.1 percent, respectively. Dispersion in load-weighted LMP, as indicated by standard deviation, was 18.2 percent lower in 2004 than in 2003 during on-peak hours, while the standard deviation was 17.9 percent lower in 2004 than in 2003 during off-peak hours.

Table C-3 - Off-peak and on-peak, load-weighted LMP (Dollars per MWh): Calendar years 2003 to 2004

	2003			2004			Change 2003 to 2004	
	Off Peak	On Peak	On Peak/ Off Peak	Off Peak	On Peak	On Peak/ Off Peak	Off Peak	On Peak
Average LMP	$31.75	$49.97	1.6	$35.28	$52.53	1.5	11.1%	5.1%
Median LMP	$22.52	$46.08	2.0	$30.42	$48.39	1.6	35.1%	5.0%
Standard Deviation	$23.53	$23.88	1.0	$19.31	$19.53	1.0	-17.9%	-18.2%

Fuel-Cost Adjustment

Fuel costs for 2003 and 2004 were taken from various published sources. 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. Oil prices are the daily price for No. 2 from the New York Harbor Spot Barge and adjusted for transportation to burner tip. Coal prices are calculated based on unit-specific cost-based offers.

The PJM load-weighted, fuel-cost-adjusted LMP has been developed using a year-over-year calculation. A price index is calculated for each month as a chain-weighted index, where the weights are the number of MWh generated by each marginal unit and the associated price of the marginal fuel type.

The percent of the marginal unit fuel mix is calculated on a monthly basis for each year. Each marginal unit is identified and the amount of system load that is influenced by each marginal unit is calculated to determine a load-weighted, monthly average for each marginal fuel. These marginal unit fuel shares are used to calculate monthly Laspeyres, Paasche and Fisher Indices.[4]

The PJM load-weighted, fuel-cost-adjusted LMP is calculated by dividing the appropriate monthly Fisher Index into the appropriate annual hourly PJM load-weighted LMP. For example, to calculate the 2004 fuel-cost-adjusted LMP, one would divide each hour of the 2004 PJM load-weighted LMP by the appropriate 2004 monthly Fisher index and then calculate the mean, median and the standard deviation.

4 J. F. Kenney and E. S. Keeping, Mathematics of Statistics, Pt. 1, 3rd ed. Princeton, NJ: Van Nostrand, 1962. pp. 65-67.

LMP during Constrained Hours: 2003 and 2004

Table C-4 presents summary statistics for load-weighted, average LMP during constrained hours in 2003 and 2004. During constrained hours, the load-weighted, average LMP was 1.0 percent higher in 2004 than it had been for constrained hours in 2003. During constrained hours, the median, load-weighted LMP was 1.3 percent higher in 2004 than in 2003, and the dispersion of LMP, as shown by the standard deviation, was 17.7 percent lower in 2004 than in 2003.

Table C-4 - Load-weighted, average LMP during constrained hours (Dollars per MWh): Calendar years 2003 to 2004

	2003	2004	Change
Average LMP	$45.41	$45.88	1.0%
Median LMP	$41.29	$41.83	1.3%
Standard Deviation	$25.11	$20.68	-17.7%

Table C-5 provides a comparison of load-weighted, average LMP during constrained and unconstrained hours for the two years. In 2004, load-weighted, average LMP during constrained hours was 12.7 percent higher than load-weighted, average LMP during unconstrained hours. The comparable number for 2003 was 30.9 percent.

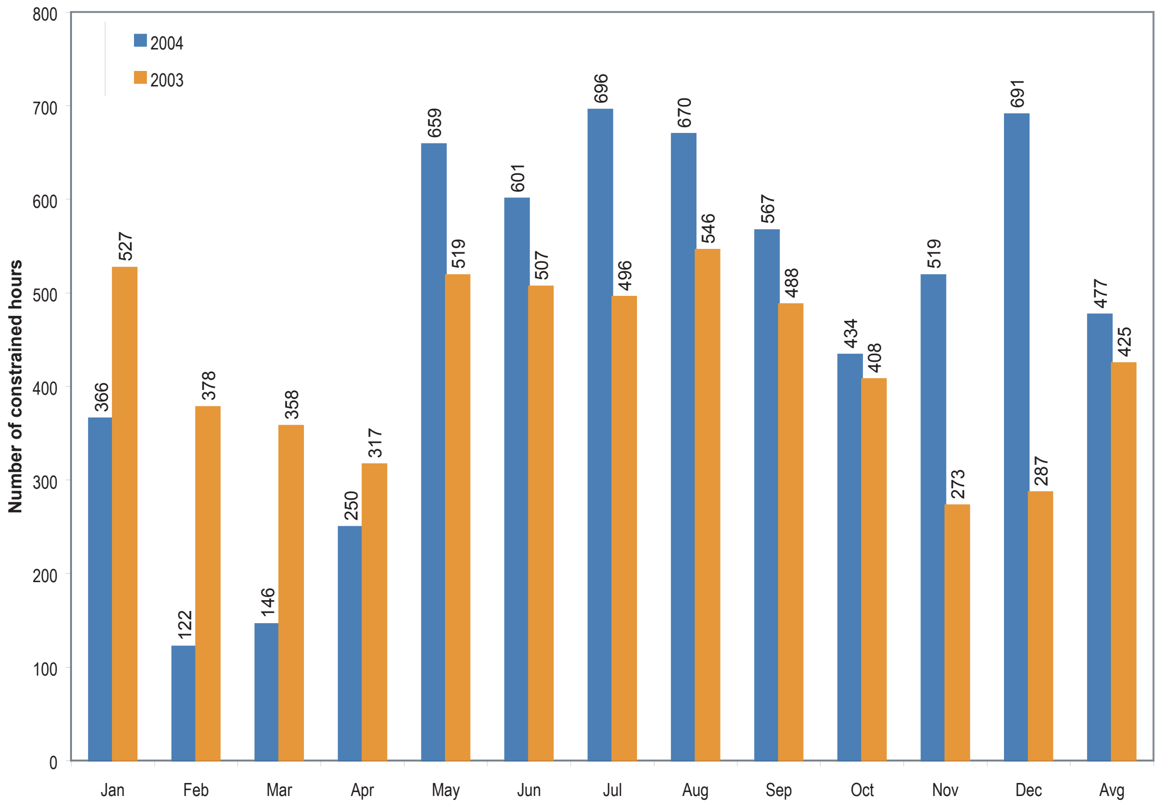
Table C-5 - Load-weighted, average LMP during constrained and unconstrained hours (Dollars per MWh): Calendar years 2003 to 2004

	2003			2004		
	Unconstrained Hours	Constrained Hours	Difference	Unconstrained Hours	Constrained Hours	Difference
Average LMP	$34.69	$45.41	30.9%	$40.72	$45.88	12.7%
Median LMP	$25.00	$41.29	65.2%	$36.55	$41.83	14.5%
Standard Deviation	$24.45	$25.11	2.7%	$22.12	$20.68	-6.5%

Figure C-15 shows the number of real-time constrained hours during each month in 2003 and 2004 and the average number of constrained hours per month for each year.[5] There were 5,104 constrained hours in 2003 and 5,721 in 2004, an increase of approximately 12.1 percent. Figure C-15 also shows that the average number of constrained hours per month was slightly higher in 2004 than in 2003, with 477 per month in 2004 versus 425 per month in 2003.

5 The constrained-hour data presented here use the convention that an hour is considered congested when the difference in LMP between at least two buses is greater than $0.00 and congestion occurs for 20 minutes or more within an hour. In prior years, this Appendix to The State of the Market Report defined a congested hour as one in which the difference in LMP between at least two buses in that hour was greater than $1.00.

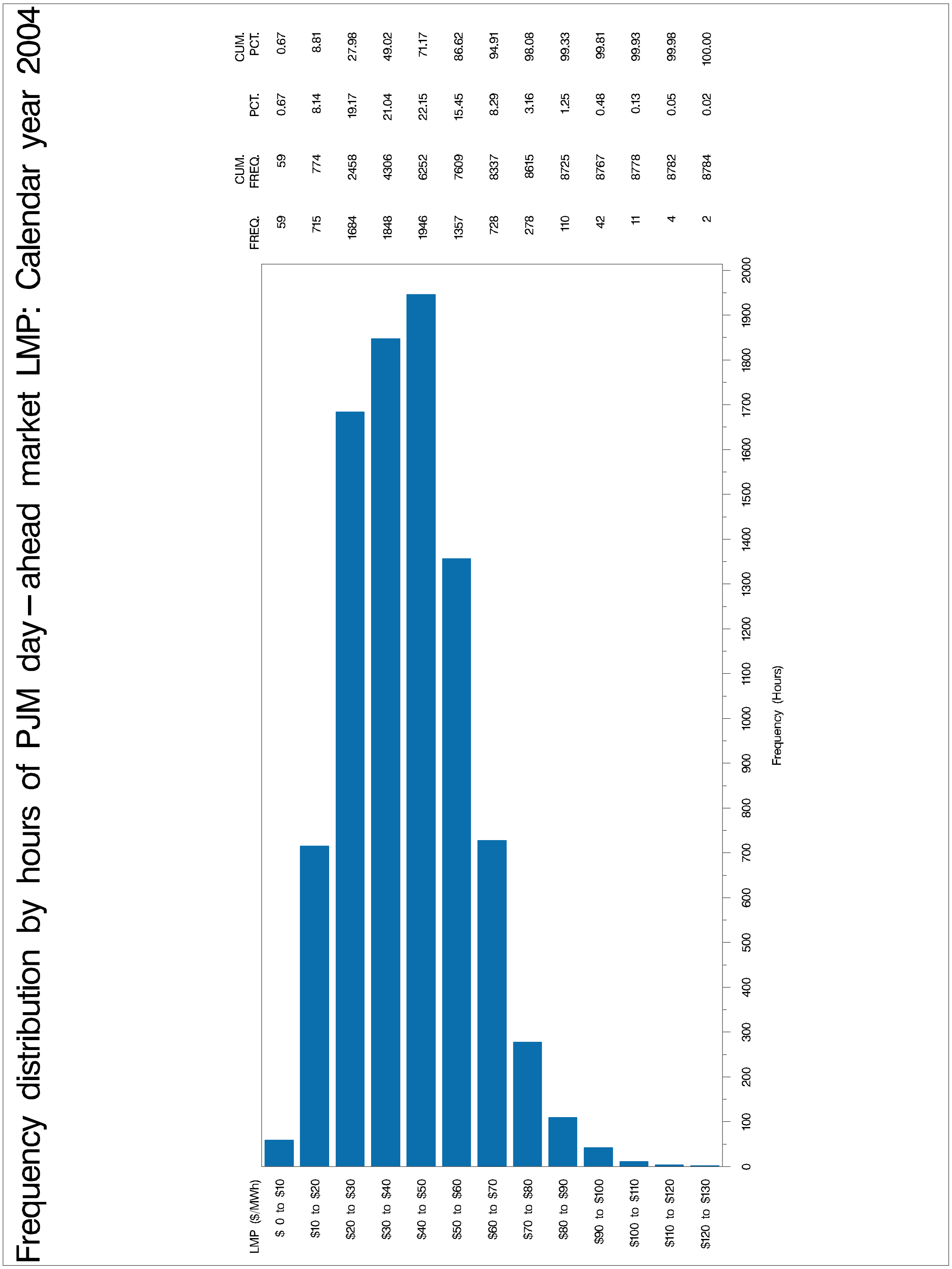
Figure C-15 - PJM real-time constrained hours: Calendar years 2003 to 2004



Day-Ahead and Real-Time Prices

Real-time prices are slightly higher than day-ahead prices on average and real-time prices show greater dispersion. This pattern of average, systemwide LMP price distribution for 2004 can be seen in Figure C-7 and Figure C-16. Together they show the frequency distribution by hours for the two markets. In PJM's Real-Time Energy Market, both the $20-per-MWh to $30-per-MWh interval and the $30-per-MWh to $40-per-MWh interval occurred with almost equal frequency, approximately 22 percent of the hours. (See Figure C-7.) The most frequently occurring price interval in the PJM Day-Ahead Energy Market was the $40-per-MWh to $50-per-MWh interval with 22 percent of the hours. (See Figure C-16.) The $30-per-MWh to $40-per-MWh interval was the next most frequently occurring with 21 percent of the hours. The $20-per-MWh to $30-per-MWh interval occurred during 19 percent of the hours. In the Real-Time Energy Market, prices were less than $30 per MWh for 32 percent of the hours, while prices were less than $30 per MWh in the Day-Ahead Energy Market for 28 percent of the hours. Cumulatively, prices were less than $40 per MWh for 54 percent of the hours in the Real-Time Energy Market and 49 percent of the hours in the Day-Ahead Energy Market; less than $50 per MWh for 70 percent of the hours in the Real-Time Energy Market and 71 percent of the hours in the Day-Ahead Energy Market; less than $60 per MWh for 81 percent of the hours in the Real-Time Energy Market and 87 percent of the hours in the Day-Ahead Energy Market. In the Real-Time Energy Market, prices were above $120 per MWh for 35 hours (0.40 percent of the hours), reaching a high for the year of $180.12 per MWh on December 20 during the hour ending 0900 EPT. In the Day-Ahead Energy Market, prices were above $120 per MWh for two hours (0.02 percent of the hours) and reached a high for the year of $129.35 per MWh on January 15, 2004, during the hour ending 1800 EPT.

Figure C-16 - Frequency distribution by hours of day-ahead energy market LMP: Calendar year 2004



LMP ($/MWh)	FREQ.	CUM. FREQ.	PCT.	CUM. PCT.
$ 0 to $10	59	59	0.67	0.67
$10 to $20	715	774	8.14	8.81
$20 to $30	1684	2458	19.17	27.98
$30 to $40	1848	4306	21.04	49.02
$40 to $50	1946	6252	22.15	71.17
$50 to $60	1357	7609	15.45	86.62
$60 to $70	728	8337	8.29	94.91
$70 to $80	278	8615	3.16	98.08
$80 to $90	110	8725	1.25	99.33
$90 to $100	42	8767	0.48	99.81
$100 to $110	11	8778	0.13	99.93
$110 to $120	4	8782	0.05	99.98
$120 to $130	2	8784	0.02	100.00

Off-Peak and On-Peak LMP

Table C-6 shows average LMP during off-peak and on-peak periods for the Day-Ahead and Real-Time Energy Markets during calendar year 2004. Day-ahead and real-time, on-peak average LMPs were 58 and 52 percent higher, respectively, than the corresponding off-peak average LMP. The real-time, on-peak average LMP was 0.6 percent higher than the day-ahead, on-peak average LMP. Median LMPs during on-peak hours were 67 percent and 63 percent higher in the Day-Ahead and Real-Time Energy Markets, respectively, than median LMPs during off-peak hours. In contrast to average prices but consistent with historical experience, the real-time, on-peak median LMP was 4.3 percent lower than the day-ahead, on-peak median LMP. Since the mean was above the median in these markets, both showed a positive skewness. The mean was, however, proportionately higher than the median in the Real-Time Energy Market as compared to the Day-Ahead Energy Market during both on-peak and off-peak periods (9 percent and 17 percent compared to 3 percent and 9 percent, respectively). The differences reflect larger positive skewness in the Real-Time Energy Market. During on-peak hours, the standard deviation in the Real-Time Energy Market was about 32 percent higher than in the Day-Ahead Energy Market, while it was 26 percent higher during off-peak hours.

Table C-6, Figure C-17 and Figure C-18 show the difference between real-time and day-ahead LMP during calendar year 2004 during the on-peak and off-peak hours, respectively. The difference between real-time and day-ahead average LMP during on-peak hours was only $0.32 per MWh. (Day-ahead LMP was lower than real-time LMP.) During the off-peak hours, the difference between real-time and day-ahead average LMP was $1.55 per MWh. (Day-ahead LMP was lower than real-time LMP.)

Table C-6 - Off-peak and on-peak hourly LMP (Dollars per MWh): Calendar year 2004

	Day-Ahead			Real-Time			Change in Real-Time Relative to Day-Ahead	
	Off Peak	On Peak	On Peak/ Off Peak	Off Peak	On Peak	On Peak/ Off Peak	Off Peak	On Peak
Average LMP	$32.53	$51.54	1.58	$34.08	$51.86	1.52	4.8%	0.6%
Median LMP	$29.84	$49.85	1.67	$29.20	$47.70	1.63	-2.1%	-4.3%
Standard deviation	$14.08	$13.08	0.93	$19.04	$19.31	1.01	35.3%	47.6%

Figure C-17 - Hourly real-time LMP minus day-ahead LMP (On-peak hours): Calendar year 2004

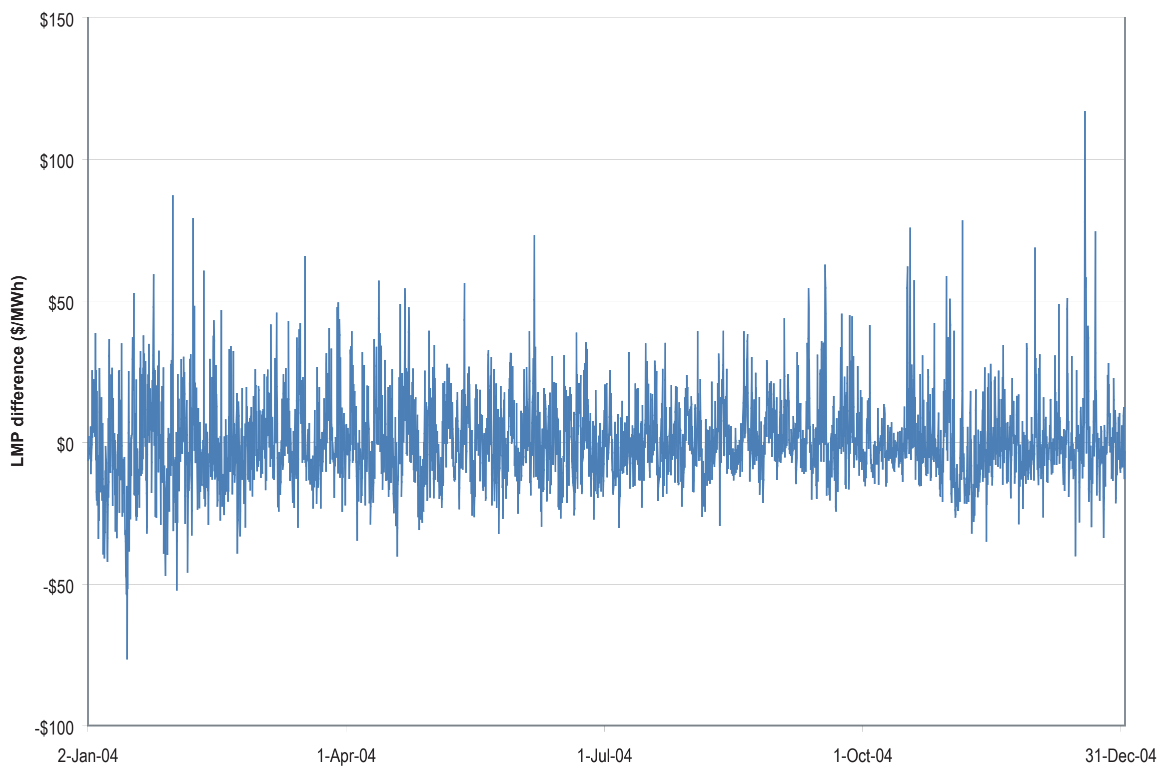
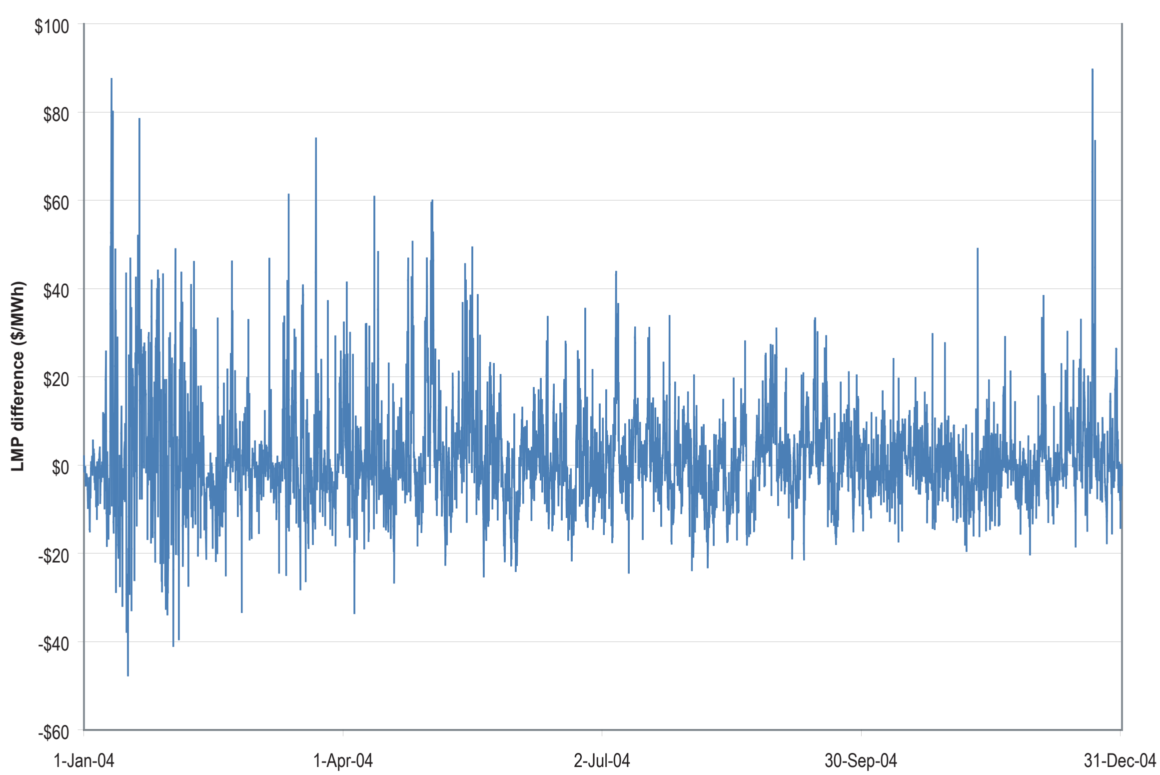


Figure C-18 - Hourly real-time LMP minus day-ahead LMP (Off-peak hours): Calendar year 2004



LMP during Constrained Hours: Day-Ahead and Real-Time Energy Markets

Figure C-19 shows the number of constrained hours in each month for the Day-Ahead and Real-Time Energy Markets and the average number of constrained hours for 2004. Overall, there were 5,721 constrained hours in the Real-Time Energy Market and 8,158 constrained hours in the Day-Ahead Energy Market. Figure C-19 shows that in every month of calendar year 2004 the number of constrained hours in the Day-Ahead Energy Market exceeded those in the Real-Time Energy Market. On average for the year, the Day-Ahead Energy Market had 43 percent more constrained hours than the Real-Time Energy Market.

Figure C-19 - Real-time and day-ahead, market-constrained hours: Calendar year 2004

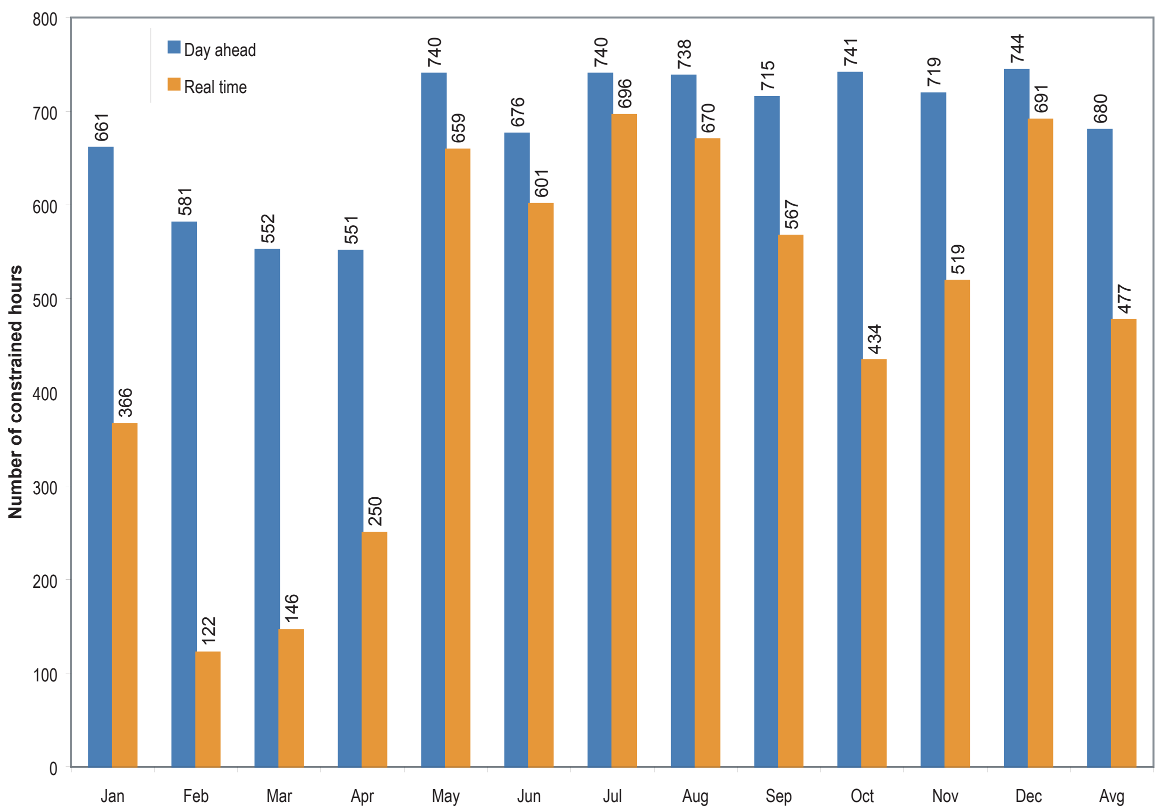


Table C-7 shows average LMP during constrained and unconstrained hours in the Day-Ahead and Real-Time Energy Markets. In the Day-Ahead Energy Market, average LMP during constrained hours was 21.5 percent higher than average LMP during unconstrained hours. In the Real-Time Energy Market, average LMP during constrained hours was 12.6 percent higher than average LMP during unconstrained hours. Average LMP during constrained hours was 5.2 percent higher in the Real-Time Energy Market than in the Day-Ahead Energy Market.

Table C-7 - LMP during constrained and unconstrained hours (Dollars per MWh): Calendar year 2004

	Day Ahead			Real Time		
	Unconstrained Hours	Constrained Hours	Percent Difference	Unconstrained Hours	Constrained Hours	Percent Difference
Average LMP	$34.53	$41.96	21.5%	$39.18	$44.13	12.6%
Median LMP	$32.29	$40.94	26.8%	$34.94	$40.09	14.7%
Standard deviation	$14.97	$16.60	10.8%	$21.81	$20.54	-5.8%

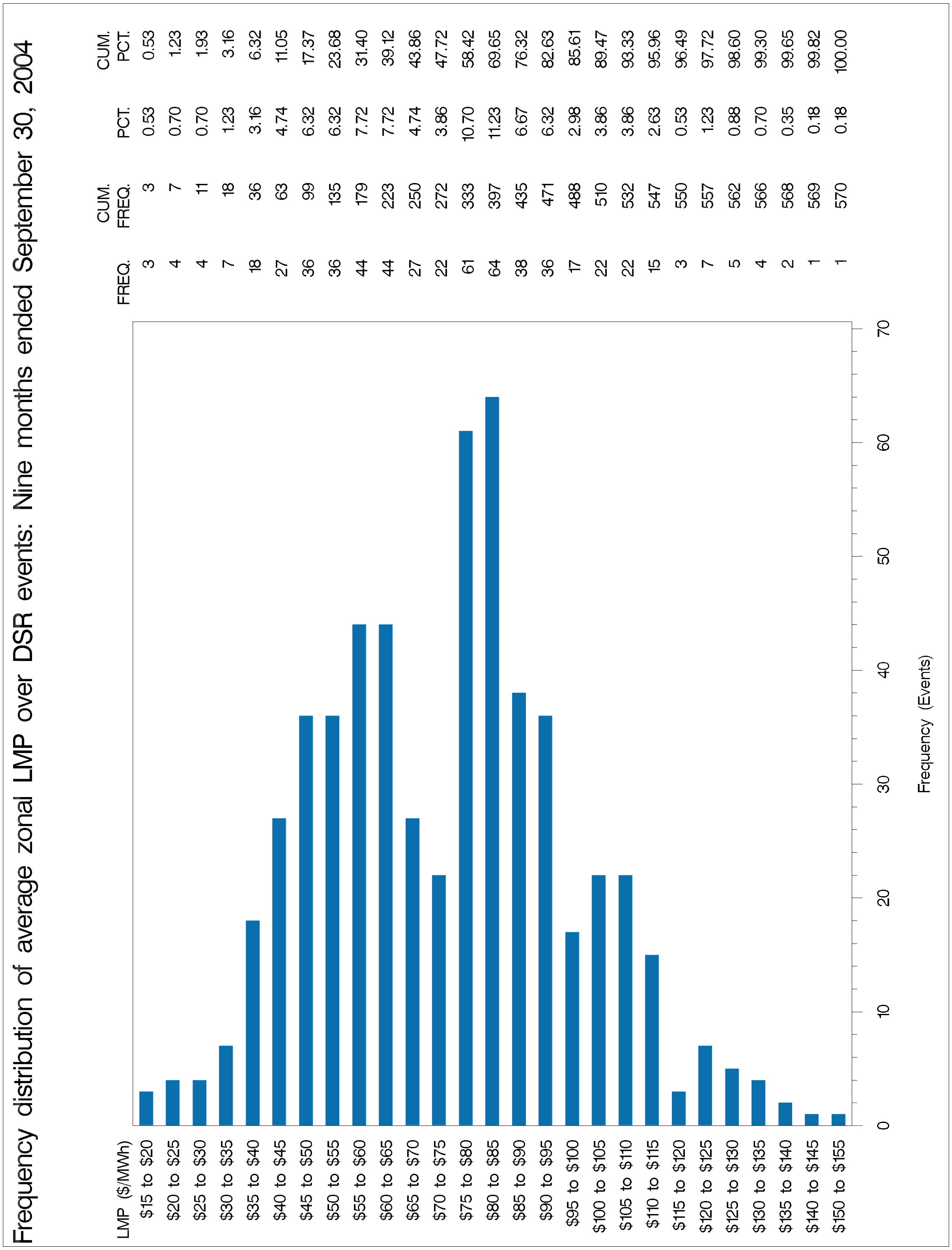
Taken together, the data shows that average LMP in the Day-Ahead Energy Market during constrained hours was 1.3 percent higher than the overall average LMP for the Day-Ahead Energy Market, while average LMP during unconstrained hours was 16.7 percent lower.[6] In the Real-Time Energy Market, average LMP during constrained hours was 4.1 percent higher than the overall average LMP for the Real-Time Energy Market, while average LMP during unconstrained hours was 7.6 percent lower.

Frequency of Demand-Side Response (DSR) Events under the Economic Program Options

Figure C-20 shows the number of demand-side response (DSR) events (frequency), the cumulative number of DSR events (cumulative frequency), the percent of DSR events (percent) and the cumulative percent of DSR events (cumulative percent) that average zonal LMP was within a given $5 per MWh price range.[7] This figure includes the nine months of available data, ended September 30, 2004. The DSR business rules provide for larger payments when LMP is above $75 per MWh than when LMP is below $75 per MWh. A DSR event is the range of hours in a day when participants in one of the zones reduce their load under one of the DSR Economic Program options. Participants in multiple zones can reduce their load during a specific DSR event simultaneously. If the zonal prices vary, this DSR event will appear in more than one of the $5 price increments of Figure C-20.

6 See Section 2, "Energy Market" for this table.
7 Average zonal LMP is calculated for every option of the Economic Program by averaging preliminary, posted real-time zonal LMP over the hours of a DSR event. For example, if a particular zone participated in multiple options of the Economic Program during a specific DSR event, then there would be average zonal LMP for each of the Economic Program's options.

Figure C-20 - Frequency distribution of average zonal LMP over DSR events: Nine months ended September 30, 2004



LMP ($/MWh)	FREQ.	CUM. FREQ.	PCT.	CUM. PCT.
$15 to $20	3	3	0.53	0.53
$20 to $25	4	7	0.70	1.23
$25 to $30	4	11	0.70	1.93
$30 to $35	7	18	1.23	3.16
$35 to $40	18	36	3.16	6.32
$40 to $45	27	63	4.74	11.05
$45 to $50	36	99	6.32	17.37
$50 to $55	36	135	6.32	23.68
$55 to $60	44	179	7.72	31.40
$60 to $65	44	223	7.72	39.12
$65 to $70	27	250	4.74	43.86
$70 to $75	22	272	3.86	47.72
$75 to $80	61	333	10.70	58.42
$80 to $85	64	397	11.23	69.65
$85 to $90	38	435	6.67	76.32
$90 to $95	36	471	6.32	82.63
$95 to $100	17	488	2.98	85.61
$100 to $105	22	510	3.86	89.47
$105 to $110	22	532	3.86	93.33
$110 to $115	15	547	2.63	95.96
$115 to $120	3	550	0.53	96.49
$120 to $125	7	557	1.23	97.72
$125 to $130	5	562	0.88	98.60
$130 to $135	4	566	0.70	99.30
$135 to $140	2	568	0.35	99.65
$140 to $145	1	569	0.18	99.82
$150 to $155	1	570	0.18	100.00

As Figure C-20 indicates, during the nine months ended September 30, 2004, DSR events when prices were below $75 per MWh increased in frequency in the $35 to $40 per MWh price range and were concentrated in the $45 to $65 per MWh range. The same figure shows that DSR events when prices were greater than $75 per MWh were concentrated in the $75 to $95 per MWh range. A majority, 52 percent, of all DSR events took place when average zonal LMP during the DSR event was equal to, or greater than, $75 per MWh.

APPENDIX D - INTERCHANGE TRANSACTIONS

In competitive wholesale power markets, price signals guide purchase and sales decisions. If neighboring wholesale power markets incorporate security-constrained nodal pricing and are designed and managed well, the interface pricing points allow economic signals to guide efficient import and export decisions. When a competitive market shares a boundary with an area reliant on bilateral contracts and associated contract paths to manage transactions, however, the independent system operator (ISO) or regional transmission organization (RTO) needs to define its interface pricing points so that imports and exports, especially under conditions of congestion, face price signals that are consistent with the underlying reality of generation and transmission resources.

PJM has an established process for developing and implementing interface prices. PJM increased the sophistication of that process in 2002 by addressing the causes of loop flow. PJM further developed the application of interface pricing for the integration of the Commonwealth Edison Company (ComEd) Control Area.[1,2] Located in Northern Illinois, the ComEd Control Area was linked to the rest of the PJM through a Pathway. On October 1, 2004, with the Phase 3 integration of the American Electric Power Company (AEP) and The Dayton Power & Light Company (DAY) Control Zones, the Pathway was internalized.[3]

PJM's evolution during 2004 required the establishment of new interfaces and interface pricing points during Phase 2, some of which were eliminated during Phase 3.

The integrations of Phases 2 and 3 created new boundaries including boundaries with the Midwest Independent Transmission System Operator, Inc. (Midwest ISO). Since the Midwest ISO is not yet operating a competitive market with security-constrained redispatch rights, congestion is currently managed through coordinated flowgates under a joint operating agreement between PJM and the Midwest ISO.

Historical Development of Interface Pricing

On July 19, 2002, PJM notified market participants that pricing for transactions scheduled at the PJM/ Dominion Virginia Power (VAP)[4] interface, but delivered at the PJM/AEP interface, would be corrected, effective at 1500 hours Eastern Prevailing Time (EPT).[5] PJM had observed significant and growing differentials between scheduled and actual flows before it issued its pricing notice. The pricing notice provided that import transactions scheduled into PJM at the PJM/VAP interface would be paid the price at the PJM/AEP interface if those transactions originate to the west of PJM, regardless of artificial contract paths constructed to avoid the required pricing. Instead, pricing would be based on the appropriate flow analysis under Section 3.3.1(d) of Schedule 1 of the Operating Agreement.[6]

1 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.
2 Control areas external to PJM are referred to as control areas not control zones. For example, the FirstEnergy control area is not referred to as the FirstEnergy control zone.
3 A description of the interfaces and interface pricing points as they evolved during 2004 can be found in Section 3, "Interchange Transactions."
4 Interfaces are named after adjacent control areas, 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 See PJM Marketing Monitoring Unit, "Interface Pricing Policy," as reported to the FERC (August 12, 2002) < http://www.pjm.com/markets/market-monitor/downloads/mmu-reports/ 200208-report-ferc1.pdf > (365 KB).
6 See PJM, "Operating Agreement" (January 25, 2005), Section 3.3.1(d) < http://www.pjm.com/documents/downloads/agreements/oa.pdf > (613 KB).

Historically, PJM had paid external transactions under the assumption that transactions scheduled from or through an adjacent control area were using a direct contract path from that control area to the interface between it and PJM. Therefore, PJM paid external transactions based on scheduled flows to interfaces. The locational marginal price (LMP) at a PJM interface did not assume that transactions were scheduled based on the purchase of contract path transmission service inconsistent with actual transaction flow.

To reflect the actual flow of transactions associated with the PJM/AEP and PJM/VAP interfaces, PJM announced the introduction of the AEPVPIMP and AEPVPEXP interface pricing points in February 2003. Effective March 1, 2003, PJM implemented system changes allowing it to price all transactions that source (have origins) in PJM and sink (have destinations) in one of the relevant defined control areas, at the PJM/AEPVPEXP interface price and all transactions that sink in PJM and source in one of the defined control areas, at the PJM/AEPVPIMP interface price.[7]

PJM Interface Pricing Point Definition – General Methodology[8]

PJM establishes prices for transactions with external control areas by assigning interface pricing points to external control areas. The interface pricing points are designed to reflect the way a transaction from or to an external area actually impacts PJM electrically. External control areas are either adjacent to PJM or not adjacent to PJM.

Transactions between PJM and external control areas need to be priced at the PJM border. A set of external pricing points is used to create such interface prices. The challenge is to create an interface price, composed of external pricing points, that accurately represents flows between PJM and an external control area and therefore to create price signals that embody the underlying economic fundamentals. Transactions between adjacent control areas and PJM flow on one or more physical tie lines that together constitute the interface between the two control areas.

Each adjacent control area either has a separate interface pricing point or, if distribution factor analysis shows that identified adjacent control areas have similar electrical effects on the tie lines connecting them to PJM, multiple adjacent control areas can use a common interface price definition. Thus an interface price definition may include external pricing points from one adjacent control area or a combination of adjacent control areas. An abbreviation of the adjacent control areas is used to create names for the interface pricing points. For example, the MidAmerican Energy Company (MEC) is adjacent to the Northern Illinois (NI) control area (now termed the ComEd Control Zone). The two acronyms, MEC and NI, were combined to create the MECNI name for the interface pricing point between MEC and NI.

7 See PJM Market Monitoring Unit, "Interface Pricing Policy" as reported to the FERC (February 28, 2003) < http://www.pjm.com/markets/market-monitor/downloads/mmu-reports/20030301-interface-pricing.pdf > (654 KB).
8 The following discussion of the PJM methodology for defining interface pricing points relies on the PJM analysis and associated white papers developed in conjunction with the 2004 integrations. The white papers are available through the PJM Web site. See generally PJM, "AEP & DP&L Transmission and Market Integration White Paper, Version 1.4" (September 24, 2004) < http://www.pjm.com/markets/market-integration/downloads/documentation/20040924-v67-aep-dpl-transmission-market-whitepaper-v14.pdf > (890 KB). See also PJM, "Draft ComEd Transmission and Market Integration White Paper, Version 2.3" (April 15, 2004) < http://www.pjm.com/markets/market-integration/downloads/ documentation/comed-transmission -market-implement.pdf> (12.6 MB).

As an example, the PJM analysis for the ComEd integration showed that transactions from specific adjacent control areas had very similar electrical effects on PJM and were, therefore, given the same interface price definition. For example, MEC and Alliant Energy Corporation West (ALTW) are adjacent control areas with similar electrical effects on tie lines connecting them to PJM. As a result, the interface price is the same for both control areas and consists of a combination of external pricing points from both the adjacent control areas.

As another example, the PJM analysis for the AEP and DAY Control Zone integrations showed a number of adjacent control areas with very similar effects on tie lines connecting them to PJM. As a result, single interface pricing points were created to define groups of adjacent control areas. As an example, a group of control areas with similar electrical effects on PJM was determined to include Central Illinois Light Company (CILCO), Illinois Power Company (IP), Indianapolis Power & Light Company (IPL), Ameren, Cinergy Corporation (CIN), East Kentucky Power Cooperative, Inc. (EKPC), LG&E Energy, L.L.C. (LGEE) and Tennessee Valley Authority (TVA). The Southwest pricing point was defined as the single interface price used to price transactions to or from this group of adjacent control areas.

Transactions from external, non-adjacent control areas are also priced at interface prices. PJM, in its AEP and DAY transition white paper, describes how standard power flow analysis tools are used to simulate transactions with external, non-adjacent control areas to obtain distribution factor data. The distribution factor data are analyzed to determine through which adjacent control area the majority of power from the external, non-adjacent control area flows. By calculating the correlation coefficient between the external, non-adjacent control area distribution factor and the distribution factor for each of the adjacent control areas, PJM determines the association of an external control area with one of the adjacent control areas and assigns a corresponding interface price.

A more complex situation arises when a transaction from an external, non-adjacent control area results in similar flows on multiple interfaces with different interface price definitions. In that case, an additional interface price definition may be required to reflect the impact of transactions from the external, non-adjacent control area on multiple interface pricing points defined with adjacent control areas. As an example, flows between the Ontario IESO and PJM tend to be split between adjacent control areas, primarily the New York Independent System Operator (NYIS) and the FirstEnergy Corp. (FE), each of which has a different interface price. Neither interface price was separately appropriate for transactions with the Ontario IEOS. So PJM created the Ontario IESO interface price to include both interface prices so as to appropriately reflect the price for transactions with the Ontario IESO.

Phase 2 Integration of the ComEd Control Area[9]

PJM was comprised of two separate control areas during Phase 2: the PJM Control Area, consisting of the Mid-Atlantic Region and the Allegheny Power Company (AP) Control Zone; and the ComEd Control Area located in Northern Illinois. The two control areas were geographically separate.

The integration of ComEd required the addition of new interface pricing points. Since energy flows from external control areas had different impacts on the two noncontiguous PJM Control Areas,

9 See generally PJM, "Draft ComEd Transmission and Market Integration White Paper, Version 2.3" (April 15, 2004) < http://www.pjm.com/markets/market-integration/downloads/ documentation/comed-transmission-market-implement.pdf> (12.6 MB).

each external control area mapped to one interface pricing point with respect to the ComEd Control Area and to a separate interface pricing point with respect to the PJM Control Area. For example, because an import from AEP impacted each control area differently, there was one interface pricing point for an AEP import into Northern Illinois (AEPNI) and another interface pricing point for an AEP import to PJM (AEPVPIMP). Several additional pricing point illustrations are presented in the PJM white paper on the ComEd integration.[10]

The use of interface pricing points allows two energy transactions with identical physical flows or generation control area (GCA) and load control area (LCA) pairs (GCA is the control area where the generator is located and LCA is the control area where the load is located), to receive the same price regardless of contract path. An import to PJM from FE before the integration of ComEd offers a good example. This import would have received the same pricing point, FE, whether it was scheduled as FE to AEP to PJM or FE to PJM. The same logic can be extended to the period during which ComEd was being integrated, but remained its own, stand alone, control area. This is important because a transaction could be constructed in such a way that a control area could be circumvented even though an electrical impact would still be experienced there. A transaction could be constructed where flows through the control area would not be indicated in its transmission path. For example, if an energy transaction originating in MEC (located west of NI) were destined for the PJM Control Area, the transmission path could be constructed several ways. One way would indicate flow through ComEd and another would not; yet both would be expected to receive the same pricing. The former might have the path MEC to NI to AEP to PJM, but the latter might have the path MEC to IP to AEP to PJM.

In this example, the noncircumventing import into the PJM Control Area comes from the MEC control area. It uses the path MEC to NI to AEP to PJM and would have two pricing points assigned to the wheel through Northern Illinois, one to the import and another to the export. The first part of the transaction is the import at the MECNI interface and it receives a credit equal to the MECNI price. The second part of the transaction is the export at AEPNI and it receives a charge equal to the AEPNI price. Then the flow is into PJM at AEPVP and it is credited the AEPVPIMP price. This yields a final pricing of [(MECNI-AEPNI)+AEPVPIMP]. The circumventing import with the path MEC to IP to AEP to PJM would simply be assigned the posted pricing point of MECPJMIMP. MECPJMIMP is defined as [(MECNI-AEPNI)+AEPVPIMP]. In both cases the final pricing is the same.[11, 12]

10 See generally PJM, "Draft ComEd Transmission and Market Integration White Paper, Version 2.3" (April 15, 2004), pp. 51-53 < http://www.pjm.com/markets/market-integration/ downloads/documentation/comed-transmission-market-implement.pdf> (12.6 MB).

11 See generally PJM, "Draft ComEd Transmission and Market Integration White Paper, Version 2.3" (April 15, 2004), pp. 8-9 < http://www.pjm.com/markets/market-integration/ downloads/documentation/comed-transmission-market-implement.pdf> (12.6 MB).

12 For simplification, these examples assume no line losses. The impact of line losses in this type of example is discussed in the PJM white paper on the ComEd integration. It explains that implementation of marginal losses was necessary given the geography of the two control areas.

Phase 2 Interface Pricing Point Definitions[13]

During Phase 2, PJM transactions occurred at 23 defined pricing points (Table D-1).

Table D-1 - ComEd interface pricing point definitions

Pricing Point	Definition
AEPNI	Price at the AEP interface with the ComEd Control Area in NI
AEPVPEXP	Export (EXP) price at the AEP/VAP interface with the PJM Control Area
AEPVPIMP	Import price at the AEP/VAP interface with the PJM Control Area
ALTE	Price at the Alliant Energy Corporation eastern (ALTE) interface with the ComEd Control Area in NI, defined as the same as the price at the Wisconsin Energy Corporation (WEC) interface with the ComEd Control Area
ALTW	Price at the Alliant Energy Corporation western (ALTW) interface with the ComEd Control Area in NI, defined as the same as the price at the MEC interface with the ComEd Control Area
AMRN	Price at the Ameren Corporation (AMRN) interface with the ComEd Control Area in NI, defined as the same as the price at the IP interface with the ComEd Control Area
CILC	Price at the Central Illinois Light Company (CILC) interface with the ComEd Control Area in NI, defined as the same as the price at the IP interface with the ComEd Control Area
DLCO	Price at the Duquesne Light Company (DLCO or DQE) interface with the PJM Control Area
FE	Price at the FirstEnergy Corp. (FE) interface with the PJM Control Area
Ontario IESO	Price at the Independent Electricity Market Operator for Ontario (Ontario IESO) interface with the PJM Control Area
IP	Price at the IP interface with the ComEd Control Area in NI
IPPJMIMP	Price to import to the PJM Control Area from a control area in the southwest pricing point group: [IP - AEPNI + AEPVPIMP]
IPPJMEXP	Price to export from the PJM Control Area to a control area in the southwest pricing point group: [AEPVPEXP – AEPNI + IP]
MEC	Price at the MEC interface with the ComEd Control Area in NI
MECPJMIMP	Price to import to the PJM Control Area from a control area in the west pricing point group: [MEC – AEPNINI + AEPVPIMP]
MECPJMEXP	Price to export from the PJM Control Area to a control area in the west pricing point group: [AEPVPEXP – AEPNINI + MEC]
NIPS	Price at the Northern Indiana Public Service Company (NIPS) interface with the ComEd Control Area in NI, defined as the same as the price at the AEP interface with the ComEd Control Area
NYIS	Price at the NY interface with the PJM Control Area
NYISNIIMP	Price to import to the ComEd Control Area in NI from a control area in the northeast pricing point group: [NYIS – AEPVPEXP + AEPNI]
NYISNIEXP	Price to export from the ComEd Control Area in NI to a control area in the northeast pricing point group: [AEPNI – AEPVPIMP + NYIS]
WEC	Price at the WEC interface with the ComEd Control Area in NI
WECPJMIMP	Price to import to the PJM Control Area from a control area in the northwest pricing point group: [WEC – AEPNI + AEPVPIMP]
WECPJMEXP	Price to export from the PJM Control Area to a control area in the northwest pricing point group: [AEPVPEXP – AEPNI + WEC]

13 See generally PJM, "Draft ComEd Transmission and Market Integration White Paper, Version 2.3" (April 15, 2004), p. 78 < http://www.pjm.com/markets/market-integration/ downloads/documentation/comed-transmission-market-implement.pdf> (12.6 MB).

Phase 3 Integration of the AEP and DAY Control Zones[14]

With the integration of the AEP and DAY Control Zones, PJM became a single Control Area. The PJM Western Region then encompassed four control zones: the AEP, DAY, ComEd and AP Control Zones. Integration of the AEP and DAY Control Zones permitted all external control areas in a group to be mapped to one interface pricing point relative to the expanded PJM Control Area.

The PJM interface pricing points are applied to transactions based on the source (imports) and sink (exports) control areas associated with a particular transaction. Adjacent control areas, connected directly to the expanded PJM marketplace, have been grouped according to the electrical impact on PJM of transactions originating in each control area. This resulted in nine different interface pricing points. Control areas with similar impacts have been assigned to the same interface pricing point. These groupings are defined in Table D-2.

Table D-2 - AEP integration interface pricing point definitions[15]

Pricing Point	Included Control Areas
Northwest	Wisconsin Energy Corporation (WEC), Alliant East, Alliant West, MEC
Southwest	Central Illinois Light Company (CILCO), IP, Indianapolis Power & Light Company (IPL), Ameren, Cinergy (CIN), East Kentucky Power Cooperative, Louisville Gas & Electric Company (LG&E), Tennessee Valley Authority (TVA)
OVEC	Ohio Valley Electric Corporation (OVEC)
NIPSCO	Northern Indiana Public Service Company (NIPSCO)
Southeast	Carolina Power & Light Company (CPL) West (CP&LW), Carolina Power & Light Company (CPL) East (CP&LE), Duke Power (DUK), Dominion Virginia Power (DVP)
DLCO	Duquesne Light Company (DQE)
Ontario IESO	Ontario IESO
MICHFE	Michigan Electric Coordinated System, First Energy

The Coordinated Flowgates of PJM and the Midwest ISO

The flowgates where PJM and the Midwest ISO have agreed to take a coordinated response to congestion events are defined in a joint operating agreement between the two organizations.[16] Under its terms, PJM redispatches generation to reduce congestion at these facilities. As of October 29, 2004, there were 316 such flowgates.[17]

14 See generally PJM, "AEP & DP&L Transmission and Market Integration White Paper, Version 1.4" (September 24, 2004), p. 21 < http://www.pjm.com/ markets/market-integration/ downloads/ documentation/ 20040924-v67-aep-dpl-transmission-market-whitepaper-v14.pdf > (890 KB).
15 See Section 3, "Interchange Transactions," for a discussion of the evolution of pricing points during 2004.
16 See the "Joint Operating Agreement between the Midwest Independent Transmission System Operator, Inc. and PJM Interconnection, L.L.C." (December 31, 2003) < http://www.pjm.com/ documents/downloads/agreements/joa-complete.pdf > (906 KB). The document is herein called the JOA between the Midwest ISO and PJM.
17 Flowgates subject to coordination can be found through the PJM OASIS system. It can be accessed via eData although acceptance of the PJM usage agreement is necessary to reach the portion of the Web site where the list is maintained.

APPENDIX E - CAPACITY MARKETS[1]

Background

PJM and its members have long relied on capacity obligations as one of the methods to ensure reliability. Before retail restructuring, the original PJM members had determined their loads and related capacity obligations annually. Combined with state regulatory requirements to build and incentives to maintain adequate capacity, this system created a reliable pool, where capacity and energy were adequate to meet customer needs and where capacity costs were borne equitably by members and their loads.

Capacity obligations continue to be critical to maintaining reliability and to contribute to the effective, competitive operation of PJM Energy Markets. Adequate capacity resources, equal to or greater than expected load plus a reserve margin, help to ensure that energy is available on even the highest load days.

On January 1, 1999, in response to retail restructuring requirements, PJM introduced a transparent, PJM-run market in capacity credits.[2] New retail market entrants needed a way to acquire capacity credits to meet obligations associated with competitively gained load. Existing utilities needed a way to sell excess capacity credits when load was lost to new competitors. The PJM Capacity Credit Market provides a mechanism to balance supply and demand for capacity credits not met through the bilateral market or self-supply. The PJM Capacity Credit Market is designed to provide a transparent mechanism through which all competitors can buy and sell capacity based on need.

The "Reliability Assurance Agreement Among Load-Serving Entities in the PJM Control Area" (RAA) states that as competitive markets evolve the purpose of capacity obligations is:

> [to] ensure that adequate Capacity Resources will be planned and made available to provide reliable service to loads within the PJM Control Area, to assist other Parties during Emergencies and to coordinate planning of Capacity Resources consistent with the Reliability Principles and Standards. Further, it is the intention and objective of the Parties to implement this Agreement in a manner consistent with the development of a robust competitive marketplace.[3]

With the Phase 2 integration of the Commonwealth Edison Company (ComEd) into PJM on May 1, 2004,[4] the "PJM-West Reliability Assurance Agreement Among Load-Serving Entities in the PJM-West Region" was amended by Schedule 17.[5] It specified capacity market rules that would be implemented only in the ComEd Capacity Market during an interim 13-month period that will end on May 31, 2005. The market rules are specified in terms of installed rather than unforced capacity and

1 The PJM Capacity Market is the capacity market for all control zones except Commonwealth Edison Company (ComEd). It is referred to here as the PJM Capacity Market, the PJM Capacity Credit Market or simply PJM. The ComEd Capacity Market is an interim market limited to that control zone. It began on June 1, 2004, and will continue through May 31, 2005. On June 1, 2005, all control zones will participate in a single regional transmission organization (RTO) Capacity Market. Until then and for the purposes of the 2004 State of the Market Report, the interim capacity market is referred to as the ComEd Capacity Market, the ComEd Capacity Credit Market or simply ComEd.
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.

2 The first PJM Capacity Credit Markets (CCMs) were run in late 1998, with an effective date of January 1, 1999.

3 "Article 2, Purpose," "Reliability Assurance Agreement among Load-Serving Entities in the PJM Control Area" (March 21, 2000), p. 8.

4 Since the ComEd Control Area's Capacity Market did not open until June 1, 2004, throughout May the Commonwealth Edison Company covered all capacity obligations operating under the guidance of PJM. See "Schedule 17, Capacity Adequacy Standards and Procedures for the Commonwealth Edison Zone during the Interim Period." See also "PJM West Reliability Assurance Agreement Among Load-Serving Entities in the PJM West Region," Section L (December 20, 2004), pp. 48C – 48D.

5 "Schedule 17, Capacity Adequacy Standards and Procedures for the Commonwealth Edison Zone During the Interim Period." See also "PJM West Reliability Assurance Agreement Among Load-Serving Entities in the PJM West Region" (December 20, 2004), pp. 48A – 48D.

operate on a monthly basis. The ComEd Capacity Credit Market does not include the Daily Capacity Credit Market Auctions that are a feature of the Capacity Credit Market in the rest of PJM. Beginning on June 1, 2005, however, when the interim market ends, all ComEd Control Zone capacity transactions and obligations will operate under the PJM Capacity Market rules then in effect.

Under the RAA governing both Capacity Markets operated by the PJM regional transmission organization (RTO), each load-serving entity (LSE) must own or purchase capacity resources greater than, or equal to, its capacity obligation. To cover this responsibility, LSEs may own or purchase capacity credits, unit-specific capacity or capacity imports.

Capacity Obligations

For the PJM and ComEd Capacity Markets, a load forecast is used to determine the forecast peak load. In both Capacity Markets, these forecast peak-load values are further adjusted to establish capacity obligations.

- **The PJM Capacity Market.** The adjusted forecast peak-load value[6] is multiplied by the forecast pool requirement (FPR) to determine the unforced capacity obligation. The FPR is equal to one plus a reserve margin, multiplied by the PJM unforced outage factor. An LSE's unforced capacity obligation is its forecast peak load multiplied by the FPR. The FPR is set for each planning period which commences every June 1.

- **The ComEd Capacity Market.** The adjusted forecast peak-load value is multiplied by an installed reserve margin (IRM) to determine the capacity obligation. The IRM is equal to one plus a reserve margin. The IRM was set for three consecutive intervals: a 1.15 IRM for the summer interval running from June 1, 2004, through September 30, 2004; a 1.4 IRM for the fall interval running from October 1, 2004, through December 31, 2004: and a 1.4 IRM for the winter interval running from January 1, 2005, through May 31, 2005.

  Each individual LSE's capacity obligation is based on its customers' aggregate share of the summer interval's forecasted peak load multiplied by the IRM. The amount is further adjusted for mandatory interruptible load (MIL). This allocation is also used to determine adjusted peak-load values for the fall and winter intervals.

Meeting Capacity Obligations

- **The PJM Capacity Market.** In this Capacity Market, an LSE's load can change on a daily basis as customers switch suppliers. The unforced capacity position of every such LSE is calculated daily when its capacity resources are compared to its capacity obligation to determine if any LSE is short of capacity resources. Deficient entities must contract for capacity resources to satisfy their deficiency. Any LSE that remains deficient must pay an interval penalty equal to the capacity deficiency rate (CDR) times the number of days in an interval.[7] If an LSE is short because of a short-term load increase, it pays only the daily penalty until the end of the month. In no case is a deficient LSE charged more than the CDR multiplied by the number of days in the interval, multiplied by each MW of deficiency.

6 Adjusted for active load-management (ALM) and local diversity.
7 The CDR is a function both of the annual carrying costs of a combustion turbine (CT) and the forced outage rate and thus may change annually. The CDR was changed to $170.96 per MW-day, effective June 1, 2003, and to $170.09 per MW-day, effective June 1, 2004.

- **The ComEd Capacity Market.** By contrast, in this Capacity Market, an LSE's load can only change monthly to reflect load shifts between LSEs as customers switch suppliers. In the ComEd Capacity Market, installed capacity rather than unforced capacity is used to meet capacity obligations. Deficient entities must contract for capacity resources to satisfy their deficiency. Any LSE that remains deficient must pay a deficiency charge equal to the MW of deficiency times the daily deficiency rate,[8] times the number of days in the interval.

Capacity Resources

Capacity resources are defined as MW of net generating capacity meeting PJM-specific criteria. They may be located within or outside of PJM, but they must be committed to serving load within PJM. All capacity resources must pass tests regarding the capability of generation to serve load and to deliver energy. This latter criterion requires adequate transmission service.[9]

Capacity resources may be owned, or they may be bought in three different ways:

- **Bilateral, from an internal PJM source.** Internal, bilateral purchases may be in the form of a sale of all or part of a specific generating unit, or in the form of a capacity credit, measured in MW and defined in terms of unforced capacity for the PJM Capacity Market or in terms of installed capacity for the ComEd Capacity Market.

- **Bilateral, from a generating unit external to PJM.** External, bilateral purchases (capacity imports) must meet PJM criteria, including that imports are from specific generating units and that sellers have firm transmission from the identified units to the metered boundaries of the RTO.

- **Capacity Credit Markets.** For the PJM Capacity Market, market purchases may be made from the Daily, Monthly or Multimonthly Capacity Credit Market Auctions. For the ComEd Capacity Market, market purchases may be made from the ComEd Monthly or Multimonthly Capacity Credit Market Auctions.

The sale of a generating unit as a capacity resource within the PJM Control Area entails obligations for the generation owner. The first four of these requirements as listed below are essential to the definition of a capacity resource and contribute directly to system reliability.

- **Energy Recall Right.** PJM rules specify that when a generation owner sells capacity resources from a unit, the seller is contractually obligated to allow PJM to recall the energy generated by that unit if the energy is sold outside of PJM. This right enables PJM to recall energy exports from capacity resources when it invokes emergency procedures.[10] The recall right establishes a link between capacity and actual delivery of energy when it is needed. Thus, PJM can call upon energy from all capacity resources to serve load within the Control Area. When PJM invokes the recall right, the energy supplier is paid the PJM real-time energy market price.

- **Day-Ahead Energy Market Offer Requirement.** Owners of PJM capacity resources are required to offer their output into PJM's Day-Ahead Energy Market. When LSEs purchase

8 Effective June 1, 2004, the daily deficiency rate is $160.00 per MW-day.
9 See PJM "Reliability Assurance Agreement," "Capacity Resources" (May 17, 2004), p. 2.
10 See PJM "PJM Manual 13, Emergency Operations, Revision 19" (October 1, 2004) <http://www.pjm.com/ contributions/pjm-manuals/pdf/m13v19.pdf> (461 KB).

capacity, they ensure that resources are available to provide energy on a daily basis, not just in emergencies. Since day-ahead offers are financially binding, PJM capacity resource owners must provide the offered energy at the offered price if the offer is accepted in the Day-Ahead Energy Market. This energy can be provided by the specific unit offered, by a bilateral energy purchase, or by an energy purchase from the Real-Time Energy Market.

- **Deliverability.** To qualify as a PJM capacity resource, energy from the generating unit must be deliverable to load in the PJM Control Area. Capacity resources must be deliverable,[11] consistent with a loss of load expectation as specified by the reliability principles and standards, to the total system load, including portion(s) of the system that may have a capacity deficiency. In addition, for external capacity resources used to meet an accounted-for obligation within PJM, capacity and energy must be delivered to the metered boundaries of the RTO through firm transmission service.

- **Generator Outage Reporting Requirement.** Owners of PJM capacity resources are required to submit historical outage data to PJM pursuant to Schedule 12 of the RAA.[12]

- **Financial Transmission Right.** Until the Auction Revenue Right (ARR) allocation rules were implemented on June 1, 2003, a Financial Transmission Right (FTR) was available to load only if a specific capacity resource was identified as the source of the delivered energy.[13] Since a capacity credit is not unit-specific, it could not be the basis for an FTR. Under ARR allocation rules in effect before June 1, 2004, an ARR was available to load only if a specific capacity resource was identified as the source of the delivered energy. The most recent modification of the ARR allocation rules, which became effective June 1, 2004, severed the link between capacity resources and ARRs. After June 1, 2004, customers may request ARRs from the resources that were historically designated to serve load in a transmission zone or a load aggregate.

Market Dynamics

RAA procedures determine the total capacity obligation for both the PJM and the ComEd Capacity Markets and thus the total demand for capacity in each market. The RAA includes rules for allocating total capacity obligation to individual LSEs in each market. An LSE's deficiency, in either market, is equivalent to its allocated capacity obligation, net of bilateral contracts, self-supply and the applicable active load management (ALM in the PJM Capacity Market) or mandatory interruptible load (MIL in the ComEd Capacity Market). LSEs bid this deficiency into the appropriate Capacity Credit Market Auctions.

The supply of capacity credits in either Capacity Credit Market is a function of:

- Physical capacity in the control area;
- Prices of energy and capacity in external markets;
- Prices in the PJM Energy and Capacity Markets;

11 Deliverable per Schedule 10, PJM "Reliability Assurance Agreement" (May 17, 2004), p. 52 <http: //www.pjm.com/documents/downloads/agreements/raa.pdf> (344 KB).
12 See Schedule 12, PJM "Reliability Assurance Agreement" (May 17, 2004), p. 57 <http: //www.pjm.com/documents/downloads/agreements/raa.pdf> (344 KB).
13 See Section 7, "Financial Transmission and Auction Revenue Rights."

- Capacity resource imports and exports; and
- Transmission service availability and price.

While physical generating units in PJM are the primary source of capacity resources, capacity resources can be exported from PJM and imported into PJM, subject to transmission limitations. It is the ability to export and to import capacity resources that makes capacity supply in PJM a function of price in both internal and external capacity and energy markets.

In capacity markets, as in other markets, market power is the ability of a market participant to increase market price above the competitive level. The competitive market price is the marginal cost of producing the last unit of output, assuming no scarcity and including opportunity costs. For capacity, the opportunity cost of selling into both Capacity Markets operated by the RTO is the additional revenue foregone by not selling into an external energy and/or capacity market.

Generation owners can be expected to sell capacity into the most profitable market. The competitive price in the capacity markets is a function of the marginal cost of capacity. The marginal cost of capacity is, in turn, determined by the time period over which a choice is made as well as by the alternative opportunities available to the generation owner. If an owner is considering whether to sell a capacity resource for a year, marginal cost would include the incremental cost of maintaining the unit (going forward cost) so that it can qualify as a capacity resource, and any relevant opportunity cost. If an owner is considering whether to sell a capacity resource for a day, the only relevant cost is the opportunity cost. The opportunity cost associated with the sale of a capacity resource is a function of the expected probability that the energy will be recalled and the expected distribution of the difference between external and internal energy prices.

Generators can be expected to evaluate the opportunities to sell capacity on a continuing basis, over a variety of time frames, depending on the rules of the capacity markets. The existence of interval markets makes the generators' decisions more dependent on assessments of seasonal energy market price differentials and recall probabilities. With longer capacity obligations, the likelihood of the net external price differential exceeding the capacity penalty for the period is lower and, therefore, the incentives to sell the system short are lower.

APPENDIX F - ANCILLARY SERVICE MARKETS

This appendix covers two subject areas: area control error and the details of regulation availability and price determination.

Area Control Error (ACE)

Area control error (ACE) is a real-time metric used by PJM operators to measure the imbalance between load and generation. ACE is the instantaneous MW imbalance between generation and load plus net interchange. PJM dispatchers seek to minimize ACE. A dispatcher's success in doing so is measured by control performance standards (CPS) that are mandated by the North American Electric Reliability Council (NERC).

The primary tool used by dispatchers to minimize ACE is regulation. Regulation is defined as a variable amount of generation energy under automatic control which is independent of economic cost signal and is obtainable within five minutes. Regulation contributes to maintaining the balance between load and generation by moving the output of selected generators up and down via an automatic generation control (AGC) signal.[1]

Generators wishing to participate in the Regulation Market must pass certification and submit to random testing. Certification requires that generators be capable of and responsive to AGC. After receiving certification, all participants in the Regulation Market are tested to ensure that regulation capacity is fully available at all times. Testing occurs at times of minimal load fluctuation. Units are subjected to a regulation test pattern for 40 minutes.[2] Units must reach their regulation levels up and down, within five minutes. Unit response is monitored. Units whose response is less than their offered regulation capacity have their regulating capacity reduced by PJM operators.

Control Performance Standard (CPS)

Two control performance standards are established by NERC for evaluating ACE control. One measure is a statistical measure of ACE variability and its relationship to frequency error. The second measure is a statistical measure of unacceptably large, net unscheduled power flows. These two measures define the NERC Control Performance Standard. The NERC Control Performance Standard is the measure against which all control areas are evaluated.

- **CPS1.** NERC requires that the first measure of the CPS survey provide a measure of the control area's performance. The measure is intended to provide the control area with a frequency-sensitive evaluation of how well it met its demand requirements. A minimum passing score for CPS1 is 100 percent. (The formal definition of CPS1 can be found in "NERC Performance Standards Document," volume 2 (November 21, 2002), Section B.1.1.1.)[3]

- **CPS2.** NERC also requires that the second measure of the CPS survey be designed to bound ACE 10-minute averages. CPS2 provides a control measure of excessive, unscheduled power flows that could result from large ACEs. (The formal definition of CPS2 can be found in "NERC Performance Standards Reference Document," volume 2 (November 21, 2002), Section

1 Regulation market business rules are defined in "PJM Manual 11: Scheduling Operations," Revision 23 (December 7, 2004), pp 47-55.
2 See "PJM Dispatching Operations Manual, M-12," Revision 10, Section 4 (March 3, 2004), p. 44.
3 For more information about the definition and calculation of CPS, refer to "M12: Dispatching Operations," revision 11 (January 01, 2005), pp. 19-21.

B.1.1.2.) CPS2 is measured by counting the number of 10-minute periods during a month when the 10-minute average of the PJM Control Area's ACE is within certain defined limits known as "L10." The specific, 10-minute periods of each hour are those ending at 10, 20, 30, 40, 50 and 60 minutes after the hour. A passing score for CPS2 is achieved when 90 percent of these 10-minute periods during a single month are within "L10." During Phases 1 and 2 of 2004, the PJM Control Area's "L10" standard was 194 MW. During Phase 3, PJM's "L10" standard was 254 MW.

PJM's CPS Performance

As Figure F-1 and Figure F-2 show, PJM generally performed well in 2004 against the CPS1 and CPS2 metrics. Nonetheless, the Phase 2 integration of the Commonwealth Edison Company (ComEd) Control Area and the Phase 3 integration of the AEP and DAY Control Zones into the PJM Control Area created two especially difficult problems. First, the establishment of the ComEd Control Area left that region without enough available regulation to meet the regulation requirement. The subsequent incorporation of the ComEd, AP, AEP and DAY Control Zones into a single PJM Control Area during Phase 3 required PJM to adapt its frequency management to a new frequency bias constant and new interchange transaction characteristics.

Figure F-1 - PJM CPS1 and CPS2 performance: Calendar years 2001 to 2004

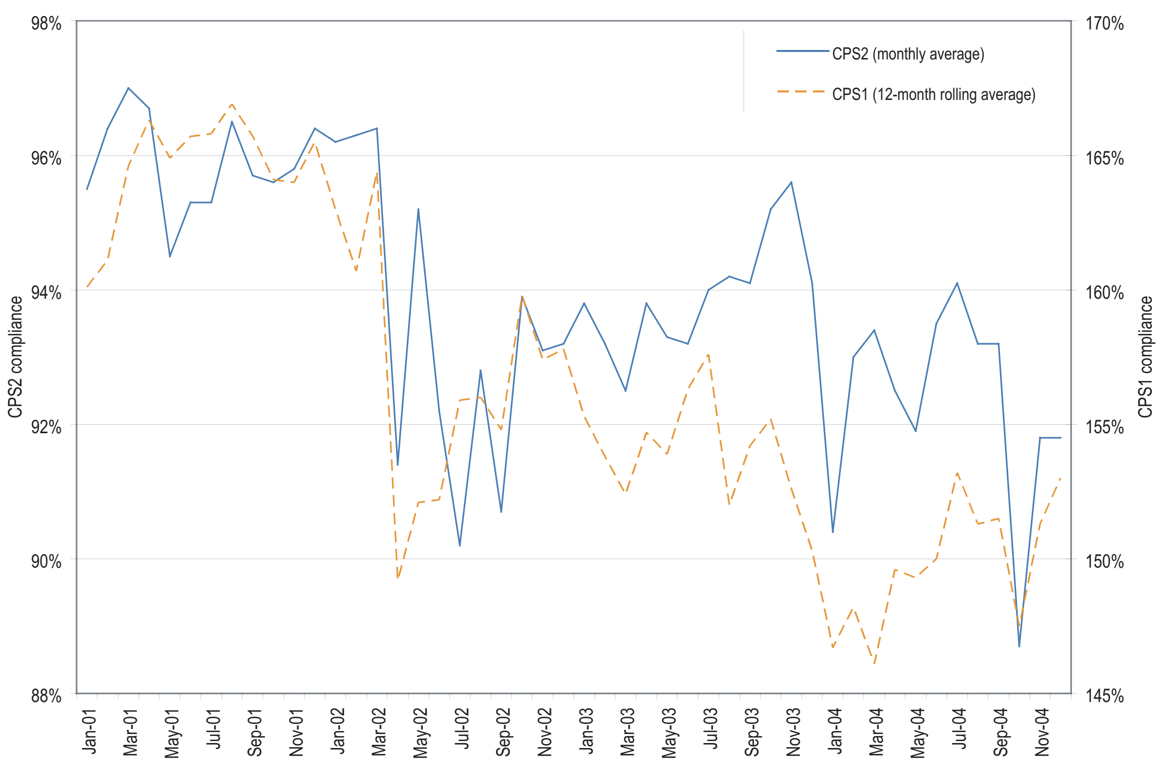
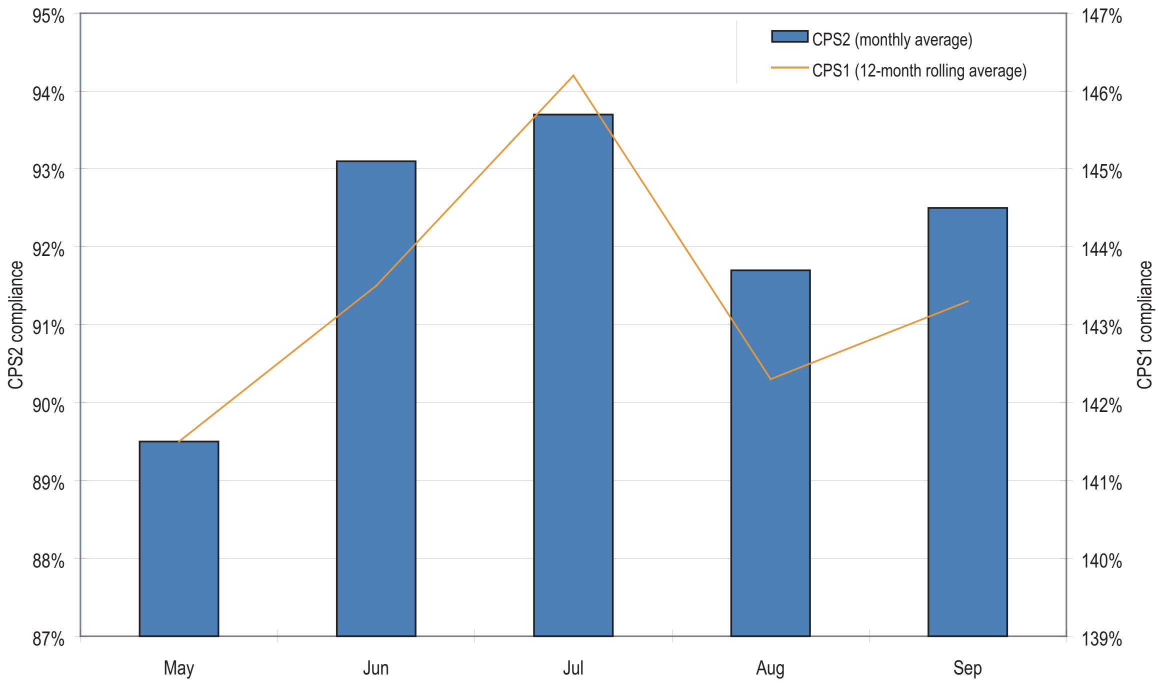
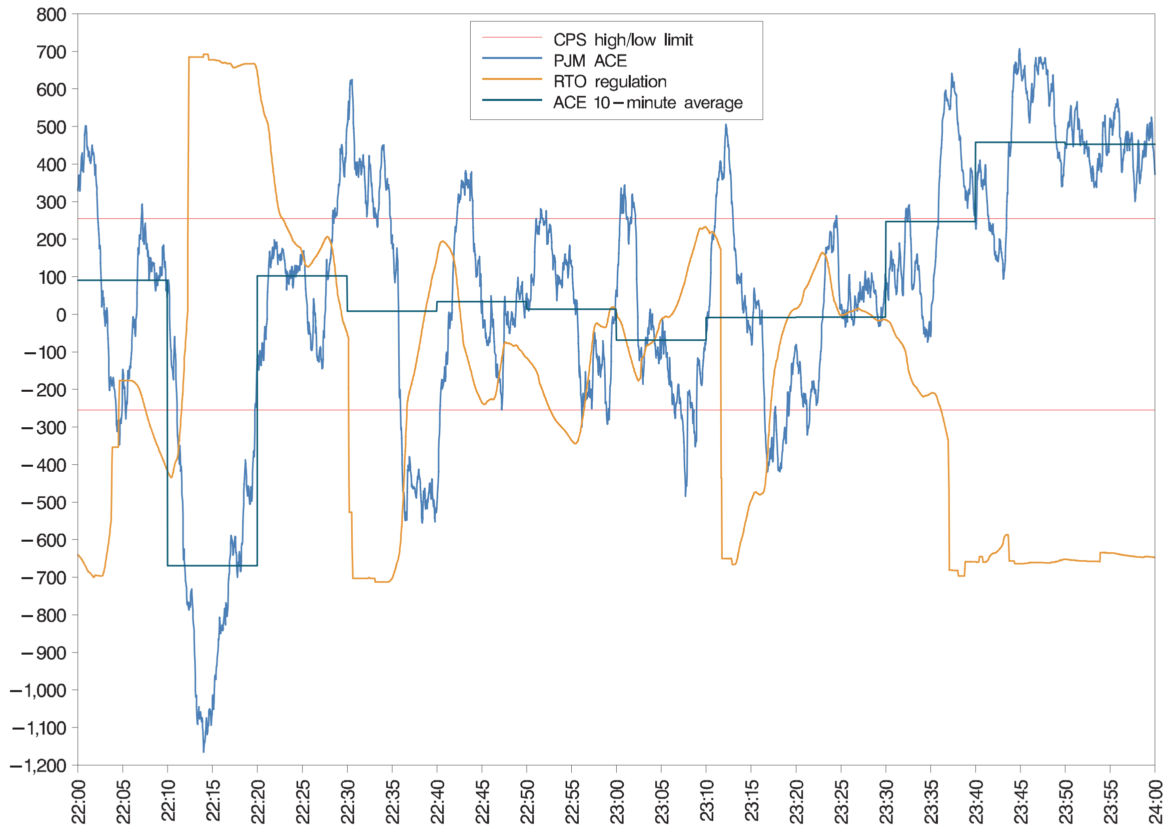


Figure F-2 - ComEd Control Area CPS1 and CPS2 performance: Phase 2, 2004



ACE is controlled by PJM's regulation AGC signal, which is updated every four seconds. ACE is particularly difficult to control during times of rapid change in load. Figure F-3 shows PJM ACE plotted against the regulation AGC signal during a period of rapid load change on October 12, 2004, in the hours ending 2300 and 2400 Eastern Prevailing Time (EPT).

Figure F-3 - PJM ACE vs. regulation signal sample: October 12, 2004



As PJM has learned, ACE has a complex relationship with the structure of the grid. Its control parameters can change in unexpected ways when the grid is expanded or altered significantly. Figure F-3 shows the regulation AGC signal (gold line), the ACE (blue line), the pass or fail CPS2 "L10" limits (red lines) and the 10-minute ACE average forming the basis for CPS2 (gray line). This two-hour segment includes three CPS2 violations at 2210 to 2220 (low ACE), at 2340 to 2350 (high ACE) and at 2350 to 2400 EPT (high ACE) on October 12, 2004. By comparing the ACE response (blue line) to the regulation signal (gold line), one can see that ACE generally reacted well to the regulation signal. Under the circumstance, regulation was adequate.

It is especially difficult to control ACE during periods of rapid change in control area load. Hours ending 2300 and 2400 EPT are normally times when load ramps down quickly. Figure F-3 shows that during these hours on October 12, 2004, ACE remained above the "L10" CPS2 limit despite a maximum corrective regulation signal. The result was two consecutive CPS2 violations at 23:40 and 23:50. Other factors affect ACE, including external transactions, system disturbances created by a unit or transmission line outage, and insufficient regulation available. The latter can be alleviated by spinning reserve, but it responds more slowly than regulation. In these cases, ACE can exceed acceptable limits for a short time even though regulation levels are adequate for short-term ACE control.

ACE is related not just to load and generation imbalance, but also to frequency bias and to discrepancies between scheduled and actual tie line flows.

Monthly CPS2 Violations for 2004

PJM had two monthly CPS violations during 2004. The first occurred in May 2004 and involved a violation of the CPS2 criterion in the ComEd Control Area. The second occurred in October 2004 and involved a violation of the CPS2 criterion for the PJM Control Area.

ComEd Control Area in May

PJM's May 2004 performance in the ComEd Control Area reached 89.5 percent, 0.5 percent below a passing 90 percent CPS2 performance standard. That CPS2 violation had two root causes. Initially, an adequate supply of regulation was unavailable. This situation improved during the five-month period of Phase 2 when ComEd was a separate Control Area. The percentage of hours during each month when there was a deficit of assigned regulation was: May with 36 percent, June with 22 percent, July with 18 percent, August with 16 percent and September with 2.4 percent. It should be noted that despite these deficits in assigned regulation, the actual regulation in the ComEd Control Area (150 MW off peak and 300 MW on peak) was more than adequate to control ACE.

The second root cause for the May 2004 CPS2 violation was a 94 percent load forecasting performance (97 percent is PJM's goal).[4] The load forecasting performance was the result of an initial inability to anticipate interchange ramp changes into the ComEd Control Area and local load behavior. The problem abated as PJM operators gained more experience in ComEd operations.

PJM Control Area in October

PJM Mid-Atlantic's October 2004 CPS2 score was 88.7, which is 1.3 percent below the passing score of 90 percent. Satisfaction of NERC CPS standards involves more than an adequate supply of regulation. Since the Phase 3 consolidation of the ComEd, AP, AEP and DAY Control Zones into the PJM Control Area, regulation supply has been adequate. Nonetheless, PJM failed CPS2 in October because PJM had to adapt its frequency management to a new frequency bias constant and new interchange transaction characteristics.

The frequency bias constant increased after October 1, 2004, rising to 1,131 MW per 0.1 hertz from 655 MW per 0.1 hertz. This required PJM to respond to frequency deviation much more quickly than any other control area in the Eastern Interconnection because the same deviation in frequency results in a significantly greater deviation in ACE for PJM. The higher frequency bias caused PJM's AGC to respond too quickly to the frequency component of ACE, increasing its momentary corrective response at the expense of exacerbating ACE oscillations longer term.

This problem was mitigated by adjusting AGC tuning parameters on October 20, 2004, to increase the responsiveness of the regulation control signal. Additional adjustments to the AGC tuning parameters were implemented on November 5, 2004. Further mitigation was accomplished by

4 See "PJM Manual 11: Scheduling Operations," Revision 23 (December 7, 2004), pp.72-73, for a full description of the load forecasting procedure.

temporarily increasing the amount of required regulation in the PJM Mid-Atlantic Region to 1.1 percent of forecast load plus 175 MW on November 19, 2004, and in ComEd to 1 percent of forecast peak load plus 175 MW. This increase was lessened on December 16, 2004, to 1.1 percent of forecast load plus 125 MW for the PJM Mid-Atlantic Region and 1 percent of forecast peak load plus 125 MW for ComEd.

Regulation Capacity, Daily Availability, Hourly Supply and Price

Regulation market-clearing price (RMCP) is determined algorithmically by the PJM Market Operations Group by first creating a supply curve of available units and their associated regulation prices, then assigning regulation to units in increasing order of price until the regulation MW requirement is satisfied. The price of the most expensive unit required to satisfy the regulation requirement is the RMCP.

The process by which available regulation is defined and assigned is complicated, but important to understanding regulation price and Regulation Market competitiveness.

- **Regulation Capacity.** A database of all generating units in a control zone is maintained by PJM's generation group. Generating units which have qualified to participate in the Regulation Market are identified. The sum of the regulation MW capability of these units is the theoretical maximum regulation capacity in that control zone. Actual regulation capacity varies over time because units that become certified for regulation may then be decommissioned, taken offline, fail regulation testing or be removed from the Regulation Market by their owners.

- **Regulation Daily Availability.** All owners of generating units in the regulation capacity pool as defined above have the right to offer their regulation capacity daily into the Regulation Market using the PJM Market User Interface. Daily regulation availability is the sum of all regulation-capable units that offer regulation into the market. Units that have entered bids into the PJM Market User Interface system have the right to set themselves to "unavailable" for regulation for the day, or for a specific hour or set of hours. They also have the right to change the amount of regulation MW offered. They do not have the right to change their regulation offer price during a day. All regulation bids are summed to calculate the total daily regulation available, a figure that changes each day.

- **Regulation Hourly Supply, Assignment and RMCP.** Sixty minutes before the market hour, PJM runs spinning and regulation market-clearing software (SPREGO) to determine the amount of regulation required, generate the regulation supply curve, assign regulation to specific units and determine the RMCP. This actual process is complicated but spinning and regulation are cooptimized for a solution that minimizes the total cost of both products. During this process, PJM dispatchers can deselect units from SPREGO for any of several reasons including: 1) to control transmission constraints; 2) to avoid overgeneration during periods of minimum generation alert; 3) to remove a unit temporarily unable to regulate; or 4) to remove a unit with a malfunctioning unit-to-PJM data link.

The spinning and regulation requirements are:

- **For regulation:**

  PJM Mid-Atlantic Region. For on-peak hours (0500 through 2359 EPT) 1.1 percent of the forecast peak load, and for off-peak hours (0000 through 0459 EPT) 1.1 percent; and

  PJM Western Regulation Market. Regardless of hour, 1.0 percent of the forecast peak load.

- **For spinning reserve:**

  PJM. Used in calculating a requirement that is 75 percent of the largest contingency, provided that double the remaining 25 percent is available for nonsynchronized, 10-minute reserve.

All regulation resource units which have bid into the daily Regulation Market are evaluated by SPREGO for regulation. SPREGO then excludes units according to the following ordered criteria:

1. The availability status of the unit as listed in the daily bid table and the hourly update table. Any unit which is set to "available" in the hourly update table is included in the list. Any unit which is set to "unavailable" in the hourly update table is excluded from the list. Any unit which has no entry in the hourly update table, but is set to "unavailable" in the daily bid table is excluded from the list.

2. If the unit is a combustion turbine generator or a steam generator and its economic maximum generation MW level is not set higher than its economic minimum generation MW level, then the unit is excluded from regulation consideration.

3. The unit must be on, unless it is a combustion turbine generator.

4. The unit must not have been assigned to spin.

Applying these exclusionary rules further diminishes the available regulation used by SPREGO in assigning regulation and in clearing the market to determine the price. The units that remain are the supply, and they are used by SPREGO to clear the market and to determine price.

For each generating unit in the supply, the regulation offer price is calculated using the sum of the unit's regulation offer cost and the OC based on the forecast LMP. The OC calculator also needs data such as economic minimum and economic maximum, regulation minimum and regulation maximum, startup costs and cost-schedule data. Finally, the MW offered and the calculated regulation price are used to create a regulation supply curve in which the MW offered are plotted against price. Units are assigned in order of price from the lowest price until the amount of required regulation has been assigned.

APPENDIX G - FTR AND ARR MARKETS

The procedure for prorating ARRs when transmission capability limits the amount of ARRs that can be allocated is illustrated here, as is the establishment of ARR target allocations and credits through the Annual FTR Auction.

ARR Prorating Procedure Illustration

Table G-1 provides an illustration of the prorating procedure for ARRs. If line A-B has a 100 MW rating, but ARR requests from two customers together would impose 175 MW of flow on it, the service request would exceed its capability by 75 MW. The first customer's ARR request (ARR #1) is for a total of 300 MW with a 0.50 impact on the constrained line. It would thus impose 150 MW of flow on the line. The second customer's request (ARR #2) is for a total of 100 MW with a 0.25 impact and would impose an additional 25 MW on the constrained line. An allocation based only on the number of ARRs requested would assign three times as many ARRs to the first customer as to the second (300/100 = 3). An allocation based solely on the per unit MW impact would assign half as many ARRs to the first customer as to the second [(1 / 0.5) / (1 / 0.25) = 0.5]. The actual allocation considers these factors together, resulting in the first customer receiving 1.5 times as many ARRs as the second.

Table G-1 - ARR allocation prorating procedure: Illustration

Line A-B Rating = 100 MW						
ARR #	Path	Per MW Effect on Line A-B	Requested ARRs	Resulting Line A-B Flow	Prorated ARRs	Prorated Line A-B Flow
1	C-D	0.50	300	150	150	75
2	E-F	0.25	100	25	100	25
Sum			400	175	250	100

The *pro rata* equation would be solved for each request as follows:

Individual *pro rata* MW = (Line capability) * (Individual requested MW / Total requested MW) * (1 / per MW effect on line)

ARR #1 *pro rata* MW award = (100 MW) * (300 MW / 400 MW) * (1 / 0.50) = 150 MW

ARR #2 *pro rata* MW award = (100 MW) * (100 MW / 400 MW) * (1 / 0.25) = 100 MW

Together the *pro rata*, awarded ARRs would impose a flow equal to line A-B's capability (150 MW * 0.50 + 100 MW * 0.25 = 100 MW).

ARR Credit Illustration

Table G-2 illustrates how ARR target allocations are established, how FTR auction revenue is generated and how ARR credits are determined. FTRs pay and ARRs are paid based on cleared nodal prices from the Annual FTR Auction. If total revenue from the auction is greater than the sum of ARR target allocations, then the surplus is used to offset any FTR congestion credit deficiencies that occur in the hourly Day-Ahead Energy Market.

Table G-2 - ARR credits: Illustration

Path	Annual FTR Auction Path Price	ARR MW	ARR Target Allocation	FTR MW	FTR Auction Revenue	ARR Credits
A-C	$10	10	$100	10	$100	$100
A-D	$15	10	$150	5	$75	$150
B-D	$10	0	$0	20	$200	$0
B-E	$15	10	$150	5	$75	$150
Total			$400		$450	$400
ARR Payout Ratio = ARR Credits/ARR Target Allocations = $400/$400 = 100%						
Surplus ARR Revenue = FTR Auction Revenue - ARR Credits = $450 - $400 = $50						

APPENDIX H - GLOSSARY

Active load management (ALM)	Retail customer load that can be interrupted at the request of PJM. Such a PJM request is considered an emergency action and is implemented prior to a voltage reduction. ALM derives an ALM credit in the accounted-for-obligation.
Aggregate	Combination of buses or bus prices.
Ancillary service	Those services necessary to support the transmission of capacity and energy from resources to loads while, in accordance with good utility practice, maintaining reliable operation of the transmission provider's transmission system.
Ancillary service area	A defined market service area for ancillary services including regulation and spinning.
Area control error (ACE)	Area control error (ACE) is a real-time metric used by PJM operators to measure the imbalance between load and generation. ACE is the instantaneous MW imbalance between generation and load plus net interchange.
Auction Revenue Right (ARR)	A financial instrument entitling its holder to auction revenue from Financial Transmission Rights (FTRs) based on locational marginal price (LMP) differences across a specific path in the Annual FTR Auction.
Automatic generation control (AGC)	An automatic control system comprised of hardware and software. Hardware is installed on generators allowing their output to be automatically adjusted and monitored by an external signal and software is installed facilitating that output adjustment.
Average hourly unweighted LMP	An LMP calculated by averaging hourly LMP with equal hourly weights.
Basic generation service (BGS)	The default electric generation service provided by the electric public utility to consumers who do not elect to buy electricity from a third-party supplier.
Bilateral agreement	An agreement between two parties for the sale and delivery of a service.

Black start unit	A generating unit with the ability to go from a shutdown condition to an operating condition and start delivering power without assistance from the transmission system.
Bottled generation	Economic generation that cannot be dispatched because of local operating constraints.
Burner tip fuel price	The cost of fuel delivered to the generator site equaling the fuel commodity price plus all transportation costs.
Bus	An interconnection point.
Capacity credit	An entitlement to a specified number of MW of unforced capacity from a capacity resource for the purpose of satisfying capacity obligations imposed under the RAA.
Capacity deficiency rate (CDR)	The capacity deficiency rate is based on the annual carrying charges for a new combustion turbine, installed and connected to the transmission system. To express the CDR in terms of unforced capacity, it must be further divided by the quantity 1 minus the EFORd.
Capacity Markets	All markets where PJM members can trade capacity.
Capacity queue	A collection of RTEPP capacity resource project requests received during a particular timeframe and designating an expected in-service date.
Combined cycle (CC)	A generating unit generally consisting of a gas-fired turbine and a heat recovery steam generator. Electricity is produced by a gas turbine whose exhaust is recovered to heat water, yielding steam for a steam turbine that produces still more electricity.
Combustion turbine (CT)	A generating unit in which a combustion turbine engine is the prime mover.
Control zone	An area within the PJM Control Area, as set forth in the PJM Open Access Tariff and the Reliability Assurance Agreement (RAA). Schedule 16 of the RAA defines the distinct zones that comprise the PJM Control Area.
Decrement bids	Financial offers to purchase specified amounts of MW in the Day-Ahead Energy Market at, or above, a given price.

1 New York Independent System Operator, "Definitions/Glossary" (February 23, 2004) < http://www.nyiso.com/services/training/glossary/index.html >.

Dispatch rate	Control signal, expressed in dollars per MWh, calculated by PJM and transmitted continuously and dynamically to generating units to direct the output level of all generation resources dispatched by the PJM Office of the Interconnection.
Disturbance control standard	A NERC-defined metric measuring the ability of a control area to return area control error (ACE) either to zero or to its predisturbance level after a disturbance such as a generator or transmission loss.
Eastern Prevailing Time	Eastern Prevailing Time (EPT) is equivalent to Eastern Standard Time (EST) or Eastern Daylight Time (EDT) as is in effect from time to time.
End-use customer	Any customer purchasing electricity at retail.
External resource	A resource located outside metered PJM boundaries.
Financial Transmission Right (FTR)	A financial instrument entitling the holder to receive revenues based on transmission congestion measured as hourly energy LMP differences in the PJM Day-Ahead Energy Market across a specific path.
Firm point-to-point transmission	Firm transmission service that is reserved and/or scheduled between specified points of receipt and delivery.
Firm transmission	Transmission service that is intended to be available at all times to the maximum extent practicable. Service availability is, however, subject to an emergency, an unanticipated failure of a facility or other event.
Fixed-demand bid	Bid to purchase a defined MW level of energy, regardless of LMP.
Generation offers	Schedules of MW offered and the corresponding offer price.
Generator owner	A PJM member that owns or leases, with rights equivalent to ownership, facilities for generation of electric energy that are located within PJM.

Gross deficiency	The sum of all companies' individual capacity deficiency, or the shortfall of unforced capacity below unforced capacity obligation. The term is also referred to as accounted-for deficiency.
Gross excess	The sum of all LSE's individual excess capacity, or the excess of unforced capacity above unforced capacity obligation. The term is referred to as "Accounted-for Excess" in the "PJM Accounted-For Obligation Manual" (Manual 17).
Gross export volume (energy)	The sum of all export transaction volume (MWh).
Gross import volume (energy)	The sum of all import transaction volume (MWh).
Herfindahl-Hirschman Index (HHI)	HHI is calculated as the sum of the squares of the market share percentages of all firms in a market.
Hertz	Electricity system frequency is measured in hertz.
HRSG	Heat recovery steam generator. An air-to-steam heat exchanger installed on combined-cycle generators.
Increment offers	Financial offers in the Day-Ahead Energy Market to supply specified amounts of MW at, or above, a given price.
Initial threshold	In the context of the PJM economic planning process, when the cumulative gross congestion cost of a constraint exceeds the applicable initial threshold, PJM begins determining the extent to which the load affected by that constraint is unhedgeable. Initial threshold values are specific to the transmission level voltage of the affected facility.
Installed capacity	System total installed capacity measures the sum of the installed capacity (in installed, not unforced, terms) from all internal and qualified external resources designated as PJM capacity resources.
Interval Market	The Capacity Market rules provide for three Interval Markets, covering the months from January through May, June through September and October through December.

Load	Demand for electricity at a given time.
Load aggregator	An entity licensed to sell energy to retail customers located within the service territory of a local distribution company.
Load-serving entity (LSE)	Load-serving entities provide electricity to retail customers. Load-serving entities include traditional distribution utilities and new entrants into the competitive power markets.
Lost opportunity cost	The difference in net compensation from the energy market between what a unit receives when providing regulation or spinning reserve and what it would have received for providing energy output.
Mandatory interruptible load (MIL)	MIL is retail customer load in ComEd that can be interrupted at the request of PJM. PJM members commit to reduce load by a fixed MW amount or to a certain MW load or to initiate cycling of end-use equipment when called upon by PJM. The account of the LSE which nominated the customer's load drop is credited the MW amount committed. The credit can either be traded or used to meet the member's capacity obligation. Performance is measured, and penalties are charged for under compliance and payments are made for over compliance.
Marginal unit	The last generation unit to supply power under a merit order dispatch system.
Market-clearing price	The price that is paid by all load and paid to all suppliers.
Market participant	A PJM market participant can be a market supplier, a market buyer or both. Market buyers and market sellers are members that have met reasonable creditworthiness standards as established by the PJM Office of the Interconnection. Market buyers are otherwise able to make purchases and market sellers are otherwise able to make sales in the PJM Energy or Capacity Credit Markets.
Market threshold	In the context of the PJM economic planning process, each market threshold represents the level of unhedgeable congestion costs that triggers the start of a one-year "market window" for the development of market solutions to unhedgeable congestion. Market threshold values are specific to the transmission voltage of the affected facility.

Market user interface	A thin client application allowing generation marketers to provide and to view generation data, including bids, unit status and market results.
Market window	In the context of the PJM economic planning process, the period of time during which PJM allows for the development of market solutions to unhedgeable congestion associated with an affected facility.
Merchant solution	In the context of the PJM economic planning process, a solution proposed to reduce or to eliminate unhedgeable congestion on an affected facility.
Mean	The arithmetic average.
Median	The midpoint of data values. Half the values are above and half below the median.
Megawatt (MW)	A unit of power equal to 1,000 kilowatts.
Megawatt-day	One MW of energy flow or capacity for one day.
Megawatt hour (MWh)	One MWh is a megawatt produced or consumed for one hour.
Megawatt-year	One MW of energy flow or capacity for one calendar year.
Min gen	An emergency declaration for periods of light load.[1]
Monthly CCMs	The capacity credits cleared each month through the PJM Monthly Capacity Credit Markets (CCMs).
Multimonthly CCMs	The capacity credits cleared through PJM Multimonthly Capacity Credit Markets (CCMs).
Net excess (capacity)	The net of gross excess and gross deficiency, therefore the total PJM capacity resources in excess of the sum of load-serving entities' obligations.
Net exchange (capacity)	Capacity imports less exports.
Net interchange (energy)	Gross import volume less gross export volume in MWh.

2 See PJM Emergency Operations Manual, Section M13, Section 2, pp. 22-27.

North American Electric Reliability Council (NERC)	A voluntary organization of U.S. and Canadian utilities and power pools established to assure coordinated operation of the interconnected transmission systems.
Obligation	The sum of all load-serving entities' unforced capacity obligations as determined by summing the weather-adjusted summer coincident peak demands for the prior summer, netting out ALM credits, adding a reserve margin and adjusting for the system average forced outage rate.
Off peak	For the PJM Energy Market, off-peak periods are all NERC holidays (i.e., New Year's Day, Memorial Day, Independence Day, Labor Day, Thanksgiving Day, Christmas Day) and weekend hours plus weekdays from the hour ending at midnight until the hour ending at 7:00 a.m.
On peak	For the PJM Energy Market, on-peak periods are weekdays, except NERC holidays (i.e., New Year's Day, Memorial Day, Independence Day, Labor Day, Thanksgiving Day, Christmas Day) from the hour ending at 8:00 a.m. until the hour ending at 11:00 p.m.
Phase-in FTRs	FTRs directly allocated to eligible customers outside of the regularly scheduled FTR allocations when new control zones are integrated into PJM after the start of the current planning period. Phase-in FTRs remain in effect until the start of the next regularly scheduled FTR allocation.
PJM member	Any entity that has completed an application and satisfies the requirements of PJM to conduct business with the PJM Office of the Interconnection, including transmission owners, generating entities, load-serving entities and marketers.
PJM planning year	The calendar period from June 1 through May 31.
Price duration curve	A graphic representation of the percent of hours that a system's price was at or below a given level during the year.
Price-sensitive bid	Purchases of a defined MW level of energy only up to a specified LMP. Above that LMP, the load bid is zero.
Primary operating interfaces	Primary operating interfaces are typically defined by a

	cross section of transmission paths or single facilities which affect a wide geographic area. These interfaces are modeled as constraints whose operating limits are respected in performing dispatch operations.
Regional Transmission Expansion Planning Protocol	The process by which PJM recommends specific transmission facility enhancements and expansions based on reliability and economic criteria.
Selective catalytic reduction (SCR)	NOx reduction equipment usually installed on combined-cycle generators.
Self-scheduled generation	Units scheduled to run by their owners regardless of system dispatch signal. Self-scheduled units do not follow system dispatch signal and are not eligible to set LMP. Units can be submitted as a fixed block of MW that must be run, or as a minimum amount of MW that must run plus a dispatchable component above the minimum.
Shadow price	The constraint shadow price represents the incremental reduction in congestion cost achieved by relieving a constraint by 1 MW. The shadow price multiplied by the flow (in MW) on the constrained facility during each hour equals the hourly gross congestion cost for the constraint.
Sources and sinks	Sources are the origins or the injection end of a transmission transaction. Sinks are the destinations or the withdrawal end of a transaction.
Special protection scheme (SPS)	A load transfer relaying scheme intended to reduce the adverse post-contingency impact on a protected facility.
Spinning reserve	Reserve capability which is required in order to enable an area to restore its tie lines to the pre-contingency state within 10 minutes of a contingency that causes an imbalance between load and generation. During normal operation, these reserves must be provided by increasing energy output on electrically synchronized equipment or by reducing load on pumped storage hydroelectric facilities. During system restoration, customer load may be classified as spinning reserve.

Standard deviation	A measure of data variability around the mean.
System lambda	The cost to the PJM system of generating the next unit of output.
Temperature-humidity index (THI)	A temperature-humidity index has been developed by the U.S. National Weather Service (NWS). It gives a single, numerical value in the general range of 70 to 80, reflecting the outdoor atmospheric conditions of temperature and humidity as a measure of comfort (or discomfort) during warm weather. The temperature-humidity index, THI, is defined as follows: THI = $T_d - (0.55 - 0.55RH) * (T_d - 58)$ where T_d is the dry-bulb temperature and RH is the percentage of relative humidity.
Unforced capacity	Installed capacity adjusted by forced outage rates.
Wheel-through	An energy transaction flowing through a transmission grid whose origination and destination are outside of the transmission grid.
Zone	See "Control zone" (above).

APPENDIX I - LIST OF ACRONYMS

ACE	Area control error
AECI	Associated Electric Cooperative Inc.
AECO	Atlantic City Electric Company
AEG	Alliant Energy Corporation
AEP	American Electric Power Company, Inc.
AGC	Automatic generation control
ALM	Active load management
AP	Allegheny Power Company
ARR	Auction Revenue Rights
ASA	Ancillary service areas
BGE	Baltimore Gas and Electric Company
BGS	Basic generation service
BME	Balancing market evaluation
C&I	Commercial and industrial customers
CCM	Capacity Credit Market
CC	Combined cycle
CDR	Capacity deficiency rate
CDTF	Cost development task force
CF	Coordinated flowgate under the Joint Operating Agreement between PJM and the Midwest Independent Transmission System Operator, Inc.
CILCO	Central Illinois Light Company
CIN	Cinergy Corporation

ComEd	The Commonwealth Edison Company
CPL	Carolina Power & Light Company
CPS	Control performance standard
CT	Combustion turbine
DAY	The Dayton Power & Light Company
DCS	Disturbance control standard
DLCO	Duquesne Light Company
DPL	Delmarva Power & Light Company
DPLN	Delmarva north
DPLS	Delmarva south
DSR	Demand-side response
DUK	Duke Energy Corp.
EDT	Eastern Daylight Time
ECAR	East Central Area Reliability Council
EDC	Electricity distribution company
EFORd	Equivalent demand forced outage rate
EHV	Extra high voltage
EKPC	East Kentucky Power Cooperative, Inc.
EPT	Eastern Prevailing Time
FE	FirstEnergy Corp.
FERC	The United States Federal Energy Regulatory Commission
FPPL	Forecast period peak load

FPR	Forecast pool requirement
FTR	Financial Transmission Rights
GCA	Generating control area
HHI	Herfindahl-Hirschman Index
HRSG	Heat recovery steam generator
ICAP	Installed capacity
IP	Illinois Power Company
IPL	Indianapolis Power & Light Company
IPP	Independent power producer
IRM	Installed reserve margin
IRR	Internal rate of return
ISO	Independent system operator
JCPL	Jersey Central Power & Light Company
JOA	PJM's Joint Operating Agreement with the Midwest Independent Transmission System Operator, Inc.
LCA	Load control area
LGEE	LG&E Energy, L.L.C.
LMP	Locational marginal price
LOC	Lost opportunity cost
LSE	Load-serving entity
LTE	Long-term emergency
MAIN	Mid-America Interconnected Network, Inc.
MAAC	Mid-Atlantic Area Council

MACRS	Modified accelerated cost recovery schedule
MAPP	Mid-Continent Area Power Pool
MC	The PJM Members Committee
MCP	Market-clearing price
MEC	MidAmerican Energy Company
MECS	Michigan Electric Coordinated System
Met-Ed	Metropolitan Edison Company
MEW	Western subarea of Metropolitan Edison Company
MICHFE	The pricing point for the Michigan Electric Coordinated System and First Energy control areas.
Midwest ISO	Midwest Independent Transmission System Operator, Inc.
MIL	Mandatory interruptible load
MP	Market participant
MMU	PJM Market Monitoring Unit
MUI	Market user interface
MW	Megawatt
MWh	Megawatt-hour
NERC	North American Electric Reliability Council
NICA	Northern Illinois Control Area
NIPSCO	Northern Indiana Public Service Company
NNL	Network and native load
NO_x	Nitrogen oxides
NYISO	New York Independent System Operator

OA	PJM Operating Agreement
OASIS	Open Access Same-Time Information System
OC	Opportunity cost
ODEC	Old Dominion Electric Cooperative
OEM	Original equipment manufacturer
OI	PJM Office of the Interconnection
Ontario IESO	Ontario Independent Electricity System Operator
OPL	Obligation peak load
OVEC	Ohio Valley Electric Corporation
PE	PECO zone
PECO	PECO Energy Company
PENELEC	Pennsylvania Electric Company
PEPCO	Pepco (formerly Potomac Electric Power Company)
PJM	PJM Interconnection
PJM/AEPNI	The interface between the American Electric Power Control Zone and Northern Illinois
PJM/AEPPJM	The interface between the American Electric Power Control Zone and PJM
PJM/AEPVP	The single interface pricing point formed in March 2003 from the combination of two previous interface pricing points: PJM/American Electric Power Company, Inc. and PJM/Dominion Resources, Inc.
PJM/AEPVPEXP	The export direction of the PJM/AEPVP interface pricing point
PJM/AEPVPIMP	The import direction of the PJM/AEPVP interface pricing point

PJM/ALTE	The interface between PJM and the eastern portion of the Alliant Energy Corporation's control area
PJM/ALTW	The interface between PJM and the western portion of the Alliant Energy Corporation's control area
PJM/AMRN	The interface between PJM and the Ameren Corporation's control area
PJM/CILC	The interface between PJM and the Central Illinois Light Company's control area
PJM/CPLE	The interface between PJM and the eastern portion of the Carolina Power & Light Company's control area
PJM/CPLW	The interface between PJM and the western portion of the Carolina Power & Light Company's control area
PJM/DLCO	The interface between PJM and the Duquesne Light Company's control area
PJM/DUK	The interface between PJM and the Duke Energy Corp.'s control area
PJM/FE	The interface between PJM and the FirstEnergy Corp.'s control area
PJM/IP	The interface between PJM and the Illinois Power Company's control area
PJM/Ontario IESO	PJM/Ontario IESO pricing point
PJM/MEC	The interface between PJM and MidAmerican Electric Company's control area
PJM/MECS	The interface between PJM and the Michigan Electric Coordinated System's control area
PJM/NIPS	The interface between PJM and the Northern Indiana Public Service Company's control area
PJM/NYIS	The interface between PJM and the New York Independent System Operator

PJM/OVEC	The interface between PJM and the Ohio Valley Electric Corporation's control area
PJM/TVA	The interface between PJM and the Tennessee Valley Authority's control area
PJM/VAP	The interface between PJM and the Dominion Virginia Power's control area
PJM/WEC	The interface between PJM and the Wisconsin Energy Corporation's control area
PLC	Peak load contributions
PNNE	PENELEC's northeastern subarea
PNNW	PENELEC's northwestern subarea
PPL	PPL Electric Utilities Corporation
PSEG	Public Service Electric and Gas Company
PSN	PSEG north
PSNC	PSEG northcentral
QIL	Qualified interruptible load
RAA	Reliability Assurance Agreement among Load-Serving Entities in the PJM Control Area
RECO	Rockland Electric Company zone
RMCP	Regulation market clearing price
RSI	Residual supply index
RTEPP	Regional Transmission Expansion Planning Protocol
RTO	Regional transmission organization
SCPA	Southcentral Pennsylvania subarea
SCR	Selective catalytic reduction

Appendix I | List of Acronyms

SEPJM	Southeastern PJM subarea
SFT	Simultaneous feasibility test
SMECO	Southern Maryland Electric Cooperative
SNJ	Southern New Jersey
SO_2	Sulfur dioxide
SPP	Southwest Power Pool, Inc.
SPREGO	Spinning and regulation market-clearing software
SPS	Special protection scheme
SRMCP	Spinning reserve market-clearing price
STE	Short-term emergency
THI	Temperature humidity index
TLR	Transmission loading relief
TVA	Tennessee Valley Authority
UGI	UGI Utilities, Inc.
VAP	Dominion Virginia Power
VOM	Variable operations and maintenance expense
WEC	Wisconsin Energy Corporation

ERRATA

If this sheet is bound with the report and not affixed to the errata page, then relevant changes are reflected in the Report. Otherwise, the corrections described below can be found in the online version currently available at http://www.pjm.com/markets/market-monitor/som.html.

Page 44- Figure 1-6 and associated text has been revised

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