2005 State of the Market Report

Market Monitoring Unit
March 8, 2006

print: 04.07.06

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 *2005 State of the Market Report* is the eighth such annual report. This report is submitted to the Board of PJM Interconnection 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 per the Commission's order:

> 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.[1]

1 96 FERC ¶61,061 (2001).

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INTRODUCTION

The PJM Interconnection operates a centrally dispatched, competitive wholesale electricity market comprising generating capacity of 163,471 megawatts (MW) and about 390 market buyers, sellers and traders of electricity in a region including more than 51 million people in all or parts of Delaware, Illinois, Indiana, Kentucky, Maryland, Michigan, New Jersey, North Carolina, Ohio, Pennsylvania, Tennessee, Virginia, West Virginia and the District of Columbia.[1] PJM grew substantially in 2005 as the result of the integrations of new members from parts of Virginia, North Carolina, Maryland and Pennsylvania.[2]

PJM Market Background

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 energy pricing with cost-based offers and market-clearing nodal prices on April 1, 1998, and market-clearing nodal prices with market-based offers on April 1, 1999. PJM introduced Daily Capacity Markets on January 1, 1999, and Monthly and Multimonthly Capacity Markets in mid-1999. PJM implemented an auction-based FTR Market on May 1, 1999. PJM 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]

During the last two calendar years, PJM has integrated five control zones. In the *2004 State of the Market Report* the calendar year was divided into three phases, corresponding to market integration dates. In the *2005 State of the Market Report* the calendar year is divided into two phases, also corresponding to market integration dates:[4]

- **Phase 1 (2004).** The four-month period from January 1 through April 30, 2004, during which PJM was comprised of the Mid-Atlantic Region, including its 11 zones,[5] and the Allegheny Power Company (AP) Control Zone.[6]

- **Phase 2 (2004).** 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).[7]

1 See Appendix A, "PJM Service Territory," for map.

2 In 2004, PJM operated 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.

3 See also Appendix B, "PJM Market Milestones."

4 See the *2004 State of the Market Report* for more detailed descriptions of Phases 1, 2 and 3.

5 The Mid-Atlantic Region is comprised of 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).

6 Zones, control zones and control areas are geographic areas that customarily bear the name of a large utility service provider operating within their boundaries. 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 PJM's 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.

7 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).

- **Phase 3 (2004).** 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.

- **Phase 4 (2005).** The four-month period from January 1 through April 30, 2005, during which PJM was comprised of the Mid-Atlantic Region, including its 11 zones, the AP Control Zone, the ComEd Control Zone, the AEP Control Zone and the DAY Control Zone plus the Duquesne Light Company (DLCO) Control Zone which was integrated into PJM on January 1, 2005.

- **Phase 5 (2005).** The eight-month period from May 1 through December 31, 2005, during which PJM was comprised of the Phase 4 elements plus the Dominion Control Zone.

Conclusions

This report assesses the competitiveness of the Markets managed by PJM during 2005, including market structure, participant behavior and market performance. This report was prepared by and reflects the analysis of PJM's independent Market Monitoring Unit (MMU).

The MMU concludes that in 2005:

- The Energy Market results were competitive;
- The PJM Capacity Market results were competitive;
- The Regulation Markets results were competitive both where market-based offers and cost-based offers set market prices;
- The Spinning Reserve Markets results were competitive (markets were cleared on cost-based offers); and
- The FTR Auction Market results were competitive.

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 remains endemic to the structure of PJM Capacity Markets. The reliability pricing model (RPM) proposal is a logical overall design to permit the benefits of competition in the Capacity Market in the context of smaller and less structurally competitive locational markets because, in addition to its other features, it explicitly includes market power mitigation rules;
- The Ancillary Service Markets in PJM are generally not structurally competitive, as they are characterized by various combinations of high levels of supplier concentration, high individual market shares, frequent occurrences of individual or jointly pivotal suppliers and inelastic demand. The actual operation of Ancillary Service Markets, including both cost-based and price-based offers and market-clearing prices, demonstrates that the benefits of competitive markets can be realized even when, for structural reasons, the offers of some or all participants are limited to a measure of cost; and
- Market structure issues in the PJM Energy Markets continue to be offset to date by a combination of high levels of supply, generally moderate demand, generators' obligations to serve load, local market power mitigation 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, generally consistent with PJM's RPM proposal, to stimulate competition, to provide direct incentives for performance, to provide locational price signals, to provide forward auctions to permit competition from new entrants and to incorporate explicit market power mitigation rules;

- Modification of PJM's rules governing operating reserve credits to generators to reduce gaming incentives and to ensure that credits and corresponding charges to market participants are consistent with incentives for efficient market outcomes;

- Improvement of the cost-benefit analysis of congestion and transmission investments to relieve that congestion, especially where that congestion may enhance generator market power and where such investments support competition;

- Improvement in the analysis of the underlying sources of loop flows in order to enhance the efficient use of PJM market resources;

- Enhancement of PJM's posting of market data to promote market transparency;

- 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;

- Implementation of scarcity pricing rules that ensure competitive prices when scarcity conditions exist in market regions;

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

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

- 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 seventh year and its analysis of the PJM Markets, the MMU recognizes the need to continue to make the market monitoring function independent, well-organized, well-defined, clear to market participants and consistent with the policy of the United States Federal Energy Regulatory Commission (FERC). The MMU recommends that the Market Monitoring Plan be modified consistent with these objectives.

Energy Market, Part 1

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, 2005 was a time of growth with two control zones being integrated into PJM Markets. The PJM MMU's 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 PJM Energy Market structure, participant conduct and market performance for 2005, including market size, concentration, residual supply index, price-cost markup, net revenue and prices. The MMU concludes that, despite ongoing concerns about market structure, the PJM Day-Ahead and Real-Time Energy Market performance results were competitive in 2005.

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.[8] 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.

8 PJM Market Monitoring Plan, OATT, Attachment M.

Overview

Market Structure

- **Supply.** During the June to September 2005 summer period, PJM Energy Markets received an average of 168,600 MW in net supply, including hydroelectric generation, excluding real-time imports or exports. The 2005 net supply represented an approximately 60,600 MW increase compared to the comparable 2004 summer period. The increase in 2005 was comprised of 39,000 MW from the Phase 3 AEP and DAY Control Zone integrations, 3,100 MW from the Phase 4 DLCO Control Area integration, 20,600 MW from the Phase 5 Dominion Control Zone integration, an average net increase of 200 MW of hydroelectric power generation and 2,300 MW from a net decrease in capacity from the Mid-Atlantic Region, the AP Control Zone and the ComEd Control Zone.

- **Demand.** The PJM system peak load in 2005 was 133,763 MW on July 26, 2005, a coincident summer peak load reflecting the Mid-Atlantic Region and the AP, ComEd, AEP, DAY, DLCO and Dominion Control Zones.[9] The PJM summer peak load in 2004 of 77,887 MW occurred prior to the integrations of the AEP, DAY, DLCO and Dominion Control Zones. If the 2004 summer peak load were adjusted to include the AEP, DAY, DLCO and Dominion zones for comparison purposes, the 2004 summer peak load of the combined area would have been 120,353 MW.[10]

- **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 necessarily mean that a market is competitive or that participants cannot exercise market power. Analysis of the PJM Energy Market indicates moderate market concentration overall. Analyses of supply curve segments indicate moderate concentration in the baseload segment, but high concentration in the intermediate and peaking segments. Specific 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 2005, 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 or group of generation owners is pivotal if the output of the owner's or owners' generation facilities is required in order to meet market demand. When a generation owner or group of owners is pivotal, it has the ability to increase the market price above the competitive level. 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 1.0, a generation owner or group of generation owners 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. The RSI results are consistent with the conclusion that the PJM Energy Market results were competitive in both 2004 and 2005, with an average one pivotal RSI of 1.64 and 1.55, respectively. In 2005, a generation owner in the PJM Energy Market was pivotal for only 24 hours, less than 0.3 percent of all hours during the year. This represents an increase in pivotal hours

9 For the purpose of the *2005 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).

10 This calculated 2004 peak load of the combined area was a total system coincident peak load and occurred on a different day and hour than the 2004 peak load for PJM.

from 2004, when a generation owner was pivotal in the Energy Market for eight hours, or less than 0.1 percent of all hours.

- **Ownership of Marginal Units.** The concentration of ownership of marginal units provides an additional dimension of the pivotal supplier results. The higher the level of concentration of ownership of marginal units the greater is the potential market power issue.

- **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 underdeveloped for a variety of complex reasons. Total demand-side response resources available in PJM during the 11-month period ended November 30, 2005, were 2,065 MW from active load management, 1,619 MW from the Emergency Load-Response Program and 2,210 MW from the Economic Load-Response Program. There were 260 MW enrolled in both the Load-Response Program and in active load management. The 10,194 MW in total DSR resources, including additional programs reported by PJM customers in response to a survey, were approximately 8 percent of PJM's peak demand.

Market Conduct

- **Price-Cost Markup.** Price-cost markups are a measure of market power when they measure the impact of particular conduct on market outcomes. 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 2005, with markup index results averaging 0.3 percent for the calendar year.

- **Offer Capping.** PJM rules provide that PJM will offer cap units when their owners would otherwise have the ability to exercise local market power. Offer-capping levels remained steady in 2005. Offer capping is an effective means of addressing local market power.

- **Frequently Mitigated Units.** Rulings in 2005 by the FERC resulted in additional compensation as a form of scarcity pricing for units that were offer-capped more than 80 percent of their real-time run hours over the prior year.

Market Performance: Load and Locational Marginal Prices (LMPs)

- **Prices.** PJM 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 2004 to 2005. The simple, hourly average system LMP was 37.0 percent higher in 2005 than in 2004, $58.08 per MWh versus $42.40 per MWh. When hourly load levels are reflected, the load-weighted LMP of $63.46 per MWh in 2005 was 43.1 percent higher than 2004's $44.34. When increased fuel costs are accounted for, the fuel-cost-adjusted, load-weighted, average LMP was 1.5 percent higher in 2005 than in 2004, $45.02 per MWh compared to $44.34 per MWh. This means that, if it had not been for fuel cost increases, LMP would have been 1.5 percent higher in 2005 than in 2004.

PJM average Real-Time Energy Market prices increased in 2005 over 2004 for several reasons, including, but not limited to, significant increases in fuel cost for the marginal units and in load. PJM load growth in 2005 reflected the geographic expansion created by the DLCO and Dominion integrations and hotter summer weather. The PJM system price was above $150 per MWh for only five hours in 2004; in 2005 it was above the $150 benchmark for 234 hours and above $200 per MWh for 35 hours.

Conclusion

The PJM MMU analyzed key elements of PJM Energy Market structure, participant conduct and market performance for calendar year 2005, including aggregate supply and demand, concentration ratios, local market concentration ratios, residual supply indices, participation in demand-side response programs, price-cost markup and offer capping in this section of the report. The next section continues the analysis of the PJM Energy Market including measures of market performance.

Aggregate supply increased by about 60,600 MW when comparing the summer of 2005 to the summer of 2004 while aggregate peak load increased by 55,876 MW, retaining the general supply-demand balance from 2004 with a corresponding moderating impact on aggregate Energy Market prices. Market concentration levels remained moderate, relatively few hours exhibited pivotal suppliers and markups remained low. This relationship between supply and demand, regardless of the specific market, balanced by market concentration, is referred to as supply-demand fundamentals or economic fundamentals. While the market structure does not guarantee competitive outcomes, overall the market structure of the PJM aggregate Energy Market remains reasonably competitive.

Energy Market results, including prices, for 2005 reflect supply-demand fundamentals. Significantly higher nominal and load-weighted prices are consistent with a competitive outcome as the higher prices reflect both higher input fuel costs and warmer summer weather. If fuel costs had been the same in 2005 as they had been in 2004, prices would have increased by 1.5 percent rather than the actual 37.0 percent increase in nominal average prices and the 43.1 percent increase in load-weighted average prices. While the existing structure of the Energy Market does not guarantee competitive outcomes, actual market performance results were reasonably competitive in 2005. Given the structure of the Energy Market, tighter markets or a change in participant behavior are potential sources of concern in the Energy Market.

Energy Market, Part 2

The PJM MMU analyzed the net revenue performance of PJM Markets, the nature of new investment in capacity in PJM, the definition and existence of scarcity conditions in PJM and the issues associated with operating reserve credits and charges.

Overview

Net Revenue

- **Net Revenue Adequacy.** 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 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 2005 net revenue indicates that the fixed costs of new peaking and midmerit units were not fully covered, but that the fixed costs of new coal-fired baseload were covered. During the seven-year period 1999 to 2005, 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.

Existing and Planned Generation

- **PJM Installed Capacity.** During the period January 1 through December 31, 2005, PJM installed capacity grew by approximately 20,100 MW, primarily as a result of the integration of new areas into the PJM markets.

- **PJM Installed Capacity by Fuel Type.** At the end of 2005, PJM installed capacity was about 163,471 MW. Of the total installed capacity, 41.5 percent was coal, 27.5 percent was natural gas, 19.1 percent was nuclear, 7.2 percent was oil, 4.3 percent was hydroelectric and 0.3 percent was solid waste.

- **Generation Fuel Mix.** During 2005, coal was 56.4 percent, nuclear 34.2 percent, natural gas 5.9 percent, oil 1.2 percent, hydroelectric 1.7 percent, solid waste 0.6 percent and wind 0.1 percent of total generation.

- **Planned Generation.** If current trends continue, it is expected that older steam units in the east will be replaced by units burning natural gas and the result is potentially significant implications for future congestion, the role of firm and interruptible gas supply and natural gas supply infrastructure.

Scarcity

- **Historical Scarcity Pricing.** Scarcity exists when supply is less than, or equal to, demand where demand includes a level of operating reserves. In PJM, scarcity pricing has resulted under these conditions as the result of the shape of the PJM aggregate supply curve. Scarcity pricing occurred, for example, in the summer of 1999 in PJM.

- **Scarcity in 2005.** In the summer of 2005, the first hot summer since the integrations of Phases 1 through 5, the dynamic in the PJM Energy Market changed. The change was due, in part, to the larger footprint. What had been PJM's entire Energy Market in 1999 was now just a regional part of the market. Units that might have been dispatched in 1999 to meet aggregate PJM load were dispatched in 2005 to resolve constraints associated with bringing lower cost power from the west to east. The result was that rather than units in the eastern part of PJM being dispatched in merit order to meet aggregate demand in the relatively small eastern part of PJM, the units were dispatched out of merit order to solve local constraints. The result, in turn, was that there was not a market mechanism to ensure that prices increased to reflect the scarcity conditions that existed on two occasions.

Credits and Charges for Operating Reserve

- **Operating Reserve Issues.** Day-ahead and real-time operating reserve credits are paid to generation owners under specified conditions in order to ensure that units are not required to operate for the PJM system at a loss. Sometimes referred to as uplift or revenue requirement make whole, these payments are intended to be one of the incentives to generation owners to offer their energy to the PJM Energy Market at marginal cost and to operate their units at the direction of PJM dispatchers. From the perspective of those participants paying operating reserve charges, these costs are an unpredictable and unhedgeable component of the total cost of energy in PJM. While reasonable operating reserve charges are an appropriate part of the cost of energy, market efficiency would be improved by ensuring that the level of operating reserve charges is as low as possible consistent with the reliable operation of the system and that the allocation of operating reserve charges reflects the reasons that the costs are incurred.

- **Operating Reserve Charges in 2005.** Operating reserve charges were significantly higher in 2005 than in prior years. The reasons for the observed increase in the operating reserve rate include increased fuel costs, unexpected transmission outages, unanticipated fluctuations in interchange transactions levels and market power.

Conclusion

Wholesale electric power markets, apparently without exception, are affected by externally imposed reliability requirements. A regulatory authority external to the market makes a determination as to the acceptable level of reliability, typically measured as an acceptable loss of load probability level. This level of reliability is enforced through a requirement to maintain a target level of installed or unforced capacity, which, based on planning models, is considered to be a level that will produce the desired loss of load probability. The requirement to maintain a target level of installed capacity can be enforced via a variety of mechanisms, including government construction of generation, full requirements contracts with developers to construct and operate generation, state utility commission mandates to construct capacity, or capacity markets of various types. Regardless of the enforcement mechanism, the exogenous requirement to construct capacity in excess of what is constructed in response to energy market signals has an impact on energy markets. The impact of having capacity in excess of the equilibrium level likely to result from the operation of an energy market alone is to reduce the level and volatility of energy market prices and to reduce the duration of high energy market prices. This, in turn, reduces net revenue to generation owners which reduces the incentive to invest.

With or without a capacity market, energy market design must permit scarcity pricing when such pricing is consistent with market conditions and constrained by reasonable rules to ensure that market power is not exercised. Scarcity pricing is also part of an appropriate incentive structure facing both load and generation owners in a working wholesale electricity market design.

While net revenue in PJM has been sufficient to cover the costs of new peaking units in some years and was sufficient to cover the costs of a new coal plant in 2005, 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 all unit types 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. Nonetheless, 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.

A capacity market is a formal market-based mechanism used to allocate the costs of maintaining the level of capacity required to maintain the reliability target. Ideally, a capacity market would include a mechanism for equilibrating energy and capacity market revenues such that, in equilibrium, generators receive a market-based return for investing in capacity from all markets taken together. A capacity market is also an explicit mechanism for valuing capacity and is preferable to non market and non-transparent mechanisms for that reason.

PJM's proposed RPM is an effort to address these issues. RPM 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.

A market design cannot be deemed truly successful until it results in the retirement and replacement of a significant portion of the existing investment in generating assets, based on incentives endogenous to the market design. The net revenue performance of the markets over six years illustrates that additional market modifications are necessary if PJM is to pass the ultimate test of a market, the successful provision of long-term incentives to invest.

Interchange Transactions

The integration of two additional service territories into the PJM regional transmission organization (RTO) in 2005 significantly expanded PJM's geographic footprint and brought modest 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 continuously. The transactions involved may fulfill long-term or short-term bilateral contracts or take advantage of short-term price differentials.

Overview

Interchange Transaction Activity

Aggregate Imports and Exports

- **Phase 4.** During the four months ended April 30, 2005, PJM, including the DLCO Control Zone, was a net exporter of power, with monthly net interchange averaging -1.2 million MWh.[11] Gross monthly import volumes averaged 3.7 million MWh while gross monthly exports averaged 4.9 million MWh.

- **Phase 5.** During the remaining eight months ended December 31, 2005, PJM, including the Dominion Control Zone, continued to be a net exporter of power. Monthly average net interchange was -1.5 million MWh. Gross monthly import volumes averaged 2.7 million MWh while gross monthly exports averaged 4.2 million MWh.

Interface Imports and Exports[12]

- **Phase 4.** During Phase 4, the two largest net exporting interfaces totaled 36 percent of the total net exporting volume: Michigan Electric Coordinated System (PJM/MECS) at 19 percent and PJM/New York Independent System Operator interface (PJM/NYIS) with 17 percent. Ninety-three percent of the net import volume was carried on three interfaces: PJM/Ohio Valley Electric Corporation (PJM/OVEC) carried 39 percent, PJM/Illinois Power (PJM/IP) carried 38 percent and PJM/Duke Energy Corp. (PJM/DUK) carried 16 percent of the volume.

- **Phase 5.** During Phase 5, the two largest net exporting interfaces totaled 51 percent of the total net exporting volume: Tennessee Valley Authority (PJM/TVA) with 29 percent and MidAmerican Electric Company (PJM/MEC) at 22 percent. Ninety-two percent of the net import volume was carried on three interfaces: PJM/OVEC carried 57 percent, PJM/IP carried 22 percent and FirstEnergy Corp. (PJM/FE) carried 13 percent of the volume.

Modified Interfaces and Pricing Points

- **Removal of Interfaces.** Integration of the DLCO Control Zone into PJM on January 1, 2005, resulted in the removal of the PJM/DLCO interface. The subsequent integration of the Dominion Control Zone on May 1, 2005, resulted in the removal of the PJM/VAP interface.

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

12 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 Point Changes.** On January 1, 2005, the DLCO pricing point was eliminated as a result of the DLCO integration. On April 1, 2005, the MISO pricing point was created as a result of the Midwest ISO's introduction of markets. On May 1, 2005, the Southeast pricing point was modified to account for the integration of the Dominion Control Zone.

Interchange Transaction Topics

Existing and Proposed Operating Agreements with Bordering Areas

- **Midwest ISO.** The "Joint Operating Agreement between the Midwest Independent Transmission System Operator, Inc. and PJM Interconnection, L.L.C." (JOA)[13] entered its second phase of implementation including market-to-market activity and coordinated market-based congestion management within and between both markets.

- **PJM, Midwest ISO and TVA Joint Reliability Coordination Agreement.**[14] The Joint Reliability Coordination Agreement (JRCA), executed on April 22, 2005, provides for the active management of seams among the wholesale electricity markets of the Midwest ISO and PJM and the service territory of TVA. The Agreement provides for comprehensive reliability management and congestion relief among the three regions.

- **PJM and Progress Energy Carolinas, Inc. (PEC) Joint Operating Agreement (JOA).**[15] An operating agreement between PJM and PEC, approved by the FERC on September 9, 2005, with an effective date of July 30, 2005, provides for market-to-non market coordination.

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.

Actual Versus Scheduled Power Flows

- Loop flows are measured as the difference between actual and scheduled flows at one or more specific interfaces. Loop flows 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. Loop flows have negative consequences because they constitute unscheduled use of PJM's transmission system, affect real-time system operations and affect the revenue adequacy of FTRs because loop flows do not pay congestion costs. Although PJM's total scheduled and actual flows differed by about 4 percent in 2005, there were significant differences for individual interfaces. PJM's method of defining pricing points

13 See "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> (2.73 MB).

14 See "Joint Reliability Coordination (JRCA) among the Midwest ISO, PJM and TVA" (April 22, 2005) <http://www.pjm.com/documents/downloads/agreements/20050422-jrca-final.pdf> (145 KB).

15 See "Joint Operating Agreement (JOA) between Progress Energy Carolinas, Inc. and PJM" (July 29, 2005) < http://www.pjm.com/documents/ferc/documents/2005/20050729-er05-___-000.pdf> (2.90 MB).

is designed to provide price signals consistent with the actual power flows and thus to minimize the incentive to create loop flow.

Interchange Issues

- **PJM and Midwest ISO Transaction Issues.** During 2005, the relationship between prices at the PJM/MISO interface and at the MISO/PJM interface appeared to reflect economic fundamentals as did the relationship between interface price differentials and power flows between PJM and the Midwest ISO.

- **PJM and New York ISO Transaction Issues.** During 2005, the relationship between prices at the PJM/NYIS interface and at the New York Independent System Operator (NYISO) PJM proxy bus appeared to reflect economic fundamentals as did the relationship between interface price differentials and power flows between PJM and the NYISO. As in 2004, however, both continued to be affected by differences in institutional and operating practices between PJM and NYISO.

- **Consolidated Edison and PSEG Wheeling Contracts.** Two contracts governing wheeling of up to 1,000 MW of power through PJM into New York City were the subject of a November 2001 complaint to the FERC. The FERC issued an order on May 18, 2005, defining a protocol to resolve this issue which was implemented in July 2005. Based on early performance of the protocol, Consolidated Edison has formally asked the FERC to require PJM and NYISO to improve operations under the protocol to increase delivery performance, and PJM and NYISO are working to resolve these issues.

- **Ramp and Transmission Reservations.** PJM should consider development of rules that limit a market participant's ability to reserve more ramp than is actually either needed or used in order to facilitate the efficient use of limited ramp capability.

Conclusion

The PJM MMU analyzed the transactions between PJM and neighboring control areas for 2005 including evolving transactions patterns, economics and issues. The location of PJM transactions with external areas has changed significantly as a result of the substantial expansion of the PJM footprint over the last two years. New interfaces dominate export and import activity. In contrast to the first five years of PJM operations, PJM continued the recent pattern of being a net exporter of energy. While exports and imports have historically primarily cleared in the Real-Time Energy Market, transactions in the Day-Ahead Energy Market continued to grow in volume. PJM has entered into a number of agreements with neighboring control areas that govern reliability and economic coordination. As interactions with external areas are increasingly governed by economic redispatch, interface prices and volumes reflect supply and demand conditions and the number of TLRs has declined. PJM continues to face significant loop flows with substantial impacts on PJM for reasons that are not yet well understood. A cooperative analysis with the Midwest ISO would contribute to the understanding that is required before a solution can be designed. The Consolidated Edison/PSEG wheeling contracts are now managed under a FERC-approved protocol that has improved operations and additional improvements are being made. The allocation and management of ramp, the capability to import into or export from PJM, continue to create potential issues and improvements are also required in this area.

Capacity Markets

Each organization serving PJM load must own or acquire capacity resources to meet its capacity obligations. Load-serving entities (LSEs) can acquire capacity resources by entering into bilateral agreements, by participating in the PJM-operated Capacity Credit Market or by constructing generation. LSEs can reduce their capacity obligations by participating in relevant demand-side response programs. Collectively, all arrangements by which LSEs acquire capacity are known as the Capacity Market.[16]

The PJM Capacity Credit Market[17] provides mechanisms to balance supply of and demand for capacity unmet by the bilateral market or self-supply. The PJM Capacity Credit Market consists of the Daily, Interval,[18] Monthly and Multimonthly Capacity Credit Markets. The PJM 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.

From June 2004 through May 2005 a separate ComEd Capacity Credit Market operated, under the terms of PJM rules, to balance supply of and demand for capacity unmet by the bilateral market or self-supply in the ComEd Control Area.[19] The ComEd Capacity Credit Market consisted of Interval, Monthly and Multimonthly Capacity Credit Markets.

Overview

When the 2004 calendar year ended, PJM was operating two Capacity Markets, the PJM Capacity Market and the ComEd Capacity Market. The PJM Capacity Market (or simply PJM) was comprised of the 11 control zones of the Mid-Atlantic Region and the AP, AEP and DAY Control Zones. DLCO, which joined PJM on January 1, 2005, and Dominion, which joined PJM on May 1, 2005, were added to the PJM Capacity Market on the dates they joined. The ComEd Capacity Market was comprised solely of the ComEd Control Zone.

The ComEd Capacity Credit Market was added to the PJM Capacity Credit Market on June 1, 2005, to create a single PJM Capacity Market.[20]

16 See Appendix H, "Glossary," for definitions of PJM Capacity Credit Market terms.

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

18 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.

19 All ComEd Capacity Market values (capacities) are in terms of installed MW.

20 For purposes of Section 5, "Capacity Markets" and Appendix E, "Capacity Markets," these markets are identified as the PJM Capacity Market (or PJM) and the ComEd Control Zone Capacity Market (or ComEd). These markets are referred to collectively as the Capacity Markets for the regional transmission organization (RTO).

PJM Capacity Market

Market Structure for the PJM Capacity Market

Ownership Concentration

- **Phase 4.** Structural analysis of the PJM Capacity Credit Market found that, on average, its daily markets exhibited low concentration levels while its monthly and multimonthly markets exhibited moderate concentration levels during the period January through April 2005.

- **Phase 5.** Structural analysis of the PJM Capacity Credit Market found that, on average, its daily markets exhibited moderate concentration levels while its monthly and multimonthly markets exhibited high concentration levels during the period May through December 2005.

- **Total Capacity.** The Capacity Credit Markets include approximately 5 percent of total capacity obligations. The MMU also analyzed the ownership of total PJM capacity in order to develop a more complete assessment of market structure for capacity. The ownership of total capacity exhibited low concentration levels throughout the year, decreasing from an HHI of 953 on January 1 to 917 on December 31. The highest market share declined from 21.6 percent to 16.6 percent. There was a single pivotal supplier throughout the year, meaning that the capacity of the largest supplier was always required in order to meet the capacity obligation.

Supply and Demand

- **Phase 4.** From January through April 2005, unforced capacity and obligations remained relatively constant in the PJM Capacity Market as compared to Phase 3. Average unforced capacity rose by 2,123 MW or 2.0 percent to 110,545 MW. Average load obligations climbed by 1,295 MW or 1.3 percent to 100,201 MW or 10,344 MW less than average unforced capacity. Overall Capacity Credit Market transactions increased by 18.7 percent from Phase 3. Daily Capacity Credit Market volumes increased by 44.7 percent, while Monthly and Multimonthly Capacity Credit Market volumes increased by 16.4 percent and 10.7 percent, respectively.

- **Phase 5.** From May through December 2005, unforced capacity and obligations increased with Dominion joining PJM on May 1 and the integration of the ComEd Capacity Market into the PJM Capacity Market on June 1. Average unforced capacity rose 35.6 percent to 149,888 MW. Average load obligation climbed 39.5 percent to 139,736 MW. Overall Capacity Credit Market transactions increased by 22.0 percent from Phase 4. Daily Capacity Credit Market volumes increased by 9.3 percent, while Monthly and Multimonthly Capacity Credit Market volumes increased by 35.7 percent and 23.8 percent, respectively.

External and Internal Capacity Transactions

- **Phase 4.** From January through April 2005, imports averaged 5,855 MW, which was a decrease of 537 MW or 8.4 percent from the Phase 3 average of 6,392 MW. Exports averaged 3,953 MW, which was an increase of 742 MW or 23.1 percent from the Phase 3 average of 3,211 MW. Average net exchange decreased 1,279 MW or 40.2 percent to 1,902 MW from the Phase 3 average of 3,181 MW. Internal bilateral transactions averaged 91,880 MW, which was an increase of 14,712 MW or 19.1 percent from the 77,168 MW average for Phase 3.

- **Phase 5.** From May through December 2005, imports averaged 4,208 MW, which was a decrease of 1,647 MW or 28.1 percent from the Phase 4 average. Exports averaged 4,856 MW, which was an increase of 903 MW or 22.8 percent from the Phase 4 average. Average net exchange decreased 2,550 MW or 134.1 percent to -648 MW from the Phase 4 average of 1,902 MW. These changes were the result of the integration of the ComEd Capacity Market into the PJM Capacity Market on June 1. Internal bilateral transactions averaged 150,597 MW, which was an increase of 58,717 MW or 63.9 percent from the average for Phase 4. This increase was the result of Dominion joining PJM on May 1 and the integration of the ComEd Capacity Market into the PJM Capacity Market.

Active Load Management (ALM Credits)

- **Phase 4.** From January through April 2005, ALM credits in the PJM Capacity Market averaged 1,654 MW, down less than 1 percent from 1,662 MW in Phase 3.

- **Phase 5.** From May through December 2005, ALM credits in the PJM Capacity Market averaged 1,993 MW, an increase of 339 MW or 20.5 percent from Phase 4. This increase was attributable to the integration of the ComEd Capacity Market into the PJM Capacity Market on June 1, 2005, as the mandatory interruptible load (MIL) credits in ComEd were converted to ALM credits in PJM.

Market Performance in the PJM Capacity Market

Capacity Credit Market Volumes and Prices

- **Phase 4.** From January through April 2005, total PJM Capacity Credit Market transactions averaged 5,649 MW (5.6 percent of obligation), which was 888 MW higher than the Phase 3 average (4.8 percent of obligation). Total PJM Capacity Credit Market prices averaged $7.72 per MW-day, which was $2.81 per MW-day less than the Phase 3 average.

- **Phase 5.** From May through December 2005, total PJM Capacity Credit Market transactions averaged 6,892 MW (4.9 percent of obligation), which was 1,243 MW higher than the Phase 4 average. Total PJM Capacity Credit Market prices averaged $5.47 per MW-day, which was $2.25 per MW-day less than the Phase 4 average.

- **Calendar Years 1999 through 2005.** Daily Capacity Market volume declined from 2.5 percent of average obligation in 2000 to 1.2 percent in 2005.[21] Monthly and Multimonthly Capacity Market volume increased from 3.0 percent of obligation in 2000 to 3.9 percent of average obligation in 2005. Capacity Market prices increased from 1999 through 2001 and have declined and remained relatively stable since 2001 with the exception of the summer of 2004.

21 The year 2000 is used as the base year because it was the first full calendar year for which unforced capacity was used rather than installed capacity.

ComEd Capacity Market

Market Structure for the ComEd Capacity Market

Ownership Concentration

- **June 2004 through May 2005.** Structural analysis of the ComEd Capacity Credit Market found that its Monthly and Multimonthly Markets exhibited high levels of concentration.

- **Total Capacity.** The ComEd Capacity Credit Markets include about 6 percent of total ComEd capacity obligations. The MMU also analyzed total ComEd capacity in order to develop a more complete assessment of market structure for capacity. The ownership of total capacity exhibited high concentration levels throughout the year, with HHI declining from 4525 on June 1, 2004, to 4070 on May 31, 2005, and with the maximum market share declining from 64.2 percent to 59.8 percent and RSI below 1.0 throughout the year, indicating the presence of a single pivotal supplier. The presence of a single pivotal supplier means that the capacity of the largest supplier was always required in order to meet the capacity obligation.

Supply and Demand

- **June 2004 through May 2005.** ComEd electricity distribution companies (EDCs) together had an 81.6 percent market share of load obligation. During this period, capacity resources exceeded capacity obligations in the ComEd Capacity Market every month, resulting in an average net excess of 6,261 MW, or 31.7 percent of average obligation for the period.

External and Internal Capacity Transactions

- **June 2004 through May 2005.** The ComEd Control Zone was a net exporter of capacity resources, with exports increasing from 747 MW on June 1 to 2,289 MW on May 31. Almost half of the increase was the result of increased exports to the PJM Capacity Market. Imports remained relatively constant. Internal bilateral transactions decreased by 6,361 MW on October 1 due to the lower interval peak for the October to December period.

Market Performance in the ComEd Capacity Market

Capacity Credit Market Volumes and Prices

- **June 2004 through May 2005.** Total ComEd Capacity Credit Market transactions averaged 1,229 MW, which was 6.2 percent of load obligation. Prices averaged $23.99 per MW-day.

Generator Performance

From 1996 to 2001, the average, PJM equivalent demand forced outage rate (EFORd) declined, reaching 4.6 percent in 2001, but then increased to 5.2 percent in 2002, 7.0 percent in 2003 and 8.0 percent in 2004.[22] In 2005, the average PJM EFORd decreased to 7.3 percent. The decrease in EFORd from 2004 to

22 As a general matter, the current year EFORd data reported in prior state of the market reports may be revised based on final data submitted after the publication of the report as final EFORd data are not available until after the publication of the reports.

2005 was the result of decreased forced outage rates across all unit types with the exception of combustion turbines. These forced outage rates are for the PJM Mid-Atlantic Region and the AP Control Zone only. The forced outage rate in 2005 was 6.5 percent for all zones within the PJM Control Area.[23]

Conclusion

The PJM MMU analyzed key measures of PJM Capacity Market and of ComEd Capacity Market structure and performance for calendar year 2005 and for the period from June 2004 through May 2005 for ComEd, including concentration ratios, prices, outage rates and reliability. 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 potential for the exercise of market power is high. Market power is endemic to the existing structure of PJM Capacity Markets.

The analysis of capacity markets begins with market structure, which provides the framework for the actual behavior or conduct of market participants. The analysis also examines participant behavior in the context of market structure. In a competitive market structure, market participants are constrained to behave competitively. In a competitive market structure, competitive behavior is profit maximizing behavior. Finally, the analysis examines market performance results. The actual performance of the market, measured by price and the relationship between price and marginal cost, results from the interaction of these elements. For example, at times market participants behave in a competitive manner even within a noncompetitive market structure. This may result from the relationship between supply and demand and the degree to which one or more suppliers are singly or jointly pivotal 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 MMU found serious market structure issues, but no exercise of market power during these time periods. The behavior of market participants in the context of the market structure and the supply and demand fundamentals offset these market structure issues in the PJM Capacity Market in 2005. The PJM Capacity Market results were competitive during 2005. The ComEd Capacity Market results were reasonably competitive for the 12-month period from June 2004 through May 2005. Market power remains a serious concern for the MMU in the PJM Capacity Market based on market structure conditions in this market.

Ancillary Service Markets

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

23 In some cases, data for the AEP, DAY, DLCO, Dominion and ComEd Control Zones may be incomplete for the years 2004 and 2005. Only data that have been reported to PJM were used.

24 75 FERC ¶ 61,080 (1996).

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 Regulation and Spinning Reserve Markets are cleared simultaneously and cooptimized with the Energy Market and operating reserve requirements 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.

In both Phase 4 and Phase 5, PJM operated two Regulation Markets: one for the Mid-Atlantic Region and a second for the Western Region. On August 1 of Phase 5, PJM combined both into a single PJM Combined Regulation Market for a six-month trial period. After the trial period, based on analysis of market results and a report by the PJM MMU, PJM stakeholders will vote on whether to keep the combined market.

During Phase 4, PJM operated three Spinning Reserve Markets: one for the Mid-Atlantic Region, one for the Western Region and one for the ComEd Control Zone. During Phase 5, PJM operated a fourth Spinning Reserve Market for Dominion.

The analysis treats each of the two Regulation Markets and each of the three Spinning Reserve Markets separately during Phase 4. The market analysis treats each of the two Regulation Markets separately during the May 1 through July 31 component of Phase 5 (Phase 5-a), and as a single Regulation Market during the August 1 through December 31 component of Phase 5 (Phase 5-b). Each of the four Spinning Reserve Markets is treated separately for the entire Phase 5 period.

Overview – Regulation and Spinning Reserve Markets

The MMU has reviewed structure, conduct and performance indicators for the identified Regulation Markets. The MMU concludes that the Regulation Markets functioned effectively, except for some minor problems of insufficient regulation supply shortly after the start of Phase 5 and during times of minimum generation. The Regulation Markets produced competitive results throughout calendar year 2005 based on the regulation market-clearing price. The Regulation Market prices reflected the fact that offers in the Western Region were capped during Phase 4 and that the offers of two large participants, AEP and Dominion, were capped at cost plus a margin throughout Phase 5, in both cases because the Western Region Regulation Market was determined to be not structurally competitive.

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 25 (August 19, 2005), p. 71.

The MMU has reviewed structure, conduct and performance indicators for the identified Spinning Reserve Markets. The MMU concludes that the Spinning Reserve Markets functioned effectively. The Spinning Reserve Markets produced competitive results throughout calendar year 2005 based on the spinning market-clearing price. The Spinning Reserve Market prices reflected the fact that all offers were capped at cost plus a margin because the markets have been determined to be not structurally competitive.

The Regulation Markets

The structure of the Mid-Atlantic Region and Western Region Regulation Markets was evaluated and the MMU concluded that these markets are not structurally competitive as they are characterized by a combination of one or more structural elements including high levels of supplier concentration, high individual company market shares, significant hours with pivotal suppliers and inelastic demand. The structure of the Combined Regulation Market was also evaluated based on the five months of available data and the MMU concluded that this market is characterized by lower levels of concentration, smaller market shares, a smaller number of hours with pivotal suppliers and inelastic demand. The conduct of market participants within these market structures has been consistent with competition consistent with existing offer capping, and the market performance results have been competitive.

- **Mid-Atlantic Region.** The Regulation Market in the PJM Mid-Atlantic Region was cleared based on participants' price offers during Phases 4 and 5-a. All suppliers were paid the market-clearing price, which is a function of the supply curve and PJM-defined demand. The supply curve consists of offered and eligible MW and the associated offer prices which are a combination of unit-specific offers plus opportunity cost (OC) as calculated by PJM.[27]

- **Western Region.** The Regulation Market in the Western Region during Phase 4 was cleared based on participants' cost-based offers. The cost-based regulation offers 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. During Phase 5-a, the market was cleared using a combination of price-based offers and cost-based offers. In Phase 5, Dominion and AEP were required to make cost-based offers based on their dominant position in the market while other participants made price offers.

- **PJM Combined Regulation Market.** During the trial period for the PJM Combined Regulation Market, the market was cleared using a combination of price-based offers and cost-based offers. Dominion and AEP were required to make cost-based offers based on their dominant position in the market while other participants made price offers.

Market Structure

- **Demand.** Demand for regulation is determined by PJM based on an evaluation of the regulation required in order to meet reliability objectives. Required regulation remained constant for each control region throughout 2005 except for two periods during which a temporary adder was implemented at the direction of PJM.

- **Supply.** The supply of offered and eligible regulation in the PJM Mid-Atlantic Region was generally both stable and adequate, with an average 1.92 ratio of regulation supply offered and eligible to the hourly regulation requirement during Phases 4 and 5-a. While the average ratio of hourly regulation supply

27 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.

offered and eligible to regulation required was 1.64 for the Western Region during Phases 4 and 5-a, at times an inadequate supply of regulation was offered and eligible to participate in the market on an hourly basis in the Western Region. The average ratio of hourly regulation supply offered and eligible to regulation required was 1.88 for the PJM Combined Regulation Market during Phase 5-b.

Concentration of Ownership

- **Mid-Atlantic Region.** During Phase 4 and Phase 5-a, the PJM Mid-Atlantic Region Regulation Market for eligible regulation had an average Herfindahl-Hirschman Index (HHI)[28] of 1751 which is classified as "moderately concentrated."[29] Less than 1 percent of the hours had an eligible regulation HHI above 2500. There were two suppliers with market shares greater than, or equal to, 20 percent. Seven percent of the hours had a single pivotal supplier, 48 percent of the hours had two pivotal suppliers and 88 percent of the hours had three pivotal suppliers.

- **Western Region.** During Phase 4 and Phase 5-a, the Western Region Regulation Market for eligible regulation had an average HHI of 2802 which is classified as "highly concentrated" and 58 percent of the hours had an HHI above 2500. There was a single pivotal supplier in 62 percent of the hours. One hundred percent of the hours had two pivotal suppliers.

- **PJM Combined Regulation Market.** During Phase 5-b, the PJM Combined Regulation Market had an average HHI of 1079 which is classified as "moderately concentrated." No suppliers had market shares greater than, or equal to, 20 percent. During 1 percent of hours, there was a single pivotal supplier. During 6 percent of hours, there were two pivotal suppliers. During 29 percent of the hours, there were three pivotal suppliers. For all units except CTs, during 5 percent of hours, there was a single pivotal supplier, during 23 percent of hours, there were two pivotal suppliers and during 68 percent of the hours, there were three pivotal suppliers.

Market Conduct

- **Offers.** The offer price is the only component of the total regulation offer price provided by the unit owner and is applicable for the entire operating day. The regulation offer price is subject to a $100 per MWh offer cap in the Mid-Atlantic Region, was subject to offer capping in Phase 4 in the Western Region and was subject only to a $100 per MWh offer cap in Phase 5 in the Western Region, with the exception of the dominant suppliers, Dominion and AEP, whose offers were capped at marginal cost plus $7.50 per MWh plus opportunity cost. The average MW-weighted offer price for regulation in the PJM Mid-Atlantic Region during Phases 4 and 5-a was $15.63. The average MW-weighted offer price for regulation in the Western Region Regulation Market during Phases 4 and 5-a was $7.73. For the PJM Combined Regulation Market during Phase 5-b, the average MW-weighted offer price for regulation was $16.29.

Market Performance

- **Price.** For the entire PJM RTO from January 1, 2005, to December 31, 2005, the average price per MWh (regulation market-clearing price) associated with meeting PJM's demand for regulation was

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

$49.73. For the PJM region during Phases 4 and 5-a, the average price per MWh for regulation was $36.39. For the Western Region Regulation Market during Phases 4 and 5-a, the average price per MWh for regulation was $42.64. For the PJM Combined Regulation Market during Phase 5-b, the average price per MWh was $64.03.

The Spinning Reserve Markets

The structure of each of the Spinning Reserve Markets has been evaluated and the MMU has concluded that these markets are not structurally competitive as they are characterized by high levels of supplier concentration and inelastic demand. As a result, these markets are operated as markets with market-clearing prices and with offers based on the marginal cost of producing the service plus a margin and opportunity cost. The conduct of market participants within these market structures has been consistent with competition, and the market performance results have been competitive. Prices for spinning in the PJM Mid-Atlantic Region, the ComEd Control Zone, the Western Region and Dominion are market-clearing prices determined by the supply curve 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.

Market Structure

- **Demand.** Computed in accordance with the specific spinning reserve requirements, the average MW spinning requirement was: 1,091 MW for the PJM Mid-Atlantic Region; 217 MW for the ComEd Spinning Zone; 437 MW for the Western Region; and 5 MW for the Southern Spinning Reserve Zone (May to December only).

- **Supply.** For the PJM Mid-Atlantic Region, the offered and eligible excess supply ratio was 1.15. For the Western and Southern Regions, the ratio was 1.76. For the ComEd Control Zone, the ratio was 1.21.

- **Concentration of Ownership.** In 2005, market concentration was high in the Tier 2 Spinning Reserve Market. The average offered and eligible Spinning Reserve Market HHI for the PJM Mid-Atlantic Region throughout 2005 was 2940. The average Spinning Reserve Market HHI for the Western Region was 4593. The average Spinning Reserve Market HHI for ComEd Control Zone was 8844. The average Spinning Reserve Market HHI for Dominion was 10000.

Market Performance

- **Price.** Load-weighted, average price associated with meeting the PJM system demand for Tier 2 spinning reserve throughout 2005 was $14.41 per MW, a $0.45 per MW decrease from 2004. The load-weighted, average price in the PJM Mid-Atlantic Region for Phases 4 and 5 was $15.44 per MW. The load-weighted, average price for spinning reserve in the ComEd Control Zone during Phases 4 and 5 was $12.73. The load-weighted, average price for spinning in the Western Control Zone during Phases 4 and 5 was $13.23. The load-weighted, average price for spinning in Dominion during Phase 5 was $13.08.

Conclusion

PJM consolidated its Regulation Markets into a single Combined Regulation Market, on a trial basis, effective August 1, 2005. PJM's consolidation of its Regulation Markets resulted in improved performance and in increased competition. The MMU will make a recommendation in the near future as to whether the consolidation has resulted in a market that is structurally competitive. The market continues to be based on price offers for most sellers and all sellers are paid a market-clearing price based on offers plus opportunity costs. The result of this design has been a competitive outcome and consistent with competitive offers from all participants whether offer-capped or not. The marginal costs of providing regulation have been clearly defined and are consistent with the offers that would be made if the suppliers were behaving competitively.

PJM's Spinning Reserve Markets have worked effectively with offers based on marginal costs plus a margin and with all participants paid a market-clearing price based on the marginal offer including opportunity costs, despite the fact that these markets are characterized by high levels of seller concentration and inelastic demand.

The benefits of markets are realized under this approach to ancillary service markets. Even in the presence of structurally non-competitive markets, there are transparent, market-clearing prices based on competitive offers that account explicitly and accurately for opportunity costs. PJM should continue to consider whether additional ancillary service markets need to be defined in order to ensure that the market is compensating suppliers for services when appropriate.

Congestion

Congestion occurs when available, lower-cost energy cannot be delivered to all loads for a period because transmission capabilities are not adequate to meet some loads for the period. When the least cost available energy cannot be delivered to load in a transmission-constrained area, higher cost units in this constrained area must be dispatched to meet that load.[30] The result is that the price of energy in the constrained area is higher than in the unconstrained area because of the combination of transmission limitations and the cost of local generation. 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.

Congestion reflects the underlying features of the power system including the nature and capability of transmission facilities and the cost and geographical distribution of generation facilities. Congestion is neither a negative nor a positive but is a direct measure of the extent to which there are differences in the cost of generation that cannot be equalized through the capability of the transmission system to deliver the cheapest energy to all parts of the system in every hour. A rational planning process would attempt to choose the least cost combination of transmission and generation and would reflect the fact that investments in both transmission and generation have costs. The transmission system provides one physical hedge against congestion. The transmission system is paid for by firm load and, as a result, firm load receives the corollary financial hedge in the form of ARRs and/or FTRs. While the transmission system and, therefore, FTRs are not a complete hedge against congestion, FTRs do provide a substantial offset to the cost of congestion to firm load.

30 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.

As PJM integrated new transmission zones during 2005, the patterns of congestion changed, reflecting additional transmission and generation resources with new cost structures, load requirements and transmission system characteristics.

Overview

Congestion Cost

- **Total Congestion.** Congestion costs have ranged from 6 percent to 10 percent of PJM annual total billings since 2000. Congestion costs were approximately 9 percent of total PJM billings for 2005, as they were in 2004. Total congestion costs were $2.09 billion in calendar year 2005, a 179 percent increase from $750 million in calendar year 2004. The increased size of the total PJM Energy Market contributed to the increase in total congestion charges. The total PJM billing for 2005 was $22.63 billion, a 160 percent increase over the approximately $8.70 billion billed in 2004.

- **Monthly Congestion.** Differences in monthly congestion costs continued to be substantial. In 2005, 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.

- **Hedged Congestion.** FTRs were paid at 100 percent of the target allocation level for the 12-month planning period that ended May 31, 2005. FTRs were paid at 91 percent of the target allocation level through December 31, 2005, of the planning period ending May 31, 2006.

LMP Differentials and Facility or Zonal Congestion

- **LMP Differentials**. 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.

- **Congested Facilities.** Congestion frequency increased in calendar year 2005 as compared to 2004. During 2005, there were 17,524 congestion-event hours as compared to 11,205 congestion-event hours in 2004. Interfaces, transformers and lines experienced overall increases in congested hours during 2005 as compared to 2004. The expansion of PJM through the integration of new control zones contributed to the increase in congestion frequency.

- **Zonal Congestion.** In calendar year 2005, the AP Control Zone experienced the largest increase in congestion frequency of any control zone in PJM. The 2,877 congestion-event hours in the AP Control Zone were a 746 percent increase over the 340 congestion-event hours the zone had experienced during 2004. The Doubs transformer and the Mount Storm-Pruntytown line together contributed 1,222 congestion-event hours or 42 percent of the AP Control Zone total. In the AECO Control Zone, there was a 119 percent increase in congestion on the Laurel-Woodstown 69 kV line. With 879 congestion-event hours, the Laurel-Woodstown line comprised 50 percent of all AECO Control Zone congestion during 2005. The AEP Control Zone saw increases in congestion on the Cloverdale-Lexington, Mahans Lane-Tidd and Kanawha-Matt Funk lines during 2005. These three facilities accounted for 1,357 congestion-event hours, or 71 percent of the total AEP Control Zone congestion during 2005. Congestion on 500 kV zone facilities increased in 2005 as compared to 2004, contributing 5,548 congestion-event hours or 32 percent of the total PJM congestion-event hours. Three 500 kV zone facilities, the Wylie Ridge transformer, Kammer transformer and the Bedington-Black Oak line contributed 4,045 congestion-event hours or 73 percent of all 500 kV zone congestion-event hours during 2005. The Wylie Ridge transformer, the Kammer transformer and the Bedington-Black Oak line were the first, second and third most frequently constrained facilities, respectively, during 2005.

Post-Contingency Congestion Management Program

- **Implementation.** PJM implemented a post-contingency congestion management protocol on September 1, 2004, under which a transmission facility may be operated to a 30-minute, short-term emergency rating if there is sufficient quick start generation capability or switching to respond to the loss of a facility.

- **Initial Results.** Beginning on June 1, 2005, there were 36 facilities included in this program, an increase of 21 facilities over the number as of June 1, 2004. During 2005, 136 hours of off-cost operation were avoided through the use of this protocol.

Economic Planning Process

- **Implementation.** PJM's regional transmission expansion planning (RTEP) protocol includes an economic planning component to identify the transmission upgrades needed to address unhedgeable congestion whether through a market window or directly through the RTEP protocol. However, the current methodology for calculating unhedgeable congestion overstates the value of economic generation as a congestion hedge unless economic local generation is owned by load. The result of such an overstatement is to undervalue the cost of unhedgeable congestion and to undervalue transmission upgrades. This, in turn, would lead to the rejection of cost-effective economic transmission upgrades under the cost-benefit calculation.

- **Early Results.** By December 31, 2005, 74 facilities had experienced sufficient levels of unhedgeable congestion to trigger the opening of a market window to solicit merchant solutions to relieve congestion. Of these, 31 or approximately 42 percent had completed their initial studies.

Conclusion

Congestion reflects the underlying features of the power system, including the nature and capability of transmission facilities and the cost and geographical distribution of generation facilities. Congestion increased in 2005 in approximate proportion to the total increase in total billing as PJM continued to expand its footprint. The year 2005 was the first full calendar year reflecting the impact of areas integrated in 2004 in addition to the phased 2005 integrations of the DLCO and Dominion Control Zones. This constituted a dramatic change in the nature of the power system managed by PJM, including large new areas under LMP-based redispatch where borders had previously been managed by TLR procedures and ramp limits. Efficient redispatch displaced the less efficient management of borders. That redispatch was more efficient and, at the same time, revealed the underlying limitations of the ability of the transmission system over the broad footprint to transfer the lowest cost energy on the system to all parts of the system for all hours. The details are revealed in the analysis of temporal patterns of congestion and of congested facilities and zonal congestion. That information, made explicit for the first time, is an essential input to a rational market and planning process that covers the entire expanded footprint for the first time. PJM has made significant steps in the transmission planning process and needs to make more, in particular ensuring that the calculation of the costs and benefits of congestion is done appropriately. With all the changes, ARRs and FTRs continued to serve as a hedge against congestion. FTRs were paid at 100 percent of their target allocation for the planning year ended May 31, 2005, and at 91 percent for the first seven months of the current planning year.

Financial Transmission and Auction Revenue Rights

FTRs and ARRs give firm transmission customers an offset against congestion costs. In PJM, FTRs have been made available to firm point-to-point and network service transmission customers as a hedge against congestion costs since the inception of LMP on April 1, 1998.[31]

FTRs and ARRs are financial instruments that entitle the holder to receive revenues or to pay charges based on nodal price differences. FTRs provide holders with revenues or charges based on the locational price differences actually experienced in the Day-Ahead Energy Market. ARRs provide holders with revenues or charges based on the locational price difference between ARR sources and sinks determined in the Annual FTR Auction.[32] These price differences are based on the bid prices of participants in the Annual FTR Auction Market. The auction clears the set of feasible FTR bids which produce the highest net revenue. In other words, ARR revenues are a function of FTR Auction participants' expectations of locational price differences in the Day-Ahead Energy Market. ARR and FTR holders do not need to physically deliver energy to receive ARR or FTR credits and neither instrument represents a right to the physical delivery of energy.

Firm transmission customers have access to FTRs because they pay the costs of the transmission system that enables firm energy delivery. Firm transmission customers receive requested FTRs to the extent that they are consistent both with the physical capability of the transmission system and with FTR requests of other eligible customers.

Effective June 1, 2003, PJM replaced the allocation of FTRs with an allocation of ARRs and an associated Annual FTR Auction.[33] Firm transmission customers have the option either to take allocated ARRs or to take the underlying FTRs through a process called self-scheduling.

PJM also runs Monthly FTR Auctions designed to permit bilateral FTR transactions and to allow any market participant to buy residual system FTRs. PJM introduced 24-hour FTRs into the Monthly Auctions for the 2003 to 2004 planning period. At the same time, PJM also added annual and monthly FTR option products to the FTR Auction Market. Unlike standard FTRs, the FTR options can never be a financial liability.

The *2005 State of the Market Report* focuses on two FTR/ARR planning periods: the 2004 to 2005 planning period which covers June 1, 2004, to May 31, 2005, and the 2005 to 2006 planning period which covers June 1, 2005, through May 31, 2006.[34]

31 PJM network and firm, long-term point-to-point transmission service customers are referred to as eligible customers.

32 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.

33 87 FERC ¶ 61,054 (1999).

34 Annual FTR accounting changed from calendar year to planning period 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.

For the 2005 to 2006 planning period (June 1, 2005, through May 31, 2006), ARR allocations were provided to eligible market participants in the Mid-Atlantic Region and AP Control Zone. The choice of ARRs or direct allocation FTRs was available in the recently integrated ComEd, AEP, DAY, DLCO and Dominion Control Zones. Participants in newly integrated control zones retain the option of ARR allocations or direct allocation FTRs for the two planning periods following integration. After that, they can participate fully in the FTR Markets and receive ARR allocations through the PJM allocation process. For example, since its May 1, 2004, integration, direct allocation FTRs were available to participants in the ComEd Control Zone for the 2004 to 2005 planning period and for the 2005 to 2006 planning period. For subsequent periods, eligible customers in the ComEd Control Zone will be full participants in the ARR allocation process.

Overview

Financial Transmission Rights (FTRs)

- **Products.** FTR products include FTR obligations and FTR options. Each of these is available for 24-hour, off-peak and on-peak periods.

- **Supply and Demand.** PJM operates an Annual FTR Auction Market for all zones in the PJM footprint. Participants in newly integrated zones must choose to receive either an FTR allocation or an ARR allocation before the start of Annual FTR Auction. In the Annual Auction Market, total FTR Auction demand was 871,841 MW during the 2005 to 2006 planning period, up from 861,323 MW during the 2004 to 2005 planning period. The Auction Market cleared 141,179 MW (16.2 percent of demand), leaving 730,662 MW of uncleared bids. In the FTR Auction Market for the 2004 to 2005 planning period, the demand was 861,323 MW while the market cleared only 119,629 MW (13.9 percent of demand), leaving uncleared bids of 741,694 MW. Under the Annual FTR Auction, there is no limit on FTR demand. 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. The principal binding constraints limiting the supply of FTRs were the Jefferson 138 kV line, the Mahans Lane 138 kV line and the Branchburg 500/230 kV transformer.

  In the allocation of FTRs or ARRs for the ComEd, AEP, DAY, DLCO and Dominion Control Zones, total demand for annual FTR allocations was 42,641 MW for the 2005 to 2006 planning period, down from 65,757 MW for the 2004 to 2005 planning period. This decrease was the net result of a number of factors including the AP Control Zone becoming ineligible for direct allocation FTRs, increased demand by customers in the ComEd Control Zone for ARRs rather than directly allocated FTRs and the integration of Dominion. Demand for allocations cleared at 39,429 MW, leaving uncleared bids of 3,212 MW. The principal binding constraints limiting the supply of allocated FTRs were the Chesterfield-Lakeside 230 kV line, the Kanawha River-Matt Funk 345 kV line, the South Canton transformer and the Crete-St Johns 345 kV line, and the Bedington-Black Oak interface.

  In addition to the Annual FTR Auction and allocation markets, PJM conducts Monthly FTR Auction Markets covering the entire PJM footprint, to allow participants to buy and sell any residual transmission entitlement that is available after FTRs are awarded from the Annual FTR Auction. Any market participant can participate in the Monthly Auctions as a buyer or as a seller.

- **Ownership Concentration.** Ownership of FTRs is moderately concentrated and maximum market shares exceed 20 percent in some cases based on the results of the Annual Auction. Given PJM's Annual and Monthly FTR Auctions, the market shares may fluctuate when FTR-owning entities trade, buy or sell the instruments.

- **Volume.** Of 914,483 MW in annual FTR requests for the 2005 to 2006 planning period, 180,609 MW (19.7 percent) were cleared. Of 927,081 MW[35] in annual FTR requests for the 2004 to 2005 planning period, 179,950 MW (19.4 percent) were cleared.

- **Price.** For the 2005 to 2006 planning period, 84.3 percent of the Mid-Atlantic Region, AP and ComEd Control Zones' annual FTRs were purchased for less than $1 per MWh and 89.1 percent for less than $2 per MWh. The overall average prices paid for annual FTR obligations were $1.56 per MWh for 24-hour, $0.40 per MWh for on-peak and $0.33 per MWh for off-peak FTRs. Comparable prices for the 2004 to 2005 planning period were $1.27 per MWh for 24-hour, $0.16 per MWh for on-peak and $0.13 per MWh for off-peak FTRs. The overall average prices paid for 2005 to 2006 planning period annual FTR obligations and options were $0.10 per MWh and $0.18 per MWh, respectively, compared to $0.31 per MWh and $0.19 per MWh, respectively, in the 2004 to 2005 planning period.

- **Revenue.** Congestion revenues are allocated to FTR holders based on FTR target allocations. PJM collected $1,672 million of FTR revenues during the first seven months of the 2005 to 2006 planning period and $1,118 million during the 12-month 2004 to 2005 planning period.[36]

- **Revenue Adequacy.** FTRs were paid at 91 percent of the target allocation level for the 2005 to 2006 planning period, through the end of calendar year 2005.[37] FTRs were 100 percent revenue adequate during the 2004 to 2005 planning period.

Auction Revenue Rights (ARRs)

- **Supply and Demand.** Total demand in the annual ARR allocation was 82,343 MW for the 2005 to 2006 planning period, up from 55,128 MW during the 2004 to 2005 planning period and 39,888 MW during the 2003 to 2004 planning period. ARR demand is limited by the 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.

- **Volume.** Of 82,343 MW in ARR requests for the 2005 to 2006 planning period, 59,410 MW were allocated. Eligible market participants subsequently self-scheduled 32,631 MW (55 percent) of these allocated ARRs as annual FTRs. 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 (39 percent) of these allocated ARRs as annual FTRs.

35 The number reported here is slightly higher than the number reported in *2004 State of the Market Report*, which was 924,154 MW, because the number reported here includes 1,524 MW of requested bids in the DLCO Control Zone and 1,402 MW of additional requested bids in the AEP and DAY Control Zones.

36 See Section 7, "Congestion," at Table 7-5, "Monthly PJM congestion accounting summary [Dollars (millions)]: By planning period."

37 See Section 7, "Congestion," for an additional discussion of FTR revenue adequacy.

- **Revenue.** Revenues from the Annual FTR Auction are first distributed to ARR holders based on ARR target allocations. If that revenue is not sufficient to meet ARR target allocations, then revenues from Monthly FTR Auctions are used to make up any shortfall. For the 2005 to 2006 planning period, the ARR target allocations were $870 million while PJM collected $892 million from the combined Annual and Monthly FTR Auctions through the end of calendar year 2005, making ARRs revenue adequate. During the 2004 to 2005 planning period, the ARR target allocations were $345 million while PJM collected $385 million from the combined Annual and Monthly FTR Auctions, making ARRs revenue adequate.

- **Revenue Adequacy.** ARRs were 100 percent revenue adequate for both the 2005 to 2006 and the 2004 to 2005 planning periods. ARR holders will receive credits valued at $870 million during the 2005 to 2006 planning period, with an average hourly ARR credit of $1.67 per MWh. ARR holders received credits valued at $345 million during the 2004 to 2005 planning period, with an average hourly ARR credit of $1.17 per MWh.

Conclusion

The annual ARR allocation and the Annual FTR Auction together provide long-term, firm transmission customers with a mechanism to hedge congestion and provide all market participants increased access to long-term FTRs. The Annual FTR Auction allows a market valuation of FTRs. The 2005 FTR Auction Market results were competitive and succeeded in providing all qualified market participants with equal access to FTRs. A potential barrier to competition was removed by implementing the rules which explicitly allow that the ARRs with positive economic values (FTRs in newly integrated zones) follow load as load shifts among suppliers, although the fact that the underlying FTRs do not also follow load in the case of self-scheduled ARRs should also be addressed. FTRs were paid at 100 percent of the target allocation level for the 12-month planning period that ended May 31, 2005, and at 91 percent of the target allocation level for the first seven months of the planning period ending May 31, 2006. Although in the aggregate, FTRs provided a hedge against 100 percent of the target allocation level during the 12-month period that ended May 31, 2005, 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.

SECTION 2 – ENERGY MARKET, PART 1

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, 2005 was a time of growth with two 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 PJM Energy Market structure, participant conduct and market performance for 2005, including market size, concentration, residual supply index, price-cost markup, net revenue and prices. The MMU concludes that, despite ongoing concerns about market structure, the PJM Day-Ahead and Real-Time Energy Market performance results were competitive in 2005.

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.

During the last two calendar years, PJM has integrated five control zones. In the *2004 State of the Market Report* the calendar year was divided into three phases, corresponding to market integration dates. In the *2005 State of the Market Report* the calendar year is divided into two phases, also corresponding to market integration dates:[2]

- **Phase 1 (2004).** The four-month period from January 1 through April 30, 2004, during which PJM was comprised of the Mid-Atlantic Region, including its 11 zones,[3] and the Allegheny Power Company (AP) Control Zone.[4]

- **Phase 2 (2004).** 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]

1 PJM Market Monitoring Plan, OATT, Attachment M.

2 See the *2004 State of the Market Report* for more detailed descriptions of Phases 1, 2 and 3.

3 The Mid-Atlantic Region is comprised of 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).

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. 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 PJM's 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.

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).

- **Phase 3 (2004).** 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.

- **Phase 4 (2005).** The four-month period from January 1 through April 30, 2005, during which PJM was comprised of the Mid-Atlantic Region, including its 11 zones, the AP Control Zone, the ComEd Control Zone, the AEP Control Zone and the DAY Control Zone plus the Duquesne Light Company (DLCO) Control Zone which was integrated into PJM on January 1, 2005.

- **Phase 5 (2005).** The eight-month period from May 1 through December 31, 2005, during which PJM was comprised of the Phase 4 elements plus the Dominion Control Zone which was integrated into PJM on May 1, 2005.

Overview

Market Structure

- **Supply.** During the June to September 2005 summer period, PJM Energy Markets received an average of 168,600 MW in net supply, including hydroelectric generation, excluding real-time imports or exports. The 2005 net supply represented an approximately 60,600 MW increase compared to the comparable 2004 summer period. The increase in 2005 was comprised of 39,000 MW from the Phase 3 AEP and DAY Control Zone integrations, 3,100 MW from the Phase 4 DLCO Control Area integration, 20,600 MW from the Phase 5 Dominion Control Zone integration, an average net increase of 200 MW of hydroelectric power generation and 2,300 MW from a net decrease in capacity from the Mid-Atlantic Region, the AP Control Zone and the ComEd Control Zone.

- **Demand.** The PJM system peak load in 2005 was 133,763 MW on July 26, 2005, a coincident summer peak load reflecting the Mid-Atlantic Region and the AP, ComEd, AEP, DAY, DLCO and Dominion Control Zones.[6] The PJM summer peak load in 2004 of 77,887 MW occurred prior to the integrations of the AEP, DAY, DLCO and Dominion Control Zones. If the 2004 summer peak load were adjusted to include the AEP, DAY, DLCO and Dominion zones for comparison purposes, the 2004 summer peak load of the combined area would have been 120,353 MW.[7]

- **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 necessarily mean that a market is competitive or that participants cannot exercise market power. Analysis of the PJM Energy Market indicates moderate market concentration overall. Analyses of supply curve segments indicate moderate concentration in the baseload segment, but high concentration in the intermediate and peaking

6 For the purpose of the *2005 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 2004 peak load of the combined area was a total system coincident peak load and occurred on a different day and hour than the 2004 peak load for PJM.

segments. Specific 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 2005, 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 or group of generation owners is pivotal if the output of the owner's or owners' generation facilities is required in order to meet market demand. When a generation owner or group of owners is pivotal, it has the ability to increase the market price above the competitive level. 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 1.0, a generation owner or group of generation owners 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. The RSI results are consistent with the conclusion that the PJM Energy Market results were competitive in both 2004 and 2005, with an average one pivotal RSI of 1.64 and 1.55, respectively. In 2005, a generation owner in the PJM Energy Market was pivotal for only 24 hours, less than 0.3 percent of all hours during the year. This represents an increase in pivotal hours from 2004, when a generation owner was pivotal in the Energy Market for eight hours, or less than 0.1 percent of all hours.

- **Ownership of Marginal Units.** The concentration of ownership of marginal units provides an additional dimension of the pivotal supplier results. The higher the level of concentration of ownership of marginal units the greater is the potential market power issue.

- **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 underdeveloped for a variety of complex reasons. Total demand-side response resources available in PJM during the 11-month period ended November 30, 2005, were 2,065 MW from active load management, 1,619 MW from the Emergency Load-Response Program and 2,210 MW from the Economic Load-Response Program. There were 260 MW enrolled in both the Load-Response Program and in active load management. The 10,194 MW in total DSR resources, including additional programs reported by PJM customers in response to a survey, were approximately 8 percent of PJM's peak demand.

Market Conduct

- **Price-Cost Markup.** Price-cost markups are a measure of market power when they measure the impact of particular conduct on market outcomes. 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 2005, with markup index results averaging 0.3 percent for the calendar year.

- **Offer Capping.** PJM rules provide that PJM will offer cap units when their owners would otherwise have the ability to exercise local market power. Offer-capping levels remained steady in 2005. Offer capping is an effective means of addressing local market power.

- **Frequently Mitigated Units.** Rulings in 2005 by the United States Federal Energy Regulatory Commission (FERC) resulted in additional compensation as a form of scarcity pricing for units that were offer-capped more than 80 percent of their real-time run hours over the prior year.

Market Performance: Load and Locational Marginal Prices (LMPs)

- **Prices.** PJM 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 2004 to 2005. The simple, hourly average system LMP was 37.0 percent higher in 2005 than in 2004, $58.08 per MWh versus $42.40 per MWh. When hourly load levels are reflected, the load-weighted LMP of $63.46 per MWh in 2005 was 43.1 percent higher than 2004's $44.34. When increased fuel costs are accounted for, the fuel-cost-adjusted, load-weighted, average LMP was 1.5 percent higher in 2005 than in 2004, $45.02 per MWh compared to $44.34 per MWh. This means that, if it had not been for fuel cost increases, LMP would have been 1.5 percent higher in 2005 than in 2004.

  PJM average Real-Time Energy Market prices increased in 2005 over 2004 for several reasons, including, but not limited to, significant increases in fuel cost for the marginal units and in load. PJM load growth in 2005 reflected the geographic expansion created by the DLCO and Dominion integrations and hotter summer weather. The PJM system price was above $150 per MWh for only five hours in 2004; in 2005 it was above the $150 benchmark for 234 hours and above $200 per MWh for 35 hours.

Conclusion

The PJM MMU analyzed key elements of PJM Energy Market structure, participant conduct and market performance for calendar year 2005, including aggregate supply and demand, concentration ratios, local market concentration ratios, residual supply indices, participation in demand-side response programs, price-cost markup and offer capping in this section of the report. The next section continues the analysis of the PJM Energy Market including measures of market performance.

Aggregate supply increased by about 60,600 MW when comparing the summer of 2005 to the summer of 2004 while aggregate peak load increased by 55,876 MW, retaining the general supply-demand balance from 2004 with a corresponding moderating impact on aggregate Energy Market prices. Market concentration levels remained moderate, relatively few hours exhibited pivotal suppliers and markups remained low. This relationship between supply and demand, regardless of the specific market, balanced by market concentration, is referred to as supply-demand fundamentals or economic fundamentals. While the market structure does not guarantee competitive outcomes, overall the market structure of the PJM aggregate Energy Market remains reasonably competitive.

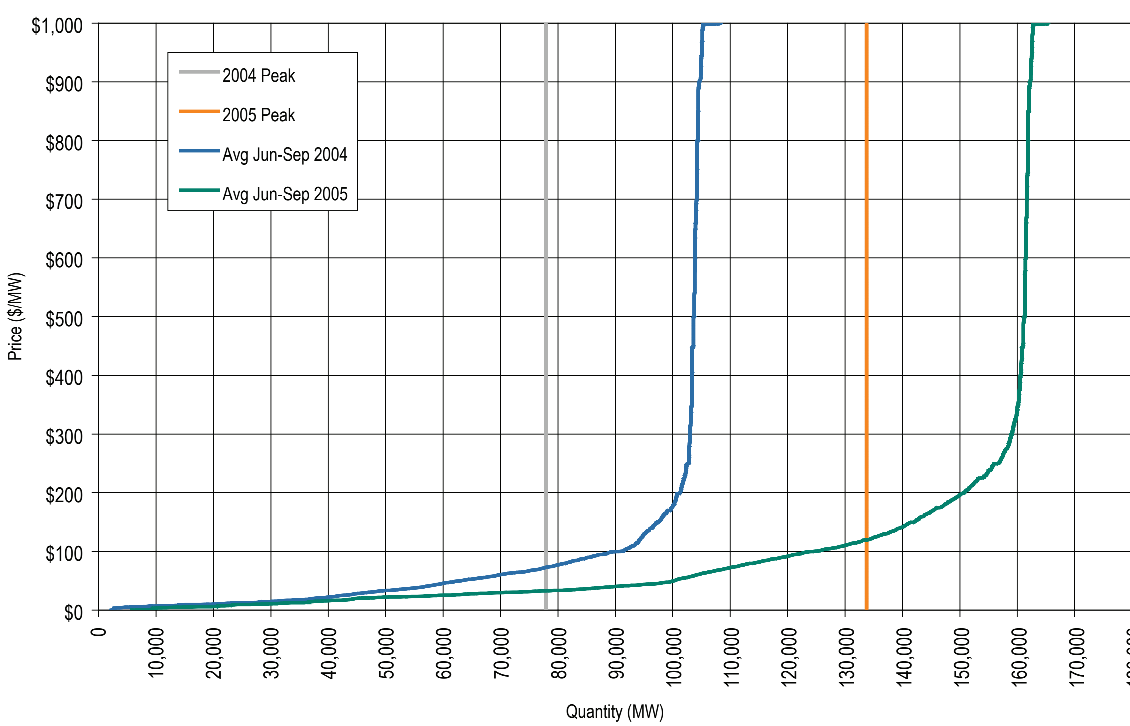
Energy Market results, including prices, for 2005 reflect supply-demand fundamentals. Significantly higher nominal and load-weighted prices are consistent with a competitive outcome as the higher prices reflect both higher input fuel costs and warmer summer weather. If fuel costs had been the same in 2005 as they had been in 2004, prices would have increased by 1.5 percent rather than the actual 37.0 percent increase in nominal average prices and the 43.1 percent increase in load-weighted average prices. While the existing structure of the Energy Market does not guarantee competitive outcomes, actual market performance results were reasonably competitive in 2005. Given the structure of the Energy Market, tighter markets or a change in participant behavior are potential sources of concern in the Energy Market.

Market Structure

Supply

During the June to September 2005 summer period, PJM Energy Markets received an hourly average of 168,600 MW in net supply, including hydroelectric generation, excluding real-time imports or exports. The 2005 net supply represented an approximately 60,600 MW increase compared to the comparable 2004 summer period. The increase in 2005 was comprised of 39,000 MW from the Phase 3 AEP and DAY Control Zone integrations, 3,100 MW from the Phase 4 DLCO Control Area integration, 20,600 MW from the Phase 5 Dominion Control Zone integration, an average net increase of 200 MW of hydroelectric power generation and 2,300 MW from a net decrease in capacity from the Mid-Atlantic Region, the AP Control Zone and the ComEd Control Zone. During the summer of 2005, the demand curve intersected the supply curve at a lower price level than would have occurred with less additional generation or with a different mix of additional generation. (See Figure 2-1.)[8]

Figure 2-1 - Average PJM aggregate supply curves: Summers 2004 and 2005



8 All figures in this paragraph have been rounded to the nearest 100 MW.

During the 12 months ended September 30, 2005,[9] approximately 1,540 MW of generation entered service in the Mid-Atlantic Region, AP and ComEd Control Zones. The additions consisted of 490 MW in upgrades to existing generation and 1,050 MW in new generation. After accounting for offsetting decreases from the derating of 250 MW of generation and the retirement of 3,560 MW, the net decrease in capacity was 2,270 MW. Of the 1,050 MW of new generation, 750 MW consisted of gas-fired combined-cycle generation, 240 MW consisted of fossil-fired steam, 20 MW consisted of diesel generation and 40 MW consisted of wind generation. Upgrades to existing facilities included 290 MW of fossil-fired steam units, 120 MW of gas-fired combined-cycle units, 10 MW of combustion turbine (CT) generation and 70 MW of nuclear generation. The ComEd Control Zone experienced the largest portion of retirements during the period with 3,200 MW out of 3,560 MW or almost 90 percent of the total retirements occurring in that Control Zone. Most of the 250 MW of derated generation was either fossil-fired steam or gas-fired combined-cycle units while the retired generation consisted of 3,060 MW of gas/oil-fired steam units and 500 MW of CTs.[10]

The net result was a slight shift to the left of the PJM aggregate supply curve as the costly retired generation was removed from the upper middle portion of the supply curve. The shape of the aggregate supply curve was changed only slightly by the new generation. Table 2-1 shows the units that retired for the entire PJM footprint from October 1, 2004, to September 30, 2005.[11]

Table 2-1 - Retired units: From October 1, 2004, through September 30, 2005

Unit Name	Installed Capacity (MW)	Unit Type	Retire Date
JC Riegel	27	CT	01-Jan-05
COM Collins 1	554	Steam	01-Jan-05
COM Collins 2	554	Steam	01-Jan-05
COM Collins 3	530	Steam	01-Jan-05
COM Collins 4	530	Steam	01-Jan-05
COM Collins 5	530	Steam	01-Jan-05
COM Electric Junction 31	59	CT	01-Jan-05
COM Electric Junction 32	59	CT	01-Jan-05
COM Electric Junction 33	59	CT	01-Jan-05
COM Lombard 32	32	CT	01-Jan-05
COM Lombard 33	32	CT	01-Jan-05
COM Sabrooke 31	25	CT	01-Jan-05
COM Sabrooke 32	25	CT	01-Jan-05
COM Sabrooke 33	24	CT	01-Jan-05
COM Sabrooke 34	13	CT	01-Jan-05
DPL Madison 1	11	CT	07-Jan-05
COM Crawford 31	56	CT	01-Mar-05
COM Crawford 32	58	CT	01-Mar-05
COM Crawford 33	56	CT	01-Mar-05
ACE Deepwater A	19	CT	01-May-05
PS Kearny 7	150	Steam	01-Jun-05
PS Kearny 8	150	Steam	01-Jun-05
ACE Vineland 7	8	Steam	17-Jun-05
Total	3,561		

9 This period was used to reflect capacity additions made through the summer.
10 All figures in this discussion have been rounded to the nearest 10 MW.
11 Retired unit parameters obtained from PJM.

The PJM supply curve (See Figure 2-1.) was extended with the additions of AEP and DAY in Phase 3, DLCO in Phase 4 and Dominion in Phase 5. Figure 2-1 compares the average supply curves for the pre and post Phase 3, 4 and 5 integrations. The pre Phase 3, 4 and 5 curve represents the average volume of offer MW for the summer period June through September 2004 while the post Phase 3, 4 and 5 integration curve represents the average volume of offer MW for June through September 2005. The average offered supply increased from about 110,000 MW for pre Phase 3, 4 and 5 integrations to about 170,000 MW for the post integration footprint.

Demand

In order to compare the 2005 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 2005 than in prior years as the result of the Phase 3, 4 and 5 integrations of the AEP and DAY, DLCO and Dominion Control Zones, respectively. The comparison is presented in two ways. The peak load for the summer of 2005 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 2005 is calculated without the Phase 3, 4 and 5 integrations compared to the PJM summer peak load for prior years for the same footprint.

Table 2-2 shows the actual coincident summer peak load for 2005 (including all integrations) and the calculated coincident summer peak loads for 2001 through 2004 for the same footprint based on an analysis of hourly loads in PJM and ComEd. Table 2-2 shows that the 2005 actual summer peak load of 133,763 MW was 13,410 MW more than the calculated 2004 summer peak load of 120,353 MW for the 2005 footprint.

Table 2-3 shows the calculated coincident summer peak load for PJM with the Phase 2 footprint for 2001 through 2003 and 2005 and the actual coincident summer peak loads for PJM in 2004 with the Phase 2 integration of the ComEd Control Zone. The 2005 calculated coincident summer peak load of 85,322 MW without the Phase 3, 4 and 5 integrations was 7,435 MW higher than the actual 2004 PJM coincident summer peak load of 77,887 MW, for the same footprint.

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

Table 2-2 - Actual 2005 summer peak demand and calculated Phase 3, 4 and 5 coincident summer peak demand: For 2001 through 2004

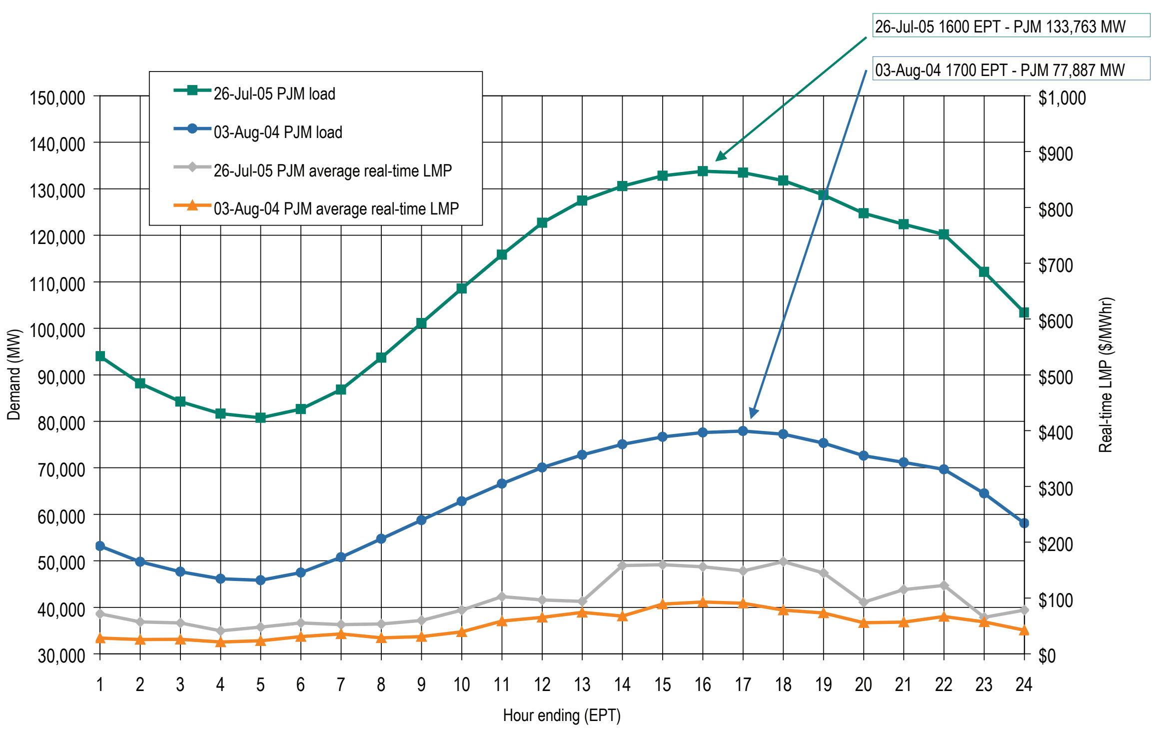
	Date	EPT Hour Ending	PJM Load (MW)	Difference (MW)
2001	09-Aug-01	1500	126,099	NA
2002	01-Aug-02	1700	128,135	2,036
2003	21-Aug-03	1700	126,288	(1,847)
2004	09-Jun-04	1700	120,353	(5,935)
2005	26-Jul-05	1600	133,763	13,410

Table 2-3 - Calculated 2005 Phase 2 coincidental summer peak demand: For 2001 through 2003 and 2005 and actual Phase 2 coincident summer peak demand for 2004

	Date	EPT Hour Ending	PJM Load (MW)	Difference (MW)
2001	09-Aug-01	1500	83,713	NA
2002	01-Aug-02	1700	84,795	1,082
2003	21-Aug-03	1700	81,992	(2,803)
2004	03-Aug-04	1700	77,887	(4,105)
2005	26-Jul-05	1600	85,322	7,435

The actual, unadjusted PJM coincident summer peak demand based on the actual footprint in each year increased from 77,887 MW in 2004 to 133,763 MW in 2005. The hourly load and average PJM LMP are shown for these two summer peak days in Figure 2-2.

Figure 2-2 - PJM summer peak-load comparison: Tuesday, July 26, 2005, and Tuesday, August 3, 2004



The unadjusted, actual summer peak demands for PJM, based on the actual footprint in each year, are shown in Table 2-4 for the years 2001 through 2005. The 2001 PJM footprint is the footprint for the PJM Mid-Atlantic Region. The AP Control Zone was integrated prior to the summer peak period in 2002; the ComEd Control Zone was integrated prior to the summer peak period in 2004 and AEP, DAY, DLCO and Dominion Control Zones were integrated prior to the 2005 summer peak period.

Table 2-4 - Actual PJM footprint summer peak loads: From 1999 to 2005

	Date	EPT Hour Ending	PJM Load (MW)	Difference (MW)
1999	06-Jul-99	1400	59,365	NA
2000	26-Jun-00	1600	56,727	(2,638)
2001	09-Aug-01	1500	54,015	(2,712)
2002	14-Aug-02	1600	63,762	9,747
2003	22-Aug-03	1600	61,500	(2,262)
2004	03-Aug-04	1700	77,887	16,387
2005	26-Jul-05	1600	133,763	55,876

Market Concentration

During all phases of 2005, concentration in the PJM Energy Market was moderate overall. Analyses of supply curve segments indicate moderate concentration in the baseload segment, but high concentration in the intermediate and peaking segments.[12] 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.[13] 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 2005, 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 and 2005. In 2004, the PJM Markets encompassed the Mid-Atlantic Region and the AP Control Zone in Phases 1 and 2 and in Phase 3, PJM Markets incorporated the ComEd, AEP and DAY Control Zones. In 2005, the PJM Markets encompass all 2004 elements, plus the DLCO Control Zone in Phase 4 and the Dominion Control Zone in Phase 5. Hourly PJM Energy Market HHIs were calculated based on the real-time energy output of generators located in each geographic footprint, adjusted for hourly net imports by owner. (See Table 2-5.)

12 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 is classified.

13 See RSI calculations in Section 2, "Energy Market, Part 1," for a direct measure of whether generation owners were pivotal.

Actual net imports and import capability were incorporated in the hourly Energy Market 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.

Hourly 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.

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 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.[14]

PJM HHI Results

Calculations for hourly HHI indicate that by the FERC standards, the PJM Energy Market during 2004 and 2005 was moderately concentrated. (See Table 2-5.) Based on the hourly Energy Market measure, overall market concentration varied from 857 to 1788 in 2004 and from 855 to 1854 in 2005.[15]

Table 2-5 - PJM hourly Energy Market HHI: Calendar years 2004 to 2005[16]

	Minimum	Average	Maximum
Phases 1 and 2	857	1182	1500
Phase 3	1164	1448	1788
Calendar Year 2004	857	1249	1788
Phase 4	1087	1428	1854
Phase 5	855	1200	1565
Calendar Year 2005	855	1275	1854

14 77 FERC ¶ 61,263, "Inquiry Concerning the Commission's Merger Policy under the Federal Power Act: Policy Statement," Order No. 592, pp. 64-70.
15 The 2004 HHI results reported in the *2004 State of the Market Report* were incorrect. The corrected 2004 HHI results are reported here.
16 Statistics shown in the tables have been derived from the underlying data and may not exactly match statistics calculated using the values shown due to rounding.

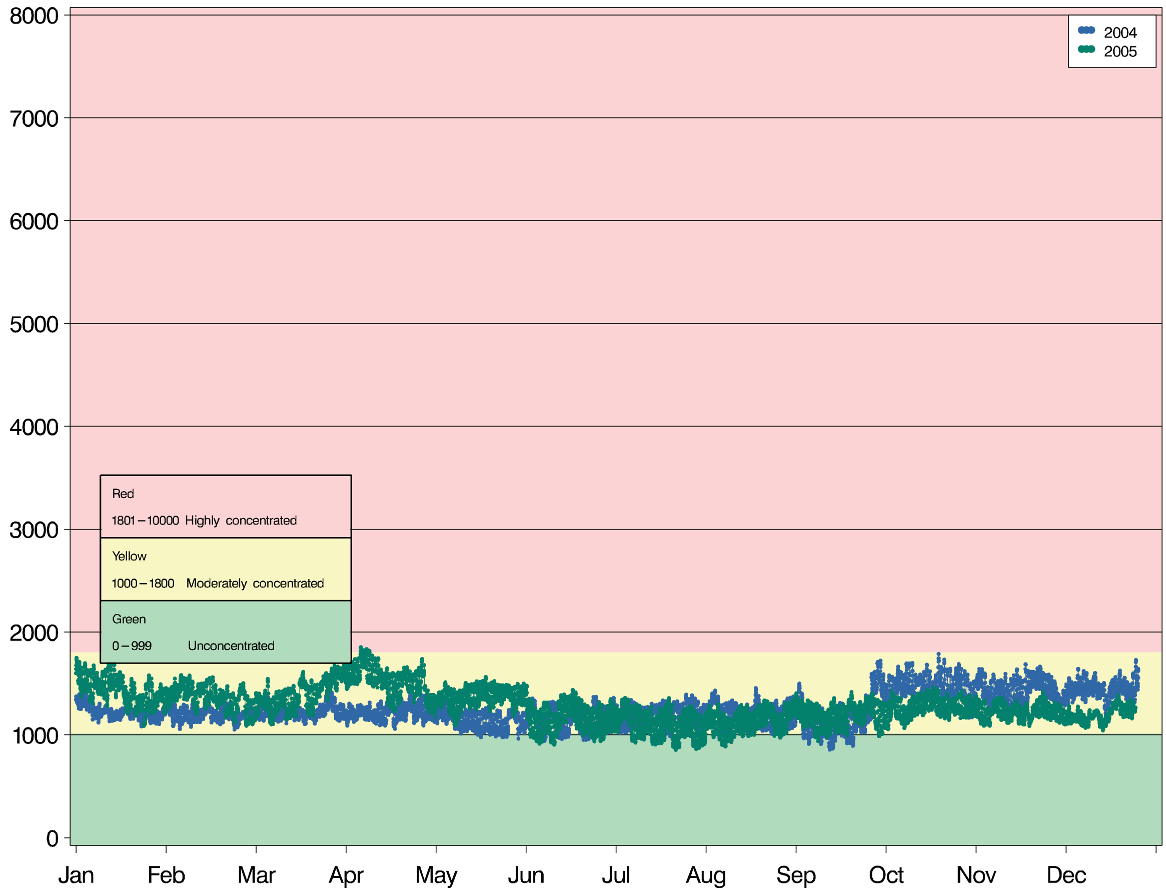
Table 2-6 includes 2004 and 2005 HHI values by supply curve segment, including base, intermediate and peaking plants. The hourly measure indicates that, on average, intermediate and peaking segments of the supply curve are highly concentrated, while the baseload segment is moderately concentrated. HHIs are calculated for facilities located in PJM; imports are not included.

Table 2-6 - PJM hourly Energy Market HHI (By segment): Calendar years 2004 to 2005

	Statistic	Base	Intermediate	Peak
Phases 1 and 2	Maximum	1594	6292	10000
	Average	1355	2065	4604
	Minimum	1209	866	1143
Phase 3	Maximum	2001	6352	10000
	Average	1762	3761	5294
	Minimum	1522	1590	931
Calendar Year 2004	Maximum	2001	6352	10000
	Average	1467	2565	4839
	Minimum	1209	866	931
Phase 4	Maximum	1995	6920	10000
	Average	1659	3705	5011
	Minimum	1399	1032	827
Phase 5	Maximum	1593	8257	10000
	Average	1362	2793	4437
	Minimum	1232	731	717
Calendar Year 2005	Maximum	1995	8257	10000
	Average	1451	3078	4612
	Minimum	1232	731	717

Figure 2-3 presents detailed hourly HHI results for the PJM Energy Market summarized in Table 2-5.

Figure 2-3 - PJM hourly Energy Market HHI: Calendar years 2004 and 2005



Local Market Concentration and Frequent Congestion

With the marked increased in total congestion-event hours in PJM from 2004 to 2005, several geographic areas in the PJM Mid-Atlantic Region, the Western Region and the Southern Region experienced frequent congestion and showed high local market concentration: namely the PSEG, AP, Met-Ed, BGE, ComEd, PECO, PENELEC, Dominion, AEP and AECO Control Zones.[17] Other areas, including the DPL, DLCO, JCPL, PPL, RECO, PEPCO and DAY Control Zones, had a limited amount of constrained hours during 2005.[18]

- **PSEG North.** In calendar year 2005, the number of constrained hours increased from 456 hours in 2004 to 784 hours, with 56 percent of all constrained hours occurring during on-peak periods. The Roseland-Cedar Grove 230 kV line contributed 364 hours of congestion, representing an increase of 143 percent from 2004 when it had been constrained for 150 hours. The Cedar Grove–Clifton 230 kV line also experienced an increase in congestion from 37 hours in 2004 to 176 hours in 2005. Twenty

17 For 2005, any area that experienced congestion for more than 100 hours was analyzed for market concentration and the effect of each constraint on load in the constrained area. HHIs were measured based on installed capacity in the constrained area for calendar year 2005.

18 A constrained hour is defined as any hour during which one or more facilities are congested. A congestion-event hour is defined as the total number of constrained hours for a particular facility. Constraints are often simultaneous and, therefore, the sum of congestion-event hours can exceed the sum of constrained hours in a zone.

other constraints, each occurring for less than 100 hours, accounted for the remainder of the congestion. While both of these lines experienced increases from 2004, over 85 percent of the constrained hours came after the installation of a third transformer at Branchburg on April 25, 2005. In March 2004, the derating of the Branchburg 500/230 kV transformer in northcentral PSEG, contributed to the increase in congestion at Branchburg. The increased Branchburg 230/500 kV transformer congestion significantly limited the flow of power into the northern PSEG area, thus eliminating overloads that might otherwise have occurred, such as the Roseland–Cedar Grove and Cedar Grove–Clifton 230 kV lines. On average, the Roseland-Cedar Grove line and the Cedar Grove-Clifton line affected 541 MW and 703 MW of load, respectively.[19] The 2005 gross congestion cost associated with the Roseland-Cedar Grove 230 kV constraint totaled $44.9 million, while the Cedar Grove-Clifton 230 kV constraint totaled $28.8 million.[20] Both the Roseland-Cedar Grove and the Cedar Grove-Clifton constraints resulted in high market concentration and HHIs of 8198 and 7582, respectively.

- **PSEG Northcentral.** In 2005, the number of constrained hours decreased from 1,121 hours in 2004 to 881 hours, with 71 percent of all constrained hours occurring during on-peak periods. The Branchburg 500/230 kV transformer constraint, which accounted for 90 percent of congestion in the area during 2004, was significantly decreased from 1,005 hours to 412 hours in 2005. The installation of a third transformer on April 25, 2005, which was necessary due to the March 2004 derating of the original transformers, was the primary cause for the decrease in congestion at Branchburg. In 2004, the derating had limited the flow through the transformer and the Branchburg constraint had reduced the occurrence of other constraints such as the Edison-Meadow Road 138 kV. In 2005, the frequency of the Edison-Meadow Road 138 kV line increased from 33 hours to 191 hours and 93 percent of the hours occurred after April 25. The Branchburg – Readington 230 kV line was also constrained for 175 hours, an increase from 108 hours in 2004. Five additional constraints contributed to the remainder of congestion in this area. On average, the Branchburg transformer affected 565 MW of load, the Edison-Meadow Road 138 kV line affected 302 MW of load, and the Branchburg-Readington 230 kV line affected 448 MW of load. The 2005 gross congestion cost for the Branchburg transformer was $125.2 million, the Edison-Meadow Road line was $13.5 million, and the Branchburg-Readington line was $30.1 million. All three constraints resulted in high market concentration with HHIs of 2998, 8070 and 8198, respectively.

- **Eastern Interface.** During 2005, congestion on the Eastern Interface decreased from 221 hours to 103 hours. Seventy-four percent of all congestion occurred during on-peak periods. The Eastern Interface affected, on average, 5,940 MW of load. The 2005 gross congestion cost associated with the Eastern Interface was $34.7 million. Market concentration in the affected area was moderate with an HHI of 1575.

- **Delmarva Peninsula (DPLS).** Congestion on the Delmarva Peninsula increased from 320 constrained hours to 402 hours, with 56 percent occurring during on-peak periods. However, no single constraint occurred for more than 100 hours during 2005.

- **Delaware North (SEPJM/DPLN).** In 2005, the northern area of Delaware in the DPL Control Zone experienced a decrease in constrained hours from 102 hours to 49 hours.

19 The affected load calculation for 2005 was derived by taking the sum of the product of MW and distribution factor. Distribution factors were limited to those greater than, or equal to, 3 percent on the high-priced side of the constraint.

20 The gross congestion cost calculation is equal to the product of the hourly affected load and the average hourly marginal value of each real-time transmission constraint.

- **Southern New Jersey (AECO).** The southern New Jersey (SNJ) subarea of the AECO Control Zone experienced 970 hours of congestion, with one constraint, the Laurel-Woodstown 69 kV line, accounting for 91 percent of all congestion in the area. The Laurel-Woodstown line was constrained for 879 hours, an increase of 119 percent from 2004, with 75 percent of all hours occurring during on-peak periods. Nine other constraints, each occurring for less than 100 hours, contributed to the remainder of congestion in the area. On average, the Laurel-Woodstown constraint affected 81 MW of load. The 2005 gross congestion cost associated with the Laurel-Woodstown constraint was $24.2 million. High market concentration resulted from the Laurel-Woodstown constraint with an HHI of 9012.

- **Cedar Subarea (AECO).** In 2005, 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 749 constrained hours experienced during 2005 represented a small increase from the 742 hours that had been experienced in 2004. Seventy-one percent of all constrained hours occurred during on-peak periods. In 2005, the Cedar interface was constrained 438 hours, a decrease from 605 hours in 2004. Additionally, the Absecon-Lewis 69 kV line constraint appeared in 2005 and was constrained for 283 hours. On average, the Cedar interface and the Absecon-Lewis line isolated 79 MW and 97 MW of load, respectively. The 2005 gross congestion cost for the Cedar interface was $5.7 million, while the Absecon-Lewis line was $5.1 million. Each constraint defined highly concentrated markets with HHIs of 10000.

- **Met-Ed West.** In 2005, the Met-Ed west subarea was constrained for 313 hours, an increase from 262 hours in 2004. Eighty-seven percent of all congestion in the area occurred during on-peak periods. The Bair-Hill 115 kV line was constrained for 225 hours in 2005, up from 27 hours in 2004. Seven other constraints, each occurring for less than 100 hours, accounted for the remaining congestion in this area. The Bair-Hill 115 kV line affected, on average, 106 MW of load. The 2005 gross congestion cost associated with the Bair-Hill line was $2.4 million. High market concentration and an HHI of 10000 resulted from this constraint.

- **PENELEC.** In 2005, the northcentral and northwest subareas of the PENELEC Control Zone were constrained for 264 hours and 170 hours, respectively. The northcentral subarea experienced 30 percent of its constrained hours during peak periods, while the northwest subarea experienced 21 percent. Two constraints contributed to the majority of congestion in these areas. The Garman – Glory 115 kV line was constrained 105 hours, up from 29 hours in 2004. Congestion on the Erie West 345/115 kV transformer also increased from one hour in 2004 to 170 hours in 2005. On average, the Garman-Glory line affected 58 MW of load and the Erie West transformer affected 142 MW of load. The 2005 gross congestion cost associated with the Garman-Glory line was $670,000 and $7 million was associated with the Erie West transformer. High market concentration resulted from both the Garman-Glory line and the Erie West transformer with HHIs of 9773 and 3306, respectively.

- **BGE Control Zone.** In 2005, the BGE Control Zone experienced 144 constrained hours and 86 percent of the hours occurred during on-peak periods. The 144 constrained hours represented a 92 percent increase in constrained hours from 75 hours in 2004. The Center-Westport 115 kV line was constrained 104 hours in 2005, compared to 48 hours in 2004. On average, the Center-Westport line affected 264 MW of load. The 2005 gross congestion cost associated with the Center-Westport line was $5.6 million dollars. The Center-Westport line created a highly concentrated market with an HHI of 7221.

- **PECO Control Zone.** In 2005, the PECO Control Zone experienced 212 constrained hours and 82 percent of the hours occurred during on-peak periods. The 212 hours represented a 51-hour increase from 2004. The Chichester-Linwood 230 kV line was constrained 128 hours and did not occur in prior years. Thirteen other constraints, each occurring less than 100 hours, contributed to the remainder of the constrained hours. The Chichester-Linwood line affected 901 MW of load. The 2005 gross congestion cost associated with this line was $12 million. The constraint created a highly concentrated market with an HHI of 2988.

- **ComEd Control Zone.** In 2005, the ComEd Control Zone experienced 401 constrained hours and 84 percent of the hours occurred during on-peak periods. This was a substantial increase from 130 hours in 2004, and only 5 percent of the hours in 2005 occurred prior to May 1, 2005. The largest contributor to the 2005 congestion was the Cherry Valley 345/138 kV transformer, which occurred for 104 hours in 2005 and only five hours in 2004. On average, the Cherry Valley transformer affected 478 MW of load. The 2005 gross congestion cost associated with the transformer was $4.3 million dollars. The market defined by the Cherry Valley transformer was highly concentrated with an HHI of 5383.

- **Dominion Control Zone.** In 2005, the Dominion Control Zone experienced 570 constrained hours and 83 percent of the hours occurred during on-peak periods. Two constraints accounted for over half of the constrained hours. The Alta Vista-Dominion 115 kV line was constrained for 173 hours and the Beechwood-Kerr Dam 115 kV line was constrained 128 hours. On average, the Alta Vista-Dominion constraint affected 45 MW of load, while the Beechwood-Kerr Dam constraint affected 55 MW of load. The 2005 gross congestion cost associated with the Alta Vista-Dominion constraint was $4.1 million and $2 million was associated with the Beechwood-Kerr Dam constraint. Each constraint defined a highly concentrated market with HHIs of 10000.

- **AEP Control Zone.** In 2005, the AEP Control Zone experienced 1,772 constrained hours and 42 percent of the hours occurred during on-peak periods. AEP congestion in 2005 increased substantially from 2004, when there were only 165 constrained hours, but was measured only during the three-month period from the AEP integration with PJM. During the same three-month period in 2005, AEP experienced 374 constrained hours in 2005 compared to 165 hours in 2004. The three major constraints that contributed to the 2005 congestion total were: the Cloverdale-Lexington 500 kV line, the Kanawha River–Matt Funk 345 kV line and the Mahans Lane-Tidd 138 kV line. The Cloverdale-Lexington line was constrained for 31 hours in 2004, or 19 percent of total hours, and 508 hours during 2005, or 29 percent of total hours. The Kanawha River-Matt Funk line was constrained 51 hours in 2004, or 31 percent of total hours, and 401 hours in 2005, or 23 percent of total hours. The Mahans Lane-Tidd line was constrained 69 hours in 2004, or 42 percent of total hours, and 448 hours in 2005, or 25 percent of total hours. On average, the Cloverdale-Lexington line affected 3,327 MW of load, the Kanawha River-Matt Funk line affected 1,694 MW of load, and the Mahans Lane-Tidd line affected 160 MW of load. The 2005 gross congestion cost associated with each of these constraints was $157.6 million, $150.8 million and $11.9 million, respectively. The Cloverdale-Lexington line and the Kanawha River-Matt Funk created moderately concentrated markets that have HHIs of 1078 and 1066, respectively. The Mahans Lane-Tidd line creates a highly concentrated market with an HHI of 10000.

- **AP Control Zone.** In 2005, the AP Control Zone experienced frequent congestion totaling 2,746 constrained hours.[21] Fifty-four percent of the constrained hours occurred during on-peak periods. In 2004, the AP Control Zone experienced 336 constrained hours. Congestion on the Krendale–Seneca 138 kV line, located in the northern AP subarea, increased to 173 hours from 14 hours in 2004. On average, the Krendale-Seneca line affected 100 MW of load. The 2005 gross congestion cost associated with this line was $3.2 million. The Krendale-Seneca line created a moderately concentrated market with an HHI of 1296.

  In addition to the northern AP congestion, three facilities located in the eastern AP subarea each experienced increases in congestion and each totaled more than 100 hours. The Bedington-Nipetown 138 kV line increased from 21 hours to 213 hours in 2005. The Bedington 500/138 kV transformer increased from 37 hours to 144 hours in 2005. The Meadow Brook 500/138 kV transformer increased from 11 hours to 135 hours in 2005. On average, the Bedington and Meadow Brook transformers affected 383 and 389 MW of load, respectively while the Bedington-Nipetown line affected 160 MW of load. The 2005 gross congestion cost for the Bedington, Meadowbrook and Bedington-Nipetown facilities was $15 million, $40.9 million and $9 million, respectively. All three constraints created highly concentrated markets with HHIs ranging from 3821 to 5684.

  Similarly, the central AP subarea also had three facilities on which congestion was increased and each totaled more than 100 hours. The Elrama-Mitchell 138 kV line increased from 59 hours to 137 hours. The Mitchell-Shepler Hill 138 kV line increased from 42 hours to 214 hours. The Charleroi-Mitchell 138 kV line increased from 10 to 318 hours. On average, the Elrama-Mitchell line affected 1,417 MW of load, the Mitchell-Shepler Hill line affected 17 MW of load, and the Charleroi-Mitchell line affected 130 MW of load. The 2005 gross congestion cost associated with these respective lines was $18.8 million, $6.2 million and $723,000. The Charleroi-Mitchell and the Mitchell-Shepler Hill constraints each created highly concentrated markets with an HHI of 5386 and 10000, respectively. The Elrama-Mitchell line created an unconcentrated market with an HHI of 916.

  Finally, three other large constraints contributed significantly to the AP Control Zone total. Congestion on the Mt. Storm-Pruntytown 500 kV line increased from zero hours in 2004, to 696 hours in 2005. Additionally, congestion on the Doubs-Mt. Storm 500 kV line increased from 87 hours in 2004, to 422 hours in 2005. Congestion on the Doubs transformers also increased from 85 hours in 2004, to 526 hours in 2005. On average, the Mt. Storm-Pruntytown line had the largest affected load total of 10,094 MW followed by the Doubs-Mt. Storm line, which affected 4,798 MW of load. The Doubs transformers affected 396 MW of load. The 2005 gross congestion cost associated with each of these constraints was $765.9 million, $672.1 million and $99.9 million. Market concentration was moderate for both the Mt. Storm-Pruntytown and Doubs-Mt. Storm with HHIs of 1048 and 1042, respectively. The Doubs transformers created a highly concentrated market with an HHI of 4841.

- **Western Interface.** In 2005, congestion on the Western Interface increased from 63 hours to 216 hours. Sixty-two percent of all constrained hours occurred during on-peak periods. The Western Interface, on average, affected 9,388 MW of load. The 2005 gross congestion cost associated with the Western Interface was $139.7 million. Market concentration was moderate overall with an HHI of 1130.

21 The AP Control Zone totals reported here exclude the contribution from the Wylie Ridge 500/230 kV transformer and the Bedington – Black Oak 500 kV line. These constraints are analyzed separately due to their size and effect on the PJM system.

- **5004/5005 Interface.** In 2005, congestion on the 5004/5005 interface increased from 19 hours to 567 hours.[22] Fifty-three percent of all constrained hours occurred during on-peak periods. The 5004/5005 interface, on average, affected 3,009 MW of load. The 2005 gross congestion cost associated with the 5004/5005 interface was $176.6 million. Market concentration was moderate overall with an HHI of 1451.

- **Kammer Transformer (AEP).** In 2005, congestion on the Kammer 765/500 kV transformer increased from 84 hours to 1,332 hours. Forty percent of all hours occurred during on-peak periods. In 2004, 100 percent of congestion on the Kammer transformer came after the integration of AEP on October 1. Comparing the last three months of 2005, the Kammer transformer was constrained 572 hours or 43 percent of the 2005 Kammer total. On average, the Kammer transformer affected 3,847 MW of load. The 2005 gross congestion cost associated with the transformer was $608.7 million. The market defined by the Kammer transformer was unconcentrated with an HHI of 916.

- **Bedington - Black Oak (AP).** In 2005, the Bedington – Black Oak 500 kV line was constrained for 1,314 hours, with 45 percent of congestion occurring during on-peak periods. Congestion was up from 2004 when it had been constrained for 1,131 hours. The location and size of this line contributed to its substantial impact on the entire PJM system, with an average affected load of 3,912 MW and a total gross congestion cost of $921.6 million. The Bedington – Black Oak 500 kV line caused moderate concentration in the affected area with an HHI of 1083.

- **Wylie Ridge (AP).** During 2005, congestion on the Wylie Ridge 345/500 kV transformers more than doubled from 642 hours in 2004 to 1,399 hours. Thirty-one percent of all congestion occurred during on-peak periods. The Wylie Ridge transformers affected approximately 1,463 MW of load and had a total gross congestion cost of $289.6 million. The area affected by this constraint was unconcentrated, with an HHI of 824.

Pivotal Suppliers

In addition to the aggregate PJM and local market HHI calculations used to measure market concentration, the RSI is a measure of the extent to which one or more generation owners are pivotal suppliers in the PJM Energy Market. A generation owner or group of generation owners is pivotal if the output of the owner's or owners' generation facilities is required in order to meet market demand. When a generation owner or group of owners is pivotal, it has the ability to increase the market price above the competitive level. For a given level of market demand, the RSI compares the market supply net of the generation supply owned by a specified owner or group of owners, 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.[23] $Supply_i$ is the supply owned by the individual generation owner or group of generation owners "*i*" and $Demand_m$ is total market demand. If the RSI is greater than 1.0, the supply of the specific generation owner or group of owners is not needed to meet market demand and that generation owner or group of generation owners has a reduced ability to influence market price. If the RSI is less than 1.0, the supply owned by the specific generation owner or group of owners is needed to meet market demand and the generation owner or group of generation owners is pivotal. As with concentration ratios, the RSI is not a bright line test. While an RSI less than 1.0 for a single generation owner clearly indicates market power, an RSI greater than 1.0 does not guarantee that there is no market power.

22 The 5004/5005 interface is comprised of two 500 kV lines, which include the Keystone – Juniata 5004 and the Conemaugh – Juniata 5005. These two lines are located between central and western Pennsylvania.

23 Total supply in the Energy Market is the sum of all offers to provide energy. If net imports are negative (exports), they are treated as additional demand.

The RSI was calculated hourly for every individual generation owner. The overall PJM Energy Market RSI is the minimum RSI for each hour, equal to the RSI for the largest generation owner in each hour. (See Table 2-7.) 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 2-8.

PJM RSI Results

The RSI results reported in Table 2-7 are consistent with the conclusion that PJM Energy Market results were competitive in both 2004 and 2005, with an average hourly RSI of 1.64 and 1.55, respectively.[24] In 2005, a generation owner in the PJM Energy Market was pivotal for only 24 hours, less than 0.3 percent of all hours during the year. This represents an increase in pivotal hours from 2004, when a generation owner was pivotal in the Energy Market for eight hours, or less than 0.1 percent of all hours. The 24 hours when a single generation owner was pivotal in the Energy Market occurred during July and August of 2005, when demand exceeded 130,000 MW. Further, the minimum RSI for the two pivotal supplier test was 0.80 while the average two pivotal RSI was 1.27. There were 861 hours in which the two pivotal RSI was less than 1.0. Ninety-five percent of the jointly pivotal hours occurred between June 6, 2005, and September 22, 2005. The probability of having one or more pivotal suppliers increases during periods of peak demand.

Table 2-7 - PJM RSI statistics: Calendar years 2004 to 2005

	Number of Hours RSI < 1.10	Number of Hours RSI < 1.00	Percent of Hours RSI < 1.00	Average RSI	Minimum RSI
Phases 1 and 2	45	8	0.12%	1.62	0.96
Phase 3	0	0	0.00%	1.67	1.14
Calendar Year 2004	45	8	0.09%	1.64	0.96
Phase 4	0	0	0.00%	1.57	1.10
Phase 5	262	24	0.41%	1.52	0.97
Calendar Year 2005	262	24	0.27%	1.55	0.98

Table 2-8 shows two pivotal supplier RSI results.

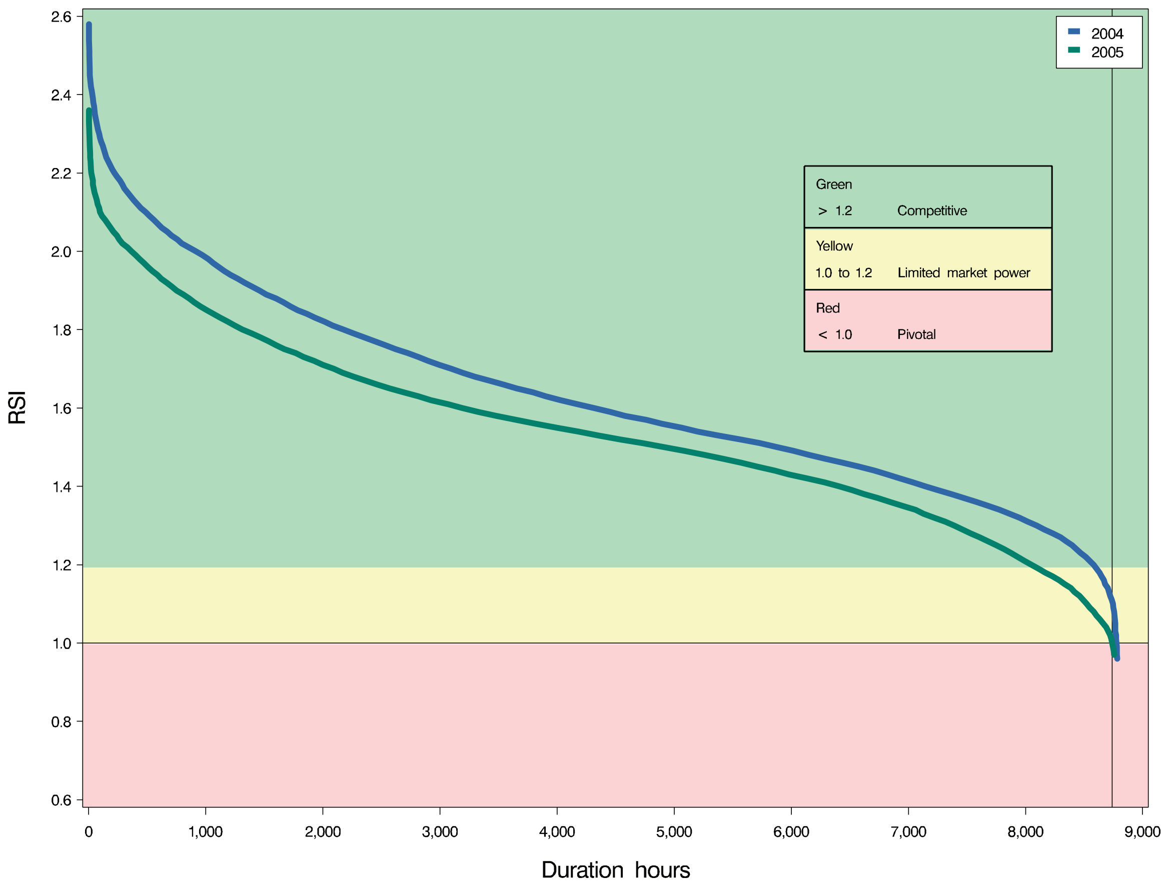
Table 2-8 - PJM top two supplier RSI statistics: Calendar years 2004 to 2005

	Number of Hours RSI < 1.10	Number of Hours RSI < 1.00	Percent of Hours RSI < 1.00	Average RSI	Minimum RSI
Phases 1 and 2	830	194	2.95%	1.35	0.81
Phase 3	138	22	1.00%	1.34	0.90
Calendar Year 2004	968	216	2.46%	1.35	0.81
Phase 4	350	43	1.49%	1.28	0.95
Phase 5	1502	818	13.91%	1.27	0.80
Calendar Year 2005	1852	861	9.83%	1.27	0.80

24 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.

Figure 2-4 shows the one pivotal supplier RSI duration curves for PJM during 2004 and 2005. The curve shows the limited number of hours below 1.0 in both 2004 and 2005.

Figure 2-4 - PJM RSI duration curve: Calendar years 2004 and 2005



Ownership of Marginal Units

Table 2-9 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 2004, one company owned the marginal unit from 20 percent to 35 percent of the time. In 2005, two different companies each owned the marginal unit from 15 percent to 20 percent of the intervals. In other words, together, two companies owned the marginal unit from 30 percent to 40 percent of the time. The higher the proportion of the time that a small number of companies own the marginal unit, the greater the potential market power concern.

Table 2-9 - Ownership of marginal units (By number of companies in frequency category): Calendar years 2001 to 2005

	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 35%
2001	14	4	2	2	0
2002	19	4	2	2	0
2003	20	4	1	2	0
2004	27	6	0	1	1
2005	45	5	1	2	0

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 underdeveloped. 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 wholesale market demand-side programs should be understood as one, relatively small part of a transition to a fully functional demand side for its Energy Market. A fully developed demand side will include retail programs and an active interaction between wholesale and retail markets.

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 in real time, will have the ability to react to real-time prices in real time and will have the ability to receive the direct benefits or costs of changes in real-time energy 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).[25] On May 31, 2002, the FERC accepted the Economic Program, effective June 1, 2002, but with a December 1, 2004, sunset provision.[26] On October 29, 2004, the FERC extended the Economic Program until December 31, 2007.[27]

The PJM Economic Load-Response Program provides a PJM-managed accounting mechanism that provides for payment of the real savings that result from load reductions, to the load-reducing customer. Such a mechanism is required because of the complex interaction between the wholesale market and the incentive and regulatory structures faced by both load-serving entities (LSEs) and customers. The broader goal of the Economic Program is 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.

On February 14, 2002, the PJM Members Committee approved a permanent Emergency Load-Response Program.[28] 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).[29] 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.[30] On October 29, 2004, the FERC extended the program until December 31, 2007, thereby making it coterminous with the Economic Program.[31]

25 *PJM Interconnection, L.L.C.*, Tariff Amendments, Docket No. ER02-1326-000 (March 15, 2002).
26 99 FERC ¶ 61,227 (2002).
27 *PJM Interconnection, L.L.C.*, Letter Order, Docket No. ER04-1193-000 (October 29, 2004).
28 *PJM Interconnection, L.L.C.*, Tariff Amendments, Docket No. ER02-1205-000 (March 1, 2002).
29 *PJM Interconnection, L.L.C.*, Tariff Amendments, Docket No. ER02-1205-000 (March 1, 2002).
30 99 FERC ¶ 61,139 (2002).
31 *PJM Interconnection, L.L.C.*, Letter Order, Docket No. ER04-1193-000 (October 29, 2004).

Emergency Program

The number of currently active sites with associated MW in the Emergency Program is shown in Table 2-10.[32] As of November 30, 2005, there were 1,618.8 MW of resources active in the Emergency Program.[33] This is a 4 percent increase from 1,557.9 MW at the end of 2004.[34]

Table 2-10 - Currently active participants in the Emergency Program

	Currently Active by Year Enrolled		Cumulative Total	
	Sites	MW	Sites	MW
2001	NA	NA	NA	NA
2002	64	514.6	64	514.6
2003	103	148.1	167	662.7
2004	3,706	895.3	3,873	1,557.9
2005	120	60.9	3,885	1,618.8

Table 2-11 presents the zonal distribution of DSR capability in the Emergency Program as of November 30, 2005.[35] One zone includes 95 percent of all available sites and 53 percent of all available MW in the Emergency Program. In addition, 95 percent of sites and 60 percent of MW of Emergency Program capabilities are located in the Western Region of PJM.

32 The data on currently active sites and MW differ from that reported in the *2004 State of the Market Report* because corrections were made to the DSR source data by PJM.

33 For both Emergency and Economic programs the results reported for 2005 are based on the 11 months, January through November, only that data was 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 LSE and EDC have an additional 10 days to verify these data. The results for 2004 reported in the table are based on 12 months of data, but the *2004 State of the Market Report* was based on the nine months of 2004 data available at that time. The 2002 program began on June 1, 2002. The 2002 data are based on the five-month period, June through October which represents all available data.

34 The numbers of registered sites and currently active sites with associated MW for Emergency and Economic programs for 2001 are not available.

35 In Table 2-11, Table 2-14 and Table 2-16 pricing zones include a UGI zone consistent with the practice of the PJM DSR department.

Table 2-11 - Current zonal capability in the Emergency Program: Eleven months ended November 30, 2005

	Sites	MW
AECO	3	4.0
AEP	0	0.0
AP	12	74.5
BGE	15	112.9
ComEd	3,681	856.3
DAY	0	0.0
DLCO	2	41.5
Dominion	0	0.0
DPL	6	17.3
JCPL	8	3.3
Met-Ed	7	6.6
PECO	76	293.0
PENELEC	14	7.7
PEPCO	10	7.5
PPL	27	163.4
PSEG	23	30.6
RECO	0	0.0
UGI	1	0.3
Total	3,885	1,618.8

During the summer of 2005, activity under the Emergency Program occurred on five days: July 25, August 3, August 4, August 5 and August 14. The maximum hourly reduction was 205 MW. Activity occurred during hours when real-time LMPs were between $68 per MW and $206 per MW. The total of individual hours of Emergency Program reductions in 2005 was 23 and all occurred between the hours ending 1500 EPT and 1900 EPT.

The total MWh of load reductions and the associated payments under the Emergency Program are shown in Table 2-12.[36] Load reduction levels decreased in 2003 by 91 percent from 551 MW in 2002.[37] There was no activity in the program during 2004 due to the mild weather conditions and associated prices. At 3,662 MWh, 2005 had the largest load reduction level since the program began. In the 11-month period ended November 30, 2005, payments under the program were $508 per MWh. There were 2 MWh of actual load reduction per currently active MW in the Emergency Program for the 11-month period ended November 30, 2005.

Table 2-12 - Performance of Emergency Program participants

	Total MWh	Total Payments	$/MWh	Total MWh per Cumulative Total MW
2002	551	$282,756	$513	1
2003	49	$26,613	$543	0
2004	0	$0	$0	0
2005	3,662	$1,859,638	$508	2

Economic Program

The Economic Program experienced a significant increase in MW enrolled in the program in 2004 and 2005, primarily associated with the integration of new areas into PJM. Data on the number of currently active sites in the Economic Program are presented in Table 2-13 along with the associated MW. As of November 30, 2005, there were 2,210.4 MW currently active in the Economic Program. This is a 34 percent increase from the 1,644.4 MW active in the Economic Program in the end of 2004 which was in turn an increase of 251 percent from the 468.7 MW active at the end of 2003.

Table 2-13 - Currently active participants in the Economic Program

	Currently Active by Year Enrolled		Cumulative Total	
	Sites	MW	Sites	MW
2001	NA	NA	NA	NA
2002	106	320.6	106	321.0
2003	142	147.7	248	468.7
2004	2,218	1,175.7	2,466	1,644.4
2005	124	566.0	2,590	2,210.4

36 In Table 2-12 and Table 2-15, the MMU includes only data that have been confirmed by PJM.

37 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.

Table 2-14 shows the zonal distribution of DSR capability in the Economic Program as of November 30, 2005. One zone includes 84 percent of total sites and 49 percent of total MW in the Economic Program. In addition, 85 percent of the sites and 67 percent of the MW in the Economic Program are located in the Western Region of PJM.

Table 2-14 - Current zonal capability in the Economic Program: Eleven months ended November 30, 2005

	Sites	MW
AECO	3	5.9
AEP	7	164.5
AP	16	195.1
BGE	147	120.8
ComEd	2,167	1074.5
DAY	0	0.0
DLCO	4	42.9
Dominion	3	77.5
DPL	25	127.8
JCPL	42	38.2
Met-Ed	15	44.8
PECO	73	72.8
PENELEC	9	81.8
PEPCO	29	35.4
PPL	14	85.0
PSEG	35	42.4
RECO	1	1.0
UGI	0	0.0
Total	2,590	2,210.4

The total MWh of load reductions and the associated payments under the Economic Program are shown in Table 2-15.[38] Load reduction levels in the Economic Program increased from 6,727 MWh in 2002 to 19,518 MWh in 2003 to 58,352 MWh in 2004 to 113,393 MWh in 2005. Payments per MWh were $106 in 2005. The Economic Program's actual MWh of load reduction per currently active MW increased to 51 for the 11-month period ending November 30, 2005.

Table 2-15 - Performance of PJM Economic Program participants

	Total MWh	Total Payments	$/MWh	Total MWh per Cumulative Total MW
2002	6,727	$801,119	$119	21
2003	19,518	$833,530	$43	42
2004	58,352	$1,917,202	$33	35
2005	113,393	$12,000,354	$106	51

38 Table 2-15 contains rounded numbers of "Total MWh" and "Total Payments."

During the 11 months ended November 30, 2005, the Economic Program showed significant differences in activity among the PJM control zones. For example, 58 percent of MWh reductions, 45 percent of payments and 27 percent of curtailed hours under the real-time rate option occurred within a single zone while one pricing zone saw no activity in any DSR program. (See Table 2-16.) The total number of curtailed hours for the Economic Program was about 113,393 and the total payment amount was $12,000,354.

Overall, approximately 66 percent of the MWh reductions, 51 percent of payments and 80 percent of curtailed hours resulted from customers with the real-time option under the Economic Program. Approximately 34 percent of the MWh reductions, 48 percent of payments and 19 percent of curtailed hours resulted from customers with the day-ahead option. Approximately 0.5 percent of the MWh reductions, 1 percent of the payments and 1 percent of the curtailed hours resulted from the dispatched-in-real-time option of the program. (See Table 2-16.)

A total of 26 retail customers registered as LMP-based customers,[39] of which seven were active load management (ALM) customers. In total, 68 customers selected the ALM option. PJM initiated ALM events twice in the summer 2005: July 27 and August 4. On July 27, ALM was invoked in the Mid-Atlantic Region and in the Dominion Control Zone. On August 4, ALM was invoked in the Mid-Atlantic Region.

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 November 30, 2005, 5,848 ComEd retail customers had enrolled in the program. Out of all registered ComEd participants, 2,167 selected the Economic Program and 3,681 selected the Emergency Program. Of the ComEd participants, 218 entered the program as ALM/mandatory interruptible load (MIL) customers.[40] None registered as LMP-based customers.

The maximum hourly load reduction attributable to the Economic Program was 226 MW in the 11-month period ended November 30, 2005. Using real-time supply curves, the price impact of this reduction in the Economic Program was estimated to be approximately $1 per MWh.[41] The total impact was approximately $124,000 during the hour of maximum hourly load reduction.

Based on real-time supply curves for a representative day during the summer of 2005 and the summer peak load, a reduction of 1,000 MW would have resulted in an approximate $4 per MW LMP decrease.

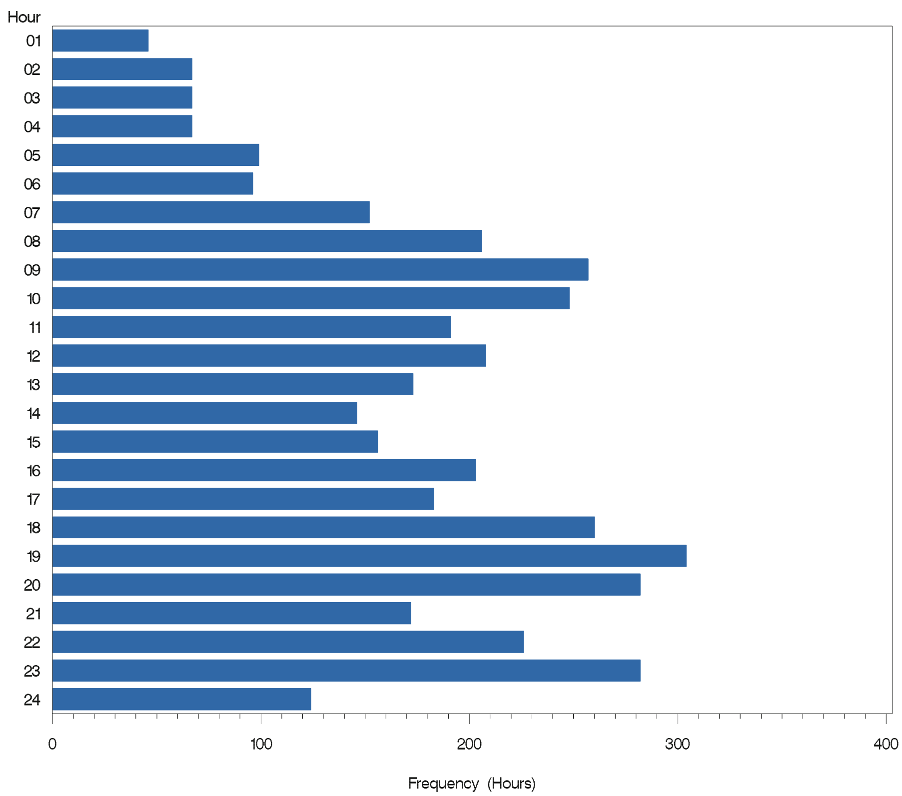
39 LMP-based customers are eligible to participate in the dispatched-in-real-time option of the program.
40 MIL is a month-by-month, year-round program for ComEd. For additional information, see Appendix H, "Glossary."
41 See Section 2, "Energy Market, Part 1," at Figure 2-1, "Average PJM aggregate supply curves: Summers 2004 and 2005."

Table 2-16 - PJM Economic Program by zonal reduction: Eleven months ended November 30, 2005

	Real time			Day ahead			Dispatched in Real Time			Totals		
	MWh	Credits	Hours	MWh	Credits	Hours	MWh	Credits	Hours	MWh	Credits	Hours
AECO	3,464.0	$300,855.08	813	0.0	$0.00	0	13.9	$3,214.75	18	3,477.8	$304,069.83	831
AEP	1,880.8	$104,605.75	227	0.0	$0.00	0	0.0	$0.00	0	1,880.8	$104,605.75	227
AP	43,357.3	$2,791,632.10	3,165	3,836.5	$823,131.70	303	315.7	$38,696.73	103	47,509.5	$3,653,460.53	3,571
BGE	7,419.7	$1,272,976.55	2,436	0.0	$0.00	0	0.0	$0.00	0	7,419.7	$1,272,976.55	2,436
ComEd	71.8	$4,052.16	183	(0.3)	$1,809.76	36	5.4	$467.14	29	76.9	$6,329.06	248
DLCO	2,718.9	$106,945.66	104	322.6	$55,878.95	14	182.5	$17,481.06	6	3,224.0	$180,305.67	124
Dominion	348.0	$35,451.81	22	0.0	$0.00	0	0.0	$0.00	0	348.0	$35,451.81	22
DPL	6,838.6	$868,445.42	1,747	32,789.3	$4,597,474.50	1,193	0.0	$0.00	0	39,627.9	$5,465,919.92	2,940
JCPL	44.8	$9,176.93	21	0.0	$0.00	0	0.0	$0.00	0	44.8	$9,176.93	21
Met-Ed	670.0	$36,819.76	720	0.0	$0.00	0	0.0	$0.00	0	670.0	$36,819.76	720
PECO	1,375.9	$224,882.91	1,105	0.0	$0.00	0	0.0	$0.00	0	1,375.9	$224,882.91	1,105
PENELEC	0.0	$0.00	0	0.0	$0.00	0	34.1	$3,695.43	29	34.1	$3,695.43	29
PPL	6,080.8	$362,615.53	504	261.7	$53,899.79	255	0.0	$0.00	0	6,342.5	$416,515.32	759
PSEG	416.4	$50,424.12	800	930.1	$233,274.64	1,005	11.1	$2,119.66	30	1,357.5	$285,818.42	1,835
RECO	3.3	$326.06	45	0.0	$0.00	0	0.0	$0.00	0	3.3	$326.06	45
UGI	0.0	$0.00	0	0.0	$0.00	0	0.0	$0.00	0	0.0	$0.00	0
Total	74,690.1	$6,169,209.84	11,892	38,140.0	$5,765,469.34	2,806	562.7	$65,674.77	215	113,392.7	$12,000,353.95	14,913
Max	43,357.3	$2,791,632.10	3,165	32,789.3	$4,597,474.50	1,193	315.7	$38,696.73	103	47,509.6	$5,465,919.92	3,571
Avg	4,668.1	$385,575.62	743	2,383.7	$360,341.83	175	35.2	$4,104.67	13	7,087.0	$750,022.12	932

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. About 33 percent of all MWh reductions, 9 percent of all payments and 28 percent of all curtailed hours under the Economic Program occurred when LMP was less than $75 per MWh. Figure 2-5 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 over hours ended 0800 EPT to 1000 EPT, 1200 EPT, 1600 EPT, 1800 EPT to 2000 EPT and 2200 EPT to 2300 EPT.

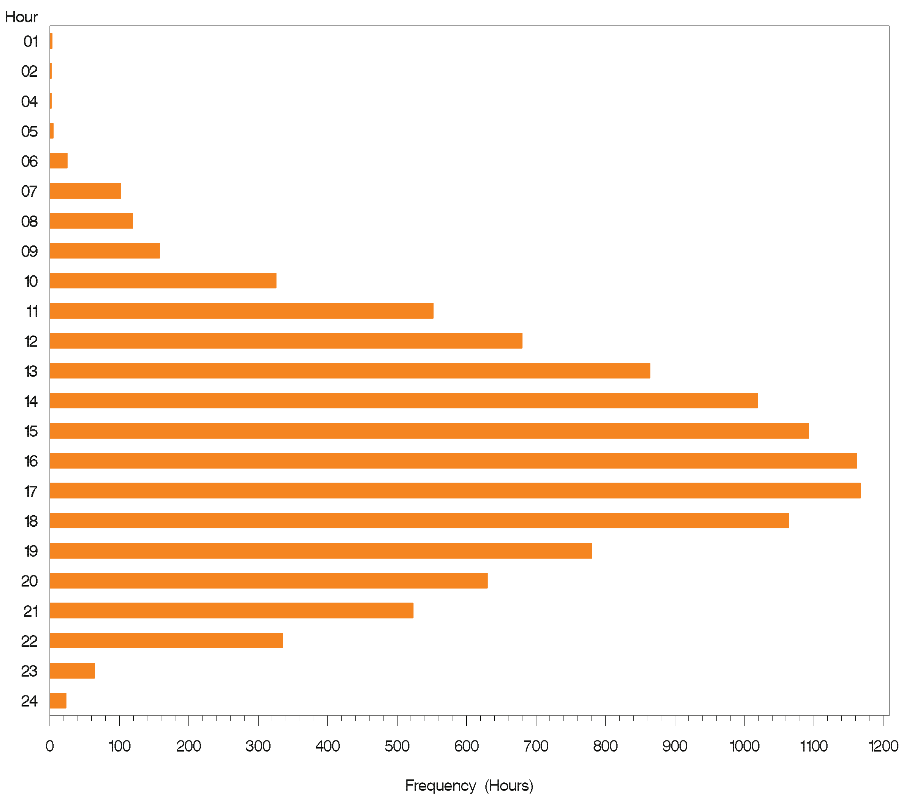
Figure 2-5 - Frequency distribution of Economic Program hours when LMP less than $75 per MWh (By hours): Eleven months ended November 30, 2005



Hour	FREQ.	CUM. FREQ.	PCT.	CUM. PCT.
01	46	46	1.09	1.09
02	67	113	1.59	2.68
03	67	180	1.59	4.27
04	67	247	1.59	5.86
05	99	346	2.35	8.21
06	96	442	2.28	10.49
07	152	594	3.61	14.09
08	206	800	4.89	18.98
09	257	1057	6.10	25.08
10	248	1305	5.88	30.96
11	191	1496	4.53	35.49
12	208	1704	4.93	40.43
13	173	1877	4.10	44.53
14	146	2023	3.46	48.00
15	156	2179	3.70	51.70
16	203	2382	4.82	56.51
17	183	2565	4.34	60.85
18	260	2825	6.17	67.02
19	304	3129	7.21	74.23
20	282	3411	6.69	80.93
21	172	3583	4.08	85.01
22	226	3809	5.36	90.37
23	282	4091	6.69	97.06
24	124	4215	2.94	100.00

Figure 2-6 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 1100 EPT to 2100 EPT, with maximum activity concentrated in hours ended 1400 EPT to 1800 EPT.

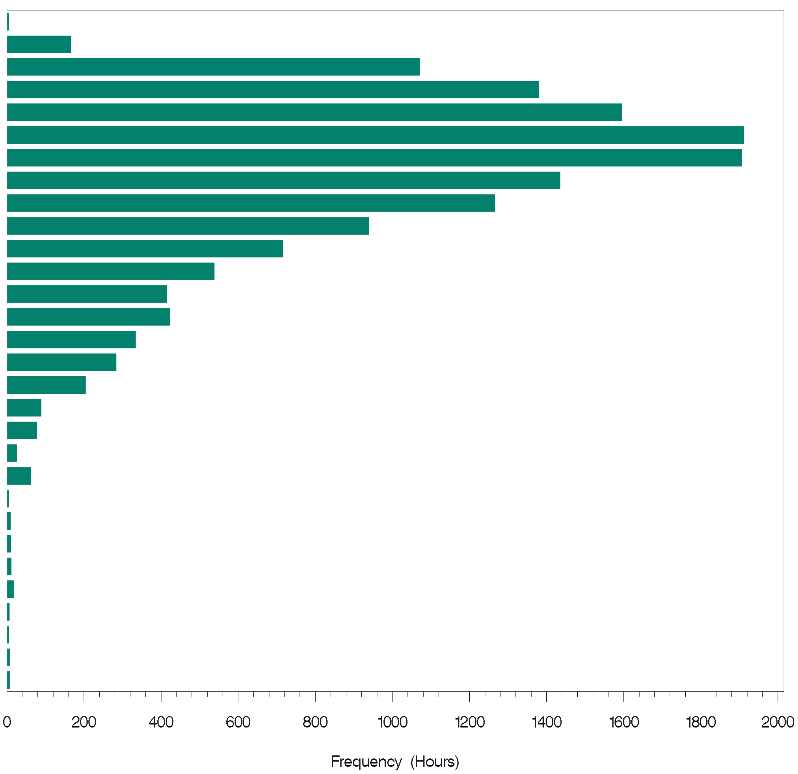
Figure 2-6 - Frequency distribution of Economic Program hours when LMP greater than or equal to $75 per MWh (By hours): Eleven months ended November 30, 2005



Hour	FREQ.	CUM. FREQ.	PCT.	CUM. PCT.
01	3	3	0.03	0.03
02	2	5	0.02	0.05
04	2	7	0.02	0.07
05	5	12	0.05	0.11
06	25	37	0.23	0.35
07	102	139	0.95	1.30
08	119	258	1.11	2.41
09	158	416	1.48	3.89
10	326	742	3.05	6.94
11	552	1294	5.16	12.10
12	680	1974	6.36	18.45
13	864	2838	8.08	26.53
14	1019	3857	9.53	36.05
15	1093	4950	10.22	46.27
16	1162	6112	10.86	57.13
17	1167	7279	10.91	68.04
18	1064	8343	9.95	77.99
19	780	9123	7.29	85.28
20	630	9753	5.89	91.17
21	523	10276	4.89	96.06
22	335	10611	3.13	99.19
23	64	10675	0.60	99.79
24	23	10698	0.21	100.00

Figure 2-7 shows the frequency distribution of Economic Program hourly reductions by real-time zonal LMP in price ranges of $15 per MWh. Activity occurred primarily when LMP was between $30 and $150 per MWh. A majority, 72 percent, of all hours in which reductions took place had an LMP greater than or equal to $75 per MWh.

Figure 2-7 - Frequency distribution of Economic Program LMP (By hours): Eleven months ended November 30, 2005



LMP ($/MWh)	FREQ.	CUM. FREQ.	PCT.	CUM. PCT.
$0 to $15	5	5	0.03	0.03
$15 to $30	166	171	1.11	1.15
$30 to $45	1070	1241	7.17	8.32
$45 to $60	1379	2620	9.25	17.57
$60 to $75	1595	4215	10.70	28.26
$75 to $90	1911	6126	12.81	41.08
$90 to $105	1906	8032	12.78	53.86
$105 to $120	1435	9467	9.62	63.48
$120 to $135	1266	10733	8.49	71.97
$135 to $150	939	11672	6.30	78.27
$150 to $165	716	12388	4.80	83.07
$165 to $180	538	12926	3.61	86.68
$180 to $195	415	13341	2.78	89.46
$195 to $210	422	13763	2.83	92.29
$210 to $225	333	14096	2.23	94.52
$225 to $240	283	14379	1.90	96.42
$240 to $255	204	14583	1.37	97.79
$255 to $270	89	14672	0.60	98.38
$270 to $285	78	14750	0.52	98.91
$285 to $300	25	14775	0.17	99.07
$300 to $315	62	14837	0.42	99.49
$315 to $330	4	14841	0.03	99.52
$330 to $345	9	14850	0.06	99.58
$345 to $360	10	14860	0.07	99.64
$360 to $375	11	14871	0.07	99.72
$375 to $390	17	14888	0.11	99.83
$390 to $405	6	14894	0.04	99.87
$405 to $420	5	14899	0.03	99.91
$450 to $465	7	14906	0.05	99.95
$480 to $495	7	14913	0.05	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.

During the 11-month period ended November 30, 2005, there was no activity under the nonhourly, metered program.

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 programs. To address this issue, PJM conducted surveys of LSEs in June 2003, June 2004 and June 2005 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 2005 PJM survey revealed that there is 3,653 MW of load in the PJM footprint that is exposed to a price signal that is a direct or indirect function of real-time prices, because of actions by state public utility commissions.

The survey results identified 1,216 MW of load that is exposed to real-time prices and an additional 2,437 MW of load that is partially exposed to real-time prices either directly or through an intermediary competitive supplier.[42] The prices paid by these retail customers are based on tariffs approved by state public utility commissions in New Jersey and Maryland or on supply contracts entered into with competitive LSEs. A total of 2,012 MW or 55 percent, take retail electric service under a rate that changes regularly to reflect current market prices. These prices change less frequently than hourly and more frequently than monthly. A total of 1,216 MW of load purchases electricity at a tariff rate tied directly to the hourly LMP. This load has chosen to pay LMP rates directly rather than to enter into a contract with a competitive supplier. The remaining 425 MW of the load pays prices determined by other contract provisions that link at least incremental usage decisions to hourly LMP prices.

The survey also identified a total of 907 MW enrolled in the programs administered by LSEs in the PJM territory. These programs provide incentives to reduce load during periods of high prices or system emergencies by means other than direct exposure to real-time LMP. Of the total, 289 MW or 32 percent was in direct load control programs under distribution LSEs that was not offered to PJM as ALM capability. Twenty-five percent or 224 MW is curtailable load. Twenty-three percent or 212 MW of load have a state approved regulated rate that provides incentives to curtail in response to market signals. Nineteen percent of the total was load that participated in the interruptible load programs of distribution LSEs and 2 percent was load subject to a distribution LSE's demand-response program and not offered to PJM as ALM capability.

The June 2005 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 exposed, at least partially, 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.

42 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 2-17. 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 2-17 - Demand-side response programs: Eleven months ended November 30, 2005

PJM Programs	MW Registered
PJM Economic Load-Response Program (rounded value)	2,210
PJM Emergency Load-Response Program (rounded value)	1,619
PJM Active Load-Management Resources	2,065
PJM ALM Resources Included in Load-Response Program	(260)
Total PJM Programs	5,634
Additional Programs Reported By Customers in PJM Survey	
MW under DSR Programs Administered by LSEs in PJM Territory	
Competitive LSEs Reported Curtailable Load	224
Distribution LSEs Reported Direct Load Control Load not in ALM	289
Distribution LSEs Reported Other Demand Response not in ALM	14
Distribution LSEs Reported Other (Price Sensitive) Regulated Retail Rate Load	212
Distribution LSEs Reported Regulated Interruptible Load	168
Total MW under DSR Programs Administered by LSEs in PJM Territory	907
MW with Full and Partial Exposure to Real-Time LMP	
Competitive LSEs Reported Load - Partial Exposure to LMP	2,012
Competitive LSEs Reported Load - Other Contract Mechanism	425
Distribution LSEs Reported LMP Based Load	1,216
Total MW with Full and Partial Exposure to Real-Time LMP	3,653
Net Load, Including Survey Responses	10,194

Market Conduct

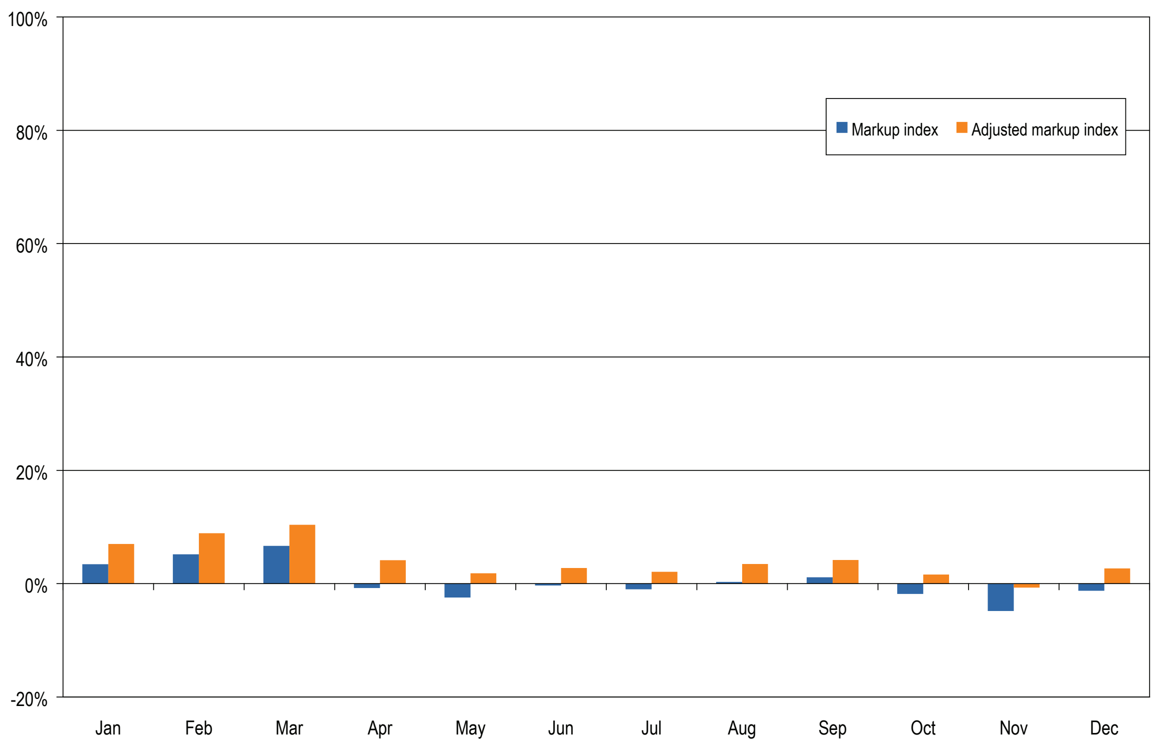
Price-Cost Markup Index

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 and marginal cost are determined by the offers of the marginal unit [The markup index = (*P* – *MC*)/*P*]. The marginal unit is the unit that sets LMP in the five-minute interval. The markup of each marginal unit is load-weighted.[43] 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.[44] (See Figure 2-8.)

PJM receives daily price and cost offers for every unit in PJM which is not exempt from offer capping. For exempt units, cost offers are estimated. The markup index is calculated for the marginal unit or units in every five-minute interval.[45]

Figure 2-8 - Load-weighted, average monthly markup indices: Calendar year 2005



43 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. Markup indices are load-weighted both within an individual five-minute interval and across intervals to determine monthly/annual averages.

44 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.

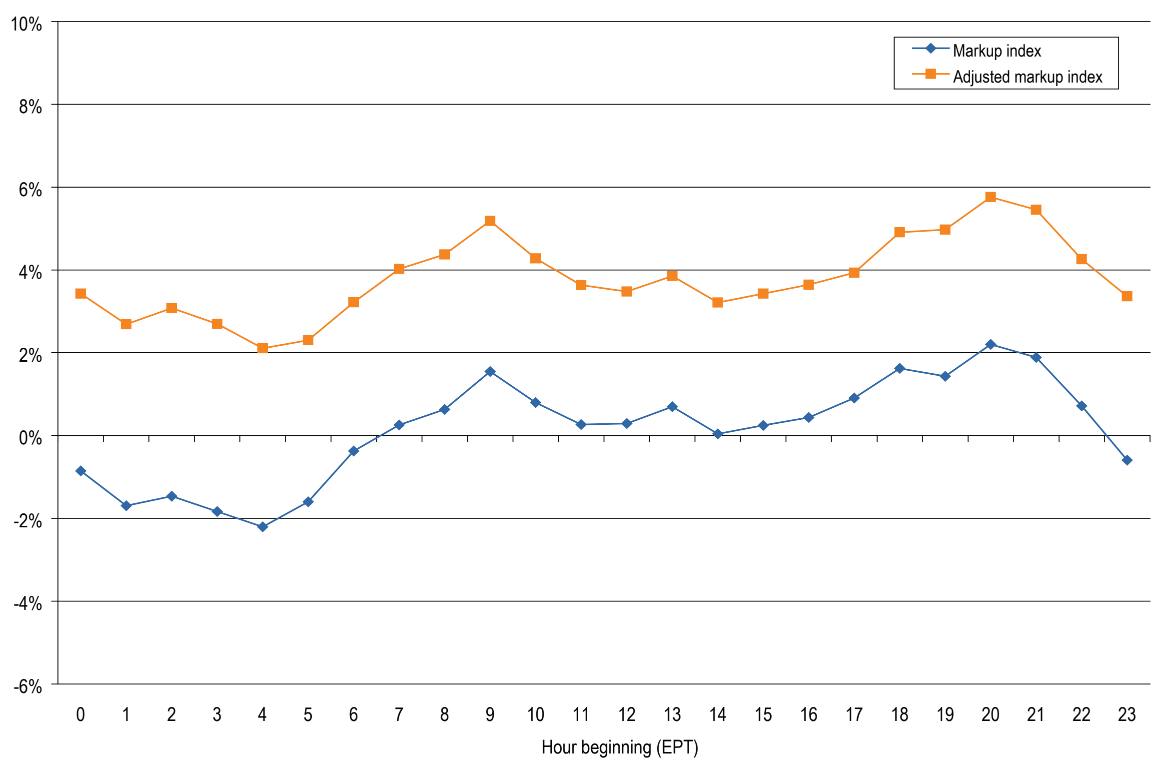
45 The markup indices incorporate several refinements including improvements to load weighting within and across hours.

Figure 2-8 shows the average monthly markup index. The load-weighted, average markup index was 0.3 percent in 2005, with a maximum of 6.7 percent in March and a minimum of -4.8 percent in November. Generators in PJM submit cost-based offers up to defined marginal cost plus 10 percent.[46] Since most, if not all, generators submit cost-based offers including this 10 percent, the calculated markup index may be low to the extent that the submitted offers are greater than actual marginal cost. The adjusted markup index in Figure 2-8 assumes that all unit owners have included a 10 percent markup over actual marginal cost and compares price to submitted cost less the 10 percent adder. This is an extreme assumption, but provides an upper bound to the actual markup index. Given this assumption, the load-weighted, average adjusted index for 2005 was 3.9 percent, with a maximum index of 10.4 percent in March and a minimum index of -0.7 percent in November. 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 higher 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 load-weighted, 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. Observed markups in 2005 are lower than in 2004.

To illustrate the variation in markup levels in the Energy Market, the MMU analyzed the load-weighted, average markup index for each hour. Figure 2-9 shows the average markup by hour for the year. The figure shows that the markup tends to be higher during the peak hours of the day.

Figure 2-9 - Load-weighted, average hourly markup indices: Calendar year 2005



46 PJM Manual M-15, "Cost Development Guidelines," Revision 5 (August 18, 2005) 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 and not to provide a mark up over cost.

The markup calculation is based on the marginal production cost of the marginal unit and could overstate the actual markup because it does not include the marginal cost of the next most expensive unit, an appropriate scarcity rent, if any, or an opportunity cost, if any. Thus, if the marginal unit is a CT with a price offer equal to $500 per MWh and the marginal cost of the 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 by fuel type and plant type. Figure 2-10 shows the average, unit-specific markup by fuel type for marginal units. The unit markup index is calculated using price and marginal cost for the specific unit of the identified fuel type that is marginal during any five-minute interval. During 2005, unit markups ranged from -1.8 percent for coal-fired units to 10.1 percent for units burning petroleum.

Figure 2-10 - Average markup index of marginal units (By type of fuel): Calendar years 2001 to 2005

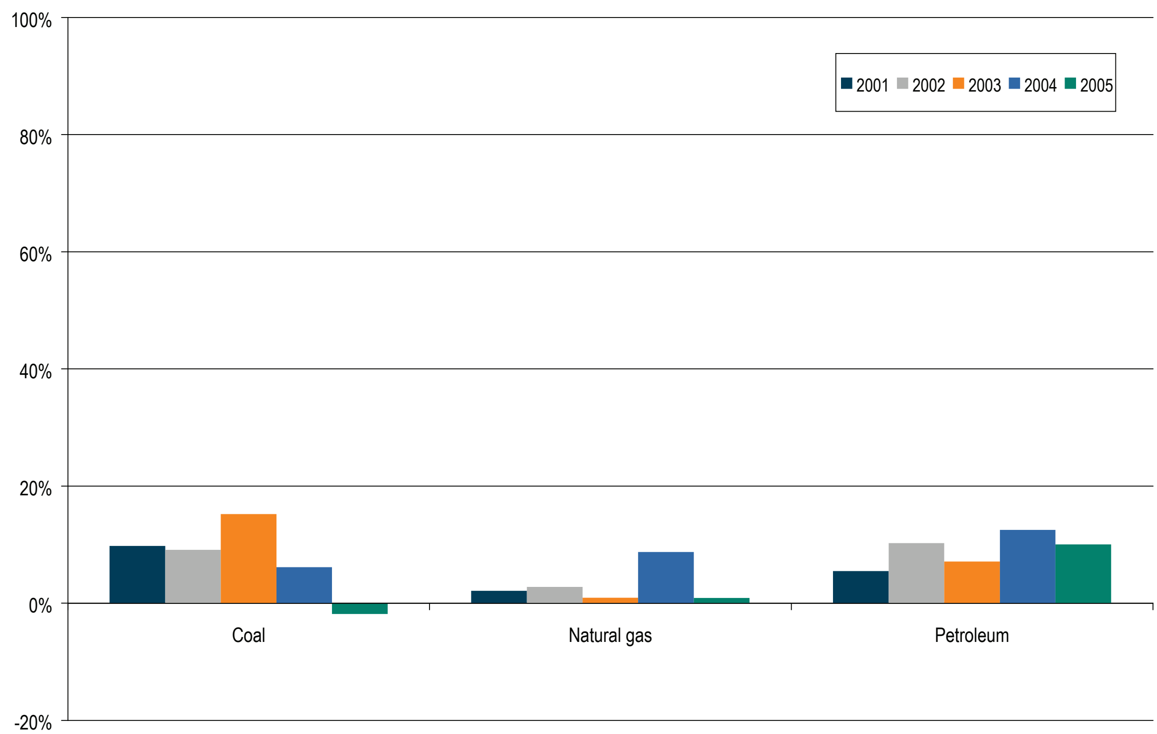


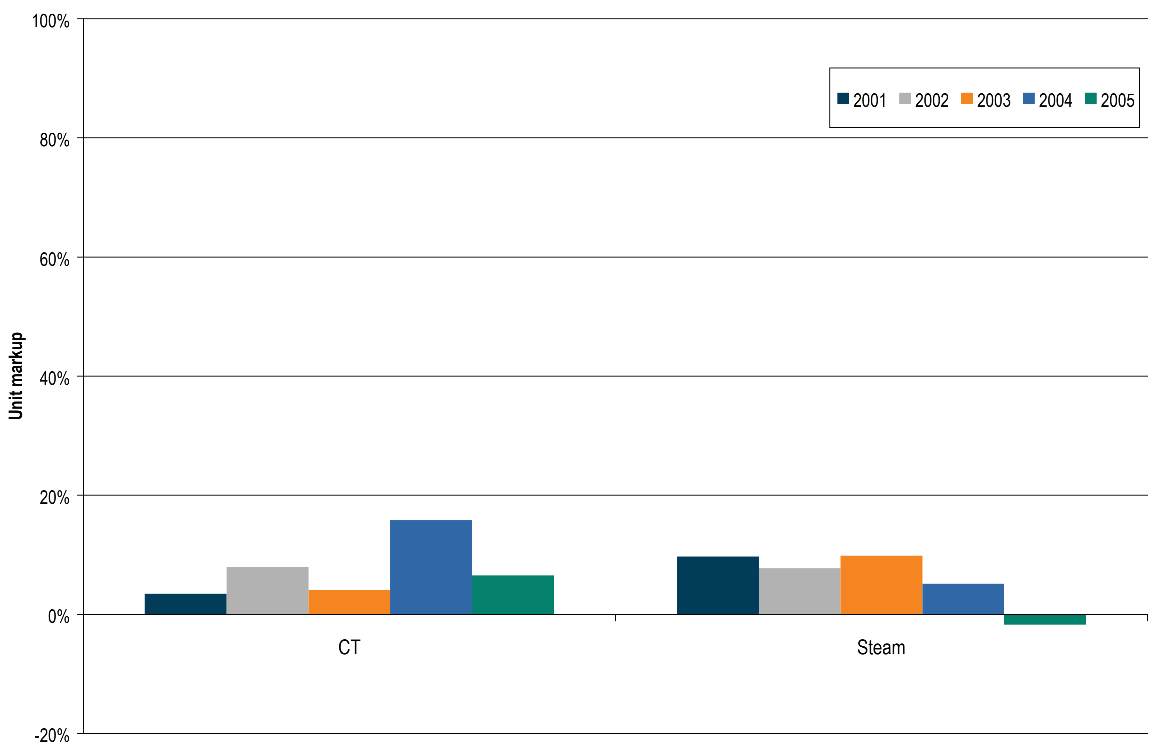
Table 2-18 shows the type of fuel used by marginal units.[47] Between 2004 and 2005, the share of coal rose from 56 percent to 62 percent; the share of natural gas decreased from 31 percent to 26 percent; the share of nuclear units held steady and the share of petroleum decreased from 12 percent to 11 percent.

Table 2-18 - Type of fuel used by marginal units: Calendar years 2001 to 2005[48]

Fuel Type	2001	2002	2003	2004	2005
Coal	49%	55%	52%	56%	62%
Misc	0%	0%	0%	0%	0%
Natural Gas	18%	23%	29%	31%	26%
Nuclear	1%	0%	1%	0%	0%
Petroleum	32%	21%	18%	12%	11%

Figure 2-11 shows the average markup index of marginal units by unit type. The markup levels reflect lower overall markups in 2005, with the average annual markup for CTs decreasing to 6.5 percent from 16 percent in 2004 and for steam units decreasing to -1.7 percent from 5 percent in 2004.

Figure 2-11 - Average markup index of marginal unit (By unit type): Calendar years 2001 to 2005



47 These percentages represent the number of times units of the specified fuel appeared on the margin versus the number of units on the margin overall. No weighting is done with respect to time or load share.

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

Table 2-19 shows the type of units on the margin from 2001 to 2005. During 2005, the marginal unit was a CT for 23 percent of the time and a steam unit for 77 percent of the time.

Table 2-19 - Type of marginal unit: Calendar years 2001 to 2005[49]

Unit Type	2001	2002	2003	2004	2005
CT	33%	26%	22%	22%	23%
Steam	67%	74%	77%	77%	77%

Overall, the markup results presented here are consistent with the conclusion that the Energy Market results were competitive in 2005.

Offer Capping

PJM has clear rules limiting the exercise of local market power.[50] 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. The offer-capping rules do not permit the offer capping of exempt units. Such exempt units can and do exercise market power, at times, that would not be permitted if the units were not exempt.

During 2005, two FERC orders modified the rules governing exemptions from the offer-capping rules.

In the January 25 order, the Commission addressed the offer-capping exemption for units whose construction had commenced on or after July 9, 1996. The Commission found "that the exemption for post-1996 units from the offer capping rules is unjust and unreasonable under section 206 of the Federal Power Act and that the just and reasonable practice under section 206 is to terminate the exemption, with provisions to grandfather units for which construction commenced in reliance on the exemption."[51] The Commission noted, however, that grandfathered units would "still be subject to mitigation in the event that PJM or its market monitor concludes that these units exercise significant market power."[52] The FERC stated: "The exemption will not apply to any unit in any PJM zone for which construction commenced after PJM submitted its proposal to remove the post-1996 exemption on September 30, 2003."[53]

In the July 5 order, the Commission modified the dates governing unit exemptions by zone.[54] These orders reduced the number of units potentially exempt from local market power mitigation from 215 to 56 as of the end of 2005.

49 Percentages for CTs include diesel units.
50 See "PJM Operating Agreement, Schedule 1," Section 6.4.2.
51 110 FERC ¶ 61,053 (2005).
52 110 FERC ¶ 61,053 (2005).
53 110 FERC ¶ 61,053 (2005).
54 112 FERC ¶ 61,031 (2005).

Despite regulatory changes, levels of offer capping have generally been quite stable over the past few years, as shown in Table 2-20.

Table 2-20 - Annual offer-capping statistics: Calendar years 2001 to 2005

	Real Time		Day Ahead	
	Unit Hours Capped	MW Capped	Unit Hours Capped	MW Capped
2001	2.8%	1.0%	2.8%	0.7%
2002	1.6%	0.3%	0.7%	0.1%
2003	1.1%	0.3%	0.4%	0.2%
2004	1.3%	0.4%	0.6%	0.2%
2005	1.8%	0.4%	0.2%	0.1%

Table 2-21 through Table 2-24 show offer capping by month, including the number of offer-capped units and the level of offer-capped MW in the Day-Ahead and Real-Time Markets.

Table 2-21 - Average day-ahead, offer-capped units: Calendar years 2001 to 2005

	2001		2002		2003		2004		2005	
	Avg. Units Capped	Percent	Avg. Units Capped	Percent	Avg. Units Capped	Percent	Avg. Units Capped	Percent	Avg. Units Capped	Percent
Jan	0.5	0.1%	0.6	0.1%	0.5	0.1%	0.4	0.1%	0.4	0.0%
Feb	3.2	0.7%	0.4	0.1%	0.7	0.1%	0.2	0.0%	0.4	0.0%
Mar	6.8	1.5%	0.1	0.0%	0.1	0.0%	0.2	0.0%	0.6	0.1%
Apr	3.4	0.8%	0.7	0.1%	0.6	0.1%	0.3	0.1%	0.4	0.0%
May	2.8	0.6%	0.2	0.0%	0.3	0.0%	0.6	0.1%	0.2	0.0%
Jun	4.7	1.0%	1.4	0.3%	0.7	0.1%	1.1	0.2%	0.4	0.0%
Jul	3.8	0.8%	1.9	0.4%	1.4	0.3%	2.6	0.4%	0.9	0.1%
Aug	1.9	0.4%	4.5	0.8%	2.1	0.4%	3.0	0.4%	1.1	0.1%
Sep	5.0	1.1%	1.9	0.4%	1.1	0.2%	3.1	0.4%	0.2	0.0%
Oct	4.2	0.9%	0.4	0.1%	0.9	0.2%	0.6	0.1%	0.3	0.0%
Nov	2.1	0.5%	0.6	0.1%	0.2	0.0%	0.5	0.1%	0.2	0.0%
Dec	0.4	0.1%	0.8	0.1%	0.1	0.0%	0.5	0.1%	0.7	0.1%

Table 2-22 - Average day-ahead, offer-capped MW: Calendar years 2001 to 2005

	2001		2002		2003		2004		2005	
	Avg. MW Capped	Percent	Avg. MW Capped	Percent	Avg. MW Capped	Percent	Avg. MW Capped	Percent	Avg. MW Capped	Percent
Jan	32	0.1%	40	0.1%	37	0.1%	51	0.1%	87	0.1%
Feb	16	0.0%	30	0.1%	27	0.1%	68	0.1%	75	0.1%
Mar	101	0.3%	6	0.0%	4	0.0%	48	0.1%	58	0.1%
Apr	286	1.0%	48	0.1%	38	0.1%	41	0.1%	34	0.0%
May	286	1.0%	14	0.0%	52	0.1%	52	0.1%	14	0.0%
Jun	591	1.7%	48	0.1%	69	0.2%	49	0.1%	28	0.4%
Jul	203	0.6%	77	0.1%	132	0.3%	243	0.4%	52	0.0%
Aug	91	0.2%	106	0.2%	148	0.3%	348	0.5%	63	0.1%
Sep	332	1.0%	78	0.2%	139	0.3%	221	0.4%	13	0.0%
Oct	193	0.6%	57	0.1%	100	0.2%	34	0.0%	16	0.0%
Nov	192	0.6%	30	0.1%	21	0.1%	28	0.0%	26	0.0%
Dec	18	0.1%	25	0.1%	25	0.1%	35	0.0%	48	0.0%

Table 2-23 - Average real-time, offer-capped units: Calendar years 2001 to 2005

	2001		2002		2003		2004		2005	
	Avg. Units Capped	Percent	Avg. Units Capped	Percent	Avg. Units Capped	Percent	Avg. Units Capped	Percent	Avg. Units Capped	Percent
Jan	0.7	0.2%	1.6	0.3%	1.5	0.3%	2.7	0.4%	2.5	0.3%
Feb	0.5	0.1%	0.8	0.2%	1.5	0.3%	0.7	0.1%	1.3	0.1%
Mar	3.4	0.8%	0.4	0.1%	0.5	0.1%	0.8	0.1%	1.4	0.2%
Apr	3.3	0.8%	1.0	0.2%	0.8	0.1%	1.9	0.3%	1.2	0.1%
May	3.5	0.8%	1.2	0.2%	1.6	0.3%	5.9	0.8%	0.8	0.1%
Jun	6.5	1.5%	3.1	0.6%	2.9	0.5%	3.9	0.5%	10.0	1.0%
Jul	4.8	1.1%	8.6	1.6%	3.3	0.6%	4.7	0.7%	13.9	1.4%
Aug	8.1	1.8%	9.7	1.8%	6.3	1.1%	6.3	0.9%	13.7	1.4%
Sep	7.3	1.6%	4.1	0.8%	3.7	0.7%	4.2	0.6%	7.9	0.8%
Oct	6.9	1.5%	1.4	0.3%	1.8	0.3%	1.1	0.1%	7.9	0.8%
Nov	4.5	1.0%	1.2	0.2%	1.0	0.2%	1.1	0.1%	3.3	0.3%
Dec	1.3	0.3%	1.5	0.3%	0.8	0.1%	3.3	0.4%	4.4	0.4%

Table 2-24 - Average real-time, offer-capped MW: Calendar years 2001 to 2005

	2001		2002		2003		2004		2005	
	Avg. MW Capped	Percent	Avg. MW Capped	Percent	Avg. MW Capped	Percent	Avg. MW Capped	Percent	Avg. MW Capped	Percent
Jan	46	0.1%	90	0.3%	87	0.2%	175	0.4%	209	0.3%
Feb	7	0.0%	46	0.2%	74	0.2%	87	0.2%	145	0.2%
Mar	84	0.3%	24	0.1%	44	0.1%	76	0.2%	74	0.1%
Apr	248	0.9%	62	0.2%	29	0.1%	115	0.3%	59	0.1%
May	291	1.1%	63	0.2%	101	0.3%	257	0.5%	78	0.1%
Jun	455	1.4%	105	0.3%	110	0.3%	167	0.3%	652	0.7%
Jul	247	0.8%	218	0.6%	252	0.6%	332	0.6%	819	0.9%
Aug	372	1.0%	311	0.7%	294	0.7%	450	0.8%	908	1.0%
Sep	553	1.9%	177	0.5%	241	0.7%	268	0.5%	477	0.6%
Oct	571	2.1%	92	0.3%	96	0.3%	77	0.1%	337	0.5%
Nov	410	1.5%	55	0.2%	53	0.2%	110	0.2%	129	0.2%
Dec	90	0.3%	52	0.1%	44	0.1%	202	0.3%	156	0.2%

Table 2-25 through Table 2-29 show the number of generating units that met the specified criteria for total offer-capped run hours and percentage of offer-capped run hours for the year indicated.[55] For example, in 2001 three units were offer-capped for more than 80 percent of their run hours and had at least 300 offer-capped run hours. The count of units in each category includes units that also met more restrictive criteria. In this example, the three units that were offer-capped more than 80 percent of their run hours and had a total of at least 300 run hours are also included in the 200 offer-capped run hour column as well as the 100 offer-capped run hour column and the one offer-capped run hour column. Similarly in this example, the three units that were offer-capped more than 80 percent of their run hours are also included in each of the following rows as they were also offer-capped more than 75 percent, 60 percent, 50 percent, 25 percent and 10 percent of their run hours. The one offer-capped run hour column shows the total number of units meeting each percentage threshold with any offer-capped hours for the year.

Table 2-25 - 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	2	2
80%	0	0	3	3	6	8
75%	0	0	4	4	9	13
60%	0	0	4	5	11	22
50%	1	1	5	6	12	30
25%	13	15	19	20	28	72
10%	18	20	24	27	38	117

55 Data quality improvements have caused values in these tables to vary slightly from previously published results.

Table 2-26 - 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%	1	1	2	5	6	6
80%	4	4	8	15	20	20
75%	4	4	8	16	26	26
60%	4	4	10	19	32	39
50%	4	5	17	26	39	54
25%	6	7	19	28	51	122
10%	6	8	20	29	61	169

Table 2-27 - 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	0	1
80%	0	1	1	1	2	10
75%	1	2	2	5	9	18
60%	1	2	2	8	16	39
50%	1	2	2	11	21	51
25%	5	9	11	20	33	97
10%	6	10	12	23	47	150

Table 2-28 - 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
60%	5	8	13	23	34	70
50%	5	8	13	24	36	80
25%	6	10	16	30	48	128
10%	8	12	20	37	71	189

Table 2-29 - Offer-capped unit statistics: Calendar year 2005

Percentage of Offer-Capped Run Hours	2005 Minimum Offer-Capped Hours					
	500	400	300	200	100	1
90%	12	13	13	14	16	17
80%	19	26	26	33	41	53
75%	19	27	30	40	55	70
60%	20	28	35	49	75	102
50%	20	28	37	51	79	115
25%	22	39	49	66	104	194
10%	22	39	50	67	111	234

Table 2-29 shows an increase in the number of units in most categories from 2004. This can be attributed to the expansion of the PJM footprint which increased the number of units, as 2005 was the first full calendar year reflecting the impact of the 2004 integrations in addition to the phased 2005 integrations of the DLCO and Dominion Control Zones. In addition, the 2005 results reflect for the first time the inclusion of 55 units that were offer-capped when running for reactive voltage support at nuclear power plants as well as the decrease in the number of units exempt from mitigation, noted above. Table 2-20 shows that real-time offer-capping levels did not increase in 2005 as a proportion of MW although they did increase slightly as a proportion of unit hours, suggesting offer capping of smaller units, and a slight decrease in day-ahead offer capping both as a proportion of MW and of unit hours.

Structural Definition of Local Market Power

PJM's market power mitigation goals have focused on market designs that promote competition and that limit market power mitigation to situations where market structure is not competitive and thus where market design alone cannot mitigate market power. In the PJM Energy Market, this situation occurs primarily in the case of local market power.

Under existing rules, PJM suspends offer capping when structural market conditions, as determined by the three pivotal supplier test, indicate that suppliers are reasonably likely to behave in a competitive manner. The goal is to apply a clear rule to limit the exercise of market power by generation owners in load pockets, but to lift offer capping when the exercise of market power is unlikely based on the application of a market structure screen.

PJM's three pivotal supplier test represents the practical application of the FERC's market power tests in real time. The three pivotal supplier test is passed if no three generation suppliers in a load pocket are jointly pivotal. Stated another way, if the incremental output of the three largest suppliers in a load pocket is removed and enough incremental generation remains available to solve the incremental demand for constraint relief, where the relevant competitive supply includes all incremental MW at a cost of less than, or equal, to 1.5 times the clearing price, then offer capping is suspended.

Through its January 25 order, the Commission instituted a section 206 inquiry to determine whether the three pivotal supplier test needed to be revised.[56] In its July 5 order, the Commission consolidated its January 25 section 206 inquiry with a second section 206 inquiry regarding PJM's proposal to conduct competitive analyses for major interfaces and issues related to scarcity pricing in PJM. [57]

On November 16, 2005, PJM filed a settlement agreement among the parties to the proceeding (the Settlement Agreement).[58] The agreement, approved by the FERC in January 2006, resolved all issues set for hearing in the consolidated proceeding.[59]

Frequently Mitigated Units

Table 2-30 - Aggregate offer-capping statistics for FMUs: Calendar year 2005

Real-Time Percent Hours Capped	80%
Real-Time Percent MW Capped	85%
Day-Ahead Percent Hours Capped	81%
Day-Ahead Percent MW Capped	74%

Early in 2005, the FERC ordered that frequently offer-capped units be provided additional compensation as a form of scarcity pricing. An FMU was defined to be a unit that was offer-capped more than 80 percent of its run hours over the prior year. FMUs were allowed either a $40 adder to their cost-based offers in place of the 10 percent adder, or the unit-specific, going-forward costs of the affected unit as a cost-based offer.

The Settlement Agreement provided for an expansion of the definition of FMUs to include units offer-capped for 60 percent of their run hours and for a set of graduated adders associated with varying levels of offer capping. In addition, the Settlement provided for the designation of associated units (AU). This designation applies to a unit that is electrically identical to an FMU, but did not reach the target threshold. For instance, if a generating station had two identical units, one of which was offer-capped for more than 80 percent of its run hours, that unit would be designated an FMU. If the second unit were capped for 30 percent of its run hours, this unit would be an associated unit and receive the same adder as the FMU at the site.

There were a total of 40 units that met the FMU criteria in 2005 along with one AU for a total of 41 units. All the units were CTs that were located in the Phase 1 PJM footprint and are on the eastern side of the Central Interface. The designated units were permitted to include the $40 adder in their offer caps as of April 1, 2005. Table 2-30 shows summary statistics for FMUs for 2005.

56 110 FERC ¶ 61,053 (2005).
57 112 FERC ¶ 61,031 (2005).
58 *PJM Interconnection, L.L.C.,* Settlement Agreement, Docket Nos. EL03-236-006, EL04-121-000 (consolidated) (November 16, 2005).
59 114 FERC ¶ 61,076 (2006).

Market Performance: Load and LMP

Energy Market Prices

The conduct of individual market entities within a market structure is reflected in market prices. The overall level of prices is a good general indicator of market performance, although overall price results must be interpreted carefully because of the multiple factors that affect them.[60]

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 regional transmission organization (RTO). Thus, during Phases 4 and 5 of calendar year 2005, load and LMP reflect the integration of new PJM control zones as they occurred.

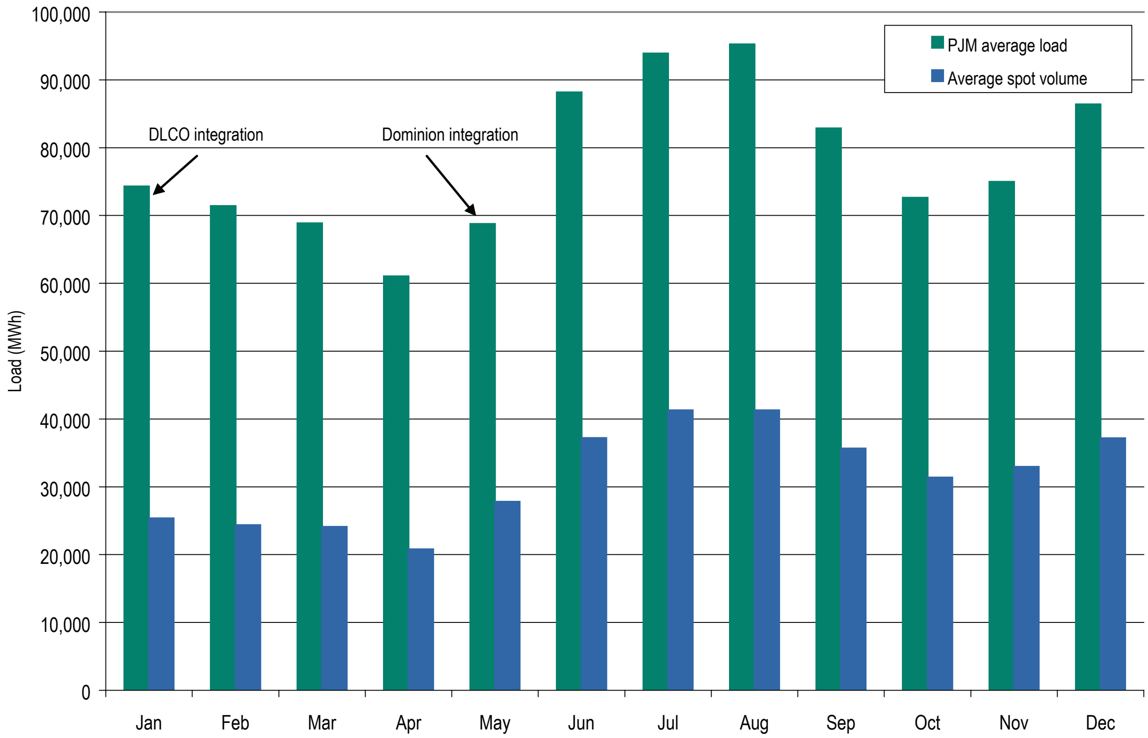
Spot Market Load and Spot Market Volume

In 2005, Real-Time Energy Market activity averaged 35,333 MW during on-peak periods, 28,226 MW during off-peak periods and 31,536 MW averaged over all hours. This represented 40.5 percent of on-peak load, 40.2 percent of off-peak load and 40.4 percent of all hours' real-time load. (See Figure 2-12.) In 2005, Day-Ahead Energy Market activity averaged 32,727 MW on peak, 25,289 MW off peak, or 28,831 MW averaged over all hours. This represented 31.9 percent of on-peak load, 30.6 percent of off-peak load and 31.3 percent of all hours' day-ahead load. 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 79.6 percent on peak and 81.3 percent off peak over 2004 levels. Total real-time load also grew in 2005 and Spot Market activity as a proportion of load in the Real-Time Energy Market increased from 35 percent in 2004 to 40 percent in 2005. Total Day-Ahead Energy Market activity increased by 85.8 percent on peak and 81.2 percent off peak over 2004 levels. Total day-ahead load also grew in 2005 and Spot Market activity as a proportion of load in the Day-Ahead Energy Market increased from 26 percent in 2004 to 31 percent in 2005.

60 See Appendix C, "Energy Market," for methodological background, detailed price data and comparisons.

Figure 2-12 - PJM average hourly load and Spot Market volume: Calendar year 2005



Real-Time Energy Market Prices

PJM Real-Time Energy Market prices increased in 2005. The simple hourly average system LMP for 2005 was 37.0 percent higher than the 2004 annual average, $58.08 per MWh versus $42.40 per MWh.[61] The simple average LMP for 2005 was higher than in all previous years since the introduction of markets in PJM. When hourly load levels are reflected, the hourly load-weighted LMP for 2005 was 43.1 percent higher than it had been for the 2004 annual average, $63.46 per MWh versus $44.34 per MWh. In 2005, the highest load levels occurred during the summer while in 2004 the highest load levels occurred in the last quarter as a result of the integrations of ComEd, AEP and DAY when LMP was relatively low.

When increased fuel costs are accounted for, the fuel-cost-adjusted, load-weighted, average LMP in 2005 was 1.5 percent higher than the load-weighted LMP in 2004, $45.02 per MWh compared to $44.34 per MWh. If fuel prices for the year 2005 had been the same as for 2004, the 2005 load-weighted LMP would have been $45.02 per MWh instead of $63.46 per MWh. This means that, if it had not been for fuel cost increases, LMP would have been only 1.5 percent higher in 2005 than in 2004.

Real-time PJM system LMP in 2005 was consistently greater than it had been during 2004 from June through the end of the year. Several factors affect LMP, including fuel prices and load. All fuel prices were higher in 2005 than in 2004. Natural gas prices were 45.6 percent higher. No. 2 (light) oil prices were 41.5 percent higher and No. 6 (heavy) oil prices were 45.6 percent higher in 2005. In addition to higher fuel costs,

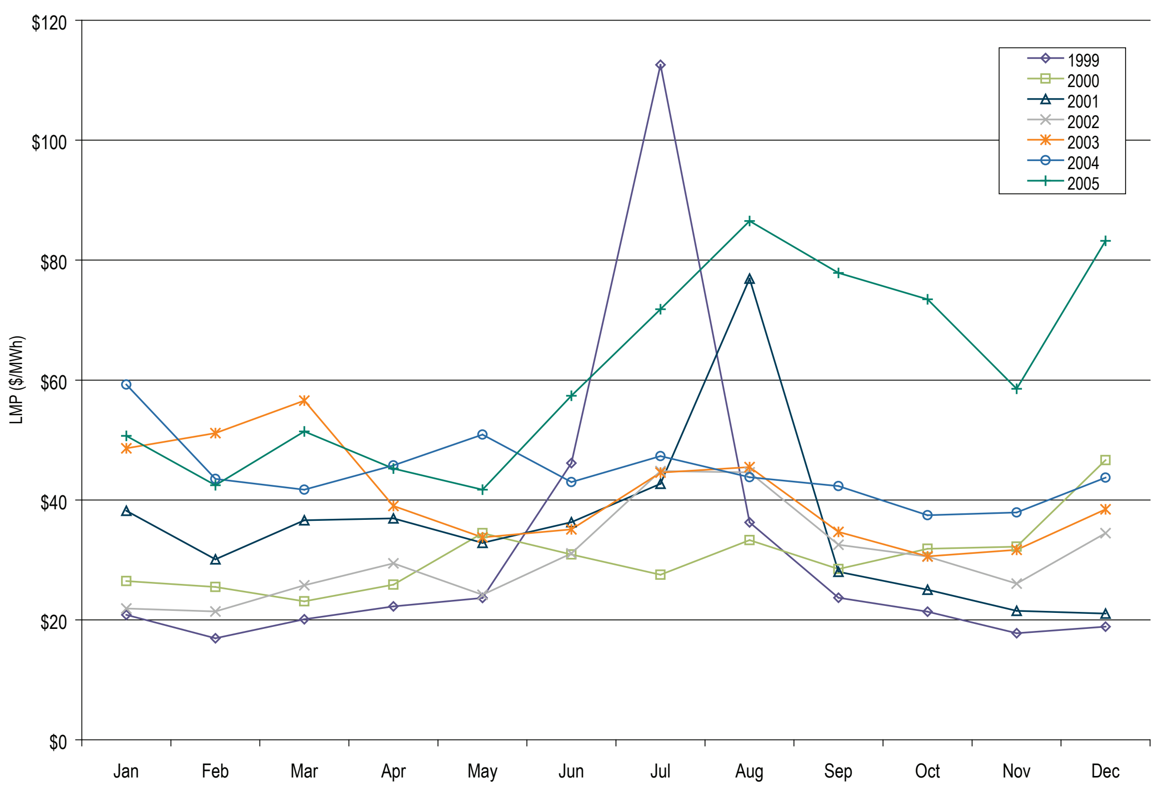
61 The simple average system LMP is the average of the hourly LMP in each hour without any weighting.

PJM load was higher in 2005 than it was in 2004 both as a result of integrations and as a result of warmer weather. Throughout the PJM footprint, the temperature-humidity index (THI) values for 2005 were higher than the THI values for 2004 indicating that the summer of 2005 was hotter than the summer of 2004.

Two principal factors contribute to higher overall LMP for 2005:

- **Fuel Prices.** Higher natural gas, oil and coal prices were a significant source of upward pressure on LMP in 2005. Figure 2-13 shows the PJM system monthly load-weighted LMP from 1999 through 2005. Figure 2-14 and Figure 2-15 show average, daily delivered coal, natural gas and oil prices for units within PJM.[62] Natural gas prices were 45.6 percent higher during 2005 as compared to 2004 with the largest differences starting in July and continuing throughout the rest of the year. No. 2 oil prices averaged 41.5 percent higher in 2005 and No. 6 oil averaged 45.6 percent higher in 2005. Higher fuel costs affect LMP when units burning those fuels are on the margin and thus setting price.[63]

Figure 2-13 - Monthly load-weighted, average LMP: Calendar years 1999 through 2005



62 Natural gas prices are the average of the daily cash price for Transco-Z6 (non-New York), Transco-Z5, Chicago Citygates and Texas Eastern-M3 and are adjusted for transportation to the burner tip. Light oil prices are the average of the daily price for No. 2 from the New York Harbor Spot Barge and from the Chicago pipeline and are adjusted for transportation. Heavy oil prices are a daily average of New York Harbor Spot Barge for 0.3 percent, 0.7 percent, 1.0 percent, 2.2 percent and 3.0 percent sulfur content. Coal prices are the average price for 1.2 and 1.5 pound sulfur content per MBtu Central Appalachian coal for prompt rail delivery and for 0.8 pound sulfur content per MBtu Powder River Basin coal for prompt rail delivery and are adjusted for transportation. All fuel prices are from Platts except for the 2004 coal data which are from Energy Argus.

63 See Table 2-18 “Type of fuels used by marginal units: Calendar years 2001 to 2005.”

Figure 2-14 - Spot coal and natural gas price comparison: Calendar years 2004 through 2005

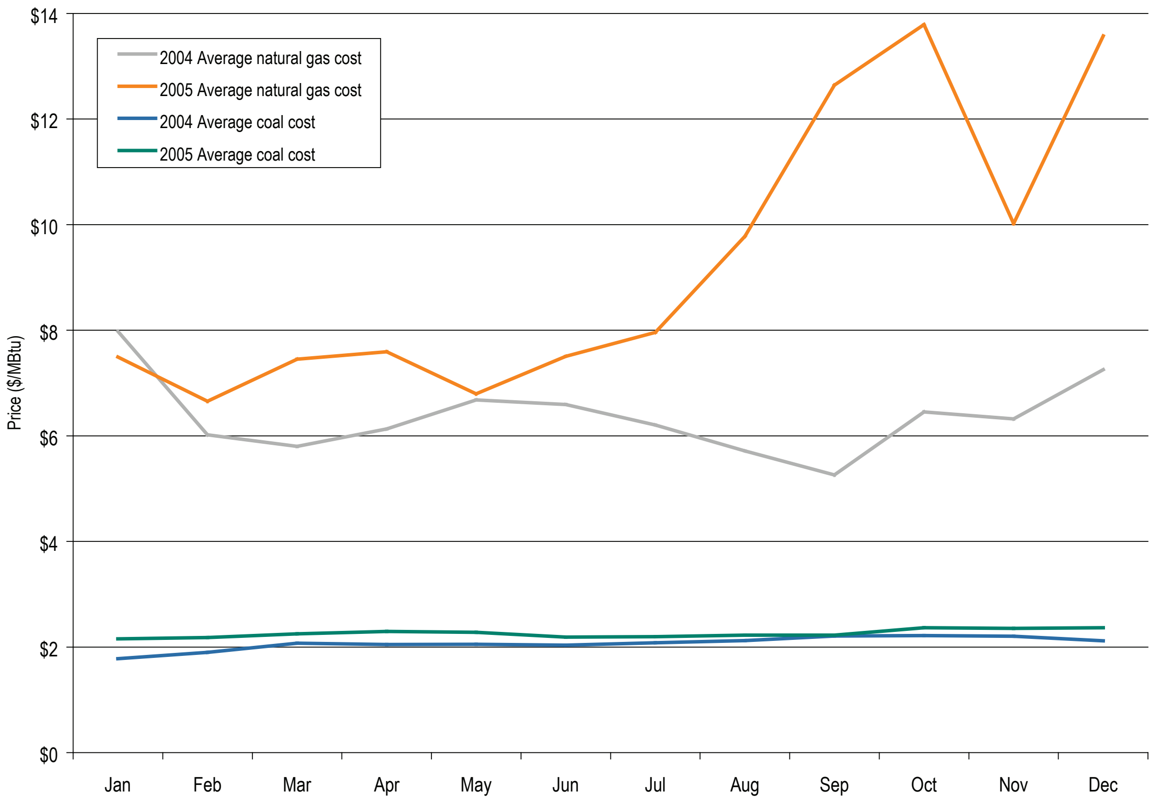
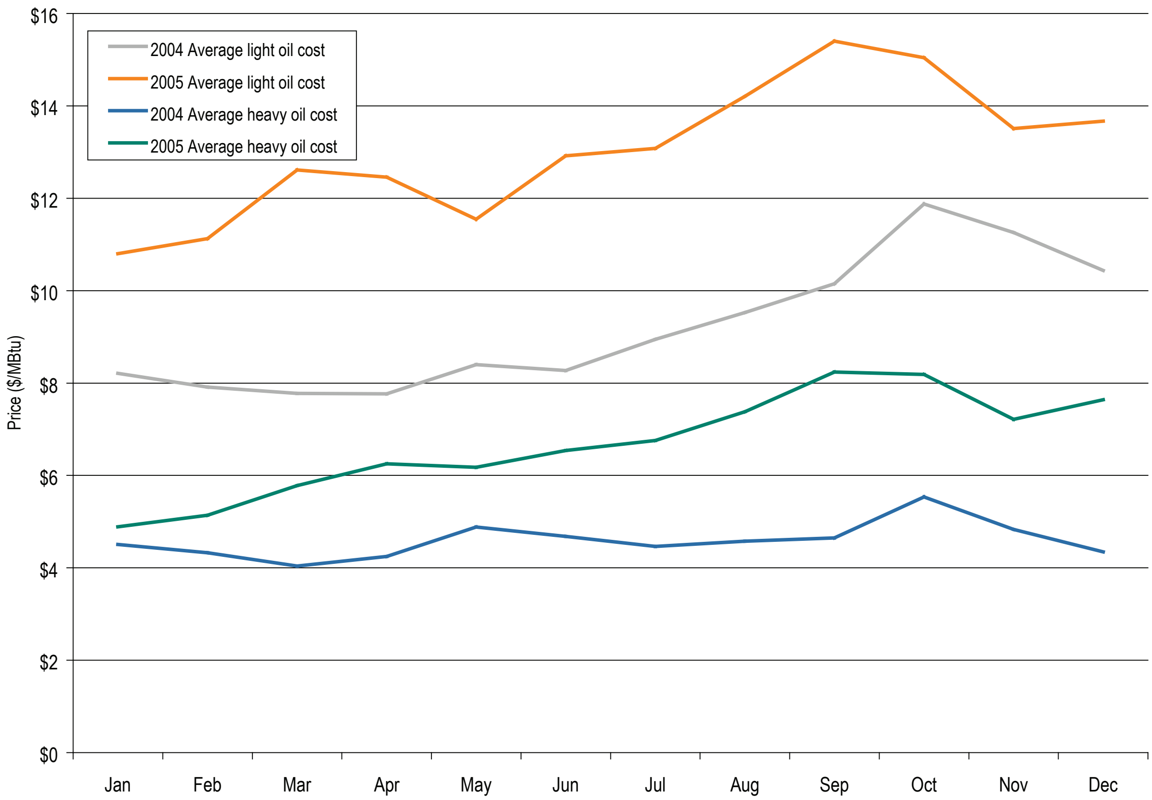


Figure 2-15 - Spot oil price comparison: Calendar years 2004 through 2005



- **Demand.** On average, PJM load increased in 2005 by 56.4 percent over the 2004 annual load primarily because of integrations and higher weather-related summer loads in 2005. Figure 2-16 shows the monthly average loads for 2004 and 2005 with and without the integrations. Figure 2-16 indicates that the 2005 PJM annual load, even without the integrations, was greater than it had been in 2004 by about 18.8 percent.

Figure 2-16 - PJM average load: Calendar years 2004 through 2005

THI is a measure of effective temperature using temperature and relative humidity. There is a correlation between THI and PJM summer load. Table 2-31 shows the monthly average of the daily maximum THI values of four representative sites within the PJM footprint: Philadelphia, Pennsylvania; Chicago, Illinois; Columbus, Ohio; and Richmond, Virginia.[64] THI is defined as follows:

temperature - .55*(1-relative humidity/100)*(temperature – 58).[65]

64 Temperature and relative humidity data that were used to calculate THI for Philadelphia, Chicago, Columbus and Richmond were obtained from Meteorlogix. See Appendix H, “Glossary,” for more detail.

65 See PJM, “Load Data Systems Manual,” Section M19, Section 3, pp. 11-16.

As Table 2-31 shows, the monthly averages of the daily maximum THI values for June, July and August within the PJM footprint were higher in 2005 than in 2004. The 2005 daily maximum THI values for June, July and August were higher than those in 2004 by 3.20 percent, 2.56 percent and 4.06 percent, respectively.

Table 2-31 - Monthly average of daily maximum THI for four representative sites

	2004	2005	Difference
May	72.12	65.58	(9.07%)
Jun	73.69	76.05	3.20%
Jul	76.54	78.50	2.56%
Aug	74.69	77.72	4.06%
Sep	72.84	74.18	1.84%

Average Hourly, Unweighted System LMP

At $58.08 per MWh, the average hourly, unweighted system LMP for 2005 was 37.0 percent higher than the annual LMP for 2004. (See Table 2-32.)[66]

Table 2-32 - PJM average hourly LMP (Dollars per MWh): Calendar years 1998 through 2005

	Locational Marginal Prices (LMPs)			Year-to-Year Changes		
	Average	Median	Standard Deviation	Average	Median	Standard Deviation
1998	$21.72	$16.60	$31.45	NA	NA	NA
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%	46.1%	10.3%
2004	$42.40	$38.30	$21.12	10.8%	24.4%	(14.5%)
2005	$58.08	$47.18	$35.91	37.0%	23.2%	70.0%

Price Duration

For 2005, PJM system prices exceeded $150 per MWh for 234 hours, and exceeded $200 per MWh for 35 hours with the maximum LMP of $286.86 per MWh occurring on July 27 during the hour ending 1400 EPT.[67]

Prices reflect the interaction of demand (in the form of energy bids) and supply (in the form of energy offers). The additional capacity provided by the 2004 integrations of the ComEd, AEP and DAY Control Zones as well as by the 2005 integrations of the DLCO and Dominion Control Zones, shifted the aggregate supply curve to the right. As a result of the fact that increases in aggregate supply exceeded increases in aggregate

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

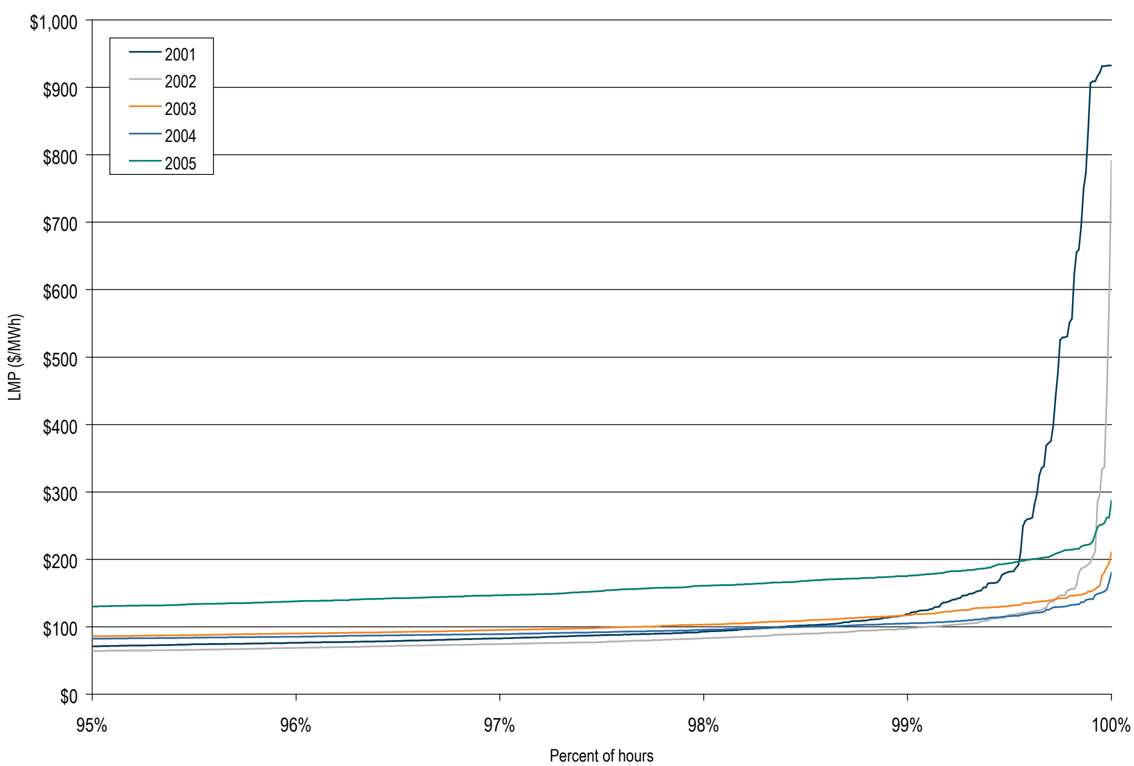
67 See Appendix C, "Energy Market," and Figure C-8.

demand, there were no hours when aggregate scarcity existed in 2005, although there were two days that exhibited regional scarcity.[68]

A price duration curve shows the percent of hours when LMP is at, or below, a given price for the year. Figure 2-17 presents price duration curves for hours above the 95th percentile from 2001 to 2005. Figure 2-17 shows that since 2001, prices have generally exceeded $100 per MWh for less than 2 percent of the hours. In the year 2001, prices exceeded $100 per MWh 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, in 2004 for 1.5 percent of the hours and in 2005 for 12.6 percent of the hours. As Figure 2-17 shows, LMPs have been less than $100 per MWh during 95 percent or more of the hours, for every year except 2005.

Figure 2-17 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. Prices in 2005 exceeded $150 per MWh for 234 hours and exceeded $200 per MWh for a total of 35 hours.

Figure 2-17 - Price duration curves for the PJM Real-Time Energy Market during hours above the 95th Percentile: Calendar years 2001 through 2005



68 For additional information, see "Scarcity" in Section 3, "Energy Market, Part 2."

Load

Table 2-33 presents summary load statistics for the eight-year period 1998 to 2005. The average load of 78,150 MWh in 2005 was 56.4 percent higher than in the 2004 annual average, reflecting the integrations of the DLCO and Dominion Control Zones and the impact of warmer summer weather.

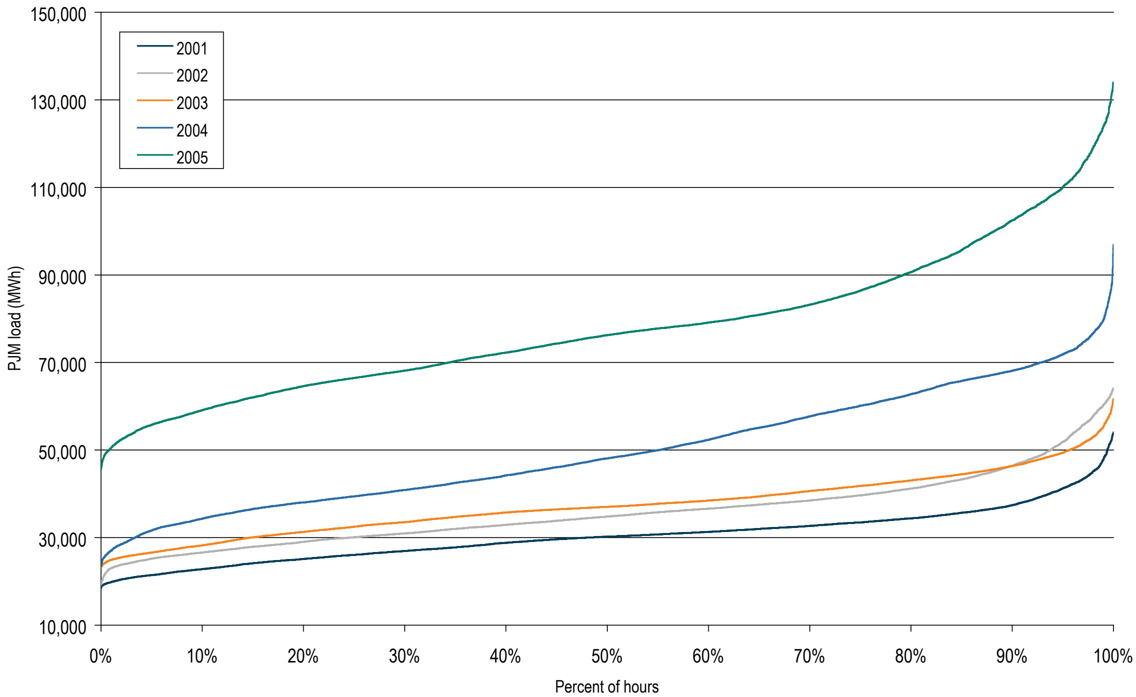
Table 2-33 - PJM average load: Calendar years 1998 through 2005

	PJM Load (MWh)			Year-to-Year Changes		
	Average	Median	Standard Deviation	Average Load	Median Load	Standard Deviation
1998	28,577	28,653	5,512	NA	NA	NA
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%
2005	78,150	76,247	16,296	56.4%	58.5%	25.3%

Load Duration

Figure 2-18 shows load duration curves from 2001 through 2005. A load duration curve shows the percent of hours that load was at, or below, a given level for the year. The 2005 load duration curve reflects the integrations of the DLCO and Dominion Control Zones as well as the impact of warmer summer weather.

Figure 2-18 - PJM hourly load duration curves: Calendar years 2001 through 2005



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. 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. When hourly prices are weighted by hourly load levels, the increase from calendar year 2004 compared to 2005 in the hourly load-weighted, average LMP was 43.1 percent while the simple average LMP increased by 37.0 percent.

As Table 2-34 shows, 2005 load-weighted LMP rose to $63.46 per MWh, 43.1 percent higher than it had been in 2004, 53.9 percent higher than in 2003 and 100.9 percent higher than in 2002.[69]

Table 2-34 - PJM load-weighted, average LMP (Dollars per MWh): Calendar years 1998 through 2005

	Load-Weighted, Average LMP			Year-to-Year Changes		
	Average	Median	Standard Deviation	Average	Median	Standard Deviation
1998	$24.16	$17.60	$39.29	NA	NA	NA
1999	$34.07	$19.02	$91.49	41.0%	8.1%	132.9%
2000	$30.72	$20.51	$28.38	(9.8%)	7.8%	(69.0%)
2001	$36.65	$25.08	$57.26	19.3%	22.3%	101.8%
2002	$31.58	$23.40	$26.73	(13.8%)	(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%)
2005	$63.46	$52.93	$38.10	43.1%	31.8%	79.3%

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 percent and 90 percent of marginal costs depending on generating technology. To account for the changes in fuel cost between 2004 and 2005, the 2005 load-weighted LMP was adjusted to reflect the changes in the price of fuels used by marginal units and the change in the amount of load affected by the price of the marginal unit.

Spot prices were used for the gas and oil fuel prices and emission costs for NO_x and SO_2 for each fuel type were calculated based on unit-specific emission rates and the spot prices for NO_x and SO_2 emission credits. The emissions costs for NO_x are applicable for the May through September ozone season and the emissions costs for SO_2 are applicable throughout the year. Coal prices were calculated based on unit-specific information and also include the costs of NO_x and SO_2 emission credit costs.

Table 2-35 compares the 2005 PJM fuel-cost-adjusted, load-weighted, average LMP to the 2004 load-weighted, average LMP. The fuel-cost-adjusted, load-weighted, average LMP for 2005 was 1.5 percent higher than load-weighed, average LMP for 2004.

Table 2-35 - PJM fuel-cost-adjusted, load-weighted LMP (Dollars per MWh): Year-over-year method

	2004	2005	Change
Average	$44.34	$45.02	1.5%
Median	$40.16	$38.75	(3.5%)
Standard Deviation	$21.25	$25.68	20.8%

69 See Appendix C, "Energy Market," for on-peak and off-peak, load-weighted LMP details.

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. Price convergence does not necessarily mean a zero or even a very small difference in price as there may be factors, from operating reserve charges to risk that result in a competitive, market-based differential. As Table 2-36, Figure 2-19 and Figure 2-21 show, day-ahead and real-time prices have converged. PJM average day-ahead prices were lower than real-time prices by $0.19 per MWh during 2005. The relationship between day-ahead and real-time prices changes from hour to hour and from year to year. In 2004, the day-ahead prices were lower than real-time prices by $0.97 per MWh. 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 2005 during Phase 4, day-ahead prices in PJM were $0.52 per MWh lower than real-time prices. During Phase 5, day-ahead prices in PJM were $0.02 per MWh lower than real-time prices. By contrast, in the DLCO Control Zone during Phase 4, day-ahead prices were greater than real-time prices by $0.03 per MWh. During Phase 5, the DLCO Control Zone day-ahead prices were greater than real-time prices by $2.25 per MWh. In the Dominion Control Zone during Phase 5, day-ahead prices were less than real-time prices by $1.97 per MWh.

Figure 2-19 shows the 2005 day-ahead and real-time price duration curves. The day-ahead prices were higher than real-time prices for 71 percent of the hours.

Figure 2-19 - PJM price duration curves for the Day-Ahead and Real-Time Energy Markets: Calendar year 2005

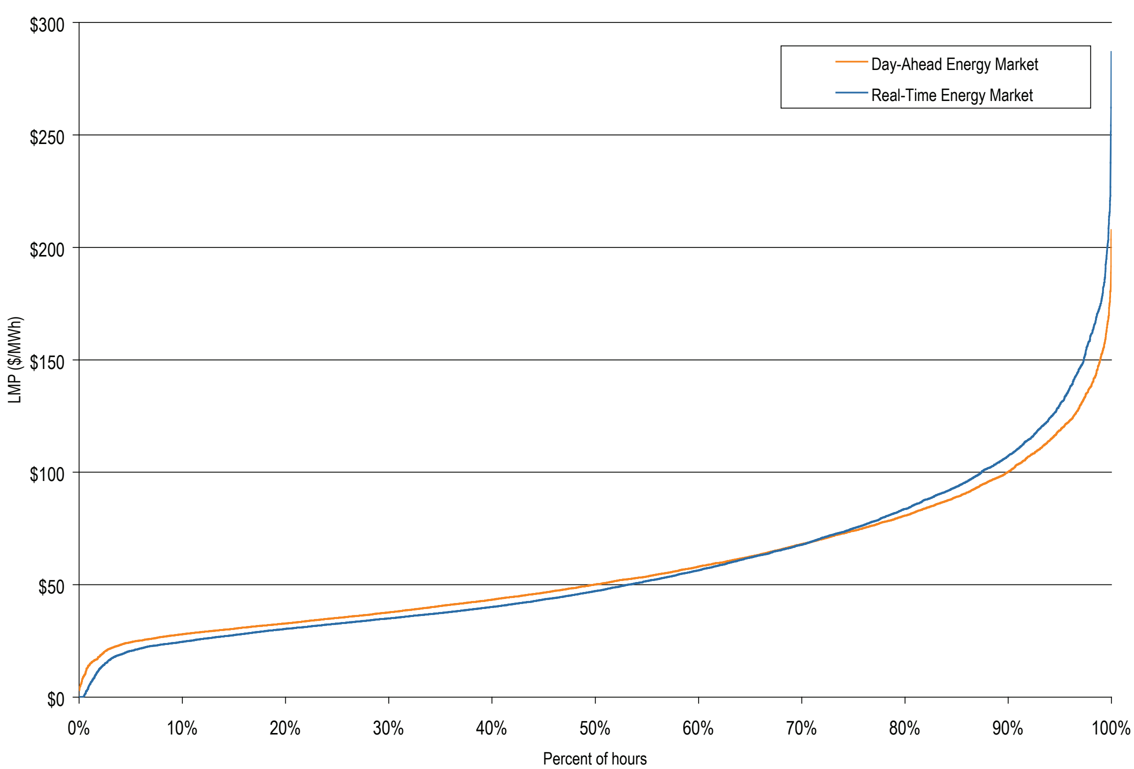


Figure 2-20 shows the hourly differences between day-ahead and real-time LMP in 2005. Although the average difference between the Day-Ahead and Real-Time Energy Markets was $0.19 per MWh for the entire year, Figure 2-20 shows considerable variation, both positive and negative, between day-ahead and real-time prices.

Figure 2-20 - Hourly real-time minus day-ahead average LMP: Calendar year 2005

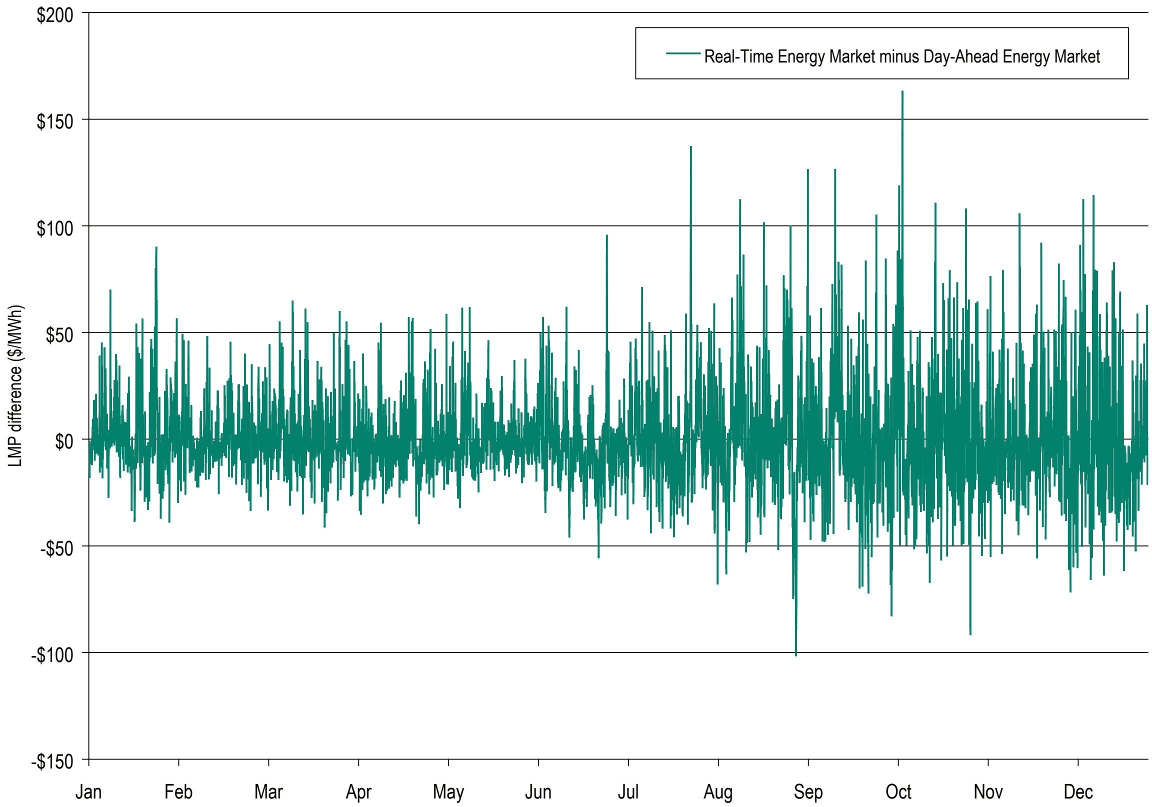
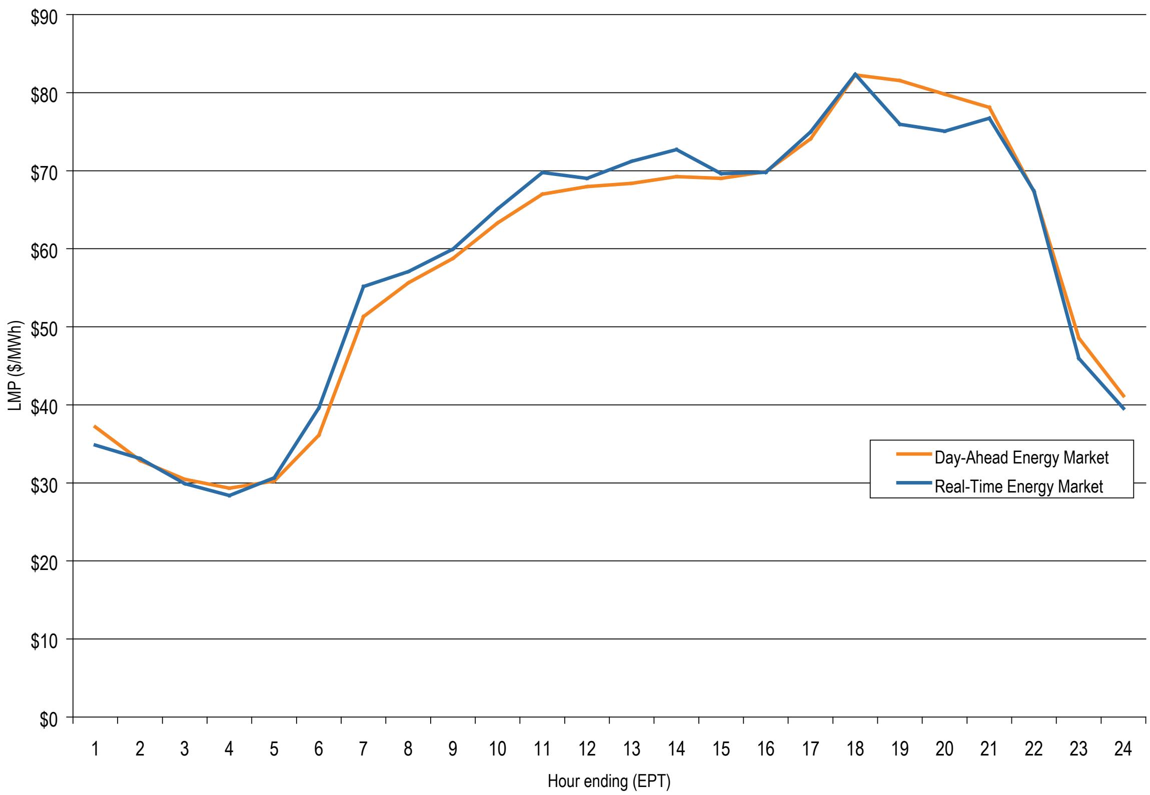


Figure 2-21 shows that average day-ahead and real-time LMPs were very close on an hourly basis, but that average real-time LMP was greater than average day-ahead LMP for 15 out of 24 hours.[70]

Figure 2-21 - PJM hourly system average LMP: Calendar year 2005



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

Table 2-36 presents summary statistics for the PJM Energy Market. During 2005, average LMP in the Real-Time Energy Market was $0.19 per MWh or 0.3 percent higher than average LMP in the Day-Ahead Energy Market. The real-time median LMP was 6.1 percent lower than day-ahead median LMP, reflecting an average difference of $2.90 per MWh. Consistent with the price duration curve, price dispersion in the Real-Time Energy Market was 16.3 percent greater than in the Day-Ahead Energy Market, with an average difference in standard deviation between the two of $5.87 per MWh.

Table 2-36 - Day-Ahead and Real-Time Energy Market LMP (Dollars per MWh): Calendar year 2005

	Day Ahead	Real Time	Difference	Difference as Percent Real Time
Average	$57.89	$58.08	$0.19	0.3%
Median	$50.08	$47.18	($2.90)	(6.1%)
Standard Deviation	$30.04	$35.91	$5.87	16.3%

Zonal LMP

Table 2-37 shows PJM's 2004 and 2005 zonal real-time average LMPs. The largest zonal increase was in the ComEd Control Zone which experienced a 56.4 percent increase over 2004 and the smallest increase was in the JCPL Control Zone which experienced a 33.9 percent increase over 2004.

Table 2-37 - Zonal Real-Time Energy Market LMP (Dollars per MWh): Calendar years 2004 and 2005

	2004	2005	Difference	Difference as Percent
AECO	$47.93	$68.17	$20.24	42.2%
AEP	$33.12	$47.36	$14.24	43.0%
AP	$41.16	$58.21	$17.05	41.4%
BGE	$44.27	$67.92	$23.65	53.4%
ComEd	$29.74	$46.50	$16.76	56.4%
DAY	$32.74	$45.95	$13.21	40.3%
DLCO	NA	$43.67	NA	NA
Dominion	NA	$73.27	NA	NA
DPL	$45.79	$65.64	$19.85	43.4%
JCPL	$49.03	$65.65	$16.62	33.9%
Met-Ed	$43.81	$64.24	$20.43	46.6%
PECO	$44.98	$65.44	$20.46	45.5%
PENELEC	$41.21	$56.55	$15.34	37.2%
PEPCO	$44.68	$69.10	$24.42	54.7%
PPL	$42.80	$63.05	$20.25	47.3%
PSEG	$49.54	$69.82	$20.28	40.9%
RECO	$46.87	$67.61	$20.74	44.3%

Table 2-38 shows the 2005 zonal day-ahead and real-time average LMPs. The difference between zonal day-ahead and real-time LMP ranged from 3.5 percent in the DLCO Control Zone, where the average day-ahead LMP was higher than the average real-time LMP, to -2.6 percent in the Dominion Control Zone, where the average day-ahead LMP was lower than the average real-time LMP.

Table 2-38 - Zonal Day-Ahead and Real-Time Energy Market LMP (Dollars per MWh): Calendar year 2005

	Day Ahead	Real Time	Difference	Difference as Percent Real Time
AECO	$68.95	$68.17	$0.78	1.1%
AEP	$47.99	$47.36	$0.63	1.3%
AP	$58.14	$58.21	($0.07)	(0.1%)
BGE	$66.88	$67.92	($1.04)	(1.5%)
ComEd	$46.94	$46.50	$0.44	0.9%
DAY	$46.83	$45.95	$0.88	1.9%
DLCO	$45.19	$43.67	$1.52	3.5%
Dominion	$71.39	$73.27	($1.88)	(2.6%)
DPL	$67.06	$65.64	$1.42	2.2%
JCPL	$65.78	$65.65	$0.13	0.2%
Met-Ed	$64.90	$64.24	$0.66	1.0%
PECO	$66.78	$65.44	$1.34	2.0%
PENELEC	$56.74	$56.55	$0.19	0.3%
PEPCO	$68.24	$69.10	($0.86)	(1.2%)
PPL	$64.14	$63.05	$1.09	1.7%
PSEG	$68.56	$69.82	($1.26)	(1.8%)
RECO	$66.30	$67.61	($1.31)	(1.9%)

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,[71] 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.[72]

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

- **Increment Offer (INC).** 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.

71 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, Part 1."

72 The definition of self-scheduled is based on documentation contained within the "PJM eMKT Users' Guide" (Revised October 2004), pp. 89-93.

Figure 2-22 shows average hourly values of day-ahead generation, day-ahead generation plus increment offers and real-time generation for 2005. Day-ahead generation is all the self-scheduled and generator offers cleared in the Day-Ahead Energy Market. During 2005, 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 2-22 - Day-ahead and real-time generation (Average hourly values): Calendar year 2005

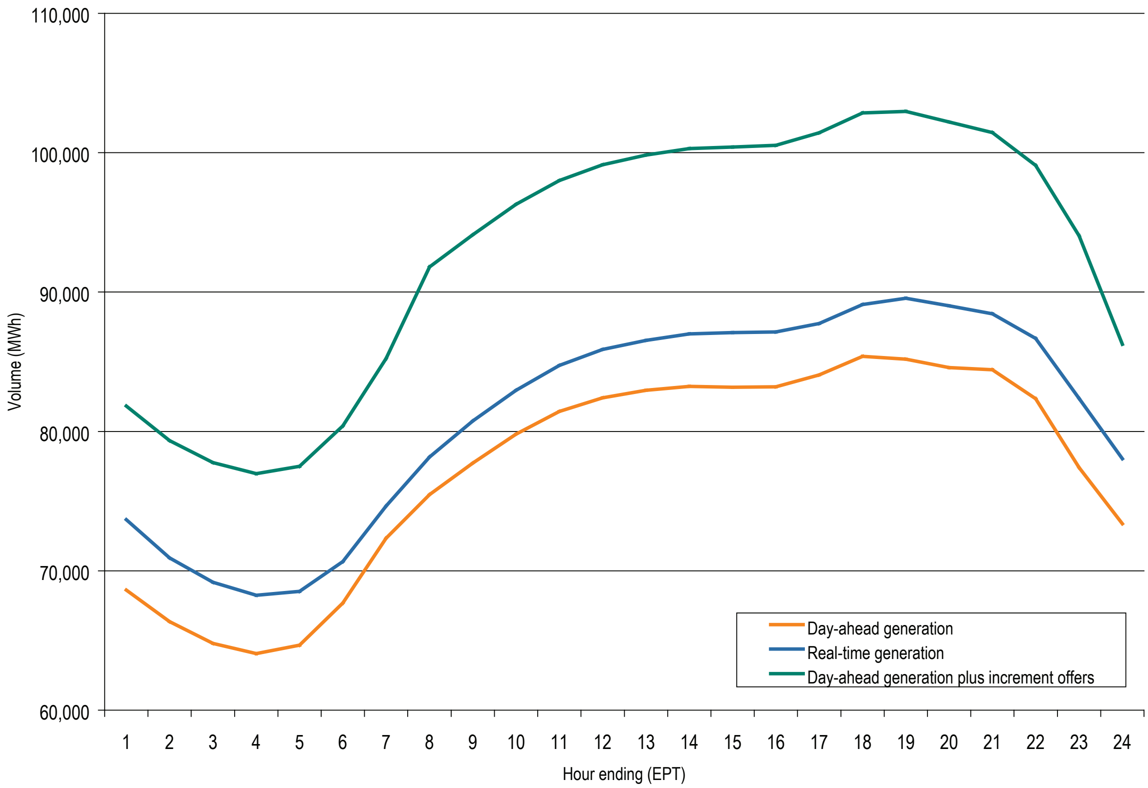


Table 2-39 presents summary statistics for 2005 day-ahead and real-time generation and the average differences between them. Day-ahead generation averaged 3,849 MWh less than real-time generation. Day-ahead generation offers plus cleared increment (INC) offers were 11,779 MWh higher than real-time generation, on average.

Table 2-39 - Day-ahead and real-time generation (MWh):[73] Calendar year 2005

	Day Ahead			Real Time	Average Difference	
	Generation	Cleared INC Offers	Generation Plus Cleared INC Offers	Generation	Generation	Generation Plus Cleared INC Offers
Average	77,278	15,628	92,906	81,127	(3,849)	11,779
Median	75,830	14,955	91,321	79,043	(3,213)	12,278
Standard Deviation	14,176	3,591	16,932	15,452	(1,276)	1,480

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 (DEC).** 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.

73 Cleared INC offers represent the offers placed at the zone and not the offers at individual buses or aggregates within the zone.

Figure 2-23 shows the average 2005 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 2-23 - Day-ahead and real-time loads (Average hourly values): Calendar year 2005

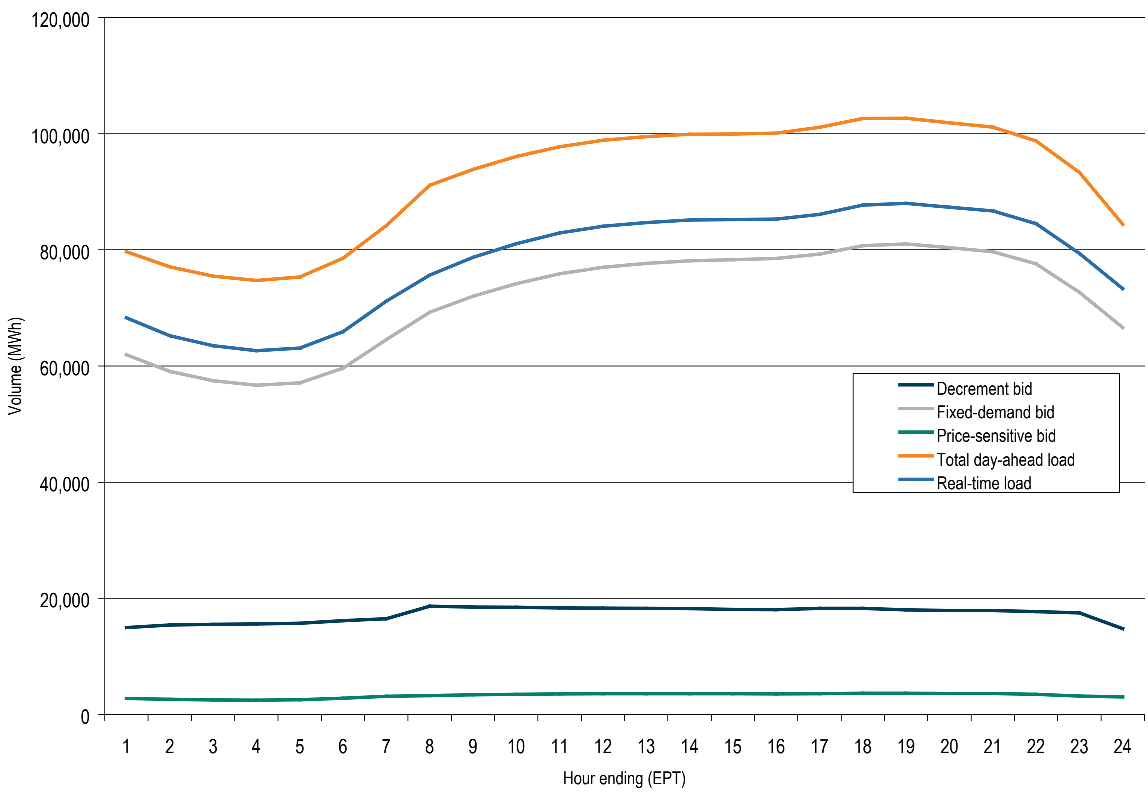


Table 2-40 presents 2005 summary statistics for day-ahead load components, total day-ahead load, real-time load and the difference between total day-ahead load and total real-time load.

Figure 2-23 and Table 2-40 show that, during 2005, total day-ahead load was higher than real-time load by an average of 13,852 MWh. The table also indicates that, at 77.7 percent, fixed demand was the largest component of day-ahead load. At 3.5 percent, price-sensitive load was the smallest component, with cleared decrement bids accounting for the remaining 18.8 percent of day-ahead load.

Table 2-40 - Cleared day-ahead and real-time load (MWh): Calendar year 2005

	Day Ahead				Real Time	
	Fixed Demand	Price Sensitive	Cleared DEC Bid	Total Load	Total Load	Difference
Average	71,469	3,246	17,287	92,002	78,150	13,852
Median	69,531	3,248	17,093	90,424	76,247	14,177
Standard Deviation	15,226	750	2,479	17,382	16,296	1,086

As Figure 2-23 shows, day-ahead load components increased during on-peak hours (i.e., hours ending 0800 EPT to 2300 EPT) as did real-time load. Table 2-41 shows average load MWh values in the Day-Ahead and Real-Time Energy Markets for 2005 during off-peak and on-peak hours. During 2005, 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.

Referring to Table 2-41, the average difference during off-peak hours was 12,446 MWh, while the average difference during on-peak hours was 15,466 MWh. The percentage of day-ahead load represented by each of the components was generally different during off-peak as compared to during on-peak periods. Fixed demand accounted for the largest percentage of day-ahead load at approximately 77 percent and 78 percent during the off-peak and on-peak periods, respectively. Price-sensitive load accounted for the smallest percentage of day-ahead load at approximately 4 percent during both the off-peak and on-peak periods. Cleared decrement bids accounted for 19 percent and 18 percent for the off-peak and on-peak periods, respectively.

Table 2-41 - Cleared day-ahead and real-time loads during off-peak and on-peak hours (MWh): Calendar year 2005

	Day Ahead								Real Time	
	Off Peak				On Peak				Off Peak	On Peak
	Fixed Demand	Price Sensitive	Cleared DEC Bid	Total Load	Fixed Demand	Price Sensitive	Cleared DEC Bid	Total Load	Total Load	Total Load
Average	63,971	2,903	15,863	82,737	80,070	3,639	18,921	102,630	70,291	87,164
Median	62,138	2,885	15,887	81,212	75,520	3,606	18,651	97,721	68,049	82,503
Standard Deviation	11,551	689	1,724	12,654	14,363	610	2,188	15,926	12,733	15,236