2003 State of the Market

Market Monitoring Unit
March 4, 2004

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 *2003 State of the Market Report* is the sixth such annual report. This report is submitted to the Board of Managers of the PJM Interconnection, L.L.C. pursuant to the PJM Open Access Transmission Tariff, Attachment M (Market Monitoring Plan):

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

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

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

Errata

PJM 2003 State of the Market Report

If this sheet is bound with the Report at page 2, relevant changes are reflected in the Report. Otherwise, the corrections described below can be found in the online version currently available at http://www.pjm.com/markets/market-monitor/som.html.

Page 101
Figure 3-7: First printing had an incorrect legend

Page 198
Figure 7-8: First printing had an incorrect graph

Page 200
Missing from first printing

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Section 1 – Introduction to the State of the Market 2003

The PJM Interconnection, L.L.C. operates a centrally dispatched, competitive wholesale electricity market comprising generating capacity of more than 76,000 megawatts (MW) and about 250 market buyers, sellers and traders of electricity in a region including more than 25 million people in all or parts of Delaware, Maryland, New Jersey, Ohio, Pennsylvania, Virginia, West Virginia and the District of Columbia.[1]

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

PJM introduced nodal energy pricing with market-clearing prices based on offers at cost on April 1, 1998, and nodal, market-clearing prices based on competitive offers on April 1, 1999. Daily Capacity Markets were introduced on January 1, 1999, and Monthly and Multimonthly Capacity Markets introduced in mid-1999. PJM implemented an auction-based FTR Market on May 1, 1999. It implemented the Day-Ahead Energy Market and the Regulation Market on June 1, 2000. PJM modified regulation market design and added a market in spinning reserve on December 1, 2002. PJM introduced an Auction Revenue Rights (ARR) allocation process and an associated Annual FTR Auction effective June 1, 2003.[2]

This report assesses the competitiveness of the Markets managed by PJM during 2003, including market structure and market performance. This report was prepared by and reflects the analysis of PJM's Market Monitoring Unit (MMU).

Conclusions

The MMU concludes that in 2003:

- The Energy Market results were competitive;
- The Capacity Market results in the PJM Mid-Atlantic Region were competitive;
- The Capacity Market results in the PJM Western Region were not based on a functioning competitive market in the PJM Western Region;
- The Regulation Market results were competitive;
- The Spinning Reserve Market results were competitive; and
- The FTR Auction Market results were competitive.

The MMU also concludes:

- There are potential threats to competition in the Energy, Capacity, Regulation and Spinning Reserve Markets that require ongoing scrutiny;
- Market power in the Capacity Markets remains a serious concern given the extreme inelasticity of demand and high levels of concentration. Market power is structurally endemic to PJM Capacity Markets and any redesign of Capacity Markets must address market power;
- The rule changes governing interface pricing have addressed significant sources of market power. Nonetheless, market participants have the ability to exercise market power at the interfaces between PJM and external regions under some conditions. Continued scrutiny of the interfaces between LMP and contract path based markets is required;
- Market participants possess some ability to exercise market power in PJM Energy Markets under certain conditions; and
- Market participants possess some ability to exercise market power in PJM Ancillary Service Markets under some conditions.

1 See Appendix A, "PJM Service Area," for map.
2 See also Appendix B, "Historic Developments in PJM Markets."

Recommendations

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

- Evaluation of additional actions to increase demand-side responsiveness to price in both Energy and Capacity Markets and actions to address institutional issues which may inhibit the evolution of demand-side price response;
- Continued development of an integrated approach to economic planning that evaluates the costs and benefits of identified alternative investments in areas where investments in transmission expansion, generation or demand-side resources would relieve congestion, especially where that congestion may enhance generator market power and where such investments are needed to support competition;
- Continued enhancements to the PJM Capacity Market to stimulate competition, adoption of a single capacity market design and incorporation of explicit market power mitigation rules to limit the ability to exercise market power in the Capacity Market;
- Development of a joint redispatch protocol with the NYISO to address loop flow issues and interface pricing issues;
- Continued development of more sophisticated methods for developing appropriate prices for transactions between PJM and external, non-market control areas to provide incentives to competitive behavior and limit loop flows;
- Retention of the $1,000 per MWh offer cap in the PJM Energy Market and other rules that limit incentives to exercise market power;
- Retention and enhancement of local market power mitigation rules to prevent the exercise of local market power while ensuring appropriate economic signals when investment is required;
- Review and appropriate modification of PJM's rules governing operating reserve payments to generators both to reduce gaming incentives and to enhance compensation under certain conditions;
- Review and appropriate modification of rules governing the reporting and verification of unit outages; and
- Based on the experience of the MMU during its fifth year and its analysis of the PJM Markets, the MMU does not recommend any additional changes to the Market Monitoring Unit or to the Market Monitoring Plan at this time.

Energy Market

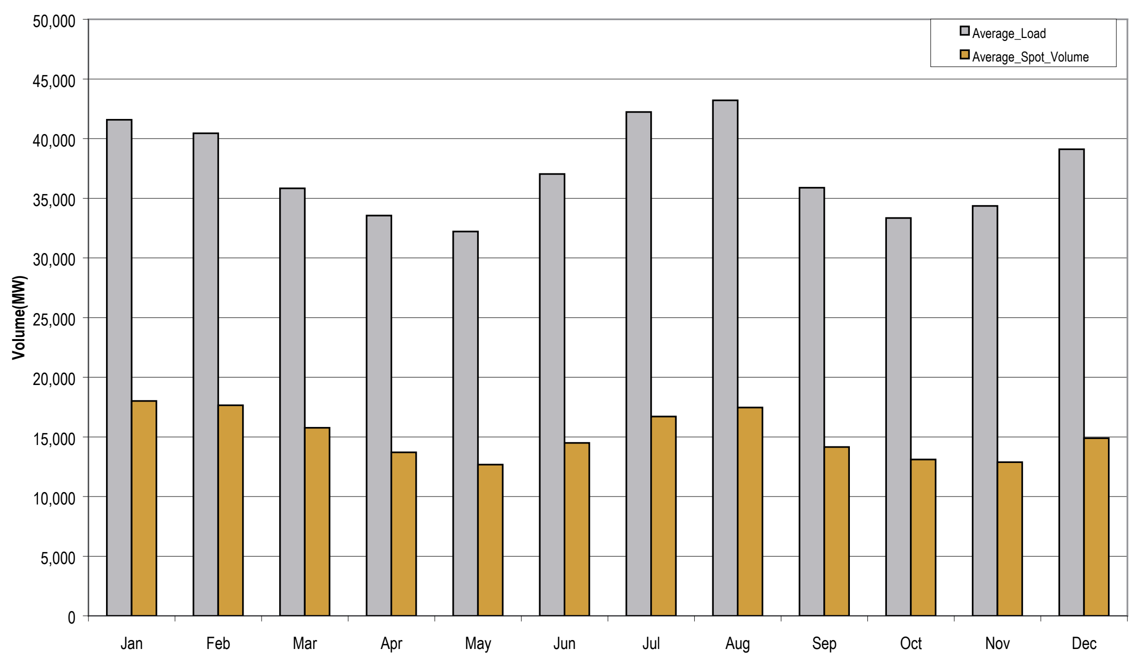
Energy Market Design

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

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

For 2003 Real-Time Spot Market activity averaged 16,194 MW during peak periods and 14,177 MW during off-peak periods, or 40 percent of average loads for all hours (Figure 1-1). In the Day-Ahead Market, spot market activity averaged 14,394 MW on peak and 12,887 MW off peak, or 31 percent of average loads for all hours. Spot market activity as a proportion of load in the Real-Time Market increased in 2003 over 2002. More participants in 2003 relied on the PJM Spot Market rather than self-supply or bilateral arrangements to clear their energy transactions. Such reliance on the Spot Market increases the importance of PJM implementing appropriate credit protections, consistent with those available to participants in bilateral transactions.

Figure 1-1 2003 PJM Average Hourly Load and Spot Market Volume



Overview

Market Structure

- **Market Size.** During the 12-month period from October 1, 2002, to September 30, 2003, approximately 5,000 MW of additional generation of which 300 MW of upgrades to existing generation and 4,700 MW of new generation were added in PJM.[3] These increases were offset in part by the derating of 100 MW of generation and the retirement of 100 MW of existing facilities. The new generation was entirely gas-fired, with most of it based on combined-cycle technology. Upgrades to existing generation included approximately 150 MW in hydroelectric, 100 MW in gas-fired and 50 MW in nuclear facilities. During this same period, approximately 100 MW of gas-fired generation was derated and another 100 MW of gas-fired generation was retired. The net result of the addition of new combined-cycle units was a flattening of the middle portion of the PJM aggregate supply curve. The PJM system peak load in 2003 was approximately 2,300 MW less than it had been in 2002.

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

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

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

Market Performance

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

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

- **Net Revenue.** Net revenue is an indicator of generation investment profitability. It is thus a measure of incentives to add generation to serve PJM Markets and a significant measure of overall market performance. Net revenue measures the contribution to capital cost that generators receive from PJM Energy and Capacity Markets, Ancillary Service Markets and operating reserve payments. In 2003, net revenue from these sources would not have covered fixed costs for a peaking unit with variable operating costs between $70 and $75 per MWh[4] if it had run during all profitable hours. Market results vary from year to year; those for 2003 reflected higher average energy and lower capacity market prices than those for 2002.

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

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

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

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

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

Mitigation

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

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

Operating Reserves

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

- Between 2002 and 2003, operating reserve payments rose by approximately $85 million from approximately $189 million to $274 million for a 45 percent increase from 2002 to 2003. Operating reserve payments as a percentage of total PJM billings remained constant at 4 percent in 2002 and 2003.

- A relatively small number of generation owners accounted for a substantial proportion of total operating reserve payments in each year from 2001 through 2003. In 2002, the top-10 units that received operating reserve payments represented 32.0 percent of total operating reserve payments and in 2003 the share of the top-10 units increased to 39.2 percent of the system total.

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

Interchange Transactions

PJM has interfaces with four contiguous, external regions. These interfaces are the seams between PJM and other regions. PJM market participants import energy from, and export energy to, external regions on a continuous basis.[5] These transactions may fulfill long-term or short-term bilateral contracts or take advantage of price differentials.

At the end of 2003, PJM's four interfaces had five interface pricing points: PJM/New York Independent System Operator (PJM/NYIS), PJM/FirstEnergy Corp. (PJM/FE), PJM/Duquesne Light Company (PJM/DLCO), PJM/AEPVP, and PJM/Ontario Independent Electricity Market Operator (PJM/IMO). The first three were in place at the beginning of the year; the last two were created in 2003 to help manage loop flow issues. In March, PJM/AEPVP was formed by combining the PJM/American Electric Power Company, Inc. (PJM/AEP) and PJM/Virginia Electric and Power Company (PJM/VAP) interfaces. On August 1, 2003, PJM/IMO was created.

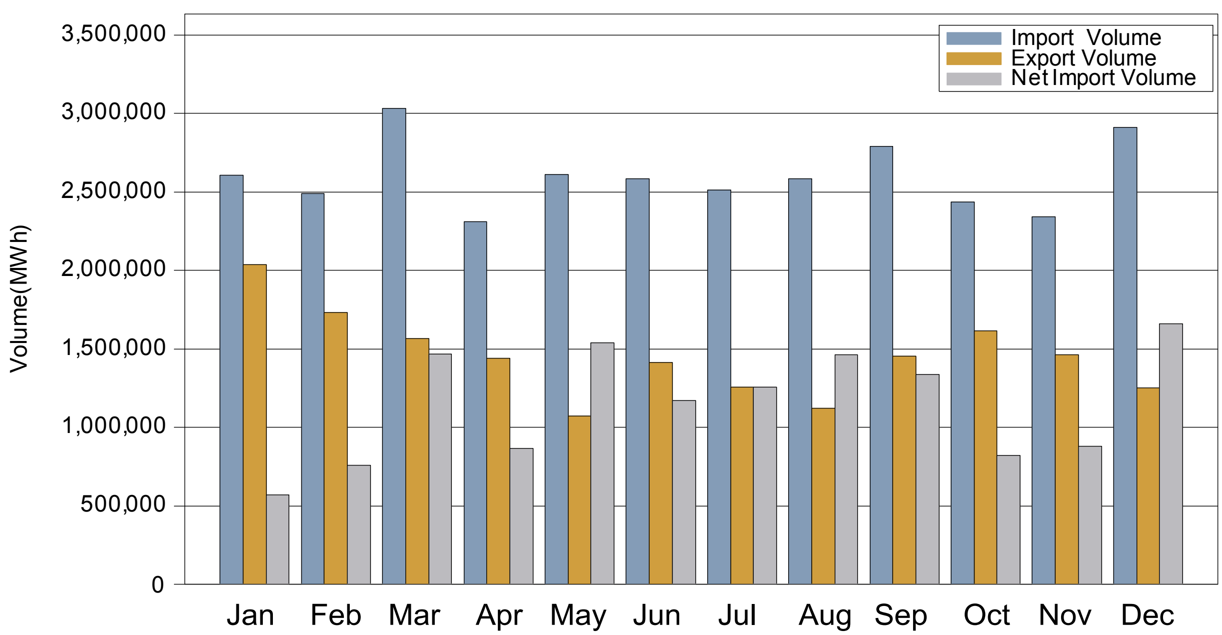
Overview

Transaction Activity

- **Aggregate Imports and Exports.** For each month of 2003, PJM was a net importer of power, averaging 1.15 million MWh of net imports per month, or slightly less than the year 2002 level of 1.23 million MWh. The 2003 average monthly gross import volume of 2.60 million MWh also represented a slight decline from 2.67 million MWh in 2002. Gross exports changed little in 2003 from 2002, averaging 1.45 million MWh in 2003 and 1.44 million MWh in 2002.

- **Interface Imports and Exports.** During 2003, net imports at two interfaces accounted for 96 percent of total net imports. Net imports at the PJM/AEPVP interface were 49 percent and net imports at the PJM/FE interface were 47 percent. Net exports occurred only at the PJM/NYIS interface.

Figure 1-2 PJM Imports and Exports: 2003



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5 These transactions occur primarily in the Real-Time Energy Market. Approximately 82 percent of total gross imports and 84 percent of gross exports take place in the Real-Time Energy Market without corresponding day-ahead transactions.

Interchange Transaction Issues

- **Loop Flow.** Loop flow results when the transmission contract path for energy transactions does not match the actual path of energy flows on the transmission system. Loop flows can arise from transactions scheduled into, out of or around the PJM system. Outside of PJM's LMP-based Energy Market, energy is scheduled and paid for based on contract path while the actual associated energy deliveries flow on the path of least resistance. Loop flows can result when a transaction is scheduled between two external control areas and some or all of the actual flows occur at PJM interfaces. Loop flows can also result when transactions are scheduled into or out of PJM on one interface, but actually flow on another. Although total PJM scheduled and actual flows were approximately equal in 2003, such was not the case for each individual interface.

- **Interface Pricing Issues.** PJM experienced continuing loop flow issues during the winter of 2002 and early in 2003 when transactions scheduled for delivery at the PJM/VAP interface actually flowed at the PJM/AEP interface. When the issue first emerged in the summer of 2002, it resulted from actions designed to exploit differences between the way in which PJM locational marginal prices (LMPs) were determined and the artificial contract paths that existed west and south of PJM. To address that problem, PJM issued updated rules in July 2002. Ongoing investigation into loop flows and circulation impacting PJM indicated, however, that further modifications were needed to the pricing rules governing external transactions. Specifically, a continuing discrepancy between scheduled and actual power flows at the PJM/AEP and the PJM/VAP interfaces worsened, particularly during the off-peak hours, late in 2002 and continued into early 2003 despite the July 2002 rule changes.[6] To address this issue, on February 24, 2003, the PJM Market Monitoring Unit (MMU) notified market participants of a rule change governing interface pricing for transactions, scheduled to and from specific control areas. The PJM/AEP and PJM/VAP interfaces were combined into a new, single, PJM/AEPVP interface. The document, "Mapping for External Transaction Pricing," was developed; it assigned specific control areas an import and export price point regardless of contract path.[7] Additionally, on August 1, 2003, PJM created the PJM/IMO interface pricing point that is applicable to transactions sourcing/sinking into IMO. This price point was added to address the fact that flows from IMO flow over both the PJM/NYIS and PJM Western Interfaces and, therefore, that neither price was appropriate for such transactions.

- **PJM and New York Transaction Issues.** The relationship between the PJM/NYIS interface price and the New York Independent System Operator (NYISO) PJM Proxy bus price appears to reflect economic fundamentals. The relationship between interface price differentials and power flows between PJM and the NYISO also appears to reflect economic fundamentals. However, both are affected by differences in institutional and operating practices in PJM and NYISO.

6 The July 2002 rule changes had mitigated the magnitude of the recurrence.

7 The language is from the current rule which was updated most recently on February 24, 2003.

Capacity Markets

Capacity Market Design

Each organization serving PJM load must own or acquire capacity resources to meet its respective capacity obligations. Load-serving entities (LSEs) can acquire capacity resources by entering into bilateral agreements or by participating in the PJM-operated Capacity Credit Markets. Collectively, all arrangements by which LSEs acquire capacity are known as the Capacity Market.[8]

The PJM Capacity Credit Market provides a mechanism 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, Monthly and Multimonthly Capacity Credit Markets. The 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.

The PJM Market Monitoring Unit (MMU) recommended in its "2002 State of the Market Report" that the PJM Mid-Atlantic and Western Regions' separate Capacity Credit Markets be combined into a single market with one set of rules. That recommendation was implemented by PJM on June 1, 2003.

Capacity Market Results

The MMU analyzed key measures of PJM Capacity Market structure and performance for 2003, including concentration ratios, prices, outage rates and reliability. The MMU found serious market structure issues, but no exercise of market power during 2003.

The PJM Mid-Atlantic Region's Capacity Market results were competitive during 2003. The PJM Western Region's Capacity Market did not operate in a meaningful way during 2003. There was not a functioning competitive market in the PJM Western Region. Beginning June 1, 2003, the two markets were combined into a single market with rules identical to those that had previously provided the operating framework for the Capacity Market in the PJM Mid-Atlantic Region alone. Inclusion of the PJM Western Region's Capacity Market in a broader capacity market is a positive step. Nonetheless, market power remains a serious concern for the MMU in the Capacity Market.

Market Structure

PJM Mid-Atlantic Region: January through May 2003

- **Supply.** Structural analysis of the PJM Mid-Atlantic Region's Capacity Credit Market found that short-term markets exhibited moderate concentration and long-term markets exhibited high concentration levels in 2003.

- **Demand.** During 2003, the original PJM Mid-Atlantic Region electric utilities and their affiliates accounted for 90 percent of the PJM Mid-Atlantic Region's load obligations.

8 See Appendix E, "Glossary," for definitions of PJM Capacity Credit Market terms..

- **Supply and Demand.** During the first interval[9] of 2003, installed capacity, unforced capacity and obligations grew in the PJM Mid-Atlantic Region. Compared to the same period of 2002, average installed capacity increased by 2,615 MW or 4.3 percent to 64,075 MW, while average unforced capacity rose by 2,467 MW or 4.2 percent to 60,960 MW. Average load obligations climbed by 2,992 MW or 5.3 percent to 59,630 MW, or 1,330 MW less than average unforced capacity. During the first interval, overall Capacity Credit Market transactions increased by nearly 22 percent. Daily Capacity Credit Market volume increased by 112 percent, while Monthly and Multimonthly Capacity Credit Market volume increased by 7.2 percent and 14.2 percent, respectively.

PJM Western Region: January through May 2003

- **Supply.** Structural analysis of the PJM Western Region's Capacity Credit Markets found extremely high concentration levels in the first interval of 2003.

- **Demand.** During the first interval of 2003, the original PJM Western Region electric utility accounted for 96.9 percent of the PJM Western Region's load obligations.

- **Supply and Demand.** In the first interval of 2003, the PJM Western Region's average installed capacity was 10,293 MW and the average available capacity was 8,482 MW. The average capacity obligation was 6,817 MW while the maximum capacity obligation was 9,002. The Capacity Credit Market was effectively not operating in the PJM Western Region during the first interval of 2003.

PJM: June through December 2003

- **Supply.** Structural analysis of the combined PJM Mid-Atlantic and Western Regions' Capacity Credit Markets found that high concentration levels were exhibited during the last two intervals of 2003.

- **Demand.** During the last two intervals of 2003, the original electric utilities in the two regions and their affiliates accounted for 85.8 percent of systemwide PJM load obligations.

- **Supply and Demand.** During the last two intervals of 2003, installed capacity, unforced capacity and obligations grew in PJM with respect to the same time period last year. Compared to the same period of 2002, average installed capacity increased by 4,774 MW or 6.5 percent to 77,728 MW. Average load obligations climbed to 70,203 MW. Overall, Capacity Credit Market transactions increased to 4,740 MW while Daily Capacity Credit Market volume increased to 1,120 MW. Monthly Capacity Credit Market volume decreased to 746 MW, but Multimonthly Capacity Credit Market volume rose to 2,874 MW.[10]

Market Performance

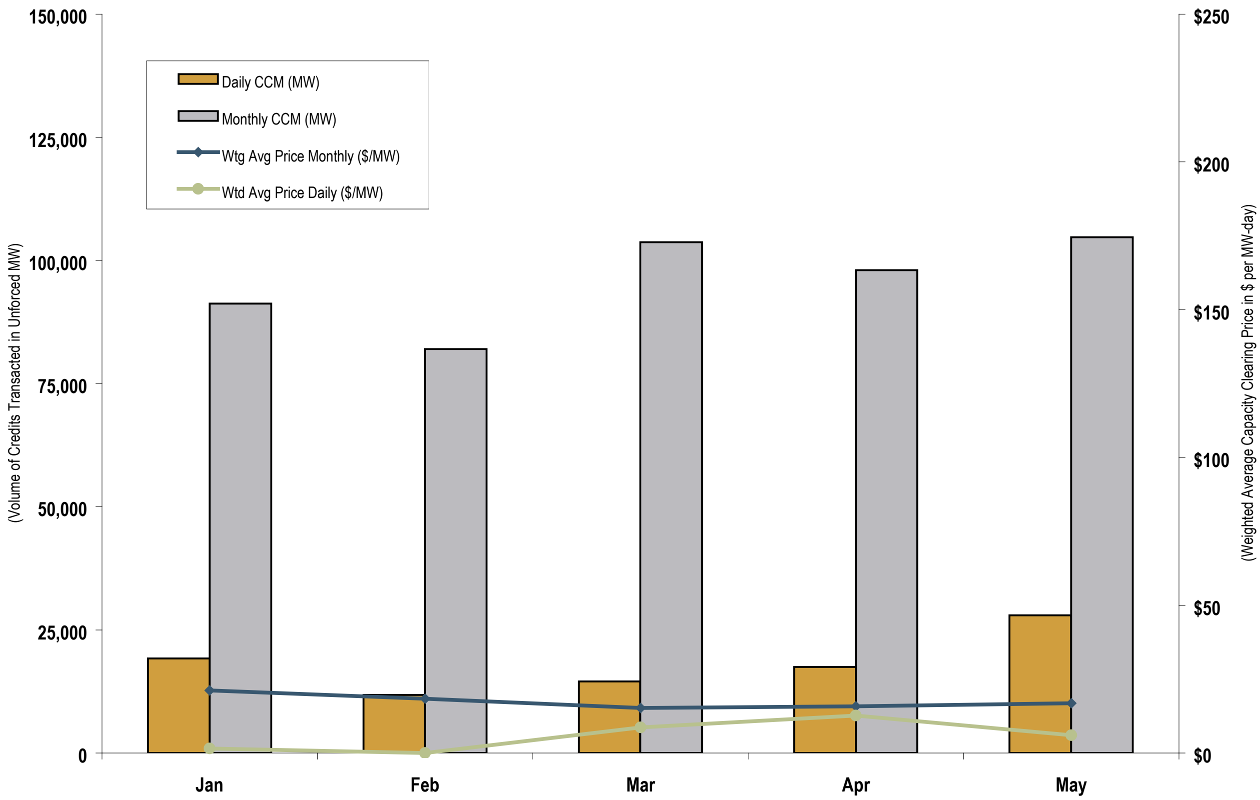
PJM Mid-Atlantic Region: January through May 2003

- **Prices.** Daily Capacity Credit Market prices were low during the first interval of 2003, averaging $6.00 per MW-day. Prices in the monthly and multimonthly markets declined slightly over the interval from $21.14 per MW-day in January to $16.87 per MW-day in May, averaging $17.36 per MW-day for the first interval (Figure 1-3).

9 PJM defines three intervals for PJM 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.

10 Since some of the measures of capacity market supply and demand were in different units for the Mid-Atlantic and Western Regions (e.g. unforced MW for the Mid-Atlantic Region and available MW for the Western Region), these measures cannot be directly compared.

Figure 1-3 PJM Mid-Atlantic Region Daily and Monthly Capacity Credit Market Performance: January through May 2003



PJM Western Region: January through May 2003

- **Prices.** Daily Capacity Market prices averaged $0.02 per MW-day. There were no trades in the monthly and multimonthly markets during 2003.

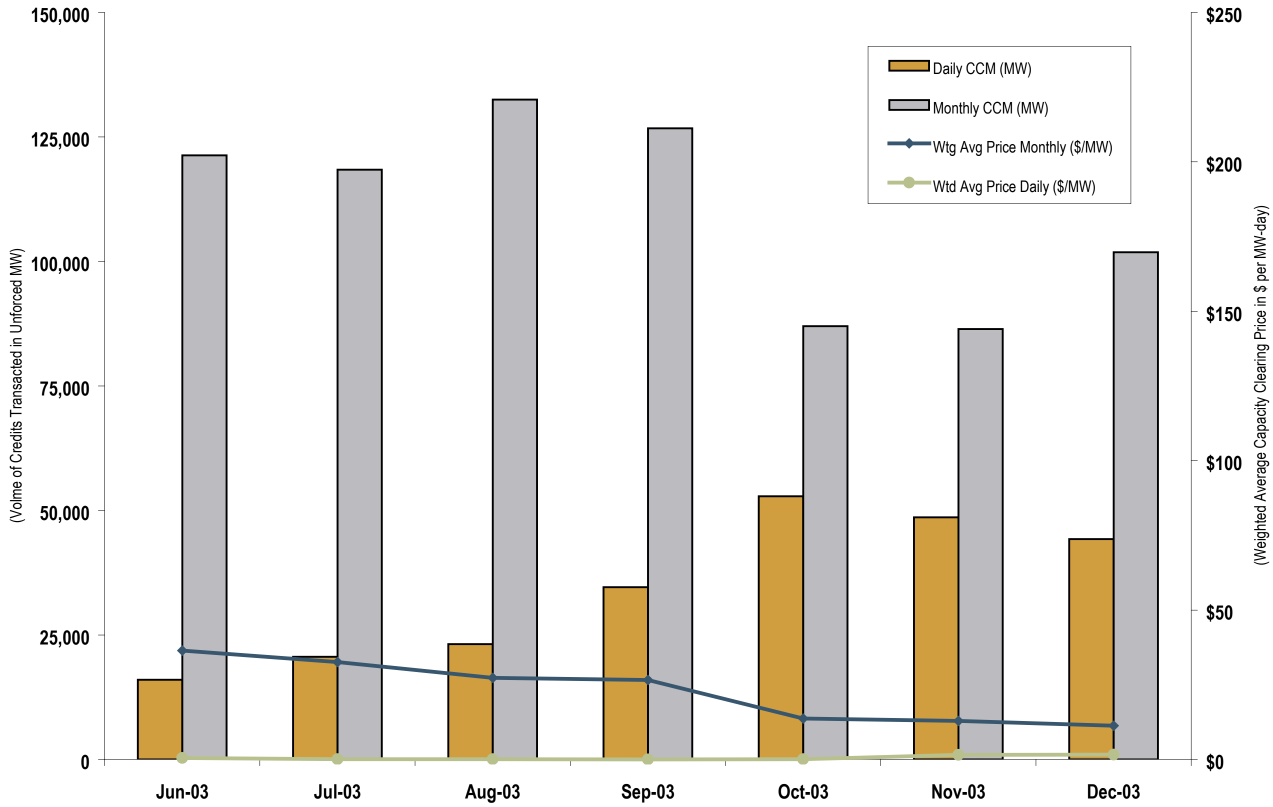
- **Volumes.** There was very little activity in the Capacity Credit Markets during the first interval of 2003. An average 0.15 MW traded in the daily market. Trades occurred on only three separate days. No trades were completed in the monthly or multimonthly markets. One very small 0.1 MW multimonthly trade from 2002 was effective through May 31, 2003.

PJM: June through December 2003

- **Prices.** Daily Capacity Credit Market prices were quite low during the last two intervals of 2003, averaging $0.68 per MW-day. Prices in the monthly and multimonthly markets declined over that period from $36.46 per MW-day in June to $11.26 per MW-day in December, averaging $24.18 per MW-day day (Figure 1-4).

- **Availability.** Between 1996 and 2001, the average PJM forced outage rate (EFORd) trended downward, reaching 4.8 percent in 2001 and then increased to 5.2 percent in 2002 and 7.1 percent in 2003. The increase in EFORd of 1.9 percent from 2002 to 2003 was the result of increased forced outage rates across all unit types.

Figure 1-4 PJM Daily and Monthly Capacity Credit Market Performance: June through December 2003



Given the basic features of Capacity Market structure in both the PJM Mid-Atlantic and the PJM Western Regions, including high levels of concentration, the relatively small number of nonaffiliated LSEs, the capacity-deficiency penalty structure facing LSEs, supplier knowledge of the penalty structure and supplier knowledge of aggregate market demand if not individual LSE demand, the MMU concludes that the likelihood of the exercise of market power is high. Market power is structurally endemic to PJM Capacity Markets. Supply and demand fundamentals offset these market structure issues in the PJM Mid-Atlantic Region's Capacity Market in 2003, producing competitive results. In the PJM Western Region's Capacity Market, the dominance of a single supplier and the extremely small load levels served by independent LSEs meant that there was not a functioning competitive market in the PJM Western Region prior to the inclusion of the PJM Western Region in the PJM Capacity Market.

Ancillary Service Markets

The United States Federal Energy Regulatory Commission (FERC) defined six ancillary services in Order 888.[11] Of these, PJM currently provides both regulation and spinning through market-based mechanisms.

Regulation matches generation with very short-term increases and decreases in load by moving the output of selected generators up and down via an automatic control signal. 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 and must be synchronized to the system and capable of providing output within 10 minutes.

The Regulation Market was introduced on June 1, 2000, and modified on December 1, 2002, at the same time the Spinning Reserve Market was implemented. Both the Regulation Market and the Spinning Reserve Market are cleared on a real-time basis.

Overview

The PJM Market Monitoring Unit (MMU) has reviewed structure and performance indicators for both the Regulation Market and the Spinning Reserve Market. The MMU concludes that both markets functioned effectively and produced competitive results in 2003.

Both the Regulation Market and the Spinning Reserve Market operate separately in the PJM Mid-Atlantic Region and in the PJM Western Region.[12] The market analysis treats each Regulation Market and each Spinning Reserve Market separately. Both the Regulation Market and the Spinning Reserve Market in the PJM Western Region are cost-based and are not competitive markets as there is only one supplier of regulation and one supplier of spinning reserve in the PJM Western Region. The Regulation Market and the Spinning Reserve Market in the PJM Mid-Atlantic Region are both based on a market-clearing price. All suppliers are paid the market price which is determined by demand and the offer of the marginal supplier. In the PJM Western Region, regulation and spinning reserve are compensated based directly on the costs of the specific units offering to provide the respective ancillary services, including opportunity costs.

Regulation Market Results

The MMU has reviewed structure and performance indicators for the Regulation Market and concludes that the Regulation Market functioned effectively and produced competitive results in 2003 (Figure 1-5).

Regulation Market Structure

- **Concentration of Ownership**. In 2003, the PJM Regulation Market saw an increase in concentration levels, although they generally remained moderate and concerns about market concentration continued to be offset by the level of available regulation supply relative to demand for the service. In the PJM Western Region, there was only one supplier.

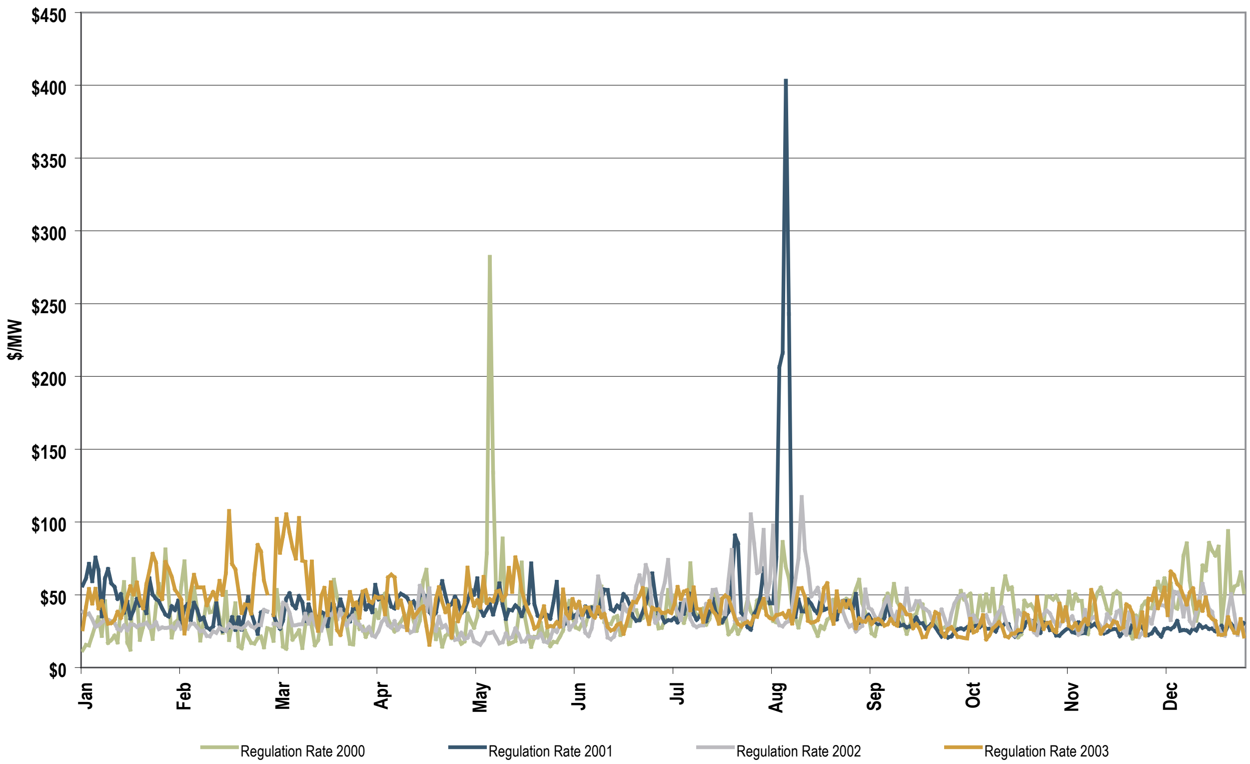
Regulation Market Performance

- **Price.** The market price of regulation exhibited the expected relationship to changes in demand and the cost of supply. Average price per MW associated with meeting PJM's demand for regulation during 2003 increased by about $5 per MW, or about 14 percent over 2002. The average cost per MW in the PJM Mid-Atlantic Region was about $45 per MW, and the average cost per MW in the PJM Western Region was about $25 per MW (Figure 1-5).

11 See FERC "Promoting Wholesale Competition through Open Access Non-Discriminatory Transmission Services by Public Utilities; Recovery of Stranded Costs by Public Utilities and Transmitting Utilities," April 24, 1996.

12 The PJM Mid-Atlantic Region is in the MAAC NERC region and the PJM Western Region is in the ECAR NERC region. MAAC and ECAR have different reliability requirements for the two services. These requirements are documented in the business rules for each market, located in the "PJM Manual for Scheduling Operations, M-11."

Figure 1-5 Daily Regulation Cost per MW



- **Availability.** Introduction of a market in regulation resulted in significant improvement in system regulation performance during 2001 and the first part of 2002. System regulation performance declined after the addition of the PJM Western Region in April 2002. However, system regulation performance was stable from December 2002 through December 2003 after the implementation of the new Regulation Market.

Spinning Reserve Market Results

The MMU has reviewed structure and performance indicators for the Spinning Reserve Market and concludes that the Spinning Market functioned effectively and produced competitive results in 2003.

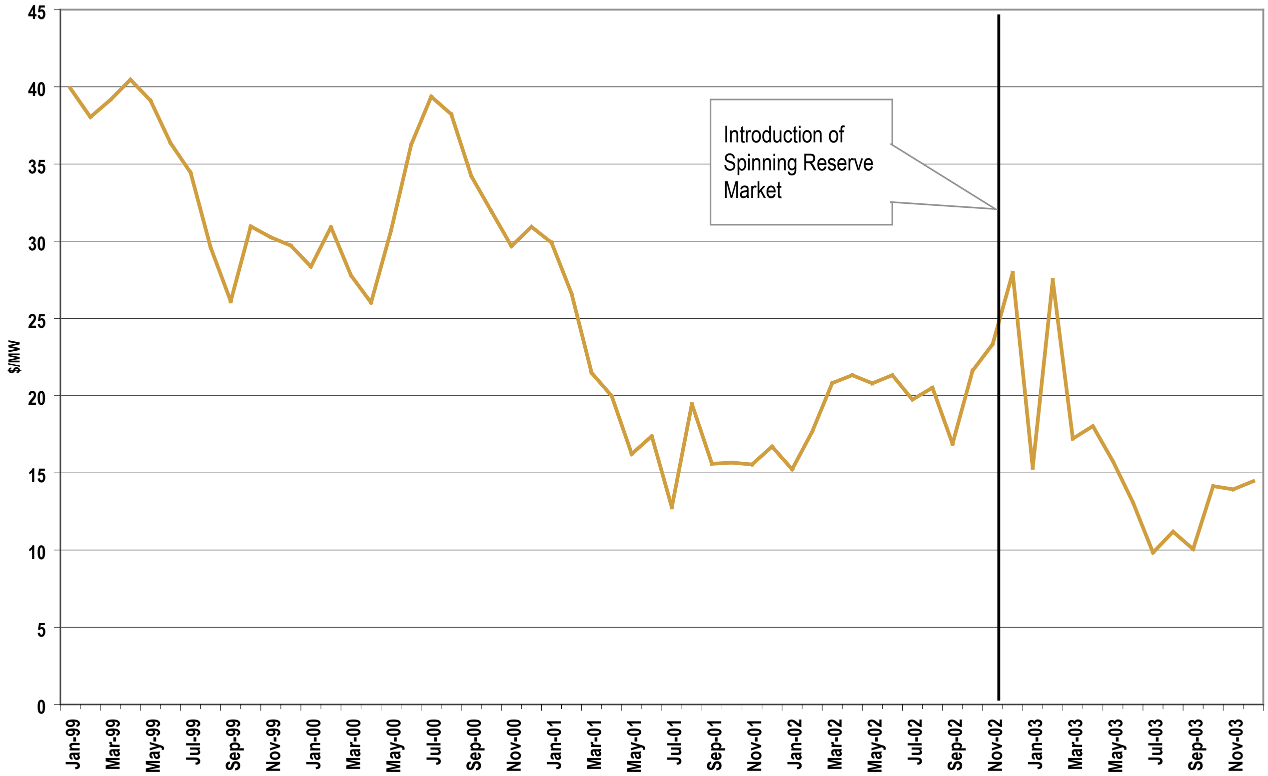
Spinning Reserve Market Structure

- **Concentration of Ownership.** In 2003, concentration was high in the Tier 2 Spinning Reserve Market. The average HHI for the PJM Mid-Atlantic Region in 2003 was 2544. In the PJM Western Region there was only one supplier.

Spinning Market Performance

- **Price.** Average cost per MW associated with meeting PJM's system demand for spinning reserve decreased about $6 per MW, or about 29 percent, in 2003 over 2002. Average cost per MW in the PJM Mid-Atlantic Region was about $15 per MW, and the average cost per MW in the PJM Western Region was about $43 per MW (Figure 1-6).

Figure 1-6 Total Spinning Credits per MW



Congestion

Congestion occurs when available, low-cost energy cannot be delivered to all loads because of limited transmission facilities. When the least cost available energy cannot be delivered to load in a transmission-constrained area, higher cost units must be dispatched to meet that load.[13] The result is that the price of energy in the constrained area is higher than elsewhere and congestion exists. Locational marginal prices (LMPs) reflect the cost 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.

Overview

- **Total Congestion.** Congestion costs were approximately $499 million in 2003, a 16 percent increase from $430 million in 2002. Congestion costs have ranged from 6 to 9 percent of annual total PJM billings since 2000. Congestion costs declined from 9 percent of total billings in 2002 to 7 percent of total billings in 2003.

- **Hedged Congestion.** Although some months had congestion credit deficiencies, excess congestion charges collected in other months offset all but $23 million of the deficiencies, and FTRs were paid at 96 percent of the target allocation level in 2003, compared to 95 percent in 2002.

- **Monthly Congestion.** Differences in monthly congestion costs continued to be substantial. In 2003, these differences were driven by loop flows, varying load and energy import levels, different patterns of generation, weather-induced changes in demand and variations in congestion frequency on constraints affecting large portions of PJM load.

- **Zonal Congestion.** LMP differentials were calculated for each PJM Mid-Atlantic Region zone to provide an approximate indication of the geographic dispersion of congestion costs. The data show some new overall congestion patterns in 2003.

- **Congested Facilities.** Both interface and transformer facilities experienced decreases in congested hours during 2003, while total congested hours on lines remained nearly unchanged from 2002 levels. There were increases in constrained hours on 230 kV lines.

- **Local Congestion.** Local congestion in the Delmarva Power & Light Company (DPL) zone continued to decrease in 2003 because of ongoing transmission reinforcement projects. Transmission reinforcements at Erie resulted in significantly less congestion in the Pennsylvania Electric Company (PENELEC) service territory and at the PJM western border. Congestion rose, however, in the Public Service Electric and Gas Company (PSEG) service territory on the Cedar Grove-Roseland 230 kV, Edison-Meadow Road 138 kV and Branchburg-Readington 230 kV lines.

- **Congestion Management Pilot.** A pilot program was conducted during the period July 11, through September 31, 2003, to measure the effectiveness of a proposed contingency management policy at reducing the incidence of off-cost operations. Analysis indicated 272 hours of avoided real-time, off-cost operations because of the new thermal emergency limits supplied under the pilot program.

Congestion associated with flows at the PJM/AEP and PJM/VAP interfaces and persistent congestion in defined areas within PJM suggest the importance of PJM's continuing efforts to improve the sophistication of its congestion analysis. Congestion analysis is central to implementing the United States Federal Energy Regulatory Commission (FERC) order to develop an approach identifying areas where investments in transmission would relieve congestion where that congestion might enhance generator market power and where such investments are needed to support competition.[14]

13 This is referred to as dispatching units out of merit order. 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.

14 96 FERC ¶61,061 (2001).

Financial Transmission and Auction Revenue Rights

In PJM, Financial Transmission Rights (FTRs) have been available to firm point-to-point and network transmission customers as a hedge against congestion charges. These firm transmission customers have had access to FTRs because they pay the costs of the transmission network that makes firm energy delivery possible. Individual firm transmission customers have received FTRs to the extent that they are consistent both with the physical capability of the transmission system and with the other firm transmission customers' requests for FTRs.

On June 1, 2003, PJM replaced the direct allocation of FTRs with an allocation of Auction Revenue Rights (ARRs) coupled with an Annual FTR Auction. The allocation of ARRs is identical to the previous process for allocating FTRs, but the value of the ARRs is based on a separate Annual FTR Auction. The ARR rules also provide that firm transmission customers are not required to take the market-based ARR value and may instead opt to take the underlying FTR via a process termed self-scheduling. ARRs provide holders with a revenue stream based on the locational price differences between ARR sinks and sources that result from the Annual FTR Auction.[15]

The Annual FTR Auction permits market participants to bid for the FTRs and thus provides a market-based determination of both ARR and FTR value. New FTR auction products were offered for the 2003/2004 planning period. These include annual and monthly FTR options, which are FTRs that, unlike traditional FTR obligations, can never be a financial liability. Additionally, 24-hour FTRs were added to the product portfolio consisting of on-peak and off-peak FTRs.

In addition to the Annual FTR Auction, PJM continues to run Monthly FTR Auctions designed to permit bilateral sales of FTRs and to permit participants to buy excess system FTRs.

Both ARRs and FTRs are financial instruments that entitle the holder to receive revenues (or pay charges) based on nodal price differences. The value of the ARRs is based on differences in nodal prices across selected paths that result from the Annual FTR Auction. The price of FTRs is determined by the auction results. The value of the FTR hedge is a function of the nodal prices in the hourly Day-Ahead Energy Market. ARR and FTR holders do not need to deliver energy to receive ARR or FTR credits, and neither instrument represents a right to the physical delivery of power. Both can, however, protect load-serving entities (LSEs) and other market participants from uncertain costs caused by transmission congestion in the PJM Day-Ahead Market. Market participants can also hedge against real-time congestion by matching real-time energy schedules with day-ahead energy schedules.

Overview

Market Structure

- **Supply and Demand.** During the 2003 ARR allocation process, 28,933 MW of ARRs were allocated, or 73 percent, out of 39,888 MW requested. Twenty percent, or 56,743 out of 279,898 MW, of buy bids for annual FTR obligations cleared. Of the cleared FTR buy bids, 25 percent were self-scheduled FTRs. Only 1 percent, or 24,175 out of 2,196,421 MW, of all buy bids for FTR options cleared. During the 2003 Monthly FTR Auctions, as in 2002, bid volume exceeded offer volume by nearly a 10:1 ratio, averaging approximately 55,000 versus 5,800 MW per month.

15 ARR values are functions of the implicit nodal price differences determined in the FTR auction since the final, optimal FTRs sold in the auction may not be identical to the ARRs.

Market Performance

- **Price.** In 2003, the $9,547 per MW-year paid for 24-hour annual FTR obligations was substantially higher than the $2,945 per MW-year paid for on-peak annual FTRs and the $1,357 per MW-year prices paid for off-peak FTRs. The overall average $3,235 per MW-year price paid for all annual FTR obligations was higher than the $1,989 per MW-year price paid for options. Prices in the 2003 Monthly FTR Auctions dropped from $369 per MW-month in 2002 to $195 MW-month in 2003, with most of the decrease occurring during the months after the June implementation of the Annual FTR Auction.

- **Volume.** Under the ARR allocation process, 28,933 MW of ARRs were allocated during the period. Introduction of the Annual FTR Auction in 2003 substantially increased the amount of long-term FTRs held by market participants. Some 32,907 MW of 24-hour, long-term FTRs were awarded, including 5,871 MW of FTRs into the Allegheny Power (APS) zone. Net of APS FTRs, these 27,036 MW of 24-hour FTRs slightly exceeded the 26,813 MW of PJM Mid-Atlantic Region FTRs held by market participants in 2002. However, an additional 28,026 MW of on-peak and 25,843 MW of off-peak FTRs were also awarded in 2003, more than doubling outstanding FTRs compared to 2002. Monthly FTR auction volume increased by 80 percent from 6,390 MW cleared in 2002 to 11,506 MW in 2003. Average monthly auction volume peaked in February 2003, with 23,188 MW of on-peak and off-peak FTRs exchanged.

- **Revenue.** During 2003, the Annual FTR Auction produced $332.8 million of net revenue, while the Monthly FTR Auction generated $22.0 million of net revenue. Average monthly auction revenue grew from $350,000 per month in 2000 to over $600,000 per month in 2001, $1.2 million per month in 2002 and $1.8 million per month in 2003.

- **Congestion Hedge.** Firm transmission customers that were allocated ARRs had $177 million of ARR credits and self-scheduled FTR target allocations and $199 million of congestion costs, a congestion hedging ratio of 89 percent. The ARR hedging shortfall was largely confined to two zones. If firm transmission customers had retained the allocated ARRs without self-scheduling FTRs, the ARRs would not have provided adequate revenue to hedge congestion fully. FTRs were paid $499 million of congestion credits against $521 million of FTR target allocations, a congestion hedging ratio of 96 percent.

A review of the operation of the 2003 FTR auction process indicates that the results were competitive and succeeded in increasing FTR access. Long-term FTR volume increased significantly via the new Annual FTR Auction, and there was a steady increase in MW of cleared FTRs in the ongoing Monthly FTR Auction. The introduction of rules explicitly providing for ARRs to track retail load shifting removes a potential barrier to competition.